Revenue Requirement Application
2004/05 and 2005/06

BC hydro

Volume 1

Chapter 7.

Electricity Distribution
and Non-Integrated Areas

Table of Contents

List of Figures

List of Tables

List of Schedules

None.

1 Introduction

The purpose of this chapter is to describe the activities and costs associated with BC Hydro's Electricity Distribution and Non-Integrated Areas (NIA) functions. Electricity Distribution involves managing, maintaining, and expanding assets between the substation fence and the point of delivery. The NIA function is specific to remote communities that are not connected to the provincial transmission grid and involves generating electricity from local stations and purchasing energy from local IPPs.

This chapter is organized into the following two sections:

- section 2 identifies the activities and costs associated with Electricity Distribution in both integrated and non-integrated areas; and
- section 3 identifies the activities and costs associated with NIA generation and power purchases.

2 Electricity Distribution

2.1 Introduction

Electricity Distribution involves the following three primary process areas.

Customer Projects: Customer Projects provides customers with new connections and upgrades to their electrical service. The component of BC Hydro's revenue requirement associated with Customer Projects is described in section 2.5.

Distribution Operations: Distribution Operations involves the routine operation of the distribution system, the coordination and restoration of the system after an outage or disturbance, and the delivery of public safety programs. The component of BC Hydro's revenue requirement associated with Distribution Operations is described in section 2.6.

Asset Management: Asset Management involves the primary functions of planning, expansion, and maintenance of the distribution system. It also includes design and construction standards, revenue metering, and research & development (R&D). The component of BC Hydro's revenue requirement associated with Distribution Asset Management is described in section 2.7.

These three areas have well-established processes to handle large volumes of work expeditiously and effectively to meet customer needs, and to maintain the capability of BC Hydro's distribution system. BC Hydro monitors and reviews these processes, as well as distribution system performance, to improve efficiency and the overall value of its distribution system expenditures. Benchmarking shows that BC Hydro's annual distribution wires expenditure per customer is 1st Quartile and amongst the lowest in North America (see section 2.7.3).

There are many drivers and constraints affecting Electricity Distribution as described in the following section. The ones that will provide the greatest challenge for expenditure levels in the test periods are:

- Net Customer Additions, which are expected to increase by 18% in F2005 over F2004 and will require significantly higher resources and expenditures;
- reliability, which has declined in each of the last two years; and
- ageing infrastructure, which requires higher investments in equipment replacements and in ongoing maintenance expenditures.

The resulting expenditure forecasts for Electricity Distribution are as follows: Direct Operating Expenditures are forecast to increase from $121.4 million in F2004 to $130.6 million in F2005 and to $131.9 million in F2006; Gross Capital Expenditures are forecast to increase from $205.7 million in F2004 to $217.6 million in F2005 and to $226.8 million in F2006. Details are provided throughout this section and are summarized in Table 7-13 and Table 7-14.

2.2 Drivers and Constraints

The major factors influencing Electricity Distribution's expenditures are as follows.

2.2.1 Economic Activity

Economic activity is a key driver that affects work requirements and expenditure levels. Significant factors include housing starts, commercial & industrial investment, and public sector investment. Customer Projects is impacted immediately when customers request service, and Distribution Operations and Asset Management are impacted subsequently as growth impacts the distribution system.

The functions within Electricity Distribution utilize BC Hydro's Load Forecast as a key source of information for distribution system planning and design, and for building long-term strategies for asset management and emergency response. Additional sources of information (e.g., specific development proposals) are utilized to establish short-term resource requirements and priortize activities.

The regional growth forecasts presented in section 2.3 have been utilized to determine forecast expenditure levels in Electricity Distribution in the test periods.

2.2.2 System Growth and Customer Expectations

In addition to growth from economic activity, demands on the system are increasing because the average consumption per residential customer is increasing. Customers are also using more outage sensitive electrical equipment in homes and businesses (e.g., computers in homes and electronic equipment controls in businesses).

Customers' use of sensitive electrical equipment requires increased effort to reduce the number of sags, swells, and other power quality problems. These customer demands add to the complexity and capacity constraints of the distribution system.

2.2.3 Asset Health and Reliability

The health of the distribution assets is a key driver for expenditure requirements. Through reliability centered maintenance (RCM) practices, lowest long-term cost investment strategies have been developed and implemented as maintenance standards. These standards ensure the ongoing viability of the assets. As increasing proportions of BC Hydro's distribution assets reach or exceed end of design life, increased funding is required to maintain assets to standard. When facilities are not maintained to standard, investment becomes less than optimal, distribution emergency restoration activities increase, and safety risks increase for the public and workers.

2.2.4 Safety

As discussed in chapter 3, BC Hydro has a goal of zero public or employee injuries. Increased economic activity generally relates to system growth and increased construction activity, which means increased public safety education and support for the construction industry is needed. This is one of the services provided by BC Hydro's Field Services organization.

2.2.5 Customer Policies

BC Hydro's Extension Policy, approved by the BCUC in 1998, provides for sharing of construction costs with customers. Notwithstanding the Extension Policy, BC Hydro incurs expenses related to extensions and improvements under the Uneconomic Extension Assistance Program (UEA) and related to social policy under the Beautification Program.

2.2.6 Weather

Weather is a significant driver for Distribution Operations. The occurrence and severity of adverse weather is a major factor in the level of funding required for emergency restoration activities.

2.2.7 Independent Power Producers

IPPs impact the distribution system through interconnection, and system performance and stability effects. Distribution Planning carefully assesses each IPP project to determine safe and effective interconnection requirements. Funding is required to interconnect these IPPs, and requirements are expected to increase as more IPPs are added to the distribution system.

2.3 Regional Customer Growth

Distribution system customer growth is measured in terms of Net Customer Additions, which is the net of customer connection installations and removals. Net Customer Additions are forecast to be approximately 21,280 in F2004; 25,174 in F2005; and 26,889 in F2006.[1] Customer growth is localized in nature and varies around the province. The following sections discuss the expectations for customer growth by region.

2.3.1 Lower Mainland, North Shore Coastal, and Fraser Valley

The Lower Mainland, North Shore Coastal, and Fraser Valley continue to lead the province in economic growth and work levels. The award of the 2010 Winter Olympics to Vancouver/Whistler is expected to generate new housing and commercial development in these areas beginning in F2005.

On the North Shore, several larger commercial developments are expected to proceed in F2005. There is a potential University project in Squamish and a significant housing proposal is proceeding in Pemberton. The widening of Highway 99 will require distribution line relocations in several areas.

In the Lower Mainland and the Fraser Valley, strong activity is expected in all sectors. Large projects that are expected to be active in F2005 and F2006 include the Bayshore Gardens on Coal Harbour, and the $3 billion Concord Pacific Place development that will house an estimated 15,000 people in numerous residential towers.

2.3.2 Northern B.C.

Expansion of the oil and gas sector is expected to continue to stimulate activity in the commercial and residential sectors in Fort St. John, Dawson Creek, and Ft. Nelson. However, the softwood lumber industry is expected to continue to be negatively impacted in many communities in the North. If the softwood lumber dispute is resolved in 2004 or 2005 there may be additional growth for F2005 and F2006.

[1] F2004 is the year-end forecast. F2005 and F2005 are from the Load Forecast.

2.3.3 Thompson/Shuswap

In the Thompson/Shuswap, residential development is expected to continue at a slow pace in F2005 and F2006. However, there are several larger multi-year projects such as the Sun Peaks Resort that will result in distribution activities during the test periods.

2.3.4 Okanagan-Kootenay

Forestry, agriculture, tourism, and government drive the Okanagan-Kootenay economy. The softwood lumber dispute has resulted in decreased activity in the forestry sector, slowing growth in the Kootenay area. Forest fire damage in 2003 was mainly confined to the Kelowna area. It is anticipated that increased housing development and reconstruction will be seen in the Westbank area in F2005 and F2006.

2.3.5 Vancouver Island

On Vancouver Island, housing starts and upgrades are fueling activity. In the South Vancouver Island area, economic growth in F2005 and F2006 is expected to be in the range of 3% to 5% for the Gulf Islands, and approximately 1% in Victoria. A 700-lot development with a mix of residential and commercial is expected on the Gulf Islands during the test periods. Several large subdivisions are expected to proceed in Victoria during this period, and the 2,500 mixed residential unit Bear Mountain project is expected to proceed in Langford.

In the North Vancouver Island area, activity will remain strong in F2005 and F2006. These trends are both in residential and commercial development. A large residential retirement development is planned for the Parksville/Qualicum area in this period.

2.3.6 Implications of Regional Growth Forecasts during the Test Periods

The levels of activity described for each region are indicative and supportive of the work that Electricity Distribution will need to undertake to provide services in various parts of the province in the test periods. Growth investment is forecast to be 3.4% higher in F2005 than in F2004, and a further increase of 6.1% is expected in F2006 over F2005 levels (see Customer Projects capital plan in section 2.5.5, Table 7-2). Workloads are typical of a growth year in an active economy and plans are in place to deal with the growth.

2.4 Standards and Policies

This section provides an overview of the standards and policies that are key to the work activities and costs incurred by Electricity Distribution.

2.4.1 Construction and Design Standards

Electricity Distribution has developed comprehensive engineered construction standards to minimize the life-cycle cost to build, operate, and maintain distribution systems. These standards are also a means to facilitate compliance with regulatory requirements and conformance with corporate, social, environmental, and financial objectives. More specifically, standards are developed taking into consideration public and worker safety, commercial availability of products, environmental impact, ease of installation, operability, maintainability, reliability, energy efficiency, aesthetics, end-of-life-disposal, and life cycle cost.

Product and technology advances are monitored and are incorporated when feasible to improve the distribution system. Standards are also reviewed with those of other companies that design, build, operate, and maintain distribution systems.

2.4.2 Planning Criteria

Electricity Distribution uses planning criteria, such as reliability standards and circuit loading criteria, to guide facility expansion and upgrade decisions. The planning criteria are designed to provide needed system capability at lowest cost, taking into account performance expectations, near and long-term system capability, asset utilization, lowest life-cycle cost, and social and environmental objectives.

