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130.0 Reference: Volume 1, Tab 10.3, Regulatory Policy: Transition Plan, Appdx. 1, Section 2.3, p. 25
Customer Call Centre Operations: Customer Service Improvements

"FortisBC is reorganizing its engineering and operations functions to better meet the challenges associated with the System Development Plan and the 2005 Capital Plan, and to improve the delivery of field service."

Q130.1 Please provide detailed information on how many additional design staff will be hired and how the number was determined. Also provide the total cost, if any, included in the 2005 revenue requirement.

A130.1 FortisBC plans to hire seven engineering/design staff in 2005 to address the present work load and reduce some of FortisBC's existing reliance on contractors.

However, even with this hiring plan, FortisBC will continue to use contract resources to supplement the internal resources for the design and execution of capital projects. These seven internal positions were determined to be necessary to improve both the timeliness and quality of distribution designs, customer extensions and the ongoing capital projects.

The impact on operations expense associated with this hiring is estimated at $75,000 as this staff will be used primarily to support the capital plan.

Q130.2 Please provide additional detailed information on the staffing plans for the South Okanagan region. Are you planning to hire new employees or will it just be a reallocation of resources? Also provide the total cost, if any, included in the 2005 revenue requirement.

A130.2 To provide better focus to our South Okanagan customers, FortisBC plans to split the existing Okanagan region into a North Okanagan region and a South Okanagan region. With the exception of a manager, there are no plans to hire additional employees for the South Okanagan.

The 2005 revenue requirement does not include any costs associated with setting up the South Okanagan region as the company is planning for a reallocation of resources only.

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131.0 Reference: Volume 1, Tab 10.3, Regulatory Policy: Transition Plan, Appendix 1, Section 2.3, pp. 25-26
Customer Call Centre Operations: Customer Service Improvements

> **"Separating the Information Technology function is a more complex matter, so the creation of a stand alone function will take more time."**

Q131.1 Please provide the detailed information/plan, if available, that sets out how FortisBC intends to create a stand-alone IT function. Also provide complete one-time and recurring cost information (both capital and operating). Are there any costs regarding this project included in the 2005 revenue requirement?

A131.1 FortisBC's IT function has, for the most part, continued to operate on a stand-alone basis, with its base of operations located in Trail, BC.

Two IT applications that are shared between FortisBC and FortisAlberta include SAP and Intergraph (AM/FM). FortisAlberta acts as an Application Service Provider for these programs. All other FortisBC IT applications and functions such as help desk, CIS+, web development and maintenance, network infrastructure, technical support and application support (other than SAP and Intergraph) have always operated as stand-alone.

FortisBC will evaluate the systems shared with FortisAlberta (i.e., SAP and Intergraph) and will develop a strategy and assess opportunities that benefit both the customer and the organization on a go-forward basis. Any resulting system changes will be supported by a business case that clearly identifies costs and associated benefits.

IT Operating Budget - 2005

There are no one-time IT costs included in FortisBC's 2005 revenue requirement. The IT operating budget for 2005 is based on continuation of existing IT operations whereby only SAP and Intergraph services will continue to be provided by FortisAlberta, and all other IT operations and support will continue to be managed out of the Company's Trail office. Tab 10.3 of the Company's Application identifies the annual cost of IT services provided to FortisBC by FortisAlberta.

IT Capital Budget – 2005

From a capital perspective, there is $460,000 identified in Tab 9 of the Company's Application for Call Centre Infrastructure and Telephony. A breakdown of the costs associated with this project is provided in the Company's response to BCUC IR1 Q108. This represents the infrastructure cost to support the Call Centre telephony requirements in Trail. It also includes an upgrade to the System Control telephony infrastructure so that it is tied to the Call Centre, and thereby provides more efficient and improved customer service.

A similar capital cost would have to be incurred if the Call Centre and Telephony infrastructure

were to remain in Alberta, since an upgrade is also required to the infrastructure there in 2005. FortisBC's component of that cost was estimated at approximately $400,000, not including the necessary upgrade to the System Control infrastructure referred to above.

