BC Hydro and Power Authority

Non-Integrated Areas (NIA) Business Strategy

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Executive Summary

BC Hydro's Non-Integrated Areas (NIA) business is at a critical juncture. Major corporate restructuring within BC Hydro has changed fundamentally the organization of key roles and responsibilities for NIA business functions. Currently, the incumbents in key roles possess the technical expertise and historical knowledge required to ensure continuity in the efficiency of operations and administration through the transition. However, over the long term, the current business model for NIA operations within the newly restructured BC Hydro is not optimal for addressing the unique characteristics and needs of service provision to remote areas, and there is a significant risk that unless new initiatives are taken, NIA business performance will deteriorate.

The purpose of this study is to assist the Distribution Line of Business (DLoB) in the development of a strategy for electricity supply to NIA in British Columbia. The study identifies strengths and issues associated with the current business model, recommends a number of opportunities to address key issues in the short term, and evaluates a variety of potential alternative business options which BC Hydro may wish to examine further in the context of preparing a strategy and corresponding business plan for NIA for the next five to ten years.

The Status Quo

Highlights of the current business model include the following:

- **Roles and responsibilities for key NIA business functions are decentralized among DLoB departments and service organizations, especially Field Services**. There is currently no clear leader to coordinate core functions and be accountable for NIA-specific objectives, and there is a need for greater clarity as to the assignment of roles, responsibilities and reporting structure. However, staff resources appear to be efficient and competency requirements are being met.

- **The NIA asset base is valued at approximately $26 million, and consists primarily of diesel generation-related assets**. **However, the asset base is ageing and an asset replacement strategy is not currently in place**. Despite the ageing fleet of diesel generating units, reliability in the NIA system is high and has improved in recent years.

- **Power purchase arrangements with Independent Power Producers (IPP) are beginning to provide cost and environmental benefits in some areas**. BC Hydro has been actively pursuing power purchase opportunities in NIA and has successfully implemented three such arrangements. A fourth is expected next year. Current contract management has been effective, IPP reliability has improved and rising diesel fuel costs have resulted in purchased power offering some cost advantages over diesel generation in two of the three areas. Other benefits of purchased power include the environmental benefits of displacing diesel generation, and the local employment which can be generated through IPP operations.

- **The costs of NIA business activities are not recovered through current rates**. The estimated cross subsidy from customers on the integrated system to NIA customers is approximately $0.12 per kWh.[1] Although there are some issues associated with estimating the actual net loss to BC Hydro associated with NIA operations, the gross margin has clearly eroded over the past several years, as rates have remained frozen while operating costs have increased annually.

- **Expansion in current NIA generating capacity is not expected to be required in the foreseeable future**. Overall population growth in NIA communities has been modest and economic activity in these areas has slowed. NIA customers benefit from low (subsidized) electricity rates and some employment related to BC Hydro and IPP operations.

- **Power Smart programs have been introduced to NIA and further opportunities to implement demand side management are not expected to be substantial.** Although the program results from 1989 to 1998 were not measured, the program was eventually discontinued as interest lessened.

- **The BC government's Energy Strategy (November 2002)[2] does not directly address NIA but does potentially constrain some strategic options.** Specific policies described in the strategy are inconsistent with rate differentials for different groups of BC Hydro customers, selling BC Hydro's assets and compromising service standards. In order to respond to the strategy, BC Hydro will have to implement changes to planning processes and accounting conventions which will impact NIA.

Our review of the current business model identified key strengths and issues to be used as criteria for evaluating alternative business models. The strengths are numbered S-1 through S-9 and the issues are numbered I-1 through I-8. These are summarized in the following table.

[1] Based on Net Margin, excludes all asset-related and allocated expenses.

[2] *Energy for Our Future: A Plan for BC*. November 2002.

Strengths		Issues	
S-1	Staff complement is efficient	I-1	Coordination/leadership with accountability is needed
S-2	Competency in key roles is adequate	I-2	Clarity of roles and responsibilities is needed
S-3	System reliability is high	I-3	Replacement of the ageing diesel GU fleet will be required
S-4	Diesel displacement is being achieved	I-4	IPP contracts are negotiated under conditions of high uncertainty
S-5	IPP contract management is effective	I-5	DLoB costs are allocated disproportionately to NIA
S-6	Local economic benefits are being realized	I-6	Gross margin for the NIA profit centre is eroding as costs have increased more rapidly than revenues
S-7	Low (subsidized) electricity rates are enjoyed by NIA customers	I-7	An ongoing subsidy to NIA is required
S-8	NIA capital and OMA costs are publicly regulated	I-8	Changes are required in planning processes and accounting conventions to respond to policy directives
S-9	Service standards and a complaints process are protected by the regulator		

Optimising the Status Quo

We expect that most of the strengths identified can be sustained for the short term. However, a number of measures can be implemented to begin to address the issues associated with the Status Quo. These include the following:

- **(I-1) Leadership**: Establish a permanent role within Operations, tasked with coordinating and delivering NIA functions and services.
- **(I-2) Decision and referral process**: Implement a decision and referral process to ensure appropriate communication in decision making.
- **(I-3) Asset management and replacement strategy**: Develop an asset management and replacement strategy which reflects the highest return on investment over the long term.
- **(I-4) Determine value of IPP contracts**: Review key cost elements used in projecting IPP cost effectiveness for current IPPs, and compare to actuals since they have been operational. This review could provide opportunities to decrease the uncertainty associated with future negotiations.
- **(I-5) Business sustaining and finance cost allocation methods**: Review cost allocation methods used for business sustaining and finance charges to ensure that they are fair relative to other DLoB business units.

- **(I-6) Production costs**: Minimize direct costs of energy production to the extent possible by ensuring that energy production inputs are at minimum levels, and that demand side management opportunities which reduce costs are fully employed.
- **(I-7) Alternative funds for NIA subsidy**: Explore potential alternative sources of funds, including federal and provincial governments.
- **(I-8) Respond to future policy directives**: Examine the requirements of the new BC Energy Strategy and assess how best to address those which apply specifically to NIA.

There are currently no constraints regarding the implementation of any of these recommendations. These issues can be addressed, at least initially, without implementing any fundamental changes to the NIA business model. Over the long-term, however, this course will not necessarily address the potential for a decline in NIA business performance. Consequently, this study also examines and evaluates a number of substantively different business models.

Alternative business models

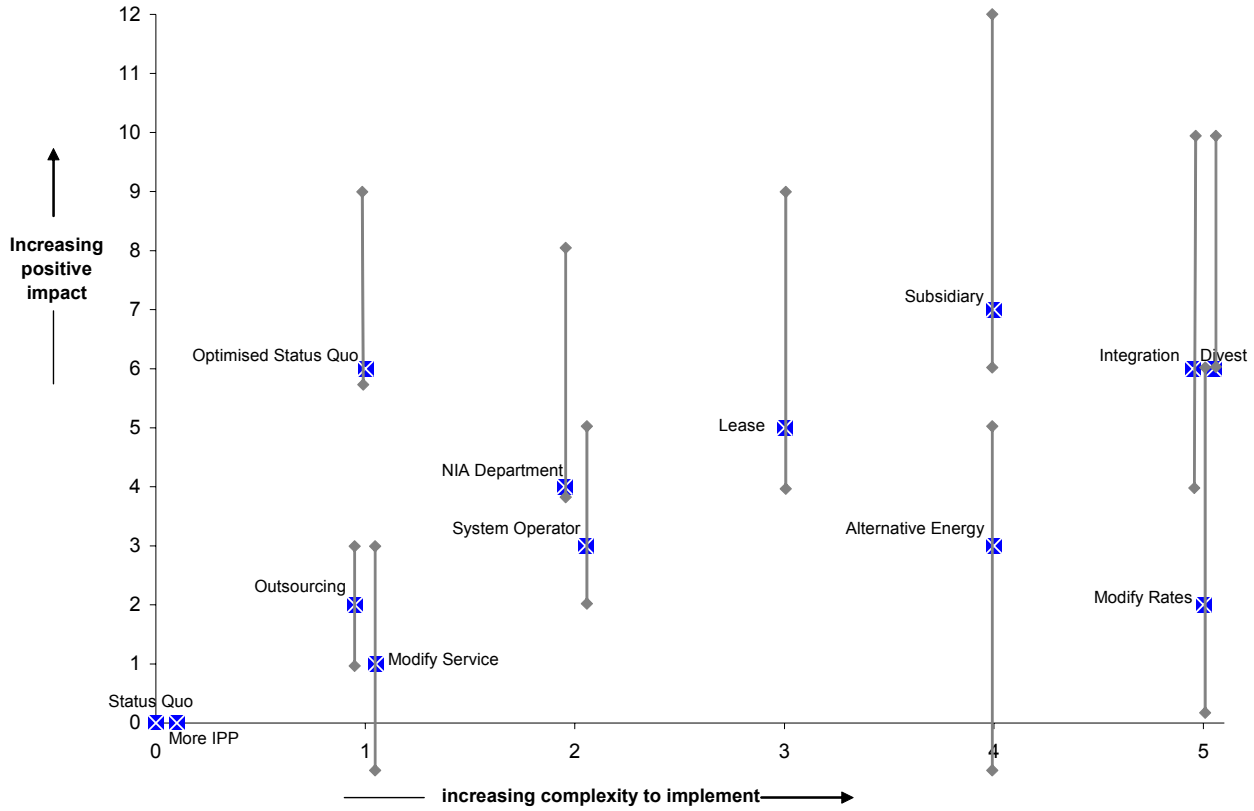
BC Hydro began examining alternative business models for NIA in the early 1990's. Through a review of previous strategic documents and interviews with senior management at BC Hydro, we identified thirteen options for assessment and evaluation in this study. These are grouped and listed below:

Option 1. Status Quo
Option 2. Optimised Status Quo
Modified corporate structure options
Option 3. Create an NIA Department
Option 4. Create an NIA Subsidiary
Option 5. Integrate NIA communities
External service provider options
Option 6. Outsource various services
Option 7. Engage a system operator
Option 8. Lease assets and their operations to a third-party
Divestiture options
Option 9. Sell assets to third party
Policy change options
Option 10. Modify rates
Option 11. Modify service levels
Alternative energy options
Option 12. Displace usage of diesel facilities through alternative energy sources
Option 13. Increase reliance on IPPs

It is also possible to combine and/or partially implement a number of these options.

Evaluation of Options

Each subsequent option was evaluated and compared to Option 1, the Status Quo. The results of the analysis are summarized in the following chart. The bases for comparison of options were two measures. The first measure reflects the **complexity**[1] associated with transitioning the NIA business to the option in question (x-axis). The second measure reflects a subjective score to characterize the (positive and negative) **impacts**[2] expected to accrue for the NIA business if the option is adopted in whole or in part (y-axis).



Options which are expected to have the greatest positive impact on the NIA business are relatively high on the chart. Those with relatively higher expected complexity to implement are located toward the right side of the chart.

When all impact (benefits) criteria are weighted equally, the relative position of options on the chart is denoted by the squares marked with an X. However, we also conducted a sensitivity analysis to assess how the relative benefits of the options might shift if specific types of criteria were weighted differently. The range of results for each option is denoted by a grey line with a diamond on each end, to show the high and low potential impact values.

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[1] Complexity is measured in terms of financial and human resources required to implement the option, timing, and consistency with prevailing public and regulatory policies.

[2] Impact is measured in terms of the strengths and issues identified for the Status Quo.

Detailed values associated with the sensitivities depicted in the chart are provided in the following table. The sensitivity analysis employed seven scenarios:

Scenario 1: All 17 impact criteria weighted equally (marked by a square with an X)
Scenario 2: Organizational criteria (S-1; S-2; I-1; I-2) assigned weighting of two times other criteria
Scenario 3: Operational criteria (S-3; I-3) assigned weighting of two times other criteria
Scenario 4: Power purchase criteria (S-4; S-5; I-4) assigned weighting of two times other criteria
Scenario 5: Financial criteria (I-5; I-6; I-7) assigned weighting of two times other criteria
Scenario 6: Socio-economic criteria (S-6; S-7) assigned weighting of two times other criteria
Scenario 7: Policy/regulation criteria (S-8; S-9; I-8) assigned weighting of two times other criteria

		Benefits (Weighted Criteria)							
Option	**Complexity**	Scenario 1: Equal weighting	Scenario 2: Organizational	Scenario 3: Operational	Scenario 4: Power Purchase	Scenario 5: Financial	Scenario 6: Socio-economic	Scenario 7: Policy /regulation	
1. Status Quo	0	0	0	0	0	0	0	0	
13. Increase reliance on IPPs	0	0	0	0	0	0	0	0	
2. Optimised Status Quo	**1**	**6**	**9**	**7**	**7**	**7**	**6**	**6**	*
6. Outsource various services	1	2	3	1	2	3	3	2	
11. Modify service levels	1	1	2	-1	1	3	1	1	
3. Create an NIA Department	2	4	8	4	4	4	4	4	
7. Engage a system operator	2	3	5	2	3	4	4	3	
8. Lease assets and their operations	3	5	9	4	5	6	6	5	
4. Establish an NIA subsidiary	**4**	**7**	**12**	**9**	7	**8**	6	**7**	*
12. Displace diesel through alternatives	4	3	3	5	5	-1	4	5	
5. Integrate NIA communities	5	6	8	6	8	10	4	6	
9. Sell assets to a third party	5	6	7	6	6	10	7	6	
10. Modify rates	5	2	2	2	2	6	0	2	

The logic of the evaluation framework employed in this study is that in order to justify increasing the level of complexity associated with implementing a new option, the option in question must offer some potential increase in benefits over less complex options. In other words, in order to seriously consider an option further to the right on the complexity scale, there must also be a corresponding move up on the benefits scale.

In keeping with this logic, Option 2 (Optimised Status Quo) offers the greatest potential benefit over the Status Quo for a small increase in complexity. The impact scores associated with this option for each of the seven scenarios are summarized and shown in bold in the table. The only other option which offer the potential for greater benefit than Option 2 is Option 4 (Create an NIA subsidiary). The impact scores associated with this option are greater than for Option 2 under all but two scenarios (scenarios 4 and 6), and

under these scenarios, the options are scored equally. Option 4 scores which are higher than Option 2 scores under each scenario are also shown in bold.

Of note, under scenarios two and six, Option 8 (Lease assets and their operations) scores equal to Option 2. However, Option 8 has a higher complexity score and therefore does not appear to offer an overall potential advantage.

Conclusions

At least in the short term, BC Hydro should give serious consideration to implementing Option 2 (Optimised Status Quo). Over the longer term, however, there are a number of options which should be examined more closely.

Creation of an NIA subsidiary (Option 4) appears to offer the potential for increased benefits for the NIA business. The relatively high impact score reflects the expectation that a separate legal entity will result in a sustained strategic focus on the unique characteristics and needs of the NIA business, maintenance of core competencies and decreased competition for capital and human resources with other larger BC Hydro business areas. It is assumed there are advantages over the more straightforward creation of a department within the BC Hydro organization, including the potential for NIA to receive unique attention by regulators and policy makers. However, the complexity associated with implementation of this option, although recognized in the evaluation framework as significant, has not been explored in detail. We recommend that this option be explored further and evaluated in the broader context of BC Hydro's corporate strategy and direction.

Many of the options identified and evaluated can be combined with other options, or implemented within a defined scope of NIA activities. BC Hydro is already exploring the potential to utilize alternative energy sources in NIA communities (Option 12) and has engaged third-party diesel station operators (Option 7) in some areas. We recommend that BC Hydro continue to explore these types of opportunities where they are advantageous.

