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1 Introduction

This report documents the System Development Plan for the FortisBC transmission and distribution systems. The report identifies necessary reinforcements in the bulk (or backbone) transmission system, the regional transmission and distribution systems, the communications and SCADA (System Control and Data Acquisition) networks, and protection systems owned and operated by FortisBC. The Capital Forecast included with this report distinguishes between “Sustaining Projects” which are directed at adequately maintaining existing facilities and modernizing obsolete equipment and systems, and “Growth Projects” which are required to serve increasing loads driven by population growth and new commercial and industrial operations in the FortisBC service area.

This System Development Plan has a broader focus than the 1998 Master Plan previously filed with the BC Utilities Commission. The new System Development Plan is a more comprehensive plan including protection and control facilities, communication facilities plus analysis of the maintenance requirements. The plan includes a long-term (20 year) study of the transmission system, a shorter (6 year) study for the distribution system, plus a detailed review of the maintenance programs and condition-based assessments of the lines and equipment.

The plan shows a significant shift in the long-term plans for some areas including rebuilding of legacy (older deteriorated) substations and rebuilding of much of the old infrastructure. One example of the impact of this change is in the Boundary area. The current plan is to construct two substations which are supplied from the high voltage transmission lines and then supplies the Boundary loads from a new distribution backbone. This plan removes the need to rebuild the sub-transmission lines and associated legacy substations in the Boundary area. The overall impact of the new plan is a significantly lower total capital cost, better ability to serve new customer growth, increased reliability, fewer facilities to maintain and increased system flexibility.

As the Okanagan continues to grow and become a larger urban load, there is a need to recognise the changing requirements of the area. In addition to the load growth driving significant transmission and distribution investments to meet the increasing demand, the larger load centre requires a new look at the reliability requirements of the area. The plan recognises this need and shows an advancement of the transmission system development to both meet the increasing loads and provide a higher level of reliability expected in large urban environments. The current South Okanagan Supply Reinforcement project set the stage to meet the increasing demands in the Okanagan.

The Kootenay region has a much lower load growth with the condition and aging infrastructure driving the rebuild of much of the system. The situation in the Kootenay does not support the elimination of the subtransmission system as is the case in the Boundary area. The distances are too great to allow a distribution system to replace the
subtransmission system as in the Boundary area. As a result, rebuilding some of the older
transmission facilities plus improving the reliability at the Lambert (Creston area) Terminal
will meet the area needs for both capacity and reliability.

A complete assessment of our maintenance plans and equipment condition was undertaken
as part of the system development planning process. The result of this review confirmed
the condition based maintenance cycles were consistent with utility practice for the age of
the facilities. The corrective work being identified requires a greater investment level than
was historically applied. The plan documents both the age and condition of the facilities
and recommends capital spending levels to adequately maintain the safety and reliability of
the system. The recommended levels are based on a combination of condition based
analysis and criticality of facilities.

A priority matrix was developed to help ensure the required capital projects were completed
in an orderly manner. This matrix considers safety, public impact, thermal capacity, voltage
support, and restoration time. The various aspects of the matrix are weighted to reflect the
importance of that item. Safety has the highest rating resulting in safety being the largest
contributor to the priority rating. The overall results of this priority system compare the
impact of each situation that exceeds the planning criteria and ranks it against other
projects. A discussion of the priority matrix can be found at Appendix C, Section 5.

1.1 Capital Plan Priority Analysis

The System Development Plan identifies more than 100 system development and
improvement projects to be implemented over the next six years at an estimated cost of
more than $400 million. In order to ensure appropriate spending a priority matrix was
developed. This matrix assigns various weighting factors to six different categories. Also a
“Mandatory” category is provided for a project that must proceed, therefore carries a
weighting greater than all other categories. The table below lists the weighting factors for
the six variable categories as applied to the System Development Plan projects.

Safety
This category is weighted the highest of the variable categories to demonstrate FortisBC’s
commitment to worker and public safety. This category demonstrates the ability to improve
safety by doing the project. If a system element is deemed unsafe at present, it is elevated
to the Mandatory category.

Restoration Time
This category demonstrates the reliability improvement value of the project as measured by
outage duration or restoration time.
Thermal Capacity
This category demonstrates the risk of equipment failure due to overload as measured by the percentage of overload compared to manufacturer rating of the equipment.

System Effect of Failure
This category demonstrates the consequence to the system if a system element failure were to occur without doing the project.

Voltage Related
This category (similar to the Thermal Capacity category) quantifies the power quality as measured by customer voltage level that is driving the project.

Public Impact
Public Impact is a measurement of the quantity of customers affected by the project.

Weighting Factors for Capital Expenditures Prioritization Matrix

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<tr>
<th>Category</th>
<th>Unit</th>
<th>Rating</th>
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<td>&lt;500</td>
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<td>&lt; 4</td>
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<td>Thermal Capacity</td>
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A complete list of projects included in the System Development Plan and their combined weightings can be found in Appendix C Section 5.

1.2 Review of 1998 Master Plan

The last comprehensive Transmission and Distribution System Master Plan for the FortisBC System was issued in November 1998 just before initiation of the most significant set of reinforcements of the FortisBC backbone transmission system in several decades. The 1998 Master Plan identified the urgent requirement to reinforce the transmission system in both the West Kootenay and South Okanagan regions. A number of system development permutations were described which would adequately mitigate the identified system deficiencies, although the ultimate configurations had not been decided at the time the plan was issued.

In the six years since the last planning report was issued the Kootenay 230 kV System Development Project has been completed, and South Okanagan Supply Reinforcement Project to reinforce the South Okanagan region is now underway. The implementation of these two projects marks substantial completion of the bulk system upgrades identified in the previous planning report, and provides a solid foundation for the next stages of modernizing and improve the adequacy of the backbone transmission system throughout the FortisBC service territory.

1.3 Significant Projects Undertaken Since 1998 Plan Issued

- Comprehensive rehabilitation initiatives on 44 Line to Osoyoos and 49 Line to Summerland.
- Complete distribution system rebuilds and voltage upgrades in Rossland, Warfield and West Trail.
- Capacitor additions at FA Lee Terminal in Kelowna and Vernon Terminal (BC Hydro) to improve import capacity into Okanagan Region.
- Circuit Switcher additions at Kaleden, OK Falls and Waterford to improve 63 kV sub-transmission performance in the South Okanagan.
- The AA Lambert Terminal in Creston rehabilitation project to provide distribution backup to the Creston area was completed in 2004 and included preparation for planned 230 kV bus reconfiguration in 2006 and 2007.
- The Kootenay 230 kV System Development Project, In Service Date (ISD) 2004 – New 230 kV transmission circuit connecting BC Hydro’s Kootenay Canal Generating Station with Columbia Power Corporation’s (CPC) new Brilliant Terminal Station (BTS) and the new Warfield Terminal Station (WTS). This project also involved salvage of most of the deteriorated 63 kV transmission lines in the West Kootenay between South Slocan and Trail, along with salvage of the deteriorated Warfield and Tadanac substations.
• South Okanagan Supply Reinforcement Project, ISD 2005 – New 500/230/161 kV substation connecting the BC Hydro 500 kV circuit between Selkirk and Nicola to the FortisBC transmission system. The 230 kV bus will be temporarily operated at 161 kV until the first 230 kV circuit is completed between the Vaseux Lake and RG Anderson (Anderson) Terminals, at which time the bus will be energized at its planned 230 kV operating. The ultimate configuration will involve a six position 230 kV ring bus terminating three 500/230 kV transformers, two 230 kV circuits between Vaseux Lake and Anderson and a single 230 kV circuit between Vaseux Lake and the proposed new Bentley Terminal near Oliver.

• Kelowna Area Upgrade including DG Bell (Bell) Terminal 230 kV Upgrade, ISD 2005 – Termination of 230 kV circuit 73 Line at Bell and the addition of a new 230/138 kV transformer and FA Lee Terminal (Lee) Upgrade ISD 2006 - Reconfigure 138 kV bus and transformer protection to improve capacity and reliability of supply to the City of Kelowna.

The timeliness of these ongoing system reinforcements was dramatically illustrated by the multi-day power outage to 50 million customers in Ontario and the US Northeast in August 2003. This event has been directly implicated in the negative third quarter 2003 GDP growth for Canada, even though two of the outage days occurred on a weekend. This event demonstrates concretely the economic and social impacts of not maintaining an adequate transmission system.

Other major electrical system developments which have taken place in the area since the last planning report was issued include the completion of CPC’s 180 MW Arrow Lakes Generating Station at the Hugh Keenleyside Dam on the main stem of the Columbia River near Castlegar and the related 230 kV interconnection via the Brilliant Terminal Station to BC Hydro’s Selkirk 500 kV substation. Work has now commenced on the Brilliant Expansion Project, which involves construction of a new 120 MW generating unit and associated water diversion facilities at the existing Brilliant Dam on the Kootenay River near Castlegar. This generator will be interconnected with the FortisBC system at the recently completed Brilliant Terminal Station.

A significant proposed regional power facility is the Waneta Expansion (TeckCominco), which will involve a new generator and diversion tunnel at the existing Waneta Dam on the Pend d’Oreille River.
2 Bulk FortisBC Transmission System

2.1 Existing System

The existing FortisBC transmission system is represented geographically in Map 1 of Appendix A, and a switching single line diagram of the system is provided in Map 2. In the west, FortisBC serves the Okanagan region which includes the cities of Kelowna and Penticton and extends south to Osoyoos and west up the Similkameen River valley to Princeton. In the east, FortisBC serves the West Kootenay region which spans the southern part of British Columbia from Creston to Rock Creek. The Kootenay region also extends north up Kootenay Lake to Kaslo and also from Trail north up to Slocan City. The nominal voltages used on the bulk system are 230 kV, 161 kV, 138 kV and 63 kV.

The FortisBC system is interconnected with the BC Hydro 500 kV and 230 kV networks at Vernon, Princeton, Kootenay Canal, Creston, Brilliant and Waneta. The generation resources that supply FortisBC’s load are primarily located in the Kootenay region or external to the FortisBC network.

The BC Hydro interconnections at Vernon, Princeton and Vaseux Lake Terminal (2005/06) play a very important role in transporting power into the Okanagan region from the generating plants in the Kootenay region. The completion of Vaseux Lake Terminal at the end of 2005 will improve the reliability of the FortisBC transmission system in the South Okanagan valley. It will also defer or eliminate the need to upgrade the existing 161 kV circuit to 230 kV (11 Line) that links the Kootenay and Okanagan regions between Trail and Oliver. However, the completion of South Okanagan Supply Reinforcement Project will substantially increase the operating complexity of the south interior transmission system, with the requirement to have additional Remedial Action Schemes (RAS) in place to trip the underlying parallel FortisBC transmission path (combinations of 11 Line, 43 Line, 73 Line and 71 Line) to avoid facility overload for various combinations of 500 kV contingencies on the BC Hydro system. Additional RAS will also be required at the south interior generation plants Kootenay Canal, Arrow Lakes Generating Station, Waneta and Seven Mile for various combinations of 500 kV contingencies within the BC Hydro system.

These interconnections are also used on an ongoing basis to import power from external suppliers and to export to external consumers during periods of excess power, typically off peak hours during the spring freshet. In 2003 the FortisBC system had net energy imports of approximately 731 GWh, comprising nearly a quarter of the 3,182 GWh of energy consumed in the system. The peak import level in January 2004 was 400 MW, more than half the peak demand of 718 MW. FortisBC only exports energy in excess of local requirements during spring freshet, with maximum export in 2004 of 245 MW recorded during July.
2.2 Bulk System Deficiencies

System impact studies were carried out to evaluate the performance of the system following various single (N-1) and selective double N-1-1 (one element out of service for maintenance, second element fails) or N-2 (double unrelated) contingency outages. The following are some of the key contingencies that were studied:

N-1 Contingencies

- 5L98 Vaseux Lake to Nicola 500 kV
- 5L96 Vaseux Lake to Selkirk 500 kV
- 5L91 Selkirk to Ashton Creek 500 kV
- One of 2L255 or 2L256 Ashton Creek to Vernon 230 kV
- One of 72 Line or 74 Line Vernon to Lee 230 kV
- 77 Line Warfield Terminal Station to Brilliant Terminal Station 230 kV
- 79 Line Kootenay Canal to Brilliant Terminal Station 230 kV
- 73 Line Anderson to Bell Terminal 230 kV
- 82 Line Brilliant Terminal Station to Selkirk 230 kV
- 30 Line South Slocan to Coffee Creek 161 kV
- 40 Line Vaseux Lake to Oliver 161 kV
- 76 Line Vaseux Lake to Anderson 161 kV
- Various N-1 transformer contingencies

N-1-1 and N-2 Contingencies

- 2L255 and 2L256 Ashton Creek to Vernon 230 kV
- 72 Line and 74 Line Vernon to Lee Terminal 230 kV
- 5L76 and 5L79 Ashton Creek to Nicola 500 kV
- 5L98 and 5L96 Vaseux Lake to Nicola and Vaseux Lake to Selkirk 500 kV
- 5L91 and 5L96 Ashton Creek to Selkirk and Vaseux Lake to Selkirk 500 kV
- Vaseux Lake 500 / 161 kV Transformer 1 and Transformer 2

In considering N-1-1 or N-2 contingencies, it must be noted that the contingency classification designates only that one or more system elements are simultaneously out of service rather than suggesting the infrequent coincidence of several low-probability events. Many N-2 contingencies actually result from a single credible event, including protection failure, stuck breaker or breaker failure, double circuit structure collapse or bus failure. For example, 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. As the load increases in the Kelowna area this event will create significant outages in Kelowna.
A number of the most significant bulk system deficiencies identified in the 1998 Master Plan have either been addressed by the Kootenay 230 kV System Development Project, or will shortly be mitigated by the South Okanagan Supply Reinforcement Project.

The next echelon of bulk system priorities includes integrating the Vaseux Lake Terminal Station into the Okanagan transmission system to addressing supply reliability deficiencies for the City of Kelowna.

Following completion of the Vaseux Lake Terminal, the City of Kelowna will still be exposed to significant load loss for coincident loss of the 230 kV circuits 72 Line and 74 Line or 2L255 and 2L256, which share a common right of way, under almost any loading condition. Completion of the Vaseux Lake Terminal is the first step in addressing this deficiency, but the new substation must be fully integrated into the FortisBC system to realize all the benefits of this new substation.

The next step involved in integrating the new Vaseux Lake Terminal into the FortisBC Okanagan region transmission system involves the almost immediate addition of a 230 kV circuit to replace existing 161 kV circuit 76 Line between the new Vaseux Lake Terminal and existing Anderson Terminal Station in Penticton. This addition will mitigate the regular occurrence of total or substantial load loss in Kelowna for outages to 72 Line and 74 Line or 2L255 and 2L256 between BC Hydro’s Vernon and Ashton Creek Terminals.

Subsequent bulk system additions will be driven by load in the major population growth centers, especially Kelowna, Penticton, Oliver and Osoyoos. The ultimate loadings considered in this System Development Plan are 450 MW for the City of Kelowna, and 270 MW for the Okanagan-Similkameen area. At these loading levels for Kelowna and Penticton, the total Okanagan Valley load between Vaseux Lake Terminal and Lee Terminal will be in the 720 MW range.

2.3 Maintenance Assessment

The condition of the FortisBC bulk system facilities varies widely by asset class, vintage and location. Notable bulk system facilities of specific concern include:

- 11 Line (161 kV) between the AS Mawdsley (Mawdsley) Terminal in Trail and the Oliver Terminal, requires a comprehensive thermal rating review, including verification of all spans to confirm maximum loading capacity. In addition to 11 Line, 63 kV circuits 9 Line and 10 Line have many segments in advanced states of deterioration. 9 Line and 10 Line were originally constructed in 1919, and although significant sustaining expenditures have been made over the last 85 years to maintain these facilities, the overall rate of deterioration is accelerating, indicating that the facilities have exceeded reasonable service life expectancy and will require either complete rebuild or abandonment in the near term to avoid unacceptably compromising supply reliability to Boundary area load centers.
• 30LE (161 kV) which is owned by TeckCominco between Crawford Bay Terminal and Kimberley, requires a thorough right of way review and appropriate vegetation management if it is to be kept in service as a backup supply for Crawford Bay, Coffee Creek and Kaslo substation.

• 32 Line (63 kV) between AA Lambert (Lambert) in Creston and Crawford Bay Terminal is in much deteriorated condition and is a candidate for a complete rebuild.

One longer-range goal for the FortisBC system is to reduce the number of nominal system voltages to three widely used standard classes: 230 kV, 138 kV and 63 kV. This will require a staged migration away from the 161 kV voltage level, a class not employed by neighboring utilities and not commonly used by utilities in North America. Because it is a relatively uncommon voltage class, maintaining 161 kV as a system voltage requires a spare parts policy for 161 kV equipment which is entirely self-contained to FortisBC, since equipment cannot be borrowed or purchased from neighboring utilities in the event of equipment failure. In addition, since the 161 kV voltage level is non-standard, there is typically a cost premium involved in purchasing equipment with this rating. Abandoning the 161 kV voltage class will require that existing 161 kV facilities are either upgraded to 230 kV as required due to load growth, or reduced to a 138 kV nominal voltage as equipment needs to be replaced if the lower voltage is adequate to meet system needs. Immediate or rapid abandonment of this voltage level would be costly and is not proposed in this System Development Plan.

A more comprehensive condition assessment of the FortisBC transmission facilities is provided in Appendix D of this report.

2.4 Bulk Transmission Capital Projects

2.4.1 South Okanagan Supply Reinforcement

2.4.1.1 Vaseux Lake Terminal Station

This project involves development of a new 500/230/161 kV Terminal Station connecting the BC Hydro 500 kV circuit between the Selkirk and Nicola Terminal Stations to the FortisBC transmission system in the Okanagan. The project also involves upgrades at the Anderson, Oliver, Grand Forks and Mawdsley Terminal Stations to enable networked operation of the FortisBC Kootenay and Okanagan transmission systems, which are presently operated as two radial systems, normally open south of Penticton. The 230 kV bus at Vaseux Lake Terminal will be temporarily operated at 161 kV until the first 230 kV circuit is completed between the Vaseux Lake and Anderson Terminals, at which time the bus will be energized at its planned 230 kV operating voltage. The ultimate configuration will involve a six position 230 kV ring bus terminating three 500/230 kV transformers, two 230 kV circuits between Vaseux Lake and Anderson and a single 230 kV circuit between Vaseux Lake and the proposed new Bentley Terminal near Oliver.
2.4.1.2 Vaseux Lake Terminal RAS Schemes

Due to the bus configuration in the initial phase of Vaseux Lake Terminal Station, failure of one 500/161 kV transformer will result in the transformer protection disconnecting both transformers. Prior to the auto sectionalizing and restoration of the healthy transformer, excessive voltage drop or voltage instability will occur in the Oliver area. To mitigate against the scenario of voltage instability in the Oliver / Penticton area, a RAS scheme is proposed to temporarily open breakers 41, 42, 43 and 44 at Oliver to shed sufficient load in the Oliver / Penticton area to ensure a stable voltage profile. Upon restoration of the healthy transformer at Vaseux Lake Terminal those same breakers can be reclosed to restore the loads.

Similarly, a simultaneous loss of both BC Hydro 500 kV lines 5L98 and 5L96, (N-2 event) or a 500 kV line breaker failure at Vaseux Lake Terminal (N-2 event) will result in a similarly extreme low voltage condition in the South Okanagan area. The same RAS can be used to maintain adequate operating voltage in the South Okanagan area during this contingency.

For prolonged N-2 contingencies, the system load can be restored by manually reconfiguring the Penticton load to be fed from Anderson substation and keeping 40 Line opened at Oliver.

In conjunction with outages to various combinations of BC Hydro’s 500 kV bulk transmission system in BC’s south interior, under different operating scenarios, direct transfer trip (DTT) of up to four FortisBC transmission lines are required as listed in Table 2.4.1.2 below. A few of these DTT schemes are already in existence and the remaining schemes are being designed and implemented in conjunction with the Vaseux Lake Terminal 500 kV project.
Table 2.4.1.2: RAS Required for Vaseux Lake and BC Hydro 500 kV contingencies

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<th>Operating Scenario</th>
<th>Contingency</th>
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<th>71L*</th>
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<th>76L</th>
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* DTT only if 71 Line is connected to BPA Boundary

2.4.1.3 RAS to Prevent Voltage Collapse or Blackout in Kelowna

Prior to the completion of the first 230 kV circuit between Vaseux Lake and Anderson Terminals, a planned or forced outage to any one of the Ashton Creek to Vernon 230 kV circuits (2L255/2L256), requires that RAS be designed and armed to prepare for the next 230 kV line sequential double contingency (N-1-1). Once armed, should there be an outage to the remaining 230 kV circuit, the RAS will automatically initiate a direct transfer trip to both Vernon to Lee 230 kV circuits (72 Line/74 Line) in addition to shedding approximately 200 MW of load in the Kelowna area to prevent overloading of Anderson Transformer 2. This scheme must also be designed to initiate the same action if and when both Ashton Creek to Vernon 230 kV circuits are lost in a simultaneous double (N-2) contingency.

A similar RAS is also needed for the Vernon to Lee 230 kV circuits (72 Line/74 Line) to cover for N-1-1 or N-2 events of the Vernon to Lee 230 kV circuits.
2.4.2 Vaseux Lake Terminal to Anderson Terminal 230 kV Circuit

With the completion of Vaseux Lake Terminal in 2005/06, simultaneous (N-2) or sequential (N-1-1) loss of 72 Line and 74 Line between Vernon and Lee or BC Hydro 230 kV circuits 2L255 and 2L256 between Vernon and Ashton Creek will result in severe voltage drop in the City of Kelowna and overloading of both Anderson Terminal transformers. To avoid this abnormal system condition, in 2005/06, as much as 200 MW of Kelowna load will be shed by an automatic RAS, only 70 MW of Kelowna load can be served from the South Okanagan under the initial Vaseux Lake Terminal configuration.

In order to provide secure supply capability to the City of Kelowna after completion of Vaseux Lake 500 kV Terminal Station, a 25 km 230 kV circuit will be constructed between Vaseux Lake and Anderson Terminals in the 2007/08 timeframe. Refer to Figure 2.4 A. The new structures will be located on the centerline of existing 161 kV circuit 40 Line to make the most efficient use of existing right of way and to avoid a protracted new right of way acquisition process. Termination of the 230 kV circuit will require completion of the 230 kV ring bus in Anderson Terminal and reconnection of the existing 168 MVA kV transformer for 230 kV operation.

Once the 230 kV circuit is in service, the RAS as described in the previous project can be turned off and retained for use during maintenance outages and other sustained system outages. Refer to Figures 2.4.2 A, B, and C for the recommended development sequence of the 230 kV bulk transmission facilities in the South Okanagan system.
Figure 2.4.2 B: Add Vaseux Lake Terminal and 230 kV Circuit to RG Anderson Terminal
Figure 2.4.2 C: Add Bentley Terminal, 230 kV Bentley to Vaseux, 138 kV Bentley to Oliver

To Princeton

To Grand Forks

To Bell Terminal

Andersson Terminal

BCH 500 kV
To Nicola

500 kV (BCH)
230 kV
161 kV
138 kV
63 kV
2.4.3 New Bentley Terminal Station

Once Vaseux Lake is converted to 230 kV, a new terminal substation is required near Oliver to supply 11 Line east to Grand Forks at 161 kV plus create a new 138 kV source to support the load growth in the Oliver-Osoyoos area. The new terminal station will be constructed at the junction of existing 161 kV circuits 40 Line and 11 Line east of Oliver Terminal. This terminal will be equipped with 230 kV, 161 kV and 138 kV buses. The 138 kV bus will be used to feed Oliver Terminal Station which will be reconfigured to include a 138 kV ring bus (modified existing 161 kV bus). The new 138 kV bus will be used to terminate 43 Line from Keremeos and Princeton and the new 138 kV from Bentley, as well as two 138/63 kV transformers to supply the 63 kV subtransmission system in the South Okanagan. The 138 kV bus at Bentley will also terminate a new 138 kV circuit which will supply a new east Osoyoos distribution source substation. The 161 kV bus at Bentley will terminate existing 11 Line from Grand Forks Terminal and Mawdsley Terminal.

As part of the Bentley Terminal Station, a new 10 km 230 kV circuit will be constructed between Vaseux Lake and Bentley Terminals on the existing 40 Line centreline. Refer to Figure 2.4.2 C.

2.4.4 Kelowna Switched Shunts and Static VAr Compensator

Almost immediately following completion of the 230 kV double circuit between Vaseux Lake and Anderson Terminals, it will be necessary to install approximately 30 MVAr of additional shunt capacitors at both Bell and Lee Terminals to provide adequate voltage support for loss of both 230 kV lines between Lee and Vernon.

When the Okanagan load reaches 530 MW, the loss of the supply from Vernon will result in extremely low voltages or voltage collapse in the Kelowna area. A 150 MVAr Static Var Compensator (SVC) or equivalent dynamic reactive support facility will be required at the Lee or Bell Terminal Stations in 2011 under the present load growth forecast.

2.4.5 Kelowna Area Upgrade

The entire Kelowna area load is supplied by two 230/138 kV terminal transformers at the Lee Terminal station. The Kelowna area load is at risk from both reliability and capacity perspectives. Reliability is compromised at the Lee Terminal by the present switchyard configuration and inadequate transformer and bus protection that has resulted in the total loss of supply to the area for certain faults. Post-contingency capacity is compromised because an outage of one Lee Terminal transformer will overload the remaining transformer requiring load shedding as early as the summer of 2005. This area is the fastest growing load center of FortisBC’s network. The proposed solution will add capacity (a new transformer, equal in size to the Lee Terminal transformers) at Bell Terminal and improve
the switchgear, switchyard configuration, and protection at Lee Terminal to ensure reliable power supply to Kelowna area distribution substations for the foreseeable future.

3 Okanagan Region Transmission and Distribution Systems

A geographically referenced system map for the FortisBC Okanagan Region is included in Appendix A as Map 3.

3.1 Kelowna Area

3.1.1 Existing Transmission and Distribution System

The Kelowna area is the fastest growing part of the FortisBC system, and one of the fastest growing urban centres in British Columbia. The load additions resulting from this growth have put the transmission and distribution systems in the area under significant stress, and will continue to drive the need for both transmission and distribution reinforcements in both the short and longer term.

Since the initial transmission interconnection between the Kootenay and Okanagan regions was first developed, Kelowna has grown from a small town into a significant urban hub. Greater Kelowna now comprises the largest urban area in British Columbia east of the lower mainland, and development of the transmission system has barely kept up with the City's growth and the increasing power reliability expectations of its residents, many of whom have relocated to the Kelowna region from other urban areas with more robust and fully integrated transmission supply systems.

3.1.2 Kelowna Area System Deficiencies

At the transmission level, the reinforcements linked to the Vaseux Lake Terminal and the subsequent transmission line developments will provide a substantially improved transmission superstructure to provide reliable electric supply. Reliability of supply throughout the City of Kelowna will be further improved by operating the existing 138 kV transmission system as a fully meshed network. The key constraint preventing this operating mode is the lack of adequate 138 kV short-line protections between the various distribution source substations in the City. Due to the lack of adequate protections, the 138 kV system is presently operated as three separate radial lines, 50 Line, 51 Line and 55 Line. Outages to any of these lines creates supply interruption to all connected load until the line is restored or the affected loads are reconnected to one of the other transmission lines by manual switching (where this is possible). Looping the three radial lines into a fully meshed system would eliminate such outages for most single-line 138 kV contingencies within the City. In the longer term looping of the 138 kV system will be required to provide secure supply to all distribution sources in the City via the 230 kV circuits from the South Okanagan for loss of the 230 kV transmission circuits from the north.
Development is occurring in almost all areas of Kelowna but is especially concentrated on the City perimeters. New distribution supply transformation capacity will be needed to address the growing loads. Planned developments in the northern and western sectors of the City cannot continue to be supported by the existing single transformer source at the Sexsmith substation. Some short term relief can be obtained by transferring load from the Sexsmith substation to the Lee Terminal, Glenmore and Duck Lake substations by constructing additional distribution line connections, although continued distribution load additions at Lee Terminal should be avoided to prevent increased risk to the system transformer which supplies this distribution load via its tertiary winding. As new subdivisions continue to be added in the north end of Kelowna it will be necessary to add a new 138 kV source substation in the area. Similarly, rapid development on the cities eastern boundary at the base of Black Mountain and on the southern boundary in what is called the South Ridge area will require additional source substations.

