



**Transmission and Distribution
System Development Plan**

Appendix D

Maintenance Planning Report

November 26, 2004

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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 Maintenance¹ (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:

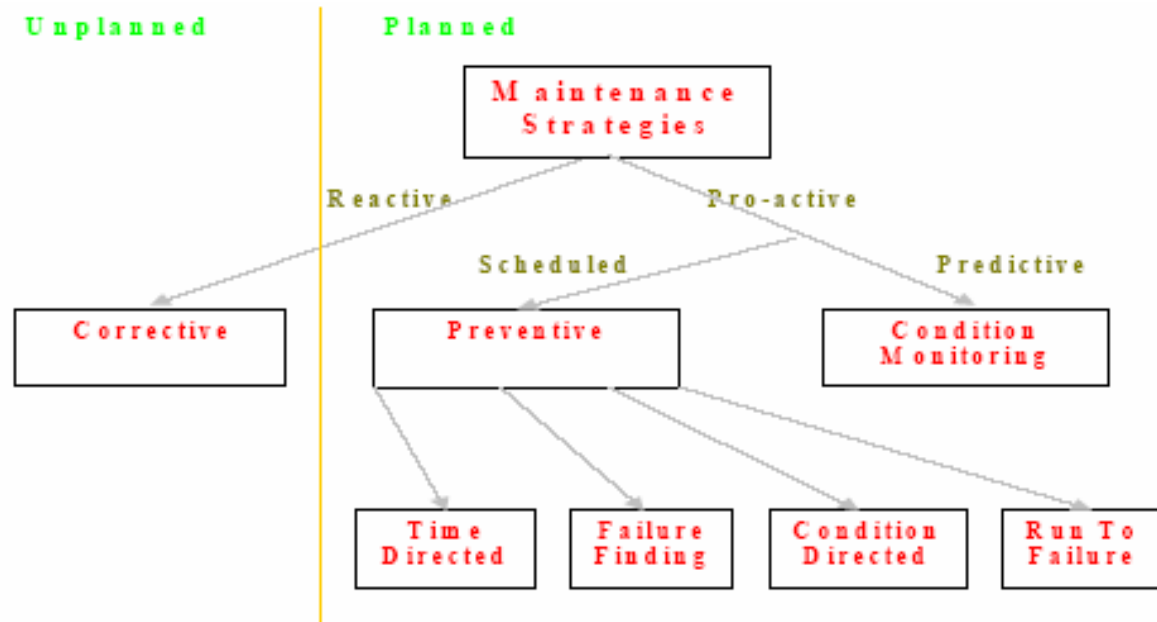


Figure 2.1 Maintenance Strategies

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:

Breakers	35 years
Transformers	40 years
Communications	20 years
Protection and Control	30 years
Buildings	50 years
Substation civil and grounding	30 years
Transmission poles and insulators	50 years

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.

