David Bennett
Vice President, Regulatory Affairs
and General Counsel

FortisBC Inc.
Regulatory Affairs Department
1290 Esplanade Box 130
Trail BC V1R 4L4
Ph: 250 717 0853
regulatory@fortisbc.com
www.fortisbc.com

October 12, 2007

Via Email
Original via mail

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

Dear Ms. Hamilton:

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

Please find enclosed FortisBC Inc.'s responses to BC Utilities Commission Information Request No. 1.

Sincerely,

David Bennett
Vice President, Regulatory Affairs
and General Counsel

cc: Registered Intervenors

1.0 Reference: Application dated August 28, 2007, pp. 18-21

Q1.1 The Project and program are represented as having two main components: installations within substation sites, and server hardware and software. Please provide a separate form of Table 4 for the server hardware and software components, including the related Estimating, Engineering, Procurement and Contingency.

A1.1 The table below shows the requested information.

Item	Costs ($000s)	
	2008	2009
eDNA Data Historical System including training	56	0
Server hardware (Production + Development servers)	30	0
IT Group installation support costs	4	0
Project Management, Engineering, Estimating, Procurement	5	0
Software integration costs (internal labour)	45	33
Subtotal	**140**	**33**
Contingency: (10%)	14	3.3
Total	**$154**	**$36.3**

Q1.2 Please describe the particular hardware and software that are proposed, and explain how they are compatible with FortisBC's current computer systems.

A1.2 The server equipment would be standard hardware deployed by FortisBC (i.e. Windows 2003 Server software). It is fully consistent and compatible with the existing systems in the FortisBC Data Centre. Please refer to response A28.1 for a discussion regarding the software components.

Q1.3 Please indicate whether the software contemplated for this project is an integrated, vendor-supplied package or is to be developed in house. If the former, please describe the nature of the contract with the vendor, indicating in particular whether there are price caps and performance guarantees. In either case, please describe the risks associated with the project and its integration with other FortisBC systems, including the CMMS, and describe the risk mitigation strategies to be used.

A1.3 The software contemplated for this Program is a commercial package that is available from an established vendor (refer also to response A28.1). No contract has been let for the purchase of the software and purchase details would be subject to a formal contract following the approval of this CPCN Application. To date, a preliminary proposal has been received and reviewed for project budgeting purposes.

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.

Q1.4 Are user-defined queries of the database(s) available to selected users, or do those users have to request software enhancements through FortisBC's IT group or external contractors to obtain new views of the data?

A1.4 Queries can be developed by any user of the system using standard desktop software tools such as Microsoft Internet Explorer and Microsoft Excel.

Q1.5 What is the level of accuracy of the cost estimate for this component?

A1.5 The accuracy level of this portion of the cost estimate (response A1.1) is approximately +/- 10%.

Q1.6 What are the incremental annual operating and maintenance expenses associated with the new server hardware and software?

A1.6 The incremental annual operating and maintenance expenses for the server hardware are included in line 59 of Appendix 1.

Q1.7 Why is the expenditure for this component not covered within the annual capital expenditures budget of FortisBC?

A1.7 Annual funding for the Distribution Substation Automation project was identified in the FortisBC 2005 Revenue Requirements Application. Commission Order G-52-05 directed FortisBC to submit an application for a CPCN for this project. The expenditure is included in FortisBC's current (2007/08) Capital Expenditure Plan.

2.0 Reference: Application, pp. 11, 18-21, Appendix 1

Q2.1 The Application at page 18 states that much of the equipment installed by the program is expected to reach a 20 year lifespan. What is the expected service life of the server hardware and software? What depreciation rate(s) will FortisBC apply to this computer equipment?

A2.1 The expected lifespan of the server hardware is five years. The server software will be upgraded over time by the vendor(s) and thus has no specific lifespan. The server hardware will be depreciated at the FortisBC approved rated of 10.6% for computer equipment.

Q2.2 For the equipment under each of the following headings from Table 1, what is the expected service life and what depreciation rate will apply?

- **metering**
- **metering communications**
- **relaying**
- **RTU**
- **Communications processor**
- **Tagging switches**

A2.2 All of the above equipment will be depreciated at the approved rate of 6% for communications equipment. Please also see response A26.3. As discussed in the Application the expected lifespan of the above equipment is expected to be 15 to 20 years.

Q2.3 Please provide a form of the Appendix 1 calculation on the basis that the useful service life of the upgrade equipment is 10 years.

A2.3 Please refer to Appendix A2.3 and response A26.3 below. The Net Present Value ("NPV") in this case increases from \$1.2 to \$1.6 million and the one time equivalent rate impact from 0.05% to 0.10%.

3.0 Reference: Application, pp. 18-21

Q3.1 Table 4 indicates annual capital expenditures of about \$1.5 million per year. Please explain why these expenditures should not be funded within FortisBC's annual capital expenditure budgets.

A3.1 Please see response A1.7 above.

Q3.2 If the upgrades are not of sufficiently high priority for the expenditures to be funded from the annual capital expenditures budgets, why should they be considered to be in the public convenience and necessity on the basis of a separate Application?

A3.2 Please see response A1.7 above.

Q3.3 If the Application is denied, over what time period will the station upgrades substantially be completed as part of normal maintenance and replacements?

A3.3 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.

Q3.4 Can the Application be viewed as a proposal to accelerate the upgrade work? If so, could the justification be structured as a comparison of the net present value cost of installing the new equipment later, compared to the NPV of the benefits and savings that would result earlier from the accelerated upgrades?

A3.4 No, the Application is not a proposal to accelerate the upgrade work as the systems described are generally only present at newly constructed substations. Some legacy stations may have one or more components of the Program depending on their vintage. Generally only metering upgrades have been carried out at specific locations to replace obsolete electromechanical metering. Unless the systems described are deployed at all FortisBC distribution substations it will not be possible to achieve the full benefits of the Program.

Q3.5 If possible, please provide an economic justification for the Project in the form described in the previous question.

A3.5 As stated in response A3.4, extending the program over a much longer period would result in a different outcome. If the program was implemented over a longer interval, there would likely be changes in the technology over the span of the program. This would result in higher costs due to multiple and different designs as well as training requirements and spare stock for newer, different devices.

4.0 Reference: Application, pp. 17, 18

Q4.1 Further to the Project Schedule outlined on page 17 of the Application, please provide a more detailed schedule for the 2008 work based on the assumption that the Application is approved, which shows the completion dates for the following steps:

- **detailed scoping and estimating ±10 percent**
- **material takeoffs and vendor negotiations**
- **engineering design and procurement**
- **construction/installation**
- **testing**
- **in-service**

A4.1 Following is a preliminary schedule assuming Program approval is received in Q4 2007. Note that some tasks appear to overlap as projects would be staged for design/construction throughout the year.

- Detailed scoping/estimating and material takeoffs/vendor negotiations: January through March 2008

- Engineering design: April through August 2008
- Construction: May through October 2008
- Testing: May through November 2008
- All 2008 projects in service by December 2008

Q4.2 Assuming the Application is approved, please discuss whether the expenditures in 2009 and later years should be contingent on the satisfactory cost and benefits performance of the upgrades installed in 2008.

A4.2 All of the systems proposed for installation under the Program are well proven at FortisBC. No “pilot programs” or test cases will be installed for evaluation. As well, there have been recent projects completed on which to base the development of +/-10% level estimates of which the benefits were used as a proxy for this application. On that basis, FortisBC feels that it is unnecessary to base later year approvals on the basis of the 2008 installations.

Q4.3 Please describe the performance metrics FortisBC will use to establish the quantifiable and non-quantifiable benefits of this Project.

A4.3 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. An after-the fact estimate would have to be made to determine the cost to restore the outages if the automation Program had not been in place. By subtracting the actual restoration costs from the estimated costs, the savings could be determined.

Q4.4 Please discuss when FortisBC would be in a position to provide a Report on the 2008 upgrades with respect to actual cost and realized benefits. Could the Report be provided in sufficient time for it to be assessed prior to deciding whether to proceed with the upgrades planned for 2009?

Q4.4 Actual costs for 2008 can be reported at the end of the 2008; however, benefits realized would be realized in following years. As such, any reporting would lag the installation by at least one year. As noted in response A4.3, benefits would likely take a number of years to be realized as the full program is achieved.

5.0 Reference: Application, pp. 18, 23, Appendix 1

Q5.1 On page 18, the Application claims savings of $590,000 per year starting in 2011, and allocates 20 percent ($118,000) of the savings to expenses and 80 percent ($472,000) to capital expenditures. Please confirm that under the form of Performance Based Regulation that applies for FortisBC, ratepayers and shareholders share equally in expense cost savings, while ratepayers are responsible for all of the costs (or savings) related to capital expenditures (or reductions in capital expenditures).

A5.1 Under the form of Performance Based Regulation that applies to FortisBC, O&M costs are formula-based for inclusion in rates for the test year, and to the extent that actual costs or savings vary from forecast (except for interest expense and other approved flow-through adjustments), the resulting variance to after-tax return on equity variance is shared equally between the Company and rate payers. Therefore, the after-tax impact of expense cost savings would be shared equally between the Company and ratepayers, and rate payers would realize the entire benefit of capital expenditure reductions.

Q5.2 Please explain how increases in utility revenue above forecast are allocated between utility ratepayers and shareholders.

A5.2 To the extent that any excess revenue above forecast increases after tax return on equity, the increased earnings are shared equally between the rate payers and the Company.

Q5.3 Table 5 quantifies four areas of potential cost savings. Of these, only Intelligent Relaying at $45,000 to $120,000 per year appears to relate to reduced capital expenditures. Please discuss whether any of the other potential cost savings relate primarily to reducing future capital expenditures.

A5.3 As discussed in section 3.5 of the Application, other categories such as Remote Operation and Operating Authority will also result in a reduction of future capital expenditures. This is primarily due to reduced restoration costs that will result during times of major forced outages. The restoration costs of widespread outages are typically capitalized due to the large amount of infrastructure that is replaced (e.g. poles, insulators, conductor, etc.). The labour costs due to switching during these outages is included as part of this capital cost; thus, any reduction of the switching costs will result in reduced capital expenditures.

The costs of restoring power for small, localized outages are charged to O&M.

Q5.4 If one assumes that the capital cost savings are the average of $45,000 and $120,000, or $83,000, the remaining $507,000 per year of savings would be reduced expenses or increased revenue. Please provide a form of the Appendix 1 calculation based on an assumption that $83,000 of the projected $590,000 annual savings relate to reduced capital expenditures and the remaining $507,000 is savings to expenses.

A5.4 Please refer to Appendix A5.4 and response A26.3 below. The estimated savings to expense is found at line 56. The Net Present Value in this case is reduced from $1.2 million to $0.7 million and the one-time equivalent rate impact from 0.05% to 0.03%.

Q5.5 Please repeat the foregoing question, but assume that one-half of the projected expense savings go to the benefit of ratepayers. That is, please provide the Appendix 1 calculation assuming the annual capital expenditure savings are $83,000 per year, and the expense savings are $254,000 per year.

A5.5 Please refer to Appendix A5.5 and response A26.3 below. The estimated savings to expense is found at line 56. The Net Present Value in this case increases from $1.2 million to $2.4 million and the one-time equivalent rate impact from 0.05% to 0.09%.

6.0 Reference: Application, pp. 30, 31

Q6.1 Table 5 estimates Annual Cost Reduction of $397,000 for Remote Operations, by eliminating 9,000 customer outage hours per year. The estimate is discussed further on pages 30 and 31. Please provide the calculation of the $397,000 figure, and explain the factors used in the calculation.

A6.1 The $397,000 savings in Table 5 comes from the reduction in labour related to "Recloser enabling and disabling" only. It is the sum of the estimated labour savings for direct switching costs of $135,000 and the crew downtime costs of $262,500, which are explained in sections 4.7.c.i and 4.7.c.ii of the Application, respectively.

Q6.2 Further to the response to the previous question, please clarify whether the estimated savings represents an increase to utility revenue, reduced OM&A expense, or value of service to customers. Also, please clarify the parties

that would benefit from the savings, under the terms of the current FortisBC Performance Based Regulation.

A6.2 As stated in response A5.1 above, the estimated operating cost savings represent reduced OM&A expense, and the after tax impact of expense cost savings would be shared equally between the Company and customers.

Q6.3 Please confirm that the remote Recloser enabling and disabling that is described on pages 31 and 32, is fully compliant with Workers' Compensation Board and other safety requirements.

A6.3 Confirmed. All remote and local closing of the associated circuit breaker/recloser is prevented when the device is tagged with a "Guarantee of Non-Reclose" ("GNR").

7.0 Reference: Application, 3.1.4 Communications, pp. 9-10

FortisBC has identified several communication systems that it intends to use to implement this program.

Q7.1 Please provide a table of the systems, protocols and standards, and security risk assessment (none, low, medium, high).

A7.1

System	Protocol(s)	Usage	Risk Assessment	Comments
Back-bone fibre network	SONET -OC1 or OC3	Broadband communications	Low	Company-owned and controlled access equipment
Satellite communications	DNP3	SCADA control	Low	Company-owned equipment that employs encryption algorithms
Licensed wireless	DNP3	SCADA control	Low	Company-owned equipment that employs encryption algorithms.
Unlicensed wireless	DNP3	SCADA control	Low	Company-owned equipment that employs encryption algorithms. Also limited deployment.
Telephone Leased-lines	DNP3	SCADA control	Medium	Non company-owned, but controlled access
Cellular modems	DNP3	SCADA control	Medium	Non company-owned, but controlled access
Dialup phone lines	SEL	Relay interrogation	Low	Controlled-access
Dialup phone lines	PML ION	Meter interrogation	Low	Not able to affect operation of the power system

Q7.2 Please describe the functions and the data associated with non-critical corporate wide-area network access to substation meters and relays.

A7.2 Devices will be connected to the corporate wide-area network (WAN) to allow fast and easy retrieval of historical data from relays and meters. Meters can be connected directly to the corporate WAN since they are unable to affect the operation of the power system and simply contain historical data. Protection relays are connected to the WAN via hardware firewalls that support virtual private-network (VPN) access. The VPN software ensures that access to relays is secure and controlled.

For security and reliability reasons, no SCADA traffic is carried via the corporate WAN.

Q7.3 Does FortisBC have a Cyber Security Plan?

A7.3 The FortisBC IT group maintains a formal security plan which covers the corporate business systems infrastructure. In addition, there are numerous internal de-facto standards that are applied in substation communications designs to ensure an appropriate level of security is achieved. 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.

Q7.4 Does this plan cover:

a. **Sabotage Reporting,**
b. **Critical Cyber Asset Identification,**
c. **Security Management Controls,**
d. **Personnel and Training,**
e. **Electronic Security Perimeter(s),**
f. **Physical Security of Critical Assets,**
g. **System Security Management,**
h. **Incident Reporting and Response Planning, and**
i. **Recovery Plans for Critical Cyber Assets**

A7.4 Please refer to response A7.3 above.

Q7.5 The intent of the proposed Cyber Security Standards is to ensure that all entities responsible for the reliability of the Bulk Electric Systems in North America identify and protect Critical Cyber Assets that control or could impact the reliability of the Bulk Electric Systems. Does FortisBC have an implementation Plan for the NERC Reliability Standards - Cyber Security Standards CIP-00-1 that became effective January 1, 2007 and CIP-002-1 through CIP-009-1 that became effective June 1, 2006? If not, please advise and explain.

A7.5 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.

8.0 Reference: Application, 3.3 Individual Scopes of Work, pp. 14-16

Table 2 describes the high-level scope of work required for the individual substations identified in Table 1.

Q8.1 Please provide a spreadsheet of this scope, associated cost per line item, item contingency (if considered), start date, finish date, to a total of $6.38 million (+/-25%)?

A8.1 The requested spreadsheet has not been developed at the present time. The +/-25% level estimates were determined using previously completed jobs as guidelines. The following table shows scope components that were used to develop the estimates. The individual station estimates were adjusted to allow for site specific factors and thus the line items in Table 4 will not necessarily be the simple sum of the following costs.

Scope Item	Cost ($000's)
Main + 1 Feeder (relaying + meters + tagging)	120
Main + 2 Feeders (relaying + meters + tagging)	140
Main + 3 Feeders (relaying + meters + tagging)	175
RTU + SCC Communication	75
Transformer Monitoring	15
Tagging switches	10
Main + 2 Feeders (meters only)	75
Main + 3 Feeders (meters only)	100
Main + 4 Feeders (meters only)	125
Communications to meters	15
Communication Processor	15
Phone-line into station	15

Start and end dates would be determined by the Project Manager during the +/- 10% level estimating phase. An overall contingency of 10% was applied to each year's costs.

Q8.2 Is there a reason that the Joe Rich Substation does not appear in the listings of substations?

A8.2 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.

Q8.3 Are there any other substations that are not in these listings?

A8.3 Yes, there are a number of other substations that are not included in the listings. This is because the stations either: (a) already have the required automation systems, or (b) will have the required automation systems completed by the end of 2008 under previously approved capital projects. Examples include:

- AAL – AA Lambert Terminal (automation systems already in place)
- CSC – Cascade Substation (previously approved upgrade scheduled for 2008)

- DGB – DG Bell Terminal (previously approved upgrade scheduled for 2008)
- LEE – FA Lee Terminal (automation systems already in place)

9.0 Reference: Application, 3.5 Project Cost, pp. 18-19

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. Is the inflation/escalation included in the $6.38 million? If not, please provide the adjustments.

A9.0 A CPI inflation escalation of 2% has been included in the estimate. Further cost escalation has not been applied as market volatility to date has not been a factor in the pricing of the equipment to be installed by the program.

Q9.1 What would be the cost and time required to refine the estimate to ±10%?

A9.1 As described in response A4.1, it would take approximately three months to refine the estimates to a +/- 10% level.

Q9.2 Would it be reasonable prudent for FortisBC to refine the scope, schedule and costs to +/- 10% prior to proceeding or would FortisBC prefer to proceed based on annual funding after an annual project report review?

A9.2 As stated in the Application at page17, post regulatory approval, FortisBC will proceed with detailed scoping and estimating to a +/-10% level. Any material changes to the estimated costs would be reported to the Commission.

10.0 Reference: Application, 3.5 Project Cost, pp. 18-19

Q10.1 As no risk analysis has been provided to identify risks or uncertainty included in the estimate, would FortisBC please provide the risk analysis

and any associated costs? If there are no risks, please confirm that no risks are associated with the programme.

A10.1 FortisBC feels that there are no significant risks associated with the Program. As discussed in the Application, all of the systems (apart from the Data Historian software) have been successfully used at FortisBC for many years. The Data Historian software is available from a well-established company with a proven record.

11.0 Reference: Application, 4.3 Maintenance Planning, p. 26

"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."

Q11.1 As the electronic meters will generate a tremendous amount of data, what will be the cost of report preparation?

A11.1 Reports will be generated on an as-needed basis. Two examples would include:

- System Planners requesting historical load information to determine the timing of substation or feeder upgrades
- Maintenance Planners requesting historical breaker or tapchanger operation data to determine maintenance cycles

The cost of generating these reports is not expected to be significant as they can be generated by any user as described in response A1.4.

Q11.2 As the electronic meters will generate a tremendous amount of data, what will be the cost of archiving this data?

A11.2 There are two levels of data collection provided for the electronic meters. The first system is the existing ION Enterprise software (supplied by Power Measurement Ltd.) that collects the various historical data, waveform capture and event logs from the meters. This existing system automatically either archives or prunes the database depending on the historical importance of the information. For example, event logs and waveforms (which consume a large amount of disk space) are automatically purged after three months. The remaining historical load data will be transferred to the new Data Server to be installed by the project and will be permanently archived by that system. The cost to archive the data is included in the cost of the Data Server Hardware and Software estimate.

Q11.3 Are the hardware and software costs of integrating the new CMMS to the station automation central database included in this Application?

A11.3 Please see response A1.3 above.

Q11.4 Is the cost of automatically issuing work orders and email warnings included in this Application?

A11.4 No. These are functions of the Company's CMMS. Please see response A1.3 above.

Q11.5 What are the additional costs to add each of the above features if not already included in the $6.38M?

A11.5 As stated in response A1.3, these features are not considered to be a primary requirement for the automation project and the cost and value of integration with the CMMS will be evaluated at a future time.

12.0 Reference: Application, 4.6 Operating Authority pp. 29-30

"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."

Q12.1 As the PIC, through the electronic system, performs all of the safety functions, please provide manufacturer's documentation to confirm that the inputs and outputs of these meters are suitable to perform safe remote breaker operation with proper verification as required for lockout purposes and employee safety.

A12.1 There are a number of systems that will be installed under the Program. It should be clarified that the "meters" as referred to in this question will not be used to operate any power system devices. FortisBC only uses electronic meters for data collection purposes. The only electronic devices approved by FortisBC for operating power system equipment (e.g. circuit breakers, high-voltage switches, tapchangers, etc.) are protective relays and RTU's. These devices are certified to rigorous standards including IEEE C37.90, IEEE C37.90.1, IEC 60255-0-20 and IEC 60255-5. A portion of the manufacturer specifications for a microprocessor relay are attached as Appendix A12.1(1). A portion of the manufacturer specifications for an RTU control card is attached as Appendix A12.1(2).

13.0 Reference: Application, 4.7 Remote Operation pp. 30-31

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."

Q13.1 As the PIC, through the electronic system, performs all of the safety functions, please provide manufacturer's documentation to confirm that the inputs and outputs of these meters are suitable to perform safe remote breaker operation with proper verification as required for lockout purposes and employee safety.

A13.1 Please refer to response A12.1.

14.0 Reference: Application, 4.9 "Intelligent" Relaying, pp. 34-36

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.

Q14.1 Please provide a table illustrating the comparison of the current scheduled maintenance cycle by distribution substation component, quantities by component and the proposed estimated maintenance cycle in man-hours as a result of this Application. Only provide relevant and significant equipment information.

A14.1 Please refer to response A18.3.

15.0 Reference: Application, Executive Summary, p. 2

Utilities around the globe have recognized the benefits of these automation systems, which have led to the development of a new industry standard. FortisBC has applied this approach in recently constructed substations and has received the commensurate benefits.

Q15.1 Please provide references and material to support this statement.

A15.1 Attached as Appendix A15.1 is the "June 2006 - T&D Automation Market Summary" published by Sierra Energy Group (a Division of Energy Central). The survey contacted 664 utilities in the US and Canada and found 336 projects related to substation automation, and RTU and communications upgrades. Three relevant excerpts from the report are highlighted below:

> *"Over the six month period of the study, our analysts have identified in excess of $76 million in planned market activity. As previously mentioned, investor owned utilities have accounted for most of the larger projects, including the majority of full system replacements and major upgrades. We believe that many of these projects have been initiated in response to pressures from NERC and FERC to improve network reliability and strengthen utility network interconnects."[p.5]*

> *"A significant number of utilities have begun to upgrade their substation capabilities, including installation of metering and fault monitoring devices, protective relays, regulator and tap changer controls and data collectors and gateways."[p.6]*

> *"Many utilities are observed to be engaged in multi-year substation automation projects to spread out the cost of implementing substation equipment and time their projects to coincide with the build out of fiber and other communications upgrades." [Ibid.]*

Q15.2 Please provide any statistics FortisBC has that support the statement that it has already received the benefits of automation at recently constructed substations.

A15.2 Three recent examples include:

- Metering installations at Castlegar allowed the summation of coincidental feeder load identifying an inadvertent meter connection error masking an extreme transformer overload. Operational correction as a result may have averted a potential costly transformer failure.
- Automated metering at Grand Forks Terminal has allowed for detailed operational analysis to allow load transfer and de-energization of Ruckles distribution source without use of a mobile substation to facilitate maintenance and capital work at Ruckles.
- The same level of load detail allowed for recent capital work to be done at Grand Forks Terminal again without the costly setup costs of the mobile substation.