Significant property developments being proposed for the downtown waterfront area will exceed the existing transformer capacity at the Recreation substation, and the limited footprint at this site will make addition of further transformation capacity a challenging proposition. At present, several 20+ storey hotels are before city council for consideration, although rezoning and relaxation of existing height restrictions would be necessary for these projects to proceed as presently proposed.

Constraints on the Big White 25 kV feeder from the Joe Rich substation due to rapid load growth at the Big White Resort will be addressed by development of a proposed new 138 kV source substation at Big White. It may be necessary to add temporary local generation supply near the resort to adequately serve loads over the next several winters until the new transmission facilities are complete.

The distribution system in Kelowna is generally not adequate to serve the growing loads in the area with reasonable backup capacity. Many feeders within the Kelowna area are already at or near their loading limits and do not have adequate capacity to serve additional point loads caused by the development of new residential subdivisions and commercial facilities such as malls or light industry. Most feeders do not have extra capacity to backup a significant portion of the load fed by adjacent feeders under either planned or emergency situations. In a number of cases fuses have blown under non-contingency loading conditions and must be replaced by higher rated fuses simply to continue serving the connected load, leading to potential loss of fuse coordination and threatening excessive load loss under fault conditions.
3.1.3 Maintenance Assessment

The condition of the Kelowna area transmission facilities is generally acceptable and on average better than some of the much older facilities in other parts of the system. Some protection equipment is outdated or obsolete and is scheduled for replacement in the near term.

The area distribution facilities represent a fairly wide demographic range. The newer facilities in recently developed subdivisions are in generally good condition (as would be expected), but facilities in the older communities, especially those adjacent to the City of Kelowna-owned core area are in mixed condition. As the City grows, the main feeders from the source substations are subjected to increasing loads as new communities are added, but many of the older feeders were originally constructed with small-gauge conductor and are unable to accommodate the extra loading imposed by additional subdivisions. In many cases the structures would not be adequate to carry heavier gauge conductor and would require complete replacement as part of a conductor upgrade.

The structure maintenance program has not been able to keep up with the eight year test cycle and many structures identified as being in poor condition have remained in service out of necessity, or repairs have been rolled forward into future years leading to an ever-increasing backlog of required structure replacements.

3.1.4 Transmission Projects

3.1.4.1 Big White 138 kV Line and Substation

The objective of this project is to accommodate the load growth around the Big White Ski Resort. Presently the load in the area is supplied from the Joe Rich 138 kV substation via a long 25 kV distribution line. According to the new load forecast the Joe Rich substation will be loaded beyond its winter peak rating by 2005/06. Based on the history of recent years the load in the Big White area is expected to continue to grow at approximately 10%-15% for a few more years. The scope of work for this project is under investigation at this time. It is expected the scope will include:

- Integrate a new line (57 Line) into the 138 kV bus at a new Black Mountain substation and Tap the existing 51 Line build, a new 138 kV line approximately 20 km in length from a point near the existing Joe Rich substation using single bundle 397 MCM ACSR conductor to the new Big White substation site.
- Complete the Big White substation and install a new 138/25 kV, 31.5 MVA transformer. A second transformer will be required by 2015 if load growth continues at the present rate. This project will also involve installation of the necessary protection and SCADA equipment at the Big White substation.
3.1.4.2 Ellison Distribution Source Substation

A new 138/13 kV source substation is proposed for construction approximately 5.5 km north of the existing Sexsmith substation.

The Sexsmith distribution substation is a 138/13kV single 32MVA transformer station with 4 feeders. 2004 summer load at Sexsmith was 27MVA or 84% of transformer rating. This substation supplies a large area of north Kelowna including Glenmore Valley to the west, sections of Hwy 97 including the Okanagan University and Kelowna International airport to the north, and Old Vernon Road to the east and north.

Currently underway and planned development in the Clifton/Glenmore Highlands and South and North University areas of over 6,000 residential units (refer to Appendix A-11) will add approximately 1.6 MW's of load to this substation per year. This does not include development in the McKinley Landing area which has not been determined at this point. This will result in capacity limits of Sexsmith being reached as early as 2008. In addition, failure of this single transformer would result in unacceptable long term outages to over 60% of the load currently fed by this substation based on current backup capabilities.

A feeder tie from Sexsmith to Duck Lake can mitigate the shorter term overload issue, however the long term capacity solution requires an additional transformer be installed in the area. Both the long term capacity and backup limitations at Sexsmith could be addressed by adding a second transformer at Sexsmith itself. However with the emerging load center in the North/South University area, the recommended solution is to position an additional source at this new load center allowing offloading of some 15 MVA of existing load plus planned development in this area. Sexsmith substation would then be utilized in conjunction with Glenmore substation to address the current load and growth in the Clifton/Glenmore Highlands development area.

Ultimate build out of this substation should incorporate three transformer bays with nine feeder termination points. Initial build will include a single 32 MVA transformer with four feeder terminations. Two feeders will head south towards Sexsmith, one along Hwy 97 supplying the Airport and University area, and the other south along Old Vernon Road. The third feeder will be the original tie to Duck Lake substation. A future fourth feeder would head west to the McKinley area, then south to create another tie with Sexsmith.

3.1.4.3 Black Mountain Distribution Source Station

A new 138/13 kV source substation is proposed for construction approximately 5 km east of Hollywood substation and 5 km south of Lee substation.
There is currently underway and planned residential development in the combined Black Mountain, Rutland, Tower Ranch and South-East Kelowna areas of over 5,500 residential units (refer to Appendix A-11). This growth will add 16.5 MVA of additional load to the area serviced by Lee and Hollywood substations. Lee 13 kV distribution source is drawn from a tertiary winding off the 230/138 kV 168 MVA main Kelowna area supply transformers. This tertiary supply is then distributed by two 13 kV distribution feeders. Hollywood substation is a typical Kelowna area 138/13 kV dual 32 MVA transformer station with six 13 kV distribution feeders.

2004 summer peak was 13 MVA at Lee substation and 48 MVA at Hollywood substation. Increased reliance on the present Lee tertiary source is not recommended due to increased risk the use of the tertiary for distribution has on these main supply transformers. Current demand on Hollywood is at 75% of total installed capacity with less than full backup capabilities from local and adjacent sources for loss of one of the two transformers. Capacity is limited for further load additions.

Increasing capacity at Hollywood, installing a separate distribution supply transformer at Lee or building a new distribution source are options to serve the existing and new load. The shorter term plan is to incorporate both the Hollywood capacity increase and the new distribution source into the system plan. The development of the Tower Ranch area would drive the addition of a separate distribution supply transformer at Lee but is not considered in this plan at this time. The immediate recommendation is to add an additional distribution source substation in the Black Mountain area where over 50% of the new growth load center is located. This source would serve this area as well as supply backup capabilities back into the central Kelowna area currently served by the Hollywood substation. The development of a substation at this site also benefits the Big White Supply project by creating a suitable tap location for the Big White transmission line described in separately.

3.1.4.4 Fault Level Reduction

Fifteen existing substations have fault levels at the distribution bus in excess of acceptable levels presenting a safety risk to workers and the public. A program to limit fault levels at these stations by installing current limiting reactors will be initiated immediately.

3.1.4.5 Loop Kelowna 138 kV Circuits

This project involves a number of breaker additions, bus modifications and the installation of new short line protections and associated communications to enable operating the 138 kV subtransmission in Kelowna as a looped network. This project will begin in 2006 and be complete by 2009.
3.1.4.6 Recreation Capacity Upgrade

The wholesale municipal distribution load served by the Recreation substation near the downtown lakefront district in Kelowna is growing at a rate significantly greater than system average. Several 20+ storey residential and commercial buildings have recently been proposed for this area but are pending rezoning and relaxation of the Kelowna building height restrictions before they can proceed. These proposals are in addition to either constructed or in progress of construction of several 10+ story residential complexes and numerous civic, commercial and institutional developments in this core area of the City. The scope of this project is to install a new 138/13 kV distribution transformer, and associated protection.

3.1.4.7 Hollywood Capacity Upgrade

The distribution load served from the Hollywood substation is increasing rapidly due to commercial developments and higher density housing projects. The scope of this project is to install a new 138/13 kV distribution transformer, and associated protection.

3.1.4.8 Braeloch (SW) Kelowna Distribution Source Substation

Distribution loads are growing rapidly southwest of Bell Terminal with several large subdivisions currently underway and more planned for a 10-15 year time frame. In the longer term a new source substation will be constructed to serve this area and provide backup to the Bell Terminal distribution loads. The scope of this project is to install a new 138/13 kV distribution transformer, a new 138 kV transmission line from Bell Terminal, and associated switchgear and protection.

3.1.4.9 OK Mission Capacity Upgrade

The distribution load served from OK Mission substation (Mission) is growing and will overload the existing transformers beyond 2010, especially when providing backup to adjacent distribution stations. The scope of this project is to install a new 138/13 kV distribution transformer, and associated protection.

3.1.5 Distribution Growth Projects

3.1.5.1 Duck Lake to Sexsmith Feeder Tie

In conjunction with the planned new Ellison distribution source in north Kelowna, a feeder tie from Sexsmith to Duck Lake will provide interim relief to the area loading issues. When the Ellison supply is completed, this tie will form part of the feeder network.
3.1.5.2 Quail Development Loopfeed

The Quail residential development in north Kelowna is growing at a rate which will soon exceed the capacity of the existing radial primary system supplying the area. A second supply into this area is required.

3.1.5.3 Dilworth Development Loopfeed

The Dilworth Mountain residential development in central Kelowna is creating load growth which exceeds the capacity of the existing radial primary system supplying the area. A second supply into this area is required.

3.1.5.4 Mission Feeder 5 to Mission Feeder 4 Extend to Springfield (Tie to Glenmore Feeder 1)

Load growth in the Mission Feeder 4 and Glenmore Feeder 1 areas is substantially eroding both capacity and backup capabilities of these two feeders. An extension of Mission Feeder 5 along Richter to Springfield tying into Glenmore Feeder 1 will allow splitting of the Guishachan load centre and also provide backup to both feeders and sources.

3.1.5.5 Bell Feeder 2 to Mission Feeder 3 Tie

In conjunction with the planned new distribution source in south west Kelowna, a feeder tie from Bell Terminal to Mission substation between Bell Feeder 2 and Mission Feeder 3 will provide interim relief to the area loading issues. When the Southwest Kelowna supply is completed, this tie will form part of the feeder network.

3.1.5.6 Glenmore Feeder 5 - Sexsmith Feeder 2 Tie Add Normally Open

With completion of a City four lane project along Glenmore Drive, a tie between Glenmore Feeder 5 and Sexsmith Feeder 3 can be completed. A new Normally Open (N.O.) point will be established along Sexsmith Feeder 3 to transfer additional load from Sexsmith to Glenmore substations to support the interim offloading of the highly loaded Sexsmith substation. This tie will also provide operational load transfer capabilities.

3.1.5.7 Kelowna Feeder Protection

As load has steadily increased on feeders in the Kelowna area, fuse sizes on feeder taps have been increased accordingly. Overloading and mis-coordination of fuses with
upstream devices has become an increasing problem. To resolve the issue will require combinations of load splitting and protection upgrades on a number of feeders.

3.1.5.8 McKinley Landing Capacity Upgrade

McKinley Landing is situated in the northwest corner of the Kelowna service area along the Okanagan Lake. Load growth in this area will exceed existing supply capacity by 2007, requiring a rebuild of the current distribution supply to higher capacity. A future feeder from the proposed Ellison source is planned into this area along with a tie to Glenmore Feeder 5 and Glenmore Feeder 6 through Clifton as load grows in this area.

3.1.5.9 New Glenmore Feeder 6 (50 Line Under Build High Road to Clifton)

A combination of high load growth in the Magic Estates, Clifton, and Glenmore Highlands development areas will exceed existing distribution supply capabilities by 2008. A new feeder from Glenmore substation into the Clifton area is required. This feeder will also tie through to McKinley Landing.

3.1.5.10 Hollywood Feeder 1 to Lee Feeder 2 Tie

In conjunction with the planned new distribution source in the Black Mountain area, a feeder tie from Hollywood substation to Lee Terminal between Hollywood Feeder 1 and Lee Feeder 2 will provide interim relief to the supply issues in the Gallagher area. When the Black Mountain supply is completed, this tie will form part of the feeder network.

3.1.5.11 Hollywood Feeder 1 to Mission Feeder 1 Tie along KLO Rd

The area between Rose Road, Gordon Road, KLO, and Springfield has heavy development on its boundaries and therefore contains ties between several major feeders including Hollywood Feeder 1, Mission Feeder 1, Mission Feeder 4, Glenmore Feeder 2, Bell Feeder 3 and Hollywood Feeder 7. These ties, other than a section along Benvoulin Road are generally small gauge conductor. As loading issues arise in the perimeter areas, upgrading these ties to a larger gauge will provide improved transfer capabilities between substations and offer operational flexibility. The Hollywood Feeder 1 to Mission Feeder 1 tie would provide a means to transfer significant load from Hollywood to Mission substations or Bell Terminal stations.
3.1.5.12 McKinley to Clifton Tie

Implementation of the McKinley Capacity Upgrade project and new Glenmore feeder to Clifton will provide an opportunity to close the two feeders between Glenmore and Sexsmith substations providing supply redundancy into the area. This tie would be built when a narrow gap between the two areas is developed.

3.1.5.13 Lee Feeder 2 to Hollywood Feeder 5 Tie

In conjunction with the planned new distribution source in the Black Mountain area, a feeder tie from Hollywood to Black Mountain between Hollywood Feeder 5 and Lee Feeder 2 will provide source transfer and feeder backup capabilities between the two substations and feeders.

3.1.5.14 Retermiate Lee Feeders

This project is required to offload the 13 kV tertiary on the 230/138 kV system transformer at Lee to reduce the system risk due to distribution faults. Ultimately the loads presently served by the Lee system transformer will be entirely fed from the new Ellison source, the new Black Mountain source and the existing Sexsmith and Hollywood sources.

3.1.5.15 New Feeder Ellison Substation

Ongoing high levels of load growth in north Kelowna will drive the need for a fourth feeder in this area, to be fed from the planned Ellison source.

3.1.5.16 Future Kelowna Distribution Upgrades

Assuming load growth in the general Kelowna area continues to grow at 3% per year, an equivalent of one additional source feeder and associated ties per year are required to maintain pace. The precise location and tie configurations will be dependent on the rate of growth in each of the development areas. Initial indications are that additional feeders would most likely be required out of Mission substation and Bell Terminal.
3.2 Penticton – Summerland Area

3.2.1 Existing Transmission and Distribution System
The Transmission system in the Penticton - Summerland area primarily consists of 63 kV subtransmission circuits fed from the 230 kV and 161 kV bulk system at RG Anderson Terminal in the City of Penticton, with alternate supply from the 161 kV Oliver Terminal to the south.

Naramata and Westminster substations are served radially via 45 Line, a single 63 kV line emanating from Anderson Terminal. The mixed urban and rural loads at Summerland, Trout Creek and West Bench are served from a radial 63 kV line (49 Line) out of Huth substation. Under normal system operating conditions, these loads are essentially being served via the BC Hydro’s Vernon 230 kV interconnection from the north as 161 kV 40 Line at Anderson and 63 kV lines 41 Line and 42 Line between Huth and Oliver are typically operated in an open configuration.

A series of small distribution substations are connected to either 41 Line and 42 Line south of Penticton, including Waterford, Kaleden and OK Falls.

3.2.2 Penticton - Summerland Area System Deficiencies
Summerland, Trout Creek and West Bench loads are radially fed from the Huth substation via 49 Line. An alternate supply is required to provide a backup to the loads in the area to increase reliability.

The Huth substation is a legacy substation with most major switching equipment at or near end of service life. The existing configuration of Huth does not enable automatic sectionalizing of the various 63 kV subtransmission circuits which terminate there, leading to multiple element losses for many single events. A substantial reconfiguration of this substation is required to adequately serve the growing South Okanagan valley loads fed from the networked subtransmission system via Huth substation.

3.2.3 Maintenance Assessment
Naramata substation is in need of major rehabilitation of the 63 kV switching facilities, 13 kV switchgear, station civil and station security. The station switch structures and equipment structures have degraded to the point of being unsafe. The station ground grid and security fence are identified by the condition assessment as in need of repair. The mobile substation, which is required for maintenance and emergency supply, cannot be parked at the existing site and no further property can be acquired adjacent to the existing site. The transformer tap changer has failed frequently and has reached the end of service life based on recent maintenance inspections.
As mentioned in Section 3.2.2, Huth substation is a legacy substation with most major equipment, and especially the 63 kV breakers, at or near end of useful service life. A complete replacement of the Huth breaker equipment should be carried out in combination with the planned reconfiguration of the substation into a proper 63 kV ring bus.

3.2.4 Transmission Projects

3.2.4.1 Waterford Substation Upgrade

The Waterford Distribution Source Substation requires increased transformer capacity to serve growing 13 kV loads in Penticton, as the city continues to upgrade from 8 kV to 13 kV. It is proposed to replace the existing 15 MVA transformer with a 25 MVA unit.

3.2.4.2 Naramata Substation Replacement

The scope of the project involves a complete rebuild of the existing substation, including a new 63/13 kV, 12/16/20 MVA transformer and ultimate accommodation for three distribution feeders, with two distribution feeders connected initially. The new 63 kV and 13 kV switching structures and equipment structures will meet modern clearance standards, and will accommodate mobile substation access and connection. A new control building will house metering, communication and protection equipment.

3.2.4.3 Summerland 63 kV Backup

A 16 km radial line (49 Line) from the Huth 63 kV substation supplies the Summerland, Trout Creek and West Bench loads. A previous project to upgrade 49 Line has increased its capacity and reduced exposure to equipment failures as a main cause of line faults. The objective of this new project is to provide a supply backup to the loads in the area and further reduce the average duration of supply interruptions and increase the reliability. The two options presently under consideration are:

- Build a new 63 kV line approximately 12 km in length using 477 MCM ACSR conductor, from Huth to Trout Creek substation. For the new line, install 63 kV line termination at Huth substation. Further, provide remote controlled line switches at West Bench and Trout Creek.
- Build a new 63 kV line approximately 16 km in length using 477 MCM ACSR conductor, from Huth to Summerland substation. For the new line, install 63 kV line termination at Huth substation. Further, provide remote controlled line switches at West Bench and Trout Creek and Summerland.
3.2.4.4 Huth Substation Rebuild

This project will involve a complete rebuild of the existing 63 kV bus and line terminations at Huth substation, including replacement of all 63 kV breakers and switches and reconfiguration of the 63 kV bus into a ring bus configuration. An alternative project which has been considered would involve eliminating the 49 Line termination at Huth and bypassing the substation to terminate 49 Line directly at Anderson Terminal. Huth would be reconfigured as a tapped 63/13 kV distribution source substation fed via taps from 52 Line and 53 Line. This simpler configuration would be a lower cost alternative, but would not provide the same flexibility and reliability as the full ring bus configuration. This project is scheduled to start in 2010.

3.2.4.5 Westminster Transformer 1 Replacement

This transformer has been identified as requiring replacement. It forms part of the transformer rehabilitation and replacement program.

3.2.4.6 Trout Creek Transformer 1 Rehabilitation

This transformer has been identified as requiring rehabilitation. It forms part of the transformer rehabilitation and replacement program.

3.2.5 Distribution Growth Projects

3.2.5.1 West Bench Feeder 1 Regulator

West Bench Feeder 1 voltage is at the lower planning limit. A voltage regulator will be required on this feeder to maintain acceptable system voltage.

3.3 Oliver – Osoyoos Area

3.3.1 Existing Transmission and Distribution System

The local transmission network operates at three distinct nominal voltage levels: 161 kV, 138 kV and 63 kV. With the completion of the South Okanagan Supply Reinforcement Project, a fourth transmission voltage level, 230 kV, will be added to the mix. This set of voltages requires a more complex transmission network than is necessary to adequately serve the South Okanagan, and it would be desirable to eliminate the 161 kV voltage level in the longer term.

Most of the distribution source substations in the area are served at the 63 kV subtransmission voltage level, with the exception of the Oliver source, where the 13 kV distribution system is fed from the tertiary winding of the 161/63 kV transformer.
Most of the distribution source substations in the area are served at the 63 kV subtransmission voltage level, with the exception of the Oliver source, where the 13 kV distribution system is fed from the tertiary winding of the 161/63 kV transformer.

3.3.2 Oliver – Osoyoos Area System Deficiencies

**Distribution**

Loads in Oliver and Osoyoos are growing rapidly, predominantly due to in-migration from urban centres outside of the Okanagan. The rate of in-migration is expected to continue or increase over the forecast period, producing ongoing load growth well above the system average.

In 2004 over 600 residential were completed or started within the Town of Osoyoos. Another 300 residential units are underway and expected to be on stream over the next two to three years. Phase 1 of the Osoyoos Indian Band’s Spirit Ridge development on the north-east boundary of Osoyoos is underway with at least 800 kVA of committed load installed at present. (refer to drawing A-7) By the summer of 2005, the load on the east side of Osoyoos will have exceeded the capacity of the single 13 kV feeder supplying this area.

Population centers such as Osoyoos are considered for loop fed transmission supply. Currently Osoyoos and areas south of Oliver serviced by Pine Street substation are fed radially at 60 kV on 44 Line. The Oliver area can be backed up by distribution but loss of 44 Line would result in complete load shedding of Osoyoos. Additionally, the failure of one of the two existing 63/13 kV 15 MVA distribution transformers in Osoyoos will result in load shedding because the remaining transformer is not capable of carrying the combined area load.

2004 summer peak demand on the Osoyoos substation was 21 MVA with 2.6 MVA of additional load expected in 2005 and future yearly additions of up to 1.5 MVA. Total load in the Osoyoos area is forecast to reach 30 MVA by 2009 exceeding presently installed transformer capacity.

**Transmission**

The existing Oliver Terminal station is not large enough to accommodate the planned future termination of a 230 kV circuit from Vaseux Lake Terminal. It would not be suggested to add another voltage level to this station in any case, given that it already has 161 kV, 138 kV, 63 kV and 13 kV buses, and access for a new line at a different voltage level would be impractical. Among the possible alternatives to address this limitation would be to eliminate the 161 kV voltage level. The transformation from 230 kV to 138 kV could happen either at the Vaseux Lake Terminal (if the footprint is adequate for a third bus voltage) or at a new Oliver Terminal station. Regardless of which alternative is ultimately selected, the Oliver distribution load should be served by a dedicated 63/13 kV transformer to reduce risk to the system transformer.
3.3.3 Maintenance Assessment

The condition of transmission facilities in this area is generally acceptable with a few specific areas of concern. Several Moloney tapchanging transformers have been identified for rehabilitation or replacement in the near future. The 63 kV subtransmission circuit 42 Line between Huth and Oliver is in need of rehabilitation. 42 Line has been kept in service mainly as a backup to 41 Line which is the primary subtransmission line in the area. If 42 Line is ultimately rebuilt to modern standards it may be prudent to use taller poles to enable suspension of an All Dielectric Self Supporting (ADSS) fibre optic cable between Vaseux Lake and Anderson Terminals to replace the ADSS which will be initially strung on 40 Line to enable initial energization of Vaseux Lake Terminal in 2005.

The existing transformers in the Osoyoos distribution source substation are both rated as condition 4 (immediate rehabilitation required) based on dissolved gas analysis. These transformers should be evaluated for their condition. They are both Moloney transformers which are known for leaking tapchangers.

3.3.4 Transmission Projects

3.3.4.1 New East Osoyoos Substation

To address the Osoyoos area supply deficiencies a new East Osoyoos 138/63/13 kV source substation is proposed in east Osoyoos. The station will be fed via a new 15 km 138 kV line from the new Bentley Terminal and a 60 kV tie to 44 Line (Appendix A7)

Ultimate layout of the substation would include two distribution supply transformers with capabilities to terminate up to six 13 kV distribution feeders. Initially one transformer and three feeder terminations will be installed supplying the east Osoyoos and Anarchist mountain areas as well as tying back to the west Osoyoos substation via 13 kV feeder tie.

The alternative is to increase station capacity in west Osoyoos either at the existing site or a new location. Additional distribution feeders across the causeway would be required to supply east Osoyoos. As the bulk of the growing load center is emerging on the east side of Osoyoos and there is more direct access to the Oliver area 138 kV source, the preferred alternative is to locate the new source substation on the east side of the town.

3.3.4.2 West Osoyoos Transformer Rehabilitation

The Osoyoos transformers are Moloney transformers. It is typical that these transformers have broken barriers between the tapchanger compartment and the main
transformer tank. There is a requirement to assess the condition of the two transformers to ensure that the gassing that is occurring in the transformers is from this type of leak or determine if the gas is coming from and internal fault in the transformer. It is expected that one transformer will require replacement and one will require rehabilitation.

### 3.3.4.3 Rebuild Oliver as Distribution Source Substation

With the transfer of the 138 kV, 161 kV and 230 kV buses to the new Bentley Terminal Station, the existing Oliver Terminal station will be converted to a 138/63/13 kV subtransmission and distribution source substation, with allowance for possible future 13 kV feeders. The initial configuration will utilize the existing 161/63/13 kV Transformer 2 to supply the 13 kV distribution circuits from the 63 kV bus, with the 161 kV terminals capped. Similarly, the 161 kV terminals will be capped on the existing 161/138/63 kV transformer.

### 3.3.4.4 Rebuild Pine Street Transformer 1

This transformer has been identified as requiring rehabilitation. It forms part of the transformer rehabilitation and replacement program.

### 3.3.5 Distribution Growth Projects

#### 3.3.5.1 Three Phase 4.4 km Osoyoos Feeder 2

A single phase tap currently supplying the Anarchist Mountain area is excessively loaded, causing voltage regulation and protection issues, and creating high phase current unbalance. Rebuilding this line section to Three Phase will address the voltage, load balance and protection concerns on this line. This line rebuild will be integrated with the new east Osoyoos supply and Boundary area supply projects.

#### 3.3.5.2 New Osoyoos Feeder 4 to East Osoyoos

Load growth in east Osoyoos is exceeding the capacity of the single feeder currently supplying the area. A second 13 kV distribution feeder from the Osoyoos substation will provide the required capacity. This feeder will be integrated into the East Osoyoos supply project planned for the area.

#### 3.3.5.3 25 kV Tie to Bridesville

As load develops in the Bridesville area, a tie from the new East Osoyoos source to the Boundary area would provide capacity and load transfer capabilities between the two
areas. Because of the difference in distribution nominal voltages, the tie would also include a 13 kV to 25 kV stepdown transformer.

3.4 Princeton – Keremeos (Similkameen) Area

3.4.1 Existing Transmission and Distribution System

The Similkameen Valley load centres of Princeton, Mascot Mines, Hedley and Keremeos are interconnected by 138 kV transmission circuit 43 Line. The Princeton load is normally supplied from BC Hydro’s Nicola Terminal via 138 kV circuit 56 Line, and 43 Line is opened at Keremeos. Under specific loading, seasonal generation and power exchange situations 56 Line is opened and the Princeton load is fed by 43 Line from Oliver.