Finally, there are a few of options which do not appear to be either advantageous or viable at this time and should likely not receive further attention. All three options which received a complexity score of 5 (Options 5 (Integration), 9 (Divestiture) and 10 (Modify rates)) are currently prohibitive due to cost, practicality or conflict with prevailing public policy. Options 3 (NIA Department), 7 (System Operator), and 8 (Lease assets) may merit further consideration if Option 4 (NIA subsidiary) is determined to be unviable.

Introduction

The recent corporate restructuring of BC Hydro has affected the way the crown corporation conducts virtually every aspect of its core business. The changes implemented reflect the high level strategic direction of the corporation, in response to both a changing electricity market environment in North America, and the provincial government's 2002 energy policy.

The Non-Integrated Areas (NIA) business, defined by the electricity servicing requirements of nine remote service areas not currently connected to the province's main transmission grid, represents 0.2% of BC Hydro's annual electric sales volume.[1] Yet despite the relatively small size of this business component, NIA is of important strategic significance to the corporation at this time for a number of reasons:

- Costs associated with service delivery to NIA are not recoverable through current rates
- BC Hydro has a legislated obligation to serve these communities
- Due to the unique generation technology employed, expertise required, and community characteristics, the business does not conform well to the disaggregated business line model of the new BC Hydro corporate structure

Over the past two years, responsibilities for key functions related to the NIA business have been reassigned from a single business unit to a mix of departments within the Distribution Line of Business (DLoB), and BC Hydro service organizations. The business is in a transitional state, as key staff, with the knowledge and expertise required to address the unique needs of this business component, are retiring or leaving to pursue other career opportunities.

Given the extent to which this business unit has been impacted by the corporate restructuring, the strategic importance of NIA to BC Hydro overall, and the urgency associated with preserving the institutional knowledge of key individuals involved in the business, BC Hydro's DLoB has commissioned this strategic planning study to review the current state of the NIA business and develop a set of options going forward for consideration by senior management.

This report documents key characteristics, strengths and issues associated with BC Hydro's current business model for electricity service delivery to NIA. Further, the report provides a set of recommendations for

[1] FY 2002-03. BC Hydro total sales of 48,677 GWh (source: www.bchydro.com/info/reports/reports921.html); NIA total sales of 97.93 GWh.

addressing important issues in the short term, without making any fundamental changes to the current business model. Finally, we have identified and evaluated a set of options, involving alternative business models which might be appropriate for the NIA business, which may require some fundamental change to the current model but could also provide some degree of benefit as measured by the strengths and issues associated with the status quo.

This report represents the results of Phase One of a two phase strategic and business planning exercise. The second phase, once a strategic direction for the business has been determined, will involve the development of a detailed business plan.

Current Business Model

This chapter provides an overview of the current NIA business model (the Status Quo), focusing on seven key aspects of the business:

- Organization design
- Operations
- Power purchase
- Finance
- Socio-economic and community issues
- Conservation initiatives
- Policy and regulatory issues

A comprehensive review of each aspect was undertaken and is summarized in this order below.

Our review of the current business model focused on developing a detailed characterization of the NIA business from facts gathered through document review, quantitative analysis, and interviews with key BC Hydro staff. The chapter is organized such that each review begins with a summary of key findings, including a discussion of key strengths and issues associated with the current model.

Each review concludes with a table highlighting those strengths and issues which form part of an evaluation framework used to assess the relative merits of alternative business options. The issues identified provide the focus for our recommendations regarding optimisation of the status quo.

Organization design

Key findings of the review

BC Hydro's reorganization has had a significant impact on NIA business activities and reporting structure. Under the previous model, NIA was a discrete business unit with clear ownership, accountability and responsibilities for key business functions. Currently, ownership of the NIA assets rests with the Distribution Line of Business (DLoB), and key functions are performed by a combination of departments within DLoB, and service organizations, many of which have assumed responsibilities for NIA in addition to corresponding functions for the integrated system. The DLoB organization chart and a depiction of the interrelationships associated with the DLoB business model are provided in Appendix A.

The NIA business encompasses all activities required to service BC Hydro customers in the nine remote communities not currently connected to the main transmission grid. Through our review of current internal organization charts, planning documents and interviews with key individuals involved with the NIA business (refer to Appendix B), we have identified six general categories of functions relevant to the successful delivery of NIA services, namely:

- Planning functions
- Operations functions
- Customer functions
- Performance management functions
- Information technology (IT) functions
- Human resources (HR) functions

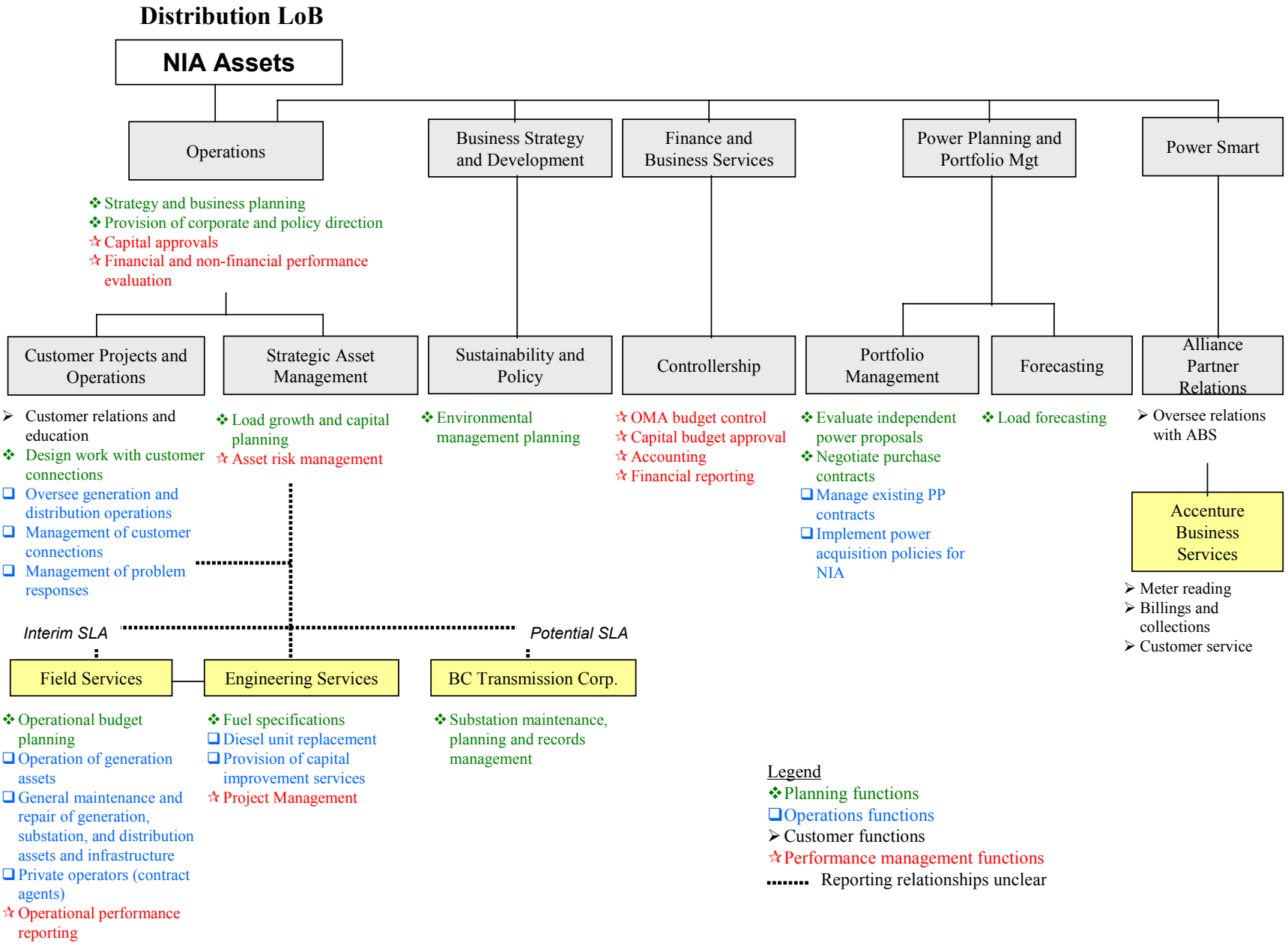
This review focuses on the first four categories since the IT and HR requirements for NIA are not likely to differ appreciably from those of the integrated system.

At the highest level, and recognizing the potential for further change, the responsibilities for the NIA business functions appear to have been allocated within the DLOB as follows:

- ***Operations*** provides general corporate planning and policy direction;
- ***Business Strategy and Development*** oversees environmental management and planning;
- ***Finance and Business Services*** provides for operating, maintenance and capital budget control and approvals, accounting and financial reporting;
- ***Power Planning and Portfolio Management*** directs contracting for energy purchases, the Independent Power proposal process, related power acquisition policies and load forecasting; and
- ***Power Smart*** oversees relations with Accenture Business Services, which provides for meter readings, billings, collections and other customer services.

Within Operations, Customer Projects and Operations oversees customer relations, education, connections and trouble response, as well as generation and distribution operations. Strategic Asset Management provides for load and capital planning as well as asset risk management. Under an interim Service Level Agreement ("SLA"), the Field Services organization is responsible for operational budget planning, and general maintenance and repair of generation, substation, and distribution assets. This is aided by the Engineering Services organization that provides project management and guidance on fuel specifications as well as services in relation to diesel unit replacement and capital improvements. Finally, it was reported that there exists the potential for a SLA to be negotiated with the BC Transmission Corporation, which currently provides direction on substation planning and substation maintenance. A schematic representation of these relationships and allocation of responsibilities in keeping with the four core business functions is provided in Figure 1 on the following page.

Figure 1: NIA business function and responsibility map



During our interview program, we received feedback from BC Hydro staff in various DLoB departments and BC Hydro service organizations on the current organization structure as it relates to NIA. Key themes from comments made include the following:

- **Need for leadership and greater clarity of roles, responsibilities and reporting structure** – The transition to the new BC Hydro organization structure has created some confusion over which individuals and units are responsible for various aspects of NIA service.

  This state of uncertainty has been exacerbated by the absence of a permanent coordinating function, with an interim manager on secondment currently fulfilling this need, as well as limited documentation that clearly describes the distribution of responsibilities for NIA assets and services, and distinctions in terms of roles.

  As a result, there is a prevailing general perception that no one individual has responsibility for NIA business services, and that there are too many units and service organizations being engaged with various tasks associated with NIA functions.

- **Staff resources are at a practical minimum** – The internal audit report (2001) deemed the, "staff complement to be logical and efficient for servicing remote locations…staff have been reduced by 15 over the last six years, and the current staff complement is at a practical minimum." In keeping with this finding, it was reported by those interviewed that resources are likely at the lowest level to effectively respond to both service demands and non-routine events within the NIA.

- **Occasional lack of coordination between BC Hydro programs which impact the NIA business, and NIA staff** – In keeping with the earlier findings on a prevailing uncertainty over accountabilities and roles, some individuals stated that select consultations and activities have been undertaken by certain units within the DLoB, and without the involvement of personnel responsible for various aspects of NIA services.

  This has created, in turn, differing levels of awareness within the DLoB as to the range of initiatives that are underway and their implications, as well as concerns that certain operational considerations are not fully accounted for in the decisions that are being rendered. Furthermore, there is a risk that some level of duplication in activities may occur. These issues are reflective of those found in the internal audit report dated 2001, in particular, "some issues including NIA roles, responsibilities, business direction as well as planning and support interface require clarification."

- **Competency requirements are currently being met** – In terms of competencies, no issues or concerns were expressed by those individuals interviewed, beyond the importance of maintaining a core group of technical personnel that can provide for ongoing maintenance and operations, and that sufficient provisions are in place to ensure the continuity in this skill base (i.e., succession).

Summary of organization strengths and issues

Strengths	Issues
• Staff complement is efficient • Competency in key roles is adequate	• Coordination/leadership with accountability is needed • Clarity of roles and responsibilities is needed

Operations

Key findings of the review

The NIA business services a total of approximately 6,000 customers, or less than one percent of BC Hydro's total customer base. Table 1 summarizes the customer profile for each NIA community.

Table 1: 2002-03 Customer Demand Profile

Community	# Customers	Billed kWh	Supplied kWh*
Anahim Lake	518	6,562,017	7,261,827
Atlin	477	4,095,518	4,501,454
Bella Bella	538	11,746,158	11,678,893
Bella Coola	1,165	17,714,705	18,813,124
Dease Lake	343	5,677,124	6,242,047
Eddontenajon	146	2,545,837	2,675,200
Massett	1,379	23,071,424	24,134,993
Sandspit	1,599	24,331,301	25,727,904
Telegraph Creek	159	2,186,831	2,359,383
Totals	6,324	97,930,915	103,394,825

** Supplied kWh = (Hydro generated kWh + Thermal generated kWh + Purchased kWh) – Station service kWh*

The NIA customer base is also predominantly residential, with only a few areas servicing small commercial and industrial loads.

Generating capacity in NIA is provided by a combination of diesel stations, hydro stations and power purchased by BC Hydro from private producers. BC Hydro owns diesel generating stations in each of the nine (9) NIAs, but relies on these stations for prime power[1] in only six (6) areas.

The other three (3) areas receive prime power from one of three (3) independent power producers (IPP). In these areas, the diesel stations provide standby or backup power during peak demand hours, or when the prime source is unable to meet demand. In Bella Coola, the diesel station (Ah-Sin-Heek) and the BC Hydro owned hydro station (Clayton Falls) jointly provide prime power.

[1] Prime power denotes that the generating station is either the only source, or one of two primary sources (Bella Coola only), of power to the area.

Table 2 summarizes the nature and amount of installed generating capacity in each NIA.

Table 2: Installed Capacity by NIA (kW)

	BC Hydro Assets				Total Installed
NIA	PPDGS	PPHGS	SBDGS	**IPP**	**Capacity**
Anahim Lake (AHM)	3,650	–	–	–	3,650
Atlin (ATL)	2,650	–	–	–	2,650
Bella Bella (BEL)	–	–	3,300	6,000	9,300
Bella Coola (ASK/CLA)	7,200	2,050	–	–	9,250
Dease Lake (DLK)	–	–	3,980	3,000	6,980
Eddontenajon (EDD)	2,200	–	–	–	2,200
Massett (MAS)	11,374	–	–	–	11,374
Sandspit (SPT)	–	–	9,650	5,700	15,350
Telegraph Creek (TCK)	2,300	–	–	–	2,300
Totals	29,374	2,050	16,930	14,700	63,054

PPDGS: Prime Power Diesel Generating Station
PPHGS: Prime Power Hydro Generating Station
SBDGS: Standby Power Diesel Generating Station
IPP: Independent Power Producers

NIA generation and distribution related assets are owned by the DLoB. Major NIA assets include:

- Sixty three (63) diesel generating units, in nine stations and a central location (Surrey)
- Two (2) hydro generating units, in one station
- Thirty diesel fuel tanks
- 837 km of overhead and 24 km of underground distribution lines
- 13,247 poles
- Approximately 6,000 meters
- Ten substations

BC Hydro is required to provide firm reliable power. Their criterion for providing this reliability is N-1, which means that they must be able to supply the peak load for the area with the largest unit out of service. In the IPP areas, the IPP is considered the largest unit in service. Accordingly, BC Hydro must be able to supply the load even with the IPP out of service. With this requirement, and if the IPP is supplying Firm Power,[1] it may be possible for some diesel generation to be taken out of service. However, if the IPP power is not considered Firm Power, no diesel generation can be taken out of service.