2.4.3 Local Operating Orders

Procedures for the safe and efficient operation of the distribution system are set out in a group of instructions called System and Local Operating Orders. These Orders are procedures for routine and emergent situations, which helps to minimize safety risks to workers and the public, and lower the cost of installing and maintaining infrastructure.

2.4.4 Distribution Instructions

Electricity Distribution has developed a series of Policy Instructions that set out, in detail, rules for implementing a variety of utility practices and Electric Tariff applications. The purpose of the Policy Instructions is to provide fair and consistent service to customers in all areas of the province.

Distribution Instructions are in place for topics within categories such as the Extension Policy, Agreements, Charges, Lighting, Metering, Operating Standards, and Permits.

2.5 Customer Projects

2.5.1 Description

This section outlines the costs and activities of Customer Projects. These activities include:

- identifying customer requirements for service upgrades or new service connections;
- designing projects, including determining installation costs and creating drawings;
- planning projects for implementation, including requisitioning materials, dealing with right-of-way issues, obtaining approvals, and issuing construction orders; and
- monitoring project progress, including coordinating with customers and service providers, closing jobs on completion, and issuing invoices as necessary for customer contributions.

Field Services executes all construction orders on behalf of Customer Projects, and associated costs are included in the operating and capital expenditures of Customer Projects.

A portion of expenditures is offset by customer contributions towards design and construction costs, as provided in BC Hydro's Electric Tariff.

2.5.2 Customer Projects Service Approach

Requests for service upgrades or new connections come from many sources, including customers, builders, and developers. The complexity of these requests varies from simple additions such as providing a secondary connection to a new house, to complicated additions that require significant extension of distribution plant such as connection of a new sub-division development.

It is the objective of Customer Projects to provide its services in a timely, cost effective manner, with a high degree of customer satisfaction. To accomplish these objectives, Customer Projects uses the following service approach.

- Customers request new services through one of seven Electric Service Coordination Centers (ESCCs) or the 'Get Connected' website. ESCCs are located in Burnaby (Edmonds Complex), Surrey, Nanaimo, Victoria, Vernon, Kamloops, and Prince George.

- Customer connection requests are then divided by design complexity and customer type into either “Express Connection Work” or “Design Work”, and assigned to an Electric Service Coordinator (ESC) or designer, respectively.
- The connection is designed using BC Hydro standards. Complex designs will often involve Engineering Services.
- Designers utilize the Distribution Analysis and Design (DAD) software package to design any needed changes to the electric distribution system, compile compatible units, and produce construction drawings. DAD provides designers with on-line, up-to-date views of all BC Hydro’s electric distribution facilities, thereby minimizing the time spent in the field. DAD is also integrated with BC Hydro’s EGIS, Work Management, and Pole Administration systems.
- A construction order is issued to Field Services.

Annual Net Customer Additions have been in the range of 15,000 to 20,000 for the period F2000 and F2003. As shown in Figure 7-1, higher levels of customer additions are forecast during F2005 and F2006, and as noted earlier, Net Customer Additions is a primary cost driver for Electricity Distribution.

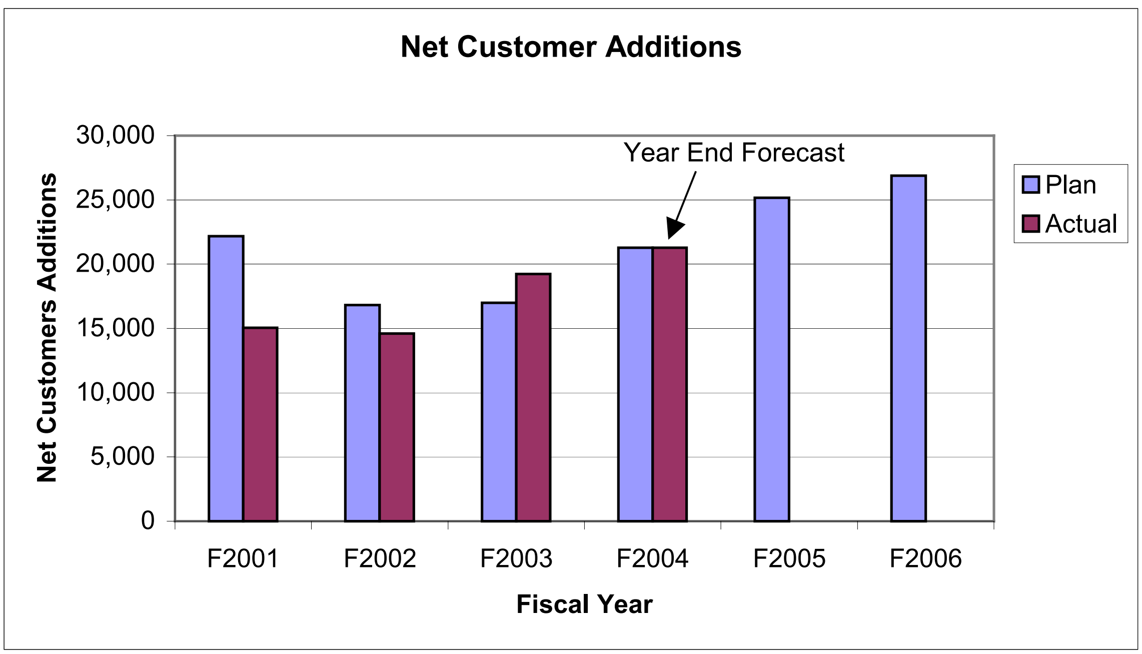

Figure 7-1. Net Customer Additions, F2001 to F2006

2.5.3 Performance Metrics and Service Levels

BC Hydro measures the effectiveness of its Customer Projects activities through two key benchmarks: customer satisfaction and productivity.

2.5.3.1 Customer Satisfaction

A good working relationship with its clients and stakeholders including developers, contractors, and municipalities is key. With this in mind, BC Hydro measures the satisfaction of those customers to understand and be responsive to their needs and expectations.

Marketrend Research conducts annual surveys of electrical contractors on behalf of BC Hydro for Customer Projects. As shown in Figure 7-2, these surveys indicated that 96% of express connection customers were satisfied with Customer Projects' performance in 2002 compared to 85% in 2001.

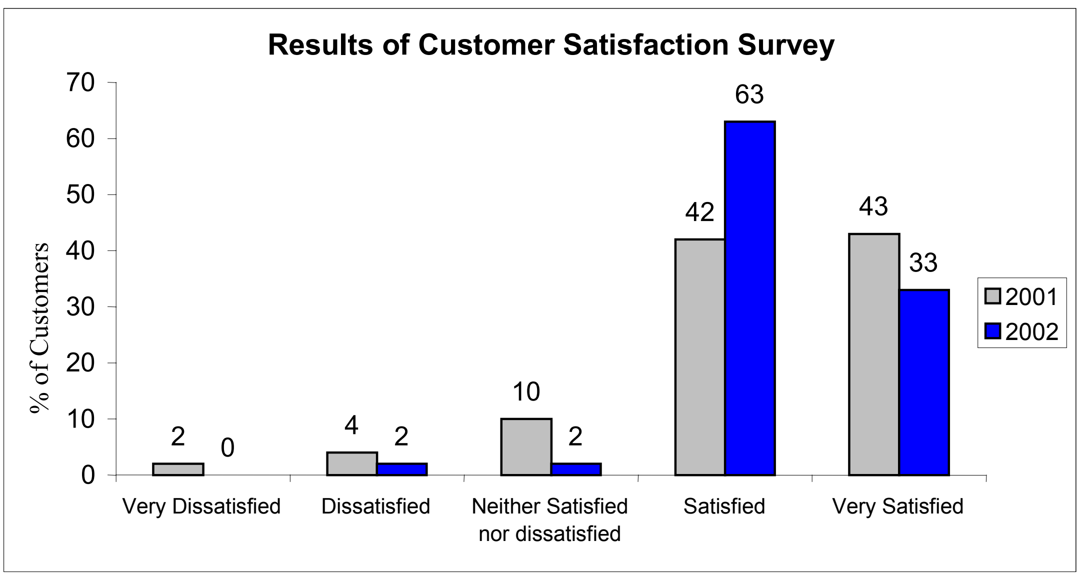

Figure 7-2. Customer Satisfaction, Customer Projects

2.5.3.2 Productivity

Customer Projects monitors service order volumes for ESCs. The purpose of measuring service order volumes is to track and adjust performance to gain further process efficiencies.

Over 80 connections per month per ESC are currently managed by the ESCCs, and the volume of work processed by each ESC indicates an upward trend. The ESCCs continued to maintain a “satisfactory” rating from their clients during this period.

2.5.4 Strategy

The strategy for Customer Projects is twofold:

- maintain customer satisfaction with new connections and service upgrades; and
- improve the productivity and efficiency of that service.

The introduction of the ESCCs in 2001 significantly improved efficiency. Previously, requests for new connections were managed in over fifty walk-in offices. The ESCCs have streamlined coordination while maintaining customer satisfaction levels through telephone services combined with personal meetings by appointment. With the ESCCs established, Customer Projects is now focusing on productivity improvements through volume processing.

Additional system changes due to the Northstar Project will need to be adopted and refined to ensure a smooth transition through the implementation and for several months following. In this period Customer Projects will strive to minimize the implementation impact on its customers and realize any available benefits of the new system.

2.5.5 Operating Plan

Customer Projects’ workload and corresponding expenditures are driven primarily by economic and customer activity levels.

Based on the economic forecast for housing starts and the regional growth forecasts, discussed in section 2.3, Customer Projects is expecting to accommodate 25,174 and 26,889 Net Customer Additions in F2005 and F2006 respectively.

Table 7-1 identifies the operating expenses for Customer Projects during the test periods.

Table 7-1. Operating Expenses, Customer Projects

($ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Direct	$20.8	$24.3	$25.9	$26.6
Support	6.7	8.9	9.6	9.3
Corporate Allocations	6.6	8.0	11.1	11.0
Less Capitalized Overhead	(23.1)	(23.4)	(24.8)	(25.4)
Less Recoveries	(0.7)	(0.1)	(0.1)	0.3
Total OMA Expense	**$10.3**	**$17.7**	**$21.7**	**$21.8**

Table 7-2 identifies the forecast capital expenditures for Customer Projects during the test periods.