Q15.3 Please provide comment on the "Summary of Findings from the Newton-Evans Study on Wi-Fi Communications in Electric Utilities Conducted for CIGRE B5 WG22."

A15.3 FortisBC would be contained in the majority grouping of utilities (84%) that does not use (and is not contemplating the use of) Wi-Fi wireless communications for substation applications. FortisBC also agrees with the majority of utilities (71%) that the security issues around Wi-Fi preclude its use in substation control systems.

With regard to a security risk assessment of wireless communications, unlike the majority of utilities, FortisBC has conducted a risk assessment. While this assessment has not been formally documented, de-facto standards have been developed and are employed. Thus, the wireless systems contemplated in the application are either licensed systems, or (in limited applications only) unlicensed systems using proprietary encoding schemes. No Wi-Fi systems are proposed.

16.0 Reference: Application, Executive Summary, p. 2

The Distribution Substation Automation Program focuses on, among other things, preventing outages.

Q16.1 Please describe all the ways in which FortisBC believes this project will prevent outages.

A16.1 It is not possible to cite all of the ways in which the Program will prevent outages. However, following are three specific examples based on previous substation events that illustrate the outcomes both if the Program <u>was not</u> implemented (Scenario 1) and if it <u>was</u> implemented (Scenario 2):

Example A: A trip coil has randomly failed in the Stoney Creek Feeder 2 circuit recloser.

Scenario 1: There is no real-time monitoring of the station and the failure goes undetected. Some time later a windstorm occurs and a tree momentarily contacts the feeder. The protective relaying detects the fault, but is unable to open the recloser due to the trip coil failure. The station main breaker correctly operates as backup protection, resulting in a complete station outage - including Stoney Creek Feeder 1 (1,368 customers). Crews must be dispatched to the station to determine the source of the problem. The entire station load (2,000 customers) experiences a multi-hour outage while switching occurs to restore the load.

Scenario 2: Immediately after the trip coil fails, an alarm is reported to the FortisBC SCC via the station RTU. The alarm is classed as an "Immediate Callout". A technician is dispatched to the station and confirms that the trip coil has failed and repairs it. When the windstorm occurs, the Stoney Creek Feeder 2 experiences only a short trip/reclose outage when the tree momentarily contacts the line. Stoney Creek Feeder 1 is unaffected.

Example B: To facilitate unplanned substation maintenance at Beaver Park Substation, some of the station load is transferred to the Glenmerry Substation.

Scenario 1: The load transfer results in an overloading of Glenmerry T1. A transformer high-temperature alarm is generated, but the station is unmanned and the alarm goes unnoticed. Shortly after, the transformer trips on high temperature resulting in an extended outage to 3,419 customers.

Scenario 2: The load transfer results in an overloading of Glenmerry T1. Immediately after the first high-temperature alarm is generated it is reported to the FortisBC SCC via the station RTU. The SCC operators dispatch field crews who are able to reduce the transformer loading by switching in distribution capacitors and instituting a forced voltage-reduction. The station outage is prevented.

Example C: Due to customer additions on the Duck Lake Feeder 1 the feeder unbalance has grown excessive.

Scenario 1: The unbalance goes unnoticed until, at peak load, it exceeds the pickup setting of the feeder neutral relay resulting in an outage to 966 customers.

Scenario 2: The installation of a PML meter on the feeder allows historical recording of the feeder unbalance. When the unbalance exceeds 80% of the neutral relay setting, an alarm is generated. A work order is created to rebalance the feeder thus preventing the outage.

Q16.2 Did FortisBC conduct an analysis to estimate the effect of the automation project on SAIDI, SAIFI, or CAIDI, or is it aware of studies published by others that would provide such estimates? If yes, please provide the studies.

A16.2 While no detailed analysis has been conducted to determine the direct impact on the referenced reliability indices, a basic estimation can be made as follows: When fully implemented, the Program is estimated to save 9,000 customer outage hours per year. On average, FortisBC experiences approximately 226,000 customer outage hours per year (three year average). Thus, the Program would be expected to result in approximately 4% fewer customer outage hours per year.

Attached as Appendix A16.2(1) and A16.2(2) are two reports entitled:

- “A Case Study: How a Utility Automated and Integrated Data/Control for 4000 Pole-Top Switches and Protection Relays, and Reduced its SAIDI” – Hydro Quebec
- “EPRI Research Plan for Advanced Distribution Automation” - Electric Power Research Institute

Both of these reports examine the reliability improvements to SAIDI and SAIFI that can be gained through the installation of automation systems. Although both are more extensive than the proposed FortisBC program (as they include the automation of pole-top devices), the remote control of station feeder breakers is clearly an important element of the automation system.

Specifically, in the second report on page9 it states:

"There is significant opportunity to improve reliability through the use of intelligent monitoring at the substation."

17.0 Reference: Application, Executive Summary, p. 2

FortisBC states that its 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.

Q17.1 Please discuss the trade-offs that FortisBC examined in rejecting the use of the "more complex load restoration and auto-transfer schemes."

A17.1 FortisBC is not rejecting the future use of auto-restoration schemes. This statement was simply intended to clarify the meaning of the word "Automation" as it relates to this Program. "Automation" has many meanings within the utility industry and it was necessary to clarify the scope of the term. The systems as proposed in the Program are expandable and have the provision to provide more advanced functions. Alternatively, it could be considered that the Program is the first step in providing a complete distribution automation solution.

Q17.2 What are the implications of not using the load restoration and auto-transfer functions on crew and control centre operations, reliability, post-

event restoration times, and outages?

A17.2 Refer to response A17.1.

Q17.3 Please provide a description and block diagram of the components of the "standard package" and state the rationale for including each component in the standard.

A17.3 While each automation installation will vary somewhat depending on a number of factors (e.g. number of feeders, number of transformers, type of communication mediums to SCC, etc.), a typical block diagram from the recently completed Nk'Mip Substation has been included as Appendix A17.3. The package is composed of the following devices (note that the index in the first column corresponds to the numbered areas in the diagram):

1

	Device	Model No.	Description and rationale
1	Protective relays	SEL-351S	Primary function is to provide fault protection for high-voltage equipment (feeders and transformers). Also provides analog telemetry (MW, Mvar, kV, etc.) and alarms to SCADA.
2	Power quality meters	PML-7650/7550	Monitors and records the following information: • instantaneous load (MW, Mvar) • energy readings (MWh) • harmonics • sags/swells and transient disturbances • waveform capture
3	Communications processor	SEL-2032	Primary function is to act as a data concentrator that gathers data from the protective relays and passes it to the station RTU. Also provides the ability to remotely access the relays for post-fault diagnostics.
4	Station RTU	GE D20	Provides real-time analog and digital telemetry to/from the FortisBC SCC. Interfaces to the Communications Processor and hardwired control and status points.
5	Communications	GE JungleMux (JMUX)	Provides the communications path between the substation and SCC. Also provides WAN access for remote interrogation of relays and meters.
6	Firewall	Cisco PIX-501	Provides secure, controlled access for remote interrogation of the station RTU and protective relays

18.0 Reference: Application, Executive Summary, p. 3

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.

Q18.1 Please describe the method(s) that will be used to "precisely measure" transformer life.

A18.1 Electronic equipment is capable of implementing insulation thermal modeling as described in the IEEE Standard "C57.91: 1995, IEEE Guide for Loading Mineral-Oil-Immersed Power Transformers". This equipment can provide a calculated loss-of-life measure based on: transformer winding temperature; instantaneous and historical loading and ambient temperature.

Q18.2 Please discuss the accuracy with which transformer failures can be predicted, with references to the relevant technical literature.

A18.2 Transformers are complicated devices with many components. The condition of many of these components can be directly tested. For example, bushings can be Doble tested, tapchangers can be visually inspected and transformer oil can be tested for insulation quality. The one major component that cannot be directly tested is the condition of the winding insulation. By understanding the condition of the insulation a better estimation can be made for the remaining life of this critical component.

The proposed thermal modeling method for measuring the transformer insulation loss-of-life will use the formula in section 5.2 of IEEE C57.91. The formula is based on experimental evidence that indicates that the transformer insulation deterioration due to time and temperature follows the Arrhenius reaction rate that models the chemical reaction of cellulose degradation with temperature. The advantage of the proposed method is that it will offer real-time information on the transformer insulation condition without the need for taking paper samples.

Q18.3 What is the impact of the proposed project on transformers (specifically) with respect to the cost and frequency of unit testing.

A18.3 Decisions regarding the frequency, and hence costs, of equipment testing would be made by the FortisBC maintenance planning group using tools such as CMMS. The automation Program is simply a source of data for the CMMS system and thus the requested data is not available at this time.

19.0 Reference: Application, Project Description, p. 6

T**he 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.**

Q19.1 To what extent does the ability to reconfigure circuits depend on switching devices located outside the substations? To what extent are outside-the-substation devices to be upgraded for remote operation through this program?

A19.1 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. Regardless, automation of the substation equipment will still reduce switching durations as it will only be necessary for crews to travel to a limited number of field devices (i.e. travel to and from the substation to complete the switching will not be required).

20.0 Reference: Application, Present Design Practices and Equipment Standards, p. 7

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.

Q20.1 Does this fact potentially put the equipment at some risk of earlier obsolescence? Please explain.

A20.1 There is always a balance between using equipment that is well-proven versus that which is leading-edge. The devices that FortisBC has standardized on were released in the last few years and have a wide range of features that covers all of the needs foreseen by this program. To date, the vendors mentioned in the application have established records of supporting legacy devices for a reasonable duration after their introduction.

21.0 Reference: Application, Protection Relays & Power-Quality Monitoring, pp. 7-8

The equipment standard for protection relays is a selection of standard devices from Schweitzer Engineering Laboratories. The standard for power quality monitoring is two standard meters from Schneider Electric.

Q21.1 Please describe the method(s) FortisBC will use to procure the equipment needed for this project.

A21.1 Once final quantities of devices (relays, meters, RTU's, etc.) for all substation locations are determined during the detailed scoping process, a Request for

Quotation will be sent to the respective vendors. This request will contain the equipment quantities for the entire Program, not just the following year. It is expected that this method of bulk purchasing will allow for reduced pricing. The necessary equipment will be either purchased outright at one time (stored by FortisBC for use in future years) or an option contract for future purchases at a fixed price may be negotiated with the vendor.

Q21.2 Does the establishment of equipment from specific suppliers as FortisBC standards potentially limit the company's ability to procure equipment at competitive prices? Please explain.

A21.2 FortisBC is aware that sole-sourcing may appear in some cases to result in higher equipment purchase costs. However, all of the vendors listed were selected many years ago on the basis of a number of factors, one of which was lowest cost. FortisBC has continued to track the pricing of the preferred vendors compared to other market participants, and has found the selected vendors are still competitive. Furthermore, the significantly reduced costs associated with equipment standardization such as reduced training requirements, reduced spare stock and optimized engineering designs outweigh any slight additional capital costs that may occasionally occur.

22.0 Reference: Application, Table 1, p. 11

Table 1 lists the substations that are slated to be included in the proposed project, and it ranks them into priorities 1, 2, 3, or 4.

Q22.1 Please describe the method(s) and criteria FortisBC used to establish the priorities. In your response, please discuss whether the stations' existing reliability statistics formed part of the evaluation criteria. Please explain how existing station reliability statistics were incorporated into the decision process.

A22.1 Quantitative station reliability statistics were not used directly in establishing the individual station priorities. Rather, the priority ranking was based on a number of qualitative factors:

- Historical reliability of station
- Distance from a FortisBC service centre
- Number of customers served by the station
- Location of the station (rural vs. urban)
- Presence or absence of a portion of the required automation systems

Finally, an attempt was made to balance the workload across the four years of the program and between the two major areas (Okanagan vs. Kootenay) of the FortisBC service territory.

Following are some specific examples:

Priority 1: Glenmore, Hollywood – these are major substations in an urban area where load growth is a significant factor. Thus, individual feeder loading information is critical for optimal planning and operating decisions.

Priority 2: Valhalla – a smaller, rural substation that is located a long distance from a FortisBC service centre.

Priority 3: Glenmerry – a newer, urban station which already has some of the automation systems installed.

Priority 4: Tarrys – a small, rural substation that supplies only one wholesale customer in normal operation and thus has limited exposure to faults.

23.0 Reference: Application, Individual Scopes of Work, p. 14

The items listed in Table 2 include the following:

- **Install communications processor**
- **Upgrade station RTU**
- **Connect existing meter for transformer monitoring**
- **Install communications to system control centre**
- **Upgrade feeder relaying**
- **Install per-feeder metering**
- **Install remote tagging switches**
- **Install transformer monitoring**
- **Upgrade feeder protection**
- **Install wireless network communications**
- **Install station mini RTU**
- **Install dial-up phone line for access to relays and meters**

Q23.1 For each of the above items, please provide a brief description of the work involved, the typical time and crew type involved, and an indication of whether the work requires an interruption in service to any customers.

A23.1 The following table shows the requested descriptions. All of the work will be completed by electricians and/or communications and protection technicians. Estimates of the required crew time are not provided as these will vary widely between locations. No customer interruptions will be required for any of the proposed work.

Description	Typical scope of work
Install communications processor	Mount and wire SEL-2032 Communications Processor. Connect to station IED's as required.
Upgrade station RTU	Install additional I/O into existing RTU.
Connect existing meter for transformer monitoring	Connect tapchanger and transformer temperature monitoring devices to an existing transformer PML meter.
Install communications to system control centre	Install SCADA communications link from the substation to the SCC. May use one of the following media: FortisBC fibre, leased-line, cellular modem, satellite system.
Upgrade feeder relaying	Replace existing feeder electromechanical relaying with SEL-351S relays.
Install per-feeder metering	Mount and wire PML-7550 meter on each distribution feeder.
Install remote tagging switches	Mount and wire Electroswitch tagging switch on each distribution feeder.
Install transformer monitoring	Install new PML-7650 meter and connect tapchanger and transformer temperature monitoring devices.
Upgrade feeder protection	Replace existing feeder protection with new SEL-351S relay or SEL-351R recloser control.
Install wireless network communications	Mount and wire GE MDS wireless spread-spectrum radio for corporate WAN access to station devices.
Install station mini RTU	Mount and wire SEL-2411 Programmable Automation Controller
Install dial-up phone line for access to relays and meters	Install Telus landline complete with appropriate entrance protection.

24.0 Reference: Application, Project Cost, pp. 18-19

A 20%-80% allocation to operating and capital, respectively, was chosen as the cost reduction ratio due to remote operation of switching devices because the majority of the quantifiable program benefits will be attributed to future capital projects. This is true even for forced outages; for widespread outages, the outage costs would be capitalized due to the large amount of power system infrastructure that is replaced.

Q24.1 Please provide any statistics that FortisBC has that support the 20/80 allocation for forced outages. If statistics on capital and operating expenditures related to forced outages are not maintained, please pick a random sample of five to ten forced outage events and examine the operating/capital ratio.

A24.1 FortisBC does not specifically track statistics on capital and operating expenditures related to forced outages.

Under the circumstances, the area of Kelowna was picked up for study as a test case. During the month of August 2007, the Kelowna Area (Service Point) logged 12 Forced Outage events. This finding is indicated in the table below:

	Outage ID	Forced Outage Cause	Component	Out Date	Feeder Name	Capitalization	Amount (Approx)
1	707777	Unknown or Other	Pole	10-Aug-07	SEX3	Yes	$2,000
2	709894	Unknown or Other	No Failure	19-Aug-07	HOL5	Yes	$600
3	715429	Unknown or Other	No Failure	28-Aug-07	DUC1	Data Unavailable	
4	715431	Fortis Error	O/H Switch	24-Aug-07	GLE1	Yes	$1500
5	715851	Public Interference	Pole	27-Aug-07	LEE1	No	$200
6	711917	Equipment or Material	Transformer	23-Aug-07	LEE1	Yes	$1500
7	704773	Birds or Animals	No Failure	5-Aug-07	SEX3	No	$200
8	704774	Birds or Animals	No Failure	5-Aug-07	SEX3	No	$200
9	707778	Birds or Animals	No Failure	11-Aug-07	SEX3	No	$200
10	709893	Birds or Animals	No Failure	18-Aug-07	GLE7	No	$200
11	715849	Birds or Animals	No Failure	25-Aug-07	DGB2	No	$200
12	715853	Birds or Animals	No Failure	29-Aug-07	HOL1	No	$200

Total Cost: **$7,000 (approx)**

Capitalized Cost: **$5,600 (approx)**

% Capitalization: **80%**

From the above results it can be seen that the 20/80 operating/capital allocation assumption for forced outages is reasonable.

Q24.2 Please provide summary statistics on the causes of forced outages in the FortisBC service territory and indicate which ones would be positively affected by the proposed project.

A24.2 Appendix A24.2 provides a summary of the causes of forced outages in the FortisBC service territory from January 1, 2007 to August 31, 2007). All outage causes could potentially benefit from this Program as it would improve system visibility and thus reduce outage durations (as discussed in section 4.7.a of the Application).

25.0 Reference: Application, Program Benefits, p. 23

Feeder loading data allows prudent load transfers based on time of day, reducing the stress on highly loaded feeders. The program will also provide "[a]dvanced indication of critical substation alarms."

Q25.1 How much inter-feeder load diversity typically exists on FortisBC's distribution system?

A25.1 Diversity factor is defined as the measure of how much higher the customer's individual peak is than its contribution to group peak. If this definition is applied at the feeder level, it would suggest how much higher is the individual feeder peak compared to its contribution to the peak of a group of feeders of which it is included in. With present peak only data, there is limited accuracy when estimating the individual feeder contribution during combined feeder peak. The metering aspect of the automation project would provide the necessary information to accurately identify these coincident contributions.

Q25.2 How will the project provide <u>advanced</u> indication of critical substation alarms?

A25.2 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.

26.0 Reference: Appendix 1 – Revenue Requirements Analysis, p. 39-40

Q26.1 Please provide a fully functional Excel model of the Revenue Requirements Analysis. If additional questions are required following the review of the model, they will be asked as soon as possible.

A26.1 A fully functional Excel model has been provided to the Commission and is attached as Appendix A26.1, including a modification to the depreciation rate for the project as explained in the response A26.3 below.

Q26.2 Please explain the basis for the yearly forecast equity return on line 12 and the debt return on line 13 for Dec-07 to Dec-25, inclusive.

A26.2 The forecast equity return ("ROE") on line 12 is based on the BCUC Automatic Adjustment Mechanism. The 2007 rate of 8.77% represents FortisBC's approved ROE for 2007. The 9.19% for 2008 and beyond is based on the July 2007 Consensus Economics forecast as presented below and includes a risk premium of 40 basis points, as confirmed by Commission Order G-58-06.

		Approved 2007	Forecast 2008
1	Bond Yield per:		
2	10 year Government of Canada Bond Yield	4.150	4.850
3	Premium from 30 Year Bond Yield	0.069	(0.068)
4			
5	Forecast 30 Year Bond Yield	4.219	4.782
6	Add/Subtract 25% of yield under 5.25%	0.258	0.117
7	Adjusted Yield	4.477	4.899
8	Premium for Low Risk Utilities	3.895	3.895
9	BCUC Benchmark Forecast	8.372	8.794
10	Rounded Benchmark ROE	8.370	8.790
11	FortisBC Risk Premium	0.400	0.400
12	FortisBC Allowed ROE	**8.770**	**9.190**

The Cost of Debt was based on a forecast weighted average cost of long and short term debt. The current forecast weighted average cost of debt in 2008 is 6.43% as presented on page 16, Tab 3 of FortisBC's Preliminary 2008

Revenue Requirements Application.

Q26.3 Capital additions are recorded for the first 5 years on line 61 from Dec-08 to Dec-12. Please explain the negative or avoided additions from Dec-13 to Dec-26 and why these negative amounts on line 48 differ from the negative amounts on lines 53 and 61. Please explain why negative depreciation expense is recorded from Dec-18 to Dec-26. If the capital assets have a 10-year life, why aren't replacement additions recorded in year 11? If much of the equipment to be installed is to have a 20-year lifespan as shown on page 18, why shouldn't a 5 percent depreciation rate be used?

A26.3 The negative amounts on line 48 are the avoided future capital additions as a result of implementing the Program. The amounts on lines 53 and 61 are the net additions to plant from the prior year that are included in rate base in the subsequent year for rate setting purposes.

A depreciation rate of 10% (which is normally used for computer hardware) was inadvertently used in the Program NPV analysis. The correct depreciation rate for equipment of this type (substation communications equipment) is 6%. A revised NPV model has been provided to the Commission (please see response A26.1 above). This change has the effect of further reducing the Program NPV and rate impact:

The Revenue Requirements analysis is attached as Appendix A26.1.

Total Capital Cost:	$6.378 million (unchanged)
Net Present Value:	$1.152 million
One-time Equivalent Rate Impact:	0.05%

Q26.4 Please explain why negative capital cost allowance ("CCA") is recorded for Dec-13 to Dec-26 if the assets have a 10-year life.

A26.4 As in the response to Q26.3 above, the negative CCA is recorded in order to reflect avoided future capital additions as a result of the program. Or viewing it from the opposite perspective, in the absence of the new equipment, capital expenditures would have been higher and resulted in higher CCA.

Q26.5 Please provide a fully functional Excel model of the Revenue Requirements Analysis that does not include negative depreciation, negative CCA, and negative additions to plant and has replacement assets starting in year 11. Please comment on the Rate Impact that results from this model.

A26.5 A fully functional Excel model has been provided to the Commission. Please also see responses A26.1 and A26.3 above. The Company has assumed that only 35% of the cost (escalated at 2% per year) of original assets would need to be replaced in year 11 and beyond. The NPV in this case increases from $1.2 to $4.5 million and the one-time equivalent rate impact from 0.05% to 0.18%.

Q26.6 The Application refers to a value of $590,000 that is used for the initial savings starting in 2011, and that 80 percent of the savings ($472,000) is apportioned to the reduction of future capital costs. Please explain why the savings increases by $10,000 to $12,000 each of the following years for Dec-12 to Dec-26.

A26.6 The estimated savings is escalated by the 2% CPI for each of the following years.

Q26.7 Please explain how the $18,000 AFUDC is calculated. Explain why AFUDC is not recorded in the future years' capital additions. Are these other capital additions recorded as CWIP not attracting AFUDC?

A26.7 The Company applies AFUDC to projects that are greater than $100,000 and more than three (3) months in duration. The AFUDC rate is equal to the weighted return on equity plus the after tax cost of debt (6.0% in 2007). The $18,000 was calculated for 2007 costs only and estimated on a weighted average capital cost in 2007 of approximately $300,000 ($300,000 X 65%). AFUDC was not recorded in the future year's capital additions because, although categorized as within the Distribution Substation Automation Program, each of the projects are discrete, and expected to be less than three months in duration.

Q26.8 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. Please explain how the change in system losses is incorporated into the model.

A26.8 There has been no attempt to incorporate the benefits from a reduction of system losses into the model. These benefits would be over and above those already listed for the Program.