Q131.2 If available, please provide a complete comparative cost schedule showing current costs for this function and the future expected cost for the function on a stand alone basis. Please explain any changes.

A131.2 As stated in the Company's response to BCUC IR1 Q131.1, FortisBC's IT function has, for the most part, continued to operate on a stand-alone basis with its base of operations located in Trail, BC. The cost of the IT function is not impacted by the current transition plan.

As indicated in Tab 10.3, FortisBC will evaluate the systems shared with FortisAlberta (i.e., SAP and Intergraph) and will develop a strategy and assess opportunities that benefit both the customer and the organization on a go-forward basis. Any resulting system changes will be supported by a business case that clearly identifies costs and associated benefits.

Q132.0 Reference: None

Please confirm that all resources (e.g. labour, materials, services) that will be acquired with the forecast 2005 revenue requirement, will be used exclusively for the operation and administration of the regulated business of FortisBC. If this is not the case, please provide a detailed explanation.

A132.0 Confirmed. This Application only requests cost recovery for the regulated business of FortisBC.

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133.0 Reference: Volume 2, p. 4

A complete assessment of FortisBC's maintenance plans and equipment condition was undertaken as part of the system development planning process.

Q133.1 Please confirm that the report arising from the assessment is that which is included as Appendix D to the SDP. If not confirmed, please provide a copy of any reports arising from the assessment.

Q133.1 FortisBC confirms that Appendix D is the report arising from the assessment.

Q133.2 Please list the performance measures by which the success (including cost effectiveness) of FortisBC's maintenance activities will be assessed, and list any specific targets that have been established for each measure.

A133.2 FortisBC has not established a list of performance measures by which the success of maintenance activities will be assessed. The measures will be established as part of the implementation of the Computerized Maintenance Management System. FortisBC requires a system to assess and establish these targets. It is the ability to establish and track targets, both financial and productivity related that drives the need for a computerized maintenance management system.

Q133.3 Can any of these measures be compared with similar measures from other utilities?

A133.3 Performance measures on particular equipment or equipment components are not readily available from other utilities. A Doble Client substation Maintenance Survey began in 2004 and is scheduled for completion at the end of 2005. This survey may contain information that can be used for comparison purposes.

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134.0 Reference: Volume 2, pp. 4-5

The Application describes the "priority matrix" through which the more than 100 system development and improvement projects were assigned priorities. Weighting factors were assigned to six different categories, and an additional "Mandatory" category was established for projects that must proceed.

Q134.1 Who developed the prioritization matrix? In answering this question, please describe (in broad terms) the skill sets of the personnel involved, and include a discussion of the extent to which customers were involved.

A134.1 The Transmission and Distribution planners developed the priority matrix.

Doug Ruse – Manager of Transmission and Distribution Planning

Professional Electrical Engineer since 1974. Thirty years in the utility business with experience with TransAlta, Enmax, Entergy, FortisBC. Experience in engineering, operations, area manager (customer service), project management and planning.

Andy Ferraro – Senior Transmission Planner

Professional Electrical Engineer since 1968. Thirty-six years experience in electrical utility business including nine years with Ontario Hydro, twenty-four years with BC Hydro, and four years with FortisBC. Experience in thermal generation, protection and control, engineering, commissioning, operations, customer service, and planning.

Edgar Frank – Senior Distribution Planner

Eighteen years with electrical utilities in Alberta and British Columbia. Experience in substation Engineering, transmission operations and distribution planning.

Waseem Arif – Senior Transmission Planner

Twenty five years professional experience in transmission system planning and substation design activities in three electric utilities, FortisBC, Saudi Electricity Company-Eastern Region Branch (SEC-ERB) Saudi Arabia and Water and Power Development Authority (WAPDA), Pakistan.

Troy Martin – Senior Maintenance Engineer

Fifteen years utility experience in three different utilities including distribution engineering, distribution planning, apparatus maintenance planning, distribution design and metering.