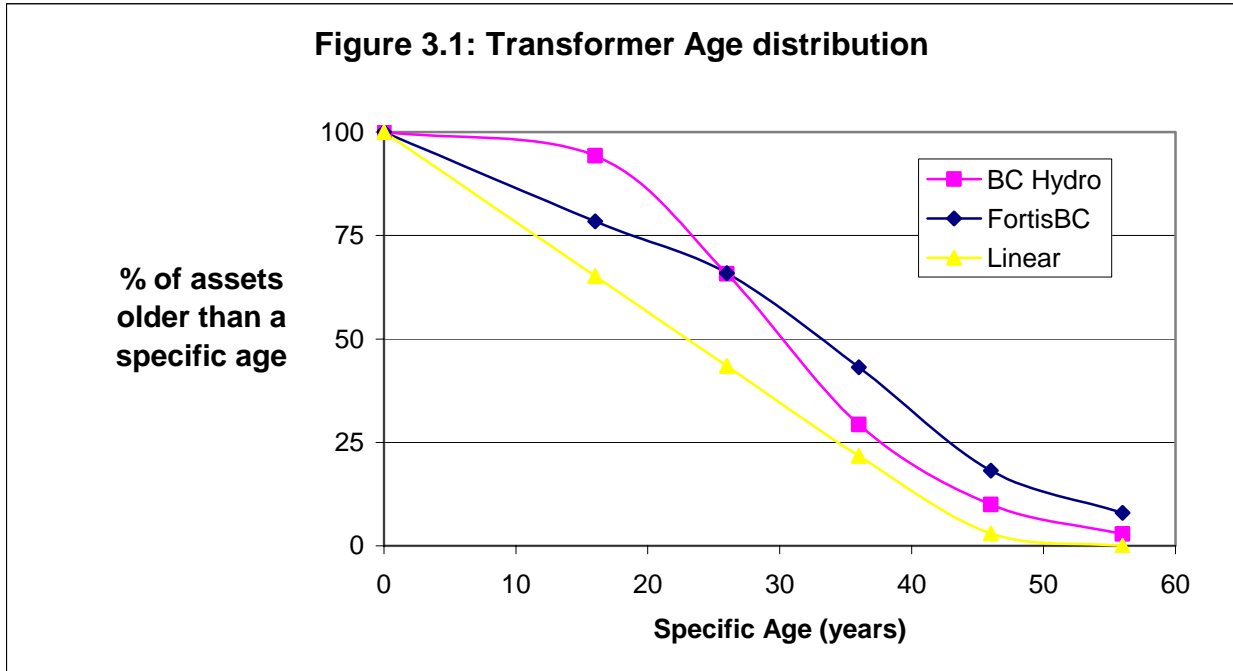
3.1 Category 1 Equipment

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.

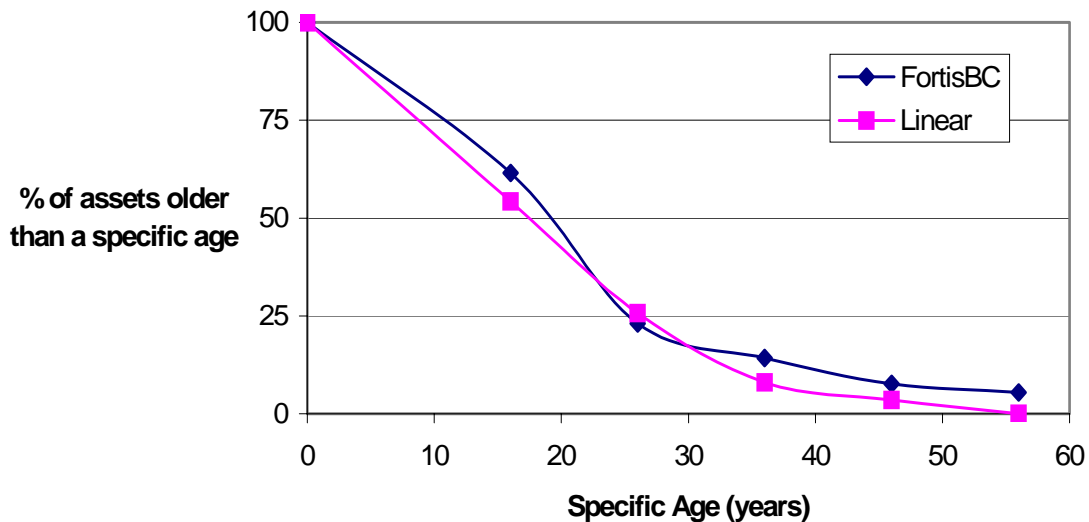


The linear projection is based on a maximum useful life of 40 to 45 years for the average transformer. A transformer built to CSA standards is designed to have a useful service life of 20 years if it is continuously loaded to nameplate thermal capacity. After this time, the cellulose insulation will 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 SF₆ 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 SF₆ 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.