Detailed system descriptions and operational statistics for each BC Hydro owned generating station are provided in Appendix C.

[1] Firm Power is defined as power that can be expected to be available during peak power usage periods unless there is a forced outage due to machine or power line failure.

Through our review of relevant documentation and interviews with key Field Services and DLoB staff, we have highlighted a number of key areas of strategic importance to the NIA business. These are:

- **A significant proportion of the diesel GU fleet is ageing and in need of replacement** – A number of major capital and maintenance investments have been made over the last two years in keeping with objectives identified in the DLoB NIA business plan (2002). These projects are consistent with an overall strategy to optimise NIA system assets and function, including mitigation of risks related to the environment from fuel storage. However, there is currently no strategy in place to address the ongoing problem of an ageing fleet of diesel generating units (DGU).

  The generally accepted estimate of useful life for a diesel generating unit (DGU) among industry experts is approximately 25 years, and the manufacturers recommended life is approximately 100,000 hours. As Table 3 illustrates, approximately 60% of the fleet is older than 21 years, approximately 27% is approaching or has exceeded 100,000 hours, and 28% of the fleet's condition is rated as poor or obsolete.

Table 3: Diesel fleet assessment

Fleet characteristics	% of total number of DGUs (total 63)
Age	
1-10 yrs old	35%
11-20 yrs old	5%
21-30 yrs old	60%
Total in service hours	
> 100,000 hrs	9%
80,000 – 99,999 hrs	18%
50,000 – 79,999 hrs	20%
< 50,000 hrs	53%
Condition Rating	
Excellent	5%
Good	25%
Acceptable	42%
Poor	25%
Obsolete	3%

Source: NIA Diesel Generating Units Condition Assessments Summary (July 22, 2003)

There are a number of both practical and cost-related issues associated with older engines. These include:

- **Poor fuel efficiency** – Newer models of diesel generators are more fuel efficient and therefore less expensive to run.
- **Anticipated difficulty obtaining replacement parts from manufacturers** – As manufacturers have updated their products and changed the technologies employed, it has become more difficult to find parts specifically designed for the older models. As the older engines in-service times are extended, replacement parts will become more difficult to find and replace.
- **Limited ability to measure efficiency of individual units, and adequately plan maintenance schedules** – The newer models of CAT engines have individual fuel metering capabilities. This allows for fuel efficiency measurement by unit, instead of the current practice of measurement by station. It also allows for better planning of maintenance schedules, since fuel consumption is a finer measurement of engine use than is hours of use.

The issue of ageing assets is of particular concern in Masset, where anticipation of an IPP to assume prime power supply has delayed all decisions on unit replacement.

- **Significant improvements in system reliability have been realized in the past two years** – Despite the relative age of NIA assets, the NIA system has been very reliable, with marked improvements observed over the last two years (FY2001-02 and FY2002-03).

  Reliability is commonly evaluated in terms of three indices, applied industry-wide. These are:

  - **Average System Availability Index (ASAI)** – ASAI is defined as the percentage of time that electricity is available.
  - **Customer Average Interruption Duration Index (CAIDI)** – CAIDI is the average outage duration, in hours, per interrupted customer.
  - **System Average Interruption Frequency Index (SAIFI).** – SAIFI is a reliability measure for the *delivery* system, and is defined as the number of sustained interruptions per customer on an annual basis.

  Changes in these reliability measures for NIA are illustrated in Table 4 below. The values listed represent the twelve months of the fiscal year ended March 31 for the years indicated.

Table 4: Reliability measures for NIA

NIA	ASAI		CAIDI		SAIFI	
	2002	2003	2002	2003	2002	2003
All functions	99.81	99.84	1.68	2.19	9.84	6.34
Distribution	99.90	99.88	2.79	3.79	3.04	2.85
DGS Source	99.92	99.98	0.99	0.99	5.61	1.67
IPP Source	99.99	99.99	0.61	0.69	1.19	1.38
Substation	n/a	99.99	n/a	1.11	n/a	0.45

Source: Distribution Trouble Reporting System Resources Outages Summary

Table 5: Reliability measures for BC Hydro overall

BC Hydro	ASAI		CAIDI		SAIFI	
	2002	2003	2002	2003	2002	2003
Actual	99.96	99.96	2.55	2.60	1.46	1.45

Sources: BC Hydro Scorecard – Year End Results Fiscal 2002, BC Hydro Annual Report 2003

Both the ASAI and CAIDI measures are industry standards for electrical utilities and are used by the Canadian Electricity Association (CEA) in annual comparisons of utilities. Higher values for the ASAI are preferable to lower values, while lower values for the CAIDI and SAIFI are preferable to higher values.

A comparison of the ASAI and CAIDI values to those for BC Hydro overall (Table 5) indicates that the NIA system is relatively reliable. Actual ASAI values for NIA are slightly below the actual values for BC Hydro in 2002 and 2003. Given the different system structure and technology employed for NIA, the reliability in terms of the percentage of time that electricity is available is very good. The actual values of CAIDI, the average outage in hours per interrupted customer, are lower for NIA than for BC Hydro in both 2002 and 2003. SAIFI for NIA overall decreased between 2002 and 2003, largely due to a decrease of 3.94 interruptions per customer for diesel generation sources.

In addition, source outages have decreased for all of prime power, standby power, and IPP power from 2002 to 2003, as summarized in Table 6 below.

Table 6: Source outages by station type

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

Source: Diesel Information (and Utility Comparisons) Reports

Summary of operational strengths and issues

Strengths	Issues
• System reliability is high	• Replacement of ageing diesel GU fleet will be required

Power purchase

Key findings of the review

There are currently three independent power producers (IPP) supplying the NIA. A fourth IPP is in the final stages of negotiations with BC Hydro. Details of each organization, and a summary of their operations, are provided in Appendix D.

Three of the IPPs involved in the NIA area are relatively small private companies, the fourth one was initiated as a First Nations' project (Stikine Nation Power Corporation). All of the projects are relatively small in nature but face a wide variety of challenges such as construction in remote regions, obtaining necessary permits, public relations and ongoing maintenance difficulties.

Table 7 below summarizes the contract arrangements with IPPs and Table 8 summarizes IPP purchase relative to total NIA Activity.

Table 7: Summary of IPP Contract Conditions

IPP	Area Served	Date Agreement Signed	Commercial Operations Date	Contract Termination	2003 Energy Delivered, kWh
Central Coast Power Corporation (CCPC)	Bella Bella, Shearwater	February 19, 1986	1987	2016	11,737,680
Stikine Nation Power Corporation (SNPC)	Dease Lake	November 1, 1993	1999	2019	6,438,120
Queen Charlotte Power Corporation (QCPC)	Sandspit	December 9, 1988 Amended Sept 1, 1992	1990	2010	20,468,160
North Island Power Corporation (NIPC)	Masset, Port Clements	April 10, 1997	Not Built Yet	August 31, 2017	

Table 8: IPP Purchase as Percent of Total NIA Activity

NIA	IPP Purchase kWh	Power Generated and Purchased, kWh	IPP as % of Total Power Generated and Purchased
Anahim Lake	0	7,580,489	0%
Atlin	0	4,657,576	0%
Bella Bella	11,737,680	11,837,741	99%
Bella Coola	0	19,142,461	0%
Dease Lake	6,438,120	6,559,755	98.1%
Eddontenajon	0	2,989,473	0%
Masset	0	25,065,732	0%
Sandspit	20,468,460	26,322,569	78%
Telegraph Ck	0	2,563,639	0%
Totals	38,644,260	106,719,435	36%

BC Hydro policy with respect to transmission of IPP power has been such that the IPP is required to deliver the power from their generating station to the 25 kV bus in BC Hydro's DGS substation. This policy could be adjusted with respect to North Island Power Corporation on Graham Island and with respect to the Stikine National Power Corporation at Dease Lake.

With IPP operations in the NIA since 1986, BC Hydro has gained valuable experience regarding how to achieve success in power purchase arrangements. The following insights are of particular interest for the development of a future strategy for NIA:

- **Cost savings from IPP are realized over the long term** – All of the existing IPP contracts resulted from an open Request for Proposals process. We were told that contracts were not awarded unless power purchased from the IPP was forecast to be less than the cost from existing diesel generation. In arranging the contracts, BCH requires that the reliability of power supply to the region being served remain as good or better than the existing diesel generation supply.

  Analysing the costs of IPP purchase relative to DG is complex. In evaluating the cost implications of potential IPPs, the time frame for the comparison is the life of the contract (usually 20 years). IPPs will usually not be able to obtain financing for a project unless they can secure a contract term of 20 years.

  The methodology used to analyse the costs of a proposed IPP, relative to the costs of diesel generation involves net present value calculations and sensitivity analyses where the following 20 year projections are reflected:

  - Diesel fuel costs
  - Load requirements
  - Diesel unit overhaul and replacement costs (comparing the IPP scenario to that in which the diesel station provides prime power)
  - Variable operating and maintenance costs for the diesel station (comparing the IPP scenario to that in which the diesel station provides prime power)

  Over a 20 year period, small fluctuations in these values away from projections can have a significant impact on the cost effectiveness of the IPPs. However, for the fiscal year ended March 31, 2003, energy, and operating and maintenance costs per kWh of energy billed was lower than the NIA average for Bella Bella and for Sandspit. IPPs supply 99% and 78% respectively of the energy in these two areas. Both of these IPPs have been in operation for a number of years and this current result indicates that if fuel oil prices remain at relatively high levels or increase, these IPP arrangements will prove to be cost effective.

- **Displacement of diesel generation has been achieved through IPP arrangements** – The main reasons for displacing diesel generation power with IPP purchase were as follows:

  - Displace/remove diesel generating units (IPPs used as firm/dependable capacity

- Lower energy costs (IPPs used as firm/dependable energy with no diesel generating units removed)
- Reduce or eliminate diesel emissions (second order benefit)
- Reduce noise and local impact of diesel generating station (second order benefit)

All three current IPP's involve hydro generation. The fourth planned IPP in Masset will involve wood waste fired steam turbine generation.

- **Management of IPP contracts has been effective** –BC Hydro Power Acquisition and NIA Operations have developed workable relationships with the three IPPs operating in NIA. It has taken a number of years and each of the three relationships has had their own unique challenges. Through our review, we have observed that the nature of serving an NIA requires that IPP arrangements be flexible, and that the contract management of these arrangements to be undertaken by one or two people with the authority to apply their judgement in decisions on occasion.

- **IPP projects accrue local economic benefits –** The North Island Power Corporation, once operational, will be completely controlled by individuals on Graham Island. The Stikine Nation Power Corporation, which used to be owned by the Tahltan Band, still has a lot of local control and input. In addition, Central Coast Power employs six people, and is therefore the largest employer in Ocean Falls. This strength of the status quo is discussed further under the socio-economic and community review.

Summary of power purchase strengths and issues

Strengths	Issues
• Diesel displacement is being achieved • IPP contract management is effective	• IPP contracts are negotiated under conditions of high uncertainty

Finance

Key findings of the review

The NIA business profit centre operates at a net loss. Over the past five years, total revenues from NIA customers have covered only 20% to 30% of total direct and allocated expenses. Year-end Profit and Loss Statements for NIA for the past five years are summarized in Table 9 on the next page.

Table 9: Five year historical NIA Profit and Loss Statement Summaries ($'000)

	Actuals				
	1998-99	**1999-00**	**2000-01**	**2001-02**	**2002-03**
Revenues					
Residential	4,525	3,727	3,574	4,117	3,820
General	8,082	3,143	3,358	3,754	3,545
Other	202	142	197	146	149
	12,809	7,012	7,129	8,017	7,514
Cost of Energy					
Fuel oil	4,673	5,877	6,740	6,414	6,118
Natural gas	287	102	70		
Power purchase	13,541	5,256	6,682	7,658	7,025
	18,501	11,235	13,492	14,072	13,143
Gross Margin	**(5,692)**	**(4,223)**	**(6,363)**	**(6,055)**	**(5,629)**
Gross Margin (%)	**-44.4%**	**-60.2%**	**-89.3%**	**-75.5%**	**-74.9%**
Direct Expenses					
Generation					
Operations	2,249	2,193	1,960	1,581	2,710
Maintenance	3,352	2,836	2,780	1,612	2,776
Administration	0	0	0	1,420	24
	5,601	5,029	4,740	4,953	5,510
Distribution					
Operations	819	772	396	835	215
Maintenance	877	299	580	261	250
Administration	1	0	0	600	167
	1,697	1,071	976	2,269	632
Other OMA costs (note 1)				913	731
Net Margin	**(12,990)**	**(10,323)**	**(12,079)**	**(13,277)**	**(12,502)**
Asset Related Charges					
Taxes	842	794	913	1,077	760
Depreciation	3,558	2,171	1,722	2,248	810
	4,400	2,965	2,635	3,325	1,570
Business Unit Margin	**(17,390)**	**(13,288)**	**(14,714)**	**(16,602)**	**(14,072)**
Allocated Charges					
Business Sustaining costs	6,625	5,773	7,056	1,788	2,173
Finance charges	4,592	3,000	3,553	4,870	1,394
	11,217	8,773	10,609	6,658	3,567
NET INCOME (LOSS)	**(28,607)**	**(22,061)**	**(25,323)**	**(23,260)**	**(17,639)**

Note 1: In F2001-02, 02-03, a line item was created for OMA costs not included under Generation or Distribution.

The internal accounting net loss for the NIA is reported to have dropped from $28.6 million in 1998-99, to $17.6 million in 2002-03. However, there are a number of difficulties associated with interpreting and explaining this change. There are also a few potential issues related to NIA accounting generally, which we encountered in our review. These difficulties and issues include the following:

Difficulties associated with year over year comparisons:

- **Integration of Fort Nelson** – Between 1998-99 and 1999-00, the majority of revenues and costs related to Fort Nelson[1] were removed from the NIA profit centre. In 2001-02, Diesel Generation expenses of $33,000 were recorded. By 2002-03, no further costs related to Fort Nelson appear to be allocated to the NIA profit centre.

- **Major changes in accounting for Direct (OMA) Expenses** – With the creation of BC Hydro service organizations in 2001-02, a significant change in the method of accounting for OMA costs was implemented:

  - Under the previous organization structure, NIA operations, maintenance and administrative activities were undertaken by the profit centre's own staff, or operating contactors paid from the NIA operating budget.

  - Under the new structure, NIA operations, maintenance and administrative activities are undertaken by Field Services staff, operating contractors paid from the Field Services operating budget, and Engineering Services staff. Field Services prepares and manages the NIA operating budget, and provides the majority of administrative services for the NIA business. Field Services' costs are recovered through a variety of loaded fees, including:

	Cost loadings (2002-03)
Field Services staff (field only)	1.81 times cost
Field Services operations contractors	1.15 times cost
Fleet Services staff	1.50 times cost
Materials	1.30 times cost

    These cost loadings are applied across BC Hydro and are not specific to NIA. The change from calculation methods used in previous years is fundamental, and does not allow for detailed year-over-year comparison of NIA OMA costs by category.

- **Only two years of detailed financial information** – We were able to obtain detailed spreadsheets for only the past two fiscal years. For the three years previous, our summary was prepared from paper copies of the P/L statements. Consequently, our detailed analysis of NIA financials focuses on 2001-02 and 2002-03.