Table 7-2. Capital Expenditures, Customer Projects

($ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Sustaining	$5.4	$4.9	$6.7	$6.4
Growth	107.9	110.6	114.4	121.4
Deferred Capital	-	-	-	-
Capital Expenditures Gross of CIA *(Note 1)*	**$113.3**	**$115.5**	**$121.1**	**$127.8**
Less Sustaining CIA	(8.2)	(2.5)	(4.2)	(3.8)
Less Growth CIA	(35.4)	(36.1)	(38.3)	(40.9)
Total CIA	**$(43.6)**	**$(38.6)**	**$(42.5)**	**$(44.7)**
Less Recoveries	(1.8)	(1.7)	(1.1)	(1.1)
Net Capital Expenditures	**$67.9**	**$75.2**	**$77.5**	**$82.0**
Year-over-year change in gross Growth Capital expenditures			3.4%	6.1%

Notes:
1. CIA = Contributions-in-Aid of construction.

The increase in growth capital expenditures in F2005 and F2006 is directly attributed to economic activity described in section 2.3.

Included in the growth capital expenditure plan is the Uneconomic Extension Assistance Program (UEA), which provides financial assistance towards the cost of 'uneconomic' overhead electrical extensions. Use of the program varies from year to year. The program has been very successful in assisting customers who are beyond the reach of the existing distribution system. The UEA program provides up to $1.5 million annually for this purpose.

To assist municipalities in placing electrical plant underground, BC Hydro offers the Beautification Program that provides up to 1/3 of the cost of converting overhead facilities to underground in central municipal areas. Approximately $1 million is allocated annually for this purpose and is included in the sustaining capital expenditure plan.

Table 7-3 identifies headcount requirements of Customer Projects.

Table 7-3. Headcount, Customer Projects

	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
M&P	21	22	22	22
IBEW	-	-	-	-
OPEIU	226	231	259	259
Total Headcount	**247**	**253**	**281**	**281**

Customer Projects is planning to increase its headcount by 28 between F2004 and F2005. These employees are predominately technologists, design representatives, and design technicians required to address the higher workloads anticipated during the test periods. The increase also includes personnel in training positions to address anticipated shortfalls in skilled positions, as discussed with respect to the Workforce Renewal Initiative in chapter 3, section 8.3.3.1.

2.6 Distribution Operations

2.6.1 Description

This section outlines the costs and activities of Distribution Operations. These activities include:

- routine operation of the electric distribution system;
- dispatch and coordination of crews to restore the distribution system after an outage or disturbance; and
- leadership and coordination of public safety education programs with the exception of advertising costs, which are included in BC Hydro's Customer Care costs discussed in chapter 8.

Field Services executes all operating and restoration field work on behalf of Distribution Operations, and associated costs are included in the operating and capital expenditures of Distribution Operations.

Engineering Services provides engineering support for Distribution Operations in the form of operating drawings, technical advice on system optimization matters, and investigation of customer initiated power quality complaints. These costs are included in the operating and capital expenditures of Distribution Operations.

Most trouble calls are initially answered through BC Hydro's call centres, which are operated by ABS. Trouble call costs are included in the operating expenditures associated with Distribution Operations.

2.6.2 Distribution Operations Service Approach

The Distribution Operations service approach is to operate the system safely and effectively to enable the delivery of electricity to meet all performance objectives. The following are key elements of Distribution Operations' approach to providing service.

2.6.2.1 Public Safety Education

Safety continues to be a primary focus. The service approach is to provide safety awareness for the public through the Public Safety Education program, which includes advertising, school education, and training for industry workers such as crane operators and first responders such as police and fire fighters. Field Services provides some of this training.

2.6.2.2 Routine Operations

For routine operations, the service approach is to align efforts and optimize expenditures with asset management. Operation of the system is only one component of the life cycle of the distribution system. Activities associated with the operation of the system must be aligned with maintenance and other asset management activities to ensure that optimum value is delivered to the customer. For example, the procedures of the area control centres will be reviewed for consistency and efficiency to ensure that Field Services is not unduly delayed when requesting protection for maintenance or system improvement work.

2.6.2.3 Emergency Restoration

For emergency restoration, the service approach is to be responsive and efficient.

Distribution Operations operates a Trouble Centre on a 24 hour per day, 7 days per week basis that serves the needs of BC Hydro’s entire service area. The activities of dispatcher staff in the trouble centre include operation of the PowerOn outage management system, dispatch of trouble orders to Field Services crews, and coordination with the police and fire departments when emergencies involving power facilities occur.

A key component of the response and restoration process is the PowerOn outage management system. The implementation of the PowerOn system was completed in June 2003. This system is designed to increase efficiency and provide better service to customers during distribution system disturbances. When customers call the PowerOn telephone number they are identified by their phone number and matched to an electric account and to a location on the distribution system. If there is an outage on the part of the system to which the caller is connected, the caller is advised that BC Hydro is aware of an outage and given an expected restoration time. If the customer wishes to speak to an agent, they are invited to stay on the line and the next available agent takes the customer call. This has improved BC Hydro's ability to meet customer expectations for restoration information when outages occur. The information provided by PowerOn also improves the level of information available for BC Hydro to manage and respond to outages by giving dispatchers more precise information regarding the locations of service disruptions.

2.6.2.4 Service Providers

Routine Operations and Emergency Restoration services are delivered primarily by Field Services, Engineering Services, ABS, and BCTC.[2] Distribution Operations works with its service providers to find innovative methods of delivering value to customers. As an example, Distribution Operations and Field Services work together to set targets relating to performance requirements such as customer response times and cost per outage, as noted in section 2.6.3 below. Other metrics, such as the accuracy of estimated restoration times, are also measured to identify performance levels and opportunities to better serve customers.

2.6.3 Performance Metrics and Service Levels

In addition to the overall system performance indicators described in section 2.7.3, the following metrics are used to ensure that BC Hydro's Distribution Operations' activities provide a cost effective service that is valued by customers:

- Emergency Response Time to ensure that response to emergency situations is reasonable considering the size of BC Hydro's service area and its topography;
- Average Labour Cost per outage to measure efficiency in providing service to customers; and
- Public Fatalities/Injuries/Contact Incidents to focus safety efforts, as provided in BC Hydro's safety policies.

Table 7-4 shows the target performance levels in these areas:

[2] Field Services and Engineering Services manage the allocation of resources used to undertake Electricity Distribution's work plans. Electricity Distribution does not create resourcing policies or directly manage these resources.

Table 7-4. Distribution Operations Performance

	Measure	Target
Responsive	Emergency Response Time	
	Rural Areas	80% of calls responded to within 2 hours
	Urban Areas	80% of calls responded to within 1 hour
Efficient	Average Labour Cost per outage	$532
Safety	Public Fatalities/Injuries/Contact Incidents	0 fatalities, injuries, contacts, incidents

BC Hydro Field Services is responsible for meeting the response time targets shown in Table 7-4, and its performance is discussed in chapter 9.

2.6.4 Strategy

The strategy for Distribution Operations is to invest in staff, continue to build relationships with service providers, and to utilize technology to maximize the value delivered to customers. This approach will improve outage management practices and the overall customer experience during disturbances.

The most important assets in Distribution Operations are the dispatchers in the Trouble Centre. Investment is required to ensure they have the necessary job skills to excel in their jobs and provide value to customers. Investments will also be made in knowledge management to ensure that the collective knowledge possessed by the existing dispatchers is transformed into corporate knowledge for junior and future dispatchers.

Technology plays a significant role in Distribution Operations' strategy. Two examples of technology that, if implemented, would increase the value of the service delivered to customers are software that allows the dispatchers to be aware of the location of crews, and technology that ties the system operation software to the outage management software. Capital funding has been included during the test periods to investigate these opportunities.

2.6.5 Operating Plan

Table 7-5 identifies the operating expenses for Distribution Operations during the test periods.

Table 7-5. Operating Expenses, Distribution Operations

($ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Direct	$34.8	$40.7	$38.0	$38.3
Support	9.1	7.4	7.2	7.1
Corporate Allocations	2.4	2.9	4.0	4.0
Less Capitalized Overhead	-	-	-	-
Less Recoveries	(0.7)	(1.2)	(1.1)	(1.0)
Total OMA Expense	**$45.6**	**$49.8**	**$48.1**	**$48.4**

Operating costs for routine operations will remain constant in F2005 and F2006. Expenditures for Emergency Restoration will increase by $0.6 million in F2005 to assist in meeting current reliability targets, and are expected to remain at that level through F2006.

Distribution Operations' costs are based on historical levels of activity. Less than 20% of direct costs are fixed costs. Restoration costs are driven primarily by weather events, maintenance activity and asset health. Routine operations costs are driven by weather events, customer activity and asset management activities.

Table 7-6 identifies the forecast capital expenditures for Distribution Operations during the test periods.

Table 7-6. Capital Expenditures, Distribution Operations

($ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Sustaining	$6.2	$3.4	$3.1	$2.7
Growth	-	-	-	-
Deferred Capital	-	-	-	-
Capital Expenditures Gross of CIA	**$6.2**	**$3.4**	**$3.1**	**$2.7**
Less Sustaining CIA	-	-	-	-
Less Growth CIA	-	-	-	-
Total CIA	**$-**	**$-**	**$-**	**$-**
Net Capital Expenditures	**$6.2**	**$3.4**	**$3.1**	**$2.7**

A portion of capital expenditures in F2003 and F2004 was related to the implementation of the PowerOn system. Capital expenditures during the test periods are expected to be lower than previous spending because of the completion of this project.

Table 7-7 identifies headcount requirements of Distribution Operations.

Table 7-7. Headcount, Distribution Operations

	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
M&P	7	8	8	8
IBEW	-	-	-	-
OPEIU	19	23	27	27
Total Headcount	**26**	**31**	**35**	**35**

Distribution Operations' staffing levels are primarily related to Trouble Centre operations. Staffing levels were increased in F2004 in response to workload and workforce renewal requirements. Headcount is expected to remain constant during the test periods.

2.7 Asset Management

2.7.1 Description

This section outlines the costs and activities of Asset Management. These activities include:

- monitoring system performance;
- planning and expanding the distribution system;
- determining asset management strategies;
- investing in maintenance and sustainment of the system;
- Revenue Metering; and
- Research & Development.