Marko Aaltomaa, P.Eng - Regional Engineer, Kootenay

Over eight years of experience as a Professional Engineer working in project management, design, planning, operations and commissioning of electrical systems.

The criteria was reviewed by George Isherwood (Regulatory) Doyle Sam (Vice President, Transmission and Distribution) and Don Debienne (Vice President, Generation) and Earl Ludlow (Senior Vice President).

George Isherwood has 25 years of diverse experience in the resource and utility industries, with emphasis in the areas of financial evaluation, cost of service and rate design.

Doyle Sam has over 16 years of utility experience in engineering, project management and planning, with a strong focus on cost-effectiveness and system reliability. His previous roles include Director of Transmission and Distribution for FortisBC, Director of Asset Management, and General Manager, FortisBC.

Don Debienne has 25 years of experience in the utility industry and has led many major capital projects and multi-party negotiations. Don's prior experience includes Vice President of Operations for FortisBC and management of West Kootenay Power's generation assets. Don also served with SaskPower on their coal fired power-generating stations.

Earl Ludlow has held progressively senior positions during his 24-year tenure with Newfoundland Power and Maritime Electric, the most recent being Vice President, Engineering and Operations Newfoundland Power before his appointment as VP Operations for FortisAlberta and FortisBC in June of 2004.

The development of the matrix did not include any direct input from customers. However the team members involvement in customer service over the course of their careers provided a solid understanding of customer impacts.

Q134.2 How were the category weights derived?

A134.2 The planning team used their engineering judgment to develop the criteria and weighting to obtain a balanced approach to items that impact customers. The ratings reflect the impact of each category. Safety was given the highest rating as it was deemed to be the number one consideration. Outage times were ranked second based on historical customer concerns over outage times. Each category was discussed and a weighting agreed upon by the planning team.

Q134.3 Was the sensitivity of the project rankings to changes in the category weights ever assessed and, if so, what were the results of that assessment?

A134.3 There was no formal sensitivity analysis completed but the team did try different weightings and categories to ensure a balanced customer impact analysis was the result.

Q134.4 Given that "the overall results of this priority system compare the impact of each situation that exceeds the planning criteria," is it the case that all of the projects are required because the existing situation violates one or more of FortisBC's planning criteria?

A134.4 Yes, the primary driver for growth projects is that they exceed currently or are anticipated to exceed in the near term one of more of FortisBC's planning criteria. The primary driver for sustaining projects is deterioration of the plant creating safety and reliability issues.

Q134.5 Were projects included in the system development plan strictly on the basis of their ranking in the priority matrix, or were there other considerations (such as financial and human resource requirements and availability, project interdependencies and/or synergies, etc.)?

A134.5 The priority matrix is a measure of the customer impact and only one of the considerations in scheduling projects. The timing is largely driven by the load growth, outage constraints and resource constraints. For example the fault level reduction project is scheduled over two years due to the number of outages required to complete this project. The staging of the Boundary area is to complete Kettle Valley first delaying the need to add transformer capacity at Grand Forks thereby allowing a timely staging of the Grand Forks conversions.

Q134.6 Please describe the process used by FortisBC staff and senior management to finalize the list of projects in the system development plan.

A134.6 Throughout the process the staging was considered and reviews with senior management considered scheduling constraints. Once the final draft was completed the project lists were reviewed by FortisBC senior management before filing the System Development Plan.

Q134.7 Please provide a list of the criteria that a project must meet to be considered mandatory.

A134.7 Mandatory projects are projects required to:

- Meet EH&S regulations
- Meet our obligation to serve new customers
- Maintain minimum voltage levels to customers
- Forced upgrades driven by third parties.

Q134.8 In assigning a rank in the *thermal capacity* category:

Q134.8.1 What data (actual measurements, forecasts, the results of computer simulations) were used in assessing overload?