3.4.2 Princeton – Keremeos Area System Deficiencies

Princeton was historically the most distant load centre supplied from the Kootenay generation area via internal FortisBC transmission (11 Line and 43 Line). Service reliability was typically poor as any outage along this lengthy radial supply path would cause an outage at Princeton. With the interconnection of the Princeton substation to BC Hydro’s Nicola Terminal via 56 Line and the typical operating configuration with 43 Line opened at Keremeos, the reliability of supply at Princeton increased significantly.

The completion of the South Okanagan Supply Reinforcement Project will dramatically shorten the supply path from the east to the Similkameen loads. 43 Line is not presently configured for networked operation between Oliver and Nicola. Operating 43 Line network configuration does not help support the South Okanagan area during a major outage.

The loss of the Vaseux Lake Terminal due to transformer failure or a BC Hydro 500 kV outage would result in the need to automatically shed loads to avoid a voltage collapse in the South Okanagan. The installation of a load shed remedial action scheme is required to shed the required amount of load and keep the system stable.

Princeton Light and Power is expanding the 25 kV system north along Hwy 5A. This 25 kV system is presently supplied by a 13/25 kV step-up bank in the field. This configuration will be optimized by upgrading to dual secondary voltage (13 and 25 kV) transformers at Princeton, facilitating the ongoing expansion of the 25 kV distribution system similar to the proposed upgrades for the Boundary area.
3.4.3 Maintenance Assessment

43 Line which connects Oliver to Keremeos and Princeton is in generally good condition. Several of the source substations in the Similkameen valley are very old and require extensive condition assessments.

Many of the distribution circuits in the Town of Keremeos, in the village of Hedley and throughout the Similkameen valley are at or near end of service life and will require extensive rehabilitation over the next several years. The old lines on 10th Avenue from Boundary Road east to 5th Street and 11th Avenue in Keremeos need to be rebuilt for condition-related reasons (old copper, poles are time-expired), as should the 10th Street and 11th Street distribution lines. The Town of Keremeos wants to widen the 10th Street roadway in 2005 and would like to coordinate that project with FortisBC’s planned activities. They would like to see the poles relocated to the south side of the road where the Telus poles are presently located. The existing facilities are at end of service life.

Several trespass issues (inadequate easements or rights-of-way) in the Similkameen area have been addressed over the last few years, although a number of trespass situations still exist which may require facility relocation or right of way negotiations.

3.4.4 Transmission Projects

3.4.4.1 Princeton Reconfiguration and Transformer Replacements

The Princeton source substation is no longer supplied at 63 kV, enabling reconfiguration to a 138/25/13 kV arrangement including salvage and relocation of any remaining 63 kV major equipment which is still in good service condition. This project requires the installation of two 138/25/13 kV 20/30/40 MVA transformers to supply both Princeton and FortisBC distribution loads. The existing Princeton transformers may form the starting point of the transformer rehabilitation and replacement program since, depending upon their condition, they will become spares. This project will also address deficiencies in the 138 kV switches and 56 Line breaker.

3.4.5 Distribution Growth Projects

3.4.5.1 Keremeos Feeder

Load on Keremeos Feeder 2 is reaching the thermal limit. Operational transfer of this load to adjacent feeders is limited. A third feeder is required in the area to meet capacity needs.
4 Kootenay Region Transmission and Distribution Systems

A geographically referenced system map of the FortisBC Kootenay Region is included in Appendix A as Map 4.

4.1 Castlegar Area

4.1.1 Existing Transmission and Distribution System

Castlegar is located amid an intensive concentration of hydro electric generating plants on the Kootenay and Columbia Rivers, and the high voltage transmission system in the area is primarily designed to move the locally generated power to more remote load centres.

Loads in the Castlegar area are served from the 63 kV subtransmission system primarily 6 Line and 26 Line. Following completion of the Kootenay 230 kV System Development Project which now links the generation systems at South Slocan and Brilliant to the Warfield Terminal Station near Trail and BC Hydro’s Selkirk 500 kV Terminal there were as many as eight parallel 63 kV circuits in the Columbia Valley between Castlegar and Trail. These circuits are now de-energized and are in the process of being salvaged. The remaining 63 kV lines are used to supply the distribution source substation at Castlegar as well as nearby source stations at Tarrys north east of Castlegar and the Blueberry source south of Castlegar, in addition to the industrial loads at the Celgar Pulp Mill and the Pope and Talbot sawmill.

Close proximity to the generating plants keeps Castlegar area supply secure and transmission voltages stable, except in cases where the main interconnections are lost with the external network. To prevent extreme over voltage and over frequency events under such circumstances, several automatic generation shedding RAS have been implemented.

4.1.2 Castlegar Area System Deficiencies

Generally the power system in the Castlegar area is secure due to the proximity of significant local generation and a fairly robust transmission grid. Most area transmission outages are caused by structure failures, tree falls and insulation failures on the older vintage 63 kV subtransmission facilities. Reliability could be enhanced by installing remotely operable Motor Operated Disconnect Switches (MODs) at several 63 kV distribution source stations, including Castlegar, Blueberry and Tarrys.

Due to phase mismatches in the local distribution system it is presently not possible to back up the distribution circuits between Castlegar and the adjacent distribution system at Tarrys.
Correcting the problem will involve reconnecting the transformer drops requiring an concurrent outages at Castlegar and Blueberry to enable ongoing load backup between the two stations.

4.1.3 Maintenance Assessment

The remaining 63 kV subtransmission facilities in the area were originally constructed in the late 1950’s, and although substantial sustaining investments have been made over the years, a significant number of deteriorated poles, crossarms and insulators still remain in service in the area.

The distribution system in the area is generally in acceptable condition, and the ongoing eight year pole testing and repair program will be adequate to keep the facilities in good operating condition.

4.1.4 Capital Projects

4.1.4.1 Castlegar Capacity Upgrade

A capacity upgrade will be required at the Castlegar distribution source substation. A second transformer will be installed as a capacity upgrade, that being the rehabilitated Princeton Transformer 3. This will allow the existing Castlegar Transformer 1 to be taken off-line and rehabilitated.

4.1.4.2 Correct Transformer Connections at Castlegar and Blueberry

This project will correct the historical misconnections of the transformers at these stations, enabling backup between all the distribution sources in the area.

4.1.4.3 Add MODs and Communications Castlegar and Blueberry

This project involves addition of motorized disconnects, associated communications and controls at the Castlegar and Blueberry distribution source stations to enable remote sectionalizing and load restoration for permanent faults on the 63 kV system, to significantly reduce outage durations. This project will occur in 2008 and 2009.
4.2 Crawford Bay Area

4.2.1 Existing Transmission and Distribution System

Crawford Bay is served by 161 kV circuit 30 Line which interconnects South Slocan, Coffee Creek, Crawford Bay, and Kimberley, and from Creston in the south via 63 kV circuit 32 Line. The Terminal is configured with 161 kV, 63 kV and 13 kV simple buses, with a single 20 MVA transformer connecting the 161 kV and 63 kV buses, and separate 2.5 MVA and 1.5 MVA transformers feeding the area 13 kV distribution loads.

4.2.2 Crawford Bay Area System Deficiencies

The 1.5 MVA 63/13 kV Transformer 3 in the Crawford Bay Terminal is overloaded. It is proposed that this transformer can be replaced with one of the spare transformers coming from the Boundary area re-configuration. This project will also address the replacement of the 32 Line breaker and associated switches.

The Crawford Bay area is subjected to inadequate voltages when supplied from the south via 32 Line following forced outages to either 30 Line or the 20 MVA 161/63 kV transformer which ties Crawford Bay to 30 Line.

4.2.3 Maintenance Assessment

32 Line between AA Lambert (Lambert) and Crawford Bay Terminals requires significant ongoing maintenance efforts to be kept in a serviceable condition. Many of the structures are presently stubbed, crossarms have often been replaced due to extreme deterioration while the related poles have been left in place. The facilities are subjected to frequent tree falls and landslides due to the narrow shore space between Kootenay Lake and the adjacent steep mountain slopes. The narrow and winding shore is shared with Highway 3A, further compromising the right-of-way.

4.2.4 Transmission Projects

4.2.4.1 Crawford Bay Capacity Increase and Grounding Bank

The Crawford Bay Terminal distribution load has gradually grown over time to the point where, by 2005, the failure of one of the two existing distribution transformers will result in load shedding because the remaining transformer is not capable of carrying the remaining load. There is no distribution backup from any other location.

The scope of this project is to install a transformer that has been made redundant by the Boundary area re-configuration. This project will also address the replacement of the 32 Line breaker and switches and associated protection.
4.2.4.2 Replace Crawford Bay Transformer 1

The Crawford Bay Transformer 1 has a long history of hydrogen gassing. This transformer may be replaced by one of the 161/63 kV transformers coming available from the Boundary area upgrades or it may be replaced with an upgrade to the Kootenay Lake crossing so that the Crawford area is only served at 63 kV. Further studies are required to choose the best option and this must be combined with the above capacity increase project because there are efficiencies to doing so. A single 161/63/13 kV transformer may be sufficient to accomplish the need for Crawford Bay.

4.3 Creston – Wynndel Area

4.3.1 Existing Transmission and Distribution System

The Creston area is primarily served from the BC Hydro 230 kV system via a 230/63 kV transformer at the Lambert Terminal station. Outages to the 230 kV BC Hydro transmission line 2L294, or the 230/63 kV transformer at Lambert, result in loss of service to most Creston area load.

Backup supply to Creston is notionally provided by 63 kV circuit 32 Line, described in more detail in the previous Crawford Bay section.

The distribution system in the Creston area is also very old, phase identification is inaccurate and requires verification, and the phases are typically poorly balanced. The existing Wynndel substation is in an advanced state of deterioration and is scheduled to be salvaged, with all Wynndel loads slated to be transferred to either the Creston substation or Lambert Terminal station.

4.3.2 Creston – Wynndel Area System Deficiencies

It is not possible to provide backup to all Creston area loads via 63 kV circuit 32 Line. Voltage levels cannot be maintained when the entire Creston area load is served from Crawford Bay. It would be necessary to upgrade 32 Line to either 138 kV or 161 kV to enable complete backup of Creston for loss of either BC Hydro circuit 2L294 or the 230/63 kV transformer Lambert Transformer 1.

4.3.3 Maintenance Assessment

The existing Wynndel 63/13 kV distribution source substation is in advanced deterioration and will be salvaged in 2005 in conjunction with the Lambert upgrade.
The distribution facilities in the Creston area are typically very old with specific sections in need of substantial rebuild.

4.3.4 Transmission Projects

4.3.4.1 230 kV Ring Bus and New Transformer at Lambert Terminal

To provide backup supply to the City of Creston, it is proposed that a second 230/63 kV 90 MVA transformer bank be installed in Lambert Terminal station. The 230 kV bus will be re-arranged into a ring bus configuration with the addition of three 230 kV breakers. This configuration will enable secure provision of Creston area loads under N-1 contingencies. An alternative configuration to be considered for this project would involve adding a fourth single phase transformer as a backup to the existing three single phase transformers which comprise the present 230/63 kV bank, with associated transfer bus and switching arrangement.

4.3.4.2 Crawford Bay – Creston 32 Line Rehabilitation

63 kV circuit 32 Line requires comprehensive rehabilitation to be kept in service. Approximately 50% of the structures require replacement or reinforcement based on the most recent condition assessment.

In the last Master Plan issued in 1998 it was recommended to upgrade 32 Line to a higher nominal voltage to enable Creston backup via an internal FortisBC circuit, thereby avoiding the anticipated longer term operating cost impact due to wheeling tariff increases into Lambert Terminal. With the stabilization of wheeling costs agreed to under the Vaseux Lake agreement with BC Hydro the operating cost differential has been substantially reduced, and the most economical overall solution to providing adequate backup to Creston is the Lambert Terminal 230 kV ring bus and second transformer alternative recommended above.

4.3.5 Distribution Projects

4.3.5.1 Creston Area Distribution Feeder Upgrades

The Wynndel distribution source station is currently being replaced by a new distribution source at Lambert Terminal, requiring a number of distribution network upgrades. The existing two feeders out of Wynndel will be replaced by two feeders from Lambert Terminal north to the load area previously served by Wynndel. To address the main Creston area distribution feeder and station backup issues another two feeders will be built from Lambert Terminal to tie into the current Creston feeder network.
4.4 Grand Forks – Boundary Area

4.4.1 Existing Transmission and Distribution System

The transmission system serving the Boundary area consists of a 161 kV circuit 11 Line which is terminated in the Kootenays at Mawdsley Terminal (and from there into Warfield Terminal via a short 63 kV connector) and in the Okanagan at Oliver Terminal. 11 Line is connected to the simple 161 kV bus at Grand Forks Terminal, and supports the underlying 63 kV subtransmission system via a 60 MVA 161/63 kV transformer. A geographically referenced map of the FortisBC Boundary area system is provided in Appendix A as Map 5.

The subtransmission system consists primarily of two 63 kV circuits, 9 Line and 10 Line, which run parallel with 11 Line from Warfield Terminal station to Rock Creek. From that point westward 9 Line has been salvaged, and 10 Line continues to feed the 2.4 kV delta connected loads at Baldy resort and the McKinney microwave site. Remnants of 10 Line still exist on the old right-of-way west of McKinney.

4.4.2 Grand Forks – Boundary Area System Deficiencies

Service reliability in the Boundary area has been below system average in part due to the deteriorated condition of the subtransmission facilities and the extreme geography which they traverse. 9 Line and 10 Line cross high elevations between Paterson and Christina Lake, and between Grand Forks and Greenwood. 10 Line goes over high elevations west of Rock Creek to its effective present termination at McKinney. Outages due to harsh weather and tree falls are common during the winter season, and it is not unusual for both circuits to be affected simultaneously on the high elevation sections.

The resort distribution system needs to be converted to a grounded Y-connected 25 kV system to reduce the safety risk posed by the existing 2.4 kV delta-configuration. The system can be served by converting 63 kV circuit 10 Line to 25 kV from the new Kettle Valley 161/25 kV distribution source near Rock Creek.

Under the existing system configuration it is not possible to serve all the Boundary Area loads following outages to 11 Line between Mawdsley and Grand Forks Terminal stations. Most of the Boundary area load is immediately lost for 11 Line outages between Mawdsley and Grand Forks Terminals because 9 Line and 10 Line are normally operated open between Christina Lake and Paterson. For extended 11 Line outages it is possible to restore service to some Boundary loads by closing the Paterson to Christina Lake segments of 9 Line and 10 Line but 9 Line and 10 Line together are inadequate to serve all Boundary area loads from the Trail end. At a minimum all loads west of Grand Forks need to remain disconnected until 11 Line can be restored. This situation will change following completion of the South Okanagan Supply Reinforcement Project, since it will then be possible to feed Grand Forks Terminal from either the Okanagan or the Kootenay systems.
4.4.3 Maintenance Assessment

9 Line and 10 Line were originally constructed in 1919, and although extensive maintenance has been performed over the years, many segments of these facilities have effectively reached the end of their expected service lives. Significant portions of these facilities will require accelerated sustaining investments to be kept in service throughout the forecast period of this System Development Plan, making them prime candidates for either complete rebuild or salvage.

Several of the 63 kV distribution source substations in the Boundary Area are also at or near the end of their expected service lives such as Baldy, Midway, Rock Creek, Ruckles, and Greenwood. Some equipment and structures are in advanced states of deterioration, and individual pieces of major equipment have been in service for more than 70 years. A Midway substation rebuild was planned for 2005 but has been replaced with the new Kettle Valley substation project.

4.4.4 Transmission Projects

4.4.4.1 New Kettle Valley and Grand Forks 161/25 kV Distribution Source Substations

Given growing area loads and the deteriorated condition of 9 Line and 10 Line and the 63 kV legacy distribution source substations between Christina Lake and McKinney Microwave, two new 161/25 kV distribution sources will be constructed. One will require new property in the Rock Creek area while the other will reside at the existing Grand Forks Terminal. These new sources will serve the distribution loads west to Anarchist Mountain and east to Christina Lake, requiring some immediate upgrades of the existing 13 kV distribution systems.

As an interim step the existing 13 kV small urban load centres such as Midway Greenwood and Christina Lake will be served using 25/13 kV step down transformers fed by the newly upgraded 25 kV main feeders. The ultimate configuration will enable 25 kV backup west of Kettle Valley from the new East Osoyoos distribution source, and east of Grand Forks and Christina Lake from the existing 25 kV system at Cascade substation in Rossland. These new 161 kV/25 kV stations will be configured for In/Out 161 kV supply with automatic breaker sectionalising, and dual transformers to enable full distribution load backup for transformer outages. See Figure 4.4 A, B C and for project staging.
Kettle Valley Distribution Source

The above mentioned west Boundary deficiencies and growth patterns mandate the Kettle Valley substation be developed first and will consist of two 30 MVA transformers connected by a meshed bus to 11 Line. The station will initially provide four 25 kV distribution feeders.
Following construction of the new Kettle Valley source, the five existing 63 kV source substations between Grand Forks and Oliver Terminals can be salvaged: Greenwood, Midway, Rock Creek, Baldy and McKinney Microwave. In addition, 63 kV circuits 9 Line and 10 Line will be salvaged or converted to 25 kV (where appropriate) between Grand Forks and Oliver Terminals. This project should enable a significant Operations and Maintenance cost reduction in the mid-term as these facilities are generally in poor condition and in need of major rehabilitation to be kept in service.

**Grand Forks Distribution Source**

A second substation at Grand Forks will be developed identical to the Kettle Valley substation and will serve east Boundary area.
Following construction of the new Grand Forks source, the three existing 63 kV source substations Ruckles, Christina Lake and Paterson can be salvaged. The customer owned Roxul station will have to be converted to 25 kV. In addition, 63 kV circuits 9 Line and 10 Line will be salvaged or converted to 25 kV (where appropriate) between Grand Forks Terminal and Cascade substation. This project should enable a further significant Operations and Maintenance cost reduction in the mid-term as these facilities are generally in poor condition and in need of major rehabilitation to be kept in service.

4.4.5 Distribution Growth Projects

4.4.5.1 Feed Baldy and Anarchist at 25 kV from Rock Creek and Convert Baldy to 25 kV

The existing distribution system at Baldy is 2400 Volt delta which is not a preferred configuration for providing proper primary feeder protection. In addition there are source capacity limitations and condition issues at Baldy substation and growth plans for the Anarchist area as well as Baldy. This project will convert 63 kV from existing Rock Creek source to Baldy and Baldy town site to 25 kV. This distribution upgrade will be coordinated with the new Kettle Valley Source project.

4.4.5.2 Boundary Area Voltage Conversion

To facilitate the reduction of the Boundary area distribution sources from eight stations to two stations will require a distribution voltage conversion to 25 kV of all area loads. This will be accomplished through a combination of load conversion and installing several new 25/13 kV step-down sources. Where appropriate existing 63 kV line facilities will be utilized as 25 kV facilities.

4.5 Kaslo – Coffee Creek Area

4.5.1 Existing Transmission and Distribution System

Coffee Creek is connected to 161 kV circuit 30 Line which runs between South Slocan and Kimberley. The substation is configured with 161 kV, 63 kV and 13 kV simple buses, with one 22.5 MVA transformer and one 10 MVA transformer connecting the 161 kV and 63 kV buses. Local distribution loads are presently fed by an 8.4 MVA 63/13 kV transformer. The station also includes a 1.5 MVA grounding transformer.

Coffee Creek is the source of 63 kV circuit 37 Line which runs north along the west shore of Kootenay Lake to the Kaslo distribution source substation. The 63/25 kV Kaslo source feeds distribution loads south and north of the town along the lakeshore, including the BC Hydro loads at Lardeau at the north end of Kootenay Lake.
4.5.2 Kaslo – Coffee Creek Area System Deficiencies

The west shore of Kootenay Lake is narrow and mountainous, so tree fall and landslide induced outages to the radial 63 kV circuit 37 Line are relatively common. The town of Kaslo has endured a number of multi-day outages in the past, although it would be extremely costly to close the loop between Kaslo and the nearest alternative power source at New Denver in the BC Hydro system due to the distance and mountainous terrain. The most practical short-term solution to address future multi-day outages at Kaslo would be to use a mobile generator to enable serving at least the most critical area loads.

4.5.3 Maintenance Assessment

37 Line between Coffee Creek and Kaslo is in mixed condition. Some sections have been entirely replaced due to landslides or rebuilds and are of recent vintage, other sections are fairly deteriorated with a high percentage of structures in poor condition.

The 3.2 km long 30 Line Kootenay Lake crossing requires a comprehensive condition assessment to determine if it can be kept in service in the longer term. This extremely long crossing consists of steel rope conductors suspended between structures anchored into the mountain sides far above the shoreline on each side of the lake. Past condition assessments were performed from a custom man-basket apparatus which travelled along the conductors across the lake. The condition of the conductors is now uncertain enough that using this equipment might be unsafe, so future condition assessments may need to be performed by helicopter.

The Kaslo substation is a candidate for rehabilitation or rebuild, demonstrating significant deterioration of equipment and structures.

4.5.4 Transmission Projects

4.5.4.1 Kaslo Substation Rehabilitation

The Kaslo substation site is a candidate for either relocation or reconditioning. The existing transformer also has condition issues that could be addressed through rehabilitation. It is proposed that this transformer be inserted into the transformer rehabilitation and replacement program.

4.5.4.2 Coffee Creek Transformer 3 Capacity Addition

By the winter of 2006/07, the total substation load at Coffee Creek is projected to exceed the maximum capacity of the existing 8.4 MVA transformer. To address the transformer overload, the existing Transformer 3 would be retired and replaced.
Breaker and grounding transformer deficiencies will also be addressed during the course of this project.

4.5.4.3 Coffee Creek Capacitor

With the loss of 30 Line anywhere between South Slocan and Coffee Creek, the loads at Crawford Bay Terminal, Coffee Creek Terminal and Kaslo substation can be served from Lambert Terminal via the 63 kV circuit 32 Line and the lake crossing segment of 30 Line with the addition of 30 MVar of reactive compensation at Coffee Creek Terminal and 5 MVar at Kaslo. Note that the Kootenay Lake crossing of 30 Line will be converted to 63 kV after 30 Line from Crawford Bay Terminal to Kimberley is abandoned. This project will need to occur in the 2005/2006 timeframe if 30LE to Kimberley has already been abandoned by that time. If 30LE has not been abandoned by 2005/06 the capacitor will be required as soon as that does occur.

4.6 South Slocan Area

4.6.1 Existing Transmission and Distribution System

The FortisBC subtransmission system in the South Slocan area primarily consists of extremely old 63 kV circuits which were originally constructed to link the generating plants along the Kootenay River to loads in the Castlegar and Trail areas in the 1930s and 1940s. The 63 kV subtransmission network terminates at the South Slocan switchyard, which is connected to BC Hydro’s Kootenay Canal via two short 63 kV circuits (12 Line and 13 Line) which cross the Kootenay River, and from there to the 230 kV network which links Kootenay Canal with Brilliant Terminal Station, Warfield Terminal Station and BC Hydro’s Selkirk 500 kV Terminal.

Area distribution loads are supplied via a series of older 63/13 kV source substations. Many of these facilities are served as simple taps or dual taps off the 63 kV subtransmission system without automated subtransmission sectionalising capability.

4.6.2 South Slocan Area System Deficiencies

Following completion of the Kootenay 230 kV System Development Project and installation of the overspeed and overvoltage RAS at the Kootenay generating plants, the subtransmission system in the South Slocan area is generally adequate. One exception is the radial 63 kV circuit 19 Line which feeds Passmore and the Slocan Valley loads at Valhalla and Slocan City. Loads served by this circuit have been subjected to extended outages due to landslides in the recent past. The circuit has experienced relatively frequent outages caused by tree falls during high winds. The location of the loads in this mountainous setting makes backup provision extremely difficult and costly.
Most of the distribution sources in this area are served as simple taps or dual taps off the 63 kV subtransmission system. Most of these sites do not have automated subtransmission sectionalising capability, so failures anywhere on the subtransmission lines can cause extended interruptions until a service crew reaches the area to perform manual switching.

4.6.3 Maintenance Assessment

Most of the remaining 63 kV circuits in the South Slocan area have extensive sections in deteriorated condition. Most of these subtransmission facilities were originally constructed in the first half of the previous century, and although substantial sustaining investments have been made over time, many of the structures are at or near end of useful service life and will require replacement in the near future.

Most of the distribution source stations in this area are also extremely old and much of the major equipment is nearing end of service life. It will be important to closely monitor the condition of these facilities to avoid significant reliability decreases in the future.

4.6.4 Transmission Projects

4.6.4.1 Add MODs and Communications at Tarrys and Playmor Substations

This project involves addition of motorized disconnects, associated communications and controls at the Tarrys and Playmor distribution source stations to enable remote sectionalizing and load restoration for permanent faults on the 63 kV system, to significantly reduce outage durations. This project will occur in 2006 and 2007.

4.6.4.2 Loop Slocan City to New Denver (BC Hydro)

This project would involve closing the 63 kV loop between Slocan City and New Denver. Construction of this circuit will be very challenging due to the narrow shore area between Slocan Lake and the mountains, which is also shared with a highway. Voltages at Slocan City will be extremely low when fed from New Denver, requiring the addition of capacitors at the substation, which will need to be energized only upon loss of 19 Line from South Slocan.

4.6.5 Distribution Growth Projects

4.6.5.1 Passmore Feeder 2 Upgrade

Passmore Feeder 2 has very limited capacity due to small conductor sizing and limited three phasing on the circuit. Voltage concerns were addressed in 2003 and 2004 with voltage regulation resulting in feeder voltage marginally above minimum planning limits. However, the heavily loaded single phase taps don’t allow for fuse coordination with the
station breaker, resulting in widespread outages for localized faults. Aggressive three phasing of this feeder will mitigate the reliability issues as well as addressing the long term capacity requirements.

**4.6.5.1 Playmor-Tarrys Feeder Upgrade**

The distribution line from Playmor to Tarrys does not have the capacity to pick up Tarrys load. Load at Tarrys substation is above recommended continuous rating of the station transformer. To reduce load on Tarrys substation, separate the rural load from the Kalesnikoff sawmill load to provide outage and maintenance backup between Tarrys and Playmor. An upgrade of the feeder between the two stations to allow for operating re-configuration of the distribution system is required.

**4.7 Trail – Salmo Area**

**4.7.1 Existing Transmission and Distribution System**

The subtransmission system in the Trail – Salmo area is extremely old, with original construction dating from the 1930’s and 1940’s. 63 kV circuits 20 Line and 27 Line link the communities of Montrose, Fruitvale, Hearns, Salmo, Ymir and the Whitewater Ski Resort to the surrounding FortisBC transmission system. The geography consists primarily of steep-sided mountain valleys, with dense forest cover and significant snowfall. The circuits are subjected to frequent tree fall and snow related outages, requiring either remote sectionalising (where possible) or crew mobilization to restore loads. The loads are mostly concentrated near local distribution sources fed from the 63 kV network, although there are also some fairly long single phase distribution circuits which parallel the subtransmission circuits, often on common structures.

**4.7.2 Trail – Salmo Area Deficiencies**

This area has inadequate remote sectionalising capability to quickly restore loads for frequent 63 kV circuit outages. Voltages are quite weak when loads must be served from the remote end (i.e. Fruitvale from Nelson or Ymir from Trail), indicating that switched shunt capacitors will be required at several locations to enable adequate load backup.

It is presently not possible to remotely sectionalize and backup the 63 kV distribution source substations fed from 20 Line and 27 Line for outages on various sections of these circuits. A program to upgrade, motorize and automate the sectionalizing switches on these circuits needs to be implemented.