Figure 3.2 Breaker Age Distribution table



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

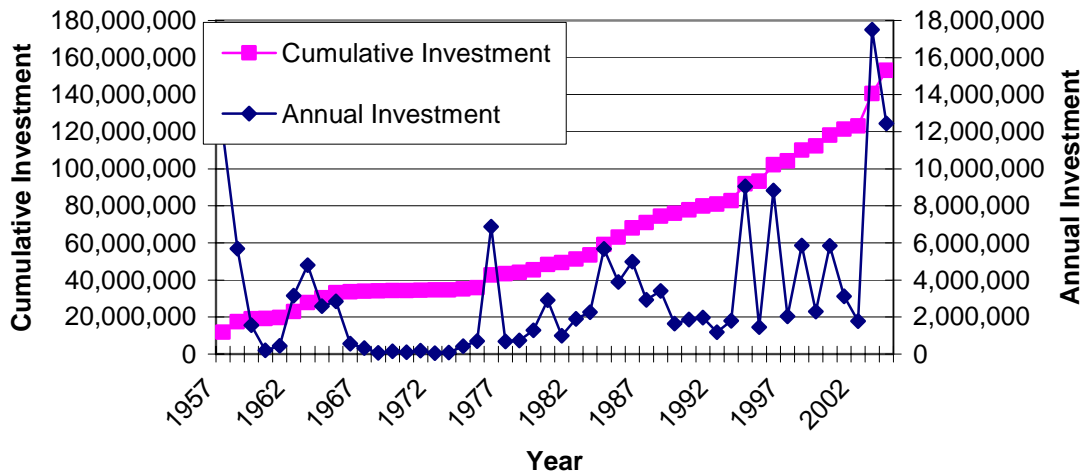
The FortisBC asset database shows capital investments in various assets starting in 1957. The 48 years of data compares well with the overall expected life of transmission line assets; however, this does not completely capture the end of service life asset replacement impacts which would probably start 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 Transmission Line Investment (normalized to \$2004)

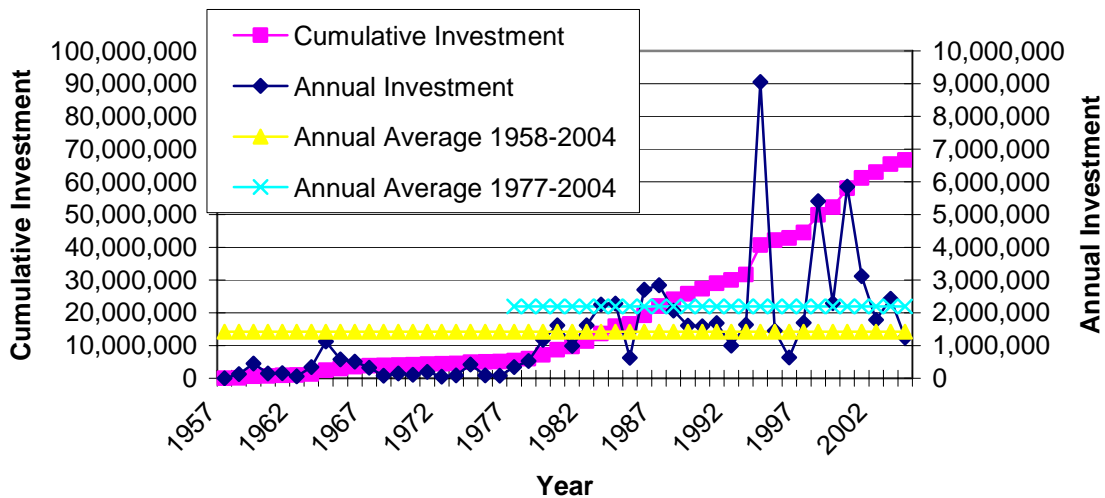


The graph shows that there was practically no investment in the system for a decade between 1967 and 1976, and this is reflected in the substation investments as well. The recent capital investments can be seen in context as “historic” investments.

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.

Figure 3.4 Transmission Line Sustaining Investment (normalized to \$2004)



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

	60 kV	138 kV	170 kV	230 kV
Manual Switches	183	73	19	42
Motor Operated Switches	34	27	10	15
Fused Switches and/or removable fuses	37	1		

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.