A134.8.1 The thermal loadings were based on actual load measurements at the substations and at distribution equipment on the system. Specific measurements were obtained by operating personnel if automated readings were not available. The actual load readings and local load growth history were used in the computerized system models to predict when overloads will occur. Equipment is sized based on the nameplate rating. Equipment replacement is based on generally accepted overload criteria.

Q134.8.2 Under the project ranking criteria, could "overload" situations result from very short-term overloads (such as during motor starts or short circuits), or were the overloads assessed based on i^2t values?

A134.8.2 Thermal overloads would not be a result of motor starts or other short-term items. The impact of motor starts and momentary inrush would be a power quality issue not an overload issue.

Q134.8.3 Was the frequency of possible equipment overloading considered? That is, would a one-time overload (either measured or forecasted) be sufficient to assign points in this category?

A134.8.3 Yes the frequency of overloads is considered. The main impact of thermal overloading of equipment is loss of life and the amount of time the overload occurs effects this calculation. No a one time overload event would not generate points in the overload category.

Q134.8.4 If overloads were determined by forecasts, how was the possibility of forecast error factored into the assignment of points to a project?

A134.8.4 The forecasts were used to develop a plan of action in case of overloads and there was no sensitivity analysis done to factor in the possibility of errors in the forecast. If the originally forecast loads do not materialize the equipment will not be replaced. In other words the forecast is verified by actual data prior to project commitment.

Q134.8.5 Is the percentage of overload the sole determinant, or is there recognition that the consequence of an overload may vary from one type of equipment to another?

A134.8.5 The consequence of the overload is a consideration. Loss of life is a consideration in transformers thus there can be acceptance of overloading at peak times. Thermal loading on lines is more of a safety issue as once the lines reach the thermal rating

the ground clearance is reduced due to increased sag in the line. This represents a hazard to the public and thermal overloads of the lines need to addressed.

Q134.9 In assessing the *System Effect of Failure* category, what criteria were used to determine whether the consequence of a system element's failure were high, medium, or low?

A134.9 The magnitude of the load is the measure used to determine the rating:

- Under 5 MW
- Between 5 and 15 MW
- Over 15 MW

Q134.10 Under the *Voltage Related* category:

Q134.10.1 Is voltage level the sole measure of voltage quality, or does FortisBC have flicker and/or harmonic standards as well? Please provide any applicable standards.

A134.10.1 No. The planning models are run to consider steady state voltage levels as the primary driver. Flicker and harmonic considerations are also studied. If the flicker or harmonic levels require action this would be taken into account and points added to the voltage category.

The following are excerpts from FortisBC's Power Quality guidelines.

Flicker Guidelines

Introduction/Scope

Voltage flicker will result from voltage variations caused by low power factor loads imposing visible and irritating voltage fluctuations on lighting circuits.

This Guideline indicates expected voltage performance at customer delivery points, and the obligations by the customer for maintaining voltage within acceptable limits. It should be used by planners when designing modifications to distribution systems, when adding new customer loads or when reviewing feeders for adequacy.

FortisBC customers should design their facilities to meet the FortisBC voltage flicker guidelines.

Flicker Guideline

Voltage flicker is an important aspect of service standards and so must be kept within reasonable limits on the system. While flicker can be produced in a variety of ways, the two worst sources are motors and capacitor banks. In both cases, the Planners should check to determine the flicker production from the proposed installation and notify the proposed new customer of the expected flicker.

Because the annoyance caused by voltage flicker is quite subjective in nature, the flicker limits should not be considered firm. However, if existing customers complain of voltage fluctuations on lighting circuits and the measured voltage is outside our flicker guidelines, then it is the customer, that is producing flicker, responsibility to meet the flicker guideline.

The Percentage voltage fluctuation is defined as 100 *(Vf –Vs)/Vs;

Where Vf = final voltage, Vs = voltage at the starting point.

Voltage flicker is the number of voltage fluctuations that is acceptable within a defined timeline.