Future consideration should also be given to upgrading the entire Fruitvale – Salmo – Ymir distribution system to 25 kV, enabling full distribution backup between these sources which is not practical with the existing 13 kV distribution voltage.
4.7.3 Maintenance Assessment

The subtransmission system in the Trail – Salmo area is extremely old, exhibiting extensive structure deterioration. Many of the structures which comprise 20 Line and 27 Line between Fruitvale and Nelson have already been stubbed, and the poles and crossarms are generally in poor condition. The 13 kV distribution underbuild on 20 Line has inadequate clearance from the 63 kV circuit, and regularly experiences outages and overvoltage transients. Substandard sections of these circuits should be rebuilt or separated to improve reliability.

The Ymir transformer is at end of service life and requires replacement.

Hearns distribution substation is at end of service life and the local load can be supplied via the Fruitvale distribution source.

4.7.4 Transmission Projects

4.7.4.1 Ymir Transformer Replacement

The Ymir transformer has condition related issues attributable to its advanced age (built in 1950), and should be replaced. It is part of the overall transformer rehabilitation and replacement program. The old Ymir transformer will be retired. Additional capacity will be required to serve the Whitewater substation load at distribution voltage level (13 kV).

The Whitewater substation facilities have reached end of service life. The existing 13 kV switchgear configuration presents an extreme safety risk as the station does not meet engineering and clearance standards. The substation is located on leased property that is not accessible by the mobile substation for backup purposes. No additional property can be acquired at the existing site. The substation is considered a “legacy” substation and will be eliminated as a result of the increased capacity at Ymir.

4.7.5 Distribution Growth Projects

4.7.5.1 West Trail Voltage Conversion

A few outstanding Trail area voltage conversion items still remain to be completed. These include salvage of the Trail substation and transmission feed and conversion of a few remaining services, including the Trail Memorial Centre.

4.7.5.2 Paterson 25 kV Feed and Voltage Conversion

The condition of Paterson substation requires it be either upgraded or eliminated. Load on this source is relatively small and can easily be supplied by the Cascade substation.
in Rossland. This project will be integrated into the Boundary area voltage conversion project.

5 General

5.1 Station Sustaining General

5.1.1 Kootenay Mobile Substation

With the immediate retirement of the Kootenay 6.5 MVA mobile, a replacement mobile substation should be purchased. The recommend unit is 20/24/30 MVA with 63 kV primary and 13 kV/25 kV secondary, and breaker protection.

5.1.2 Station Urgent Repairs

The urgent unforeseen projects are an ongoing project required for failures that occur without warning.

5.1.3 Load Tap Changer (LTC) Oil Filtration Program

The transformer load tap changers are known to develop a coke on the contacts and switches. This coking is a result of the development of carbon deposits from arcing of the connection and disconnection of the contacts. This carbon resides in the oil until it saturates and then forms a high resistance path on the contacts which causes heating and pitting of the contacts.

The filtration of the load tap changers removes these carbon deposits. The result is a longer time between fixing and/or maintaining the load tap changers. With some tapchangers, this can lead to moving maintenance cycles from two years to four years.

The business need for this project is reliability and reduced maintenance. This project will allow FortisBC to significantly reduce the amount of maintenance required for tapchangers. Load tap changers are the most common system to fail in a substation. Extending the service life of these apparatus makes good economic sense. The program is a five year project so that the filtration system may be installed during the course of the scheduled maintenance of the transformers. This project will be included in the transformer rehabilitation program where it is applicable.

5.1.4 Station Assessments, Ground Grid Upgrades and Minor Planned Program

Two projects are operating under this program. The Station Condition Assessment program reviews the safety and reliability issues at seven to eight stations per year. There are a total
2005-2024 T&D System Development Plan

of 70 stations that are in need of review. These stations are tracked in a ten-year cycle. Included in this project is a ground grid assessment completed by a specialized testing group.

The work resulting from the condition assessments is then planned for the following year in the Station Minor Planned Program.

Historically, assessment of the condition of the ground grid has indicated poor grounding at some stations. The ground grid upgrades project is to attend to any grid rehabilitations that were identified in the tests from the previous year.

5.1.5 Bulk Oil Breaker Replacement Program

The Company has a total of 14 bulk oil circuit breakers that are 1927 to 1968 vintage. All are showing signs of significant wear and deterioration. Replacement parts are no longer available and some breakers are leaking oil that will require lengthy and costly outages to repair.

This program will see the replacement of these breakers over the course of the next ten years. By replacing two of the most critical breakers spare parts will be available for the remaining breakers allowing a timely replacement of the remaining breakers as identified by the condition based program. Planning replacement over a number of years ensures the equipment can be properly assessed and replaced only when the breaker's condition or ratings require replacement.

The first breakers scheduled for replacement will take place at Coffee Creek Terminal Station. Both breakers have reached the end of their service life. One was acquired in 1950 and the other in 1951. Routine maintenance in 2000 identified that both breakers need to be replaced.

5.1.6 Computerized Maintenance Management System (CMMS)

The current FortisBC investment in upgraded generation, transmission and substation assets demands an enhanced maintenance management system to properly maintain the equipment and ensure system reliability. The existing maintenance system will not allow FortisBC to employ new methods of maintenance management such as condition based maintenance that uses predictive tasks to measure the condition of the equipment. This system requires the use of computerized tools to track all of the data to support proper maintenance.

A computerized maintenance management system is a tool that tracks assets and identifies what condition will cause equipment to require maintenance. It then trends, stores history and schedules the maintenance work accordingly. FortisBC's current system does not track maintenance notifications, identify deficiencies or schedule maintenance of the assets.
Computerized maintenance management is standard in the electrical industry. It is fundamental to assuring that the utility's apparatus operate well. The trend in maintenance philosophy is towards condition based monitoring and predictive analysis prior to doing intrusive maintenance. An effective management system is required to accomplish this. It is the backbone of the maintenance program. All analysis techniques, maintenance tasks and maintenance schedules are triggered from the management system.

5.1.7 Tap Changer Leak Repair and Upgrades

FortisBC has a number of Federal Pioneer tap changers that are high maintenance and are known for their failures due to contact wear. This is where contacts wear and leakage occurs into the main tank. This project is for repairing the leaks and upgrading the tap changers at the same time.

5.2 Transmission General

5.2.1 Transmission Line Urgent Repairs

Component failures on the transmission system due to inclement weather, defective equipment, animal intrusions, vandalism, abnormal operating conditions, vehicle collisions and human error cause outages or present risks that must be addressed in an expedient manner to ensure that employee and public safety is not at risk and electrical service continuity is maintained.

This project is for capital expenditures for repair or replacement of failed equipment. This strategy ensures provision of a safe, reliable transmission system.

5.2.2 Right of Way and Easements

This project is required for acquiring rights of ways and easements for power systems that cross over a customer’s property. The estimate for this project is based on historical cost. This project has historically been used to obtain easements to remove existing trespass situations. New easements are obtained as part of the new projects requiring easement and are not included in this project.

5.2.3 Right of Way Reclamation

The reclamation project is required to allow FortisBC to remove trees increasing the tree free zone around the transmission lines. The increased tree free zones improve clearances improving both safety and reliability of the transmission system. The trees included are ones that FortisBC can economically remove versus cycle trim or brush. The estimate for 2005 is based on historical cost.
5.2.4 Transmission Line Assessment and Rehabilitation

The transmission line assessment program is an eight-year cycle test and patrol program for all of FortisBC’s transmission lines. 2005 will brings the transmission lines to year eight of an eight year patrol cycle that began in 1997. The cycle will start over again in 2006.

The rehabilitation project involves expenditures for structural stabilization of multiple transmission lines that were identified for rehabilitation in the previous year. Included in the scope of work are replacement of cross-arms and poles and maintenance of structures according to the needs at each specific pole location. Also, there are some minor requirements in terms of insulator and guy wire changes and pole wraps.

The up-to-date patrol data supports a broadly based program of remediation.

5.2.5 Switch Additions

To improve the reliability of the existing power supply and to provide acceptable service after a contingency some of the old disconnect switches in the system need to be replaced. These disconnect switches are neither capable of switching load nor can they be remotely operated from SCC. Installing new disconnect switches with remote controlled switching capability will not only enhance sectionalizing ability it will also improve the reliability of power supply and minimize load interruptions by reducing the restoration times after contingencies. The switches that need to be replaced are:

- Disconnect switches on 20 Line and 27 Line at the Glenmerry, Beaver Park and Ymir substations.
- Disconnect switches Grand Forks 10-1, 9-10 and 9-1 at Grand Forks Terminal.

The existing disconnect switch Keremeos 43-1 on 43 Line at the Keremeos substation is currently not capable of interrupting line charging current and is subjected to arcing problems when the line is de-energized with the circuit breaker open at Oliver end. Installing vacuum interrupters on this switch will allow sectionalizing of 43 Line without outage of Keremeos substation.

A disconnect switch is currently being installed on 9 Line near Christina Lake substation. The objective is to shift the Christina Lake load from the outage prone section of 10 Line to 9 Line with the new disconnect as the open point on 9 Line between Christina Lake and Paterson. This will increase the reliability of the power supply to Christina Lake substation that in the past has had one of the most customer hours of outage due to transmission problems.
5.3 Distribution General

5.3.1 Small Capacity Improvements

Unforeseen load emergence will require capacity upgrades and voltage correction projects not accounted for in the present five year capital plan. The projects may include service upgrades, voltage regulation, ties to accommodate load splitting, single to three phase upgrades, and conductor upgrades.

5.3.2 Distribution Condition Assessment and Rehabilitation

Aging distribution poles require a proactive program to manage the risk of employee and public safety, and ensure acceptable level of service.

The FortisBC system poles are patrolled and tested on an eight-year cycle.

Pole Testers and Powerline Technicians (PLT) condemn poles during pole testing and detail patrol on distribution circuits. Pole testers are to condemn poles because of internal decay and severe surface rot. A Powerline Technician will condemn a pole because of climability on critical structures (Transformer and Switching Structures). This program looks at the condition of the attachments to the poles and will replace cross-arms, guying, insulators and grounding as part of the program.

Extending the service life of poles, limits the number of new poles required and costs associated with replacement. FortisBC treats, stubs, wraps and replaces distribution poles to ensure public and personnel safety and to maintain a reliable distribution system.

As the age of the distribution poles increase, so does the incidence of decay and insect infestation, decreasing the structural integrity of the poles to the point where the poles will structurally fail causing outages and safety hazards. The incidences of decay dramatically increase after 20 years which is consistent with Industry findings. There are two methods possible to decrease the incidence of rot on distribution poles. Replacing all of the poles that have significant decay and/or are insect infested provides the most significant impact to reduce the incidence of decay. However, applying the proper combination of replacement, stubbing, wrapping, and treatment to poles still significantly reduces the incidence of rot and is less expensive than the former method. This method extends the service life of the poles from 7 to 30 years depending on the type of treatment.

FortisBC manages the program to obtain maximum service life of existing poles.

5.3.3 Distribution Right of Way Reclamation

The reclamation project is required to allow FortisBC to remove trees increasing the tree free zone around the transmission lines. The increased tree free zones improve clearances improving both safety and reliability of the transmission system. The trees included are ones
that FortisBC can economically remove versus cycle trim or brush. The estimate for 2005 is based on historical cost.

### 5.3.4 Distribution Line Rebuilds

In 2003, the Maintenance Planning group audited all of the FortisBC distribution feeders. This audit comprised of field visits with service crews in the entire service territory. Formal discussions and physical site visits were completed for all FortisBC distribution feeders.

The results of these audits were prioritized for safety, reliability and for compliance. Each recommendation resulting in rebuild was prioritized and scheduled over the next four to five years.

This project is for the rebuilding of specific safety and reliability deficiencies on the distribution system. Projects include rebuilding failing conductor, replacing rotted platforms, replace leaking transformers, installing ground grids at services that do not have grounding.

### 5.3.5 Small Planned Capital

Repairs to distribution line due to weather, clearance issues, and aging equipment are addressed to maintain a safe and reliable power system.

Each year operational and safety concerns are identified on the distribution system as a result of storm damage, clearance problems, aging equipment, reports by Powerline Technicians, and other inspections or inadequate design due to standards changes. Repairs to address these concerns are required to maintain a safe and reliable power system. Each year a plan is established to pro-actively address these concerns. These concerns are prioritized according to their impact of the reliability of the system in the event of a failure, safety of employees and the public, and the likelihood of such a failure / occurrence. These repairs are generally non-urgent in nature and are performed within one year of the initial request.

### 5.3.6 PCB Program

FortisBC has approximately 26,000 in-service, oil filled distribution apparatus that do not undergo oil testing as part of regular maintenance. Draft legislation, expected to be enacted within a few years, will require that all remaining in service equipment containing PCB concentrations greater than 50 ppm must be inventoried and reported annually. There is also a requirement to label any equipment that is found to contain concentrations greater than 50 ppm. To meet these requirements, FortisBC must first determine the concentrations in each device.

The gathering of equipment data and identification of sensitive locations will be undertaken as part of a scheduled line patrol over an eight-year period. This project is expected to cost approximately $750,000 annually, beginning in 2005, with the commencement of oil
sampling, lab testing and any necessary mitigation measures taken on in-service, oil-filled distribution apparatus.

5.3.7 Forced Upgrades and Line Moves

Requests are received each year from the Ministry of Transportation (MoT), municipalities and customers to relocate distribution lines to accommodate road widening or improvements.

This project is to relocate distribution lines due to highway/road widening or improvements that are initiated based on requests from MoT and/or municipalities. Each project is approved on a case by case basis. Miscellaneous customer requests where FortisBC does not have sufficient land rights for the facilities located on customer property also falls within this project.

5.3.8 Distribution Urgent Repairs

Component failures on the distribution system due to inclement weather, defective equipment, animal intrusions, vandalism, abnormal operating conditions, vehicle collisions and human error cause outages or present risks that must be addressed in an expedient manner to ensure that employee and public safety is not at risk and electrical service continuity is maintained.

This project is for capital expenditures for repair or replacement of failed equipment. This strategy ensures provision of a safe, reliable distribution system.

6 Communications, SCADA, Teleprotection and Other Systems

6.1 Telecommunications Scope

In planning telecommunications systems for vertically integrated electric utilities, it is desirable and common to consider all traffic types that may benefit from the dramatic cost advantages and operational efficiencies of shared facilities. For that reason, the telecommunications part of the Transmission and Distribution System Development Plan considers telecom traffic in transmission, distribution, generation and administrative areas of FortisBC, as well as traffic to/from surrounding utilities that impacts the FortisBC telecom systems.

Traffic for the telecommunications systems may be driven from a variety of systems that are needed for the operation of the utility. To adequately assess these traffic needs now and in future, the contributing systems must be characterized, and future growth forecast. The systems in List 5.1 below are in service, planned or possible in future at FortisBC. Also
noted are neighboring utilities whose actions may have an impact on FortisBC systems or telecom.

**List 6.1 FortisBC Systems affecting Telecom**

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For each of these systems the study included:

- Updating the assessment of existing facilities - Situation analysis: a description of the system and its use in FortisBC, planning criteria, updating from the 2001 study.
- Requirements analysis - identifying future needs by assessment of:
  - the existing system deficiencies,
  - the impact of near-term projects,
  - the impact of the Transmission and Distribution System Development Plan,
  - any possible impact of telecommunications activities in surrounding utilities: BC Hydro, and TeckCominco, for example, the BC Hydro Capital Plan of May 2004
  - likely future administrative and operations systems additions.
- Budget planning: evaluating alternatives and preparing budgetary studies and integrated timeframes.
6.2 Introduction

FortisBC operates a private telecommunications system to support protection, control and monitoring for the power system, as well as operations and business communications requirements. Some 106 locations are presently or potentially served by the telecommunications system, including some 59 distribution locations, 11 generation, 12 transmission, and 6 office locations. The telecommunications system also connects to other utilities for the exchange of protection signals and operating voice communications.

A variety of telecommunications transport systems are used, depending on technical requirements, economics and system reliability requirements. These include power line carrier, fibre-optic cable, copper pairs, Telus leased lines, and radio (VHF, microwave, spread spectrum and packet radio). The primary purpose of the telecommunications system is to be an integral component of the protection relaying system, RAS, substation operations and control, and generation dispatch systems. It also provides a low-cost alternative to the public network for internal business data and some voice traffic.

6.3 Teleprotection and Remedial Action Schemes (RAS)

6.3.1 Description and Planning Criteria

Teleprotection (TP) is a means of transmitting protective relaying signals amongst the protection relays between substation locations. This provides fast and accurate fault clearing, and implements RAS, thereby protecting transmission equipment from damage and improving stability and reliability of the system.

Criteria

- locations, number of channels, and bandwidth of teleprotection and RAS channels are set by the layout of the protection zones, the particular protection techniques used in the transmission design, and the system stability requirements.
- Performance requirements for teleprotection and RAS channels are stringent in availability, absolute delay, and delay asymmetry, and thus common carrier (telephone company) channels are not normally used in this application.
- Where teleprotection or RAS on the bulk system affect other utilities, redundant communications paths are required by WECC standards.
- Where teleprotection channels are implemented by radio technology, licensed frequencies must be acquired – unlicensed bands are inappropriate for teleprotection.
6.3.2 Existing facilities

Power line carrier (PLC) is traditionally used for teleprotection within FortisBC, but recently optical fibre channels are being installed, and the teleprotection channels are being transferred to the fibre facilities using JungleMux and new technology. By the end of 2005, the only PLC facilities will be in the Oliver - Mawdsley, Brilliant Terminal Station – Kraft, Joe Rich – Big White, and South Slocan – Coffee Creek cross sections; all other teleprotection channels will run on fibre.

Most of the existing PLC equipment is obsolete, aging and unreliable, and some upgrades are being done coincident with station construction and rehabilitation activities, as follows:

- Vernon (BC Hydro) – Oliver Terminal: existing PLC channels, to be replaced with fibre in 2005
- Oliver Terminal – Mawdsley Terminal: PLC channels. Upgrades to the Oliver – Mawdsley PLC are being done in 2005 to improve noise performance and redundancy, funded by the South Okanagan Supply Reinforcement Project.
- Mawdsley – South Slocan: Fibre rings
- South Slocan – Coffee Creek: PLC Carrier
- Princeton – Oliver: no teleprotection channels
- South Slocan – Slocan City: no teleprotection channels
- Coffee Creek – Kaslo, Crawford Bay and Lambert: no teleprotection channels
- South Slocan – Emerald – Waneta: PLC decommissioned in 2004, these TP channels are now run on TeckCominco OC1 microwave.

6.3.3 Teleprotection and RAS Deficiencies

The age of the teleprotection channel equipment is affecting its reliability and maintainability – some shelves are so old that test switches have been designated “do not operate” by FortisBC because they will fail if operated. So the channels cannot be tested nor preventative maintenance adjustments done. After the upgrades of 2005, the Kraft - Brilliant Switching Station and South Slocan - Coffee Creek cross sections will remain critically obsolete.

Non-redundant teleprotection channel equipment: All PLC teleprotection channel equipment in FortisBC is non-redundant. Upgrades in 2005 will improve the redundancy of the Oliver - Mawdsley cross section by duplicating the channel equipment, but the channels will still run on only one carrier channel on one transmission line. Kraft - Brilliant Switching Station and South Slocan - Coffee Creek will remain non-redundant.
BC Hydro bulk power interconnections will require RAS changes. This may require upgrading to redundant communications paths as per Western Electricity Coordinating Council (WECC) standards in some cross sections.

**Kelowna Loop:** FortisBC intends to reconfigure the Kelowna 138 kV subtransmission system into a loop or mesh arrangement with automatic fault isolation. If so, Lee Terminal, Bell Terminal and each of six distribution substations will require teleprotection signaling to its neighbors. This number increases to ten if considering the proposed new Ellison, Black Mountain and South West Kelowna substations, and eleven if Duck Lake is also looped. The present 900 MHz radio system used in this area for SCADA is inadequate in speed, capacity and redundancy for teleprotection purposes.

### 6.4 Transmission, Generation and Distribution SCADA

#### 6.4.1 Description and Planning Criteria

The SCADA system provides real time telemetering of MVA, kV and VARS from equipped substations, with central historical records kept in the Warfield SCC database, and in some locations this is used for revenue metering. These measurements are used in balancing load flows and adjusting voltage performance on the bulk transmission system.

The system also provides substation status and visibility to SCC operators and remote control of terminal and substation switches. SCC operators assume “person in charge” (PIC) responsibilities for these substations. Included in this function are approximately 20 isolated line switches remotely operated by SCC for fault isolation and restoration purposes.

Increasing duties in the operation of the system are being undertaken by SCC operators. This trend is motivated by cost savings, freeing up field personnel for other duties, safety concerns, and maintaining the performance of a system operating increasingly closer to capacity.

Technology improvements have made it economical to extend remote monitoring and control to smaller stations. This will reduce on-site manual operating visits and costs and improve performance of the transmission and distribution systems. Specifically capabilities that will reduce operator visits and save Operations and Maintenance are:

1. remote tap changing (lowering voltage to less than the automatic control range to avoid load shedding),
2. remote restoration (switching feeders to other transformer[s] in multiple transformer sites)
3. remote automatic recloser disable (for brushing and hot line crews, now requires one visit in morning, one evening).
(4) remote relay and reclosure settings.

Criteria:

- All terminal stations, any new distribution substations, and significant distribution substation upgrades will have an installed Remote Terminal Unit (RTU) for telemetering, visibility and control.
- Where warranted by sufficient levels of activity, sufficient load (>10MW), or sufficient criticality to customer load, existing older distribution subs will have RTU’s and communications installed, staged at an achievable rate over the next few years. Remote, failure prone areas, or difficult to access substations will have priority.
- Where important to restoration plans, line switches (e.g. Rosemont, Grand Forks) will have SCADA control.
- SCC shall have redundancy in operator stations, processors, databases and communications.
- SCC operating functionality shall be available at a retreat site in the event of site failure or evacuation, or at a minimum, the system shall be safely operable by field personnel should SCC functions fail.
- Where SCADA communication channels are implemented by radio technology, licensed frequencies must be acquired – unlicensed bands are inappropriate for SCADA, except for temporary or emergency situations.

6.4.2 Existing facilities

Fifty-three remote terminal units communicate to the system control centre over FortisBC power line carrier, radio systems (VHF, data radio and microwave), fibre-optic circuits and via common carrier leased circuits. The SCADA system supports the operation of 12 generation, 12 transmission, and 3 switching station locations, 23 line switches, and 3 distribution substations.

Generation SCADA is a separate system from the transmission SCADA system. The generation SCADA system communicates to Programmable Logic Controllers (PLC’s) at the stations via fibre optic circuits. In addition, water level gauges at dam sites and at Nelson and Queen’s Bay (between Nelson and Coffee Creek) are monitored. The generation operator is responsible for generation dispatch and tagging energy transactions on the central internet site.

The SCC central site has dual redundant DEC Alpha servers, four operating stations (transmission, distribution, generation and development) connected via a local area network. The SCC is one node on the Trail fibre loop, which provides communications to the RTU’s, PLC’s and the mobile radio system.
Transmission RTU's are a variety of vintages, the older Quindar / Surveillant RTU's using 3 mutually incompatible protocols. FortisBC has standardized on Harris RTU's. RTU upgrades will be done in 2005 in Anderson, Vaseux Lake, Oliver (South Okanagan System Development Project), and Lee, Bell (Kelowna Area Upgrade project) Terminals.

Twenty three motor operated line switches are controlled remotely via DART RTU's using a Simrex packet radio system at SCC (via the Red Mountain Repeater), or “poll on demand” mRTU's that piggyback on the mobile radio VHF system, or, in the Kelowna area, over microwave radio from Okanagan Mountain.

6.4.3 SCADA Deficiencies

System coverage and control of distribution substations: The SCADA system provides visibility and control of only a few distribution substations. An opportunity to improve safety, system performance and Operations and Maintenance costs exists by, for example, adding remote control of tap changers, reclosers, and feeder switching.

MRTU narrowbanding: Nineteen of the small RTU's have integral VHF radios and will have to be upgraded or replaced in the period 2004 – 2010, see Section 5.8.

Telecom speed constraints: Most of the SCADA remote locations are constrained by low telecommunications bandwidth, because of high capital or Operations and Maintenance costs to provide normal channels to these locations. Thus far, no operational impact has resulted from this constraint, but as the operational responsibilities of the SCADA system evolve, the bandwidth and reliability requirements will increase, and the existing limitations may become impediments. These systems should be replaced over time as opportunity and requirements dictate. Systems affected are the VHF system (see Section 5.8), PLC carrier (see Section 5.12), the Red Mountain data radios, and the Grouse Mountain multipoint system.

SCC backup operations capability: As SCC becomes more pivotal to the operation of the system and assumes more operating responsibilities, backup operational capability will become a concern. Planning for the loss of SCC capability may include procedures for operating safely from the field, a retreat site and communications for SCC operators, or backup operating positions located elsewhere on the telecommunications loop.

Internet access for Energy Transaction Tagging: Increased FortisBC responsibilities for energy transaction tagging may require improved security of web access for SCC generation operator.
6.5 Power quality and Customer metering

6.5.1 Description and Planning Criteria

FortisBC uses electronic power quality station meters to monitor line and bus performance, voltage quality (sag, swell, disturbance), and harmonics for the purposes of load monitoring, power quality analysis, and energy consumption tracking. A few meters are also used as check meters and for revenue purposes.

Older electromechanical meters are used for non time-critical load monitoring purposes.

Criteria:
It is valuable to utility operations to have all transformers and feeders monitored with electronic power quality meters. The deployment of power quality meters will continue at an achievable rate over time, with the following criteria and priorities:

- Bulk power transformers and lines,
- all substation busses that support customer load 10 MW or greater (including transmission or generation subs that may supply a distribution feeder),
- all feeders at new substations,
- individual feeders where large load (10 MW), large customers or critical conditions exist.
- Where meter information is critical and viewed regularly, permanent telecommunications access is required (WAN system access is preferable where telecommunications is feasible). Where the information is required on a daily basis, dial up access is acceptable. Where metering information is not time critical, manual monthly visits are sufficient.
- Where radio communications is used, unlicensed radio bands are suitable.

Revenue meters are deployed at larger customer locations (>500KVA) to achieve not only timely load information, but power quality monitoring as well. Remote or difficult to read locations are also candidates for remote or automatic meter reading through a suitable communication system.

6.5.2 Existing facilities

FortisBC currently has 400 meters (electromechanical or electronic) installed on transformers, most feeders and critical customer locations. Some 130 of these are electronic meters that can monitor power quality parameters, and of these, 74 (less than 20% of the total meters) are remotely accessible via communications at five out of six
generation locations, 8/11 transmission terminal locations, 15 out of 70 distribution substation, and 25 customer locations. Of the meters that have the capability of being accessed remotely by FortisBC personnel, most use dial access (largely cellular) every 24 hours, some use the WAN system. The remaining meters are read manually, usually monthly. Power Measurement ION meters are used, with the ION Enterprise server system located in Trail. Revenue meters are dialed from Calgary (changing to Trail in 2004).

6.5.3 Metering Deficiencies

**Location and Feeder Coverage:** The existing power quality electronic meters tend to be deployed at the generation and bulk transmission levels, with poor coverage at the distribution substation and feeder levels. Continued installation of remotely accessible electronic meters at lower levels will improve the proper characterization of load profiles (temperature and time) at feeder and transformer levels, and improve performance monitoring. Communications increases the timeliness and therefore usefulness of the information gathered by these meters.

**Telecommunications costs:** As the FortisBC telecommunications and WAN systems extend to more FortisBC locations, meter information can be obtained faster and at lower cost by either connecting meters directly to the FortisBC systems, or arranging dial access from closer locations that are on the system, which lowers long distance costs. These arrangements to avoid external Operations and Maintenance costs are ongoing and will continue.