27.0 Reference: Commission Letter No. L-18-04, p. 6 of 7

"(ii) a study comparing the costs, benefits and associated risks of the project and alternatives, which estimates the value of all of the costs and benefits of each option or, where not quantifiable, identifies the cost or benefit and states that it cannot be quantified;"

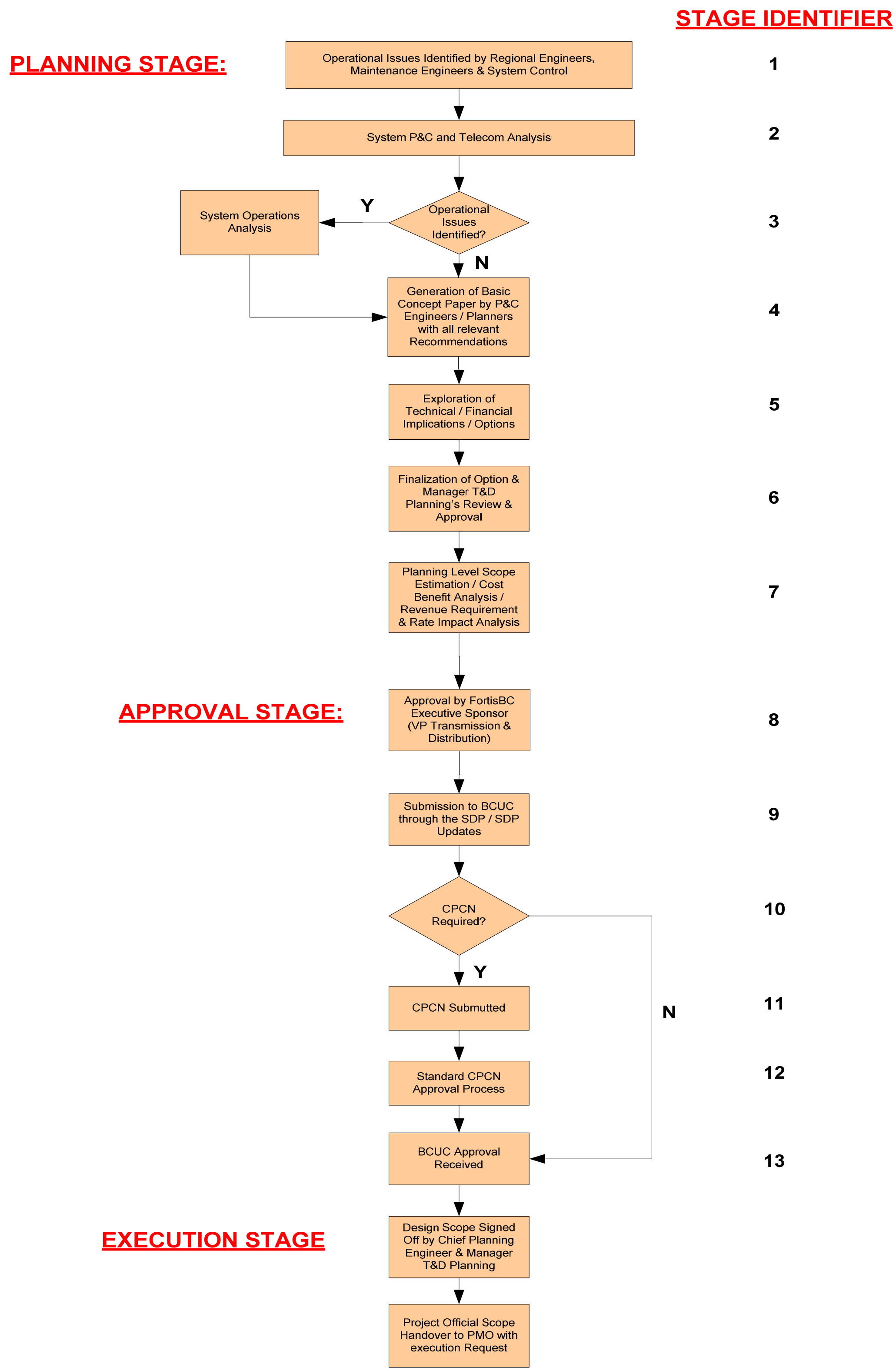
Q27.1 Has FortisBC performed a study comparing the costs, benefits and associated risks of the project and alternatives, which estimates the value of all of the costs and benefits of each option? If yes, please provide the study. If not, please explain why a study was not performed.

A27.1 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.

Q27.2 Please describe the internal project approval process and identify the executive sponsor for this project. Report the current status of internal approval for this project.

A27.2 The project Planning & Approval sequence is depicted in the Flow Chart below. The Executive Sponsor for this Program is the Vice President, Transmission & Distribution. The Program is presently at Stage 12 (refer to flowchart: Stage Identifier).

PROJECT NAME: Distribution Substation Automation CPCN Application
REQUESTOR NAME: British Columbia Utilities Commission
PROJECT INFORMATION REQUEST NO: 1
TO: FortisBC Inc.
REQUEST DATE: October 4, 2007
RESPONSE DATE: October 12, 2007



1

Q27.3 Please provide a complete business case, Project Charter and other project submissions required for the approval of FortisBC senior management and executive sponsor.

A27.3 The business case for the project was developed in conjunction with the CPCN application and forms part of this application. The development of and final form of the CPCN were prepared with the participation and approval of senior management including the Vice President, Transmission and Distribution.

Q27.4 Utilities usually undertake a post-implementation review ("PIR") 6-12 months after a project is completed to confirm if the project has been executed according to the plan, its objectives have been met and expected benefits have been realized. Does FortisBC have a similar post-implementation review process in place? Please describe FortisBC's review process and methodology for post-implementation project performance evaluation.

A27.4 FortisBC does have a project close-out process that is completed for major T&D capital projects. The process examines the following aspects of project performance: environmental and safety; quality; and cost. A sample Project Close-out form is attached as Appendix A27.4.

28.0 Reference: Application dated August 28, 2007, pp. 18-21

Q28.1 If the software contemplated for this project is a vendor-supplied package, please discuss the risk of the software vendor being acquired or encountering financial difficulties which would result in the discontinuance of product development or suspension of product support.

A28.1 The Data Server software listed in the Application is proposed to be a vendor-supplied package. The proposed vendor (InStep Software, LLC) is well-established and has been in business for over 12 years. They have supplied similar systems to numerous utilities such as Southern California Edison, Southwest Power Pool, and Great River Energy.

In any event, it should be noted that the Data Server is relatively small portion of the overall Program cost (approximately $150,000 out of a total Program cost of $6.3 million). Even in a worst-case scenario, the server software could be replaced with another software package if required; the underlying substation and server hardware would not require any changes.

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
	Summary											
	Revenue Requirements											
1	Operating Expense (Incremental)	Line 59	0	10	25	45	(53)	(54)	(55)	(56)	(57)	(58)
2	Depreciation Expense	Line 64	0	0	32	119	204	294	354	325	296	266
3	Carrying Costs	Line 71	0	20	94	197	295	372	367	304	243	183
4	Income Tax	Line 85	0	(33)	(130)	(208)	(248)	(237)	(112)	29	122	181
5	Total Revenue Requirement for Project		0	(3)	21	153	198	375	554	603	604	572
6	**Net Present Value of Revenue Requirement**	10.00%	1,643									
	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
8	Rate Impact		0.00%	0.00%	0.01%	0.06%	0.08%	0.14%	0.21%	0.22%	0.22%	0.20%
	Annual Incremental Rate Impact over previous year		0.00%	0.00%	0.01%	0.05%	0.02%	0.07%	0.06%	0.01%	0.00%	-0.02%
9	**NPV of Project / Total Revenue Requirements**		0.10%									
	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%
11	Debt Component		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%
13	Debt Return		6.40%	6.50%	6.50%	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					
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)
49	Total Cash Outlay in Year		**526**	**1,456**	**1,409**	**1,516**	**998**	**(481)**	**(491)**	**(501)**	**(511)**	**(521)**
50	Cumulative Cash Outlay		526	1,983	3,392	4,908	5,906	5,424	4,933	4,432	3,921	3,400
51			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
53	Additions to Plant		0	526	1,456	1,409	1,516	998	(481)	(491)	(501)	(511)
54	Cumulative Additions to Plant		0	526	1,983	3,392	4,908	5,906	5,424	4,933	4,432	3,921
55	CWIP		526	1,456	1,936	3,499	4,390	4,427	5,415	4,923	4,422	3,911
	Annual Operating Costs / (Savings)											
56	Estimated Cost Savings						(118)	(120)	(123)	(125)	(128)	(130)
57	Communications - Leased Line Costs			10	20	40	60	61	62	64	65	66
58	Software Maintenance Costs				5	5	5	5	5	6	6	6
59	Total Incremental Operating Costs (Savings)		0	10	25	45	(53)	(54)	(55)	(56)	(57)	(58)
	(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
61	Additions in Year	Line 53	0	526	1,456	1,409	1,516	998	(481)	(491)	(501)	(511)
62	Cumulative Total		0	526	1,983	3,392	4,908	5,906	5,424	4,933	4,432	3,921
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%
64	Depreciation Expense		0	0	32	119	204	294	354	325	296	266
	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
66	Accumulated Depreciation		0	0	(32)	(151)	(354)	(649)	(1,003)	(1,328)	(1,624)	(1,890)
67	Net Book Value		0	526	1,951	3,241	4,554	5,257	4,421	3,605	2,808	2,031
	Carrying Costs on Average NBV											
68	Return on Equity		0	10	46	95	143	180	178	148	118	89
69	Interest Expense		0	10	48	101	152	191	189	157	125	94
70	AFUDC		0	0	0	0	0	0	0	0	0	0
71	**Total Carrying Costs**		0	20	94	197	295	372	367	304	243	183
	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%
	Income Tax on Equity Return											
73	Return on Equity	Line 68	0	10	46	95	143	180	178	148	118	89
74	Gross up for revenue (Return / (1- tax rate)		0	14	67	138	206	259	256	212	170	128
75	Less: Income tax on Equity Return		0	5	21	43	63	79	78	65	52	39
76	Net Income (equal return on equity)		0	10	46	95	143	180	178	148	118	89
	Income Tax on Timing Differences											
77	Depreciation Expense		0	0	32	119	204	294	354	325	296	266
78	Less: Capital Cost Allowance	Line 92	0	79	353	677	912	1,016	789	406	135	(57)
79	Total Timing Differences		0	(79)	(321)	(558)	(709)	(721)	(434)	(81)	161	323
80	Income Tax on Timing Differences		0	(26)	(103)	(173)	(216)	(220)	(132)	(25)	49	98
81	Before Tax Revenue Requirement [=Line 52/(1-tax)]		0	(38)	(151)	(251)	(311)	(317)	(191)	(35)	70	142
85	**Total Income Tax**	Lines 75 + 81	0	(33)	(130)	(208)	(248)	(237)	(112)	29	122	181
	Capital Cost Allowance											
86	Opening Balance - UCC		0	0	447	1,551	2,284	2,887	2,869	1,599	702	66
87	Additions to Plant		0	526	1,456	1,409	1,516	998	(481)	(491)	(501)	(511)
88	Subtotal UCC		0	526	1,904	2,960	3,800	3,885	2,388	1,108	201	(445)
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%
90	CCA on Opening Balance		0	0	134	465	685	866	861	480	211	20
91	CCA on Capital Expenditures (1/2 yr rule)		0	79	218	211	227	150	(72)	(74)	(75)	(77)
92	Total CCA		0	79	353	677	912	1,016	789	406	135	(57)
93	Ending Balance UCC		0	447	1,551	2,284	2,887	2,869	1,599	702	66	(388)

Appendix A5.4

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	(442)	(451)	(460)	(469)	(478)	(488)	(498)	(507)
2	Depreciation Expense	Line 64	0	0	32	119	204	294	378	373	367	362	357	351
3	Carrying Costs	Line 71	0	20	94	197	295	386	410	375	341	306	272	238
4	Income Tax	Line 85	0	(33)	(130)	(208)	(248)	(260)	(163)	(36)	49	107	144	168
5	Total Revenue Requirement for Project		0	(3)	21	153	(191)	(30)	166	243	279	288	276	250
6	**Net Present Value of Revenue Requirement**	10.00%	686											
	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%	0.01%	0.06%	-0.08%	-0.01%	0.06%	0.09%	0.10%	0.10%	0.10%	0.09%
	Annual Incremental Rate Impact over previous year		0.00%	0.00%	0.01%	0.05%	-0.14%	0.06%	0.07%	0.03%	0.01%	0.00%	-0.01%	-0.01%
9	**NPV of Project / Total Revenue Requirements**		0.03%											
	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						(83)	(85)	(86)	(88)	(90)	(92)	(93)	(95)
49	Total Cash Outlay in Year		**526**	**1,456**	**1,409**	**1,516**	**1,387**	**(85)**	**(86)**	**(88)**	**(90)**	**(92)**	**(93)**	**(95)**
50	Cumulative Cash Outlay		526	1,983	3,392	4,908	6,295	6,210	6,124	6,036	5,946	5,854	5,761	5,665
51			0	0	0	0	0	0	0	0	0	0	0	0
52	Cumulative Project Cost		526	1,983	3,392	4,908	6,295	6,210	6,124	6,036	5,946	5,854	5,761	5,665
53	Additions to Plant		0	526	1,456	1,409	1,516	1,387	(85)	(86)	(88)	(90)	(92)	(93)
54	Cumulative Additions to Plant		0	526	1,983	3,392	4,908	6,295	6,210	6,124	6,036	5,946	5,854	5,761
55	CWIP		526	1,456	1,936	3,499	4,779	4,823	6,208	6,122	6,034	5,944	5,852	5,759
	Annual Operating Costs / (Savings)													
56	Estimated Cost Savings						(507)	(517)	(527)	(538)	(549)	(560)	(571)	(582)
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	(442)	(451)	(460)	(469)	(478)	(488)	(498)	(507)
	(Forecast inflation rate 2%)													
	Depreciation Expense													
60	Opening Cash Outlay		0	0	526	1,983	3,392	4,908	6,295	6,210	6,124	6,036	5,946	5,854
61	Additions in Year	Line 53	0	526	1,456	1,409	1,516	1,387	(85)	(86)	(88)	(90)	(92)	(93)
62	Cumulative Total		0	526	1,983	3,392	4,908	6,295	6,210	6,124	6,036	5,946	5,854	5,761
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		0	0	32	119	204	294	378	373	367	362	357	351
	Net Book Value													
65	Gross Property	Line 54	0	526	1,983	3,392	4,908	6,295	6,210	6,124	6,036	5,946	5,854	5,761
66	Accumulated Depreciation		0	0	(32)	(151)	(354)	(649)	(1,026)	(1,399)	(1,766)	(2,128)	(2,485)	(2,836)
67	Net Book Value		0	526	1,951	3,241	4,554	5,646	5,184	4,725	4,269	3,817	3,369	2,924
	Carrying Costs on Average NBV													
68	Return on Equity		0	10	46	95	143	187	199	182	165	149	132	116
69	Interest Expense		0	10	48	101	152	199	211	193	175	158	140	123
70	AFUDC		0	0	0	0	0	0	0	0	0	0	0	0
71	**Total Carrying Costs**		0	20	94	197	295	386	410	375	341	306	272	238
	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	46	95	143	187	199	182	165	149	132	116
74	Gross up for revenue (Return / (1- tax rate)		0	14	67	138	206	270	286	262	238	214	190	166
75	Less: Income tax on Equity Return		0	5	21	43	63	82	87	80	73	65	58	51
76	Net Income (equal return on equity)		0	10	46	95	143	187	199	182	165	149	132	116
	Income Tax on Timing Differences													
77	Depreciation Expense		0	0	32	119	204	294	378	373	367	362	357	351
78	Less: Capital Cost Allowance	Line 92	0	79	353	677	912	1,074	947	637	420	267	160	84
79	Total Timing Differences		0	(79)	(321)	(558)	(709)	(780)	(570)	(265)	(53)	95	197	267
80	Income Tax on Timing Differences		0	(26)	(103)	(173)	(216)	(238)	(174)	(81)	(16)	29	60	81
81	Before Tax Revenue Requirement [=Line 52/(1-tax)]		0	(38)	(151)	(251)	(311)	(342)	(250)	(116)	(23)	42	86	117
85	**Total Income Tax**	Lines 75 + 81	0	(33)	(130)	(208)	(248)	(260)	(163)	(36)	49	107	144	168
	Capital Cost Allowance													
86	Opening Balance - UCC		0	0	447	1,551	2,284	2,887	3,200	2,168	1,444	936	579	327
87	Additions to Plant		0	526	1,456	1,409	1,516	1,387	(85)	(86)	(88)	(90)	(92)	(93)
88	Subtotal UCC		0	526	1,904	2,960	3,800	4,274	3,115	2,081	1,356	846	487	234
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	960	650	433	281	174	98
91	CCA on Capital Expenditures (1/2 yr rule)		0	79	218	211	227	208	(13)	(13)	(13)	(13)	(14)	(14)
92	Total CCA		0	79	353	677	912	1,074	947	637	420	267	160	84
93	Ending Balance UCC		0	447	1,551	2,284	2,887	3,200	2,168	1,444	936	579	327	150

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	(189)	(193)	(196)	(200)	(204)	(208)	(213)	(217)
2	Depreciation Expense	Line 64	0	0	32	119	204	294	378	373	367	362	357	351
3	Carrying Costs	Line 71	0	20	94	197	295	386	410	375	341	306	272	238
4	Income Tax	Line 85	0	(33)	(130)	(208)	(248)	(260)	(163)	(36)	49	107	144	168
5	Total Revenue Requirement for Project		0	(3)	21	153	62	228	429	511	553	567	561	541
6	**Net Present Value of Revenue Requirement**	10.00%	2,352											
	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%	0.01%	0.06%	0.02%	0.09%	0.16%	0.19%	0.20%	0.20%	0.20%	0.19%
	Annual Incremental Rate Impact over previous year		0.00%	0.00%	0.01%	0.05%	-0.04%	0.06%	0.07%	0.03%	0.01%	0.00%	-0.01%	-0.01%
9	**NPV of Project / Total Revenue Requirements**		0.09%											
	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						(83)	(85)	(86)	(88)	(90)	(92)	(93)	(95)
49	Total Cash Outlay in Year		**526**	**1,456**	**1,409**	**1,516**	**1,387**	**(85)**	**(86)**	**(88)**	**(90)**	**(92)**	**(93)**	**(95)**
50	Cumulative Cash Outlay		526	1,983	3,392	4,908	6,295	6,210	6,124	6,036	5,946	5,854	5,761	5,665
51			0	0	0	0	0	0	0	0	0	0	0	0
52	Cumulative Project Cost		526	1,983	3,392	4,908	6,295	6,210	6,124	6,036	5,946	5,854	5,761	5,665
53	Additions to Plant		0	526	1,456	1,409	1,516	1,387	(85)	(86)	(88)	(90)	(92)	(93)
54	Cumulative Additions to Plant		0	526	1,983	3,392	4,908	6,295	6,210	6,124	6,036	5,946	5,854	5,761
55	CWIP		526	1,456	1,936	3,499	4,779	4,823	6,208	6,122	6,034	5,944	5,852	5,759
	Annual Operating Costs / (Savings)													
56	Estimated Cost Savings						(254)	(259)	(264)	(270)	(275)	(280)	(286)	(292)
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	(189)	(193)	(196)	(200)	(204)	(208)	(213)	(217)
	(Forecast inflation rate 2%)													
	Depreciation Expense													
60	Opening Cash Outlay		0	0	526	1,983	3,392	4,908	6,295	6,210	6,124	6,036	5,946	5,854
61	Additions in Year	Line 53	0	526	1,456	1,409	1,516	1,387	(85)	(86)	(88)	(90)	(92)	(93)
62	Cumulative Total		0	526	1,983	3,392	4,908	6,295	6,210	6,124	6,036	5,946	5,854	5,761
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		0	0	32	119	204	294	378	373	367	362	357	351
	Net Book Value													
65	Gross Property	Line 54	0	526	1,983	3,392	4,908	6,295	6,210	6,124	6,036	5,946	5,854	5,761
66	Accumulated Depreciation		0	0	(32)	(151)	(354)	(649)	(1,026)	(1,399)	(1,766)	(2,128)	(2,485)	(2,836)
67	Net Book Value		0	526	1,951	3,241	4,554	5,646	5,184	4,725	4,269	3,817	3,369	2,924
	Carrying Costs on Average NBV													
68	Return on Equity		0	10	46	95	143	187	199	182	165	149	132	116
69	Interest Expense		0	10	48	101	152	199	211	193	175	158	140	123
70	AFUDC		0	0	0	0	0	0	0	0	0	0	0	0
71	**Total Carrying Costs**		0	20	94	197	295	386	410	375	341	306	272	238
	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	46	95	143	187	199	182	165	149	132	116
74	Gross up for revenue (Return / (1- tax rate)		0	14	67	138	206	270	286	262	238	214	190	166
75	Less: Income tax on Equity Return		0	5	21	43	63	82	87	80	73	65	58	51
76	Net Income (equal return on equity)		0	10	46	95	143	187	199	182	165	149	132	116
	Income Tax on Timing Differences													
77	Depreciation Expense		0	0	32	119	204	294	378	373	367	362	357	351
78	Less: Capital Cost Allowance	Line 92	0	79	353	677	912	1,074	947	637	420	267	160	84
79	Total Timing Differences		0	(79)	(321)	(558)	(709)	(780)	(570)	(265)	(53)	95	197	267
80	Income Tax on Timing Differences		0	(26)	(103)	(173)	(216)	(238)	(174)	(81)	(16)	29	60	81
81	Before Tax Revenue Requirement [=Line 52/(1-tax)]		0	(38)	(151)	(251)	(311)	(342)	(250)	(116)	(23)	42	86	117
85	**Total Income Tax**	Lines 75 + 81	0	(33)	(130)	(208)	(248)	(260)	(163)	(36)	49	107	144	168
	Capital Cost Allowance													
86	Opening Balance - UCC		0	0	447	1,551	2,284	2,887	3,200	2,168	1,444	936	579	327
87	Additions to Plant		0	526	1,456	1,409	1,516	1,387	(85)	(86)	(88)	(90)	(92)	(93)
88	Subtotal UCC		0	526	1,904	2,960	3,800	4,274	3,115	2,081	1,356	846	487	234
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	960	650	433	281	174	98
91	CCA on Capital Expenditures (1/2 yr rule)		0	79	218	211	227	208	(13)	(13)	(13)	(13)	(14)	(14)
92	Total CCA		0	79	353	677	912	1,074	947	637	420	267	160	84
93	Ending Balance UCC		0	447	1,551	2,284	2,887	3,200	2,168	1,444	936	579	327	150

General Specifications

Important: Do not use the following specification information to order an SEL-351S. Refer to the actual ordering information sheets.

Terminal Connections	Terminals or stranded copper wire. Ring terminals are recommended. Minimum temperature rating of 105ºC. Tightening Torque: Terminal Block: Minimum: 8 in-lb (0.9 Nm) Maximum: 12 in-lb (1.4 Nm) Connectorized®: Minimum: 4.4 in-lb (0.5 Nm) Maximum: 8.8 in-lb (1.0 Nm)
AC Voltage Inputs	**300 V_{L-N}, three-phase four-wire (wye) connection or 300 V_{L-L}, three-phase three-wire (open-delta) connection** (when available, by global setting PTCONN=DELTA) 300 V continuous (connect any voltage from 0 to 300 Vac). 600 Vac for 10 seconds. Burden: 0.03 VA @ 67 V; 0.06 VA @ 120 V; 0.8 VA @ 300 V.
AC Current Inputs	**IA, IB, IC, and neutral channel IN** 5 A nominal: 15 A continuous, 500 A for 1 second, linear to 100 A symmetrical. 1250 A for 1 cycle. Burden: 0.27 VA @ 5 A, 2.51 VA @ 15 A. 1 A nominal: 3 A continuous, 100 A for 1 second, linear to 20 A symmetrical. 250 A for 1 cycle. Burden: 0.13 VA @ 1 A, 1.31 VA @ 3 A. **Additional neutral channel IN options** 0.2 A nominal neutral channel (IN) current input: 15 A continuous, 500 A for 1 second, linear to 5.5 A symmetrical. 1250 A for 1 cycle. Burden: 0.002 VA @ 0.2 A, 1.28 VA @ 15 A. 0.05 A nominal neutral channel (IN) current input: 1.5 A continuous, 20 A for 1 second, linear to 1.5 A symmetrical. 100 A for 1 cycle. Burden: 0.0004 VA @ 0.05 A, 0.36 VA @ 1.5 A. The 0.2 A nominal neutral channel IN option is used for directional control on low-impedance grounded, Petersen Coil grounded, and ungrounded/high-impedance grounded systems (see Table 4.1). The 0.2 A nominal channel can also provide non-directional sensitive earth fault (SEF) protection. The 0.05 A nominal neutral channel IN option is a legacy non-directional SEF option.