Table 4.1 Sustaining Capital Budgetary and Actual Expenditures

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1998 System Plan											
Kootenay Lines		0.81	0.98	1.39	0.24	0.15	0.19	0.41	1.03	0.55	0.85
Okanagan Lines		0.15	0.15	0.21	0.73	0.38	0.44	0.26	0.15	0.15	0.15
Kootenay Terminals		0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Okanagan Terminals		0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Kootenay Substations		No separate identification									
Okanagan Substations											
Budget of the Year											
Kootenay Lines	0.43	0.81	0.88	1.52	0.60	0.63	1.07	2.63	1.28	1.08	1.21
Okanagan Lines	0.18	0.15	0.17	0.23	0.43	0.59	0.49	1.13	0.98	1.08	1.13
Kootenay Terminals	0.10	0.15	0.15	0.12	0.11	0.00	Combined into substations below				
Okanagan Terminals	0.10	0.21	0.15	0.14	0.09	0.00					
Kootenay Substations	0.48	0.47	0.48	1.23	1.33	1.04	1.42	2.98	1.80	2.20	1.40
Okanagan Substations	0.20	0.39	0.25	0.32	0.36	1.04	0.73	1.15	1.60	3.00	1.10
Actuals of the Year											
Kootenay Lines	0.77	1.11	0.93	1.62	0.80	0.84					
Okanagan Lines	0.11	0.22	0.08	0.14	0.92	0.44					
Kootenay Terminals	0.11	0.48	0.13	0.04	0.01	0.04					
Okanagan Terminals	0.07	0.21	0.09	0.08	0.05	0.00					
Kootenay Substations	0.33	0.26	0.38	1.13	0.58	0.77					
Okanagan Substations	0.22	0.32	0.26	0.05	0.53	1.01					

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

Location	TOA Condition	Action / Analysis	Timeframe
Osoyoos Transformer 2 (#1399)	4	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)	2005
Grand Forks Transformer 1 (#12530)	4	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.	2005
Westminster Transformer 1 (#20142)	4	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)	2005
Oliver Transformer 2 (#20153)	4	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.	2005/2008
Trout Creek Transformer 1 (#20258)	4	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.	2005
Osoyoos Transformer 1 (#20274)	4	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)	2005
Pine Street Transformer 1 (#20356)	4	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)	2005

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. 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

Location	TOA Condition	Action / Analysis	Timeframe
6.5/8 MVA Mobile (#1072)	Was 4, now 3	Remove from service when new mobile station is available. The mobile is well past useful life mechanically and electrically.	2006
AS Mawdsley Transformer 1 (#12969)	Was 4, now 3	Remove from service and refurbish, and spare for Mawdsley Transformer 2 and Crawford Bay Transformer 1.	2006
Coffee Creek GT's (#14521,2,3)	Was 4, now 1	Advanced age of units (built in 1933) dictates replacement is the best option with Brilliant Generating Station spare grounding transformer	2008
Ruckles Transformer 2 (#14576)	Was 4, now 1	Reconditioned and running well, remove from service and use in other location when the Grand Forks 25 kV conversion is completed	2010+
Crawford Bay Transformer 1 (#14863)	Was 4, now 3	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.	2008
DG Bell Transformer 1 (#21165)	Was 4, now 1	Tapchanger repaired, unit OK	
FA Lee Transformer 4 (#22171)	Was 4, now 3	Ongoing gassing. Perform Fuller's Earth and vacuum degasification and monitor closely. Continue monitoring monthly.	2005

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

Location	Action / Analysis	Timeframe
Crawford Bay Transformer 2, Crawford Bay Transformer 3	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.	2006/2007
Ruckles Transformer 1	Overload in 2007/2008. Condition 4 for DGA. Will be removed when the Boundary area plan is implemented.	2007
Naramata Transformer 1	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	2006
Huth 4,5,6 7	Overloaded in 2008/9, But Waterford installation will offload all of this in 2005 when it is installed. Salvage Huth transformers in 2006.	2006
OK Falls Transformer 1	Replace due to loading constraints	2014
Princeton Transformer 1, Transformer 2, Transformer 3	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,	2005
Sexsmith Transformer 2	Sexsmith T1 will be overloaded in 2009/10 and will require an additional transformer.	2009
Hollywood Transformer 2	Hollywood T1 will be at capacity in 2007. Install a third transformer at Hollywood in the mobile location	2007
Recreation Transformer 2	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.	2008

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
- Oliver T2
- Baldy T1
- Rock Creek T1
- Midway T1
- Greenwood T1
- McKinney
- 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 5.4 – Transformers Manufactured in 1950 or Earlier

Location	Manufacture Date	Action	Timeframe
Ymir Transformer 1 (#12916)	1950	Replace, and scrap Ymir Transformer 1. This enables the elimination of Whitewater substation	2009