### 6.6 Protection Relay Status and Fault Recorders

#### 6.6.1 Description and Planning Criteria

FortisBC uses protection relay status information and fault recorder data for identifying fault locations, post-fault analysis, and outage duration calculation and tracking.

#### 6.6.2 Existing facilities

At the end of 2005, about 20% of the data from the system relays and existing digital fault recorders will be remotely accessible (WAN and dial up) by authorized FortisBC personnel. Information from the remaining relays is inspected on-site, and captured by month-end reports.

Tesla digital fault recorders will be installed at all transmission terminal subs within 2005. Tesla and Schweitzer software and databases are used for central information access.
Schweitzer relays in newer substations are accessed via the WAN, with firewall protection limited to certain personnel.

6.6.3 Relay Status and Fault Recorder Deficiencies

The lack of remote telecommunications access to relay and distribution fault recorder information can hamper or delay restoration efforts. There is presently no regular upgrade program in this regard.

Three transmission level substations do not have up to date capabilities in remotely accessible relays and digital fault recorders (Lambert, Grand Forks, Princeton).

Since remote access to these capabilities can be achieved using dial up facilities, there is not a big impact on telecommunications loads.

6.7 Mobile Voice (VHF Radio and Cellular)

6.7.1 Description and Planning Criteria

Mobile voice communications is used in FortisBC for dispatching field personnel and coordinating maintenance and restoration activities by crews in the field. Mobile communications is an essential element of FortisBC operations, both from SCC to the field, and for crew to crew communications. Cellular communications from Telus is used for less critical operational and business communications.

Criteria:
Operations crews shall have access to non-blocking voice communications to other crews and SCC:

- Over 90% of the service area
- At all substations

Where voice communications does not exist or is unreliable, effective procedures shall be in place to assure safe operation of the system.

6.7.2 Existing facilities
FortisBC operates a 153 MHz VHF radio system for voice telecommunications comprised of some 13 repeater sites, 22 base stations, and 200+ vehicle and handheld mobile radios, and tie trunks linking to the System Control Centre. The system provides communications coverage to about 90% of the service area, and covers all of the 67 substations.

Telus Mobility covers about 75% of the FortisBC service area, and is commonly used by operations personnel. It is particularly weak in the Princeton – Grand Forks area, except areas immediately surrounding Princeton, Oliver, Osoyoos and Grand Forks. About 10 substations have no cellular coverage. Telus Mobility coverage improvements are “planned” along the boundary highways, but no committed timeframe is offered. Telus Mobility has the potential to block during major traffic times or outage events, and cannot be solely relied upon for contingency operations.

6.7.3 Mobile Voice Deficiencies

Narrowbanding: Industry Canada is rearranging the VHF mobile communications band, with deadlines over the period 2004 – 2010. This will require FortisBC VHF equipment to use denser and narrower frequency band allocations than previous. FortisBC systems affected will be the 200+ mobile radios, portables and pagers, 22 base stations, 13 repeaters, and about 19 small SCADA RTU’s with integrated VHF radios. (the Simrex data radios used for SCADA control of Paterson, Fruitvale and Whitewater line switches are not affected by the “narrowbanding” issue, as these radios are already narrow band.) Some equipment can be modified to comply and some will need to be replaced. These systems will encounter small but increasing risk of interference from other users over the next few years. Where interference occurs, FortisBC could be required to comply or stop using the affected frequency within 90 days. It is prudent to begin narrowbanding or replacing at this time, and continue over the next few years.

Mobile trunks E-W: All mobile radio repeater sites are linked to the System Control Centre with trunk circuits. Where high capacity fibre circuits are not installed, leased lines or power line carrier are used. The Oliver - Mawdsley telecommunications cross section is capacity limited, so leased lines are used with accompanying cost and reliability concerns.

Shared use with SCADA: Because of the excellent coverage of the VHF mobile system, FortisBC has used the mobile communications system to “piggyback” SCADA communications for 12 locations. The SCADA communications occurs only rarely, but when it does, it interferes with voice communications. Unfortunately, the communications conflicts occur in contingency conditions (during storm outages, for example, crews are active in the field at the same time the System Control Centre will be performing switches on the SCADA system). Efforts should be made over time to remove these SCADA transmissions from the VHF system to more reliable channels.
6.8 Fixed Voice - Operations

6.8.1 Description and Planning Criteria

Operations personnel require dedicated voice access to transmission and generation control rooms, and from the System Control Centre for switching and restoration coordination and safety guarantees. Switched voice from Telus is suitable for distribution, but not for transmission, substations. Telecommunications personnel usually have “order wire” channels normally supplied as part of radio or multiplex equipment.

6.8.2 Existing facilities

Station fixed voice to transmission stations is provided on the FortisBC high capacity systems, where they exist. Other transmission locations have voice telecommunications provided on power line carrier, and after 2005, voice on power line carrier will only be used in the Oliver - Mawdsley, Kraft - Brilliant Terminal Station and South Slocan - Coffee Creek cross sections. For distribution, dial access is available to about a third of the substations.

6.8.3 Fixed Voice Deficiencies

PLC age and reliability: The same age-related performance and reliability issues as described in 6.3. Teleprotection affect the fixed voice system in the power line carrier cross sections.

VHF Piggybacking: The Coffee Creek voice access shares the telecommunications channel with the SCADA link, and both use the VHF mobile radio system to Crawford Bay, resulting in occasional interference amongst these varied uses.

Dial access to Transmission substations: Lambert and Princeton are transmission stations that only have dial up telecommunications to the control rooms, which could be blocked given a public emergency in the area.

6.9 Wide Area Network and Administrative Voice

6.9.1 Description and Planning Criteria

The FortisBC enterprise Wide Area Network (WAN) is used extensively by operations crews in their work order process, and by other personnel for access to meter, relay and digital fault recorder information. The company wide voice system is used by FortisBC personnel in ten office locations and most transmission and generation stations. Both are supplied by
Telus as an enterprise voice and data system, based largely on the Telus ATM network. The Telus contract is presently being renegotiated, with an expected decision by year end 2004.

6.9.2 Existing facilities

The WAN will extend (after 2005) to nine district offices, nine terminal stations, nine dam locations, SCC, Bell Terminal, the Trail office, and Calgary. The Telus ATM network is used for WAN access to most offices, the FortisBC fibre network is used for the terminal and dam stations, SCC, Bell and Benvoulin Road. Wireless access is available in Warfield, Benvoulin and Trail, dial access is available from other locations not served by the WAN. Access to critical substation operating functions is protected by firewall.

A test of spread spectrum radio technology for WAN bus extension is presently underway from Benvoulin to Lee. This will complete when the Okanagan fibre loops are completed in 2005.

6.9.3 WAN and Administrative Communication Deficiencies

Operations and Maintenance costs from Telus for WAN and voice channels on their ATM network are significant, and are increasingly being avoided by using the FortisBC fibre facilities for 10 MbpS WAN busses (used operationally for access to meters and protection relay information), and for voice. This will continue as the fibre network grows to more locations.

WAN access to more locations and at higher transmission speeds would be useful to FortisBC operations personnel, particularly as increasing amounts of data on status and condition of the Transmission and Distribution system become more available.

6.10 Neighboring Utilities

FortisBC communications, control and protection systems governing the operation of the system interface with BC Hydro and TeckCominco at several system points. In addition, BC Hydro will be providing two T-1 channels for FortisBC use from Vaseux Lake to Kootenay Canal, which will be used for partially interconnecting the existing fibre rings in the West Kootenay to the Okanagan region ring (2005).

There are no further changes foreseen to the TeckCominco interfaces after the completion of the 230 kV changes in the West Kootenay area in 2004.
BC Hydro has an aggressive capital plan for 2005 – 2010. No major impacts on FortisBC telecommunications facilities as a result of this BC Hydro work are evident at this time, beyond the changes resulting from the South Okanagan Supply Reinforcement Project. However, the BC Hydro projects as they develop may have an impact and thus bear watching. Example BC Hydro projects that should be monitored for possible operational or planning impact on FortisBC telecommunications include:

- BC Hydro Growth – “Nelway 71 Line Re-termination” – year unknown
- BC Hydro sustaining – “Line Protection Replacements - 500 kV, Stage 1 (5L98)” – was scheduled for 2004, possibly included in the South Okanagan Supply Reinforcement Project.

### 6.11 Backbone Telecommunications System

#### 6.11.1 Description and Planning Criteria

**Criteria** - FortisBC-owned private telecommunications are installed where:

- Protection designs require communications,
- Non blocking communications must be available for use in contingency circumstances (e.g. mobile voice)
- Traffic volumes are such that a private shared system is more economic.
- If radio is used, licensed frequencies are required for teleprotection and SCADA, unlicensed bands may be used for metering and administrative traffic.
- Fibre optics cable is the preferred option where future traffic growth is anticipated.

#### 6.11.2 Existing facilities

FortisBC uses a combination of fibre, leased circuits, power line carrier, BC Hydro circuits, 900 MHz. microwave, and VHF radio. Wireless spread spectrum technology is presently being tested.

Vernon – Oliver: presently power line carrier, will be upgraded to folded loop fibre (including Joe Rich and Benvoulin) in 2005. FortisBC has access to:

- 6 fibres Vernon – Anderson;
- 12 fibres Anderson to OK Falls;
- 72 fibres OK Falls to Vaseux Lake
- 40 fibres Vaseux Lake to Oliver.
Princeton – Oliver: 4-w leased line for SCADA, dial-up for meters.
Oliver – Mawdsley: existing Power line carrier, BC Hydro 2T-1’s (2005)
Mawdsley – Brilliant Terminal Station: Trail (South) Ring - folded loop fibre
Brilliant Terminal Station – South Slocan and Plants: River Ring - folded loop fibre
South Slocan – Coffee Creek: Power line carrier, VHF radio to Crawford Bay
Brilliant Terminal Station – Kraft: Power line carrier
Joe Rich – Big White (2005): Power line carrier

FortisBC has been implementing a progressive change to fibre facilities where required by transmission improvements, then progressively converting other circuits to the fibre facilities - e.g.: some operations Centrex voice circuits to SCC, WAN facilities to substations and plants, and Telus 4-w circuits rearranged to the closest fibre location to reduce Operations and Maintenance.

6.11.3 Backbone Telecom System Deficiencies

**Oliver – Mawdsley cross section limited bandwidth (4 channels):** This limitation will be somewhat relieved by the BC Hydro channels that will be installed from Vaseux Lake to South Slocan during 2005, but this solution does not provide for long term growth, nor redundancy. As traffic and reliability requirements build in coming years, this cross section will again become a constraint.

**Folded loops:** FortisBC fibre optics channels are engineered as redundant loop systems, but both loop directions are contained in the same cable sheath, which does not meet the “diverse path” requirement as standardized by the WECC.

**Outer areas are weak:** Telecommunications facilities to Princeton, Coffee Creek, Crawford Bay, Lambert, Kaslo and Kraft are very limiting, resulting in leased lines Operations and Maintenance costs, poor operating reliability, and no provision for growth.

6.12 Possible Future Requirements

It is challenging to create a 20 year plan for communicating systems in a transmission and distribution system when there are support technologies just in the embryonic stages of development. Although none of these are in active development at FortisBC, this plan assumes that some, not all, of the following application technologies will prove effective in the FortisBC system in the 2010 to 2025 time period. Any of them will have an effect, small or large, on the telecommunications and control systems of FortisBC, and thus should be considered in long term planning.
Video Surveillance: FortisBC has begun using video surveillance in several locations around the Warfield yard and in the Trail Office, carried on the FortisBC networks. In 2005, the Bell and Lee Terminals, both in vandalism-prone areas, will have video surveillance installed, routed to SCC on the network. Other utilities are also making more extensive use of video, even including in some cases using video to visually verify switch operation. Although the use of video will probably reach only a limited number of locations, it can consume large bandwidth. FortisBC’s present strategy of implementing fibre for the telecommunications backbone is prudent for this and similar future applications as fibre provides ample bandwidth for growth.

Automatic Meter Reading (AMR): Utilities similar to FortisBC in size and geography have found AMR systems effective in reducing residential customer meter reading cost, errors and complaints. These systems can be implemented with a central computer and customer meter interface modules, and often use the distribution wires for local communications, coupled with the company’s backbone telecommunications system. Sometimes the systems are shared with municipalities for combined electrical, water and gas meter reading.

Administrative Voice Traffic: It may become attractive to carry more of the FortisBC administrative traffic on the internal network, because of two factors:

(1) the increasing coverage of the FortisBC fibre backbone; and

(2) the developing technology (and suppliers) in Voice-over Internet Protocol (VoIP), as noted in the 2001 communications study.

At a minimum, holding this as an active possibility will assist in negotiations with common carriers such as Telus.

Demand Side Management (DSM) to Customers: As the electrical industry evolves, various versions of DSM and customer access to time of day or other rate choices may become prevalent. Implementing these may have a drastic effect on FortisBC’s communications and control systems.

Feeder Automation: The technology for providing automated functions on distribution feeder lines (communicating mid-point reclosers, for example) is developing, and some utilities are finding these technologies beneficial. Benefits that contribute to the business case for feeder automation are more localized fault clearing, more accurate network monitoring, more intelligent protection and restoration switching designs.

Transformer Condition Monitoring: Advances in transformer instrumentation are allowing closer monitoring of this critical asset. For example, the newer transformers at Lambert, Warfield Terminal Station and Brilliant Terminal Station have Hydran oil monitoring equipment installed. This (and perhaps other future condition monitoring mechanisms) will require communications to a central database to capture and trend the information. This will likely have only a minor additional effect on the communications and control systems, as
the substation automation project will provide communications for this and similar low bandwidth requirements.

6.13 Projects

The major drivers of the development of the telecommunications systems at FortisBC are

- the completion of the backbone and
- substation automation.

Additionally, a number of particular cross sections and technical issues should be addressed:

- Off-backbone extensions: Princeton, Coffee Creek (TP), Kraft (TP)
- VHF piggybacking
- Kelowna Loop
- Wide Area Network extension to more locations

6.13.1 Mawdsley-Okanagan High Capacity Communication Network

**Project Description:** This project will enable the transfer of data at high speeds and volumes in FortisBC’s entire service territory (Kootenay and Okanagan). This is required for system protection purposes as well as for monitoring and controlling the system remotely, and will displace Operations and Maintenance costs for east-to-west leased lines used for system control and operational communications. The project will be undertaken in segments, coincident with the decommissioning of 9 Line and 10 Line and the replacement of the distribution substations along this route in 2005-2015.

**Discussion:** FortisBC has secured rights to fibre communications paths in the Vernon to Penticton area, and will be constructing fibre facilities from Penticton to Oliver as part of the South Okanagan Supply Reinforcement project. Previous high capacity communications exists in the Kootenay area. The overall communications system remains constrained (both in capacity and reliability) in the Oliver to Trail cross section. This causes increased Operations and Maintenance costs for leased facilities to compensate for the constraint, and a lower degree of system protection and control in this area and across the system from east to west. Improved protection and control capability on this cross section becomes more critical as the system becomes more fully interconnected and is operated closer to capacity.

The securing of some BC Hydro communications paths from Vaseux Lake to South Slocan will relieve some of the constraining effects of the Oliver – Mawdsley cross
section, but does not provide for redundancy or growth. Additionally, redundant paths east to west may be required for system protection and RAS improvements required by interconnection to the BC Hydro 500 kV system.

FortisBC is increasing the level of protection and control of the Transmission and Distribution system, including locations along this route. Accessing intermediate points (Grand Forks, Kettle Valley) on a telecommunications route in a “drop and insert” fashion is far less expensive with fibre loop technology rather than radio.

The understung fibre option requires a review of the structure capacity and conditions of 11 Line. Deteriorated structures, clearance issues and span length considerations may drive up the cost of fibre in some parts of the build, and radio options may prove more suitable for some parts of this cross section. Conversely, a fibre sharing arrangement with another company could decrease the net cost of the fibre option dramatically. Detailed engineering and negotiations will determine the appropriate choices.

### 6.13.2 Distribution Substation Automation

**Project Description:** This multi-year project will extend the coverage of substation automation in the FortisBC system. This project broadens the integration and use of remote monitoring and control to distribution level substations, including the quality monitoring of lines, transformers and feeders, fault recording and locating, and equipment condition monitoring. It will provide common communications mechanisms for gathering, storage, access and analysis of the resulting data. Resulting benefits are improvements in system performance, productivity, safety and economics. The project includes the initial study to define the engineering standards and benefits, the development of a central data repository, individual projects in appropriate substations (synchronized with station rebuild or major addition), and an emergency backup plan.

**Discussion:** Utilities are increasingly recognizing the cost, safety and reliability advantages of substation automation. The improvement of technology in this field, the technical standards development by the Institute of Electrical and Electronics Engineers (IEEE), the International Engineering Consortium (IEC) and industry organizations, and the decreasing cost of these technologies will allow smaller utilities such as FortisBC to make the best of these advantages.

Substation automation is a “catch all” term used to describe the integration and use of system information from substations for the remote monitoring and control of substation equipment, the quality monitoring of lines, transformers and feeders, fault recording and locating, equipment condition monitoring, automatic closed loop switching, as well as common communications mechanisms for gathering, storage, access and analysis of the resulting data. Resulting benefits are improvements in system performance, productivity, safety and economics, as follows.

November 26, 2004
Substation Automation Benefits:

SCADA visibility and control

- Energy metering – wider and more exact visibility and monitoring of system load flow will allow more exact energy and VAR management, improving system performance and reducing energy costs.

- Recloser enable and disable – when brushing a rural line, auto 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 them. Remote control avoids these labour costs.

- Line isolation switching – Faults will be sectionalized remotely and faster, improving restoration performance, and reducing Operations and Maintenance costs for line crews.

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

- Tap changer – extending remote control to more distribution tap changers will help to avoid exceeding the peak energy capacity penalty.

- Support for future feeder distribution automation, for example, midpoint reclosers which can localize the outage effects of a distribution fault.

- Breaker switching – energize remotely will speed restoration, rather than PLT returning to substation.

- Feeder switching – to one transformer if capacity permits, restores non-faulted feeders faster, or recovers from a faulted transformer.

Metering

- Individual feeder metering – more accurate load profiling (e.g. time of day, temperature variability) will assist system load balancing.

- Electronic meters improve time resolution of load data, and provide improved monitoring of quality factors - more accurate load profiling improves forecasting and system planning (avoids unnecessary capital), improved quality data supports troubleshooting and improves customer service.

- Remote access – more timely data analysis results in faster corrective actions.

Intelligent relays

- Remotely accessible fault location – speeds crew dispatch to the exact fault location, lowering outage times.

- Fault recording – improved fault analysis from accessing all appropriate data reduces future outages

- Condition monitoring – allows condition-based, “just in time” maintenance which reduces labour, outages, and equipment damage
Human Machine Interface (HMI)

- Reduces station complexity, standardizes station operator interface, allows remote operation.

Local Area Network (LAN) / Firewall

- Eliminates redundant sensors, wiring and transducers, which reduces capital cost. Prevents unauthorized access and operation.

Central database

- Provides more comprehensive and more accurate data for analysis of equipment condition, fault analysis and operational history, which will improve system reliability, safety and economics.

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

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

The project includes a preparation stage followed by substation installations as follows:

**Study, database and emergency response planning:** The major hurdle to developing station automation is ensuring that a common platform is used to ensure that all of the intelligent electronic devices in the stations work with each other. This project includes the engineering study that is required to identify the common intelligent electronic devices being implemented inside the stations and to set standards for future systems. The study will also assess the benefits to be expected and establish a business case for proceeding. The project will also include the development of an emergency restoration plan for SCC. As SCC becomes more pivotal to the operation of the system, the risk of an evacuation–type contingency can no longer be tolerated. This project will also examine if minimum system operating capability can be restored elsewhere on the high capacity communications system by the provision of a spare operating station at that location, and if that would be justified.

As detailed standards and deployment plans have not yet been developed, this project is still in the planning stage. For outage coordination, safety and cost reasons, we
assume that substation automation installations will largely be done in coordination with other substation work.

**Major terminal station work:** Terminal automation changes and additions will be included in all major projects in terminal and switching substations. The required funds will be included in the budget amounts for that work, and are thus not included here.

**New substation builds:** during rehabilitation, rebuild, relocation or new sub projects. This project budgets only the automation and communications costs (remote terminal unit (RTU), LAN, communications, meters, hub, firewall, Positron, HMI, labour), but not the basic cost of the substation (switches, Schweitzer relays, DFR, transducers, potential transformers (PT), current transformers (CT), Hydran, building, battery) which, where appropriate, will be included in the substation project. Planning examples used for budgetary estimates are new substations at Ellison, Black Mountain, Brae Loch, East Osoyoos and Kettle Valley, as well as rebuilds and upgrades at Grand Forks, Ruckles, Christina Lake and at the conversion of Oliver to a distribution substation.

**New distribution transformer in distribution or transmission substation:** Retrofit existing subs with standard automation and communications when adding a new transformer, major load redistribution or transformer rotation. Planning examples used for budgetary estimates are Crawford Bay, Recreation capacity addition, and transformer rotations at (old, west) Osoyoos, Westminster (rotation and breaker replacements), Pine Street, Trout Creek and Ymir.

**Existing critical, remote or vulnerable lines or substations:** Where substations serve long vulnerable lines where restoration efforts are difficult, or which have a significant customer load or significant effect on system loading, FortisBC can achieve significant operational benefits by increasing automation levels. The project includes SCADA controlled motor operated line switches to aid in sectionalizing and restoration, remotely controlled line switches to substations that have feeds off two transmission lines for restoration purposes, and remote substations.

### 6.13.3 Protection and Communications Upgrades

**Project Description:** This multiyear program will upgrade protection and control equipment in several substations, will upgrade telecommunications routes in the West Kootenay region, and will improve emergency response capability. The program is expected to continue at similar expenditure rates until 2015.
Discussion: Much of the FortisBC protection and telecom equipment is near or beyond its designed operational service life, some being up to 40 years old. It is no longer reliable, and the manufacturers no longer supply spare parts. In some extreme cases, equipment can no longer be tested and adjusted regularly because it fails when test systems are operated, and cannot reliably be put back into service.

The impact is that this equipment can cause failure of the transmission and distribution systems it supports, or prevent restoration efforts, exposing the system to possible equipment damage, extended outage times, or possibly causing public safety issues.

FortisBC will pursue a two-fold strategy to address this issue:

- upgrade parts of the telecom, protection and control systems regularly over several years, and
- prepare an emergency response plan and supply spare new systems that may be used in emergency restoration.

The 1999 System Protection Study performed by Acres International Ltd. identified the need for protection upgrading and replacement requirements for FortisBC’s systems. This work was structured into a multi-year program that has been running since 2000 at a level of between $150,000 and $300,000, and at this rate, the identified work has not been capable of being completed. To work through the identified backlog, it is recommended to ramp up expenditures over the next years. The benefit of work captured in this category is primarily in system protection and control, and deferring this work would prolong the risk of system damage, and public exposure to obsolete protection techniques, and thus possible exposure to downed, energized lines.

There are two databases being developed to track what protection and telecommunications equipment is operational in the system, and its condition. This is the first step in developing the needs for the rehabilitation and maintenance of the equipment. The success of the rehabilitation program depends critically on this database work.

Since immediate replacement of all the “at-risk” equipment is impractical, emergency response planning for telecommunication, protection and control systems needs to be improved, a spare radio hop and other equipment should be provided, disaster planning, regular exercising of plan (emergency scenarios) and regular updating will be undertaken.

It is anticipated that the communication, protection and control upgrade expenditures will continue at a similar level as a result of implementing the communication
equipment test/maintenance process. The new process will identify and prioritize the required replacements.

6.13.4 Communications and Relay Testing and Maintenance Program Studies

FortisBC plans to carry out a study of the existing communications systems and required maintenance cycles to continue providing adequate communications service. The study will utilize test records, environmental factors, manufacturer recommended tests and maintenance cycles and operational history for existing circuits and equipment.

FortisBC is also undertaking a study of the protection relays in the system and the maintenance cycle requirements for each type of relay in each type of application. The data gathered will include the individual relay testing history, environmental situation, manufacturer recommended tests and maintenance cycle, and the operating history. Data will be accumulated in an existing FortisBC database, and the study will set standards for the maintenance program for relays, system wide.

6.13.5 VHF Narrowbanding (2004/05 project)

**Project Description:** This project will upgrade FortisBC’s existing VHF mobile telecommunications equipment, driven by a spectrum management change from Industry Canada. The project will start in 2004 and be complete by 2005.

**Discussion:** Industry Canada is rearranging the VHF mobile communications band, with deadlines over the period 2004 – 2010. This will require equipment to use denser and narrower frequency band allocations than previous. FortisBC systems affected will be the mobile radios, portables, pagers, base stations, repeaters, and about 19 small SCADA RTU’s with integrated VHF radios. Some equipment can be modified to comply and some will need to be replaced. These systems will encounter small but increasing risk of interference from other users over the next few years, so it is prudent to begin narrowbanding or replacing them at this time.

6.13.6 Telecommunications Backbone Loop Close

**Project Description:** This project will complete the FortisBC telecommunications backbone system into a loop configuration as commonly used by most utilities, and as required by WECC standards. The system will be completed in about 2020 by building fibre or radio channels from Vernon to South Slocan. Several sharing options with other companies will be explored before committing project monies.
Discussion: In the long term, providing a complete loop for the telecommunications systems will be required.

The medium term system (after the completion of the Okanagan fibre installations from Vernon to Oliver and the high capacity link from Oliver to Mawdsley), will be a series of interconnected folded loops. But the communications system will not be redundant in the strict sense, which requires alternate diverse paths. Diverse paths are required by WECC standards for bulk power systems and are normally used in utility telecommunications.

The BC Hydro channels acquired as part of the South Okanagan Supply Reinforcement Project provide a limited amount of path diversity which will cover some requirements for some years, but the Oliver – Kelowna (and Vernon) leg is unprotected. Long term loop closing requires a high capacity path from Vernon to South Slocan.

Several broad alternatives are available:

- Build fibre or microwave. This alternative is expensive ($10 – $20 million), will encounter environmental and land acquisition issues, and should be saved for a last resort.

- Unfold loops – short spans. The existing folded loops can be made somewhat more path diverse by selecting high risk areas and providing another fibre cable path for some kilometres around the risk location. (An example risk area is the part of 25 Line where the fibre cable is close to the road and a vehicle accident could cause an outage of both loop paths [same cable] and the transmission facility at the same time. Providing another cable route around the immediate area for one of the fibre loop paths would mitigate the risk.) Providing short loop paths in high risk situations (where the fibre cable runs beside roads, through high vandalism areas, over fire prone valleys, high impact TP or RAS cross sections, etc.) would reduce the folded loop vulnerability significantly, and may be sufficient to postpone the need for overall loop closing.

- Unfold Interior Loops – provide a diverse path for the interior loops (OLI – AS Mawdsley is a good candidate), since they carry the accumulated traffic from the end loops, and thus have more of a failure impact. This would result in a system that is fully redundant in parts. Continuing this strategy for other loops over years has the advantage of achieving a fully redundant system in smaller increments than the major “closing the loop” build.

- Tolerate risk and mitigate. Accepting that a long term communications disruption is possible, FortisBC can prepare for operating the system under this eventuality. Spare protection and communications equipment can be deployed in several locations, capability for operating the west area without SCC oversight may be developed, (perhaps a backup SCC in the west), databases could be duplicated several places, perhaps a backup customer call centre, and so forth. This
alternative would require significant response planning closely integrated across transmission, distribution, generation and administrative systems.