[1] Fort Nelson integrated with the Alberta integrated transmission grid in 1998-99.

Issues related to NIA accounting (focus on 2001-02 and 2002-03):

- **Imprecise methods of allocating a portion of business line costs to NIA** – Business sustaining (overhead) and finance charges are allocated to NIA as a portion of total costs for the Line of Business[1] overall. These costs represent a significant proportion of total costs as Table 10 illustrates.

Table 10: Analysis of NIA business sustaining and finance expenses ($'000)

	1998-99	1999-00	2000-01	2001-02	2002-03
Total NIA expenses	41,416	29,073	32,452	31,277	25,153
Business sustaining costs	6,625	5,773	7,056	1,788	2,173
% of total expenses	16.0%	19.9%	21.7%	5.7%	8.6%
Change from previous year		-12.9%	22.2%	-74.7%	21.5%
Finance charges	4,592	3,000	3,553	4,870	1,394
% of total expenses	11.1%	10.3%	10.9%	15.6%	5.5%
Change from previous year		-34.7%	18.4%	37.1%	-71.4%

  - The NIA allocation of business sustaining costs is comprised of two parts:
    a) a portion of T&D or DLoB Non-Operating OMA,[2]
    b) a portion of T&D or DLoB share of Corporate Business Sustaining Costs.

    In **2001-02**, the allocation was 2.6% of (a) and 0.97% of (b). The NIA allocation of (a) was determined by the ratio of NIA OMA to total T&D Operating OMA, and the allocation of (b) was determined by the NIA proportion of total NBV of T&D assets.

    In **2002-03**, the allocation was 4.087% of both (a) and (b). In this year, the allocation of both (a) and (b) was determined by the ratio of NIA OMA to total DLoB Operating OMA.

    In previous years, the allocation methods are unknown, but as Table 10 indicates, both the nominal values, and the values relative to total costs, have fluctuated substantially.

    It is not clear from our review of the notes to the financial statements whether the methods used result in a fair allocation, which reflects the actual value of services provided by both DLoB and Corporate to NIA. For example, IT services are currently provided to NIA by Field Services and charged through the cost loadings discussed earlier. However, Business Knowledge and Information is one of the services included under the NIA allocation of DLoB Non-Operating OMA. Consequently, it appears that NIA may be paying both Field Services and DLoB for IT services.

[1] Transmission & Distribution for years 1998-99 through 2001-02; Distribution for year 2002-03.

[2] Includes: Business Support; Strategic HR; Business Knowledge and Information; Sr. V.P. Distribution (CC1005), as described in the notes to NIA Profit/Loss Statements for FY 2002-03.

- The NIA allocation of finance charges is 0.97% of total finance costs for T&D in 2001-02. The allocation was determined by the NIA proportion of total NBV of T&D assets. In 2002-03, the NIA allocation is 1.11% of total DLoB finance costs, and was also determined by the NIA proportion of total NBV of DLoB assets.

  This allocation method does not account for the relative age of assets in the DLoB asset database. Since we know that the NIA asset base has not changed significantly over the past five years, as very little capital investment has been made in NIA, we would expect that financing costs would remain somewhat stable during this period. However, as Table 10 illustrates, the nominal values increase or decrease significantly from one year to the next. We expect that the finance charges allocated to NIA are likely disproportionately high, relative to other business units within DLoB.

- **Surplus assets assigned to the NIA profit centre** – In the 2002-03 P/L statements, the NIA asset base was estimated to have a NBV of approximately $25.65 million.[1] However, we were advised that this value had since been revised to more than $30 million.[2] We reviewed reports produced from the asset database for all cost centres assigned to the NIA profit centre and it appears that there may be some assets assigned to NIA from Fort Nelson, which was integrated with the Alberta transmission system in 1998-99.

  A summary of the current NBV of NIA assets (as of September 2003) is provided in Appendix E. The total NBV of NIA assets as of the date the reports were run is approximately $31 million. However, Approximately $4.9 million appears to reflect the value of generation and transformer assets in Fort Nelson (CC6694). When these assets are removed, the total NBV is $26.2 million.

At a more strategic level, and more aligned to the matter of the financial health of the NIA business, we have identified two key financial issues to be addressed in the context of introducing any alternative business model. These are:

- **Erosion of the Gross Margin is resulting since revenues have not been increasing at the rate of costs** – Electricity rates have been frozen for the past ten years. However, diesel fuel costs have increased by more than 65% since 1999. As Table 11 illustrates, the increased was most dramatic between 1999 and 2001.

[1] Notes to the NIA Profit/Loss Statements, NBV as of March 31, 2003.

[2] BC Hydro asset database: Cognos PowerPlay Web Explorer, Cube report created on Wednesday, September 10, 2003.

Table 11: Fuel cost trends 1998-99 to 2003-04 Q1

Fiscal Year	Average Fuel Cost $/litre	% change from prev. year
1998-99	0.2511	--
1999-00	0.3064	+22.02%
2000-01	0.3969	+29.54%
2001-02	0.3884	-2.14%
2002-03	0.4028	+3.71%
2003-04 Q1 only	0.4531	+12.49%

Source: Diesel Information (and Utility Comparisons) Reports

Other operating costs, including salaries and IPP costs, have also been increasing every year.

- **In the absence of a differentiated rate structure for NIA, a source of funds is required to make up the subsidy to this customer group**– As Table 12 illustrates, current revenues are less than half of direct costs. Moreover, the potential for increasing revenue is constrained considerably by prevailing public policy.

Table 12: Estimated net subsidy to NIA (per KWh)

	2001-02	2002-03
Avg revenue per KWh billed	$0.081	$0.077
Cost of Energy & Direct Expenses per KWh billed	$0.216	$0.197
Estimated subsidy to NIA per KWh (based on Net Margin)	**$0.135**	**$0.120**

In addition, if there are opportunities to reduce costs or change the method of allocating finance and overhead costs to be more favourable to NIA, the effects will likely not be sufficient for the NIA business to approach full cost recovery.

Consequently, it is most likely that any business model adopted going forward will have to identify some means of addressing the subsidy requirement.

Summary of financial strengths and issues

Strengths	Issues
	• DLoB costs are allocated disproportionately to NIA • Gross margin for the NIA profit centre is eroding as costs have increased more rapidly than revenues • An ongoing subsidy to NIA is required

Socio-Economic and Community Issues

Key findings of the review

BC Hydro's NIA customers live in small communities, and are represented by a large proportion of reserve and non-reserve First Nations. BC Hydro generally plays an important role in these communities, both in terms of providing power in support of economic and social activities, and as a local source of employment. Socio-economic profiles of each NIA service area are provided in Appendix F. Highlights from these profiles include the following:

- **Load growth from population changes in NIA communities not expected to require short term installation of new capacity –** Table 13 indicates that NIA non-reserve communities are almost all decreasing in population from 1996 to 2001. In addition, the decline shown does not reflect more recent and ongoing shutdowns of resource industries and related government jobs in rural communities in British Columbia, thus, the figures are likely to be even more negative. However, First Nations reserves adjacent to or near the non-reserve communities are increasing in population, with the exception of the Stikine area, partly as a result of high birth rates on reserves and a popular movement to return to native homelands, despite few major employers. However, in areas that are hardest hit by economic downturns, reserve populations have declined more dramatically than non-reserve populations.

Table 13: Population change in NIA communities 1996 to 2001

	Non-Reserve		Nearby Reserve		All	
Community	**1996/2001**	**Change**	**1996/2001**	**Change**	**1996/2001**	**change**
Anahim Lake	872/880	+1%	198/319	+61%	1070/1199	+12%
Atlin, Dease Lake	1003/931	-7%	200/129[1]	-35.5%	1203/1060	-12%
Bella Bella	244/143	-41%	1211/1253	+3.5%	1455/1396	-4%
Bella Coola	1517/1592	-1%	873/909	+4%	2390/2501	+5%
Iskut, Telegraph Creek	100/88	-12%	505/366	-27.5%	605/454	-25%
Masset (Graham Island North communities)	1851/1442	-22%	692/769[2]	+11%	2543/2211	-13%
Sandspit (Graham Island South & Moresby Island communities)	2360/2043	-13%	695/743	+7%	3055/2786	-9%

Seasonal residency is not accounted for clearly in Census data or otherwise documented, however, a large summer influx of residents is reported in many communities in the Stikine and North Coast, mainly to service the summer and fall industries (resource based and tourism/outdoor recreation).

[1] Source: August 2003 Indian and Northern Affairs Canada registered population for Taku River Tlingit people on and off reserves. Statistics Canada reports a 2001 population of 17 people on an unnamed reserve near Atlin.

[2] Indian and Northern Affairs Canada (FNProfiles), July 2003 registered on-reserve population at Old Masset reserve. Note: Statistics Canada 2001 data for Old Masset reports 707 on-reserve residents, an increase of 2.2%.

Nonetheless, because electricity load is highest in winter in these communities, this variation is not likely to affect NIA planning in the foreseeable future.

- **Load growth from increases in commercial and industrial activity in NIA communities not expected to require short term installation of new capacity** – Mineral exploration is currently very active in the NIA areas, especially in the Stikine region. There are some new mine proposals expected and some proposals that have been on hold for several years that are well-developed which could reactivate depending on market conditions. However, in any case, it is likely to be another two or more years before any projects are approved to start production. Also, given their distance from the grid in remote areas, most of the projects are likely to generate electricity for their own needs.

  Similarly, due to increased logging and sawmilling activity in response to the Mountain Pine Beetle epidemic east of the coastal mountains in lodgepole pine areas, sawmills are expected to re-open, expand, or portable mills will be used. However, it is expected that such sawmills will, for the most part, generate electricity for their own needs.

  Although tourism activity has declined in recent years due to worldwide travel concerns, there is evidence that tourism in some NIA areas, such as the Queen Charlotte Islands, may be slightly increasing.

  Existing IPPs or BC Hydro itself may be able to expand or service a larger area, e.g. the Stikine National Power Corporation has expansion plans for power supply and distribution into Eddontenajon. The existing EPA with North Island Power (wood residue generation) on Graham Island near Masset has not yet been fulfilled and is requesting a delay for its contractual in service date to late 2004.

  Several IPP proposals, in particular for water power, are active or on the books in NIA areas. Synex Energy Resources Ltd has two active water power applications on Pine Creek and Spruce Creek in the Atlin district, and Coast Mountain Power Corp has submitted a bid for BC Hydro's most recent call for green power to connect over 100 km to the grid. The Nai-Kun Wind Farm proposal, offshore of Graham Island (Masset), is very preliminary. The Heiltsuk First Nation (Bella Bella) identified Ellerslie Lake as a possible IPP project several years ago, but there is no application for a project on record.

  All of the NIA communities have a significant proportion of First Nations residents. First Nations land claims continue to be strengthened by various court decisions, and as a result, major development proposals will be slower to proceed, or may not proceed, unless there is involvement of First Nations that is beneficial to their interests.

The current NIA business model has been highly favourable for these communities. As the financial review illustrated, NIA customers benefit significantly from the postage stamp rate model, and reliability has been high and improving overall.

Over the past decade, however, BC Hydro has downsized some of its local offices and resource requirements, resulting in the loss of a number of relatively high paying local jobs. It appears, however, that the downsizing process is largely completed.

From a strategic perspective, the impact of a change in the NIA business model on the local communities is likely to focus on how the new model affects rates.

Summary of socio-economic strengths and issues

Strengths	Issues
• Local economic benefits are being realized • Low (subsidized) electricity rates are enjoyed by NIA customers	

Conservation and environmental initiatives

A specific Power Smart program was offered in certain NIA areas from 1989 to 1998, it involved providing the following incentives for installing non-electric alternatives in residential dwellings:

Space heating systems	$1,500
Domestic water heating units	$500
Propane Clothes Dryers	$500
One time fuel subsidy	$500

The objective of this Power Smart program was to increase the efficiency of fossil fuel use. The propane and oil fired systems that were installed under this program displaced existing or avoided the installation of new electric systems that obtain their energy from oil fired diesel generators. The efficiency of the residential oil and propane systems would be approximately 75% while the combined efficiency of oil fired electric generation and electric-heating systems is approximately 35%.

The incentive levels were established to offset the initial capital cost premium of propane and oil fired systems. The concept of the program involved the assumption that the cost to the residences of oil and propane fuel is close to the level of electricity under the Zone 2 electricity tariff.

This program was not offered in the Bella Bella and Sandspit distribution areas due to take or pay contracts with hydroelectric IPPs being in place in these areas. It was not appropriate to offer incentives in these areas because the program would not have displaced fossil fuel generation and because BC Hydro by means of the take or pay contract had already purchased the electricity for the residential load.

In general the program was well received in the areas in which it was offered. There were 1,000 incentive applications processed over the 1989 to 1998 period with a total incentive funding of $2.6 million. This is a significant number of applications considering that the total market was in the order of 5,000.

The application rate declined to a very low number by 1998 mainly due to a significant decline in the number of new homes being constructed. Due to the small number of applications being processed, the program was terminated.

There was no evaluation completed of the Program to determine its effectiveness.

Looking forward, a new federal government climate change initiative may provide NIA communities with opportunities to increase involvement in energy planning and generation. Under this initiative, $30 million has been earmarked for assisting and supporting the approximately 130 remote, and Aboriginal and northern communities that rely on diesel generation as they work to improve their energy efficiency and adopt alternative energy sources to reduce their dependence on diesel fuel. The new initiative can provide assistance for community energy planning, management, renewable energy and improved technology applications (e.g., small hydro, wind, solar, variable generators), and capacity building, training and tools.

It is not yet known how this program will be applied in the NIA communities, however, there are several First Nations communities that have identified interest in pursuing IPPs or expansions of existing IPPs in their areas, e.g Tahlan and Heiltsuk areas.

Policy and regulatory issues

Key findings of the review

In November 2002, the BC government issued a wide-ranging energy strategy, *Energy for Our Future: A Plan for BC* . While there are no direct assignments to NIA in the Plan, NIA is included in the scope of the Plan by virtue of it being a part of BC Hydro's distribution and generation systems.

The Plan covers some of the key strategic components of the existing and alternative business models for NIA. The Plan retains and reinforces important elements of the *status quo*, while encouraging movement in other areas.

Overall, the Plan re-activates regulatory scrutiny of costs and rates, encourages green resources, continues public ownership of existing generation resources, and encourages private ownership of new generation resources. The following policies of the November 2002 Energy Strategy are of interest:

Policy #1 – Heritage Contract
Policy #3 – Public ownership
Policy #5 – BCUC to regulate BC Hydro
Policy #9 – Least-cost planning
Policy #13 – New generation by IPPs

Policy #23 – Amend the Utilities Commission Act to allow capitalization of energy efficiency expenditures.

Policies #1,3 and 5 support the *status quo*. Policy #1 ensures that the benefits of existing low-cost hydro accrue to B.C. consumers. This in turn implies that an ongoing NIA customer subsidy is consistent with the Plan because NIA costs will continue to be higher than the low average rates made possible by the Heritage Contract.[1] Policy #3 rules out sales of assets to private owners and, together with Policy #5, ensures that NIA expenditures and rates are subject to BCUC overview.

The other policies suggest change, some of which is likely to have been anticipated and acted on anyway. Policy #9 encourages movement towards a community-specific supply-and-efficiency approach to planning and resource development. Policy #13 indicates that new plant should be independent power wherever it is feasible and competitive. Policy #23 presents an opportunity to improve the financials on DSM in non-integrated areas, as well as anywhere else in the BC Hydro Service Area.