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:

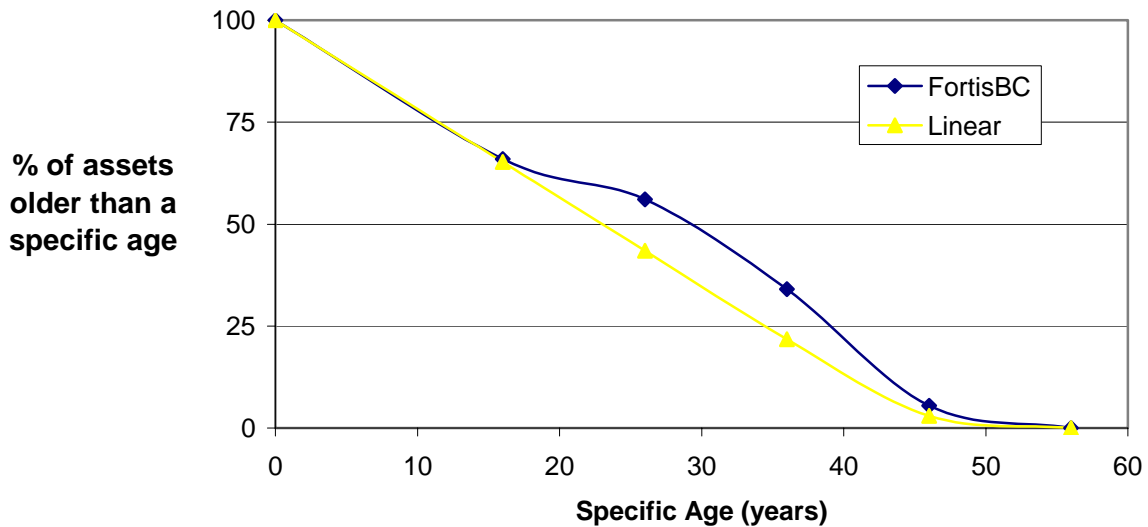
- Naramata
- Whitewater
- Hearn
- Kaslo
- Paterson

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 Hearn, Whitewater and Paterson substations will be removed from service and their loads supplied by nearby distribution sources. In the case of Hearn, less than 1 MVA of local load remains, and can be supported from either Fruitvale or Salmo. The option to rebuild Hearn 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.

Figure 5.1: Transformer Age Distribution in 2010



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.

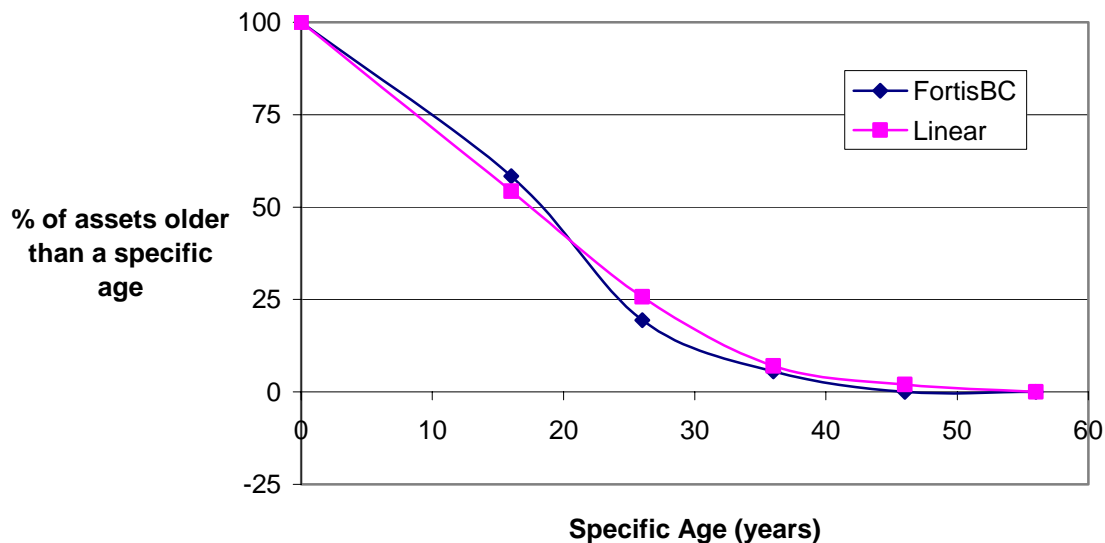
The work identified in Table 5.5 will address most bulk oil breaker issues for the next ten years, and the installed base of minimum oil and SF₆ breakers should not be experiencing any age related issues for at least another ten years. Therefore, the sustaining capital investments in breakers should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