- BC Hydro negotiations. BC Hydro has assets that could prove extremely useful to FortisBC:
  - Channels from Vernon – SLC for emergency restoration only. BC Hydro is very adverse toward committing their bandwidth to others. But perhaps they would consider providing Vernon to SLC bandwidth limited to (a) a bona fide FortisBC emergency situation, (b) while it was spare and unused, (c) a limited length of time, and (d) a limited amount.
  - Vernon to Vaseux Lake channels from BC Hydro would loop the Okanagan area communications portion of the backbone nicely.
  - right of way sharing on 5L91 to reduce cost of build for fibre
  - Share their microwave sites? Install FortisBC OC3 radios at BC Hydro sites and towers, cooperative maintenance agreement.
  - Trade fibres Vaseux Lake to Waneta for channels Vernon – South Slocan, FortisBC staff have developed a scenario where BC Hydro might be interested in FortisBC dark fibres from Vaseux Lake to Waneta, such that they might consider a trade: upgrading their existing radio system to OC3 and giving FortisBC an OC1, preferably from Vernon to South Slocan, in return for the dark fibres.

- Shared build
  - Shaw or others, but the low population of the Castlegar – Trail area probably limits the interest of other companies. However, the government of BC is contemplating a broadband system to all communities in BC, similar to Alberta’s SuperNet, and Telus has indicated a willingness to consider shared builds in this regard, so shared builds may be achievable in routes of interest to FortisBC.

Assuming some combination of the above will prove suitable for operating the system in the long term, $10 million is budgeted in year 2010+.

6.13.7 Business systems

**Project Description:** This far future project provides for the use of the FortisBC telecommunications system for possible future applications that may be developed for company operations in the period 2010 – 2025. In each case, use of the FortisBC telecommunications system will improve the performance of these systems, and lower the Operations and Maintenance costs for the telecom portion of the systems (displacing common carrier costs).
Discussion: As system operations mature in the long term and technology advances, more and more of the system operations will become dependent on communications and automation. It will become economically viable to use capacity on the FortisBC telecommunications backbone, when completed, for these applications, motivated by Operations and Maintenance savings. Example systems used for rough budgetary estimates might be:

1. a VoIP system for company wide switched voice traffic that would displace a portion of the $150,000 per month Telus charges,
2. a system-wide automatic meter reading system that would automate meter reading, reducing meter reading costs, reading errors, estimates, and re-reads, and
3. Feeder automation. Although none of these application developments are certain, these and several others are possible, and it is prudent to assume that at least some of them will prove viable and proceed.

6.13.8 Harmonic Remediation

Project Description: This project provides for investigating and resolving harmonic problems as they arise.

Discussion: FortisBC’s experience with harmonic difficulties is that they arise periodically and typically need to be investigated, although only infrequently mitigated. FortisBC has recently resolved a harmonic problem in Kaslo with a harmonic filter, and has data gathering and investigations underway on 43 Line, in the Glenmore area, and on 20 Line. Investigation involves installing test equipment for a period of time, then engaging a consultant for detailed analysis.

6.13.9 Creston Central Protection Upgrade (plus RTU)

Project Description: The project will establish state of the art electronic protection and metering for feeders as well as improved line transfer trip protection for transformer fault clearing and an RTU for proper control and status reporting of station condition. The work will be completed in 2005. The existing systems in Creston are obsolete, and have not been updated or coordinated with the changes in Lambert.

Discussion: 1998 fault studies confirmed inadequate protection for feeders, and this has been experienced by field staff. The existing 200E transformer high side fuses do not coordinate with 31 Line and 32 Line protection at Lambert Terminal. They are also too large to reliably recognize 13 kV bus ground faults or to provide backup for the distribution feeder protection. A breaker failure, protection failure, or bus fault will result in loss of total station by protective relay operation at Lambert (31 Line distance protection). Inadequate metering creates operational and planning inaccuracies.
Appendix A – Maps and Diagrams

1. FortisBC Service Area
2. System Single Line Diagram
3. Okanagan Region System
4. Kootenay Region System
5. Boundary Area System
6. Neighboring Systems
7. New Osoyoos Substation
8. Boundary Area Conversion
9. South Okanagan Upgrade
10. Kootenay Area Upgrade
1. **FortisBC Service Area**
2. **System Single Line Diagram**

Single Line Diagram is available in Hard Copy only.
3. Okanagan Region System
4. Kootenay Region System
5. Boundary Area System
6. **Neighboring Systems**
7. **New Osoyoos Substation**
8. **Boundary Area Conversion**

[Diagram of Boundary Area Conversion]

- **Existing 161 kV**
- **New 25 kV**
- **Existing 63 kV to be Salvaged**

Key Nodes:
- Kettle Valley Sub (in Rock Creek Area)
- Grand Forks Terminal (GFT)
- Grand Forks Distribution (at GFT site)
- To Maedsley
- Oliver tie (future) (~ 50 km to Kettle Valley)
- McKinney (~ 22 km)
- Ruckless 4/13 kV

**Legend:**
- 11L (161 kV or 138 kV)
- ~22 km
- ~25 km
- 69 kV
- 25 kV
- 25 km
- ~36 km
- Christina Lake
- Cascade tie
9. **South Okanagan Upgrade**

![South Okanagan Upgrade Diagram]
10. Kootenay Area Upgrade
Appendix B – Load Forecast

- Note that the “Ultimate” loadings in these listings indicate expected load in the year 2023.
- Substations are listed under the BC Health Districts in which they are physically located, although some feeders connected to certain substations may serve a small portion of load in an adjacent district.

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Growth: 3.67% 2.15% 3.14% 3.23% 3.23% 3.22%
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**Growth** 1.22% 0.73% 1.35% 1.37% 1.38%
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## Appendix C - Capital Forecast

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| **STATION SUSTAINING**                                    |             |               |      |      |      |      |      |      |      |       |
| Station Assessment and Minor Projects                     | 5,950       | 6,550         | 600  | 950  | 1,000| 1,000| 1,000| 1,000| 1,000| 1,000 |
| Station Unforeseen Repairs                                | 1,800       | 2,000         | 200  | 300  | 300  | 300  | 300  | 300  | 300  | 300   |
| Olenerry Soil Reclamation                                 | 0           | 400           | 400  |      |      |      |      |      |      |       |
| 10/12 MVA Mobile Upgrade                                  | 300         | 300           | 300  |      |      |      |      |      |      |       |
| Kootenay Mobile Station                                   | 2,000       | 2,000         | 2,000|      |      |      |      |      |      |       |
| CMMS                                                      | 700         | 700           | 500  | 200  |      |      |      |      |      |       |
| GOF, CIP, WES AND BULK OIL BRAKERS                        | 3,400       | 4,600         | 500  | 900  | 800  | 400  | 400  | 400  | 400  | 1,200 |
| Ground Grid Upgrades                                      | 1,500       | 1,500         | 250  | 250  | 250  | 250  | 250  | 250  | 250  | 250   |
| Transformer OIL Filtration/Replacement                    | 1,500       | 1,500         | 250  | 250  | 250  | 250  | 250  | 250  | 250  | 250   |
| LTC Oil Filtration                                        | 900         | 900           | 150  | 150  | 150  | 150  | 150  | 150  | 150  | 150   |
| West Osoyoos Transformer Rehab                            | 1,900       | 1,900         | 100  | 1,800| 0    | 0    |      |      |      |       |
| Grand Forks Terminal Noise Reduction                      | 150         |               |      |      |      |      |      |      |      |       |
| Kaslo Sub Upgrade                                         | 2,000       | 2,000         | 1,200| 800  |      |      |      |      |      |       |
| Pine Street T1 Rehab, 44L BREAKERS, Switches              | 1,000       | 1,000         | 750  | 250  |      |      |      |      |      |       |
| Westminster T1 Replace                                    | 500         | 500           | 500  | 0    |      |      |      |      |      |       |
| Trout Creek T1 Rehab                                      | 800         | 800           | 800  |      |      |      |      |      |      |       |
| Replace Coffee Creek T2                                   | 1,500       | 1,500         | 1,500| 250  |      |      |      |      |      |       |
| Replace Crawford Bay T1                                   | 1,500       | 1,500         | 1,500| 250  |      |      |      |      |      |       |
| Tap Changer Leak Repair and Upgrade                       | 600         | 600           | 600  |      |      |      |      |      |      |       |
| **SUBTOTAL - STATIONS SUSTAINING**                        | 28,000      | 30,400        | 1,200| 6,050| 7,300| 3,800| 2,350| 3,400| 5,100| 1,200 |

| **TOTAL - TRANSMISSION**                                  | 284,677     | 368,762       | 53,885| 67,051| 60,136| 40,100| 50,380| 48,160| 18,850| 30,200 |

November 26, 2004
## Distribution Projects

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| KELOWNA AREA                     |            |             |      |      |      |      |      |      |      |       |
| **DUIC1-SEX1 477 TIE**           | 450        | 450         |      |      |      |      |      |      |      |       |
| **QUAL DEVELOPMENT LOOPFEED**    | 200        | 200         |      |      |      |      |      |      |      |       |
| **DILWORTH DEVELOPMENT LOOPFEED**| 200        | 200         |      |      |      |      |      |      |      |       |
| **OKMS-OKM3 TIE, EXT TO SPRINGFIELD**| 600   | 600         |      |      |      |      |      |      |      |       |
| **DG2-DG03 TIE, REBUILD 4.5 KM TO 477**| 550  | 550         |      |      |      |      |      |      |      |       |
| **COMPLETE GLE5-SEX2 TIE ADD N.O.**| 85        | 85          |      |      |      |      |      |      |      |       |
| **KELOWNA GENERAL FEEDER PROTECTION**| 450     | 450         | 150  | 100  | 50   | 50   | 50   | 50   | 50   |        |
| **MCKINLEY LANDING CAPACITY UPGRADE (#2 TO 477) FED FROM SEX3**| 450      | 450         |      |      |      |      |      |      |      |       |
| **NEW GLE6 FEEDER (50L U/B HIGH RD-CLIFTON)**| 1,000   | 1,000       |      |      |      |      |      |      |      |       |
| **HOL1-DGB3/LE2 TIE**            | 600        | 600         |      |      |      |      |      |      |      |       |
| **HOL1-OKM1 TIE ALONG KLO RD**   | 450        | 450         |      |      |      |      |      |      |      |       |
| **MCKINLEY TO CLIFTON TIE**      | 200        | 200         |      |      |      |      |      |      |      |       |
| **LEE2-HOL5 TIE, ADD N.O.**      | 200        | 200         |      |      |      |      |      |      |      |       |
| **RETERMINATE LEE FEEDERS AT NEW N. KELOWNA SUBSTATION**| 500      | 500         |      |      |      |      |      |      |      |       |
| **NEW FEEDER N. KELOWNA SUBSTATION**| 0        | 1,500       |      |      |      |      |      |      |      |       |
| **FUTURE KELOWNA DISTRIBUTION UPGRADES**| 3,000  | 4,500       |      |      |      |      |      |      |      |       |

| PENTICTON                        |            |             |      |      |      |      |      |      |      |       |
| **WEB1 VOLTAGE REGULATOR**       | 85         | 85          |      |      |      |      |      |      |      |       |

| OSYOOS/OLIVER                    |            |             |      |      |      |      |      |      |      |       |
| **3 PHASE 4.4KM 1&2 PHASE OSO2** | 350        | 350         |      |      |      |      |      |      |      |       |
| **NEW Feeder D/C OSO4 ACROSS CAUSEWAY TO EAST OSYOOS + BREAKER**| 650  | 650         |      |      |      |      |      |      |      |       |
| **25 KV TIE TO ANARCHIST/BRIDESVILLE**| 2,000  | 2,000       |      |      |      |      |      |      |      |       |

| SIMILKAMEEN                      |            |             |      |      |      |      |      |      |      |       |
| **KEREMEO'S FEEDER**             | 600        | 600         |      |      |      |      |      |      |      |       |

| BOUNDARY/GRAND FORKS             |            |             |      |      |      |      |      |      |      |       |
| **FEED BALDY & ANARCHIST @ 25 KV FROM ROCK CREEK & CONVERT BALDY TO 25 KV**| 650   | 650         |      |      |      |      |      |      |      |       |
| **W. TRAIL VOLTAGE CONVERSION**  | 300        | 1,450       | 1,150 | 300  |      |      |      |      |      |       |
| **PATTERSON 25 KV FEED**         | 300        | 300         |      |      |      |      |      |      |      |       |

| SOUTH SLOCAN                     |            |             |      |      |      |      |      |      |      |       |
| **PASSMORE FEEDER UPGRADE**      | 950        | 950         |      |      |      |      |      |      |      |       |
| **PLAYMOR - TARRYS FEEDER UPGRADE**| 1,500   | 1,500       |      |      |      |      |      |      |      |       |

| CRESTON AREA                     |            |             |      |      |      |      |      |      |      |       |
| **CRESTON DIST FEEDER UPGRADES RELATED TO LAMBERT**| 4,000  | 4,000       | 2,000 | 2,000 |      |      |      |      |      |       |

| GENERAL                          |            |             |      |      |      |      |      |      |      |       |
| **SMALL CAPACITY IMPROVEMENTS (UNFORSEEN PRIMARY & SECONDARY VOLTAGE PROBLEMS, NEW OPERATIONAL SWITCHES)**| 3,000  | 3,000       | 500  | 500  | 500  | 500  | 500  | 500  | 500  | 500  |

| SUBTOTAL - DISTRIBUTION GROWTH   | 44,661     | 57,811      | 6,150 | 11,732 | 9,590 | 4,935 | 5,976 | 7,085 | 5,344 | 7,000 |

| DISTRIBUTION SUSTAINING          |            |             |      |      |      |      |      |      |      |       |
| **DISTRIBUTION CONDITION ASSESSMENTS**| 2,700  | 3,050       | 350  | 450  | 450  | 450  | 450  | 450  | 450  | 450  |
| **DISTRIBUTION REHABILITATION**  | 9,000      | 10,500      | 1,500 | 1,500 | 1,500 | 1,500 | 1,500 | 1,500 | 1,500 | 1,500 |
| **ROW RECLAMATION**              | 3,390      | 3,955       | 565  | 565  | 565  | 565  | 565  | 565  | 565  | 565  |
| **DISTRIBUTION LINE REBUILDS**   | 4,500      | 5,270       | 770  | 750  | 750  | 750  | 750  | 750  | 750  | 750  |
| **SMALL PLANNED CAPITAL**        | 3,210      | 3,645       | 435  | 535  | 535  | 535  | 535  | 535  | 535  | 535  |
| **PCB PROGRAM**                  | 4,500      | 4,600       | 100  | 750  | 750  | 750  | 750  | 750  | 750  | 750  |
| **FORCED UPGRADES AND LINE MOVES**| 3,000  | 3,500       | 500  | 500  | 500  | 500  | 500  | 500  | 500  | 500  |
| **DISTRIBUTION URGENT REPAIRS**  | 3,000      | 7,000       | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 |
| **GLENMERRY UNDERGROUND**        | 2,000      | 2,300       | 300  | 2,000 |      |      |      |      |      |      |

| SUBTOTAL - DISTRIBUTION SUSTAINING| 38,300     | 43,820      | 5,520 | 8,050 | 6,050 | 6,050 | 6,050 | 6,050 | 6,050 | 0     |

| TOTAL - DISTRIBUTION              | 82,961     | 101,631     | 11,670 | 19,782 | 15,640 | 10,985 | 12,026 | 13,135 | 11,394 | 7,000 |

November 26, 2004
## Telecommunications, SCADA and Protection Projects

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Maintenance of Substations and Transmission Lines

1 Introduction

For the entire period since the 1998 Master Plan, the FortisBC workforce has maintained the system in a Performance Based Regulation (PBR) environment utilizing an Asset Management philosophy and decision structure. Since that time, the Transmission and Distribution asset base has grown from $319 million in 1998 to $470 million at the end of 2003, driven by demand in specific regions. This increase in asset base reflects complete replacement of selected portions of the system where demand growth has been highest, rather than increased expenditures across all components in all areas of the system. This has resulted in a system that has both new state-of-the-art equipment and design, and old equipment and infrastructure that has been kept running without upgrades to serve areas of static or declining demand.

Several maintenance strategies and objectives are discussed in this chapter. The ability to apply different strategies to different classes of equipment defines FortisBC’s maintenance program for the future. Next, the effect of the condition of the installed base on the near-term maintenance program is evaluated in order to define the investment necessary to bring the installed base to an overall condition from which a “levelized” maintenance program can then be established to keep pace with needs of the system.

Finally, the effect of the above investment strategy is reflected in a long-term capital investment profile and benchmarked against available data.
2 Maintenance Strategy

There are two basic maintenance modes: reactive and proactive. When in reactive mode, the best an organization can do to have an effect on reliability indicators (SAIFI, SAIDI, CAIDI) is in the speed of response. However, once an organization adopts a proactive maintenance approach, a variety of maintenance strategies are available that will each incrementally improve reliability indicators, but with corresponding increasing effort and cost.

Not all equipment failures have similar effects on the reliability indicators. Therefore, equipment should be separated into various categories, with the categorization criteria being that a different maintenance strategy applies to each category of equipment. This philosophy traces its roots back to Reliability Centred Maintenance\(^1\) (RCM) as a foundation, but with the realization that there are several maintenance strategies available to deliver optimal reliability/cost performance.

2.1 Maintenance Strategies

In general, the two most basic approaches to maintenance are an unplanned approach (corrective, fix when broken) and a planned approach that offers many decision trees of how and when to fix equipment before it breaks down. A corrective maintenance strategy can not deliver equal reliability at the same cost as a planned maintenance strategy. The reason for this is twofold: first, a successful corrective maintenance strategy requires that sufficient resources (both labour and equipment) must always be on hand to handle the higher frequency of unanticipated failures (because planned maintenance reduces failure rates), and second, planned maintenance cost-effectively extends the service life of certain equipment, thereby reducing capital replacement costs.

Therefore, the two primary motivations for a utility to depart from a strategy of a simple corrective program is to cost-effectively improve (or prevent from degrading) reliability indicators, and to reduce overall costs to the ratepayers. Once the decision is made to
move towards a planned maintenance program, a variety of techniques are available as shown in Figure 2.1:

![Figure 2.1 Maintenance Strategies]

Figure 2.1 Maintenance Strategies

The easiest move away from a simple corrective maintenance strategy is to plan and initiate the adoption of a time-based strategy. This approach has been attempted in the past and has more often than not, failed to achieve the levels of success that had been expected. One reason for this is that when moving from an unplanned program to a time-based planned program, more maintenance personnel are not usually added, or not enough are added. Even if enough personnel are added to address a given planned maintenance program, these programs have failed in the past because unplanned failures do not stop occurring, and resources are re-assigned to urgent corrective tasks. The result is that the time-based planned maintenance program gets further and further behind each passing year. This has driven the development of techniques that modify planned maintenance programs from doing a task every-so-often, to intelligently being able to skip that task for one or more periods based on knowledge of the equipment’s condition and function.
An additional complication is introduced if records are not kept up-to-date, and the confidence to determine when a piece of equipment was last maintained is lost. In these situations, significant effort is required to re-capture that history. A computerized maintenance management system (CMMS) is a useful tool to prevent the loss of important equipment history, but is usually not enough to guarantee the success of a time-based planned maintenance program. Therefore, it has been recognized that more sophisticated planned maintenance strategies must be employed to advance from the shortcomings of the past.

A powerful technique to design the most effective maintenance program for a particular industry is Reliability Centered Maintenance (RCM). Reliability Centered Maintenance was developed in response to the needs of the aviation industry and the creation of the 747 aircraft which would have been unprofitable to operate if maintenance was performed by the conventional methods of the time. The adoption of Reliability Centered Maintenance resulted in significant cost reductions in labour, material and inventory. The method was soon adopted by the nuclear power industry for many of the same reasons.

The electrical transmission and distribution industry has adopted Reliability Centered Maintenance, but not to the same degree as the classical Reliability Centered Maintenance approach in the airline and nuclear industry. The classical Reliability Centered Maintenance approach analyzes the specific function of each component in the larger system and determines the consequences of failure, and thereby designs a customized maintenance approach for each piece of equipment in the system, based on its specific function and criticality. This is a time and effort intensive exercise to apply to each piece of equipment in a system. Instead, the electrical transmission and distribution industry has classified the equipment into various categories, and through knowledge of equipment failure modes gained over a long history, determined the best maintenance strategy to apply to a given class of equipment. Thus, the Reliability Centered Maintenance exercise becomes one of implementing the correct maintenance strategy for a given class of equipment as depicted in Figure 2.2. This can also include relying on corrective (reactive) strategies for some equipment.
Figure 2.2 Application of Reliability Centered Maintenance in Maintenance Strategy Selection

Planned Maintenance strategies can be broken down into two categories, preventative strategies and predictive strategies. Preventative strategies rely on performing maintenance according to some frequency that is determined by something other than the actual performance characteristics of the equipment. These maintenance drivers could be things such as time (maintain every given time period), failure finding (testing for operational functionality, for example protective relay testing, or cycling of disconnect switches), condition other than actual performance characteristics (maintain after a pre-determined number of operations), or even run-to-failure. Although these strategies are useful for some types of equipment, there are inherent shortcomings when these strategies are applied to critical equipment because they do not consider the actual condition of the equipment. This can result in maintenance being performed when it is not required, or more importantly, unanticipated failure of equipment that could have been detected and prevented.

Predictive maintenance strategies rely on condition based information to schedule maintenance activities. This is particularly useful for critical equipment in electrical
transmission systems because knowledge of equipment condition can be used to perform “just-in-time” maintenance and reduce failure rates.

Diagnostic procedures that do not require equipment to be taken out of service are key to predictive maintenance programs, because the key point is not having to take the equipment out of service in the first place. Some examples of techniques used for predictive maintenance strategies are:

- Oil analysis
- Infrared thermography
- Partial discharge and corona detection

Other diagnostic techniques can be used when the equipment is removed from service for preventative maintenance procedures. Useful predictive tasks can be derived from the data gathered, but an equipment outage is required:

- Power Factor and dielectric loss measurements
- Breaker timing and contact resistance

It should be recognized that it is acceptable to have several maintenance strategies for a given equipment category, but pre-defined targets should be set for the level of each maintenance strategy. In this way, if targets are being met, they can be adjusted to determine the most cost effective maintenance mix for a given class of equipment. For instance, in the case of disconnect switches, it may be acceptable to annually employ some predictive maintenance (infra-red scanning a percentage of the population), some preventative maintenance (refurbishing switches with excessive operations), and accepting a small percentage of reactive maintenance (one random switch failure per year). In this way, the most cost effective mix of maintenance effort can be evaluated by performing a cost-benefit analysis of the amount of maintenance versus the component’s contribution to system reliability indicators.
2.2 Equipment Categories

The equipment considered in this evaluation is confined to the transmission system, defined as including those assets from the fence of the generation substations to the low side of the distribution substation transformers. This transmission system equipment is further divided into three categories, based on criticality of failure and its function in the system. Each category of equipment demands a different approach to its maintenance in order to get the best balanced level of effect on reliability indicators versus maintenance effort and investment.

Category 1 equipment is defined as that equipment that will cause an immediate degradation of a reliability indicator upon its failure, and whose condition can be reasonably determined through existing standard routine diagnostic procedures. This equipment is almost exclusively that which actually carries transmission system current (except in the case of line structures). The following equipment is in this category:

- Circuit breakers
  - Types: Bulk Oil, Minimum Oil, SF₆, Vacuum
  - Components: Contacts and Media, Bushings
- Transformers
  - Types: Power (Two-winding, Three-winding, Auto) and oil-filled current transformers and potential transformers
  - Components: Oil, active component, bushings, tap changer
- Lines
  - Types: 63 kV, 138 kV, 161 kV, 230 kV
  - Components: Poles, vegetation
- Mobile substations

The proposed target for Category 1 equipment is no reactive maintenance, with all equipment failures being anticipated and prevented by suitable predictive (condition-based) techniques. There are some pieces of equipment whose failure can have the same effect on reliability indicators as Category 1 equipment above, but for which no standard diagnostic procedure is in place to predict failure, or equipment where failure can occur
sporadically, even immediately following inspection. Examples of this type of equipment include transmission line and bus support insulators and disconnect switches. There are continuing advances in diagnostic techniques that may lend themselves to predictive condition analysis for this equipment, and as those techniques become accessible, this equipment will be incorporated into Category 1. Until that time, this equipment is placed in Category 2.

Category 2 equipment covers the broadest range. The following criteria identify a piece of equipment as belonging to Category 2:

- Non-power current carrying equipment that supports Category 1 equipment, but whose failure would not cause an immediate outage to the Category 1 component, or
- Power current carrying equipment for which no predictive diagnostic techniques can be used to predict incipient failure, or
- Non-power current carrying equipment whose failure would not cause an outage, but would prolong the extent of the next outage.

The following equipment is in this category:

- Non oil-filled current and voltage protection and metering transformers
- Protection and metering relays
- Shunt capacitors and harmonic filters
- Line and station insulators
- Disconnect switches
- Bus bar and line conductor
- Wiring systems
- Surge arrestors
- Battery banks, back-up power systems, and station service power (including emergency generators)
- Communications (Power line carrier, microwave, and fibre)
- Fire protection systems
- Lighting
This equipment is best placed in a time or frequency based preventative maintenance program, specifically tailored to each type of equipment in the category. Some amount of reactive maintenance should be expected in this category, as some equipment displays random failure frequency, and may fail immediately after being tested. Therefore, testing should be used as a means of validating operation only in cases where the equipment has not been called upon to operate since the last time or frequency testing cycle.

Category 3 equipment contains all other equipment and facilities not found in Category 1 and/or Category 2. The maintenance regime in this category is one of reactive maintenance, or where the period of time or frequency based preventative maintenance is greater than ten years. The equipment and facilities in this category are:

- Station ground grids
- Station surface conditions
- Fences, buildings and structures
- Access roads
- Other civil works (berms, etc.)

This categorization strategy is only applicable when the particular equipment is within its useful service life window since initial installation or last life-cycle rehabilitation. Typical useful life windows for equipment are:

<table>
<thead>
<tr>
<th>Equipment</th>
<th>Life Window</th>
</tr>
</thead>
<tbody>
<tr>
<td>Breakers</td>
<td>35 years</td>
</tr>
<tr>
<td>Transformers</td>
<td>40 years</td>
</tr>
<tr>
<td>Communications</td>
<td>20 years</td>
</tr>
<tr>
<td>Protection and Control</td>
<td>30 years</td>
</tr>
<tr>
<td>Buildings</td>
<td>50 years</td>
</tr>
<tr>
<td>Substation civil and grounding</td>
<td>30 years</td>
</tr>
<tr>
<td>Transmission poles and insulators</td>
<td>50 years</td>
</tr>
</tbody>
</table>

After a piece of equipment reaches the end of its service life, a comprehensive evaluation of that piece of equipment should be conducted. There are three outcomes to the evaluation: equipment replacement, life-cycle rehabilitation, or a re-assessment of remaining life. This should be considered outside the normal maintenance requirements of the equipment.
3 Demographics of Equipment

The data in this section is taken from the most recent FortisBC equipment assessment database. The methods of collecting and managing this information are not tightly coordinated or cross-referenced and would benefit from the utilization of a Computerized Maintenance Management System (CMMS). All Category 1 equipment and specific Category 2 and 3 equipment that could benefit from structured programs addressing that class of equipment is discussed. The rest of the equipment in these categories is addressed through the substation condition assessment program where specific deficiencies are identified and corrected.

