Final Report on Phase One of
Muskrat Falls Project
Potential Rate Mitigation Opportunities

Presented to:

**The Board of Commissioners of Public Utilities
Newfoundland and Labrador**

Presented by:

The Liberty Consulting Group

December 31, 2018

**1451 Quentin Rd Suite 400
#343
Lebanon, PA 17042**

Table of Contents

I. Introduction and Summary

A. Background

On September 5, 2018, the Government of Newfoundland and Labrador issued a reference (the Reference) directing the Board of Commissioners of Public Utilities of Newfoundland and Labrador (the Board) to review and report on a number of matters, including options to reduce the impact of the Muskrat Falls Project (MFP) on electricity rates through to the year 2030. The Board retained The Liberty Consulting Group (Liberty) to assist with the review required for this Reference. The MFP, consists of: the Muskrat Falls Generating Station (MF), the Labrador Transmission Assets (LTA), and the Labrador Island Link (LIL).

The Board asked Liberty to perform the following tasks:

- Determine the total revenue requirements to recover the costs of these three components of the MFP with no rate mitigation options included (Base Revenue Requirement)
- Examine the structure of Nalcor Energy Corporation and its subsidiaries and affiliated companies (Nalcor) and identify cost savings opportunities associated with Nalcor activities
- Identify cost savings and opportunities related to the operations and maintenance of the three MFP components
- Identify the impacts on the Base Revenue Requirement of various alternative cost savings initiatives and rate mitigation approaches.

The full scope of work required will span two phases. This report presents the results of our Phase One work, which consisted of two primary areas:

1. Revenue Requirements: We created an interactive model that can calculate and display mitigated and unmitigated Base Revenue Requirements under a variety of scenarios and assumptions. It will support comprehensive description and quantification of pre-mitigation revenue requirements. It will also permit quantitative assessment of revenue requirements impacts of mitigation opportunities identified as work progresses.
2. Corporate Structure and Costs: We examined organization structures, resources, processes, activities, and costs of Nalcor business operations, excluding Oil and Gas, and identified areas to examine for potential cost savings that will result in revenue requirement mitigation in the second phase of our work.

This report describes the work we undertook and the results obtained. In particular, it identifies those areas that we believe warrant more detailed evaluation in Phase Two. We based that identification on judgments, informed by Phase One examination, about the likely magnitude and probability of producing material changes to the Base Revenue Requirements. Following the Board's interim report in February, as required by the Reference, we will examine in further detail those opportunities that are to be investigated in Phase Two.

B. Phase One Work Description

We performed Phase One work with a team of utility industry experts having decades of experience and industry knowledge in the areas they examined. We requested information from Nalcor, and held several meetings and discussions with Nalcor representatives to explore fully the areas under examination. We focused on costs of all functions typically performed by a vertically-integrated utility. Particularly after divestiture of oil and gas related business activities, Nalcor's remaining operations are typical of what such utilities do. Treating some portion of those activities as "non-regulated," which Nalcor has done, may have affected Nalcor to date from the perspective of cost and revenue assignment and allocation. From a business operations perspective, however, what will be left in Nalcor, after the removal of oil and gas activities, fits the classic definition of a vertically-integrated utility.

We began our analysis by examining the corporate entity structure, the business organization of groups that carry out Nalcor's utility operations, their structure, and their staffing. We then examined historical and projected costs, both operating and maintenance (O&M) and capital. We examined generation, transmission, distribution, customer service, corporate leadership and services (*e.g.*, finance), and administrative services (*e.g.*, human resources). We managed our work using regular team interaction, to ensure exposure of a robust range of potential revenue-maximization or cost-savings opportunities. We found as many cross-organizational opportunities as intra-organizational ones.

We also examined cost sources and opportunities involving outside entities. Financing arrangements for the MFP involving more than $12 billion dollars will create equity return, debt service, and sinking fund payments beginning at about $500 million per year, growing to nearly $800 million over time. Parties apart from Nalcor with substantial interests in those revenues include the Province, which receives guaranteed returns on the equity portion of that financing, and the federal government, which has provided loan guarantees, and requires interest and sinking fund payments under MFP financing agreements. Our Phase One work has also identified that Newfoundland Power, the primary distribution utility in the province, may play a significant role in mitigation, given the nature and extent of its operations on the island, and its expertise in providing service at the retail level.

We conducted Phase One under a short schedule, which did not foreclose opportunity identification, but limited the extent to which the magnitude of potential opportunities and the likelihood of their eventual execution could be evaluated. Nevertheless, we developed a reasonably complete list of opportunities, a plan for assessing them in Phase Two, and a process for culling early those opportunities that lose promise after additional screening.

The support from Nalcor and Newfoundland and Labrador Hydro (Hydro) personnel was overall consistent, strong, and prompt, and proved essential in completing Phase One on time. We appreciate the cooperation we received from management and from Board Staff. All contributed greatly to our efforts.