Table 5.5 – Existing Breaker Investment Requirements

Location	Condition	Action
Westminster 45L	Sheer age. This bulk oil breaker is over 70 years old, and there are no Doble results to review. Mechanical condition identified in database	2007 (combine with transformer rehab)
RG Anderson 45L	Age and interrupting capability insufficient for duty. Mechanical condition identified in database	2005 Replace as part of South Okanagan (VAS) Supply Reinforcement Project (no separate budget line item)
Huth 53A	Age with no supporting Doble date. Bulk oil breaker manufactured in 1936. Mechanical condition identified in database	2007 Replace as part of Huth replacement (no separate budget line item)
Pine Street 44L	Age with no supporting Doble date. Bulk oil breaker manufactured in 1945. Mechanical condition identified in database	2006 (combine with transformer rehab)
Coffee Creek 37L Coffee Creek T1	Although not yet triggering replacement solely due to age (built in 1951). Mechanical condition identified in database.	2007 (coordinate with transformer work)
Crawford Bay 32L	Aged bulk oil breaker. Mechanical condition identified in database	2008 (combine with transformer work)
Hedley 43A	Bushing Replacement required and is de-energized, replace with a fuse.	2005
Princeton 56L Grand Forks Terminal T3 Duck Lake 46L Oliver TA	Either condition related issues identified, or Doble bushing test data is misleading, CONFIRM CONDITION.	2005-2009

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.

Figure 5.2: Breaker Age Distribution in 2010



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.

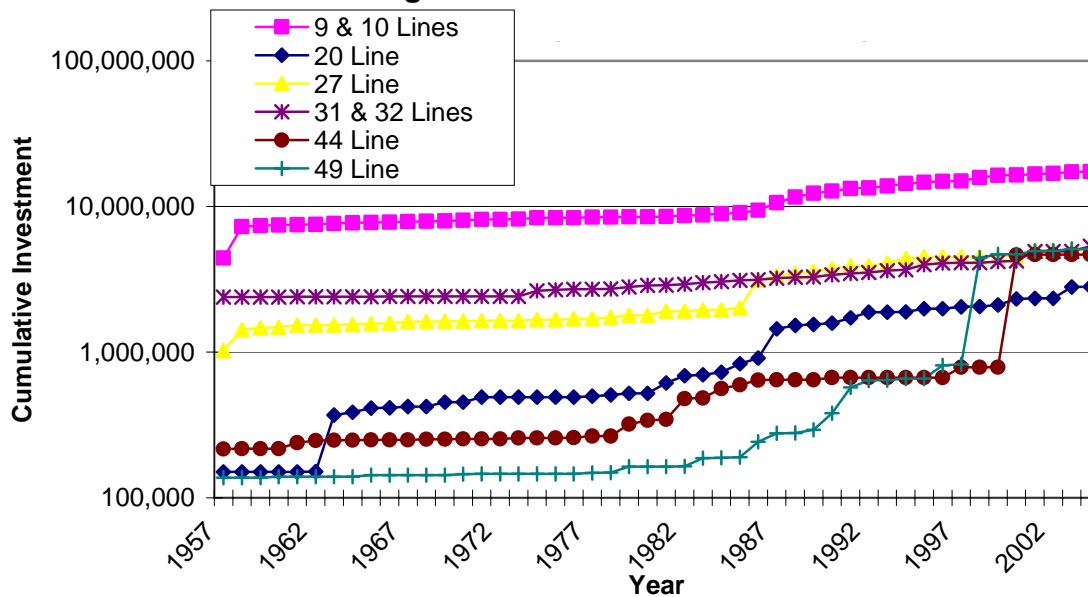
Table 5.6 – Disconnect/Sectionalizing Switch Investment Requirements

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

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

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