Power Supply

Rated: 125/250 Vdc or Vac
Range: 85–350 Vdc or 85–264 Vac
Burden: <25 W

Rated: 48/125 Vdc or 125 Vac
Range: 38–200 Vdc or 85–140 Vac
Burden: <25 W

Rated: 24/48 Vdc
Range: 18–60 Vdc polarity dependent
Burden: <25 W

Frequency and Rotation

60/50 Hz system frequency and ABC/ACB phase rotation are user-settable. Frequency tracking range: 40.1–65 Hz (V_A or V_1 [positive-sequence voltage] required for frequency tracking; tracking switches to V_1 if $V_A < 20$ V).

Output Contacts

Standard:

30 A Make per IEEE C37.90: 1989
6 A continuous carry at 70ºC; 4 A continuous carry at 85ºC
50 A for one second
MOV protected: 270 Vac, 360 Vdc, 40 J;
Pickup time: Less than 5 ms.
Dropout time: Less than 5 ms, typical.

Breaking Capacity (10,000 operations):

24 V	0.75 A	L/R = 40 ms
48 V	0.50 A	L/R = 40 ms
125 V	0.30 A	L/R = 40 ms
250 V	0.20 A	L/R = 40 ms

Cyclic Capacity (2.5 cycles/second):

24 V	0.75 A	L/R = 40 ms
48 V	0.50 A	L/R = 40 ms
125 V	0.30 A	L/R = 40 ms
250 V	0.20 A	L/R = 40 ms

Note: Breaking and Cyclic Capacity per IEC 60255-0-20: 1974.

Note: EA certified relays do not have MOV protected standard output contacts.

High-Current Interruption Option for Extra I/O Board:

30 A Make per IEEE C37.90: 1989
6 A continuous carry at 70ºC; 4 A continuous carry at 85ºC
50 A for one second
MOV protected: 330 Vdc, 130 J;
Pickup time: Less than 5 ms.
Dropout time: Less than 8 ms, typical.

Breaking Capacity (10,000 operations):

24 V	10 A	L/R = 40 ms
48 V	10 A	L/R = 40 ms
125 V	10 A	L/R = 40 ms
250 V	10 A	L/R = 20 ms

Cyclic Capacity (4 cycles in 1 second, followed by 2 minutes idle for thermal dissipation):

24 V	10 A	L/R = 40 ms
48 V	10 A	L/R = 40 ms
125 V	10 A	L/R = 40 ms
250 V	10 A	L/R = 20 ms

Note: Do not use high-current interrupting output contacts to switch ac control signals. These outputs are polarity dependent.

Note: Breaking and Cyclic Capacity per IEC 60255-0-20: 1974.

Auxiliary Trip/Close Pushbuttons (0351Sxxx5/6/A/B models only)

Resistive DC or AC Outputs with Arc Suppression Disabled (see Tables 2.9 and 2.10):

30 A make per IEEE 37.90 : 1989
6 A Continuous carry
50 A for 1 second

MOVprotected: 250 Vac, 330 Vdc, 130 J

Breaking Capacity: (L/R = 40 ms):

48 V	0.5 A	10,000 operations
125 V	0.3 A	10,000 operations
250 V	0.2 A	10,000 operations

High Interrupt DC Outputs with Arc Suppression Enabled:

30 A make per IEEE 37.90 : 1989
6 A Continuous carry
50 A for 1 second

MOV protected: 330 Vdc, 130 J

Breaking Capacity: 10 A 10,000 operations
48 and 125 Vdc (L/R = 40 ms)
250 Vdc (L/R = 20 ms)

Breaker Open/Closed LEDs:

250 Vdc:	on for	150–300 Vdc;	192–288 Vac
125 Vdc:	on for	80–150 Vdc;	96–144 Vac
48 Vdc:	on for	30–60 Vdc;	
24 Vdc:	on for	15–30 Vdc	

With nominal control voltage applied, each LED draws 8 mA (max.). Jumpers may be set to 125 Vdc for 110 Vdc input, and set to 250 Vdc for 220 Vdc input.

Optoisolated Input Ratings

When used with dc control signals:

250 Vdc:	on for	200–300 Vdc;	off below	150 Vdc
220 Vdc:	on for	176–264 Vdc;	off below	132 Vdc
125 Vdc:	on for	105–150 Vdc;	off below	75 Vdc
110 Vdc:	on for	88–132 Vdc;	off below	66 Vdc
48 Vdc:	on for	38.4–60 Vdc;	off below	28.8 Vdc
24 Vdc:	on for	15–30 Vdc		

When used with ac control signals:

250 Vdc:	on for	170.6–300.0 Vac;	off below	106.0 Vac
220 Vdc:	on for	150.3–264.0 Vac;	off below	93.2 Vac
125 Vdc:	on for	89.6–150.0 Vac;	off below	53.0 Vac
110 Vdc:	on for	75.1–132.0 Vac;	off below	46.6 Vac
48 Vdc:	on for	32.8–60.0 Vac;	off below	20.3 Vac
24 Vdc:	on for	12.8–30.0 Vac		

AC mode is selectable for each input via Global settings IN101D–IN106D; IN201D–IN208D. AC input recognition delay from time of switching: 0.75 cycles maximum pickup; 1.25 cycles maximum dropout.

Note: 24, 48, 125, 220, and 250 Vdc optoisolated inputs draw approximately 5 mA of current, 110 Vdc inputs draw approximately 8 mA of current. All current ratings are at nominal input voltages.

Time-Code Input

Relay accepts demodulated IRIG-B time-code input at Port 2. Relay time is synchronized to within ±5 ms of time-source input.

Serial Communications

Two rear-panels and one front-panel EIA-232 serial communications port. Rear-panel EIA-485 serial port with 2100 Vdc of isolation.

Per Port Baud Rate Selections: 300, 1200, 2400, 4800, 9600, 19200, 38400

Dimensions

See Figure 2.1.

Weight

16 lbs (7.24 kg)—3U rack unit height relay

Routine Dielectric Test

Current inputs, optoisolated inputs, and output contacts: 2500 Vac for 10 seconds.
Power supply: 3100 Vdc for 10 seconds.

IEC 60255-5 Dielectric Tests : 1977:

2500 Vac for 2 seconds on analog inputs, optoisolated inputs, and output contacts.

3100 Vdc for 2 seconds on power supply.

Operating Temp.

-40° to 185°F (-40° to +85°C) (type test).
(LCD contrast impaired for temperatures below -20ºC.)

IEC 60068-2-1: 1990 Basic environmental testing procedures, Part 2: Tests - Test Ad: Cold (type test).

IEC 60068-2-2: 1974 Basic environmental testing procedures, Part 2: Tests - Test Bd: Dry Heat (type test).

Environment	*IEC 60068-2-30: 1980 Basic environmental testing procedures, Part 2: Tests, Test Db and guidance: Damp heat, cyclic (12 + 12-hour cycle)*, (six-day type test). *IEC 60529: 1989-[EN 60529 – 1992] Degrees of Protection Provided by Enclosures (IP code): Object penetration and dust ingress,* IP30 for category 2 equipment.
RFI and Interference Tests	*IEEE C37.90.1 - 1989 IEEE SWC Tests for Protective Relays and Relay Systems* (3 kV oscillatory, 5 kV fast transient) (type test). *IEEE C37.90.2 - IEEE Trial-Use Standard, Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers, 10* V/m (type test). Exceptions: 5.5.2(2) Performed with 200 frequency steps per octave. 5.5.3 Digital Equipment Modulation Test not performed. 5.5.4 Test signal turned off between frequency steps to simulate keying. *IEC 60255-22-1: 1988 Electrical disturbance tests for measuring relays and protection equipment, Part 1: 1 MHz burst disturbance tests.* Severity Level 3 (2.5 kV common mode, 2.5 kV differential) (type test). *IEC 60255-22-3: 1989 Electrical relays, Section 3: Radiated electromagnetic field disturbance tests*, Severity Level 3 (10 V/m) (type test). *IEC 60255-22-4: 1992 Electrical disturbance tests for measuring relays and protection equipment, Section 4 - Fast transient disturbance test,* Severity Level 4 kV at 2.5 kHz and 5 kHz (type test).
Impulse Tests	*IEC 60255-5: 1977 Electrical relays, Part 5: Insulation tests for electrical relays, Section 6: Dielectric Tests, Series C (2500 Vac on analog inputs; 3000 Vdc on power supply, contact inputs, and contact outputs). Section 8: Impulse Voltage Tests*, 0.5 Joule 5 kV (type test).
Vibration and Shock Test	*IEC 60255-21-1: 1988 Electrical relays, Part 21: Vibration, shock, bump, and seismic tests on measuring relays and protection equipment, Section One - Vibration tests (sinusoidal),* Class 1 (type test). *IEC 60255-21-2: 1988 Electrical relays, Part 21: Vibration, shock, bump, and seismic tests on measuring relays and protection equipment, Section Two - Shock and bump tests,* Class 1 (type test). *IEC 60255-21-3: 1993 Electrical relays, Part 21: Vibration, shock, bump, and seismic tests on measuring relays and protection equipment, Section Three - Seismic tests,* Class 2 (type test).
ESD Test	*IEC 60255-22-2: 1996 Electrical disturbance tests for measuring relays and protective equipment, Section 2: Electrostatic discharge tests*, Severity Level 4 (8 kV contact discharge all points except serial ports, 15 kV air discharge to all other points) (type test).

2.0 PRODUCT SPECIFICATIONS

2.1 Electrical (@ +25 degrees Celsius).

Outputs:	- 16 KU series type relays or 8 KUL latching type relays. - contacts available per relay: Form 1X Form 2C Form 2A
Contact Ratings: (KUE)	10A @ 150 VDC (1X). 5A @ 150 VDC (2A). 3A @ 150 VDC (2C).
Isolation Rating:	2,200 VRMS (KU relay).
Di-Electric Rating:	- 1000 VDC.
Protection:	- SWC as per ANSI / IEEE C37.90.1-1974 . 5KV, 1.2 / 50 microsec as per IEC-255-4.

2.2 Environmental

Operating Temperature Range: -30 degrees Celsius to +70 degrees Celsius.

Humidity:	<95%, non-condensing @ +40 degrees Celsius.

2.3 Physical

Dimensions:	19.0 x 5.25 inches KI1. 19.0 x 7.00 inches KI2.
Terminations:	- KI1 - compression terminal blocks #12 AWG (max.). - KI2 - barrier terminal blocks.

SIERRA ENERGY GROUP
Market Intelligence and Research Solutions

T&D Automation Market Summary

June 2006

ENERGY CENTRAL®

SIERRA ENERGY GROUP
Market Intelligence and Research Solutions

Study Objectives

From November 2005 to May 2006, Sierra Energy Group ("SEG") has been engaged in an extensive study of the US/Canadian T&D Automation market for the purpose of assessing capital spending trends in the area of T&D automation, and identifying new projects that utilities of all types will be involved in over the next few years. Cumulatively, this project and market data tell us much about the state of the industry and the commitment that is being made by utilities today to upgrade or replace aging communications and operations infrastructure.

It was not the intent of this study to cover all aspects of utility automation in use by the utility industry today. Its focus on operational data monitoring and control has centered around EMS/SCADA systems, distribution and substation automation and associated communications infrastructure and hardware devices.

SEG has conducted this extensive research initiative to learn how much attention is being placed on improving network infrastructure and which utility types are involved in these types of projects. Over 650 utilities of all types were contacted over this 6 month period, and a significant number of projects were identified. The past few years have brought a return to reasonable levels of profitability for many utilities, and it appears they have again begun to invest in critical systems and infrastructure. Our analysts have reported a significant amount of market activity in all categories included within the study.

Of course, utilities are not all driven by the same sets of goals and objectives. Investor owned utilities, municipals and rural electrics each have their own form of governance, and will make purchasing decisions based on the competitive and regulatory environment in which they operate. As the study was conducted, SEG analysts found that many utilities have adopted phased upgrade programs that no longer employ the old outdated "forklift" approach to system replacement. It has also become clear that the effects of an aging work force have begun to hamper the efforts of many utilities to manage several projects at the same time. Hence, as utilities grapple with everyday challenges such as repairing storm damage and improving customer service, they are finding that capital improvement projects must wait in line until sufficient staff resources become available.

Perhaps the highest priority for many utilities is the need to take a serious look at network security involving their older systems. Our analysts found a growing trend towards replacement of older, outdated systems with new systems using encrypted communications that are less vulnerable to outside penetration. New NERC and FERC guidelines are being implemented that encourage utilities to achieve a high level of monitoring and control capability in order to meet improved ISO/RTO interconnect requirements.

SIERRA ENERGY GROUP
Market Intelligence and Research Solutions

Study Parameters

This study was conducted during the six month period from November 2005-May 2006, and involved contact with 664 utilities in the U.S. and Canada. Our analysts have attempted to include a representative group of utilities covering all utility types and sizes. Figure 1 below provides a breakdown of the survey results by utility type.

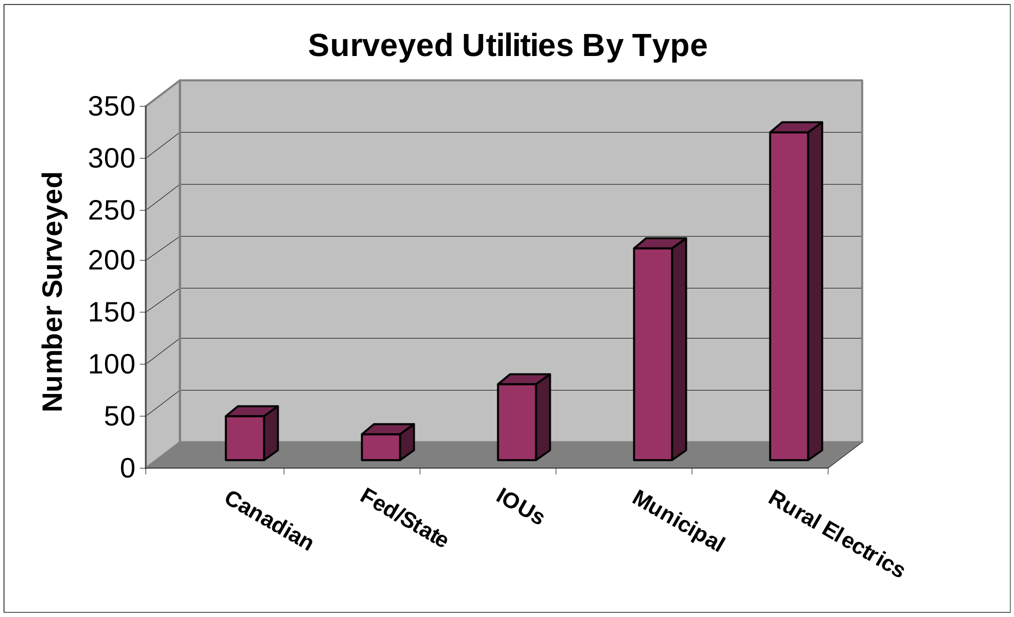


Figure 1

Data for this study was conducted through use of a specially designed survey form intended to ensure that data gathered is consistent and provides a significant amount of quantitative data for comparison purposes. Among the information collected was:

- Information on Current Systems and Supplier
- Communications Type and Protocol
- Consultant Information if Available
- Expected Project Award Dates
- Future Project Costs
- Planned Award Date
- Selected Vendor if Known

Recognizing that a much larger number of municipals and rural electric cooperatives exists in the U.S., it is not surprising that the survey results reflected a significantly greater number of these utilities.

SIERRA ENERGY GROUP
Market Intelligence and Research Solutions

Project Survey Results

During the course of the 6 month survey period, a total of 490 projects were identified. As might be expected, many of the larger reported projects were attributed to the investor owned utility category. Figure 2 shows the relative comparison between number of calls (interviews completed) and value of reported projects. In the investor owned utility category, for example, 11% of the completed surveys produced 42% of the reported project dollar activity.

Rural electric cooperatives also accounted for a significant amount of market activity. During the 6 month study period, 47% of the completed surveys involved rural electrics, producing 34% of reported project dollar value, suggesting that rurals have finally begun making important investments in critical network infrastructure.

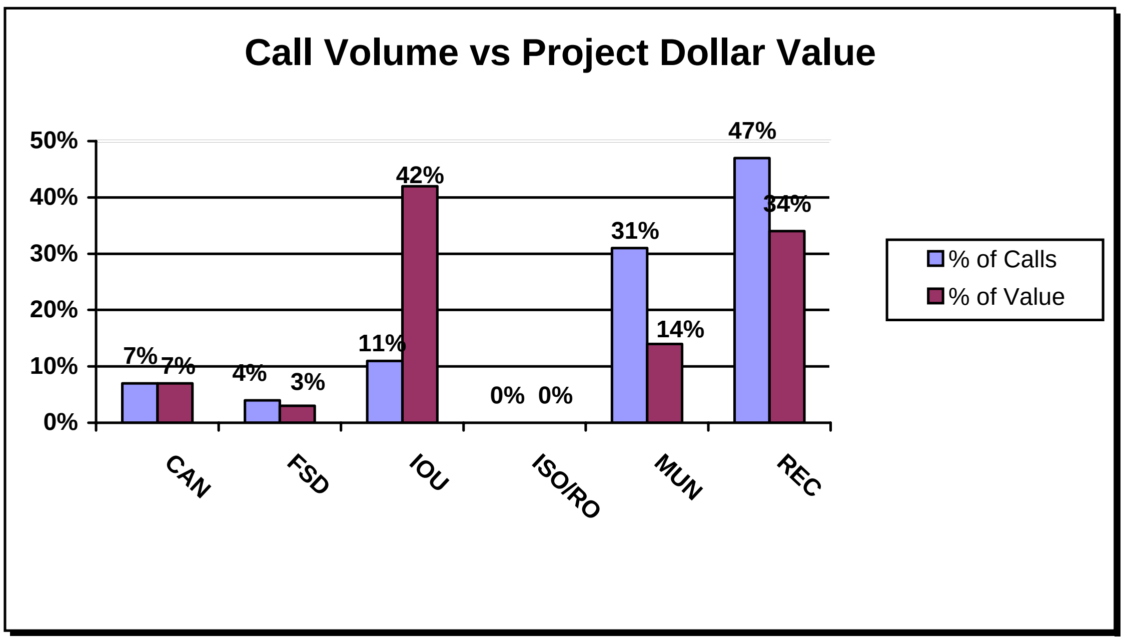


Figure 2

Municipal utility activity, while not matching the strong project activity of the investor owned and rural electric sectors, nonetheless showed surprising strength with in excess of $10 million in projects identified. It appears that municipals have finally begun to take a serious look at their network automation systems, and are proceeding with projects that upgrade their systems and make better use of their fiber optic communications networks.

Our analysts report that many municipals have opted to proceed with automated meter reading first, however, in the belief that the benefits of AMR, including applications such as improved outage detection, will carry over to their other systems. In fact, many utilities have simultaneously begun moving ahead with communications upgrades with the intention of using their increased bandwidth to accommodate both new SCADA and distribution automation systems along with AMR. It also appears that municipals' aging work force issues have become a factor in moving ahead with many network automation projects, including substation automation, to address staffing issues that have produced a shortage of personnel who are available to conduct field monitoring and switching operations.

In addition to rural electrics, the number of municipal utilities is also significantly greater than the number of investor owned utilities, which accounts for the larger number of completed surveys for the municipal industry sector. We also observed that relatively few forklift replacements of automation systems are taking place as municipals proceed with smaller substation automation projects and convert to DNP, Modbus and other open standards such as TCP/IP.

Reported Market Activity

Over the six month period of the study, our analysts have identified in excess of $76 million in planned market activity. As previously mentioned, investor owned utilities have accounted for most of the larger projects, including the majority of full system replacements and major upgrades. We believe that many of these projects have been initiated in response to pressures from NERC and FERC to improve network reliability and strengthen utility network interconnects. Figure 3 below provides a dollar breakdown of reported market activity.

Many older systems have continued to use proprietary protocols that have limited their ability to smoothly integrate SCADA with other systems. As the need for improved network switching and substation automation functions has increased, it appears many utilities have struggled with the ability to handle multiple protocols effectively.

SIERRA ENERGY GROUP
Market Intelligence and Research Solutions

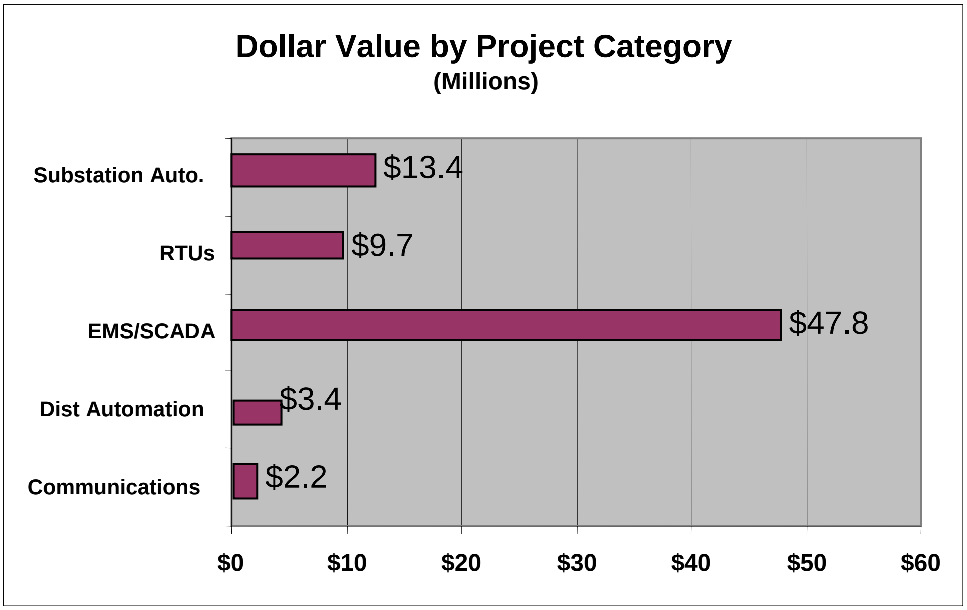


Figure 3

It is interesting to note that substation automation has become the second largest category of project activity. A significant number of utilities have begun to upgrade their substation capabilities, including installation of metering and fault monitoring devices, protective relays, regulator and tap changer controls and data collectors and gateways. Many have also begun to install devices for converting intelligent electronic device (IED) protocols to DNP or TCP/IP. Use of Ethernet communications over fiber or wireless Ethernet is also gaining increased acceptance.

Many utilities are observed to be engaged in multi-year substation automation projects to spread out the cost of implementing substation equipment and time their projects to coincide with the build out of fiber and other communications upgrades. In some cases, communications bandwidth has become the limiting factor as utilities implement AMR, work force management, vehicle positioning and other systems that also have extensive field communications requirements.