In setting revenue requirements for BC Hydro, the BCUC may be expected to move, as it has for Terasen and Aquila, towards performance-based ratemaking (PBR). However a PBR arrangement makes sense only if the cost-base, from which performance targets are defined, is shown to be acceptable. That cost base is likely to be closely scrutinized by the Commission and by interveners, in view of the extraordinary length of time since the financial records of BC Hydro were last examined by the BCUC. There may also be interventions in support of greater efforts in DSM and green power.

Summary of policy and regulatory strengths and issues

Strengths	Issues
• NIA capital and OMA costs are publicly regulated • Service standards and a complaint process are protected by the regulator	• Changes are required in planning processes and accounting conventions to respond to policy directives

Summary of current business model strengths and issues (Status Quo)

The current model characterizations highlighted in Table 14 below represent those areas of strategic importance to the NIA business going forward. Consequently, our recommendations regarding optimisation of the status quo focus on the "Issues to be addressed" (I-1 through I-8), recognizing that in the absence of any significant change to the current business model, the current strengths are likely to be sustained in the short term.

[1] Policy #1 states that the benefits of low-cost hydro are "for B.C. consumers", presumably including those not physically connected to the low-cost hydro.

Table 14: Summary of current model strengths and issues

Strengths	Issues
Organization S-1 Staff complement is efficient S-2 Competency in key roles is adequate	I-1 Coordination/leadership with accountability is needed I-2 Clarity of roles and responsibilities is needed
Operations S-3 System reliability is high	I-3 Replacement of the ageing diesel GU fleet will be required
Power Purchase S-4 Diesel displacement is being achieved S-5 IPP contract management is effective	I-4 IPP contracts are negotiated under conditions of high uncertainty
Finance	I-5 DLoB costs are allocated disproportionately to NIA I-6 Gross margin for the NIA profit centre is eroding as costs have increased more rapidly than revenues I-7 An ongoing subsidy to NIA is required
Socio-economic and Community S-6 Local economic benefits are being realized S-7 Low (subsidized) electricity rates are enjoyed by NIA customers	
Policy and Regulation S-8 NIA capital and OMA costs are publicly regulated S-9 Service standards and a complaints process are protected by the regulator	I-8 Changes are required in planning processes and accounting conventions to respond to policy directives

The points summarized here will also be used as criteria against which alternative business options are evaluated. The evaluation framework is described in detail later in this report.

Optimisation of the Status Quo

This chapter addresses the issues associated with the current business model (I-1 through I-8), identified in the previous chapter. The recommendations outlined here assume that no fundamental change in the current model is immediately forthcoming. Accordingly, all recommendations are implementable, and in some cases they point to the need for further study of the issue so that any change of a significant nature can be evaluated by senior management at BC Hydro.

A summary of the issues and recommendations associated with optimising the status quo is provided in Table 15 below. Detailed explanations of each recommendation follow.

Table 15: Summary of issues and recommendations regarding an Optimised Status Quo

Issues		Recommendations
I-1	Coordination/leadership with accountability	• Assign leadership
I-2	Clarity of roles and responsibilities	• Implement a decision and referral process
I-3	Replacement of diesel GU fleet	• Develop asset management and replacement strategy
I-4	High uncertainty during contract negotiations	• Review of key cost elements used in projecting IPP cost effectiveness
I-5	Disproportionate allocation of DLoB costs	• Review of cost allocation methods
I-6	Eroding gross margin	• Minimize direct costs of energy production
I-7	Required subsidy	• Explore alternative sources of funds
I-8	Changes required in planning processes and accounting conventions to respond to policy directives	• Examine requirements and assess how best to address those which are unique to NIA

Detailed recommendations

Leadership

To optimise the current organizational and reporting structure, the most critical improvement would involve establishing a permanent role within Operations such that there is a central person to provide overall coordination and direction in the delivery of NIA functions and services. The individual assigned this role may or may not have other responsibilities in addition to NIA coordination, depending on how the role is

ultimately defined. However, the value of this position would include ensuring that appropriate communications are maintained in support of decisions that can impact on the provision of NIA services.

Decision and referral process

In support of ensuring appropriate communication in decision making, a decision and referral process needs to be established that reflects current roles and responsibilities. This process should draw on the four generic functions identified earlier, namely planning, operations, customer and performance management, with lead accountabilities for decisions and secondary referral contacts. A framework for this process is provided in Table 16 below.

Table 16: Assignment of lead accountabilities for decisions and referrals by functional area

Functional Area for Decision	Lead Accountability	Referral
Planning		
(a) General strategy and business planning	(a) Operations	(a) Finance and Business Services
(b) Capital investment planning	(b) Strategic Asset Management (Operations)	(b) Finance and Business Services
(c) Financial planning	(c) Finance and Business Services	(c) Field Services
(d) Environmental planning	(d) Sustainability and Policy	(d) Field Services
(e) Load forecasting and planning	(e) Strategic Asset Management	(e) Power Planning and Portfolio Management
(f) Maintenance planning and standards	(f) Strategic Asset Management	(f) BC Transmission Corporation and Engineering Services
Operations		
(g) Customer response	(g) Customer Projects and Operations	(g) Power Smart
(h) Power acquisition	(h) Power Planning & Portfolio Management	(h) Customer Projects and Operations
(i) Generation asset acquisition	(i) Strategic Asset Management	(i) Finance and Business Services
(j) Generation asset maintenance	(j) Field Services (BC Transmission Corp.)	(j) Engineering Services
(k) Distribution asset maintenance	(k) Field Services	(k) Engineering Services
Customer		
(l) Customer relations and outreach	(l) Customer Projects and Operations	(l) Power Smart
(m) Billings, collections and service	(m) Power Smart (Accenture)	(m) Customer Projects and Operations
Performance Management		
(n) Risk management	(n) Strategic Asset Management	(n) Field Services
(o) Financial controls and reporting	(o) Finance and Business Services	(o) Strategic Asset Management
(p) Operational reporting	(p) Field Services	(p) Engineering Services (BC Transmission Corporation)

As reflected in Table 16, and the business function and responsibility map described in the previous chapter, the working relationship between Field Services, Engineering Services and the BC Transmission Corporation should be clarified. This would be accomplished through the finalization of a SLA with Field Services and establishing a similar agreement with the BC Transmission Corporation.

Asset management and replacement strategy

Under the current NIA business model, we understand that diesel generation unit (DGU) replacement needs are evaluated on a case-by-case basis, on the recommendations of Field Services staff. A recommendation to purchase or replace a DGU is referred to the Strategic Asset Management group (within Operations), where a business case for the capital expenditure is prepared and referred to the Director of Operations for approval.

This approach, while effective from a process perspective, has some weaknesses in terms of achieving an overall goal for the NIA business of optimising the return on investment for the full complement of DGU assets over the long term. What is needed is a long term strategy for asset management and replacement which reflects a balance of the costs of continued deployment of ageing DGUs, versus the operating cost efficiencies expected from the use of newer technologies that are better able to measure both use and efficiency. This point is illustrated as follows:

- **Operating cost implications of efficiency gains should be measured**. In 2002-03, the fuel efficiency index for all NIA diesel stations was approximately 3.5.[1] If this value were to be increased to 3.7 through the replacement of older units,[2] the real savings in fuel costs, given total power generated in 2002-03 and recent fuel prices,[3] would be approximately $354,000 per year. This analysis is summarized in Table 17 below.

Table 17: Calculation of operating cost savings from diesel fuel efficiency gains

Fuel efficiency index	3.5[1]	3.7[2]	Change	%
Energy production - kWh (total NIA, 2002-03)	55,942,700	55,942,700	--	--
Diesel fuel consumption - litres	15,901,976	15,119,648	(782,328)	-4.92%
Total fuel cost[3]	$7,205,185	$6,850,712	($354,473)	-4.92%

[1] *2002-03 actual values for energy production and diesel consumption*
[2] *Alternative scenario for illustrative purposes*
[3] *Using an assumed fuel cost of $0.4531 from Table 12, 2003-04 Q1 average fuel costs .*

Further efficiency gains could also be achieved through the individual unit metering of fuel consumption. Currently, maintenance schedules are correlated with unit in-service hours, regardless of the average capacity at which a unit is operated. Maintenance schedules for units used at less than full capacity when in operation could be extended, resulting in some efficiency.

Older models of DGUs can be refit with fuel use metering systems. Most newer models are designed with this capability.

Determining Value of IPP Contracts

As indicated in the previous chapter, BC Hydro has previously used a rather extensive analysis to compare the potential benefits of an IPP contract before actually awarding the contract. This analysis involved comparing on a Net Present Value (NPV) basis the 20 year projected costs of Power from the IPP contract with the 20 year projected 20 year costs from existing diesel generation. Some of the key projections in this analysis are the following estimates for the IPP case:

[1] Fuel efficiency index is a measure of power generated per unit of fuel volume (ie. kWh/litre).

[2] The most efficient newer diesel generating units can achieve fuel efficiency of up to 4.1. Other jurisdictions (reviewed in the next chapter) range from approximately 3.1 to 3.7.

[3] See Table 13, 2003-04 Q1 average fuel price of $0.4531 per litre.

- Overall cost for standby diesel generation operation
- Engine replacement cost with standby operation;
- Variable operating & maintenance costs for standby operation.

In a previous internal audit (Internal Audit Report, Non-Integrated Area, May 4, 2001), statements were made which indicated that BC Hydro's cost of maintaining diesel generating stations in the standby mode meant that the IPP contracts were not cost effective. In order to address this concern the following is recommended. The initial comparative analysis that was used to evaluate the IPPs that are now in operation should be reviewed with respect to the assumptions for the above bullets. This review would determine what the actual standby costs have been with respect to the estimates. The results of this review could then be used in future IPP evaluations with respect to these costs.

It is suggested that at this point there appears to be a variation in opinion within BC Hydro as to the actual cost/benefit of IPP contracts. The key question around this variation in opinion is the cost of standby operation versus baseload operation with respect to the Diesel Generating units. The above-recommended review and resulting refinement of cost assumptions in IPP contract evaluations would help reduce this uncertainty for future evaluations.

Business sustaining and finance cost allocation methods

As was discussed in the financial review of the previous chapter, business sustaining and finance charges, allocated out among business units as a portion of total DLoB costs, represent a significant proportion of the total net internal accounting loss attributed to the NIA business. However, over the past five years, there does not appear to have been a single approach taken to render fair and consistent allocations.

We recommend that BC Hydro review the current allocation methods, with a goal to producing internal Profit and Loss statements that more accurately describe the magnitude of the net loss of this business unit. We suspect that the current allocations are disproportionately high, relative to both the level and scope of services provided by DLoB and Corporate to NIA (business sustaining charges), and the debt service requirements of the NIA asset base (finance charges). We also recommend that the asset database be reviewed for surplus items, to ensure that costs calculated directly from the estimated NBV of NIA assets are not overstated.

Minimize direct cost of energy production

Given the prevailing policy in BC concerning rate setting for BC Hydro customers, significant increases in revenue are not expected in the near term. Therefore, in order to slow the erosion of the NIA business' Gross Margin, steps need to be taken to ensure that the costs associated with energy production inputs, including diesel fuel, are at minimum levels.

This recommendation is consistent with our earlier recommendations concerning the need for an asset management and replacement strategy.

In addition, opportunities for further cost effective demand side management (DSM) should be explored and implemented.

Alternative funds for NIA subsidy

Currently, all BC Hydro customers are subsidizing electricity service provision to BC's remote communities. It may be beneficial to explore whether the federal or provincial governments, in the context of their legislative mandates or other fiduciary responsibilities, could assume any portion of this subsidy. This option has not been explored in detail within the scope of this study. However, it would be beneficial to investigate the experience of Manitoba Hydro, which negotiated with the federal government in the late 1990's to receive funding for the integration of remote legal Indian Reserves with the province's main transmission grid.

Respond to future policy directives

Those policies of the BC Energy Strategy that are expected to result in the need for increased resources or a change in the methods used to account for specific costs should be examined to ascertain which ones have specific implications for the NIA business. Least cost planning will likely require added engineering, commercial, negotiation and staff time at the NIA business unit level. DSM accounting will likely be addressed at a corporate level, in consultation with the organization's auditors and is therefore not expected to have a direct impact on NIA activities.

Inter-jurisdictional Review

This chapter summarizes our review of other jurisdictions with organizational and operational issues comparable to those confronting the BC Hydro NIA business. The purpose of the review was to gain insight into the business models employed in other areas, and assess whether their experiences can inform BC Hydro's NIA business strategy.

There are eight other jurisdictions within Canada that provide diesel prime power to remote communities:

- Yukon Territory
- Northwest Territories
- Nunavut Territory
- Alberta
- Manitoba
- Ontario
- Quebec
- Newfoundland and Labrador

We reviewed each of these jurisdictions, along with Alaska, in our research.

Business models for delivery of generation and distribution services

- **Yukon Territory** – Since 1998, Yukon Energy Corporation (YEC), a territorial crown corporation, has been the main electric utility servicing the territory. Prior to this date, between 1988 and 1997 Yukon Electrical Company Limited (YECL), a subsidiary of Alberta-based Atco Electric, was contracted to be the electricity system operator on behalf of the territorial government. Currently, approximately 80% of the territory's generation capacity is hydro. YECL still provides generation and distribution to approximately 10% of the territory, including nine remote communities, supplied by diesel stations.

- **Northwest Territories** – Northwest Territories Power Corporation (NTPC) is a wholly owned GNWT crown corporation. NTPC owns and operates all but two of the territory's electricity generation facilities. NTPC purchases power from the Snare Cascades Hydro facility (4.3MW), owned by the Dogrib Power Corporation and leased back to NTPC who operates the facility, and from Esso Resources Canada Ltd. (ERCL), which owns a plant in Norman Wells to power its

processing and pumping station for crude oil. Sixty percent (60%) of the territory's generating capacity is hydro. NTPC services approximately 13 remote communities in the western Arctic and Arctic coast from diesel stations.

- **Nunavut Territory** – Nunavut Power Corporation (NPC) is a crown corporation, wholly owned by the Nunavut territorial government. There is no connected transmission grid in the territory. Twenty five independent diesel stations are used to serve all communities. This jurisdiction is very comparable to BC Hydro's NIA business.

- **Alberta** – Atco Electric is a privately owned utility which services the northern half of the province, including 13 remote communities. All remote communities are powered by diesel stations.

- **Manitoba** – Manitoba Hydro is a provincial crown corporation responsible for electricity service to the whole province. There are currently four remote communities powered by diesel stations. In the late 1990's, Manitoba Hydro negotiated a cost sharing arrangement with the federal government to integrate a number of remote legal Indian Reserves with the main transmission grid. To date, eight (8) of the 12 communities have been integrated, and four (4) are still isolated.

- **Ontario** – Hydro One is a 51% publicly owned electricity delivery company in Ontario. It is also a holding company for Hydro One Remotes, which operates and maintains generation and distribution assets used to supply 19 remote communities in the province. All remote communities are powered by diesel stations.

- **Quebec** – Hydro Quebec (HQ), a provincially owned electric utility, provides power to the whole province. The utility serves 25 remote communities, primarily from diesel stations. However, HQ also has 21,000 kW of capacity in two hydro units independent of the integrated grid.