Field Services executes all construction and maintenance orders on behalf of Asset Management, and Engineering Services provides study and design services. Associated costs are included in the operating and capital expenditures of Asset Management.

2.7.1.1 Summary of Distribution Assets

BC Hydro owns and operates approximately 56,400 km of primary line, 876,000 poles and other facilities as described in Table 7-8. The net book value of the assets is currently $2.0 billion and the replacement cost is estimated at $5.3 billion (excluding NIA).

Table 7-8. Distribution Infrastructure

Component	Approximate No. of Units	Estimated Replacement Value ($ millions)
Poles	876,000	$1,113
Services	1,038,757	$406
O/H Primary Line	47,660 km	$1,118
U/G Primary Line	8,775 km	$1,510
No. of Transformers	344,363	$844
Meters	1,588,000	$252
Streetlights	95,000	$76
Distribution O/H Corridor	47,508 km	N/A
Total Replacement Value		**$5,319**

2.7.1.2 Overview of Asset Health

Asset health is a direct driver of operating, maintenance, and capital expenditures. The distribution network asset health is generally good, meaning that in the near term it is able to continue to provide the service that it was designed for. The major caveat is that an increasing proportion of the facilities is at or approaching end of life, which means increasing maintenance efforts and expenditures will be required.

Figure 7-3 shows an age profile for poles, one of the major asset categories.

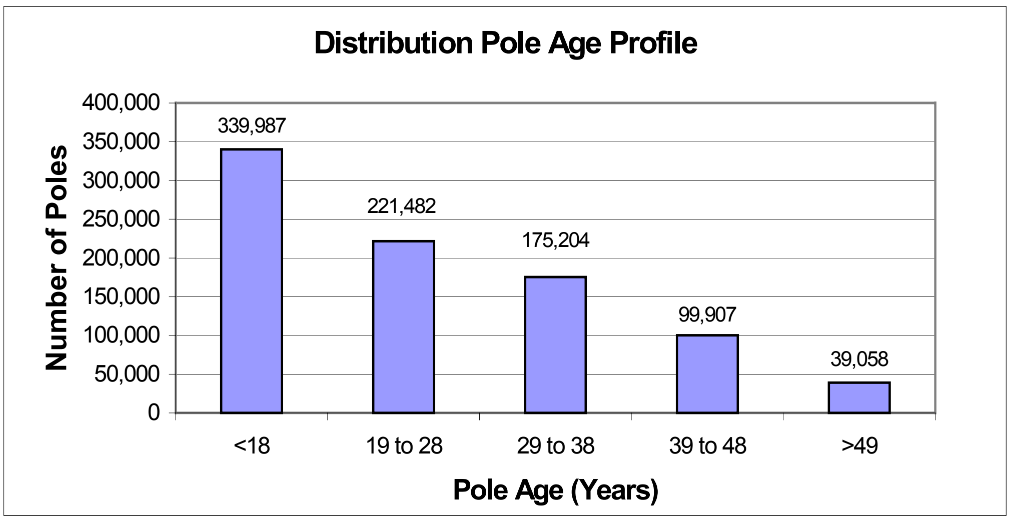

Figure 7-3. Distribution Pole Age Profile

The age profile of distribution poles is considered typical for other asset categories. The average life expectancy for poles is 40 years. As noted in Figure 7-3, 15% of poles are older than the average life expectancy, and with an additional 20% reaching that threshold within 10 years, a disproportionately high number of poles is nearing the end of their expected lives. Age is a major factor influencing asset health and this age profile indicates that additional sustaining investments (maintenance or replacement) will be necessary to manage asset failures and equipment-related outages.

BC Hydro conducts an annual assessment of the condition of its distribution assets. The following is a summary of the current condition of the assets, as well as BC Hydro’s response to asset condition.

- Primary conductors, overhead services, and streetlights are in good condition. Their age profile is similar to distribution poles, indicating that increasing maintenance costs and replacement investment will be required.
- Cutouts (fused disconnects) are on average only in fair condition as a result of a defect that potentially affects all pre-1997 cutouts. A multi-year change-out program has been implemented for these assets.
- Underground facilities are generally in good condition and are performing to standard, with the following limitations:
  - ⇒ underground feeder cables have an expected life of 30 to 50 years and approximately 70% of them are now over 40 years old;
  - ⇒ 50% of submarine cables are in poor condition and may not be repairable after the next failure, though there is a spare cable at each installation; and
  - ⇒ livefront equipment (part of old underground systems) is obsolete and requires replacement now.
- Corridors for overhead lines are in good condition but are deteriorating. When vegetation encroaches on power lines the impact on system performance is direct: outage restoration costs increase and reliability decreases. Increased attention is required in the immediate future.

Programs are already underway to address many of these concerns, and strategies for managing the remaining concerns are incorporated into the overall Asset Management operating plan.

2.7.1.3 Overview of System Utilization and Growth Issues

In areas where there is significant load growth, the high utilization of the existing distribution system requires costlier facilities such as new feeders. Nearly 20% of feeders are utilized to 90% or higher, and on average five new feeders are required annually to keep pace with load growth. Some high load growth areas such as metro-Vancouver, the Fraser Valley and the Whistler area have also exceeded substation capacity. New substations have been identified as the least cost option for serving the load in the following areas: Mount Pleasant in Vancouver, Port Kells in the Fraser Valley, and Function Junction in Whistler. Distribution infrastructure is being configured to better utilize these new substations when they come on-line.

Growth capital expenditures for distribution feeder infrastructure related to the above projects is included within the capital expenditures described in this chapter. The capital cost of new substations is included in chapter 6.

2.7.2 Approach to Asset Management

2.7.2.1 Introduction

Asset Management develops strategies to manage the integrity of the distribution system to deliver long term, reliable service to customers at the least cost. This involves performance monitoring, planning, capital investment, standards development, quality assurance, revenue metering, and R&D.

Asset Management integrates the strategic plans of Distribution Planning, Maintenance, and Operations to optimize solutions and align investments with performance targets and customer expectations.

2.7.2.2 Distribution Planning

The role of Distribution Planning is to ensure that system needs are identified, evaluated, and capital programs and projects are initiated to meet customer and system performance expectations, now and in the future.

Distribution Planning prepares an annual distribution substation load forecast, which provides a basis for capacity addition and system reinforcement requirements resulting from load growth and changing system performance needs. These forecasts draw on a number of information sources, such as substation peak demand readings, temperature data, and major expected loads. The forecast guidelines ensure that substation peak demand forecasts are consistent with corporate economic and load forecasts.

Investment plans are developed using long-term forecasts and system modeling tools. Plans are reviewed regularly and projects are identified as needs arise. This development process coupled with a project prioritization procedure enables projects to be thoroughly reviewed and alternative solutions to be considered. Project design and installation standards are developed to ensure that all projects fit into overall asset management strategies.

Another key role of Distribution Planning is to develop strategies for implementing distribution systems that incorporate new technical innovations, and that support energy efficiency and sustainability. Examples include advancements in automation and an open loop system that allows major commercial customers to reduce their exposure to extended outages. These strategies are implemented throughout the design, construction, maintenance, and operating policies and standards that were summarized in section 2.4.

2.7.2.3 Distribution Maintenance

The role of Distribution Maintenance is to ensure that distribution assets operate as designed. Maintenance is focused on a continuous improvement model that seeks to establish consistent least cost practices to provide highly reliable electrical supply to customers. Distribution Maintenance works with its service providers, primarily Field Services and Engineering Services, to implement those practices.

Asset management programs are focused on overhead and underground wires and facilities, and vegetation control along the electrical facility corridor. Distribution maintenance work includes:

- overhead and underground system safety inspections and condition assessment;
- maintenance of switches, reclosers, regulators, and capacitors;
- maintenance of wires, cables, and submarine cable systems;
- maintenance of kiosks, vaults, manholes, and associated civil facilities;
- renewal of lamps, repairs to pole fixtures, conductors, transformers, and other items associated with street and lease light systems; and
- testing, treatment, and replacement of distribution poles.

Reliability centered maintenance techniques have been applied to maintenance programs in an effort to optimize operating and capital spending, allowing asset condition assessment to drive annual maintenance and capital investment. This approach will continue to be developed in the coming years through data enhancements and additional condition assessments.

The vegetation maintenance process deals with living systems, which are subject to environmental forces beyond the control of the process to manage. Vegetation management programs are focused on continuous optimization of the various block-cycle programs and pruning standards to mitigate impacts on system reliability performance because of the differing seasonal growth patterns in the various regions of the service territory. The primary areas addressed with these programs are:

- pruning and slashing of planned blocks;
- hazard tree removal;
- hotspot pruning to keep area blocks on cycle; and
- focused pruning to improve reliability in target areas.

As part of its safety responsibility, BC Hydro has established standards of electrical safety awareness for vegetation maintenance workers and developed a program to ensure all contractors working on the system meet the standards. BC Hydro is also developing behavioral-based safety programs for contractors.

Weather, diseases, and infestations all play a role in the rate of growth or failure of trees that infringe upon BC Hydro's powerlines. In addition, since BC Hydro does not own the trees, issues of tree ownership, access to private property, and municipal and community values are a constant concern. Vegetation management integrates a number of initiatives leading to long-term, sustainable programs, including:

- converting right-of-way corridors to low growing, compatible plant species;
- a corridor pest management plan; and
- upgrading the BC Hydro Wildlife Tree course.

2.7.2.4 Revenue Metering

Revenue Metering is responsible for the supply and maintenance of devices that record electrical energy as defined by the Electric Tariff, consistent with Measurement Canada's revenue metering requirements. To accomplish this task Revenue Metering designs a life cycle 'cradle to grave' plan for each metering application. The meter plan includes purchase specifications, installation guides, wiring standards and drawings, and maintenance standards to monitor the ongoing accuracy of installed devices.

Revenue Metering works closely with MMBU, Customer Projects, Distribution Operations, Field Services, Engineering, BCTC, ABS, and IPP's to coordinate metering applications for new installations. Revenue Metering also manages and maintains a stand-alone records system for BC Hydro's 1.6 million meters, which enables periodic 'sample testing' of BC Hydro's meters.