3.1 Category 1 Equipment

3.1.1 Transformers

The chart in Figure 3.1 shows the age of the FortisBC transformer population base compared to BC Hydro. BC Hydro is chosen as a comparable utility because although it is roughly ten times larger than FortisBC, the two companies share many characteristics including:

- Similar regulatory environment
- Main resource is hydro electricity
- Sparse load distribution over the majority of the service area with one major load growth center located away from majority of generation

The total population of transformers for Figure 3.1 was 89 in the case of FortisBC, and 700 in the case of BC Hydro, again reflecting a rough ten to one ratio. The figure shows an interesting crossover at about 25 years, where each company has 66% of their equipment older than this age. What is of particular concern to FortisBC is that there is roughly twice as much equipment as BC Hydro older than 40 years and still in service. There are several reasons why this particular situation may have come about, but the result is that FortisBC is faced with a higher amount of equipment replacement or refurbishment given that the equipment design life is roughly 40 years.
The linear projection is based on a maximum useful life of 40 to 45 years for the average transformer. A transformer built to CSA standards is designed to have a useful service life of 20 years if it is continuously loaded to nameplate thermal capacity. After this time, the cellulose insulation will have degraded to the point of losing the mechanical and electrical qualities necessary for reliable operation. In a utility application, especially for load serving purposes, transformers rarely go into service at their full rating and are never continuously loaded at maximum. Exceptions to this are generator step-up transformers and transformers at terminal stations that serve as inter-utility tie points or on congested transmission paths. However, for most transformers in load-serving applications, the useful thermal life is typically between 40 and 45 years. Some transformers may be exceptionally lightly loaded through their lifetimes, and do not suffer thermal end of service life, but rather mechanical deterioration. This segment of the population is reflected by the small percentage older than 45 years in the linear extrapolation.
3.1.2 Breakers

The chart in Figure 3.2 shows the breaker age distribution. The total population of breakers rated at 60 kV or greater is 98 with 31 SF$_6$ breakers, 14 bulk oil breakers and 53 minimum oil breakers. The age distribution of the breaker population is remarkably good, and is not a major driver of re-investment requirements in this five year window because only about 15% of the breakers are 35 years of age or older. There is a caveat in that there is a small population of breakers that are over 55 years old. As with transformers, breakers will have a portion of the population that will exceed the intended 35-year service life because of relatively light duty and because of their location in the system, require limited interrupting capability. Again, general mechanical deterioration will govern the need to replace these typically bulk oil breakers, some of which can remain in service for 50 years. This prolonged life expectancy is unique to bulk oil breakers, and as discussed below, probably is not applicable to SF$_6$ and minimum oil designs. Therefore, as the bulk oil breakers get phased out, the “tail” of the “linear” trend line in Figure 3.2 will be truncated at least ten years earlier than it is now.

The most aged breakers are of the bulk oil variety and have significant over-capacity built in by virtue of their design. However, although the breakers may have sufficient fault
interrupting capability, this is offset by gradual mechanical deterioration and the environmental risk associated with bulk oil equipment, and their replacement is a prudent step.

Industry experience is indicating that the minimum oil and SF₆ technologies do not possess the same longevity as their bulk oil counterparts, and will require replacement/refurbishment at a greater rate as their design life is surpassed. Consequently, there are two distinct technological life cycles that are both coming due at the same time (long-lived bulk oil, and shorter life minimum oil and SF₆), and both driving the need for capital re-investment in breakers. In addition to the 5% of breakers that are currently in service beyond their design lifetime (all of the bulk oil design), approximately another 10% of the breaker population will reach or exceed their design life over the next ten years. These will be both minimum oil and bulk oil design. The installed base of SF₆ breakers is relatively young and will not start reaching their intended design lifetimes until at least 2020.

3.1.3 Transmission Lines

The FortisBC asset database shows capital investments in various assets starting in 1957. The 48 years of data compares well with the overall expected life of transmission line assets; however, this does not completely capture the end of service life asset replacement impacts which would probably start impacting within the next five or ten years. The following lines predate the start of the 1957 asset record, and their construction dates are taken from Mouat³:

- 9 & 10 Lines (Warfield to Oliver), 1919
- 49 Line (Huth to Summerland), 1921
- 27 Line (Corra Linn to Salmo), 1928
- 20 Line (Tadanac to Salmo), 1931
- 44 Line (Oliver to Osoyoos), 1936
- 28 Line (Upper Bonnington to the City of Nelson), 1938
- 31 and 32 Lines (Crawford Bay to Creston), 1953
There are obviously lines in existence that pre-date the asset record, however they have been substantially rebuilt since they were first installed. In fact, from the list above, both 44 Line and 49 Line have been significantly replaced in 2000 and 1998 respectively. The other lines above are in need of significant investment to replace their function.

The investment in transmission line assets since 1957 is shown in Figure 3.3. The investment values have been normalized to 2004 dollars using Canadian CPI. Figure 3.3 includes both original and sustaining investments.

![Figure 3.3](image)  
**Figure 3.3  Transmission Line Investment**  
(normalized to $2004)

The graph shows that there was practically no investment in the system for a decade between 1967 and 1976, and this is reflected in the substation investments as well. The recent capital investments can be seen in context as “historic” investments.

From a maintenance perspective, it is more useful to show the sustaining capital that has been applied to the asset after the initial investment. This is shown in Figure 3.4, again normalized to 2004 dollars and with the initial capital costs stripped out. The large investments in 1994, 1998 and 2000 were the rebuilds of 43 Line, 49 Line and 44 Line and are considered sustaining capital for three reasons: the lines were pre-existing, their function was largely the same both before and after investment, and most condition related issues were addressed by the investments. It is interesting to note that these large
investments are not reflected in recent base capital budgets, nor do the “sustaining” or “rehabilitation” categories of the recent budgets reflect the amount of capital actual flowing into the line assets. This is discussed further in Section 4.0. Another point to note is that over the last 25 years, sustaining capital has outstripped new capital.

The long term (57-04) average annual sustaining capital has been approximately $1.4 million but this includes a decade of no investment. In the last 25 years, the average annual sustaining capital investment has been 50% higher or approximately $2.2 million annually. Although it may appear that the three recent line rebuilds skew the recent average, this data should not be treated as an anomaly because it is representative of future trends. This will be discussed in greater detail in Section 4.1.

3.1.4 Mobile Substations

Mobile substations represent both contingency response capability and the ability to plan de-energized work in distribution substations. There has been a practice to keep a fleet of four mobile substations, two in the Okanagan and two in the Kootenay. The mobile substations were not interchangeable for all applications because of the secondary voltage requirements. The Okanagan has virtually no 2.4 kV distribution, which was common until
recently in the Kootenay. This effectively meant that the two mobiles in each region normally did not move outside their region.

The oldest mobile in the fleet is the 6.5 MVA unit in the Kootenay region with the equipment built in 1957. Several factors are leading toward its retirement. These factors are the advanced deterioration of the mobile trailer and the fact that most of the 2.4 kV distribution voltage level in the Kootenay region had been converted to other voltage levels. The development of the 161 kV system in the boundary system will eventually remove the need for the 2.4 kV installations and the existing 10/12 MVA mobile (the only mobile left with 2.4 kV secondary capability) would be sufficient to cover any emergencies until the system is converted. The planned 2.4 kV distribution loads will be converted as part of the development of the boundary area eliminating the need for the 2.4 kV mobile supply. Nevertheless, a second mobile unit must be considered for post-contingency support in the Kootenay region, especially since many of the older distribution substations may be undergoing rehabilitation that requires the use of the other mobile.

The 10/12 MVA mobile that remains is also in need of improvements because its design reflects past practice of a fused rather than breaker protected primary connection.

Both Okanagan mobile substations are in good condition and have many years of useful service life ahead.

In situations involving multiple contingences, a small fleet of mobile substations owned by other entities may be available for short-term deployments. An active contact list is maintained, but FortisBC has often offered the use of the spare mobile rather than been in the position of having to rent a mobile substation.
3.2 Category 2 and Category 3 Equipment

Although protective relaying and communications equipment is important to the operation of the system, special consideration of this equipment is not included in this section of the system development plan for two reasons. Firstly, there is an overall project that is addressing communications system-wide, and secondly, many of the problematic relaying situations are being addressed by the investments associated with the South Okanagan Supply Reinforcement Project. The items considered in this section of the plan satisfy the following criteria: they are not captured by other planned projects and they have a significant impact on the safety and operability of the system. A structured investment program that is presented below addresses these issues. Two categories of equipment satisfy these criteria: disconnect switches and substation infrastructure (ground grid, buildings).

3.2.1 Disconnect Switches

In today’s system, disconnect switches are still the pieces of equipment that receive the greatest amount of interaction with the operating personnel. The system is not fully automated, and manual switching is still both required and commonplace. Table 3.1 below displays the population and type of switches in use on the transmission system.

There are switches of many different vintages, and aside from relying on specific failure or trouble reports or thermographic imaging while in operation, there is little that can be done to predict or prevent failures. The switches typically have far greater current ratings than their application, so thermal imaging shows loose connections reasonably well against a cooler background. However, the most common problem with switches is misalignment and this must wait until the circuit can be de-energized before the problem can be rectified. If this problem is detected when the switch is being operated for another maintenance procedure, it is frequently too late or time consuming to coordinate necessary upstream isolation to isolate the switch for maintenance. Misalignment tends to be more tolerated but less common on breaker isolating switches. The greater tolerance stems from less frequent operation, and the lower frequency is because of better alignment of breaker and bus
support structures as compared to transformer and line applications. The substation condition database has identified 20 switches in “priority” applications that are in sub-optimal condition or should be replaced because of their age and specific application.

**Table 3.1 Population and Type of Disconnect Switches**

<table>
<thead>
<tr>
<th></th>
<th>60 kV</th>
<th>138 kV</th>
<th>170 kV</th>
<th>230 kV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Manual Switches</td>
<td>183</td>
<td>73</td>
<td>19</td>
<td>42</td>
</tr>
<tr>
<td>Motor Operated Switches</td>
<td>34</td>
<td>27</td>
<td>10</td>
<td>15</td>
</tr>
<tr>
<td>Fused Switches and/or removable fuses</td>
<td>37</td>
<td>1</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

There have been some switches that have recently failed when called on to operate, but this appears to be manufacturer-specific at this time with a limited installed base. The remaining switches from that manufacturer have been visually inspected, and there is no further remedial action program for remaining switches from the affected manufacturer.

Many remote operation switches are now used for line sectionalizing purposes where there are sources at both ends of a line and a number of distribution substations along its length. In the recent past, many lines were only fed from one end (radial lines), and the substations along the line typically had only fused switches protecting the distribution transformer. With the recent system improvements, many lines are now looped, and a jump in reliability can be realized by installing remotely operable switches to sectionalize faulted portions of lines. This is the next step until in/out breakers can be installed at the substations, followed by small ring bus architectures. This level of system security is still some way off, but as mentioned the implementation of remotely operable disconnect switches is the next step on that path.

With all the above taken into account, a program to install remotely operable switches in key locations will help improve reliability. In many cases, this program would also capture switches that have been identified for replacement because of their age, condition and
application. A targeted replacement program would address the rest of the switches identified for replacement. This is captured under the switch additions and 20/27 Line operating switch projects in the Transmission Line Sustaining project for a total of $300,000 per year.

3.2.2 Substations (ground grids, surfaces and structures)

Both the Kootenay and Okanagan regions have substations and sites that go back many decades. However a key difference between the two areas is that demand in the Okanagan area has increased steadily over time, whereas, the Kootenay loads are below historical peaks at many individual distribution substations. This trend has resulted in Okanagan locations undergoing periodic rebuilds to add capacity, whereas more Kootenay locations are “frozen in time”. With no demand to drive upgrades, more Kootenay stations typically are rebuilt when condition degradation results over time and reliability or safety is unacceptably compromised. For example, there are eleven Kootenay stations that fall into this category as compared to only four Okanagan stations.

Another characteristic of these old stations is that they do not reflect modern standards, and what was once acceptable and common practice is now lacking as compared to recently built stations. Station grounding is an important example of this trend. New modelling software and testing methods are showing that the old stations do not have adequate ground grids to limit step and touch potentials in all locations. This is a difficult feature of a station to upgrade with undertaking an overall rehabilitation. Other typical improvements that are necessary at these older substations include replacement of timber supports with steel members, redesign of bus bar supports and clearance requirements, security improvements, surface rehabilitation (vegetation control, drainage and crushed rock), mobile substation access and improvements to control buildings or cubicles. For substations where there is no appreciable demand growth to drive improvements via capacity upgrades, a program to address the condition of the older “legacy” substations is proposed to bring them up to present day standards. The cost for this program is Ground Grid Upgrades for $250,000 per year for five years in the Station Sustaining section of the System Development Project budget.
4 Review of Past Practice

4.1 Capital Program

The 1998 Master Plan identified both a five-year and ten-year projection of transmission level maintenance-related capital expenditures, but did not include separate identification of distribution level expenditures. At the time, the distribution concerns were being addressed at a regional level, and sustaining investments were most likely incorporated into feeder and demand-driven distribution substation upgrades.

The transmission level maintenance capital was separated into terminal station and line categories for both the Kootenay and Okanagan regions. The system plan did not identify individual projects. The budget planning consisted of two project categories: the first category was based on the past year’s unplanned (emergency capital) expenditures, and this amount was forecasted into future years. The second category included condition-based jobs that had been discovered in the last or present year, but did not require immediate investment. The jobs were then separately identified and planned as rehabilitation projects in the coming years. Neither of the project categories were supported by a structured program that looked at the maintenance needs of the system in a planned fashion. In the case of the first category, the expectation was that the coming years’ failures would roughly approximate the past years’ failures, and in the case of the second category, a problem had to be known before it was addressed. Although it was a reactive program, there were some attempts to modify future years’ budgets based on the expectations of system condition. For instance, the 1998 Master Plan budget reflected a reduction in Kootenay Line maintenance when the Kootenay 230 kV System Development Project was due to be completed (in 2002). Table 4.1 shows these trends.
As the 1998 Master Plan was being prepared, a transmission line condition assessment program was initiated. The 1998 budget did not contain any targeted line rehabilitation, but based on early indicators from the condition assessment, it was recognized that transmission line investment would have to increase. The condition assessment program focused on several of the oldest lines first, and it was thought that these would represent the worst of the population. Once the oldest lines were addressed, it was believed that the rest of the population would not require as much capital to stabilize. This belief is reflected in the 1998 Master Plan capital projection, where the 1999 through 2002 budgets are approximately double the 1998 actual expenditures. Starting in 2003, the budget goes back down to the historic levels of 1998 and before. The program was intended to have an eight year cycle, and this is reflected by the increase in the 2006 budget, when the oldest lines were due to be re-assessed. However, after the first two years of condition assessment, it was apparent that the bulk of the asset base was in far worse condition than previously thought, and that a doubling of the budget would be necessary to stabilize the lines within the desired eight year cycle. In the capital constrained environment that existed, the most prudent course of action was the stabilization of the lines to less than the full eight year
cycle, with an accompanying commitment to re-visit the condition related issues as their term came up.

In any given year it has been difficult to complete all budgeted Kootenay distribution substation sustaining projects because the actual expenditures are below budget in all years, yet it is the Kootenay substations that continue to show the most action items during substation condition assessments. This is indicative of a need for a structured program to address the entire population of distribution substations rather than attempting to do numerous small projects at many locations. Notwithstanding this apparent annual under spending, there is projected growth of distribution substation sustaining capital expenditures in the years 2004 to 2008. This is driven partly by the elimination of the “Extraordinary” category of projects, but also by the introduction of the sustaining programs. In fact, if past sustaining extraordinary capital projects were included in Table 4.1, the past annual expenditures would be much closer to the future budgeted amounts. The South Okanagan System Reinforcement Project and the Kootenay 230 kV System Development Project corrected action items in many terminal stations; now those terminals (Coffee Creek, Crawford Bay, Princeton) not affected by those or other major projects must be addressed. Because the development plan of the Boundary area removes many of the stations that are of concern. The scope of work for all of the stations has been significantly reduced.

4.2 Operating and Maintenance (O&M) Program

The deployment of the available maintenance resources within FortisBC is difficult to track because of ineffective task identification in time and equipment tracking systems. The enterprise level platform to track Operating and Maintenance has changed twice within the last seven years, and this has created inconsistencies in time tracking methods. A dedicated system integrated into, but separate from, the enterprise level platform should be implemented to start building equipment history and tracking deployment of maintenance resources.

Some data is available for the Okanagan region based on a stand-alone time tracking initiative that was pursued internally. This data has been analyzed annually, and will be
used as a proxy for the activities in the Kootenay Region. Reports for 2001, 2002 and 2003
[3] have been analyzed for corrective/preventative utilization and activity by equipment
category.
5 Effect on Future Sustaining Capital and Programs

5.1 Transformers and Stations

This section discusses the need for addressing certain transformers within the existing population. This need arises from replacement within the growth capital budget, some rehabilitation program in the sustaining budget, or by removing the need for the substation or transformer altogether.

There are four major drivers that influence the structure and sequence of sustaining investments for the transformer population.

1) transformer condition as indicated by dissolved gas analysis (DGA), and electrical tests such as Doble tests;
2) transformer loading compared to nameplate capacity;
3) transformer age (>55 years) and mechanical condition; and
4) substation age and application.

Once all these factors are known, a sequenced program can be designed that addresses the known problems in a manner that both uses capital funds efficiently, and can achieve a desired investment profile over time. As a starting point, it is assumed that the desired investment profile is flat (constant investment over time).

The transformer condition as indicated by dissolved gas analysis is tracked in the Transformer Oil Analyst (TOA) database program. The results of individual tests are entered into the database and can be trended, analyzed and archived. The Transformer Oil Analyst program also provides some “expert system” suggestions, and classifies the equipment into four categories, ranging from 1 (good) to 4 (address immediately). There are currently seven transformers in the Transformer Oil Analyst database as condition 4, and a further eight that have been at condition 4 in the recent past. Table 5.1 identifies the current condition 4 transformers and the suggested actions to address the individual units. Most of the poor dissolved gas analysis readings in Table 5.1 are caused by oil migration from the tap-changing compartment to the main tank. This in itself won’t cause imminent transformer problems, but the high gas readings could mask problems due to other more
serious causes in the main tank. The Westminster Transformer 1 could fall into this category.

A trend that has been noticed is that most Moloney transformers between 10 and 20 MVA and manufactured between 1970 and 1985 show gas and oil migration from the tap-changer compartment into the main tank. Rehabilitation for these transformers and tests for their condition is suggested to address the Moloney transformers.

Table 5.1 – Transformer Oil Analyst Current Condition 4 Transformers

<table>
<thead>
<tr>
<th>Location</th>
<th>TOA Condition</th>
<th>Action / Analysis</th>
<th>Timeframe</th>
</tr>
</thead>
<tbody>
<tr>
<td>Osoyoos Transformer 2</td>
<td>4</td>
<td>Recondition LTC and barrier between Main tank and LTC to prevent the migration of gasses between the tank and LTC. (DGA most likely tap-changer and load related)</td>
<td>2005</td>
</tr>
<tr>
<td>(##1399)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Grand Forks Transformer</td>
<td>4</td>
<td>Install new conservator for the LTC and separate the transformer conservator from the LTC. Treat the oil with Fuller’s earth and degas the transformer. Sample for gases at 3, 6 and 9 months and if all is normal, put into an annual oil testing program.</td>
<td>2005</td>
</tr>
<tr>
<td>(##12530)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Westminster Transformer</td>
<td>4</td>
<td>Treat oil immediately. Replace in 2005. The gassing and cellulose deterioration in this transformer are significant (DGA is possibly tap-changer related, but may have other problems, careful internal examination required)</td>
<td>2005</td>
</tr>
<tr>
<td>(##20142)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oliver Transformer 2</td>
<td>4</td>
<td>Oil Treatment immediately and remove from service after terminal conversion in 2008 (possible spare) (DGA indicates internal arcing, internal examination required) This transformer has also had a fault in it in 1998 which was not completely isolated.</td>
<td>2005/2008</td>
</tr>
<tr>
<td>(##20153)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Trout Creek Transformer</td>
<td>4</td>
<td>Known gas migration from tap changer. Seal the LTC and upgrade the LTC to 1200 amp to improve the operation and maintenance of the LTC.</td>
<td>2005</td>
</tr>
<tr>
<td>(##20258)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Osoyoos Transformer 1</td>
<td>4</td>
<td>Recondition LTC and barrier between Main tank and LTC to prevent the migration of gasses between the tank and LTC. (DGA most likely tap-changer and load related)</td>
<td>2005</td>
</tr>
<tr>
<td>(##20274)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pine Street Transformer</td>
<td>4</td>
<td>Recondition LTC and barrier between Main tank and LTC to prevent the migration of gasses between the tank and LTC. (DGA most likely tap-changer and load related)</td>
<td>2005</td>
</tr>
<tr>
<td>(##20356)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 5.2 identifies those transformers that have shown gassing problems in the recent past, and have either been repaired, or are “band-aided” and will need attention in the near future.
future. The DG Bell unit is also a Moloney transformer and has been performing well after a recent tapchanger replacement.

There are several transformers for which there were no current results for dissolved gas analysis. It is of some concern that Summerland Transformer 1 (a 1982 Moloney) has caused past concern. It is recommended to either recover the data from previous tests (which are believed to have been done), or collect and analyze oil samples immediately.

### Table 5.2 – Transformer Oil Analyst Recent Condition 4 Transformers

<table>
<thead>
<tr>
<th>Location</th>
<th>TOA Condition</th>
<th>Action / Analysis</th>
<th>Timeframe</th>
</tr>
</thead>
<tbody>
<tr>
<td>6.5/8 MVA Mobile (#1072)</td>
<td>Was 4, now 3</td>
<td>Remove from service when new mobile station is available. The mobile is well past useful life mechanically and electrically.</td>
<td>2006</td>
</tr>
<tr>
<td>AS Mawdsley Transformer 1</td>
<td>Was 4, now 3</td>
<td>Remove from service and refurbish, and spare for Mawdsley Transformer 2 and Crawford Bay Transformer 1.</td>
<td>2006</td>
</tr>
<tr>
<td>Coffee Creek GT’s (#14521,2,3)</td>
<td>Was 4, now 1</td>
<td>Advanced age of units (built in 1933) dictates replacement is the best option with Brilliant Generating Station spare grounding transformer</td>
<td>2008</td>
</tr>
<tr>
<td>Ruckles Transformer 2</td>
<td>Was 4, now 1</td>
<td>Reconditioned and running well, remove from service and use in other location when the Grand Forks 25 kV conversion is completed</td>
<td>2010+</td>
</tr>
<tr>
<td>Crawford Bay Transformer 1</td>
<td>Was 4, now 3</td>
<td>Replace with reconditioned Grand Forks Transformer 1, Mawdsley Transformer 2 or Oliver Transformer 1 when the Boundary area plan is completed. Crawford Bay Transformer 1 has a long history of hydrogen gassing.</td>
<td>2008</td>
</tr>
<tr>
<td>DG Bell Transformer 1</td>
<td>Was 4, now 1</td>
<td>Tapchanger repaired, unit OK</td>
<td></td>
</tr>
<tr>
<td>FA Lee Transformer 4</td>
<td>Was 4, now 3</td>
<td>Ongoing gassing. Perform Fuller’s Earth and vacuum degasification and monitor closely. Continue monitoring monthly.</td>
<td>2005</td>
</tr>
</tbody>
</table>

The second driver for “sustaining” transformer capital investments is related to demand exceeding nameplate capacity. Although these are perhaps more correctly termed “growth” investments, they can sometimes accomplish some “sustaining” goals as well when the improvement is located at an existing, rather than Greenfield, site. There are several sites that fall into this category. The Distribution Planning Manual at Appendix E has identified a number of transformers that must be replaced due to overload. The summary for this is
included for continuity sake and visibility of all of the transformer replacements within the FortisBC service territory.

**Table 5.3 – Transformer Capacity Replacements**

<table>
<thead>
<tr>
<th>Location</th>
<th>Action / Analysis</th>
<th>Timeframe</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crawford Bay Transformer 2, Crawford Bay Transformer 3</td>
<td>Overloaded at 140% in 2005, but very low growth in the area so replace when a 60/13 kV transformer comes available from the recondition program. – 2-6/8 MVA transformers are preferred.</td>
<td>2006/2007</td>
</tr>
<tr>
<td>Ruckles Transformer 1</td>
<td>Overload in 2007/2008. Condition 4 for DGA. Will be removed when the Boundary area plan is implemented.</td>
<td>2007</td>
</tr>
<tr>
<td>Naramata Transformer 1</td>
<td>Overloaded in 2006/2007, the LTC on this unit is inoperable, gassing, power factor of the transformer is significantly deteriorating, and the transformer is 1962</td>
<td>2006</td>
</tr>
<tr>
<td>Huth 4,5,6,7</td>
<td>Overloaded in 2008/9, But Waterford installation will offload all of this in 2005 when it is installed. Salvage Huth transformers in 2006.</td>
<td>2006</td>
</tr>
<tr>
<td>OK Falls Transformer 1</td>
<td>Replace due to loading constraints</td>
<td>2014</td>
</tr>
<tr>
<td>Princeton Transformer 1, Transformer 2, Transformer 3</td>
<td>The T3 transformer is overloaded in 2004/2005 and the gas results are indicating faults in the transformer and migration of gases from the LTC. T1 has gasses migrating from the LTC to the main tank. T2 has very advanced cellulose deterioration. It is a 1957 transformer and it is not required if T1 and T3 are replaced with 138/13kV transformers,</td>
<td></td>
</tr>
<tr>
<td>Sexsmith Transformer 2</td>
<td>Sexsmith T1 will be overloaded in 2009/10 and will require an additional transformer.</td>
<td>2009</td>
</tr>
<tr>
<td>Hollywood Transformer 2</td>
<td>Hollywood T1 will be at capacity in 2007. Install a third transformer at Hollywood in the mobile location</td>
<td>2007</td>
</tr>
<tr>
<td>Recreation Transformer 2</td>
<td>Additional loads in the downtown core (if approved by the city) will require a new transformer. Time lines for this project are variable. 2008 was used to keep the project at the forefront.</td>
<td>2008</td>
</tr>
</tbody>
</table>

Other sites in need of some “sustaining” work that have been addressed by “growth” investment are Rock Creek, Baldy, Midway and Greenwood. For instance, the need for additional capacity at Rock Creek offers an opportunity to relocate the distribution supply source to another location, and eliminate the existing site with its numerous condition and
location related concerns. The development plan for the Boundary area will resolve all these sustaining issues. The transformers and stations that will be addressed are:

- Oliver T1
- Baldy T1
- Midway T1
- McKinney
- Oliver T2
- Rock Creek T1
- Greenwood T1
- Rock Creek T2

The third driver for sustaining transformer capital investment is the replacement of units that are so old that their mechanical integrity has become compromised. For the first five years of this capital plan it is suggested that all transformers older than 55 years be phased out. Table 5.4 lists the transformers manufactured in 1950 or earlier and the suggested courses of action. If the replacement and rehabilitation program recommended in Tables 5.1, 5.2, and 5.3 is adopted, the second five year window of the System Development Plan (2010 to 2014) would see only three transformers being replaced because of age, those being Coffee Creek Transformer 2, Kaleden, and Passmore.

<table>
<thead>
<tr>
<th>Location</th>
<th>Manufacture Date</th>
<th>Action</th>
<th>Timeframe</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ymir Transformer 1</td>
<td>1950</td>
<td>Replace, and scrap Ymir Transformer 1. This enables the elimination of Whitewater substation</td>
<td>2009</td>
</tr>
<tr>
<td>(#12916)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The remainder of the transformers that need attention must be addressed either through rehabilitation or removal. A class of transformers that deserves focussed attention is the fleet of Moloney transformers where a rehabilitation program is proposed. There are 15 Moloney tap-changing transformers in the FortisBC fleet. One (DG Bell T1) has already been repaired, three are in service on the remaining three mobile substations, and the programs described in the tables above address further units (Osoyoos Transformer 1 and Transformer 2, Princeton Transformer 3, Westminster Transformer 1, Pine Street Transformer 1, and Waterford). This leaves two units unrepaired (Castlegar and Kaslo), and one unit for which no dissolved gas analysis data is available (Summerland). At this time, it is a prudent step to schedule the rehabilitation of the Kaslo and Castlegar in 2005 and 2007 respectively. Kaslo is also driven by site condition. The Summerland unit may be
more problematic to rehabilitate because of its size, and may require the full-time deployment of a mobile substation in 2009.