- **Newfoundland and Labrador** – Newfoundland and Labrador Hydro (NLH) is a publicly owned utility which services Labrador, and some remote parts of Newfoundland. With the exception of Churchill Falls which is connected to the Quebec transmission system, all of Labrador is non-integrated. Communities along the coast of Labrador, and the south coast of Newfoundland receive power from diesel stations, although a few communities are powered by natural gas generation. Most of Newfoundland is serviced by Newfoundland Power, a subsidiary of privately owned Fortis.

- **Alaska** – The Alaska Village Electric Cooperative (AVEC) provides power through a not-for-profit co-operative owned by the villages it serves. The Co-op sets rates to achieve full cost recovery. Most of the state is supplied by diesel stations. However, AVEC has installed 200 kW of wind turbine capacity and has one 500 kW run-of-river hydro facility.

About 45% of the energy delivered by the eight Canadian utilities surveyed is from hydro-electric sources. In the Yukon, the Northwest Territories and Quebec, hydro is produced at conventional dam sites. The hydro-electric sites in BC generate power through low-head or run-of-river systems.

BC Hydro, Yukon Energy Corp., Northwest Territories Power Corp. and Newfoundland Hydro purchase power from other businesses. BC Hydro has the largest percentage of purchased power at 33% of all non-integrated power. The other four utilities examined did not have any IPP contracts.

Less than 2% of power comes from alternative renewable sources, primarily wind.

Comparative data

Table 18 shows some basic comparative data about the utilities surveyed, and then presents reliability, cost and efficiency information for each utility. Table 19 compares financial information and rate structure across jurisdictions, where we were able to receive data.

Table 18: Comparative Operating Information

Utility	BC Hydro (NIA)	Atco Electric (Alberta)	Yukon Energy Corp.	Northwest Territories Power Corp.	Manitoba Hydro	Hydro One (Ontario)	Quebec Hydro	Nunavut Power Corp.	Newfound-land & Labrador Hydro[1]
General (2002/2003 data)									
Number of diesel stations	13	13	9	31	4	21	25	25	25
Number of gensets	61	54	18	84	16	60	87	85	86
Number of prime gensets	36	28		63	16	57	67		86
Number of accounts	6,208	n/a	17,160[2]	7,200	685	3,800	14,299	11,000	4458
Energy generated (million kWh)	105	89	279	350	11	58	322	123	63.8
From gensets	50	24		103	11	56	65	123	49.1
From hydro	12	7	263	240	-	2	79	-	-
Purchased	35	-	15	7	-	-	-	-	14.7
Reliability[3]									
ASAI	99.81	n/a	n/a	99.67	99.97	99.82	99.92	n/a	99.86
CADI	1.68	n/a	1.04	1.00	1.47	0.80	1.62[4]	n/a	0.80
SAIFI	9.84	n/a	6.26	--	1.55	30.0	1.66[5]	n/a	14.19
SAIDI	16.59	n/a	6.5	0.30	2.36	16.0	6.40[6]	n/a	11.42
Efficiency									
Fuel efficiency	3.49		3.9	3.64	3.61	3.36	3.66	3.63	3.1
Station service (kWh)	7.3%			3.1%	9%	1.6%		3.8%	7.9%
Maintenance ($/kWh)	3.53			2.73	10.3	8.1			

[1] General information provided is as of year-end 2002. Reliability indices are 5-year average values. Financial information is based on 2002 forecast cost of service as approved by PUB.

[2] Of these, 1,691 are served by YEC. The rest are served by YECL.

[3] Indices for NIA only are: BC, Manitoba, Ontario, Quebec and Newfoundland. Yukon and Northwest Territories indices are system-wide.

[4] Magdalen Islands only

[5] Magdalen Islands only

[6] Magdalen Islands and Boreal

Table 19: Comparative Financial Information

Utility	BC Hydro (NIA)	Atco Electric (Alberta)	Yukon Territory	Northwest Territories Power Corp.	Manitoba Hydro	Hydro One	Quebec Hydro	Nunavut Power Corp.	Newfound-land & Labrador Hydro
Finance									
Revenue (million)	$7.5		$24.6	$66.7	$3.7	$13.2	$70.5	$52.8	$6.4
Fuel Cost	$6.1		$1.3	$15.2	$2.1			$22.2	$6.4
OMA Costs	$6.8		$18.2	$34.2	$5.4			$38.5	$8.1
Net Income	($17.6)		$3.8	$7.7	($3.7)			$7.9	($19.8)
Full-Cost (¢/kWh)	18		7.17	16.9[1]	35.9			49	53
Rates									
Residential – base rate	0.0577 (integrated grid)		$0.1407[2]	$0.1819	0.0589 (integrated grid)	0.0875 (integrated grid)	(integrated grid)	0.1182 plus fuel rider[3]	$0.07185 (grid)
Residential – base block	First 1500 kWh/month		First 1,000 kWh/month	First 700 kWh/month		n/a	> 30 kWh $0.265	n/a	700 kWh
Subsidy	yes		Fuel rider $0.0059/kWh	Community Based rate	yes	yes	yes	First 700 kWh	yes

[1] Calculated. Yukon Territory is low because 70% of its power is from hydro-electric sources.

[2] From Yukon Energy Corporation 2002 Annual Report.

[3] Subsidized rate. Base rate is $0.3346/kWh. Source http://www.nunavutpower.com/npc/

Alternative Business Models

In order to move forward, and beyond the current policy and structure for delivering NIA services, this section outlines a series of alternative business models. Specifically, 13 alternative models have been identified and are summarized below.

Historical strategic planning initiatives for NIA

The early foundation for the alternative business models profiled below can be found in the strategies for NIA that were prepared in the early to mid 1990's, and which made reference to options for changes in rate structures, extension policies, use of Independent Power Producers, and alternative fuel infrastructure. The NIA Strategic Plan prepared in 1995, for example, describes the potential for Aboriginal communities and businesses to approach BC Hydro about assuming responsibilities for existing energy services and capital. Further, the plan outlines opportunities for purchases of electricity from Independent Power Producers, integration of communities to the Provincial power grid, and changes in rate structures.

More recently, the Provincial Energy Policy makes explicit commitments to low electricity prices, secure and reliable supply of energy, more private sector opportunities (e.g., smaller scale generation) and environmental responsibility.[1] These commitments are translated into strategies of:

- Engaging the private sector in new electricity generation;
- New rate structures (i.e., stepped and time-of-use) to promote energy efficiency;
- Enabling Independent Power Producer participation; and
- Purchases of at least 50% of new power supply from "clean resources" that are renewable or allow for net environmental improvements among other actions.

[1] For further information, refer to, "Energy for our Future: A Plan for BC", Ministry of Energy and Mines, 2003.

Options to be evaluated in this study

Combined with the feedback received through our interview program, this earlier work provided the basis for defining 13 potential options which could, either alone or in combination, form the basis of a new business model for NIA. These are:

Option 1. Status Quo
Option 2. Optimised Status Quo

Modified corporate structure options

Option 3. Create an NIA Department
Option 4. Create an NIA Subsidiary
Option 5. Integrate NIA communities

External service provider options

Option 6. Outsource various services
Option 7. Engage a system operator
Option 8. Lease assets and their operations to a third-party

Divestiture options

Option 9. Sell assets to third party

Policy change options

Option 10. Modify rates
Option 11. Modify service levels

Alternative energy options

Option 12. Displace usage of diesel facilities through alternative energy sources
Option 13. Increase reliance on IPPs

Option 1. Status Quo

This option involves maintaining the current direction for the NIA business as described in the "Current Business Model" chapter of this report. This is the option against which all others are evaluated.

Advantages:

- No organizational or operational changes are required

Disadvantages:

- None of the issues associated with the status quo are addressed
- Risk of loss of focus on unique needs of NIA over the long term

Option 2. Optimised Status Quo

This option encompasses the recommendations described in the "Optimised Status Quo" chapter of this report, and does not involve any substantive changes to the current business model. All recommendations can be implemented within a short time frame.

Advantages:

- All issues associated with the status quo are addressed to some degree
- Provides a short term solution for BC Hydro

Disadvantages:

- Risk of loss of focus on unique needs of NIA over the long term remains

Option 3. Create an NIA Department

This option reflects the model which existed prior to the most recent restructuring of BC Hydro, where all authorities and overall accountability for the operations, maintenance and ownership of NIA assets and services were consolidated in a single Line of Business and Department. Responsibilities can then be delegated through the use of Service Level Agreements or other mechanisms to service organizations, as they are currently.

Advantages:

- Provides for a consolidation of experienced management and staff resources and accountabilities for the provision of NIA energy services
- Addresses concerns over unclear roles and responsibilities as well as communications

Disadvantages:

- Does not provide opportunities for Aboriginal and private sector engagement or for BC Hydro to transfer certain risks associated with NIA energy services to a third-party interest
- Subject to the business unit model that is adopted, may create the need for additional human resources

Option 4. Create an NIA Subsidiary

Creation of a subsidiary would result in a new legal entity, with its own resources, structure and governance to assume responsibilities for the management of NIA assets and services. A subsidiary could be structured in a number of ways (generation and distribution).

Advantages:

- Provides for a consolidation of resources, expertise and accountabilities for the provision of NIA energy services
- Greater distinction in accounting for costs of NIA service delivery
- Maintains public ownership of assets
- Organizational goals and strategies are focused on unique characteristics and needs of NIA

Disadvantages:

- Transitioning to a new organizational entity would require the establishment of a governance structure, interim funding arrangements, transfers of staff and labour provisions, and other management issues to be addressed
- Will be a need to incur additional ongoing costs associated with financial reporting and regulatory filing
- Does not specifically address the need for a source of funds to make up subsidy

Option 5. Integrate NIA communities

This option involves construction of transmission lines to integrate NIA communities with the main BC Hydro transmission grid. This option could apply on an area basis and need not apply to all NIA communities simultaneously. Earlier BC Hydro strategies made reference to integration subject to confirming financial performance, customer service, environmental, economic development and social factors. This option is likely less attractive for communities currently served by IPPs, in light of take-or-pay contract terms.

Advantages:

- Expensive and environmentally disadvantageous diesel generation is displaced
- Brings NIA priorities and service delivery requirements in line with those of the rest of the province

Disadvantages:

- Is likely to be cost or technically prohibitive in most areas
- Comprehensive business case demonstrating financial and less tangible costs and savings associated with integration needs to be established

Option 6. Outsource various services

This option involves establishing contractual agreements for the outsourcing of operational, maintenance and capital improvement services with a third party, external to BC Hydro. This option presumes that a third party could offer something in addition to or at a lower cost than BC Hydro service organizations (Field Services, Engineering Services) which currently perform these services on behalf of DLoB. The scope of services to be outsourced and associated standards of practice must be well-defined. Contractors could include Original Equipment Manufacturers (OEM), commercial firms, or local contractors (including First Nations).

Advantages:

- Could provide opportunities for Aboriginal and private sector engagement at a community level
- Builds off the emerging practice of establishing Service-Level Agreements
- Allows for BC Hydro to transfer certain financial and non-financial risks associated with NIA energy services to a third-party interest

Disadvantages:

- Unclear whether a third-party interest at the community level would have the capability and capacity to assume responsibility and maintain operations in a manner that meets current service standards and expectations
- Negotiating an agreement would be subject to certain complexities such as determining the distribution of risks

Option 7. Engage a system operator

This option would involve contracting out the “asset owner” role (currently held by DLoB, Operations) to an external third party. The outside organization, or asset manager would be charged with operation and management of the NIA assets, and would likely perform all functions related to the NIA business on a cost recovery for operations plus operating fee basis. BC Hydro would maintain responsibility for IPP contract negotiation and management. Currently, four of the NIA diesel stations are operated by local entities. The option could involve broadening the current arrangement to include more stations, or it could see a single operator assume responsibility for the entire NIA system.

Advantages:

- Could provide opportunities for Aboriginal and private sector engagement at a community level
- May be opportunity for economic efficiencies to be gained through the use of technology and centralization of operations
- May allow BC Hydro to transfer certain financial and non-financial risks associated with NIA to a third-party interest

Disadvantages:

- Unclear whether a third-party interest at the community level would have the capability and capacity to assume responsibility and maintain operations in a manner that meets current service standards and expectations
- Negotiating an agreement would be subject to certain complexities such as determining the distribution of risks

Option 8. Lease assets and their operations to a third party

DLoB could ultimately lease the generation and/or distribution assets to a third-party private sector or Aboriginal group (agency), and transfer operational responsibilities, while maintaining ultimate ownership of the assets. This option removes BC Hydro one step further from NIA service delivery and decision making. It also presumes that a third party can realize some cost advantage over BC Hydro in undertaking NIA activities.

Advantages:

- Allows BC Hydro to transfer a number of financial and non-financial risks associated with NIA to a third-party interest
- Could provide opportunities for Aboriginal and private sector engagement at a community level
- Could result in a consolidation of expertise for the provision of NIA energy services

Disadvantages:

- Unclear whether a third-party interest at the community level would have the capability and capacity to assume responsibility and maintain operations in a manner that meets current service standards and expectations
- BC Hydro would be relinquishing some control over an activity which is its ultimate legislated responsibility, and additional costs would have to be incurred if the contractual arrangement failed

Option 9. Sell assets to a third party

DLoB could transfer through sale, in whole or in part, generation and/or distribution assets to third-party private sector or Aboriginal interests along with responsibilities for their operation. Adoption of this option would not reduce or eliminate BC Hydro's responsibility to provide electricity service to NIA.

Advantages:

- Allows BC Hydro to transfer a number of financial and non-financial risks associated with NIA to a third-party interest
- Could provide opportunities for Aboriginal

Disadvantages:

- Model is not consistent with the BC Energy Policy commitment towards public ownership
- Unclear whether a third-party interest at

and private sector engagement at a community level
- Could result in a consolidation of expertise for the provision of NIA energy services

the community level would have the capability and capacity to assume responsibility and maintain operations in a manner that meets current service standards and expectations
- BC Hydro would be relinquishing some control over an activity which is its ultimate legislated responsibility, and additional costs would have to be incurred if the contractual arrangement failed

Option 10. Modify rates

This option involves increasing electricity consumption prices in NIA to address the current revenue shortfall associated with service provision to these areas. Rates could be tailored to the specific costs of a given area, or apply universally across NIA. This option presumes that the BC Utilities Commission (BCUC), and the provincial government, would be amenable to rate differentials across BC Hydro customer groups.

Advantages:
- The issues of an eroding gross margin and the ongoing requirement of a subsidy to these areas would be addressed
- Earlier BC Hydro strategies made reference to increases in trailing block rates and adjusting blocking points to promote greater efficiency in energy use by reflecting marginal costs (in particular for larger general customers with demand exceeding 35 kW); in keeping with this, initial work was carried out on assessing customer impacts in terms of price responsiveness

Disadvantages:
- Model is not consistent with prevailing public policy and the historical rate rulings of the BCUC
- Potential for communities to express concerns over unstable economies and the potential for rate increases to exacerbate these circumstances

Option 11. Modify service levels

This option also addresses the ongoing issue of revenue shortfalls for NIA, but from the perspective of reducing costs by providing a reduced level of service. This option also presumes that the provincial government would be amenable to service level differentials across BC Hydro customer groups.

Advantages:
- The issues of an eroding gross margin and the ongoing requirement of a subsidy to these areas would be addressed to some extent

Disadvantages:
- Potential for communities to express concerns over differentiated treatment

- Service levels are currently very high in these areas, and could possibly be reduced with minimal impact on quality of life and economics in these communities

Option 12. Displace usage of diesel facilities through alternative energy sources

This option provides for additional investment and acquisition of energy from mini-hydro, wind, alternative fuel, co-generation and fuel-cell sources.