The FortisBC flicker guideline is five percent voltage change, if the fluctuation occurs less that four times per day. If the voltage fluctuation occurs more than four times per day then the voltage flicker limit will decline.

Harmonics Guidelines

1.0 Introduction

The purpose of this document is to establish the responsibilities for the control of harmonic distortions at the point of influence between FortisBC and its customers.

1. Limits are defined on the type and amount of harmonic distortion that a customer installation may induce into the power system.

2. This document also defines the responsibilities of FortisBC in providing and administering interconnections for harmonic producing customers and in defining and administering limits for the total harmonic distortion allowable on the system.

A recommended reference is IEEE Standard 519-1992 “Recommended Practices and Requirements for Harmonic Control in Electric Power Systems”.

Q134.10.2 If the answer to the previous question is "yes," are the standards applied in establishing project priority, or was the assessment based strictly on voltage magnitude?

A134.10.2 Please see response to BCUC IR1 Q134.10.1.

Q134.10.3 Was the assignment of points in this category based on actual measurements, customer complaints, system studies, or something else?

A134.10.3 The points were determined by the planning group based on our experience with customers and customer concerns over the years.

Q134.11 In assigning a *public impact* score:

Q134.11.1 Was there any consideration other than number of customers (e.g., load lost [MW], total energy not served [MWh])?

A134.11.1 No. The only factor in this category is the number of customers affected. The system impact category considers the MW of load.

Q134.11.2 Would a municipality, an industrial load, and a residential customer each be counted as one customer?

A134.11.2 In a municipality the number of residential customers would be counted individually as would the commercial and industrial customers. The purpose of the public impact category is to ensure the number of individual customers affected is considered.

Q134.12 Please provide a cumulative revenue and rate-impact chart in the order of project priorities.

A134.12 As no single category is the single driver for a project this breakdown can not be provided.

135.0 Reference: Volume 2, p. 6

The Plan contains a list of significant projects undertaken since the 1998 Plan.

Q135.1 For each of the projects completed, please provide the actual cost, the original budget, and a description of the reasons for any significant deviations between estimated and actual costs.

A135.1 The following table provides a list of the projects in the 1998 plan that have been completed or are currently in progress

Project	CPCN Number	Cost ($M)		Reason for deviation between estimated and actual cost
		Approved Budget	Actual	
44 Line rebuild	C-13-98	3.88	4.4	Live line work procedures were more complex than anticipated, increasing labour and associated contractor costs.
Insulator Replacement		2.9	2.66	Under budget. No significant deviation.
Joe Rich Feeder Upgrade	C-11-02 C-6-04	1.23 1.16	1.46 1.06	The 2003/04 portion of the work was compressed due to unexpected load growth. The extra crew mobilization due to the compressed schedule lead to increased costs.
Kootenay 230 kV Development	C-10-00	78.2	90.1 *	The project variance was reviewed in detail at the 2003 revenue requirements workshop.
South Okanagan Supply Reinforcement	C-3-03	75.9	75.9 *	
Okanagan HV Capacitors	C-12-01	1.64	1.36	Under budget. No significant deviation.
Penticton Subtransmission	C-16-00	2.4	2.2	Under budget. No significant deviation.
Lee Terminal Upgrade (Kelowna Area Upgrade)	C-1-04	14.7	14.63 *	
New Lambert Substation (Lambert Terminal Upgrade)	C-2-03	4.26	4.0	

Project	CPCN Number	Cost ($M)		Reason for deviation between estimated and actual cost
		Approved Budget	Actual	
Distribution System Rebuild and Conversion				The combined conversion projects were completed 15% over budget. These rebuilds and conversions are very complex projects difficult to estimate due the complexity of urban systems.
Rossland (conversion)	C-10-01	4.13	4.08	
Warfield (conversion)	C-6-01	1.38	1.32	
West Trail(conversion)	C-1-03	1.5	2.45 *	
-Trail Area Upgrades	C-7-02	1.5	1.96	
Rehabilitation of 49 Line	C-9-97	3.72	4.28	The cost increase is attributable to schedule delays, line routing charges and design modifications required to address stakeholder concerns that developed after project approval.