Figure 4 below provides a breakdown of market activity by project type. RTU and substation automation projects, while not the leader in dollar volume, constitute the largest two categories of reported projects. Clearly, the smaller dollar totals for these categories reflect a trend toward smaller projects, including replacement of older RTUs and installation of new substation automation devices in utility substations. Many utilities have begun mixing new RTUs in with older devices, requiring use of multiple network protocols and more sophisticated communications infrastructure.

SIERRA ENERGY GROUP
Market Intelligence and Research Solutions

Figure 4: Summary of Market Activity

Project Category	Total Projects	USD ($000s)
EMS/SCADA	114	$47,795
Dist. Automation	40	$3,435
Substation Automation	148	$13,380
RTU Projects	142	$9,720
Communications	46	$2,192
Totals	490	$76,522

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.

Distribution automation projects remain the smallest category of reported projects. While switching functions have received increased priority from investor owned utilities, we continue to see reluctance on the part of municipals and rural electrics to conduct remote switching functions, in part because of reduced need for EMS functions and issues of limited operational control. Many municipals and rural electrics continue to operate older SCADA systems that would require considerable operations center upgrades to add the ability to conduct remote switching operations. An additional but still significant reason is a concern by some utilities that such operations could pose a safety risk as utility field crews work on lines that might suddenly become energized.

If market activity is broken down by utility type, one can see that rural electrics have reported the largest amount of projects, even though the dollar value of these projects is less than for investor owned utilities. As might be expected, however, the investor owned utility category reports the largest average project cost. Figure 5 below provides the breakdown for all utility types.

SIERRA ENERGY GROUP
Market Intelligence and Research Solutions

Figure 5: Market Activity by Utility Type

Utility Type	Total Interviews	Total Projects	Dollar Value (000)
Canadian	43	44	$5,705
Federal, State, District	25	18	$1,933
Investor-Owned	73	68	$32,053
ISO/RTO	---	---	---
Municipal	205	136	$10,381
Rural Electric Co-ops	318	224	$26,450
TOTAL	**664**	**490**	**$76,522**

As we continue to examine the data, it is interesting to look at the breakdown of project categories by the number of projects reported for each. As previously mentioned, Figure 6 reveals that substation automation leads the project totals with 148 reported projects and has come into its own as a key focus of network automation activity. Rural electrics lead the way with 70 substation projects, suggesting that many of these projects are add-ons that can be easily managed with limited budgets and staffing resources.

There is much anecdotal evidence that points to a changing philosophy whereby utilities are replacing older high maintenance RTUs with IEDs located within the substations. Many of the advanced IEDs are serving multiple functions including acting as gateways or data collectors with multi-port and multi-protocol capability. As new substations are built and older substations are upgraded, utilities are increasingly using fiber optic communications within the substation to interconnect with many substation IEDs. Some new multi-port data collectors will permit a utility to run multi-channel communications back to the data center so that both proprietary and open protocols can be used simultaneously. The survey results suggest that rurals are moving in this direction in a big way.

SIERRA ENERGY GROUP
Market Intelligence and Research Solutions

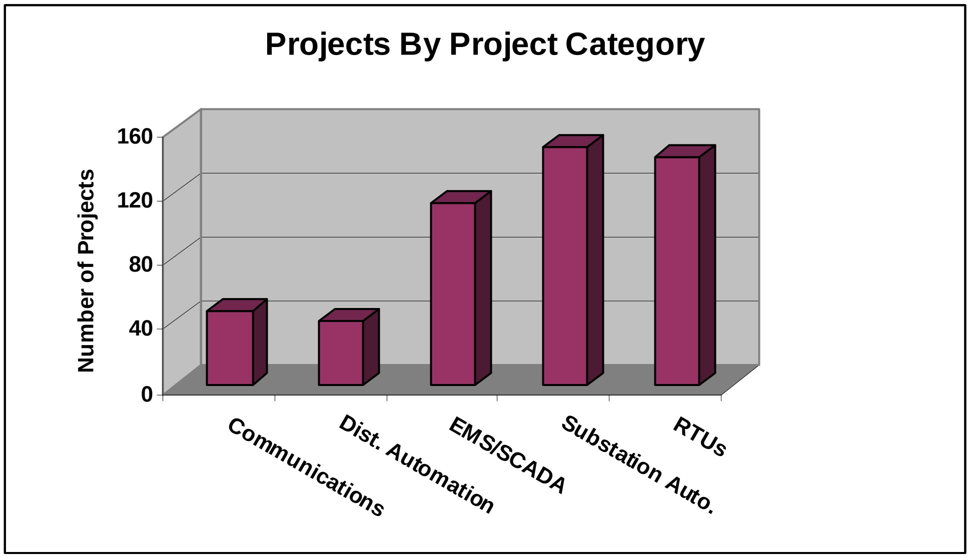


Figure 6

It is also clear, however, that the market for replacement RTUs is not expected to disappear anytime soon. The use of open protocol standards has opened the door for utilities to replace outdated RTUs with newer RTUs that communicate over utility networks that handle both open and proprietary network protocols at the same time. In the past, utilities were forced to replace older SCADA systems when vendors discontinued manufacturing replacement parts and performing repairs. Vendors have now come onto the scene that manufacture interchangeable RTU devices which enable utilities to extend the life of their older SCADA systems.

Vendor "Mentions"

Because the vendor selection process is usually predicated on the use of an RFP for project bid purposes, especially when large systems are involved, only limited vendor information can be derived from a study of this type. Utility personnel are understandably reluctant to disclose project bid information in advance of project award, and in many cases a fairly long lead time exists once project approval is received before specifications can be developed, proposals are received and evaluated and a vendor is eventually selected. Consequently, it is typical in a study of this type to receive many responses indicating that selection of the anticipated vendor remains "open".

Figure 7 below provides a breakdown of vendor "mentions", which as expected shows a significant number of open responses where vendor selection is concerned. Since larger systems typically require much more planning and lead time, it is reasonable to conclude that many of the more sophisticated, high end EMS/SCADA installations are included in the open category. Distribution and substation automation projects typically involve the purchase of specific devices that interconnect with a utility's head end master station software, rather than a complete system. For this reason, equipment vendors do not typically show up in the study results since utility managers rarely use only one manufacturer for all equipment purchases.

Among the more notable participants in this category, however, are Schweitzer labs, Cooper, Basler, S&C, Satec, Beckwith, G&W, GE, Joslyn, Schneider and others. In the communications area, we find MDS, Alligator, DataRadio, Radius, Motorola, and more. Some of the more notable substation software providers are Cybectec, Subnet Solutions, Bow Networks, Cannon, and PML/Schneider Electric. Obviously, this is only a small number of the system and equipment vendors that are successfully marketing network automation products in utility markets today.

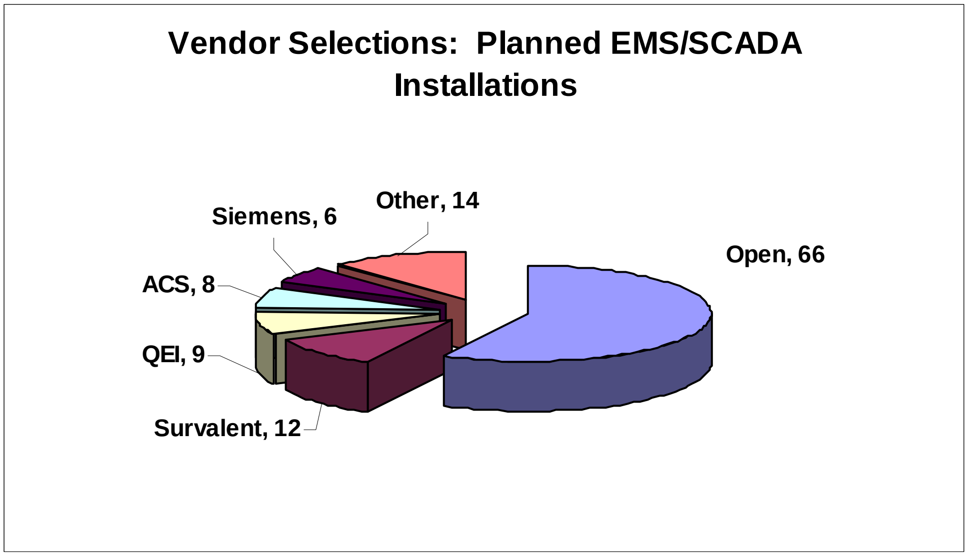


Figure 7

Survalent Technology received the highest number of vendor mentions among survey participants in our study. Of the 48 respondents providing a specific vendor selection, Survalent received 12 mentions, or 25% of the total. Other vendors receiving significant mentions were QEI, ACS and Siemens. No other vendors received more than 3 mentions, with the remaining vendors falling into the “other” category which constitutes 27% of the total mentions.

Our analysts believe that the large number of open vendor selections, which represents 58% of planned EMS/SCADA projects, is further influenced by several important factors:

- EMS/SCADA systems are becoming much more complex, involving more functionality and integrating with other enterprise utility systems

- Communications networks support multiple systems, provide much more bandwidth and frequently involve multiple paths such as fiber, WiFi, wireless Ethernet, frame relay and spread spectrum radio.

- Utilities have become much more price sensitive to the cost of these and other systems, and are increasingly more reluctant to accept pricing proposals that exceed staff's expectations.

Analysis of Market Conditions

Based on the results of this study, it is SEG's conclusion that the market for T&D automation systems is and will continue to be quite strong for the foreseeable future. Of the 664 utilities surveyed for this study, our analysts identified 490 different EMS/SCADA, substation automation, distribution automation, RTU and communications projects with a total dollar value in excess of $76 million. Given the thousands of investor owned, municipal and rural electric utilities existing in the U.S. and Canada, it is likely that the total market for T&D automation systems is substantially larger.

A significant number of changes is clearly taking place in the energy sector today. When the lights went out on August 14, 2003 placing 50 million people in darkness, the industry quite possibly changed forever. Many observers characterized the U.S. as having a third world transmission network that could not be relied upon to provide reliable electric service. While this conclusion was certainly overstated, the events of August 14 did expose some serious problems with the electricity grid that are continuing to be addressed by utilities even today.

The active market for T&D automation systems reflects to a significant degree the continuing fallout from the August blackout, and the resulting recommendations that have been provided by FERC and NERC for upgrading the electric utility grid. Additional steps were taken in 2005 with the enactment of the 2005 Energy Act, which among other things repealed the Public Utility Holding Company Act, provided FERC with greater enforcement authority and encouraged utilities to improve grid reliability by investing in improved network infrastructure. These steps should all portend well for the future of utility automation in U.S. utility markets.

Many utilities operate SCADA systems that were placed into service 20-30 years ago, and are no longer performing at a high level. In some cases, manufacturers have quit producing parts for these older systems, and they cannot efficiently interface with today's advanced equipment and open protocols. With the improving economy over the past few years, utilities have now begun to address these deficiencies and we expect to see increasing levels of capital expenditures being authorized to upgrade or replace these antiquated systems. And with the growing trend towards ISO and RTO membership which requires minimum reliability standards for participation, investor owned utilities, municipals and even generation and transmission cooperatives are looking to further upgrade their interconnect protection and monitoring capabilities.

And finally a word on technology. Perhaps no other industry has undergone such dramatic change as the market for T&D automation systems and related equipment. New communications technologies are rapidly changing the automation landscape, with greater attention being placed on improving network security in addition to system performance. Open standards are in effect the standard by which EMS/SCADA systems interface with distribution automation, load control and new substation intelligent electronic devices (IEDs).

The trend today is towards an intelligent electric grid that integrates system control and enterprise asset management programs to support a life cycle cost optimization environment that doesn't compromise network reliability. Energy Central believes that these developments have created a fertile environment in which to market new technologies and systems.

A Case Study: How a Utility Automated and Integrated Data/Control for 4000 Pole-Top Switches and Protection Relays, and Reduced its SAIDI

Hervé Delmas, Eng. - Hydro-Quebec
Patrick Cossette, Eng. - Cooper Power Systems Inc., Energy Automations Solutions - Cybectec
Robert O' Reilly, Senior Applications Engineer - Cooper Power Systems Inc., Energy Automations Solutions - Cybectec

Abstract

The ability to cost-effectively monitor and control more than 4,000 pole-top devices spread throughout a large territory (958 189 square miles) is one of the great challenges that Hydro-Quebec faced in 2001 when it decided to integrate and automate its entire distribution network.

The main goal of this project was to reduce the duration of the interruption to its clients: with a faster means of identifying the interruption(s), customer satisfaction would go up! Moreover, because of the great distances covered by the distribution network in Quebec this item was identified as a priority by the utility. However, the question remained: On a project of this magnitude, would the goal of achieving a 20% reduction of the System Average Interruption Duration Index (SAIDI) be achievable?

The overall communications costs represent a major factor in this type of project. The paper presents the approaches selected by the utility in the implementation of this massive project on such a large territory, and how it also engineered the systems to provide high reliability and indirectly provide savings on the communications while targeting its 20% reduction in overall System Average Interruption Duration Index.

The case study will also explore how this colossal amount of data was brought back to the different systems and the approaches that Hydro-Quebec developed in the overall management of all these devices and their information.

A Short History

Since 1999, the SAIDI index in the Province of Quebec had reached a stable value at 2 hours per customer, per year. However, in the same period, 15% of Hydro-Quebec's customers had a reliability index higher than 4 hours.

Since outages remained a major concern for customers, and they were addressing these concerns to the energy regulatory body.

A major study was undertaken in order to identify and survey the potential schemes that would help Hydro-Quebec reach a more equitable reliability for the same rates and reduce the outage duration in selected sectors. Some of the scenarios evaluated consisted of:

- Remote fault indication only
- Optimized recloser installation (1 per feeder) <u>without</u> remote control
- Remote control of actual switches and breakers
- Remote control of actual switches and breakers with addition of breakers when needed
- Remote control of actual switches and breakers, addition of breakers when needed and automatic reconfiguration

This study confirmed that the solution of choice was the "automated distribution line" and was in accordance with the current industry trend, especially:

- CEATI Distribution Roadmap (January 2004)
- EPRI Advanced Distribution (June 2004)

Initial Pilot Project

Like all potential major projects, Hydro-Quebec undertook a small-scale pilot project to validate the automation of the distribution network approach. The objectives were:

- To remotely operate control equipment already on the distribution network, of which:
    - o 14 overhead line switches
    - o 2 circuit breakers
- To install a telecommunication network (conventional dial-up telephone lines)

After a period of nine months, a gain of one (1) hour in service reliability (i.e. 22%) had been measured on the remote control feeders of the pilot project.

Project Goals

From the results obtained during the initial pilot project, Hydro-Quebec's commitments with respect to the improvements provided by the Automation Program would be:

- The ratio of customers with a reliability index above 4 hours, was then at about 15% (500,000 customers) and it should drop to 8%;
- SAIDI should be reduced by 15 minutes per customer, per year in average;
- Labor costs should be reduced significantly;
- Total amount of customer claims should be cut down by about 20%.

The automation program would include the remote control of 3750 MV switches and breakers on 1100 feeders and be implemented in a time frame of approximately 6 years

The final goals of the project are:

- *In the short-term, a* ***Reliability gain*** – the project's main focus is that only technology is required to achieve the estimated gain;
- *In the long-term, an* ***Intelligent network*** – should be considered as a long term goal and focus on the real objectives.

Technical Challenges

The planning of a project involving some 3,750 pole top devices to be implemented over a period of nearly 6 years, of which the first equipment installations would be in 2006 thus only providing a time frame of 4 years to install the new equipment (approximately 1000 cabinets a year).

In integrating these devices across the Province of Quebec, which covers an area of 1,540,680 square kilometers (roughly 3 times the size of the state of California), the communications infrastructure required is critical to its success. Without the proper communications framework to control and receive data in a timely fashion, the project in itself would not be worthwhile. An overview of the telecommunications architecture is presented in figures 1 and 2.

Apart from the planning and manpower intricacies of the project; integrating the data that would be received from all of these new devices was also unique in its magnitude. These requirements can be summarized, has follows:

For Binary Inputs, the following provides a good representation:

- Equipment status

    - Equipment position
    - Recloser position
    - Local mode
    - Alternate mode
    - Neutral protection
    - Fault detection
- Power status
    - Battery status
    - Power supply status
    - Charger input status
- Environment
    - Cabinet door position
    - Handle stowed
    - Water penetration (underground)
    - Pump working (underground)
- Miscellaneous
    - Decoder problems (drift, calibration, checksum)
    - Over current, undershoot, etc.
    - Counters

From the previous list, one can easily see that on average there are by far more than 100 binary inputs per equipment.

As for the analog data, the following presents a summary of the potential inputs per equipment:

- Current, angle and magnitude (A,B,C,N)
- Voltage, angle and magnitude (A,B,C,N)
- MegaVar, MegaWatt.
- Indoor and outdoor temperature.

From this list the reader can easily visualize a possibility of more than 20 analog pieces of data per equipment.

When one adds up these 120 binary and analog data points for each of the 3750 nodes, the total is 450,000 data points at any given time for the whole system!

Hence, the first technical challenge in reading and integrating this massive amount of information was coming up with front end gateway systems to handle all of these devices, and allowing for the next level of deployment, which would potentially add another 3000 devices to the network at a later date.

To manage the 450,000 data points generated from the first phase of the project, 5 regional control centers front end systems were setup to receive the information. Splitting up the information amongst the regional control centers has made data more manageable. Within this subdivision, each control center front end system has been designed to handle a peak load of 250,000 data points.

The front end communication processor (FEP) developed for this project is located at the 5 regional control centers, to collect and distribute the information from the different geographical areas. The FEP performs the following tasks:

- Manages communications with all field devices
- Performs data acquisition
- Provides information to the distribution control centers
- Allows remote control of the switches and protection relays
- Provides for redundancy of systems
- Supports security requirements (NERC)
- Supports multiple protocols such as:
  - DNP3
  - IEC870
  - 61850
  - Modbus
- Supports cluster architecture (fail over)
- Supports multiple communication links:
  - Modems
  - Serial line
  - Cellular
  - TCP/IP

The Unforeseen Challenge: the Human Factor

With the implementation phase underway, this far-reaching project is now subject to the human factor: from human resources and training needs to quality issues and installation challenges, Hydro-Quebec has resolved to meet each of these head-on.

First and foremost, this project's span is unprecedented in Hydro-Québec's recent past: more than 2000 persons are involved with the project, directly or indirectly. The sheer quantity of data produced by the pole-top devices makes it attractive and useful to a wide range of groups:

- Installation technicians
- Automation engineers and technicians
- Communications specialists
- Operators and their technical support teams
- Logistics and planning groups
- Device maintenance groups

The high number of interested parties makes project management more difficult. One must ensure not to end up with too many cooks spoiling the soup. Also, labor unions are a delicate matter to manage. For example, the project is affected by the installation personnel's ongoing negotiations for their work contract, which slows downs the speed of installation.

Another example of the human-resources challenges is related to new abilities that are now required to perform certain tasks. For example, equipment operators can now perform a lot of control tasks remotely, such as opening and closing switches. This requires that operators receive supplemental training with the new software. Also, it will have an impact on the way personnel is promoted to dispatch, since the dispatch task now requires computer and software skills. In a setting where promotions were given based on seniority, this change already has a profound impact on the project's advancement: as a pressure method during negotiations with Hydro-Quebec, operators have not taken training nor participated in the project meetings.

The second human factor has to do with quality issues. The cabinets were assembled by a third party, and there we some quality issues with the general workmanship of the cabinets. This has required a lot of vigilance and some adjustments with the cabinet supplier.

The third human factor is completely external to Hydro-Québec. The cabinets were designed to be installed at four feet from the ground, so that operators could access it without needing a ladder. Unfortunately, in urban areas, especially in Montreal, these cabinets have been judged to take up too much sidewalk space, and city authorities have forbidden Hydro-Québec from installing the cabinets as designed. Engineering teams must now find a solution to be as unobtrusive as possible to pedestrian traffic, while still being able to operate the equipment without needing to climb up the pole.

These unforeseen issues have had an effect on the rate of installed cabinets in the network. It is expected that only half of the planned installations will be performed in 2007 (400 instead of the planned 800), and that the expected rate of 1000 installations per year will only be reached by 2008.

Conclusion

We had planned the technology side in detail and very carefully, we also had planned the human factor (we thought). Today, looking back, we realize the technology aspects have been easy to handle and work with when required, but the sheer number of people involved has created an environment which is currently slow to react.

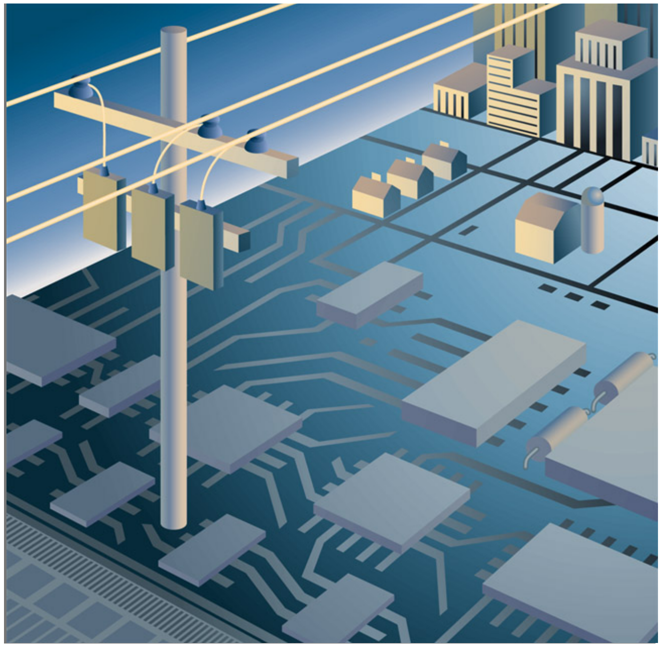
From a technology point of view, the integration at the Enterprise level of this magnitude of pole top devices with the planning of the communications infrastructure and of all the associated applications to provide the timely information at the different levels within the organization have been interesting to implement and put on line.

As of the writing of this paper, we have not had a chance to properly measure our SAIDI within the new architecture, but we are more than confident that, from the preliminary results we are seeing, we will be meeting the targets given to the energy regulatory body.