Advantages:

- Consistent with the BC Energy Policy commitment towards the development of alternative energy resources that are less harmful to the environment, as well as current strategic directions and initiatives of BC Hydro (i.e., aligned with certain projects that are underway or planned)
- Builds off prior experiences with alternative energy production in NIA, including Clayton Falls, research into solar thermal initiatives, and the engagement of Independent Power Producers
- Could provide opportunities for Aboriginal and private sector engagement at a community level

Disadvantages:

- Comprehensive business cases demonstrating the financial and less tangible costs and savings associated with alternative energy need to be established
- Certain technologies may be geographically limited in their application (e.g., solar) or subject to other functional constraints
- There is a need to maintain standby power sources to backup alternative energy facilities
- Not likely to provide cost advantages over the status quo

Option 13. Increase reliance on Independent Power Producers

This option would involve additional investment and contracting with Independent Power Producers for the provision of energy within NIA. The option presumes that opportunities exist which are not currently being exploited by BC Hydro.

Advantages:

- Consistent with the BC Energy Policy strategy of enabling Independent Power Producer participation, as well as current strategic directions and initiatives of BC Hydro (i.e., aligned with certain projects that are underway or planned)
- Builds off prior and current experiences with Independent Power Producers

Disadvantages:

- Given the level of effort expended by BC Hydro in this area over the past 20 years, there are not likely to be any significant, unexplored opportunities available
- Not likely to provide cost advantages over the status quo

Major considerations for implementing an alternative business model for NIA

One of the major considerations associated with many of these options is that of ensuring Aboriginal or private-sector third-party interests have sufficient managerial, technical and financial resources available to provide for the ongoing operation and maintenance of facilities, and provision of related services to NIA communities. One of the more salient risks is the problem of "orphan plants," where a business or group abandons a facility with no plan or resources in place to ensure its ongoing operation and maintenance, and the continued provision of energy to community members. As such, in order to be feasible the options relating to outsourcing or transfer of responsibilities and assets to third-party interests must incorporate allowances for a combination of risk mitigation measures including insurance and financial guarantees to be put in place to protect against such circumstances.

For the alternative model of establishing a subsidiary, the recent experience of the BC Transmission Corporation could serve as a guide in terms of putting in place governance and management structures with the attendant financial and staff resources. By its very nature though, this is more of a medium to longer-term option.

With respect to consolidating authorities and resources, some of the options that were advanced by those interviewed for the purposes of this study included Field Services, the Distribution or Generation Line of Business, or the BC Transmission Corporation. For example, load and customer service requirements could be established at a headquarters level, and then Field Services or the BC Transmission Corporation would be responsible for managing all aspects of the generation and distribution of energy in non-integrated areas. In contrast, it was proposed by another individual that Customer Projects and Operations within the Distribution Line of Business could evolve to become the "super coordinator" for NIA, and in keeping with more of a customer-driven perspective.

For outsourcing, the services being considered need to have clearly defined service requirements (standards) and means for compensation. Core technical and managerial qualifications, and accountabilities, are also important. Although the specifics of the contractual arrangement can vary from case to case, generally there is a greater shift of the risk-reward ratio in favour of the service provider. Furthermore, the ability to provide a lower cost service and the re-engineering of business processes to reduce overall costs are the primary drivers under outsourcing.

Evaluation of Business Alternatives

This chapter summarizes our comparative evaluation of the impact of the alternative business models described in the previous chapter on the NIA business.

Evaluation framework

The criteria, against which each option has been evaluated, are the nine (9) strengths and eight (8) issues associated with the status quo, summarized again in Table 20.

Table 20: Evaluation criteria

Strengths		Issues	
S-1	Efficient staff complement	I-1	Coordination/leadership with accountability
S-2	Competency in key roles	I-2	Clarity of roles and responsibilities
S-3	High system reliability	I-3	Replacement of diesel GU fleet
S-4	Diesel displacement	I-4	High uncertainty during IPP contract negotiations
S-5	Effective IPP contract management	I-5	Disproportionate allocation of DLoB costs
S-6	Local economic benefits	I-6	Eroding gross margin
S-7	Low (subsidized) electricity rates	I-7	Required subsidy
S-8	Public regulation of capital and OMA costs	I-8	Changes required in planning processes and accounting conventions to respond to policy directives
S-9	Preservation of service standards and complaint process		

Each option has been evaluated in terms of two measures.

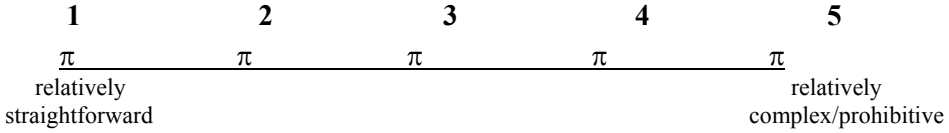
Complexity of implementation

The first measure used in the evaluation framework reflects the **complexity** associated with transitioning the NIA business to the option in question. Elements of complexity include:

- Magnitude of expected costs associated with implementation of the option (but which are not expected to be ongoing once the option is fully implemented).

- Time and human resources required to implement the option
- Degree to which the option does not conform to current government policy and the historical priorities of the BCUC.

A single score ranging from one (1) to five (5) has been assigned to each option as follows:



Complexity scores and the corresponding explanations for each option are summarized in Table 21 below.

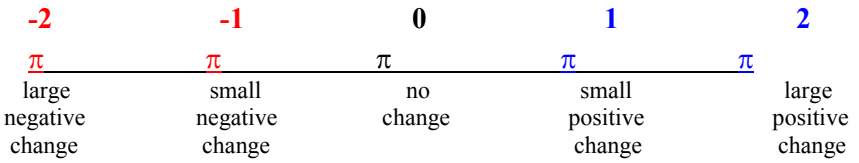
Table 21: Summary of complexity scores assigned to options 1 through 13

Option	Score	Explanation
1. Status Quo	0	No changes to current activities required
2. Optimised Status Quo	1	Some resources required to implement recommendations
3. Create an NIA Department	2	Would require some organizational change and resources
4. Create an NIA Subsidiary	4	Legal and regulatory advice required; governance, finance and labour issues to resolve; costs associated with establishing new legal entity; but, not currently prohibited by policy or law.
5. Integrate NIA communities	5	Likely prohibitive in most cases by cost and/or practicality
6. Outsource various services	1	Some resources required to seek out and negotiate contract arrangements
7. Engage a system operator	2	Resources required to seek out and negotiate contract arrangements; some organizational refinement to manage operator relationship
8. Lease assets and their operations to a third-party	3	Legal and regulatory advice required; resources required to seek out and negotiate contract arrangements
9. Sell assets to third party	5	Currently prohibited by government policy
10. Modify rates	5	Contrary to current policy of postage stamp rates in BC
11. Modify service levels	1	Some resources required to assess options and implement changes
12. Displace usage of diesel facilities through alternative energy sources	4	Intensive planning required; need to incur capital costs; longer time horizon; applicability of technology must be assessed by area; but, not currently prohibited by law or policy
13. Increase reliance on IPPs	0	No changes to current activities required

Expected impacts of implementation

The second measure used in the evaluation framework reflects a subjective score to characterize the (positive and negative) **impacts** expected to accrue if the model were to be adopted in whole or in part.

The impact score is the sum of individual scores, ranging from minus two (-2) to plus two (2), assigned to each of the 17 evaluation criteria described in Table 20. If the option is expected to negatively impact a strength or issue of the current model, then a negative score has been assigned. If the option is expected to positively impact or address a strength or issue, then a positive score has been assigned. If the option in question is not expected to result in a significant change from the status quo, then a score of zero (0) has been assigned.



Results of the evaluation are summarized in Table 22 and explained in the following section.

Table 22: Results summary

	Strengths									Issues								Scores	
	Staff efficiency	Competency	Reliability	Diesel displacement	IPP Contracts	Local economics	Low rates	Public regulation	Service standards	Accountability	Roles & responsibilities	Asset replacement	IPP contract uncertainty	Cost allocation	Eroding gross margin	Required subsidy	Ability to change		
Business Model	**S-1**	**S-2**	**S-3**	**S-4**	**S-5**	**S-6**	**S-7**	**S-8**	**S-9**	**I-1**	**I-2**	**I-3**	**I-4**	**I-5**	**I-6**	**I-7**	**I-8**	**Impact**	**Complexity**
1. Status Quo	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
2. Optimised Status Quo	0	0	0	0	0	0	0	0	0	2	1	1	1	1	0	0	0	**6**	**1**
Modified corporate structure																			
3. Create an NIA Department	-1	1	0	0	0	0	0	0	0	2	2	0	0	0	0	0	0	**4**	**2**
4. Establish an NIA subsidiary	-1	2	0	0	0	0	-1	0	0	2	2	2	0	2	-1	0	0	**7**	**4**
5. Integrate NIA communities	2	0	0	2	0	-2	0	0	0	0	0	0	0	0	2	2	0	**6**	**5**
External service provider																			
6. Outsource various services	1	-1	-1	0	0	1	0	0	0	0	1	0	0	0	1	0	0	**2**	**1**
7. Engage a system operator	2	-1	-1	0	0	1	0	0	0	0	1	0	0	0	1	0	0	**3**	**2**
8. Lease assets and their operations to a third-party	2	-1	-1	0	0	1	0	0	0	0	1	0	0	0	1	0	0	**3**	**3**
Divestiture																			
9. Sell assets to a third party	2	-1	-2	0	0	1	0	0	0	0	0	2	0	2	2	0	0	**6**	**5**
Policy change																			
10. Modify rates	0	0	0	0	0	0	-2	0	0	0	0	0	0	0	2	2	0	**2**	**5**
11. Modify service levels	1	0	-2	0	0	0	0	0	0	0	0	0	0	0	1	1	0	**1**	**1**
Alternative energy																			
12. Displace usage of diesel facilities through alternative energy sources	0	0	0	2	0	1	0	0	0	0	0	2	0	0	-2	-2	2	**3**	**4**
13. Increase reliance on IPPs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**

Results of comparative evaluation

Option 2. Optimised Status Quo

This option is expected to impact organizational and operational issues, but is not expected to affect financial or policy issues in the short term. It is also relatively straightforward to implement.

- **S-1 to S-9; I-6 to I-8**: No effect
- **I-1** (Accountability): 2 - immediate impact
- **I-2** (Roles and responsibilities): 1 - delayed and uncertain impact
- **I-3** (Asset replacement): 1 - delayed and uncertain impact
- **I-4** (IPP contract uncertainty): 1 - further study of issue
- **I-5** (Cost allocation) 1 - delayed and uncertain impact
- **Total** **6**

Option 3: Create an NIA Department

This option only effectively addresses organizational strengths and issues. Some staff efficiency gains realized through the decentralized organization structure may be lost. However, competency levels can be expected to increase. Experience prior to the recent organization suggests that clear leadership and accountability can be assigned, and roles and responsibilities more clearly defined.

- **S-3 to S-9; I-3 to I-9**: No effect
- **S-1** (Staff efficiency): -1 - requirements increase
- **S-2** (Competency): 1 - increased slightly
- **I-1** (Accountability): 2 - immediate impact
- **I-2** (Roles and responsibilities): 2 - clarity addressed
- **Total** **4**

Option 4: Establish an NIA subsidiary

This option is expected to result in a number of significant changes to the business drivers. As a separate legal entity, an NIA subsidiary will have more clearly defined revenues and costs. This model can be expected to focus on maximizing efficiency for the NIA business, in the relative absence of constraints imposed by the need to balance the objectives of the integrated system.

As with Option 3, some of the staffing efficiencies gained through decentralization will likely be lost, but competency will likely improve, as will the emphasis placed on strategic asset management and acquisition, and generation technologies. The policy and regulatory response to this option is unknown, since there is no precedent for a regulated subsidiary. However, review of rates would likely occur independently of BC Hydro.

- **S-3 to S-6; S-8; S-9; I-4; I-7; I-8**: No effect
- **S-1** (Staff efficiency): -1 - requirements increase
- **S-2** (Competency): 2 - increased slightly
- **S-7** (Low rates): -1 - differential rates more likely in long term

- **I-1** (Accountability): 2 - clarity addressed
- **I-2** (Roles and responsibilities): 2 - clarity addressed
- **I-3** (Asset replacement): 2 - focus on efficiency
- **I-5** (Cost allocation) 2 - delayed and uncertain impact
- **I-6** (Eroding gross margin) -1 - delayed and uncertain impact
- **Total** **7**

Option 5: Integrate NIA communities

This option would not necessarily apply universally across NIA operations. The incremental impacts of area integration on the NIA business overall are expected to be similar across all areas. Integration of each area will result in gains in staffing level efficiencies, reduced diesel energy costs, and displacement of diesel generation. It is not clear whether integration of IPP areas would render any benefit since BC Hydro contracts are likely to remain in effect. Expected negative impacts include reductions in local BC Hydro-related employment.

- **S-2; S-3; S-5; S-7 to S-9; I-1 to I-5; I-8**: No effect
- **S-1** (Staff efficiency): 2 - greater staff efficiency
- **S-4** (Diesel displacement): 2 - direct impact
- **S-6** (Local economics): -2 - fewer opportunities for employment
- **I-6** (Eroding gross margin): 2 - undifferentiated costs from integrated system
- **I-7** (Required subsidy): 2 - reduced
- **Total** **6**

Option 6: Outsource various services

Further opportunities for outsourcing services may include operations and maintenance functions. Theoretically, outsourcing will result in reduced staff requirements, and clarify roles related to the outsourced service. However, ensuring appropriate competencies in local communities, and compromising the continued reliability of the NIA systems, are very real risks, since accountability in these areas rests ultimately with BC Hydro. Also, additional support services would likely be required in DLoB to administer and supervise the contractors.

- **S-4; S-5; S-7 to S-9; I-1; I-3 to I-8**: No effect
- **S-1** (Staff efficiency): 1 - some staff efficiency gain
- **S-2** (Competency): -1 - may not be comparable to BC Hydro in short term
- **S-3** (Reliability): -1 - may decline
- **S-6** (Local economics): 1 - some potential for local employment
- **I-2** (Roles and responsibilities): 1 - some increased clarity
- **I-6** (Eroding gross margin): 1 - assume some cost savings motivation
- **Total** **2**

Option 7: Engage a system operator

This option would reduce Field Services' staff requirements, and relevant roles and responsibilities would be clarified through the contract. Also, depending on the contractor(s), there may be some potential for local

economic benefit. Also, assuming that the motivation for adopting this model is the ability to realize cost savings, the option may slow the increase in the costs associated with diesel generation.

- **S-4; S-5; S-7 to S-9; I-1; I-3 to I-5; I-7; I-8**: No effect
- **S-1** (Staff efficiency): 2 - staff efficiency gain
- **S-2** (Competency): -1 - may not be comparable to BC Hydro in short term
- **S-3** (Reliability): -1 - may decline
- **S-6** (Local economics): 1 - some potential for local employment
- **I-2** (Roles and responsibilities): 1 - some increased clarity
- **I-6** (Eroding gross margin): 1 - assume some cost savings motivation
- **Total** **3**

Option 8: Lease assets and their operations to a third party

This option mirrors the previous option, with the one exception that BC Hydro relinquishes some control over how the assets are applied to meet electricity service needs in NIA communities. In exchange, BC Hydro will likely gain additional revenue and transfer some operating risk to the contractor. The nature and level of this trade-off will likely be a subject of negotiation. However, system reliability will be less certain, and the service standards and complaints process currently experienced will be a further step removed from the regulator.