(*) Forecast

Q135.2 Please provide a list of significant projects undertaken since the 1998 Plan that were not included in that plan, along with the associated costs.

A135.2 The following table provide the only significant project undertaken since 1998 that was not in the plan.

Completely Self Protected Transformer Replacement	$1.74 million

The Completely Self Protected Transformer Replacement project addressed a serious worker safety concern involving s specific type of transformer which had an inherent design flaw. This work focused on a total of 700 such transformers in 2000 and 2001.

Q135.3 Please provide a list of any significant projects from the 1998 Plan that were never started, along with an explanation of why the project is no longer required.

A135.3 The following table provides a list of the projects in the 1998 plan that were scheduled for the five year period but were not started.

Project	Explanation	Notes
Huth Substation Upgrade	Included in the new SDP for 2010	Load transfer problems noted in the 1998 Master Plan were partially resolved by adding motor operators to line switches and Penticton area growth was essentially flat from 1998 to 2002.
Rebuild Greenwood Substation	Included in the new SDP as part of the Boundary Area Development	No growth in area allowed deferral of the rebuild.
Rebuild Ruckles Substation	Included in the new SDP as part of the Boundary Area Development	Load transfer to Grand Forks Terminal and slow growth allowed deferral of rebuild.
New 138 kV Line to Big White and New Big White Substation	Included in the new SDP to be completed by 2007	Original plan was based on approximately 8% growth rate from 1993 to 1996. However, no growth occurred from 1996 to 2000 to allow deferral
Upgrade Recreation Substation	Capacity increase included in the new SDP for 2008	The growth rates used in the 1998 plan have not materialized in the Recreation area. The loads are being monitored and the aggressive development along the waterfront is expected to require the capacity increase for 2008.
Rebuild Creston Feeder #1	Included in the SDP for 2005-2006	The new plan includes a comprehensive Creston area upgrade as a result of the new Lambert distribution source. The Lambert source was completed in 2004, essentially on target.

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Q136.0 Reference: Volume 2, p. 7

A significant proposed regional power facility is the Waneta Expansion, which will involve a new generator and diversion tunnel at the existing Waneta Dam on the Pend d'Oreille River.

Will any significant upgrades to the transmission system be required to handle the output from this facility? If so, have they been included in the SDP?

A136.0 The system impact studies for "The Kootenay 230 kV System Development Project" and the "South Okanagan Supply Reinforcement Project" considered the Waneta generation expansion and assumed that it will be connected directly to Selkirk. No significant upgrades in the FortisBC transmission system are envisaged to handle the output from this plant. Any costs that would occur would be the responsibility of the Waneta Expansion project not FortisBC.

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137.0 Reference: Volume 2, p. 9

Both 230 kV circuits between Lee Terminal and Vernon Terminal have been simultaneously forced out of service on at least four occasions in the last five years.

Q137.1 Please describe the circumstances leading to the simultaneous outages.

A137.1 The table below identifies recent Kelowna area blackout outages for the past five years.

Outage Date	Outage Duration (minutes)	Outage Cause
2000-07-08	0.07	Source outage (BC Hydro)
2000-07-20	8.12	Source outage (BC Hydro)
2000-07-25	0.22	Lightning
2001-08-22	17.43	Lightning
2002-08-19	0.22	Lightning
2003-07-04	0.17	Protective relay
2003-07-09	0.18	Protective relay
2003-08-15	0.18	Protective relay
2004-05-20	0.22	Lightning

Q137.2 What, if anything, has been done to date to avoid a recurrence?

A137.2 To date, the Company has not undertaken any formal studies or action to determine if a solution exists to prevent lightning related outages on the two 230 kV circuits. The fault location records have been analyzed to determine if there are any solutions to mitigate the lightning strikes.