2.7.2.5 Research & Development

R&D is a prime driver for long-term asset optimization, ensuring future systems align with customer needs and provide low cost solutions. BC Hydro Distribution’s R&D portfolio currently focuses on investments at Electric Power Research Institute (EPRI) and at the Canadian Electrical Association (CEA). These industry R&D organizations provide significant leveraging of investment dollars, for the benefit of BC Hydro customers and for the industry as a whole. The R&D program also looks at opportunities to partner with industry, communities and technical schools and universities to explore innovative technologies.

A few examples of R&D products implemented by BC Hydro Distribution are:

- system fault detection to improve safety and assist in power restoration;
- wood pole preservative to protect the environment;
- cable condition assessment to extend our assets and keep costs low; and
- dynamic voltage restorer (DVR) to assist customers with power quality issues.

The budget for BC Hydro’s R&D programs is identified in chapter 3, section 10.3.

2.7.3 Performance Metrics and Service Levels

The following performance metrics and services levels are utilized to identify and manage the performance of the distribution system and the effectiveness of asset management strategies.

2.7.3.1 System Performance Metrics

BC Hydro tracks the performance of its distribution system using industry standard benchmarks. Key system performance benchmarks are Average System Availability Index (ASAI), which is the percentage of time electricity is available, and Customer Average Interruption Duration Index (CAIDI), which is the average outage in hours per interrupted customer.

The key cost performance benchmark is Electricity Distribution Cost per Customer (COMA/Customer).

The target and current performance levels are shown in Table 7-9.

Table 7-9. Key System Performance Targets

Measure	F2003		F2004		F2005	F2006
	Target	Actual	Target	Actual *(Note 1)*	Target	Target
ASAI	99.970%	99.957%	99.970%	99.949%	99.970%	99.970%
CAIDI	2.15 hrs	2.60 hrs	2.15 hrs	2.97 hrs	2.15hrs	2.15 hrs
Electricity Distribution COMA/Customer	$152.6	$159.3	$169.7	$172.0	$178.7	$181.8

Notes:
1. F2004 Actual results for ASAI and CAIDI are 12-month rolling actuals to October 31, 2003. Year-end forecasts are ASAI: 99.951%, CAIDI: 3.00 hours (based on actual to October 2003). COMA/Customer is a year-end forecast.

The ASAI and CAIDI actuals for F2003 and F2004 indicate that performance targets have not been met. However, those same targets are retained for F2005 and F2006 on the basis that they are reasonable and reflect the minimum level of service expected by BC Hydro's customers. The rising COMA per Customer costs in the forecast period reflect the requirement for increasing investment needed to address the reliability targets and the ageing distribution infrastructure.

System performance including ASAI and CAIDI are also utilized at a feeder level and a district level. Actual performance is evaluated against past performance, against the reasonable capability of the system, and against current customer needs and expectations. Where performance gaps exist, improvement efforts are initiated. Major storms and other events are also assessed to see if system changes would be appropriate to avoid or minimize interruptions due to similar events in the future.

2.7.3.2 Benchmarking

The 2002 PA Consulting Benchmarking report ranked BC Hydro Distribution in 1st Quartile in costs but 3rd Quartile in system performance.

The cost comparison shown in Figure 7-4 is based on overall distribution capital and operating expenditures per customer, and shows that BC Hydro's distribution function is a low cost leader in the industry. Even with the increased expenditures forecast for F2005, distribution costs will remain low.

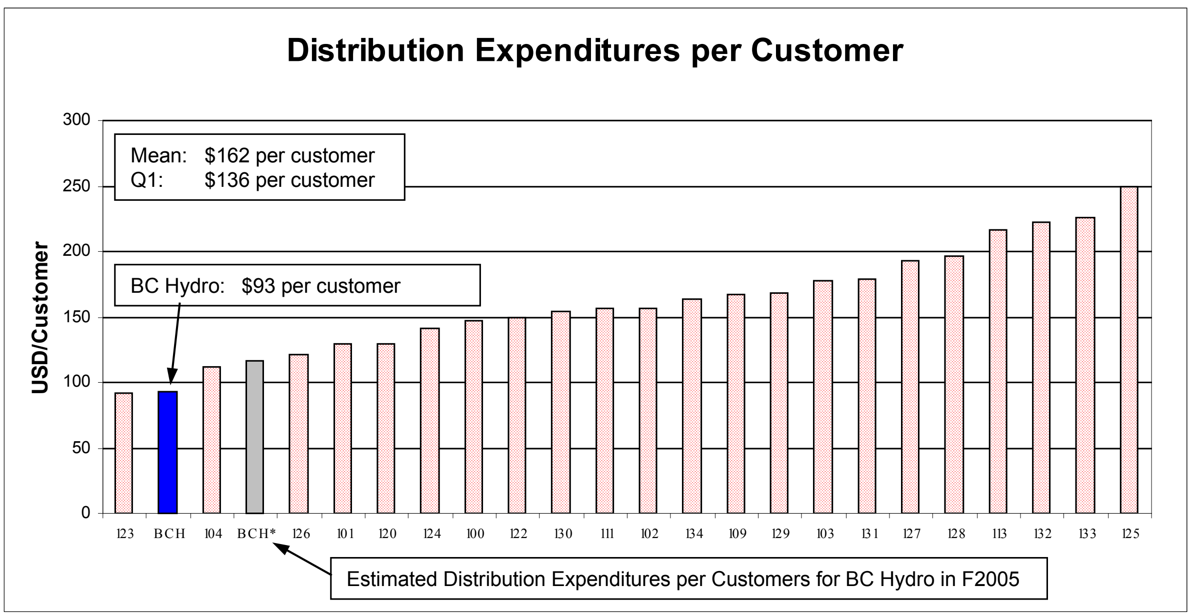

Figure 7-4. Distribution Expenditures per Customer

System performance as measured by ASAI and CAIDI are also benchmarked by PA Consulting and the results are shown in Figure 7-5 and Figure 7-6, respectively. BC Hydro's relatively poor performance is partially attributable to its large, densely treed, rural service area. As shown in Figure 7-7, BC Hydro has approximately three times as many trees per mile of overhead line as the PA Consulting average.