Our Phase One work in developing a Revenue Requirements Model began with early-stage consultation with Board Staff and Nalcor, seeking to establish consensus on cost definition and categorization across various areas of operations, functional areas, and cost groupings, such as:

- Capital Costs for MFP and other generating resources - - Allowance for Funds Used During Construction (AFUDC), interest expense, and other
- Financing Costs
- Tax Costs
- Depreciation and Amortization Expenses
- Supply and Energy Costs and Revenues
- Transmission and Delivery Costs
- Governance, Corporate and Support Costs
- Other Affiliate Costs and Revenues

- Rate Base
- Capital Expenditures and levels of funding
- Capital Structure - - Long Term Debt and Equity (Common and Preferred)
- Dividends and other distributions
- Revenues (sale of electricity and other major categories)
- Other Material Cost Sources - - Adjustments to revenue requirements such as weather, storms, inaccurate accounting transactions and adjustments, depreciation studies, etc.

Guided by these initial efforts and the data provided by management, we began the development of a model that would permit variable cost entries, create proper relationships among interdependent categories, and produce an accurate measure of total revenue requirements when populated with cost entries developed in substantive work. We populated the model with current, best estimates of future costs provided by management to produce a Test Revenue Requirements Forecast, in order to establish a basis for model validation and to establish management's baseline measure of revenue requirements over the modeled duration. We further explored the estimated cost and revenue factors for such items as customer and sales growth, capital spending and depreciation. We also incorporated the ability to make adjustments for factors like risk, changes in escalation, and other exogenous factors.

The model has reached readiness to prepare at the outset of Phase Two Forecasted Pre-Mitigation Base Revenue Requirements, which will provide a baseline for measuring future revenue requirements reduction. While the model will be shared with Nalcor, if that produces less than full consensus between Nalcor and Liberty, it will nevertheless allow a clear delineation of differences, allowing all to express clearly what specific factors, assumptions, and inputs drive those differences.

The model will also assist our efforts to gauge optimization and cost mitigation opportunities, and provide a vehicle for incorporating all identified, realistic potential cost savings and revenue enhancement opportunities into a single forecasted, post-mitigation rate path. We will carefully consider and apply substantiated analysis in determining risk ranges to assign to forecast cost and revenue sources. Such factors include operating expense growth, cost of capital, wage and tax rate increases, and sales changes, level of capital spending, and depreciation.

We will run the model as structure, cost, and risk analysis continues to re-orient work focus to concentrate on promising alternatives. We will regularly review and discuss model re-runs with team members engaged in structure, cost, and risk analysis. When all adjustments to the base forecast are complete, we will produce a revised, 20-year forecast of revenue requirements before mitigation.

C. Summary

In Phase One Liberty identified a number of cost savings and revenue enhancement opportunities which can contribute to reducing the electricity rate impacts for customers from the MFP. These opportunities vary in magnitude and ease of implementation and require detailed analysis in Phase Two to determine their feasibility and effectiveness. The following section summarizes the opportunities identified to date while subsequent chapters provide more detail on each.

1. *Export Sales - - Aligning Utility Costs and Revenues with Utility Customer Rates*

Apart from soon-to-be-gone oil and gas business activities, Nalcor does what vertically integrated utilities do - - generate electricity, transmit and distribute it, and enter off-system transactions to sell excess and buy supplemental electrical energy. However, Nalcor's structure assigns the costs of utility facilities to Hydro and in turn its customers through rates, without also providing the usual offset to those costs and rates - - margins from export sales of electricity from those facilities.

We found the MFP financing arrangements complex, but the physical facilities mainstream - - a hydroelectric generating station at Muskrat Falls and transmission links from there to Churchill Falls and to the island of Newfoundland. Nalcor proposes that the rates for Hydro customers include the capital, financing, and operating costs of project facilities - - again, not unusual on the surface. What stands out is that Hydro customers must pay all of Nalcor's $12.7 billion in costs while receiving the benefits of only a portion of the energy produced with revenue from export sales excluded. Concomitantly, excluding revenues from out-of-province sales means that Hydro's customers lose the normal rate benefits provided by sales from assets whose costs are included in rates. Here, it is contemplated that the export revenues go to Nalcor and in turn to the Province.

The essential question here is which of two groups (all but equivalent as it turns out) benefit from revenues or costs produced:

- The Province's people and businesses in their capacity as ***Residents*** or ***Taxpayers*** whose government uses returns and dividends from what it has deemed to be the ***Unregulated*** portions of utility operations to fund institutions, systems, and activities whose availability would otherwise require more taxes or government fees
- The Province's people and businesses in their capacity as ***Utility Customers***, whose rates for ***Regulated*** utility service would be lowered if those returns and dividends the government obtains from utility operations were instead used to align more closely the costs net of revenues for utility service with the rates charged for those services.

The election to treat some of the revenue streams and returns generated by these traditional electric utility activities as "unregulated" makes a vast difference in the assignment of costs and revenues. The typical ratemaking structure applied to traditional utility activities includes costs and revenues from utility activities in calculating customer rates. In that construct, revenues from utility activities offset the costs of those activities. The result is that utility customers pay their utility service provider's capital and operating costs in serving them net of off-system revenues.