References

Hydro-Québec Distribution Automation Program – Regulatory Approach,
Denis Chartrand and Georges Simard Hydro-Québec

Hydro-Québec – Distribution Automation Roadmap 2005-2020,



EPRI Research Plan for Advanced Distribution Automation

Mark McGranaghan
Vice President
EPRI Solutions, Inc

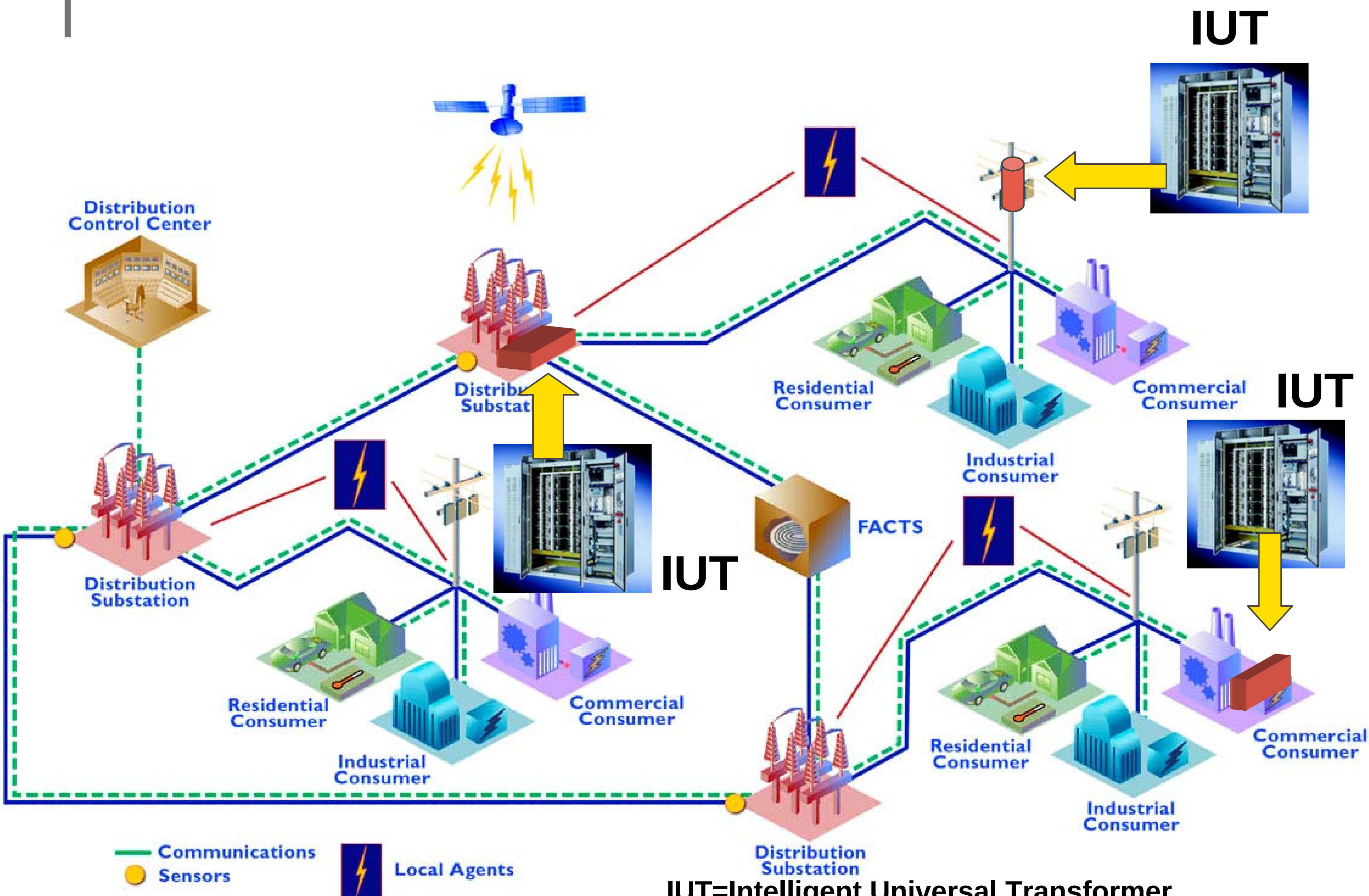
Frank R. Goodman, Jr.
Technical Lead: Distribution Automation
Electric Power Research Institute

IEEE Power Engineering Society
2005 General Meeting
San Francisco, CA
June 14, 2005

Outline

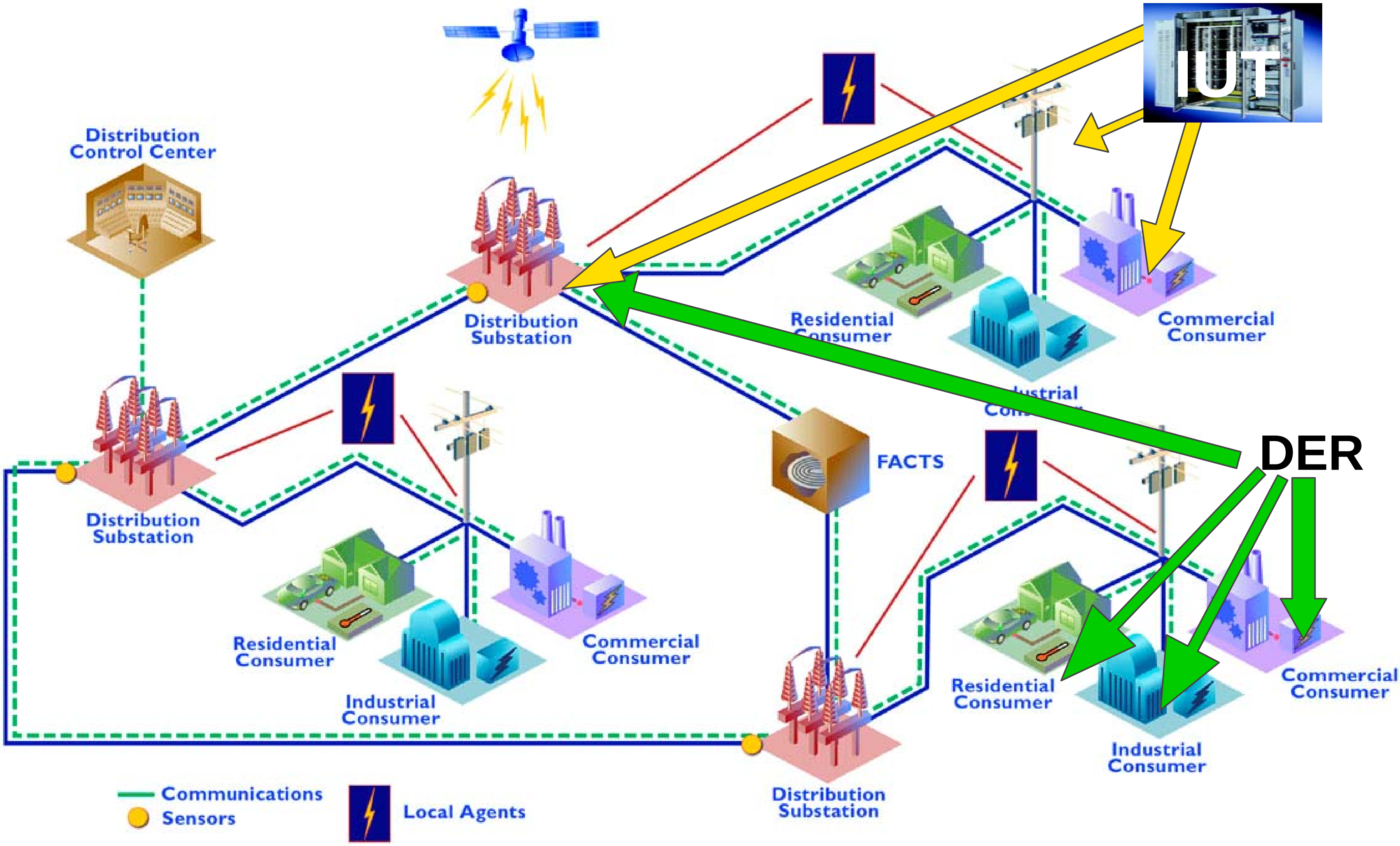
- Overview of Advanced Distribution Automation (ADA)
- Distribution Automation and Reliability
- The EPRI Advanced Distribution Automation research plan

ADA creates the distribution system of the future



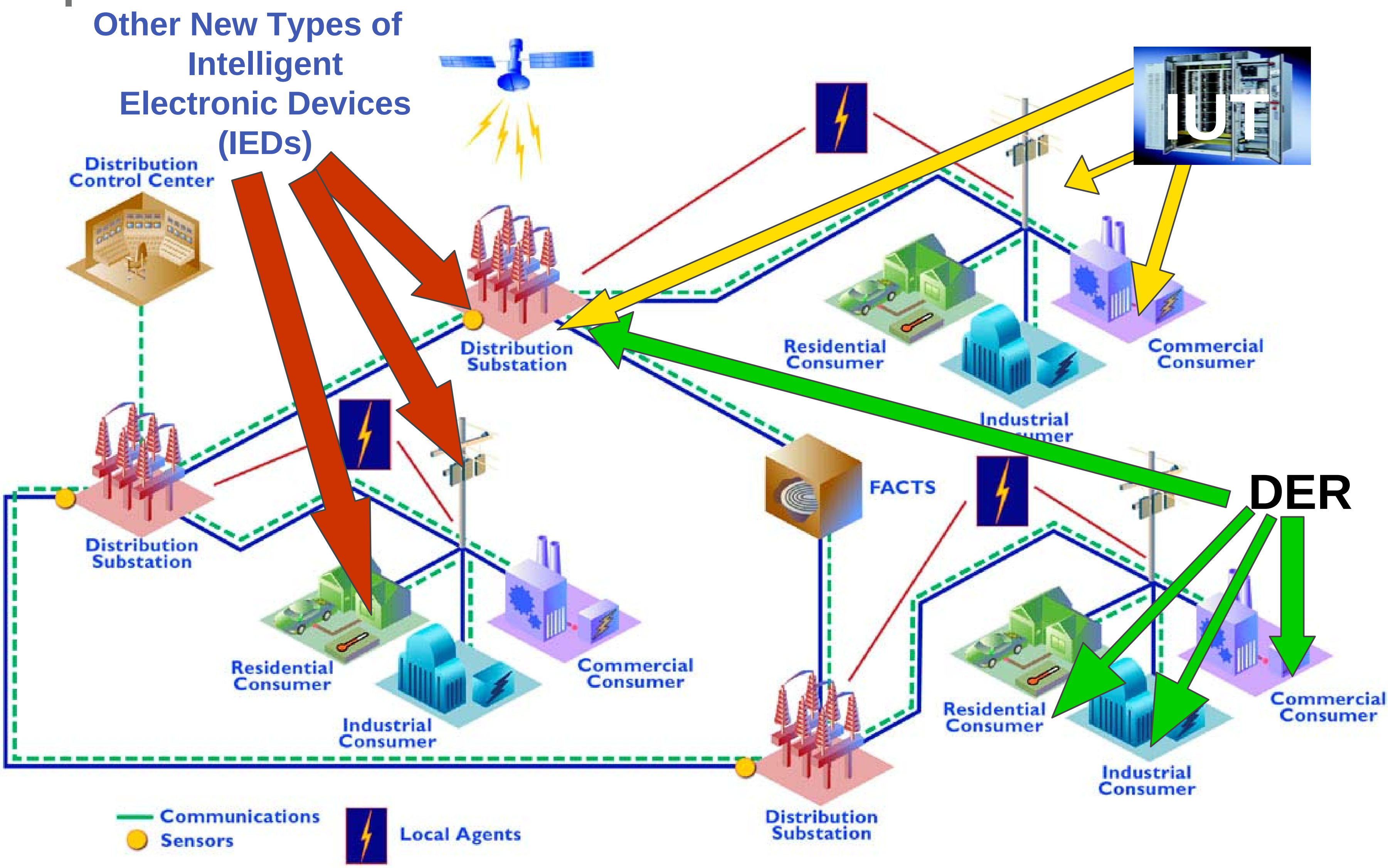
IUT=Intelligent Universal Transformer

DER integration is a component of ADA



IUT=Intelligent Universal Transformer

Other IEDs will be components of ADA



IUT=Intelligent Universal Transformer

Role of Intelligent Universal Transformer

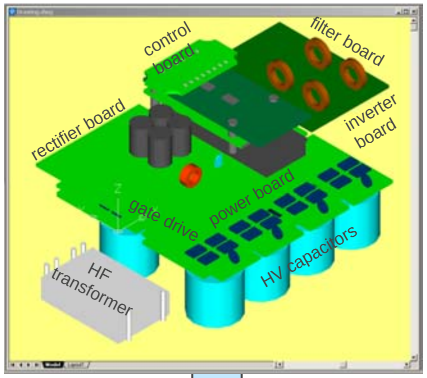
Core Technologies Needed

New State-of-the-Art Power Electronic Topology

New High-Voltage, Low-Current Power Semiconductor Device

Interoperable with Open Communication Architecture

All Solid-State Replacement for Distribution Transformers



Product Spin-offs

Emergency EHV transformer replacement (substations)

Other power electronic applications

Functions and Value

Traditional voltage stepping, plus..

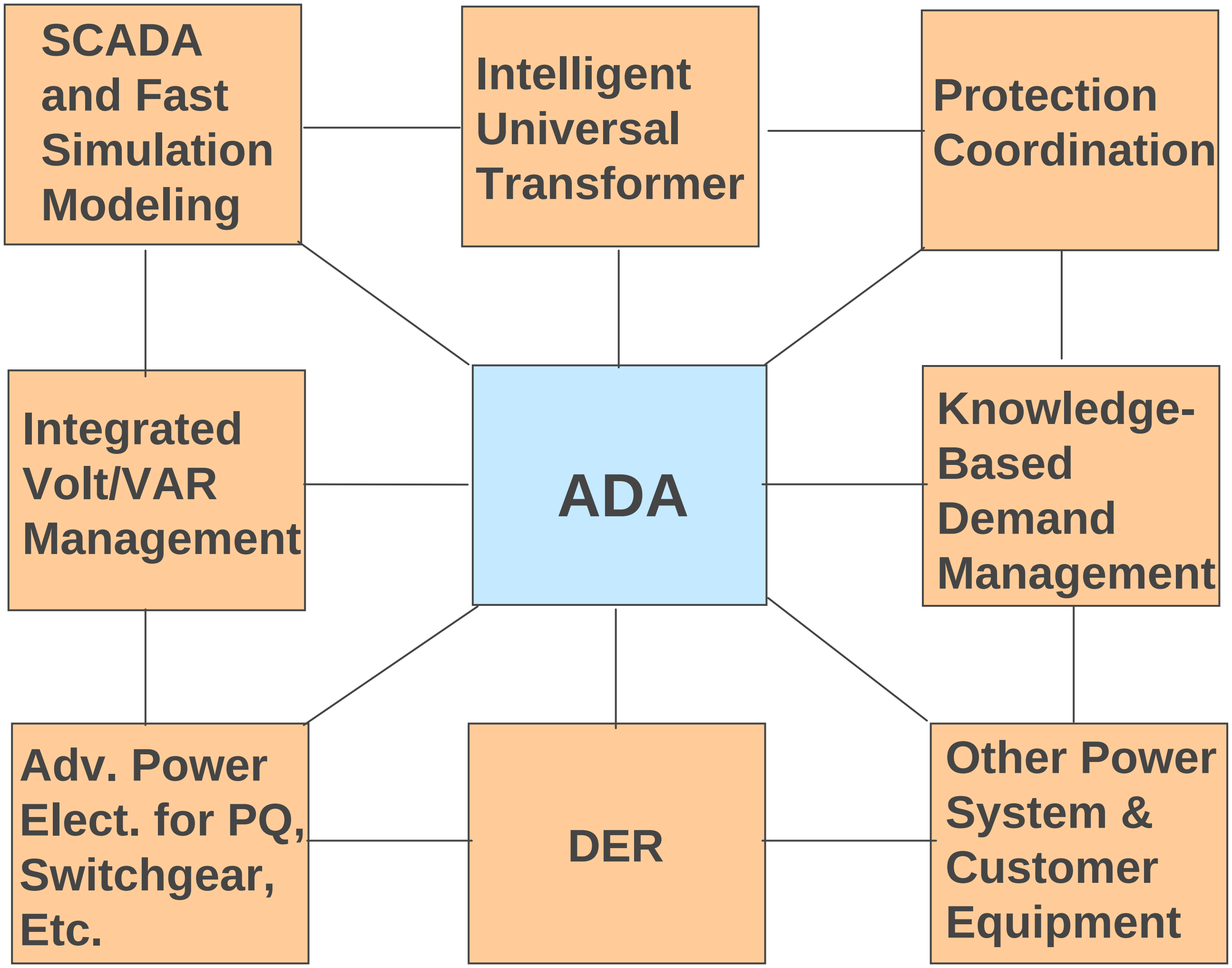
New service options, such as dc

Real-time voltage regulation, sag correction, system monitoring, and other operating benefits

Other benefits: standardization, size, weight, oil elimination

Cornerstone device for advanced distribution automation (ADA)

Future Distribution System Components Will Be Intelligent Electronic Devices (IEDs) That Are ***Interoperable***

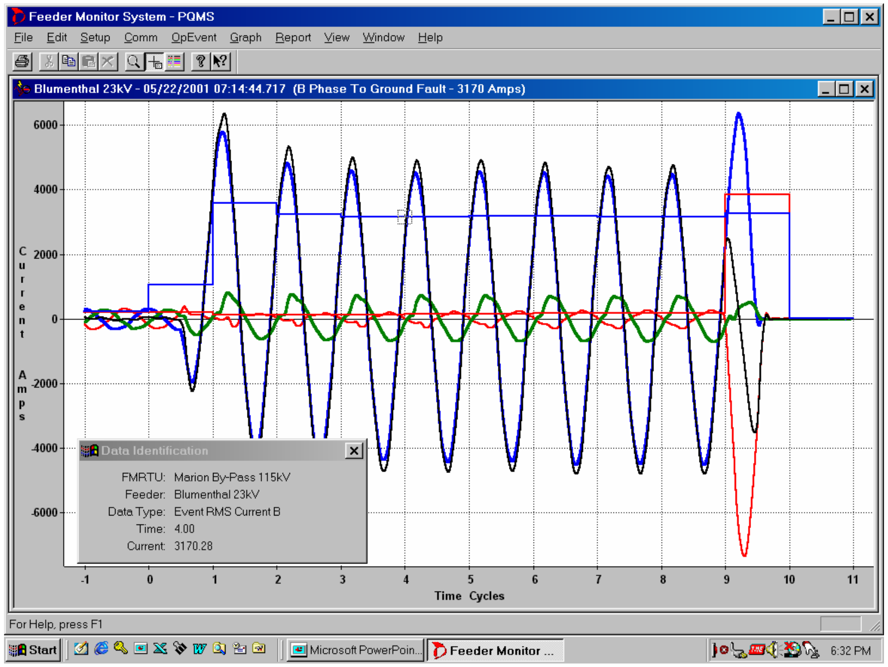


Distribution Automation
The most important impact on reliability

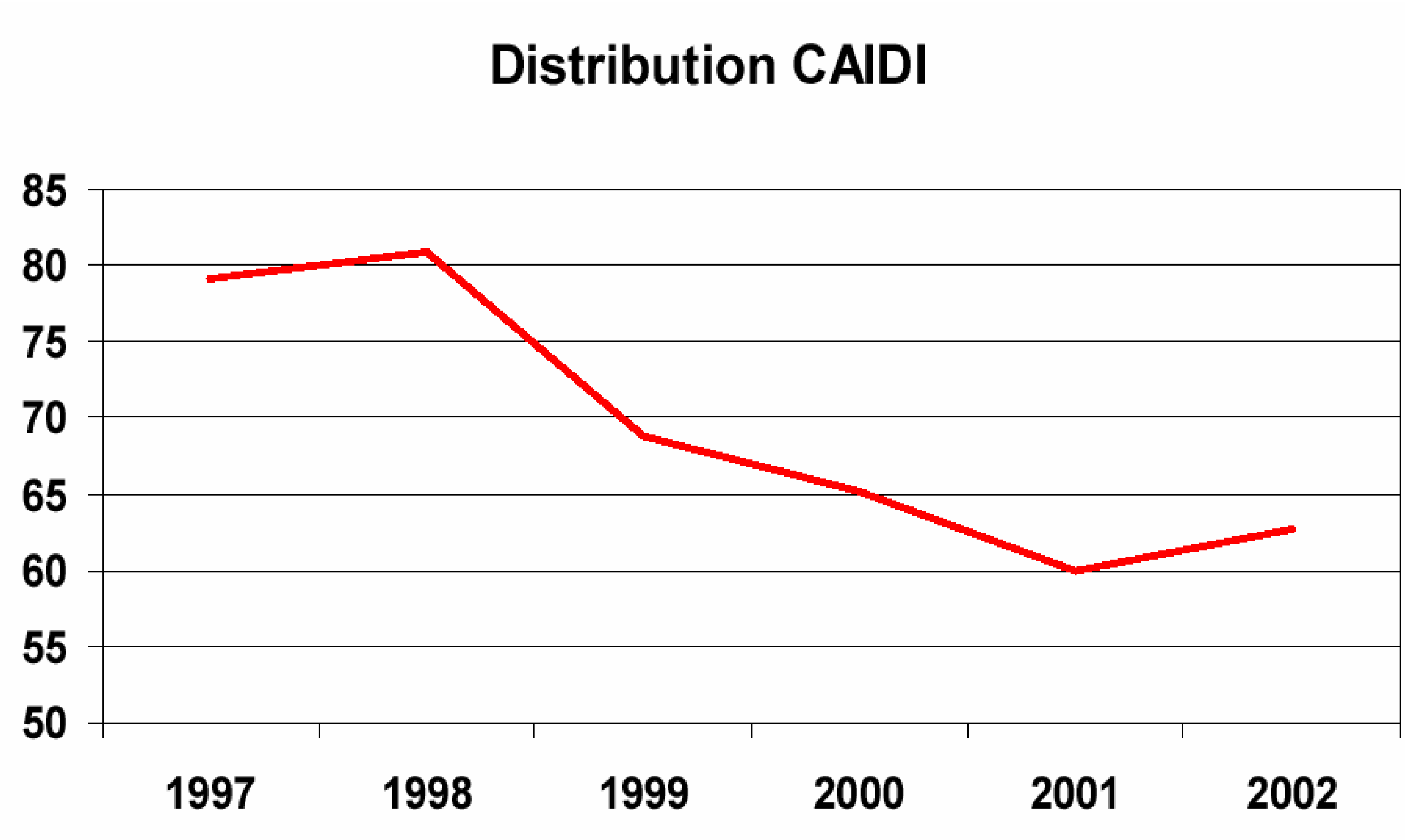
- Substations
  - Less than 1% of outages
  - Contribute 5% to reliability
- Primary distribution circuits
  - 44% of outages
  - Contribute 87% to reliability
- Secondary distribution
  - 55% of outages
  - Contribute 8% to reliability

Intelligent Monitoring Systems

- There is significant opportunity to improve reliability through the use of intelligent monitoring at the substation
- Further improvement when monitoring data from throughout the distribution system is available
- Examples
  - Incipient fault detection
  - Distribution fault anticipator
  - Equipment problem identification
  - Multiple faults in same location
  - Galloping conductors