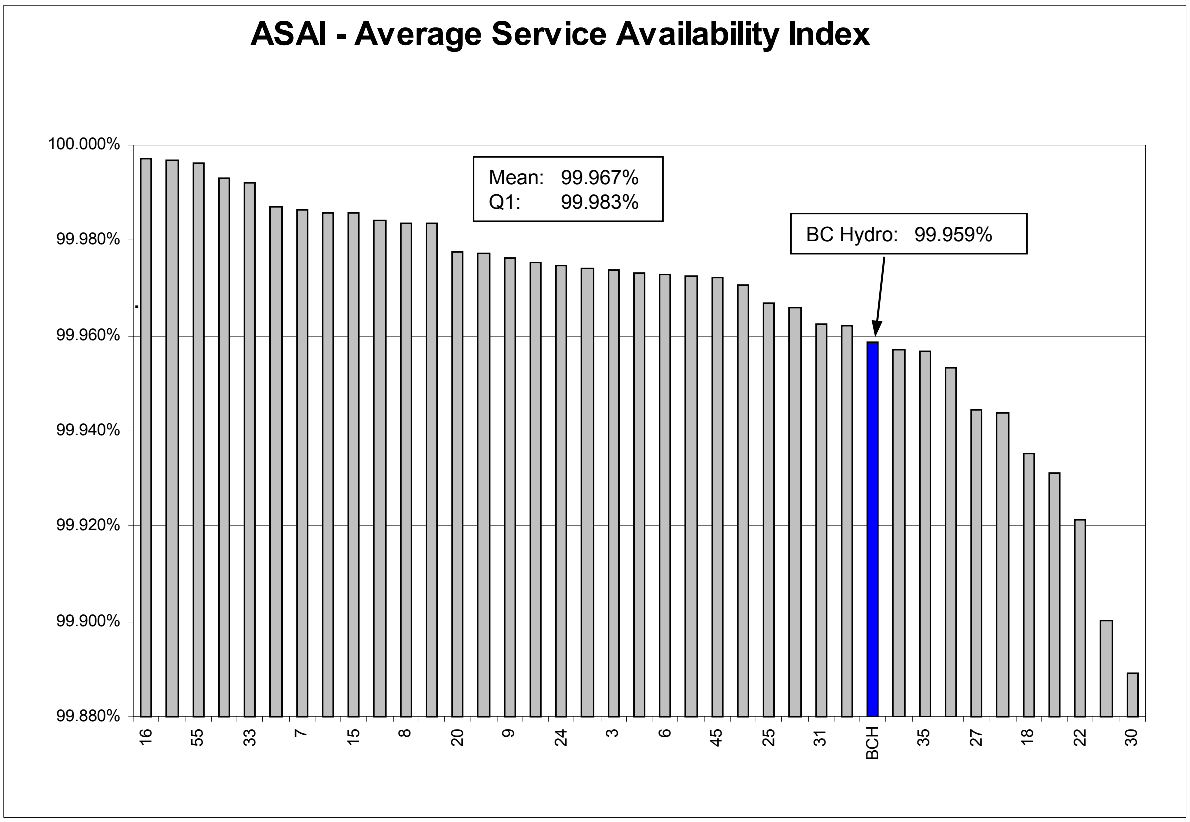

Figure 7-5. ASAI: 2002 PA Consulting

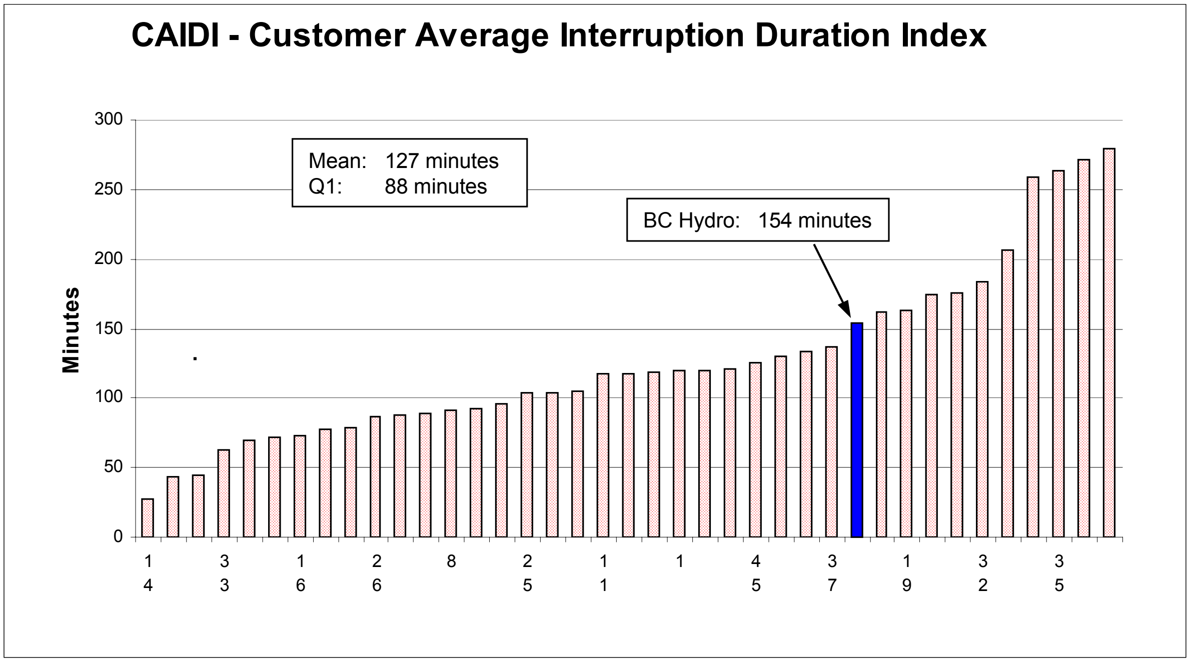

Figure 7-6. CAIDI: 2002 PA Consulting

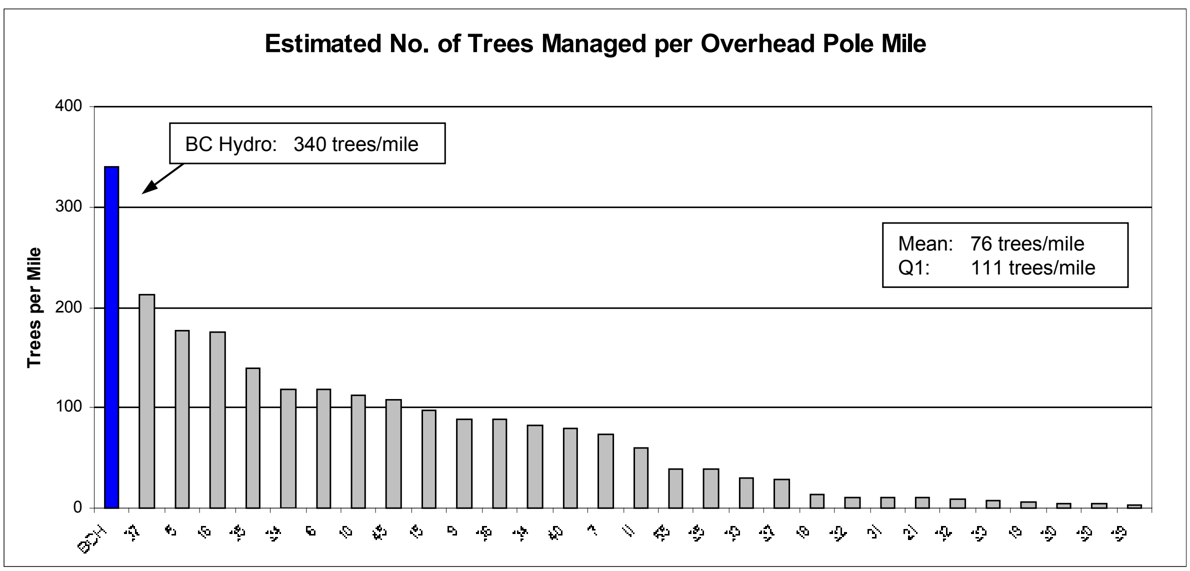

Figure 7-7. Estimated Number of Trees per Overhead Pole Mile

When compared to Canadian utilities, BC Hydro's distribution system performance is slightly below average, in 2nd Quartile, as shown in Figure 7-8. CEA data is used for this comparison because the PA Consulting survey includes a greater number of utilities with concentrated urban service areas, while Canadian utilities tend to serve larger rural areas.

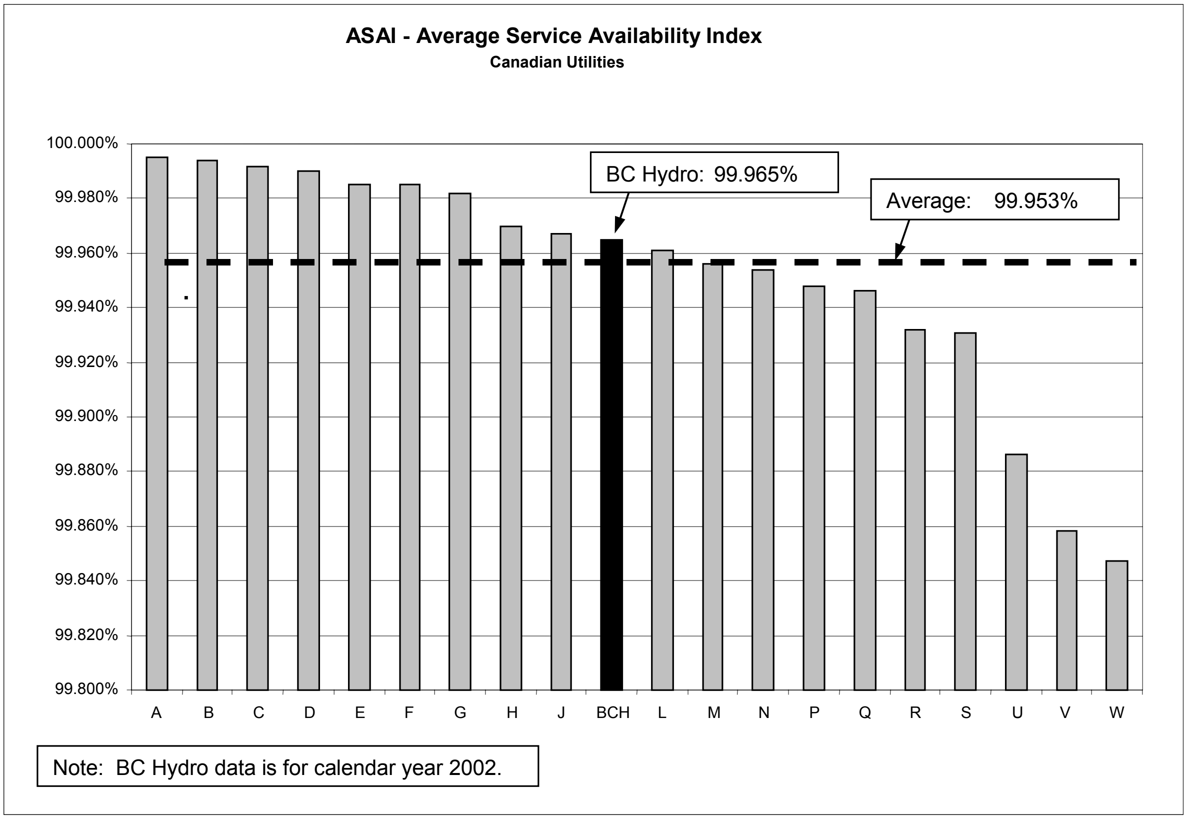

Figure 7-8. Distribution Performance – ASAI: BC Hydro vs. CEA

2.7.3.3 Replacement Capital Ratio

Replacement Capital Ratio (RCR), or the sustaining infrastructure capital as a percentage of the estimated replacement value, is used to measure the level of reinvestment that BC Hydro makes to sustain the ongoing viability of the distribution infrastructure by replacing non-performing assets.

RCR is derived from the spending required for sustaining the distribution infrastructure and is used as a means to provide a comparison of BC Hydro's reinvestment levels relative to industry practices. Other electric utilities' RCRs range from 0.25% to 3.5%, depending on the position of the infrastructure on the life-cycle. Based on the asset condition assessment and replacement requirements, BC Hydro's target RCR for F2004 is 1.49%. Future target RCRs will be adjusted if system performance and asset health deviate from acceptable levels.

2.7.3.4 Vegetation Management Performance

Figure 7-9 shows customer hours lost due to various vegetation causes.

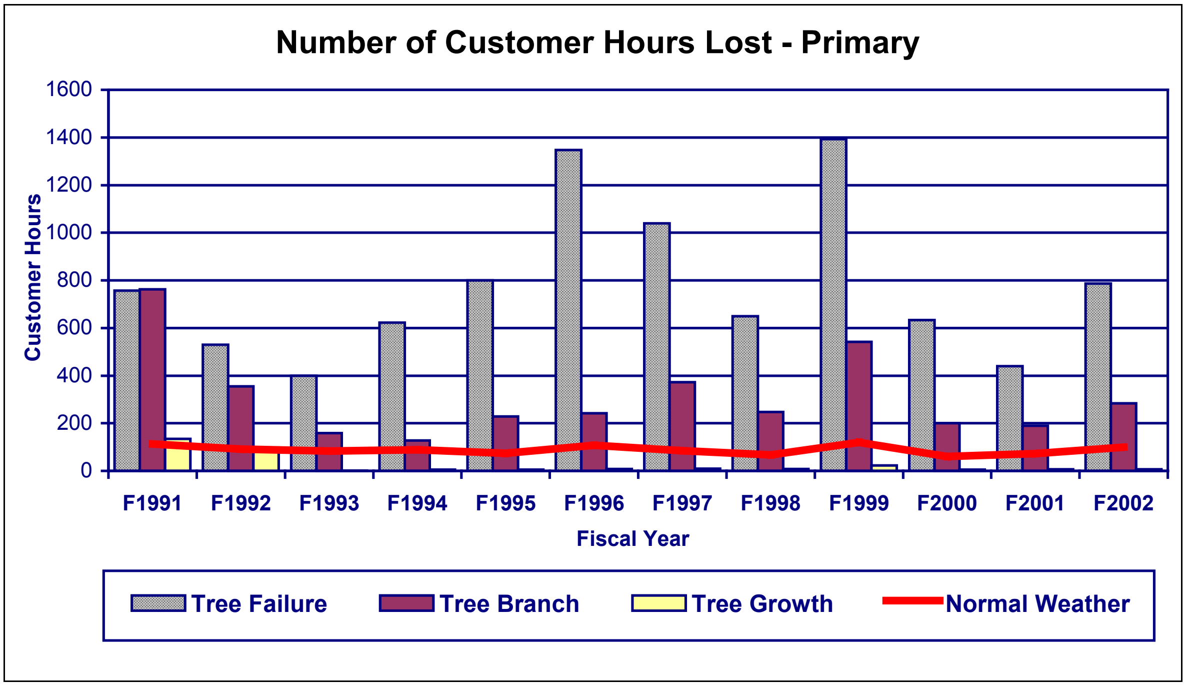

Figure 7-9. Vegetation Impacts on Outages

Tree growth outages are almost entirely a tree pruning issue and the near-elimination of tree growth outages as shown in Figure 7-9 demonstrates that vegetation management programs are well optimized to avoid a potentially-significant cause of outages.