The "Protective relay" outages were caused by defective equipment that has been repaired awaiting replacement under the present Kelowna Area Upgrade project (BCUC Order C 18 04). This project is planned for completion in 2005.

The planned double circuit 230 kV lines from Vaseux to Penticton will ensure the Kelowna area loads will continue to be supplied in the event of a loss of supply from Vernon. This increased ability to supply Kelowna from the south will address the risk of a major outage to the 230kV lines or substations from Vernon in addition to the relatively short outages caused by lightning.

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138.0 Reference: Volume 2, p. 10

The Plan notes that 11 Line requires a comprehensive thermal rating review, and that 9 Line and 10 Line have many segments in advanced states of deterioration.

Q138.1 Are all line components (poles, insulators, conductors, etc.) badly deteriorated?

A138.1 Line 11 is in acceptable operating condition. The line only requires inspection and rehabilitation each eight years as per our eight-year planning cycle.

Line 9 and Line 10 have approximately 40 percent of its line in poor operating condition. This is the result of deterioration of the poles, cross arms and insulators. We have had a number of pole fires in the past three years due to insulator tracking. This created concern with respect forest fires. The most recent assessment of the conductor indicates it is in acceptable condition.

Q138.2 Do these lines constitute a public hazard?

A138.2 No, The lines were patrolled last year and any imminent failures have been addressed. We will continue to do annual patrols of these lines to ensure that the line is safe.

Refer to the transmission Line Condition – Life Extension eight-year cycle Volume 1, Tab 9, Page 32 for details.

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139.0 Reference: Volume 2, p. 12

To mitigate against possible voltage instability in the Oliver/Penticton area, a RAS scheme is proposed to temporarily open breakers 41, 42, 43, and 44 at Oliver.

Q139.1 How long will this arrangement be in effect?

A139.1 This arrangement will remain in effect until Vaseux Lake 161 kV is upgraded for 230 kV operation. At that time the requisite number of 500 kV and 230 kV circuit breakers will be installed so that the two transformers have separate bus position and protection. This is scheduled for completion in 2008.

Q139.2 How often does FortisBC expect the RAS will operate?

A139.2 The RAS could operate for the failure of a Vaseux transformer, the simultaneous outage of the two 500 kV circuits or for a 500 kV line breaker failure. The number of operations of the RAS scheme is expected to be very low as the above events are double contingency (N-2) events. FortisBC has no historical data to predict these events.

Q138.3 How many customers, and which major ones, would be affected by the operation of the RAS?

A139.3 The RAS operation could effect up to 14,500 customers in Oliver, Osoyoos, Hedley, Keremeos and Princeton. The list of affected customers could also include Mascot Mines and Terasen Gas near Princeton.

Q139.4 Should the RAS operate, what is the likely load restoration time?

A139.4 The restoration time after RAS operations is difficult to predict. The restoration time may be momentary if the system is automatically reconfigured to remove the contingency creating the concern. There may be rare occasions the cause of the contingency will require the load to remain off line until the equipment or lines have been repaired.

Q139.5 Could the RAS be avoided by feeding the Penticton load from Anderson Substation and keeping 40 Line open at Oliver (or through some other arrangement)?

A139.5 No. The RAS is required to reduce loads in the Okanagan in the event of a total station outage at the Vaseux. Regardless of the system configuration a total outage of the Vaseux Station will require a RAS operation to reduce load. Leaving 40 Line open at Oliver will expose the loads in the Oliver and Boundary areas to interruption for outages on 11 Line and degrade reliability. The RAS scheme will still be required.

Q139.6 Could the initial bus configuration be altered to avoid the need for the RAS and, if so, at what cost?

A139.6 No. Installing a 500 kV and a 230 kV circuit breaker at Vaseux to provide separate bus position and protection for the two transformers can alter the initial bus configuration removing the need for the RAS to operate in the event of a single transformer outage. The RAS schemes would still be required to remove load in the event of other total outages and can not eliminated by reconfiguring the bus arrangement.