Results of feeder monitoring system and fault locating – Carolina Power & Light



Integration of monitoring information is critical

RTU

Revenue Meter

DFR

Recloser Control

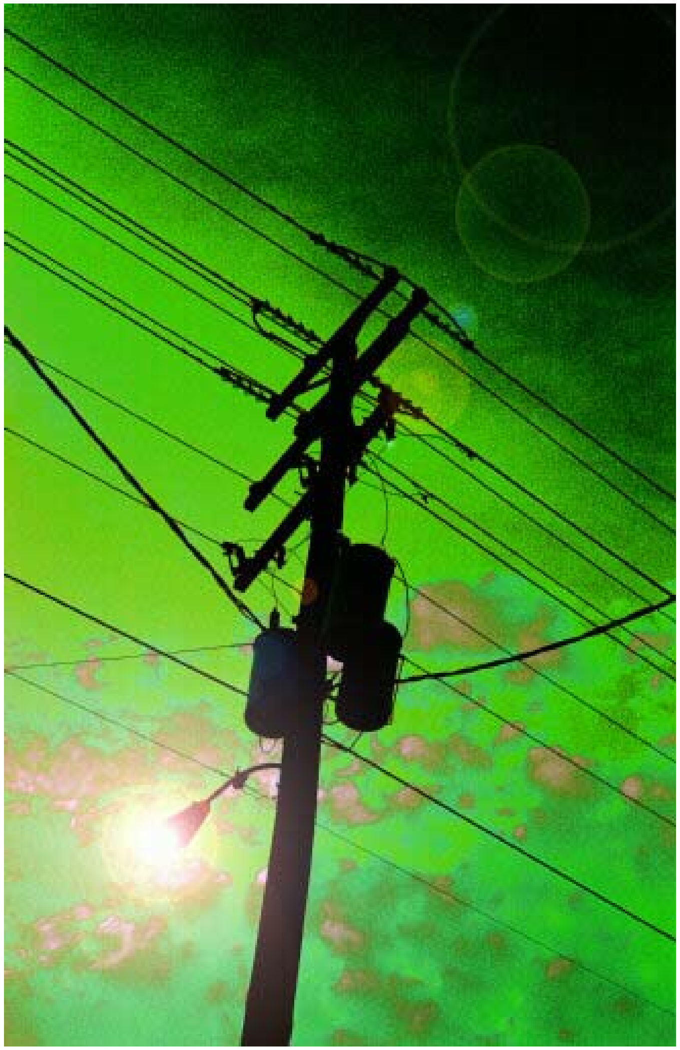
Relay

Capacitor Bank Controller

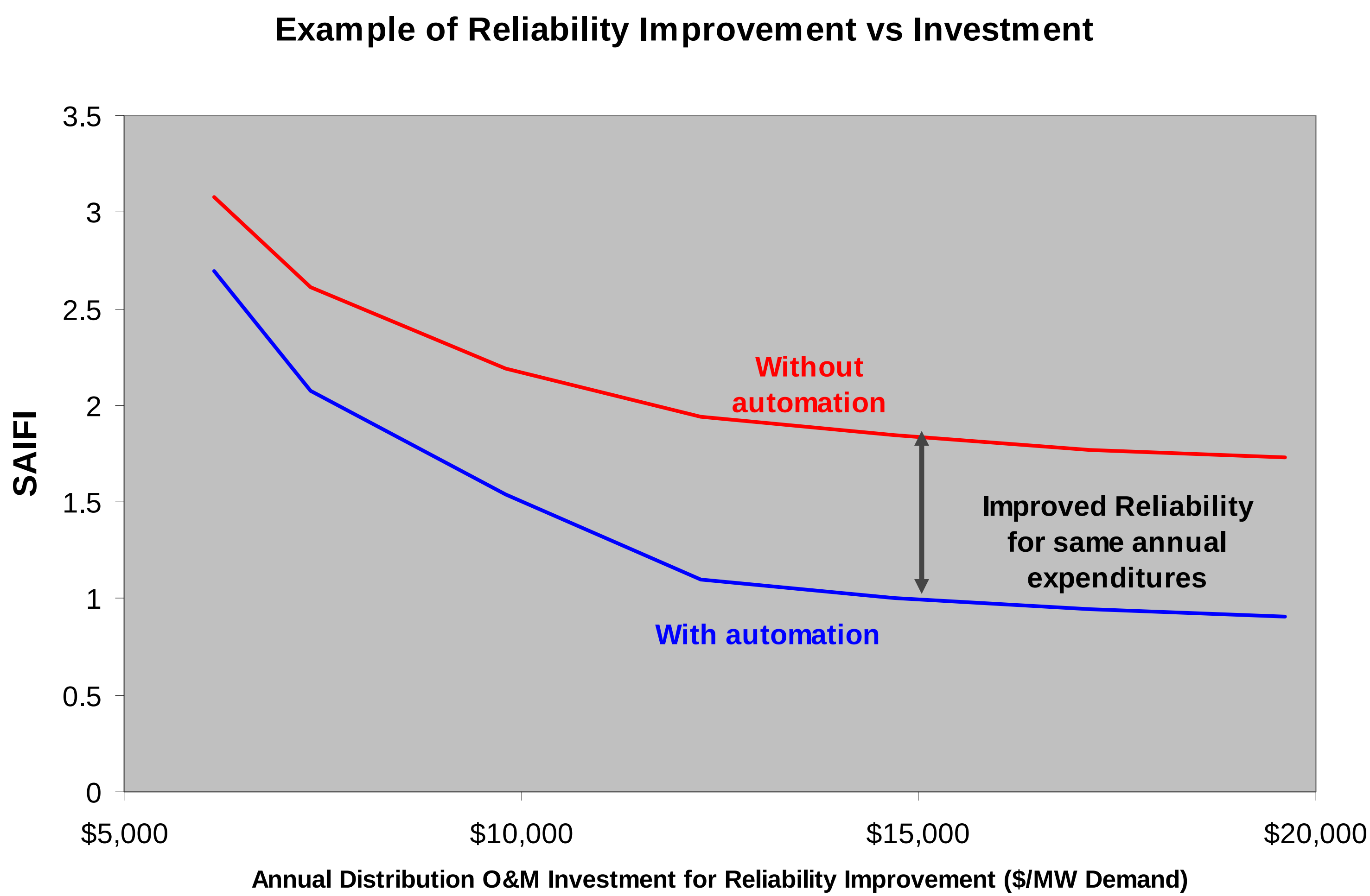
EPRI

Automating Distribution Feeder Circuits

- More flexible operation of distribution system
- Automated system response to disturbances and outages
- Improved reliability with multiple options for supplying load
- Optimized asset management and system efficiency
- Integration of DER to improve system performance and allow integration with energy management systems



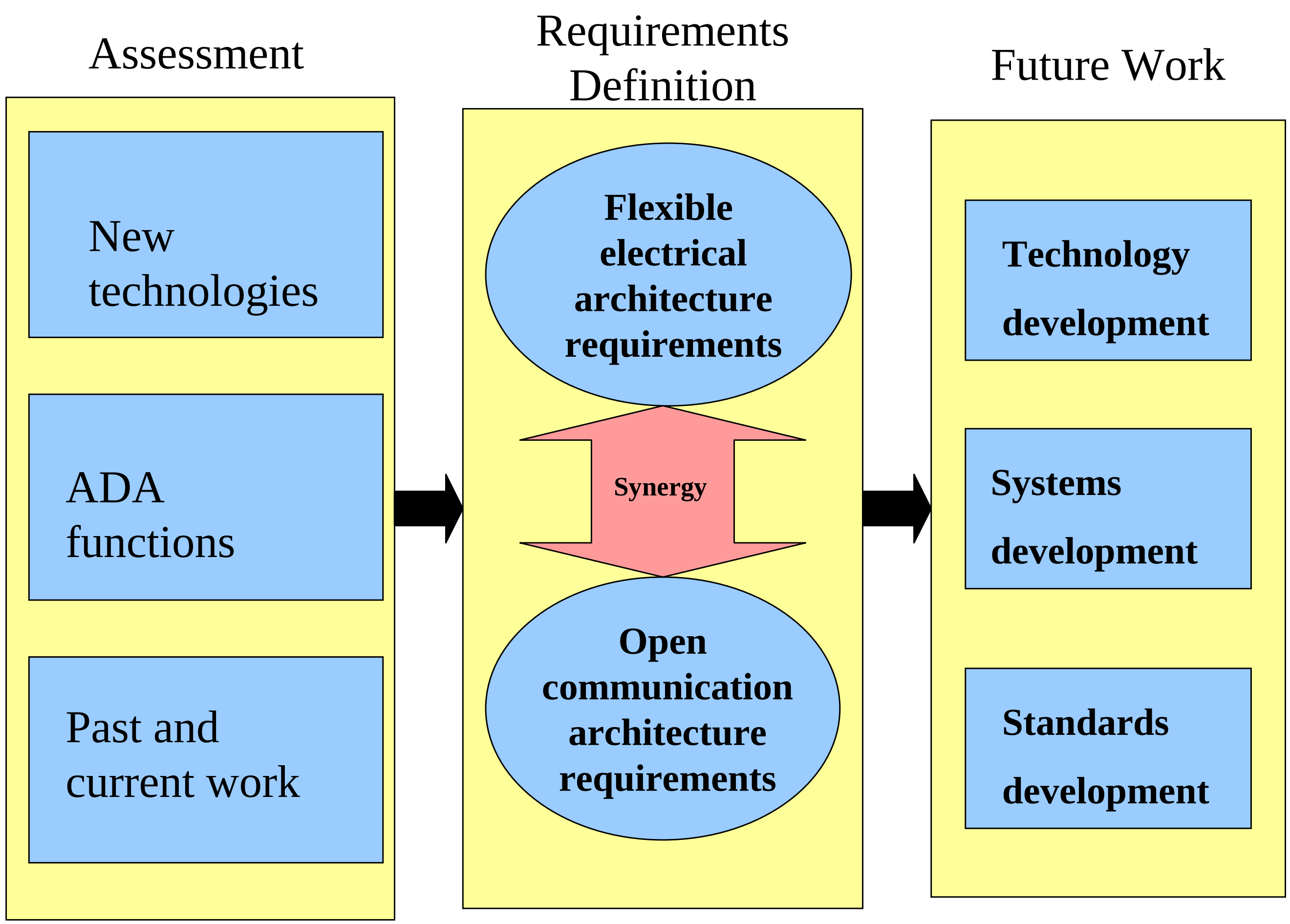
Summary – automation can provide step change in reliability



Major components of ADA

- Flexible electrical system architecture (including integration of power electronics and DER)
- Real-time state estimation tools and predictive fast simulation modeling to continuously optimize system performance (energy, demand, efficiency, reliability, quality)
- Communications and control system based on open architecture and information exchange model
- Integration of system operation and control all the way to consumer facilities

Developing the ADA Research Plan



ADA Workshop hosted by Con Edison

- Expertise invited from three key stakeholder groups in roughly equal numbers
  - Electric utility industry
  - Equipment vendors and consultants
  - Academic and other research organizations
- State-of-the-art
- Prioritize research activities

General flow of ADA implementation

Distribution Substation Automation

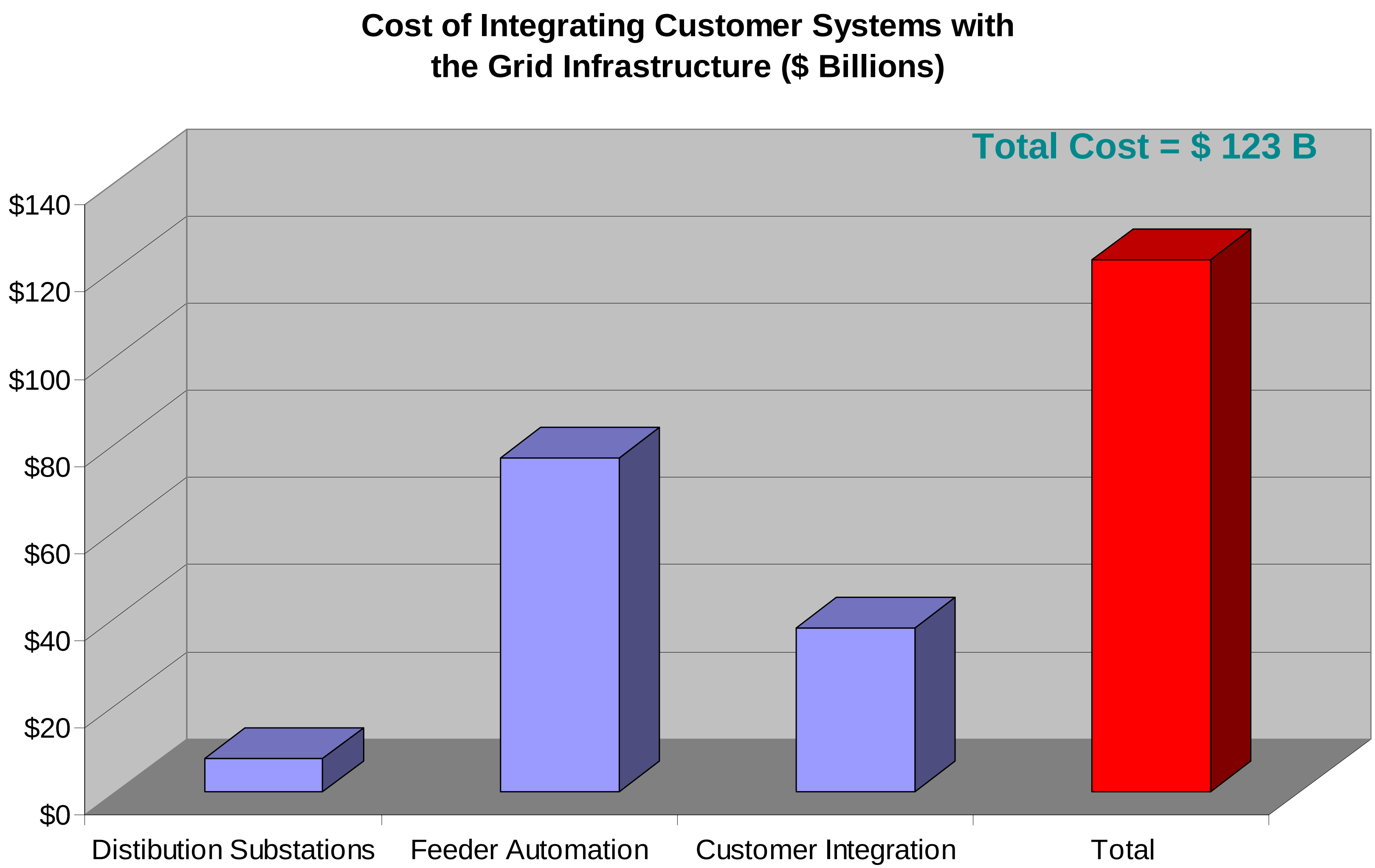
→

Feeder Automation and Integration of DER

→

Customer System Integration

Cost for the distribution system of the future: Initial estimate



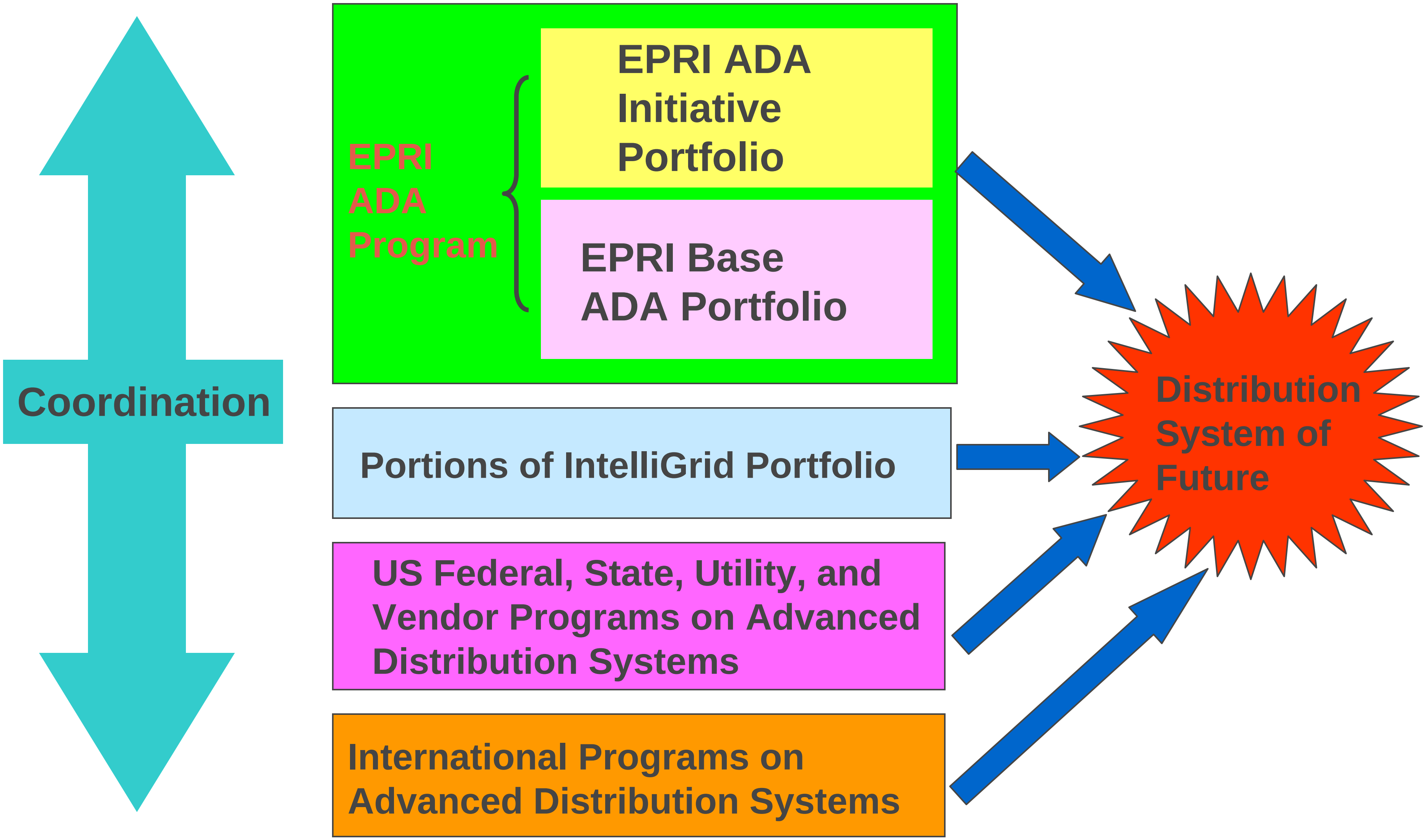
EPRI Vision for Advanced Distribution Automation

- Traditional Distribution Automation
  - Automation of switching functions with some reconfiguration capabilities
  - VAR control
  - Other individual functions
- Advanced Distribution Automation
  - Automation of all controllable equipment and functions
  - Advanced reconfiguration capabilities for optimizing performance and improving reliability
  - Communication and control infrastructure
  - Distribution systems become multi-function systems
  - Integration of distributed generation, including microgrids

Strategic drivers for ADA

1. Improve reliability and power quality
2. Reduce operating costs
3. Improve outage restoration time
4. Increase customer service options
5. Integration of DER
6. Integration of the customer

Revolution by evolution will be a collaborative process



All Current EPRI ADA Projects by Functional Area

Functional Area from EPRI ADA Roadmap	Project Title	EPRI Base ADA Program No. 124	EPRI ADA Initiative Program
New Distribution System Topologies and System-Level Concepts	Distribution Design to Integrate Distributed Generation and Other New Intelligent Electronic Devices	x	
	Feeder and Network Evolution to Support ADA		x
	Advanced System Reconfiguration Capabilities		x
	Distribution Protection for ADA		x
Electronic/Electrical Technology Development for ADA	Family of Multi-Function Low-Cost Solid-State Switchgear	x	
	Intelligent Universal Transformer	x	
	Smart-Node Power Electronics for ADA		x
Sensor/Monitoring Systems for ADA	Distribution Fault Anticipator: Algorithm/Locator Development	x	
	First-Generation Integrated Sensor and Monitoring System for ADA	x	
	Advanced System Monitoring for ADA (Second-Generation System)		x
Communication Systems and Standards for ADA	Communication Architecture/Standards for ADA Feeder Equipment		x
	Communication Standards for DER in Electric Power Systems (under the IntelliGrid DER/ADA project)		
Advanced Distribution System Controls	Advanced Volt/VAR Management		x
	Advanced Management of System Performance		x
	Adaptable, Distributed Control for ADA		x

EPRI ADA Initiative Project Content

Functional Area from EPRI ADA Roadmap	Project Title
New Distribution System Topologies and System-Level Concepts	Feeder and Network Evolution to Support ADA
	Advanced System Reconfiguration Capabilities
	Distribution Protection for ADA
Electronic/Electrical Technology Development for ADA	Smart-Node Power Electronics for ADA
Sensor/Monitoring Systems for ADA	Advanced System Monitoring for ADA (Second-Generation System)
Communication Systems and Standards for ADA	Communication Architecture/Standards for ADA Feeder Equipment
Advanced Distribution System Controls	Advanced Volt/VAR Management
	Advanced Management of System Performance
	Adaptable, Distributed Control for ADA

A few important conclusions

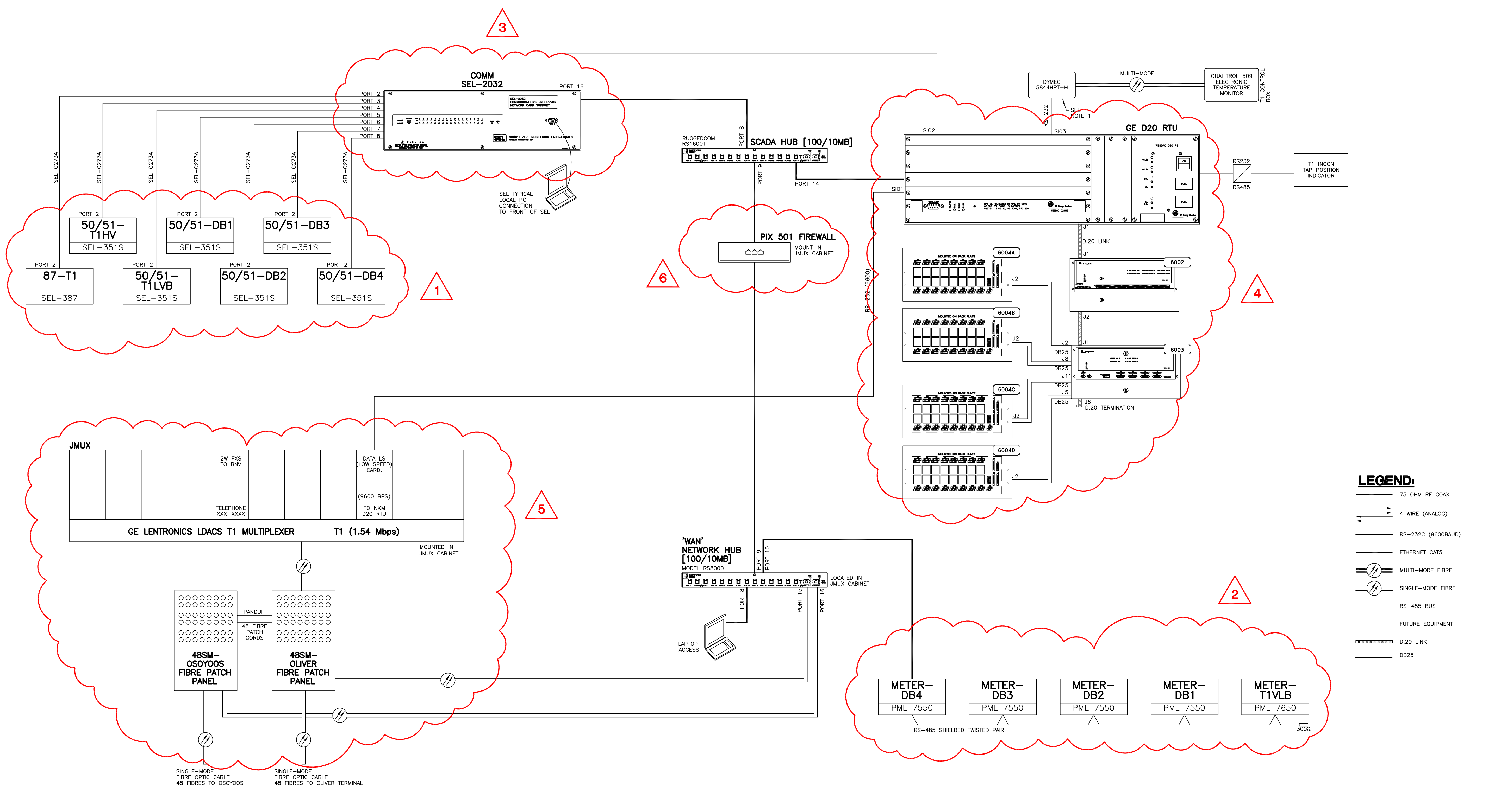
- COORDINATION
  - European and UK projects have specific tasks in the initiatives related to tech transfer and coordination
- ADA is an international priority, especially involving integration of DER
- Vendor involvement is very important to make sure that results can be implemented in actual products
- Results must be available to assure that they are used
  - Especially in development areas that relate to standards
  - Open Source development is a possible approach to accomplish this
- Tremendous opportunity to make a step change in the performance of distribution systems
  - Reliability improvement
  - Optimizing performance