The PA Consulting comparisons to other utilities demonstrate that costs for vegetation management are well controlled and, considering the number of trees managed per overhead line mile in the province, performance is excellent. Rankings on some of the key indicators are:

- first Quartile for distribution vegetation management expense per overhead line mile;
- first Quartile for average number of trees managed per overhead line mile; and
- first Quartile in optimization of tree pruning cycles.

Vegetation management costs have been contained through detailed standards and inspections to ensure practices meet the standards. Over the past 10 years a highly skilled contingent workforce has been developed through competitive tendering for vegetation contracts.

Figure 7-10 shows the low cost of BC Hydro's vegetation management practices when compared to other North American utilities. However, tree-related outages account for a significant proportion of all customer interruptions and customer hours lost. The 2002 PA Consulting findings place BC Hydro in the 3rd Quartile in terms of tree-related SAIDI, which is largely attributable to the fact that BC Hydro manages three times as many trees per overhead mile as the PA Consulting average. Reductions in tree-related outages can only be achieved through increased funding in vegetation management programs.

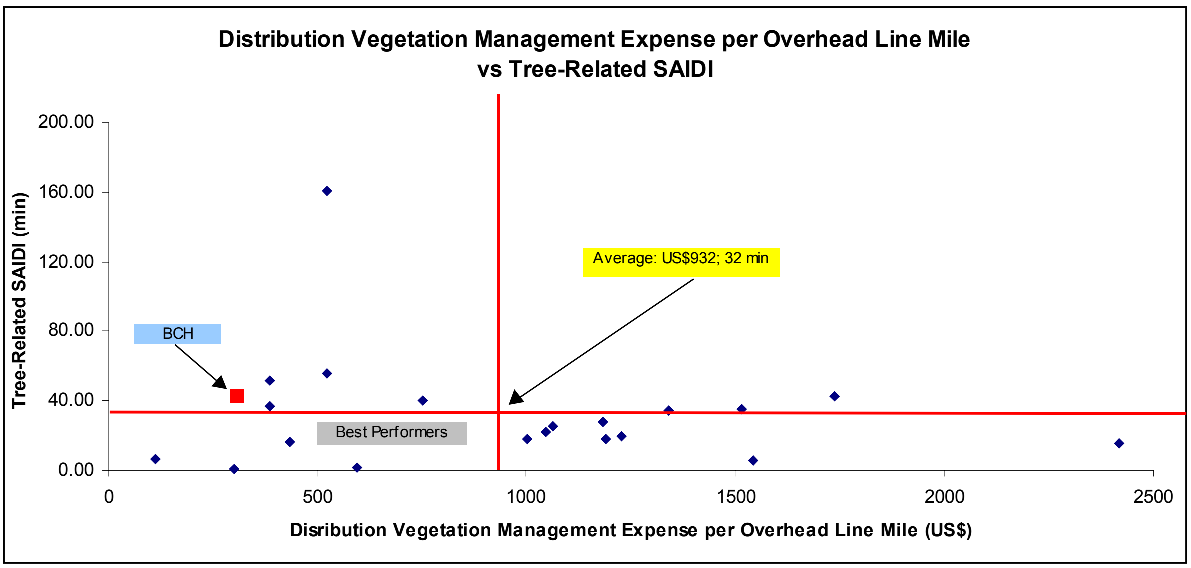

Figure 7-10. Distribution Vegetation Management Expense vs. SAIDI

<u>*2.7.3.5 Implications of Asset Management Benchmarks and Performance Targets*</u>

The benchmarking confirms the challenge of balancing system performance against costs given the diverse and large geographic service territory served by BC Hydro. Increased expenditures are required to improve system reliability to at least current targets.

Notwithstanding the need for increased investment, BC Hydro intends to keep distribution asset management costs within the 1st Quartile.

2.7.4 Operating Plan

Asset Management effectively develops and maintains the integrity of the distribution system to deliver long term, sustainable, and reliable service to customers. Through short and long term planning, asset health assessment and system performance monitoring, Asset Management is able to develop and implement programs and projects that allow the distribution system to continue to provide the service that is valued and expected by customers.

With a large portion of the infrastructure reaching or exceeding end of life, the need for increasing re-investment is growing and significant. Effective asset management practices will help to minimize long-term costs. There is also an opportunity to better align reliability with customer expectations as improvements are implemented.

Table 7-10 identifies the operating expenses for Asset Management during the test periods.

Table 7-10. Operating Expenses, Asset Management

($ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Direct	$50.1	$56.4	$66.7	$67.0
Support	6.8	9.4	9.6	9.4
Corporate Allocations	6.3	7.8	10.8	10.8
Less Capitalized Overhead	(11.9)	(15.8)	(17.2)	(17.3)
Less Recoveries	(5.2)	(5.8)	(6.4)	(6.7)
Total OMA Expense	**$46.1**	**$52.0**	**$63.5**	**$63.2**

Table 7-11 identifies the forecast capital expenditures for Asset Management during the test periods.

Table 7-11. Capital Expenditures, Asset Management

($ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Sustaining	$53.0	$78.4	$83.2	$85.7
Growth	13.8	8.4	10.2	10.6
Deferred Capital	-	-	-	-
Capital Expenditures Gross of CIA	**$66.8**	**$86.8**	**$93.4**	**$96.3**
Less Sustaining CIA	(0.5)	-	-	-
Less Growth CIA	(0.5)	(0.5)	(0.1)	(0.1)
Total CIA	**$(1.0)**	**$(0.5)**	**$(0.1)**	**$(0.1)**
Less Recoveries	(3.8)	(5.1)	(5.5)	(5.9)
Net Capital Expenditures	**$62.0**	**$81.2**	**$87.8**	**$90.3**

Growth capital reflects system expansion requirements as discussed previously in section 2.7.1.3. Sustaining capital was increased in F2004 in response to asset health and reliability concerns.

Table 7-12 identifies headcount requirements of Asset Management.

Table 7-12. Headcount, Asset Management

	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
M&P	33	39	46	48
IBEW	-	-	-	-
OPEIU	39	46	49	49
Total Headcount	**72**	**85**	**95**	**97**

2.8 Summary of Electricity Distribution Revenue Requirement

Table 7-13, Table 7-14 and Table 7-15 summarize operating and capital expenditures and headcount requirements during the test periods for the overall Electricity Distribution function, respectively. These tables represent the aggregate of the operating plans for Customer Projects, Distribution Operations, and Asset Management, which are described in sections 2.5.5, 2.6.5, and 2.7.4.

Table 7-13. Operating Expenses, Electricity Distribution

($ millions)	**F2003 Actual**	**F2004 Forecast**	**F2005 Plan**	**F2006 Plan**
Direct	$105.7	$121.4	$130.6	$131.9
Support	22.6	25.7	26.4	25.8
Corporate Allocations	15.3	18.7	25.9	25.8
Less Capitalized Overhead	(35.0)	(39.2)	(42.0)	(42.7)
Less Recoveries	(6.6)	(7.1)	(7.6)	(7.4)
Total OMA Expense	**$102.0**	**$119.5**	**$133.3**	**$133.4**

Table 7-14. Capital Expenditures, Electricity Distribution

($ millions)	**F2003 Actual**	**F2004 Forecast**	**F2005 Plan**	**F2006 Plan**
Sustaining	$64.6	$86.7	93.0	94.8
Growth	121.7	119.0	124.6	132.0
Deferred Capital		-	-	-
Capital Expenditures Gross of CIA	**$186.3**	**$205.7**	**$217.6**	**$226.8**
Less Sustaining CIA	(8.7)	(2.5)	(4.2)	(3.8)
Less Growth CIA	(35.9)	(36.6)	(38.4)	(41.0)
Total CIA	**$(44.6)**	**$(39.1)**	**$(42.6)**	**(44.8)**
Less Recoveries	**(5.6)**	**(6.8)**	**(6.6)**	**(7.0)**
Net Capital Expenditures	**$136.1**	**$159.8**	**$168.4**	**$175.0**

Table 7-15. Headcount, Electricity Distribution

	F2003 Actual	**F2004 Forecast**	**F2005 Plan**	**F2006 Plan**
M&P	61	69	76	78
IBEW	0	0	0	0
OPEIU	284	300	335	335
Total Headcount	**345**	**369**	**411**	**413**

3 Non-Integrated Areas

3.1 Introduction

The purpose of this section is to describe the activities and costs associated with providing energy in BC Hydro's Non-Integrated Areas (NIA). NIA serves remote areas using local generating stations that are not connected to the transmission grid.

Operating and capital expenditures associated with generation and distribution in NIA are included in the costs of Electricity Distribution, discussed in section 2, and are presented in section 3 for information purposes only. The cost of energy associated with NIA is presented in this section.

This chapter does not include costs associated with managing customer accounts in NIA. These costs are included in the Customer Care costs, discussed in chapter 8.