The final driver of sustaining capital for transformers is associated with substations that have been termed “legacy” substations. These are substations that are at least 30 years old that were built to the standards of the day, and have either experienced a decline in load or no load growth. Consequently, the substations have not required capacity upgrades, and tended to be “left behind” in terms of investment. Stations that have already been addressed by this program include Rossland (replaced with Cascade), Slocan (still in service for light industrial load, but largely replaced by Valhalla), and Trail, Warfield, and Wynndel. In some cases, the strategy has been to supply distribution-level voltages from nearby substations, and in other cases, a complete rehabilitation or relocation of the substation. There are still many substations in the system that fall into this category. These are:

- Naramata
- Whitewater
- Hearns
- Kaslo
- Paterson

The majority of these stations mesh well with the activities already described. Naramata, and Kaslo are condition-driven site reconstruction or relocation projects. The common issues are clearance distances to live equipment, mobile substation access, ground grid integrity and overall perimeter security. Both also have transformers in need of attention, thus the opportunity to combine site and transformer rehabilitation.

The Hearns, Whitewater and Paterson substations will be removed from service and their loads supplied by nearby distribution sources. In the case of Hearns, less than 1 MVA of local load remains, and can be supported from either Fruitvale or Salmo. The option to rebuild Hearns in the future will be kept as a contingency plan in case the local light industrial spot load re-materializes. Whitewater substation will be eliminated following upgrading of the Ymir substation transformer, with the possible introduction of a regulator bank to maintain voltage at the ski hill. Paterson will be replaced by 25 kV distribution from Cascade.
Figure 5.1 depicts the resulting overall demographic profile of the FortisBC transformer population in 2010 if the capital plan, including the above described projects, is implemented.

![Transformer Age Distribution in 2010](image)

With the retirement of the Kootenay 6.5 MVA mobile substation, it would be prudent to purchase a second mobile substation for the Kootenay region immediately. This station should be configured with a 63 kV primary for future flexibility. With the consolidation of distribution voltages in the Kootenay area, secondary voltages of 13 kV and 25 kV should suffice. The transformer should be sized between a 12/16/20 MVA or a 24/32/40 MVA depending on the technology being used by the manufacturer. New generation mobile substation transformers have started incorporating advanced thermal insulation, such as Nomex, in order to get transformer size to a minimum. For the Kootenay region, an ultimate capacity of 25 MVA would be sufficient to replace any single unit in the region, but a 24/32/40 MVA unit should be considered if Okanagan support is to be provided. The primary role of the second mobile in either region is to provide post-contingency support in the event the other unit is being deployed for maintenance activities.
5.2 Breakers and Disconnect Switches

Breakers and disconnect switches have been included together in this section because they have been used interchangeably in the past throughout the FortisBC system. Breaker replacements through sustaining capital fall into two categories: those breakers that have reached end of service life, and those that are added to enhance system operation and reliability. The disconnect switch sustaining capital investments are focussed on those applications that are “quasi-breakers”, that is, they are used to re-configure the system, rather than those applications that are used solely for equipment isolation. The former switches must be very dependable, and are used in real-time situations, whereas the latter switches are normally used in maintenance situations where the time and operational pressure is not as great, so more compromises are tolerable in their performance.

Breaker end of service life can be driven by mechanical, electrical, environmental or operational factors. Although a number of old bulk oil breakers are still acceptable from an electrical perspective, the dependability of their mechanical operation comes into question, and their environmental characteristics are no longer acceptable by modern standards. Conversely, some minimum oil breakers may still be mechanically and environmentally sound, but no longer can be depended upon to have the electrical performance that is required.

For this plan, analysis of the breaker population has identified three investment drivers: age, condition indicators, and overall facility rehabilitation. There were no instances found of breakers not being fit for purpose that were not already captured by one of the foregoing criteria. Table 5.5 identifies the breakers that should be addressed in the next five-year investment cycle, the driver, and the suggested action.

As noted in the table, over 50% of the breaker work should be combined with other capital work going on at the station. Breakers at Princeton, Huth, and Oliver should be included as line items in larger project at those stations, while breakers at Westminster, Pine Street, Coffee Creek and Crawford Bay can stand as separate items in the capital budget, but the work on those breakers should be coordinated with other work at the stations, (typically the
transformer rehabilitation program) to make the most efficient use of the mobile substation and crew mobilization.

The work identified in Table 5.5 will address most bulk oil breaker issues for the next ten years, and the installed base of minimum oil and SF₆ breakers should not be experiencing any age related issues for at least another ten years. Therefore, the sustaining capital investments in breakers should hit something of a minimum between 2010-2014 before requiring new investment starting in about 2015.

**Table 5.5 – Existing Breaker Investment Requirements**

<table>
<thead>
<tr>
<th>Location</th>
<th>Condition</th>
<th>Action</th>
</tr>
</thead>
<tbody>
<tr>
<td>Westminster 45L</td>
<td>Sheer age. This bulk oil breaker is over 70 years old, and there are no Doble results to review. Mechanical condition identified in database</td>
<td>2007 (combine with transformer rehab)</td>
</tr>
<tr>
<td>RG Anderson 45L</td>
<td>Age and interrupting capability insufficient for duty. Mechanical condition identified in database</td>
<td>2005 Replace as part of South Okanagan (VAS) Supply Reinforcement Project (no separate budget line item)</td>
</tr>
<tr>
<td>Huth 53A</td>
<td>Age with no supporting Doble date. Bulk oil breaker manufactured in 1936. Mechanical condition identified in database</td>
<td>2007 Replace as part of Huth replacement (no separate budget line item)</td>
</tr>
<tr>
<td>Pine Street 44L</td>
<td>Age with no supporting Doble date. Bulk oil breaker manufactured in 1945. Mechanical condition identified in database</td>
<td>2006 (combine with transformer rehab)</td>
</tr>
<tr>
<td>Coffee Creek 37L</td>
<td>Although not yet triggering replacement solely due to age (built in 1951). Mechanical condition identified in database</td>
<td>2007 (coordinate with transformer work)</td>
</tr>
<tr>
<td>Coffee Creek T1</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Crawford Bay 32L</td>
<td>Aged bulk oil breaker. Mechanical condition identified in database</td>
<td>2008 (combine with transformer work)</td>
</tr>
<tr>
<td>Hedley 43A</td>
<td>Bushing Replacement required and is de-energized, replace with a fuse.</td>
<td>2005</td>
</tr>
<tr>
<td>Princeton 56L</td>
<td>Either condition related issues identified, or Doble bushing test data is misleading, CONFIRM CONDITION.</td>
<td>2005-2009</td>
</tr>
<tr>
<td>Grand Forks Terminal T3 Duck Lake 46L Oliver TA</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Figure 5.2 depicts the projected overall demographic profile of the FortisBC breaker population in 2010 following the investments contained in the capital plan. For the breaker population greater than 25 years old, the FortisBC population will be “under” the modelled life curve, which supports a reduction in sustaining capital investment for approximately five years.

For switching applications, the system is broken down into three categories. The first category is that part of the system where suitable configuration flexibility already exists, and the objective is to keep the equipment functioning (for example 41 Line and 42 Line, or 43 Line). The second category is that part of the system where additional switching capability will yield measurable reductions in outage times to be able to switch around bad portions of transmission line (e.g. 20 Line and 27 Line). The third category is that part of the system that will undergo considerable reconfiguration in the next few years, so although new switching would benefit reliability, the addition would be short-lived (for example, 9 Line and 10 Line). The sustaining capital budget as applied to disconnect switches focuses on that part of the system that is in the second category, where measurable reductions in outage times can be realized with new switches that can be used for system configuration changes. Work in the first category should be addressed via a “minor station capital” budget line item, and work in the third category should be deferred until after the system is reconfigured.
The biggest opportunity for reduction of outage times is in the 20 Line and 27 Line loop. Although full supply of the loop from either end is still problematic because of the poor voltage profile at the opposite end of the line, in N-1 scenarios outside peak loading times, substantial relief can still be provided.

Table 5.6 identifies locations where switch problems and/or switch opportunities have been identified and classifies the switches into one of the three previous categories.

**Table 5.6 – Disconnect/Sectionalizing Switch Investment Requirements**

<table>
<thead>
<tr>
<th>Category 1</th>
<th>Category 2</th>
<th>Category 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Repair switch under maintenance or “minor station capital” budget</td>
<td>Install new switch based on outage time reduction opportunities</td>
<td>Although opportunity/problem exists, defer investment until after system reconfiguration</td>
</tr>
<tr>
<td>Keremeos 43-1 OK Falls Fruitvale Mawdsley Crawford Passmore Joe Rich</td>
<td>Ymir Beaver Park Castlegar Blueberry Creek Tarrys Glenmerry West Bench</td>
<td>9L and 10L applications (Christina, Ruckles, Baldy, Rock Creek, Greenwood, etc.) Whitewater Hearns Paterson Kaslo Huth Oliver</td>
</tr>
</tbody>
</table>
5.3 Transmission Lines

Transmission line sustaining capital investment needs to be focussed on the lines that have been in existence the longest with major rehabilitations. From Figure 5.2, it can be seen that 20 Line, 27 Line and 32 Line are strongly in this category, while 44 Line and 49 Line have been rebuilt recently. The trends associated with 44 Line and 49 Line are informative. Prior to their rebuilds, the amount of capital flowing into these lines to keep them in acceptable condition had ramped up considerably. At some point, the continuing need for investment was deemed to be inefficient, and the decision was made to perform a complete rebuild, at a cost that was half-an-order-of-magnitude higher than what had been invested to-date. For instance, the invested capital in 49 Line prior to rebuilding was $870,000 over 40 years, and the rebuild required $3.8 million. 44 Line shows the same pattern. The important trend to note is that 9 Line, 10 Line, 20 Line, 27 Line and 32 Line are all showing the rising need for investment. It is interesting to note that a rebuild of 20 Line appears to have occurred in the early 1960s, and the same-half-an-order-of-magnitude investment was required four decades ago.

Figure 5.2  Transmission Line Investment (normalized to $2004)
It has been decided to retire 9 and 10 Lines in favour of a reconfiguration of the Boundary area supply. The enabling condition that has led to this decision is the new ability to source 11 Line from either Oliver or Mawdsley.

The same level of analysis is required prior to the decision to rebuild 32 Line. This is another area of the system that has some potential for reconfiguration, but the most cost-effective solution may still end up being a reconstruction of the existing configuration. Current rehabilitation efforts are running at $600,000 per year, and based on the past experiences of 44 Line, and 49 Line, a reconstruction of 32 Line could reach $15 million to $20 million. For the present plan, a rebuild of the line in 2005 and 2006 is recommended.

The combination of 20 Line and 27 Line do not appear to have the same opportunity for system configuration changes as other areas. Therefore, line reconstruction must be anticipated in due course. 20 Line appears to have been reconstructed in 1962 so, it should not require large investments yet. However, 27 Line does appear to be overdue for investment. An allowance of $1 million should be allocated to 27 Line over this planning cycle to address rehabilitation and reconstruction issues.

The annual average sustaining investment in transmission lines over the last 25 years has been $2.2 million per year. This includes the reconstruction of 43 Line, 44 Line and 49 Line, but with looming needs identified for 20 Line and 27 Line, this average may even be understating the annual sustaining capital requirements.

The level of sustaining capital required to maintain a system is partially dependent on the design life of the system. Lines have generally accepted design life of about 50 years. This would translate into an annual replacement rate of 2% per year resulting new lines every 50 years. With an investment in transmission line assets of about $140M since 1957 this represents an annual investment of $2.8M. This investment is not a linear investment since new lines require much less replacement and maintained and as they age the requirement for replacement increases. The FortisBC system is an older system requiring greater levels of capital investment at this time.
The transmission line assessment program started in 1997 has done much to identify where the need for sustaining capital is the greatest, and offers the opportunity to create a baseline for the amount of degradation that occurs over eight years (the cycle time of the assessment program). Based on the amount of identified rehabilitation work that has occurred in the past, the backlog that has accumulated and the known age and condition of the lines, in addition to the lines mentioned above, the following lines should be given priority in the sustaining capital budget: 21 Line to 24 Line, 30 Line and 42 Line.

5.4 Staging and Schedule

The sequence of the transformer rehabilitation and replacement program may lend itself well to integration with the overall growth and reconfiguration capital expenditures. However, for optimal capital efficiency, the timing of certain project may have to be delayed or advanced by one year to coordinate properly. There are accompanying risks with the delays or advancements, but these are mitigated by the presence of specific action plans, so the risks should be prudent and manageable.

As an added advantage, the transformer rehabilitation and replacement program is mostly focussed around older stations. The breaker and disconnect switch work that has been identified is at most of the same stations, allowing another opportunity for coordinating the work and achieving some efficiency by combining outages and reducing repeated mobilizations.

6 Recommendations

1. Adopt a philosophy of “Condition Based Maintenance”. This will ensure the equipment is maintained on an as needed bases. This philosophy will ensure the proper level of maintenance is completed and show operating and maintenance savings as older equipment is replaced with new equipment. A good condition based maintenance system will ensure work load is reduced on newer equipment initially requiring less maintenance.
2. Identify maintenance regimes for each of three equipment categories, with Category 1 equipment receiving the most attention based on criticality and development of diagnostic techniques.

3. Replace older vintage disconnect switches in single transformer feed and line switching applications, and install more remote capability switches.

4. For older substations, where forecasted demand growth will not drive capacity upgrades for at least ten years, a rehabilitation program is recommended to address ground grids, security, surface condition, clearances to live equipment, mobile substation access and control enclosures.

5. Initiate a rehabilitation, re-conditioning and replacement program for the questionable transformers.

6. Purchase immediately a new mobile transformer for the Kootenay region rated at 30 MVA, with a 63 kV primary.

7. Implement a computerized maintenance management system to help the design and management of ongoing maintenance programs, and assist in being able to verify maintenance activities in response to increasingly comprehensive audit obligations.
7 References


Transmission and Distribution
System Development Plan

Appendix E
Distribution Planning Manual

November 26, 2004
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1 Distribution Planning Philosophy

This document identifies the philosophy utilized by System Planning in the development of the distribution system with voltage levels 35 kV and below.

1.1 Goals

- To plan the development of the most economical distribution systems that will provide service within specified standards to meet projected distribution loads of the future.
- Determine the changes required over the next five years to maintain standards of service while at the same time providing the most economical development of future distribution systems.
- Evaluate new facilities or anticipated rebuilds by comparing alternatives and recommending changes that will produce the most economical long-term development of the future distribution system.

1.2 Activities

- Project growth rates and forecast future load for areas within the service boundaries. Communicate with Regional Districts, Town Planners, etc., to gather information on anticipated development plans in their respective areas to incorporate into load forecasts.
- Develop alternative plans for systems that will supply projected future loads. Analyze each plan. Select the most economical as the long-range plan. Revise the long range plans and five year plans as a result of changing load patterns, regional and municipal plans or changing service standards.

1.3 Standards of Service

- Maximum feeder load during normal operating conditions is limited to the ampacity of the underground cable or overhead conductor exiting the substation. Refer to section 2.2 “Overhead Conductor and Underground Cable Ampacity”
- Maximum distribution equipment load during normal operating conditions is limited to the continuous rating of the equipment unless otherwise specified. Refer to section 2.3 “Capacity of Distribution Equipment”.
- Minimum Voltage as per CSA publication C235 “preferred Voltage Levels for AC Systems, 0 to 50,000 Volts”. Refer to Section 2.1
- Maximum Voltage as per CSA publication C235 “preferred Voltage Levels for AC Systems, 0 to 50,000 Volts”. Refer to Section 2.1
- Maximum three phase fault current is 8000 amps on primary distribution systems.
- Maximum single line to ground fault current is 5000 amps on primary distribution systems.
- Maximum load/L-G short circuit ratio is 25%.
- Maximum load/3-P short circuit ratio is 40%.
2 Planning Criteria

2.1 Voltage - Steady State Criteria

2.1.1 Introduction

This Planning criteria covers the application of minimum and maximum voltage levels on the distribution system. This criteria specifies the minimum and maximum voltage levels under steady state conditions used to plan the distribution system.

2.1.2 Planning Criteria

Planning designs the distribution feeders to ensure that customers have acceptable voltage at their utilization point. Planning will take corrective action when the predicted loading on the distribution feeder model indicates that the primary voltage (three phase and/or single phase) is outside of the minimum or maximum voltage parameters stated below:

<table>
<thead>
<tr>
<th></th>
<th>Minimum</th>
<th>Maximum</th>
</tr>
</thead>
<tbody>
<tr>
<td>Three Phase Voltage</td>
<td>115 V</td>
<td>127 V</td>
</tr>
<tr>
<td>Single Phase Voltage</td>
<td>113 V</td>
<td>127 V</td>
</tr>
</tbody>
</table>

The minimum voltages shown above apply when the source voltage is set at 123.5 V and the maximum voltages shown above apply when the source voltage is set at 126.5 V. The 123.5 V and 126.5 V levels reflect the typical operating range of a source substation.

2.1.3 Background

Planning assesses the need for voltage support to ensure that customers have acceptable voltage at their utilization point in accordance with CSA Standard CAN3-C235-83: “Preferred Voltage Levels for AC systems 1 to 50 000 V”. This standard outlines the recommended steady state voltage variation limits for circuits up to 1000 V at the utilization point (i.e. plug in) as follows:

<table>
<thead>
<tr>
<th></th>
<th>NORMAL</th>
<th>EXTREME</th>
</tr>
</thead>
<tbody>
<tr>
<td>Three Phase</td>
<td>110 V – 125 V</td>
<td>108 V – 127 V</td>
</tr>
<tr>
<td>Single Phase</td>
<td>108 V – 125 V</td>
<td>104 V – 127 V</td>
</tr>
</tbody>
</table>
Planning will initiate voltage improvements when the voltage reaches or is projected to reach the minimum recommended voltage under normal operating conditions. Corrective action is also initiated for instances where the voltage is or is expected to be in excess of the maximum recommended levels under normal operating conditions.

Some extreme operating conditions are temporary in nature. So the decision to initiate system improvements will depend on factors such as location, customer type and the extent to which limits are exceeded (i.e. magnitude and duration reflecting safety concerns as well as the probability of equipment damage).

2.1.4 Process

Recognizing that the specified CSA voltage limits apply at the utilization point, some allowance must be made for the voltage regulation through the service transformer as well as the secondary and internal wiring voltage drop to the plug ins. Generally, a 3-5 Volt drop from the main line to the customer utilization point under peak loading conditions and a 1 – 2 volt drop under light load is assumed. In order to comply with CSA limits, Planning models the distribution feeder and will take corrective action when the primary voltage of a peak load feeder model indicates an existing or projected steady state voltage of 115 V (120 V base) or less on the three phase lines and/or 113 V (120 V base) or less on single phase lines. Similarly, Planning will take corrective action when the primary voltage of a light load feeder model (three phase or single phase) indicates an existing or projected steady state voltage of 127 V (120 V base) or more.

2.2 Overhead Conductor and Underground Cable Ampacity

2.2.1 Introduction

This document covers the Planning Criteria for the application of ampacity levels for overhead conductors and underground cable used in the distribution system. This document specifies the maximum ampacity levels used to plan the distribution system.

During actual operations, higher ampacity ratings may be used taking into account actual temperatures, wind speed, pre-loading and duration of loading. Operation at higher ampacity levels may reduce the life of the equipment in order to supply load and such risks will be assessed at time of operation.

2.2.2 Planning Criteria

Planning designs the distribution feeders to ensure that the conductors, cables and connectors, on the distribution system, have the capability to supply customer load for forecast load conditions without any conductor, cable and connector loss of life.
This document outlines the normal ampacity ratings for overhead conductors, underground cable, and the maximum feeder loading used by Planning in the distribution system.

2.2.3 Overhead Conductor

Planning models the distribution feeders to ensure that the overhead conductors are not loaded above their ratings. Planning will take corrective action, when the model of the distribution feeder indicates that any equipment will be operated above its rating under the forecast peak load conditions.

Table 3 – Overhead Conductor Ampacity Limits

<table>
<thead>
<tr>
<th>Conductor Type</th>
<th>Trigger Ampacity</th>
<th>MVA by Voltage</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>25 kVLL 3Ø</td>
</tr>
<tr>
<td>8C</td>
<td>110</td>
<td>4.8</td>
</tr>
<tr>
<td>6C</td>
<td>147</td>
<td>6.4</td>
</tr>
<tr>
<td>4C</td>
<td>195</td>
<td>8.4</td>
</tr>
<tr>
<td>3C</td>
<td>228</td>
<td>9.8</td>
</tr>
<tr>
<td>2ACSR</td>
<td>210</td>
<td>9.1</td>
</tr>
<tr>
<td>2C</td>
<td>276</td>
<td>11.9</td>
</tr>
<tr>
<td>2/oACSR</td>
<td>318</td>
<td>13.7</td>
</tr>
<tr>
<td>3/oACSR</td>
<td>385</td>
<td>16.6</td>
</tr>
<tr>
<td>90C</td>
<td>329</td>
<td>14.2</td>
</tr>
<tr>
<td>266ACSR</td>
<td>510</td>
<td>22.0</td>
</tr>
<tr>
<td>336ACSR</td>
<td>652</td>
<td>28.2</td>
</tr>
<tr>
<td>397ACSR</td>
<td>660</td>
<td>28.5</td>
</tr>
<tr>
<td>477ACSR</td>
<td>745</td>
<td>32.2</td>
</tr>
<tr>
<td>927AAC</td>
<td>1118</td>
<td>48.3</td>
</tr>
</tbody>
</table>
2.2.4 Underground Cable

Planning models the distribution feeders to ensure that the underground cables are not loaded above their ratings. Planning will take corrective action, when the model of the distribution feeder indicates that any equipment will be operated above their rating under the forecast peak load conditions.

Table 4 – Underground Cable Ampacity Limits

<table>
<thead>
<tr>
<th>Cable</th>
<th>Grounding</th>
<th>In Duct</th>
<th>Cable at Riser</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Normal</td>
<td>Emergency</td>
</tr>
<tr>
<td>#2 Cu</td>
<td>Both Ends</td>
<td>164</td>
<td>200</td>
</tr>
<tr>
<td>#1 Cu</td>
<td>Both Ends</td>
<td>183</td>
<td>222</td>
</tr>
<tr>
<td>350Al</td>
<td>Both Ends</td>
<td>322</td>
<td>389</td>
</tr>
<tr>
<td>750Al</td>
<td>Both Ends</td>
<td>435</td>
<td>543</td>
</tr>
<tr>
<td>750Al</td>
<td>One End</td>
<td>555</td>
<td>667</td>
</tr>
<tr>
<td>1000Al</td>
<td>Both Ends</td>
<td>484</td>
<td>609</td>
</tr>
<tr>
<td>1000Al</td>
<td>One End</td>
<td>663</td>
<td>799</td>
</tr>
<tr>
<td>1000Cu</td>
<td>Both Ends</td>
<td>634</td>
<td>801</td>
</tr>
<tr>
<td>1000Cu</td>
<td>One End</td>
<td>828</td>
<td>1002</td>
</tr>
</tbody>
</table>

Note: Emergency rating is limited to 1500 hours in the life of the cable.

2.3 Capacity of Distribution Equipment

2.3.1 Introduction

This document covers Planning Criteria for the application of ampacity levels for equipment used on the distribution system. This document specifies the maximum ampacity levels used to plan the distribution system.

Under actual operations, higher ampacity ratings may be used taking into account actual temperatures, wind speed, pre-loading and duration of loading. Operation at higher ampacity levels may reduce the life of the equipment in order to supply load and such risks will be assessed at time of operation.
2.3.2 Planning Criteria

Planning designs the distribution feeders to ensure that the equipment on the distribution system has the capability to supply customer load for forecast load conditions. This Planning criteria outlines the ampacity ratings for equipment used in the distribution system.

2.3.3 Distribution Service Transformers, Voltage Regulators and Switches

Planning models the distribution feeders to ensure that the distribution line voltage regulators and switching devices are not loaded above their ratings.

Planning does not model individual service transformer loading, but recommends that when load is found to exceed the rating on these transformers that corrective action is taken.

Planning will take corrective action, when the model of the distribution feeder indicates that any equipment will be operated above the rating of the equipment under the forecast peak load conditions.

<table>
<thead>
<tr>
<th>Table 5 – Distribution Equipment Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Voltage Regulators</td>
</tr>
<tr>
<td>Switches and Cutouts</td>
</tr>
<tr>
<td>Distribution Service Transformers</td>
</tr>
</tbody>
</table>

2.3.4 Distribution Source Transformers

Planning monitors the load on distribution source transformers to ensure that they are not loaded above their ratings.

Distribution source transformers are those that supply distribution feeders at 25 kV or below, predominantly 25 kV and 13 kV, including transmission transformer secondaries where used.

Transformer capacity upgrades will be planned in the year that the forecasted transformer load:

1. exceeds nameplate rating at the forecast summer peak, or
2. exceeds nameplate rating plus 25% at the forecast winter peak.
3 Backup Planning Guidelines

3.1 Introduction

This guideline addresses the criteria for backup associated with the distribution system. Backup in addition to service continuity (i.e., absence of interruptions) composes reliability. Backup refers to the ability to restore service after an interruption without necessarily first repairing the cause of the interruption.

3.2 Backup Requirements

3.2.1 Distribution Contingencies

Planning will assess the distribution system to determine the backup capability for a single Distribution contingency event. In the event of a single Distribution contingency, a percentage of the peak load must be able to be supplied from the remaining distribution feeders in the study area. The percentage of peak load to be supplied is determined from the load duration curve shown below if available or 80% of peak load.

After the interruption, without first repairing the cause of the interruption, the remaining distribution feeders should have the capability to supply the load on the upper flat portion of the load duration curve. In the graph below, this would be 7 MW. Hence, it is recognized, that during peak load conditions the remaining distribution system may not have the capability to supply the entire load in the event of a distribution contingency.

In municipalities that require subdivisions be supplied underground, the company will ensure that all new underground circuits are looped and that the load can be fully supplied by either end of the loop for a single cable section failure.

When determining the capability of the remaining distribution system in the event of a distribution contingency, the minimum voltage level will be allowed to drop by 2 V to 113 V for three phase and 111 V for single phase.

Planning will take corrective action, when for the predicted loading, the distribution system is not capable of meeting this backup criteria.

3.2.2 Transmission Contingencies

Planning will study the distribution system to develop the backup requirement for the loss of one substation transformer in either a single or multi transformer substation.
• For loss of the transformer in a single transformer substation, a percentage of the peak load normally supplied by that transformer must be able to be supplied from the remaining distribution feeders and substations in the study area. The percentage of peak load to be supplied is determined from the load duration curve shown below if available or 80% of peak load. After the interruption, without first repairing the cause of the interruption, the remaining distribution feeders should have the capability to supply the load on the upper flat portion of the load duration curve. In the graph below, this would be 7 MW. Hence, it is recognized, that during peak load conditions the distribution system may not have the capability to supply the entire load in the event of the loss of the single transformer and full recovery may be dependent on installation of a mobile transformer.

• For loss of a single transformer in a multi transformer substation, 100 percent of the peak load must be able to be supplied from the remaining station transformer or a combination of the remaining station transformer and other supplies in the study area.

When determining the capability of the distribution system, in the event of the loss of the single transformer, the minimum voltage level will be allowed to drop by 2 V to 113 V for three phase and 111 V for single phase.

Planning will take corrective action, when for the predicted loading, the distribution system is not capable of meeting this backup criteria.

Graph 1 – Typical Load Duration Curve