Questions/Discussion

Benefits and Value of ADA

- **Improvements in:**
  - – **Cost of Energy**
  - – **Service Capabilities**
  - – **Security**
  - – **Quality and Reliability**
  - – **Environment**
  - – **Safety**
  - – **Accessibility**
  - – **Productivity**

Appendix A17.3



MCW AGE Power Consultants
1050 Eldorado Street, Suite 202, Trail, BC V1R 3V7
Toronto, Ottawa, Winnipeg, Vancouver

REVISIONS						
REV	DATE	BY	CHECKED	DESCRIPTION	REVISION APPROVAL	DATE
P0	FEB/07	SY	RY	ISSUED FOR FORTISBC REVIEW		
2						
3						
4						

DRAWN BY: S. YEUNG FEB/07
DESIGNED BY: R. YANG
CHECKED BY:
APPROVALS: ELEC / CIVIL / MANAGEMENT

FORTISBC

DIVISION: OKANAGAN
DEPARTMENT: TELECOMMUNICATIONS
LOCATION: NK'MIP SUBSTATION
TITLE: COMMUNICATION BLOCK DIAGRAM

SCALE: NONE SCALE FACTOR: 1
DRAWING NUMBER: 3-337-2002
REVISION: P0

	CAUSE NAME	CAUSE DESCRIPTION	# OUTAGES	% OF TOTAL	TOTAL CUSTOMERS AFFECTED	TOTAL CUSTOMER HOURS	SAIDI 93273	SAIFI 93273
1	Unknown or Other	Used when the cause is unknown or does not fit in any of the described causes.	82	9.5%	8,208	11,946.65	0.1281	0.0880
2	Tree Falling	Tree falling and contacting our lines.	85	9.0%	3,691	9,330.38	0.1000	0.0396
3	Tree Growth	Tree growing into and contacting our lines.	40	4.6%	3,339	6,724.05	0.0721	0.0358
4	Lightning	Failure of equipment or material due to lightning.	34	3.9%	5,002	7,354.25	0.0788	0.0536
5	Equipment or Material	Equipment or material which was defective or deteriorated causing an outage.	92	10.7%	4,166	10,415.56	0.1117	0.0447
6	Adverse Weather-Snow or Rain	Failure of equipment or material due to adverse precipitation weather conditions such as snow, ice, rain, sleet, etc.	15	1.7%	180	393.53	0.0042	0.0019
7	Adverse Weather-Wind	Failure of equipment or material due to extreme wind conditions.	33	3.8%	2,419	5,525.42	0.0592	0.0259
8	Contamination	Contamination on bushings or insulators which causes tracking and flashover.	3	0.3%	253	156.72	0.0017	0.0027
9	Forest Fire, Flood, other Disasters	Large scale outages caused by catastrophic events.	2	0.2%	218	1,619.50	0.0174	0.0023
10	FortisBC Error	Outages due to switching error, inadequate procedures, improper installation, poor workmanship, or improper design.	22	2.6%	4,154	2,686.10	0.0288	0.0445
11	Public Interference	External contacts with our system such as kites, ladders, vehicles, dig ins, and vandalism.	43	5.0%	6,771	9,924.22	0.1064	0.0726
12	Birds or Animals	Outages caused by birds or animals.	144	16.7%	4,150	10,941.42	0.1173	0.0445
13	Animals on Ground	Outages caused by large animals on the ground.	7	0.8%	100	199.37	0.0021	0.0011
14	Customer Equipment	Outages caused by customer equipment failures which affect our network.	9	1.0%	21	45.32	0.0005	0.0002
Forced Distribution Outages			611	70.9%	42,672	77,262.48	0.8283	0.4575
15	Loss of Supply (Transmission Only)	Outage due to failure on Transmission System or caused by REA Equipment	51	100.0%	44,056	24,373	0.259	0.468

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	32	119	204	294	354	325	296	266	235	204
3	Carrying Costs	Line 71	0	20	94	197	295	372	367	304	243	183	125	69
4	Income Tax	Line 85	0	(33)	(130)	(208)	(248)	(237)	(112)	29	122	181	215	233
5	Total Revenue Requirement for Project		0	(3)	21	153	198	375	554	603	604	572	516	445
6	**Net Present Value of Revenue Requirement**	10.00%	1,152											
	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%	0.01%	0.06%	0.08%	0.14%	0.21%	0.22%	0.22%	0.20%	0.18%	0.15%
	Annual Incremental Rate Impact over previous year		0.00%	0.00%	0.01%	0.05%	0.02%	0.07%	0.06%	0.01%	0.00%	-0.02%	-0.02%	-0.03%
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		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		0	0	32	119	204	294	354	325	296	266	235	204
	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	(32)	(151)	(354)	(649)	(1,003)	(1,328)	(1,624)	(1,890)	(2,126)	(2,330)
67	Net Book Value		0	526	1,951	3,241	4,554	5,257	4,421	3,605	2,808	2,031	1,275	539
	Carrying Costs on Average NBV													
68	Return on Equity		0	10	46	95	143	180	178	148	118	89	61	33
69	Interest Expense		0	10	48	101	152	191	189	157	125	94	64	35
70	AFUDC		0	0	0	0	0	0	0	0	0	0	0	0
71	**Total Carrying Costs**		0	20	94	197	295	372	367	304	243	183	125	69
	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	46	95	143	180	178	148	118	89	61	33
74	Gross up for revenue (Return / (1- tax rate)		0	14	67	138	206	259	256	212	170	128	87	48
75	Less: Income tax on Equity Return		0	5	21	43	63	79	78	65	52	39	27	15
76	Net Income (equal return on equity)		0	10	46	95	143	180	178	148	118	89	61	33
	Income Tax on Timing Differences													
77	Depreciation Expense		0	0	32	119	204	294	354	325	296	266	235	204
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)	(321)	(558)	(709)	(721)	(434)	(81)	161	323	430	498
80	Income Tax on Timing Differences		0	(26)	(103)	(173)	(216)	(220)	(132)	(25)	49	98	131	152
81	Before Tax Revenue Requirement [=Line 52/(1-tax)]		0	(38)	(151)	(251)	(311)	(317)	(191)	(35)	70	142	189	219
85	**Total Income Tax**	Lines 75 + 81	0	(33)	(130)	(208)	(248)	(237)	(112)	29	122	181	215	233
	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	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	32	119	204	294	383	383	383	383	383	383	419
3	Carrying Costs	Line 71	19	94	197	295	390	420	391	362	333	304	298	313
4	Income Tax	Line 85	(34)	(133)	(218)	(254)	(265)	(173)	(50)	34	91	129	119	93
5	Total Revenue Requirement for Project		(15)	3	123	290	367	575	668	722	749	757	740	764
6	**Net Present Value of Revenue Requirement**	10.00%	4,485											
	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		-0.01%	0.00%	0.05%	0.12%	0.14%	0.22%	0.25%	0.27%	0.27%	0.27%	0.26%	0.26%
	Annual Incremental Rate Impact over previous year		-0.01%	0.01%	0.05%	0.07%	0.03%	0.08%	0.03%	0.02%	0.00%	0.00%	-0.01%	0.00%
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%	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									10	0
15	Castlegar			345									144	0
16	Duck Lake			131									55	0
17	Fruitvale			42									17	0
18	Glenmore			125									52	0
19	Hollywood			375									157	0
20	Keremeos			54									22	0
21	Summerland			89									37	0
22	Beaver Park				152								0	64
23	Blueberry				140								0	59
24	OK Mission				383								0	160
25	Osoyoos				122								0	51
26	Playmor				183								0	76
27	Saucier				37								0	15
28	Valhalla				91								0	38
29	Westminster				140								0	59
30	Christina Lake					180							0	0
31	Glenmerry					186							0	0
32	Hedley					348							0	0
33	Salmo					155							0	0
34	Trout Creek					223							0	0
35	West Bench					286							0	0
36	Huth						190						0	0
37	Passmore						139						0	0
38	Sexsmith						272						0	0
39	Slocan City						95						0	0
40	Stoney Creek						291						0	0
41	Tarrys						348						0	0
42	Data Server hardware & software			140	33	0	0						59	14
43	Initial engineering, estimating, procurement		462										0	0
44	Capital Cost Subtotal		462	1,324	1,281	1,378	1,336	0	0	0	0	0	554	536
45	Contingency (10%)		46	132	128	138	134	0	0	0	0	0	55	54
46	AFUDC		18	0	0	0	0	0	0	0	0	0	0	0
47	Cumulative Project Cost Substotal		526	1,983	3,392	4,908	6,378	6,378	6,378	6,378	6,378	6,378	6,987	7,576
48	Estimated Annual Capital Savings													
49	Total Cash Outlay in Year		**526**	**1,456**	**1,409**	**1,516**	**1,470**	**0**	**0**	**0**	**0**	**0**	**609**	**589**
50	Cumulative Cash Outlay		526	1,983	3,392	4,908	6,378	6,378	6,378	6,378	6,378	6,378	6,987	7,576
51			0	0	0	0	0	0	0	0	0	0	0	0
52	Cumulative Project Cost		526	1,983	3,392	4,908	6,378	6,378	6,378	6,378	6,378	6,378	6,987	7,576
53	Additions to Plant		526	1,456	1,409	1,516	1,470	0	0	0	0	0	609	589
54	Cummulative Additions to Plant		526	1,983	3,392	4,908	6,378	6,378	6,378	6,378	6,378	6,378	6,987	7,576
55	CWIP		0	526	1,983	3,392	4,908	6,378	6,378	6,378	6,378	6,378	6,378	6,987
	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	526	1,983	3,392	4,908	6,378	6,378	6,378	6,378	6,378	6,378	6,987
61	Additions in Year	Line 53	526	1,456	1,409	1,516	1,470	0	0	0	0	0	609	589
62	Cumulative Total		526	1,983	3,392	4,908	6,378	6,378	6,378	6,378	6,378	6,378	6,987	7,576
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		0	32	119	204	294	383	383	383	383	383	383	419
	Net Book Value													
65	Gross Property	Line 54	526	1,983	3,392	4,908	6,378	6,378	6,378	6,378	6,378	6,378	6,987	7,576
66	Accumulated Depreciation		0	(32)	(151)	(354)	(649)	(1,031)	(1,414)	(1,797)	(2,179)	(2,562)	(2,945)	(3,364)
67	Net Book Value		526	1,951	3,241	4,554	5,729	5,347	4,964	4,581	4,199	3,816	4,042	4,213
	Carrying Costs on Average NBV													
68	Return on Equity		9	46	95	143	189	204	190	175	161	147	144	152
69	Interest Expense		10	48	101	152	201	216	201	186	171	156	153	161
70	AFUDC		0	0	0	0	0	0	0	0	0	0	0	0
71	**Total Carrying Costs**		19	94	197	295	390	420	391	362	333	304	298	313
	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	9	46	95	143	189	204	190	175	161	147	144	152
74	Gross up for revenue (Return / (1- tax rate)		14	67	140	208	272	293	273	252	232	212	208	218
75	Less: Income tax on Equity Return		5	22	45	64	83	89	83	77	71	65	63	67
76	Net Income (equal return on equity)		9	46	95	143	189	204	190	175	161	147	144	152
	Income Tax on Timing Differences													
77	Depreciation Expense		0	32	119	204	294	383	383	383	383	383	383	419
78	Less: Capital Cost Allowance	Line 92	79	353	677	912	1,087	981	687	481	337	236	256	359
79	Total Timing Differences		(79)	(321)	(558)	(709)	(792)	(598)	(304)	(98)	46	147	126	60
80	Income Tax on Timing Differences		(26)	(104)	(178)	(220)	(242)	(183)	(93)	(30)	14	45	39	18
81	Before Tax Revenue Requirement [=Line 52/(1-tax)]		(39)	(155)	(262)	(319)	(348)	(263)	(133)	(43)	20	65	55	26
85	**Total Income Tax**	Lines 75 + 81	(34)	(133)	(218)	(254)	(265)	(173)	(50)	34	91	129	119	93
	Capital Cost Allowance													
86	Opening Balance - UCC		0	447	1,551	2,284	2,887	3,270	2,289	1,602	1,122	785	550	903
87	Additions to Plant		526	1,456	1,409	1,516	1,470	0	0	0	0	0	609	589
88	Subtotal UCC		526	1,904	2,960	3,800	4,357	3,270	2,289	1,602	1,122	785	1,159	1,492
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	134	465	685	866	981	687	481	337	236	165	271
91	CCA on Capital Expenditures (1/2 yr rule)		79	218	211	227	220	0	0	0	0	0	91	88
92	Total CCA		79	353	677	912	1,087	981	687	481	337	236	256	359
93	Ending Balance UCC		447	1,551	2,284	2,887	3,270	2,289	1,602	1,122	785	550	903	1,133

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	32	119	204	294	354	325	296	266	235	204	172
3	Carrying Costs	Line 71	19	94	197	295	372	367	304	243	183	125	69	14
4	Income Tax	Line 85	(34)	(133)	(218)	(254)	(237)	(112)	29	122	181	215	233	240
5	Total Revenue Requirement for Project		(15)	3	123	290	376	555	604	605	573	518	447	365
6	**Net Present Value of Revenue Requirement**	6.00%	884											
	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		-0.01%	0.00%	0.05%	0.12%	0.15%	0.21%	0.23%	0.22%	0.21%	0.18%	0.16%	0.13%
	Annual Incremental Rate Impact over previous year		-0.01%	0.01%	0.05%	0.07%	0.03%	0.07%	0.01%	0.00%	-0.02%	-0.02%	-0.03%	-0.03%
9	**NPV of Project / Total Revenue Requirements**		0.03%											
	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 Substotal		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		526	1,456	1,409	1,516	998	(481)	(491)	(501)	(511)	(521)	(532)	(542)
54	Cummulative Additions to Plant		526	1,983	3,392	4,908	5,906	5,424	4,933	4,432	3,921	3,400	2,869	2,327
55	CWIP		0	526	1,983	3,392	4,908	5,906	5,424	4,933	4,432	3,921	3,400	2,869
	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	526	1,983	3,392	4,908	5,906	5,424	4,933	4,432	3,921	3,400	2,869
61	Additions in Year	Line 53	526	1,456	1,409	1,516	998	(481)	(491)	(501)	(511)	(521)	(532)	(542)
62	Cumulative Total		526	1,983	3,392	4,908	5,906	5,424	4,933	4,432	3,921	3,400	2,869	2,327
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		0	32	119	204	294	354	325	296	266	235	204	172
	Net Book Value													
65	Gross Property	Line 54	526	1,983	3,392	4,908	5,906	5,424	4,933	4,432	3,921	3,400	2,869	2,327
66	Accumulated Depreciation		0	(32)	(151)	(354)	(649)	(1,003)	(1,328)	(1,624)	(1,890)	(2,126)	(2,330)	(2,502)
67	Net Book Value		526	1,951	3,241	4,554	5,257	4,421	3,605	2,808	2,031	1,275	539	(175)
	Carrying Costs on Average NBV													
68	Return on Equity		9	46	95	143	180	178	148	118	89	61	33	7
69	Interest Expense		10	48	101	152	191	189	157	125	94	64	35	7
70	AFUDC		0	0	0	0	0	0	0	0	0	0	0	0
71	**Total Carrying Costs**		19	94	197	295	372	367	304	243	183	125	69	14
	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	9	46	95	143	180	178	148	118	89	61	33	7
74	Gross up for revenue (Return / (1- tax rate)		14	67	140	208	259	256	212	170	128	87	48	10
75	Less: Income tax on Equity Return		5	22	45	64	79	78	65	52	39	27	15	3
76	Net Income (equal return on equity)		9	46	95	143	180	178	148	118	89	61	33	7
	Income Tax on Timing Differences													
77	Depreciation Expense		0	32	119	204	294	354	325	296	266	235	204	172
78	Less: Capital Cost Allowance	Line 92	79	353	677	912	1,016	789	406	135	(57)	(195)	(294)	(367)
79	Total Timing Differences		(79)	(321)	(558)	(709)	(721)	(434)	(81)	161	323	430	498	539
80	Income Tax on Timing Differences		(26)	(104)	(178)	(220)	(220)	(132)	(25)	49	98	131	152	164
81	Before Tax Revenue Requirement [=Line 52/(1-tax)]		(39)	(155)	(262)	(319)	(317)	(191)	(35)	70	142	189	219	237
85	**Total Income Tax**	Lines 75 + 81	(34)	(133)	(218)	(254)	(237)	(112)	29	122	181	215	233	240
	Capital Cost Allowance													
86	Opening Balance - UCC		0	447	1,551	2,284	2,887	2,869	1,599	702	66	(388)	(715)	(952)
87	Additions to Plant		526	1,456	1,409	1,516	998	(481)	(491)	(501)	(511)	(521)	(532)	(542)
88	Subtotal UCC		526	1,904	2,960	3,800	3,885	2,388	1,108	201	(445)	(909)	(1,246)	(1,494)
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	134	465	685	866	861	480	211	20	(116)	(214)	(286)
91	CCA on Capital Expenditures (1/2 yr rule)		79	218	211	227	150	(72)	(74)	(75)	(77)	(78)	(80)	(81)
92	Total CCA		79	353	677	912	1,016	789	406	135	(57)	(195)	(294)	(367)
93	Ending Balance UCC		447	1,551	2,284	2,887	2,869	1,599	702	66	(388)	(715)	(952)	(1,127)

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	32	119	204	294	354	325	296	266	235	204	172
3	Carrying Costs	Line 71	19	94	197	295	372	367	304	243	183	125	69	14
4	Income Tax	Line 85	(34)	(133)	(218)	(254)	(237)	(112)	29	122	181	215	233	240
5	Total Revenue Requirement for Project		(15)	3	123	290	376	555	604	605	573	518	447	365
6	**Net Present Value of Revenue Requirement**	8.00%	1,072											
	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		-0.01%	0.00%	0.05%	0.12%	0.15%	0.21%	0.23%	0.22%	0.21%	0.18%	0.16%	0.13%
	Annual Incremental Rate Impact over previous year		-0.01%	0.01%	0.05%	0.07%	0.03%	0.07%	0.01%	0.00%	-0.02%	-0.02%	-0.03%	-0.03%
9	**NPV of Project / Total Revenue Requirements**		0.04%											
	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 Substotal		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		526	1,456	1,409	1,516	998	(481)	(491)	(501)	(511)	(521)	(532)	(542)
54	Cummulative Additions to Plant		526	1,983	3,392	4,908	5,906	5,424	4,933	4,432	3,921	3,400	2,869	2,327
55	CWIP		0	526	1,983	3,392	4,908	5,906	5,424	4,933	4,432	3,921	3,400	2,869
	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	526	1,983	3,392	4,908	5,906	5,424	4,933	4,432	3,921	3,400	2,869
61	Additions in Year	Line 53	526	1,456	1,409	1,516	998	(481)	(491)	(501)	(511)	(521)	(532)	(542)
62	Cumulative Total		526	1,983	3,392	4,908	5,906	5,424	4,933	4,432	3,921	3,400	2,869	2,327
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		0	32	119	204	294	354	325	296	266	235	204	172
	Net Book Value													
65	Gross Property	Line 54	526	1,983	3,392	4,908	5,906	5,424	4,933	4,432	3,921	3,400	2,869	2,327
66	Accumulated Depreciation		0	(32)	(151)	(354)	(649)	(1,003)	(1,328)	(1,624)	(1,890)	(2,126)	(2,330)	(2,502)
67	Net Book Value		526	1,951	3,241	4,554	5,257	4,421	3,605	2,808	2,031	1,275	539	(175)
	Carrying Costs on Average NBV													
68	Return on Equity		9	46	95	143	180	178	148	118	89	61	33	7
69	Interest Expense		10	48	101	152	191	189	157	125	94	64	35	7
70	AFUDC		0	0	0	0	0	0	0	0	0	0	0	0
71	**Total Carrying Costs**		19	94	197	295	372	367	304	243	183	125	69	14
	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	9	46	95	143	180	178	148	118	89	61	33	7
74	Gross up for revenue (Return / (1- tax rate)		14	67	140	208	259	256	212	170	128	87	48	10
75	Less: Income tax on Equity Return		5	22	45	64	79	78	65	52	39	27	15	3
76	Net Income (equal return on equity)		9	46	95	143	180	178	148	118	89	61	33	7
	Income Tax on Timing Differences													
77	Depreciation Expense		0	32	119	204	294	354	325	296	266	235	204	172
78	Less: Capital Cost Allowance	Line 92	79	353	677	912	1,016	789	406	135	(57)	(195)	(294)	(367)
79	Total Timing Differences		(79)	(321)	(558)	(709)	(721)	(434)	(81)	161	323	430	498	539
80	Income Tax on Timing Differences		(26)	(104)	(178)	(220)	(220)	(132)	(25)	49	98	131	152	164
81	Before Tax Revenue Requirement [=Line 52/(1-tax)]		(39)	(155)	(262)	(319)	(317)	(191)	(35)	70	142	189	219	237
85	**Total Income Tax**	Lines 75 + 81	(34)	(133)	(218)	(254)	(237)	(112)	29	122	181	215	233	240
	Capital Cost Allowance													
86	Opening Balance - UCC		0	447	1,551	2,284	2,887	2,869	1,599	702	66	(388)	(715)	(952)
87	Additions to Plant		526	1,456	1,409	1,516	998	(481)	(491)	(501)	(511)	(521)	(532)	(542)
88	Subtotal UCC		526	1,904	2,960	3,800	3,885	2,388	1,108	201	(445)	(909)	(1,246)	(1,494)
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	134	465	685	866	861	480	211	20	(116)	(214)	(286)
91	CCA on Capital Expenditures (1/2 yr rule)		79	218	211	227	150	(72)	(74)	(75)	(77)	(78)	(80)	(81)
92	Total CCA		79	353	677	912	1,016	789	406	135	(57)	(195)	(294)	(367)
93	Ending Balance UCC		447	1,551	2,284	2,887	2,869	1,599	702	66	(388)	(715)	(952)	(1,127)

Appendix A27.4

FORTISBC

Project Close-Out Form –T&D Projects

Project Name	
Project WBS	
Project SDP number	
Project Manager	

The project manager is to certify by initialing below that each item is complete or not applicable, then sign and date at the bottom of the form. The form should then be submitted to the Project Manager Office administrative assistant for logging and filing.

Environmental and Safety

Item Description	Complete	Not Applicable
Clean up completed. Confirm that salvaged material left in designated areas.		
All safety and environmental incident reports and investigations have been submitted and action items completed or in-progress.		
Confirmation that the "normally open" and "normally closed" points have been returned to original service. If not returned, explanation why not.		

Quality

Item Description	Complete	Not Applicable
As builts required to update FieldView (transmission or distribution) or Engineering drawings (substations)		
Operational sign-off received from Network Services		
Operational sign-off received from SCC		
Equipment labeled correctly		
Confirmation that all private property issues have been resolved (ie: access locks cut and replaced, gate damage, damage from driving over lawns, debris cleaned from customer property, etc)		
Keys returned		
Vehicle signage returned		

Cost

Item Description	Complete	Not Applicable
All invoices received and submitted to Accounts Payable		
Salvage costs verified and charged to correct asset		
Salvage credits verified, received and charged to correct asset		
Customer billings completed and charged to correct WBS		
Asset retirements have been identified in FieldView (distribution) or in Excel spreadsheet to Finance (transmission and substations)		
Surplus materials scrapped, transferred to another project or returned stores/vendor for credit		
Orders and purchase orders closed. Finance notified to close WBS.		
Variance explanation submitted to Manager, T&D Projects if greater than +/- 10%.		

Project Manager Certification

I certify that the above information is correct to the best of my knowledge.

Signature	Name (please print)	Date