- **S-4 to S-9; I-1; I-4; I-5; I-7; I-8**: No effect
- **S-1** (Staff efficiency): 2 - staff efficiency gain
- **S-2** (Competency): -1 - may not be comparable to BC Hydro in short term
- **S-3** (Reliability): -1 - may decline
- **S-6** (Local economics): 1 - some potential for local employment
- **I-2** (Roles and responsibilities): 1 - some increased clarity
- **I-6** (Eroding gross margin): 1 - assume some cost savings motivation
- **Total** **3**

Option 9: Sell assets to a third party

This option could take one of a number of forms, and could involve all or part of the NIA business. A few possible scenarios include:

- Sale of standby diesel stations to existing IPPs, while BC Hydro maintains ownership and control of substations and distribution infrastructure
- Sale of one or more individual diesel or hydro stations to outside interests (local businesses, First Nations, other organizations) while BC Hydro maintains ownership and control of substations and distribution infrastructure
- Sale of NIA business, including all generation and distribution assets to a third party, answerable to the regulator

Each scenario has a unique set of advantages, disadvantages and constraints. BC Hydro staff needs are either reduced or eliminated, and there is some potential for local economic benefit. Risks are transferred to the new owner(s), in exchange for lessened control over competency levels, reliability and service standards. Financial issues, with the exception of the ongoing requirement to subsidize the NIA business, are fully addressed.

- **S-4; S-5; S-7 to S-9; I-1; I-2; I-4; I-8**: No effect
- **S-1** (Staff efficiency): 2 - staff efficiency gain
- **S-2** (Competency): -1 - may not be comparable to BC Hydro in short term
- **S-3** (Reliability): -2 - will likely decline to reduce costs
- **S-6** (Local economics): 1 - some potential for local employment
- **I-3** (Asset replacement): 2 - responsibility transferred to new owner(s)
- **I-5** (Cost allocation): 2 - no longer issue
- **I-6** (Eroding gross margin) 2 - no further operational accounting
- **Total** **6**

Option 10: Modify rates

This option assumes that the regulator is amenable to adjusting rates charged to NIA customers over time to narrow the gap between current revenues and costs. Local communities will pay higher rates; however, the gross margin would improve and the required subsidy would decrease.

- **S-1 to S-6; S-8; S-9; I-1 to I-5; I-8**: No effect
- **S-7** (Low rates): -2 - increased
- **I-6** (Eroding gross margin) 2 - reduced
- **I-7** (Required subsidy): 2 - reduced
- **Total** **2**

Option 11: Modify service levels

This option involves allowing a softening of current service levels to reduce direct costs. Reliability of the current system, and service standards, will necessarily be affected. Other expected impacts include some recovery of the gross margin and a reduced subsidy requirement.

- **S-2; S-4 to S-8; I-1 to I-5; I-8**: No effect
- **S-1** (Staff efficiency): 1 - staff efficiency gain
- **S-3** (Reliability): -2 - will likely decline to reduce costs
- **I-6** (Eroding gross margin) 1 - slightly reduced
- **I-7** (Required subsidy): 1 - slightly reduced
- **Total** **1**

Option 12: Displace usage of diesel facilities through alternative energy sources

This option will likely have operational and financial implications for the NIA business. In areas where alternative energy projects are introduced, diesel standby capacity will likely continue to be required. Therefore some operating efficiencies are likely but their magnitude will depend on the specific

characteristics of the project(s). If the objective of this model is to displace diesel generation, even if the alternatives are not more cost effective, then operating costs can be expected to increase. However, there may be opportunities for local economic benefit.

- **S-1 to S-3; S-5; S-7 to S-9; I-1; I-2; I-4; I-5**: No effect
- **S-4** (Diesel displacement): 2 - direct impact
- **S-6** (Local economics): 1 - some potential for local employment
- **I-3** (Asset replacement): 2 - need reduced
- **I-6** (Eroding gross margin): -2 - likely more expensive to operate
- **I-7** (Required subsidy): -2 - likely to increase
- **I-8** (Ability to change): 2 - directly addresses policy requirement
- **Total** **3**

Option 10: Increase reliance on IPPs

This option is largely consistent with the status quo, in that there are currently no constraints on the number of independent producers operating in NIA, except those that exist either technically, or financially. BC Hydro is actively seeking to negotiate new IPP arrangements wherever possible. Consequently, this option will not impact the current NIA business.

- **S-1 to S-9; I-1 to I-8**: No effect

Sensitivity analysis

In the initial analysis, no weighting was assigned to any of the impact criteria. However, we understand that not all criteria are of equal importance to BC Hydro in the context of strategy development. Therefore, we have undertaken a high level sensitivity analysis to assess the extent to which the relative benefits of the options might change if certain types of criteria were assigned more weight.

The sensitivity analysis employed seven scenarios:

Scenario 1: All 17 impact criteria weighted equally
Scenario 2: Organizational criteria (S-1; S-2; I-1; I-2) assigned weighting of two times other criteria
Scenario 3: Operational criteria (S-3; I-3) assigned weighting of two times other criteria
Scenario 4: Power purchase criteria (S-4; S-5; I-4) assigned weighting of two times other criteria
Scenario 5: Financial criteria (I-5; I-6; I-7) assigned weighting of two times other criteria
Scenario 6: Socio-economic criteria (S-6; S-7) assigned weighting of two times other criteria
Scenario 7: Policy/regulation criteria (S-8; S-9; I-8) assigned weighting of two times other criteria

Table 23 summarizes the results of the analysis. The options are organized by level of complexity. The first benefits column shows the scores reflected in Table 22, where no weighting is assigned. The last six

columns show how the benefits scores are impacted when a weighting of two times[1] is assigned, in turn, to only those criteria in each of the categories. These are:

Table 23: Sensitivity of Option benefits to weighting of specific types of criteria

Option	Complexity	Benefits (Weighted Criteria)							
		Scenario 1: Equal weighting	Scenario 2: Organizational	Scenario 3: Operational	Scenario 4: Power Purchase	Scenario 5: Financial	Scenario 6: Socio-economic	Scenario 7: Policy /regulation	
1. Status Quo	0	0	0	0	0	0	0	0	
13. Increase reliance on IPPs	0	0	0	0	0	0	0	0	
2. Optimised Status Quo	**1**	**6**	**9**	**7**	**7**	**7**	**6**	**6**	*
6. Outsource various services	1	2	3	1	2	3	3	2	
11. Modify service levels	1	1	2	-1	1	3	1	1	
3. Create an NIA Department	2	4	8	4	4	4	4	4	*
7. Engage a system operator	2	3	5	2	3	4	4	3	
8. Lease assets and their operations	3	5	9	4	5	6	6	5	
4. Establish an NIA subsidiary	**4**	**7**	**12**	**9**	7	**8**	6	**7**	*
12. Displace diesel through alternatives	4	3	3	5	5	-1	4	5	
5. Integrate NIA communities	5	6	8	6	8	10	4	6	
9. Sell assets to a third party	5	6	7	6	6	10	7	6	
10. Modify rates	5	2	2	2	2	6	0	2	

* *denotes the option with the highest potential benefit for a given level of complexity.*

The logic of the evaluation framework employed in this study is that in order to justify increasing the level of complexity associated with implementing a new option, the option in question must offer some potential increase in benefits over less complex options. In other words, in order to seriously consider an option further to the right on the complexity scale, there must also be a corresponding move up on the benefits scale.

There are three options which have been assigned a complexity score of one (1). Of these, the **Optimised Status Quo** scores consistently higher than the other two, regardless of which category of criteria is weighted more heavily. Therefore, this option appears to be the most desirable among those which are relatively straightforward to implement.

There are two options which have been assigned a complexity score of two (2). Of these, the **NIA Department** scores at least as high as or higher than the **System Operator** option under all scenarios. Although the scores for this option are lower than those for the **Optimised Status Quo**, they are sufficiently high to warrant further consideration by BC Hydro senior management.

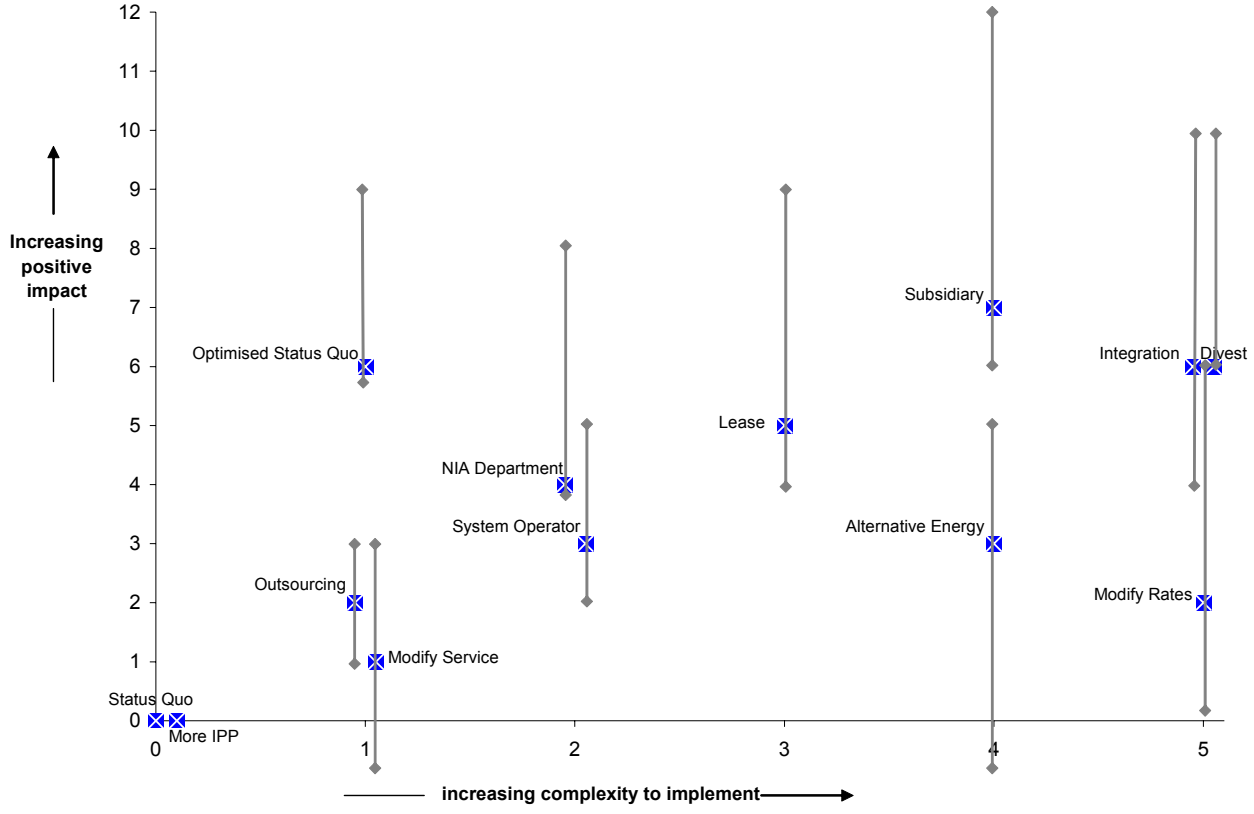
[1] A weighting of two times was chosen randomly to emphasize the relative importance attributed to these criteria.

Moving to the next level of complexity (3) provides only the **Lease Assets** option which scores as high as the **Optimised Status Quo** when organizational and socio-economic criteria are more heavily weighted. Consequently, given the higher complexity associated with this option, it is not recommended for further consideration.

There are two options which have been assigned a complexity score of four (4). Of these, the **NIA Subsidiary** scores consistently higher than the **Alternative Energy** option, and at least as high or higher than all other options considered, including the Optimised Status Quo. This option appears to offer increased benefits for the increase in complexity and should be examined further.

There are three options which have been assigned a complexity score of five (5). Both the **Integration** and the **Asset sale** options score higher than the Subsidiary option when financial criteria are more heavily weighted. We recommend that they be considered in the context of BC Hydro's long term strategy for NIA. However, given the nature of complexity associated with these options, which present real barriers to implementation, they are not likely to provide realistic options in the medium term.

Figure 2: Graphical representation of evaluation and sensitivity results



The results of the evaluation and sensitivity analysis are presented graphically in Figure 2. The blue squares marked with an X indicate the relative scores for each option when no weighting is assigned to the 17 criteria. The grey lines represent the range of sensitivity as described above for each option.

Summary and Conclusions

Historically, the NIA business has been well managed, the assets have been well maintained, and key staff have had the appropriate competencies. Consequently, system reliability has been high and improving with minimal resources. NIA has also experienced success negotiating and managing IPP arrangements, realizing cost advantages, and benefiting from the local environmental effects of diesel generation displacement.

Although the precise value of the total net loss (including allocated costs) is not clear, the business cannot recover more than a small proportion of total costs through sales revenues. In addition, the impact of the corporate restructuring on the NIA organization structure has been significant, and with attention to the needs of this business now more diffuse, there is a real risk that the strengths currently enjoyed could deteriorate over time if some element of change in the current business model is not implemented. The NIA asset base is in need of a permanent champion, to ensure that they generate a maximum return to the owner, and continue to meet the legislated obligations of the company.

There are a number of options which BC Hydro may wish to pursue to take the NIA business forward under the new corporate structure and the current provincial energy policy. In the near term, several steps can be undertaken to optimise the status quo (Option 2). However, over the longer term, BC Hydro wishes to examine whether or not an alternative business model for service delivery in NIA is more appropriate.

Creation of an NIA subsidiary (Option 4) appears to offer the potential for increased benefits for the NIA business. The relatively high impact score reflects the expectation that a separate legal entity will result in a sustained strategic focus on the unique characteristics and needs of the NIA business, maintenance of core competencies and decreased competition for capital and human resources with other larger BC Hydro business areas. It is assumed there are advantages over the more straightforward creation of a department within the BC Hydro organization, including the potential for NIA to receive unique attention by regulators and policy makers. However, the complexity associated with implementation of this option, although recognized in the evaluation framework as significant, has not been explored in detail. We recommend that this option be explored further and evaluated in the broader context of BC Hydro's corporate strategy and direction.

Many of the options identified and evaluated can be combined with other options, or implemented within a defined scope of NIA activities. BC Hydro is already exploring the potential to utilize alternative energy sources in NIA communities (Option 12) and has engaged third-party diesel station operators (Option 7) in

some areas. We recommend that BC Hydro continue to explore these types of opportunities where they are advantageous.

Finally, there are a few of options which do not appear to be either advantageous or viable at this time and should likely not receive further attention. All three options which received a complexity score of 5 (Options 5 (Integration), 9 (Divestiture) and 10 (Modify rates)) are currently prohibitive due to cost, practicality or conflict with prevailing public policy. Options 3 (NIA Department), 7 (System Operator), and 8 (Lease assets) may merit further consideration if Option 4 (NIA subsidiary) is determined to be unviable.

The NIA strategy must reflect the needs and priorities of the organization as a whole, in addition to those of the NIA business specifically. Therefore, we have not presupposed the corporate priorities, recognizing that this report represents the first of a two phase strategic and business planning exercise. Once a strategic direction for the business is chosen by BC Hydro decision makers, phase two will involve the development of a corresponding detailed business plan.