3.2 Scope of Services

BC Hydro serves nine remote communities in three geographic regions in the province, which are:

- the Stikine area in Northwest British Columbia (Atlin, Dease Lake, Telegraph Creek and Eddontenajon);
- the Queen Charlotte Islands (Masset and Sandspit); and
- the Bella Coola valley (Bella Coola, Bella Bella, and Anahim Lake).

These communities are served by local generating stations and distribution networks.

3.2.1 Customer Profile

The total population in the three geographical regions is approximately 12,000, with 6,324 metered accounts. The customer base is predominantly residential, with only a few areas servicing institutional, small commercial and industrial loads.

3.2.2 Electrical Generation

Generating capacity in the NIA is provided by a combination of diesel stations and small hydro stations. IPPs are also used in some areas. Major generation assets include:

- sixty three diesel generating units (DGU) in nine stations;
- two hydroelectric generating units in one station; and
- thirty diesel fuel tanks.

Approximately one third of power supplied is purchased from IPPs. BC Hydro owns diesel generating stations in communities served by IPPs but rely on them for standby service only.

BC Hydro's NIA generating stations are staffed by BC Hydro Field Services personnel and agents under contract, as summarized in Table 7-16.

Table 7-16. Non-Integrated Generating Stations

District	Location	Station	Station Operation	
			Employees	**Contractors**
Bella Coola	Anahim Lake	Anahim Lake DGS		1 agent
	Bella Coola	Ah-Sin-Heek DGS Clayton Falls HGS	4 operators (*Note 1*)	
	Bella Bella	Bella Bella DGS		1 agent
Stikine	Atlin	Atlin DGS		1 agent
	Dease Lake	Dease Lake DGS		1 agent
	Iskut	Eddontenajon		1 agent
	Telegraph Creek	Telegraph Creek DGS		1 agent
Queen Charlotte Islands	Masset	Masset DGS	6 operators	
	Sandspit	Sandspit DGS	2 operators	
Total:			**12 operators**	**6 agents**

Notes:
1. Clayton Falls HGS is operated by the same operators as Ah-Sin-Heek DGS.

Table 7-17 identifies BC Hydro's NIA generating capability (including BC Hydro owned facilities and IPPs under contract).

Table 7-17. Summary of BC Hydro's NIA Generating Capability

District	Location	Capacity		Type
Bella Coola	Anahim Lake	3.65	MW	Prime
	Bella Coola	9.25	MW	Prime
	Bella Bella	2.7	MW	Standby
	Bella Bella IPP	6	MW	IPP
Stikine	Atlin	2.65	MW	Prime
	Dease Lake	3.98	MW	Standby
	Dease Lake IPP	3	MW	IPP
	Iskut	2.2	MW	Prime
	Telegraph Creek	2.2	MW	Prime
Queen Charlotte Islands	Masset	11.37	MW	Prime
	Sandspit	9.2	MW	Standby
	Sandspit IPP	5.7	MW	IPP
Total Prime		31.32	MW	50.5%
Total Standby		15.88	MW	25.6%
Total IPP		14.70	MW	23.9%
Total Capacity		**61.90**	**MW**	**100%**

3.2.3 Distribution Networks

Major distribution assets in NIA communities include:

- 837 km of overhead and 24 km of underground distribution lines;
- 13,247 distribution poles;
- 6,324 revenue meters; and
- ten substations.

BC Hydro Field Services' power line technicians provide extension, improvement, and maintenance services for the distribution networks in the NIA communities, except for Atlin, which is served by the Yukon Electric Company Ltd. under contract with BC Hydro.

3.3 NIA Strategy

BC Hydro's policy regarding rates and services for NIA customers is currently under review. At present, BC Hydro's objective is to provide NIA customers with a similar level of service to that which is provided to its integrated customers, while minimizing costs to the extent possible given the remoteness of the communities served.

Key issues and strategies facing NIA generation include the following:

3.3.1 Cost Minimization

BC Hydro's Electric Tariff provides a different rate structure for non-integrated customers (Zone 2) than for the larger integrated network (Zone 1). The cost of providing electricity supply to the remote communities in NIA is not fully recovered through rate revenue. A degree of subsidization exists from Zone 1 customers, and cost minimization in NIA continues to be a key strategy.

The strategies being utilized to minimize the costs associated with NIA service delivery include the following:

- replace old generators with new fuel efficient ones;
- obtain cheaper and cleaner sources of power from IPPs;
- contract out unit/equipment maintenance; and
- restructure the organization and reduce staff level.

BC Hydro is currently reviewing its strategy to determine an appropriate structure for the NIA function. The process was initiated in August 2003 and is expected to be completed by the end of the year.

3.3.2 Replacement of the Diesel Fleet

Many of BC Hydro's diesel units in NIA communities are now older than the manufacturer's recommended service life. Approximately 60% of the units are more than 21 years, and only 30% of the units are rated better than acceptable condition. The average age of the fleet is 28+ years, which is higher than the industry standard of 25 years.

BC Hydro plans to replace one diesel unit in each of the next two years. In the longer term (i.e., ten years) more than 30% of the fleet will need to be replaced. This approach will lower the average age of the fleet to below the accepted industry standard.

BC Hydro is also looking for IPP projects to supplement or replace reliance on the diesel fleet when economically attractive. Three IPPs presently serve Bella Bella, Sandspit and Dease Lake.

3.3.3 Managing Environmental Risks

The biggest environmental risk associated with diesel stations is fuel/oil spills. At each diesel generating station, appropriate spill prevention systems and protective equipment are installed. Fuel custody and handling (containment) projects have been completed in Masset and Sandspit to minimize environmental risk. BC Hydro plans to upgrade two additional stations, Anahim Lake and Telegraph Creek, in the next two years.

BC Hydro is also looking for IPPs that can provide environmental benefits compared to diesel stations.

3.3.4 Fuel Price Volatility

More than half of all energy supplied in NIA is generated from diesel stations, and the cost of diesel fuel represents approximately 30% of BC Hydro's direct operating costs in these areas.

Increased fuel prices have had a significant impact on the cost of service delivery. As shown in Table 7-18, fuel costs have increased approximately 80% in just over five years.

Table 7-18. Fuel Costs, Non-Integrated Areas

Fiscal Year	Average Fuel Cost $/litre	% change from previous year
F1999	0.2511	--
F2000	0.3064	+22.02%
F2001	0.3969	+29.54%
F2002	0.3884	-2.14%
F2003	0.4028	+3.71%
F2004	0.4531	+12.49%

While fuel purchase volumes are not expected to increase, rising fuel prices will continue to increase the cost of service to NIA communities.

To mitigate the financial risks associated with this cost item, BC Hydro has been actively seeking alternative sources of power generation for the past several years. Power purchase agreements involving independent hydroelectric stations and a proposed wood waste thermal station have been signed, providing potential economic advantages over diesel supply.

3.4 Performance Metrics and Service Levels

Reliability targets in NIA are similar to those in integrated areas, and the NIA system has been very reliable despite its relative age. Reliability in NIA is measured by system performance metrics including ASAI and CAIDI. Table 7-19 provides an overall summary of reliability in NIA, as well as reliability by function.

Table 7-19. System Performance in Non-Integrated Areas

	ASAI (%)		CAIDI (hrs)	
NIA	**F2002**	**F2003**	**F2002**	**F2003**
All Functions	99.81	99.84	1.68	2.19
Distribution	99.90	99.88	2.79	3.79
DGS Source	99.92	99.98	0.99	0.99
IPP Source	99.99	99.99	0.61	0.69
Substation	n/a	99.99	n/a	1.11
BC Hydro Integrated System	99.96	99.96	2.57	2.60

CAIDI, the average outage in hours per interrupted customer, is lower in NIA than for the integrated area in both F2002 and F2003. The relatively short distribution feeders in NIA allow outage causes to be determined quickly and enable the power from a single source to be restored in a shorter period of time.

ASAI, the percentage of time electricity available, is lower in NIA than in the integrated system for both F2002 and F2003. The reliance on a single source of power results in more outages when source problems occur because there is no backup supply available as there is in the integrated areas.

Source outages have decreased for prime power, standby power, and IPP power over the previous two years, as summarized in Table 7-20.

Table 7-20. Source Outages, Non-Integrated Areas

Source Outages	2002	2003
Prime Power	47	36
Standby Power	7	1
IPP Power	14	11

3.5 Operating Plan

The operating plan for NIA in the test periods is summarized as follows.

3.5.1 Cost of Energy

Table 7-21 summarizes the cost of fuel and power purchases in NIA.

Table 7-21. Cost of Energy, Non-Integrated Areas

($ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Total Cost of Energy	$14.1	$12.9	$14.1	$15.0

3.5.2 Operating Expenses

Operating expenses for the test periods are based on actual expenditures in F2003 and previous fiscal years.

Maintenance costs in F2004 and F2005 are affected by the delayed in-service date of North Island Power Corp., which was scheduled to start in October 2002 but is now scheduled for December 2004. A consequence of this delay is the deferral of Masset DGS unit overhauls. The cost of these overhauls ($600,000), previously deferred, is now needed in F2004-F2005 to ensure units at Masset DGS are appropriately maintained to provide reliable prime power service.

Table 7-22 shows the forecast for operating expenses in NIA.

Table 7-22. Operating Expenses for Non-Integrated Areas

($ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Total Operating Expenses	$6.9	$7.7	$8.1	$8.1

3.5.3 Capital Plan

The capital plan for NIA concentrates on minimizing environment risks, promoting IPP connections, replacing deteriorated equipment, and maintaining the present level of service reliability. Capital investments include fuel custody and handling system improvement, substation transformer replacement/exchanges, diesel engine replacement program, and establishing mobile emergency power generation facilities.

Table 7-23 summarizes capital expenditures forecast for NIA.

Table 7-23. Capital Plan, Non-Integrated Areas

($ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Sustaining	$0.3	$1.6	$4.2	$2.8
Growth	0.3	0.3	0.3	0.3
Capital Expenditures Gross of CIA and Recoveries	0.6	1.9	4.5	3.1
Less Growth CIA	(0.1)	(0.1)	-	-
Less Recoveries	(0.1)	(0.1)	-	-
Total Net Capital Expenditures	**$0.4**	**$1.7**	**$4.5**	**$3.1**