2. *Nalcor's "Equity" Return on MFP Financing*

Utility financing costs generally include a "return" designed to compensate owners for providing the equity it takes to finance a capital-intensive business. This equity return is properly considered a cost in the case of investor-owned utilities - - paying returns is necessary to induce shareowners to make equity investments needed to create a proper financial structure. There are no outside equity holders here, but the legal arrangements provide that the Province will eventually receive from Nalcor returns largely equivalent to what an investor owned utility expects, even though actual costs are much lower, for two reasons:

- The debt portion of MFP capital structure comes from loans at rates much lower than investor-owned utilities can secure
- No outside equity providers have to be compensated in the form of equity returns.

As a result, the rates for customers include several returns that far exceed actual "costs," and will do so many times over after commissioning of the MFP assets:

- The payments that Hydro makes under agreements for purchases from and use of MFP assets include a substantial return (over $6 billion in the first 20 years of operation), more reflective of investor-owned utility costs; Hydro includes these payments in its revenue requirements.
- Nalcor will receive the "profits" expected to come from out-of-Province sales, with no rate offset to Hydro customers.

Applying returns and dividends from these sources as an offset to utility revenue requirements would avoid a very substantial portion of the increase in rates expected in the coming years. Small in early years after commissioning, the very large annual growth expected would eventually offset more than half the expected increase in rates. However, applying these benefits to the Province's residents and businesses as utility customers would be matched essentially equally by revenue losses to the Province from returns and dividends foregone.

Deciding where and when to apply these revenues is therefore not simple, nor is it one for us to decide. Neither choice lacks legitimacy. However, the Province's ultimate decision on sharing the billions of dollars involved may benefit from a starting point that makes more transparent the true net costs of utility operations. How large those sums will prove to be in the future depends upon a number of forecasted factors (such as, for example, the amount of retail sales, fuel costs, and power sale profits). Therefore, we consider it beneficial for Phase Two work to continue refining the values involved, and determining how they will be affected by other variables that will be studied.

Even more importantly, employing these sources of rate mitigation is not free of prohibitions, encumbrances, and other limitations that would require change to effectuate them. Those barriers with respect to dividend flows arise from sources like legislation affecting entity structure, operations, and financial risks/rewards of Nalcor entities and business areas.

Barriers to other mitigation opportunities that we address below exist as well, for example:

- MFP financing arrangements providing rights to and security for the Canadian government
- Rights that Hydro Quebec holds with respect to the management of Churchill Falls operation
- North American grid interconnection requirements
- Bargaining unit and other contractual agreements.

We did not consider these barriers as "non-starters" in the search for mitigation opportunities. However, our Phase Two work will, when working with Nalcor and others, as necessary, clearly identify those barriers and any changes needed to make opportunities for revenue requirement reduction executable.

3. MFP Debt Financing

<u>*Payments Associated with Federal Loan Guarantee*</u> - - After earnings and dividend streams from utility operations not applied as an offset to Hydro revenue requirements, the largest source of mitigation arises from changes in MFP financing agreements. While smaller in total, they do not suffer from a "zero sum" nature, but may offer true net cost savings. The financing agreements require annual sinking fund payments, with recovery of the amounts paid from Hydro's utility customers. Changes in the financing arrangements, following negotiation with the federal

government, would be required to eliminate these payments and eliminate their recovery from Hydro customers.

Additional Debt Issuance - - A second source of mitigation involves the issuance of new debt permitted, given the amount of equity projected to exist in MFP financial structure after commissioning. Application of such debt could go to reducing:

- Financing payments in the earlier years when other sources of mitigation are lower in magnitude; with repayment structured later, as other sources of mitigation become more robust
- Equity level to the extent that the Province determines not to forego a portion of returns on equity from MFP investment

4. *Combining Nalcor Functions and Organizations*

Potential revenue requirement mitigation through capturing dividends and returns and MFP financing changes have a value measured in hundreds of millions of dollars annually. Other opportunities, while amounting at most to the low tens of millions annually, nevertheless warrant review.

Other comparatively small enterprises conducting vertically integrated electric utility operations do so under significantly less complicated structures than does Nalcor. Nalcor operates through two primary business lines - - Hydro and Power Supply. The latter has responsibility for Muskrat Falls, the LIL, the LTA, Churchill Falls, and Nalcor Energy Marketing. Hydro operates the balance of Nalcor generation, transmission, and distribution operations. We do not see significant need for continuing their separation after completion of Muskrat Falls and the LIL. Apart from focusing organizational attention on the difficult challenges in MFP completion, separating cost, revenue, and "profit" distribution arrangements has served as the reason for the separation.

The former need is ending and the duplication required by the latter has and will continue to come at the cost of efficiency. Separate Nalcor organizations under separate direction and management perform related activities that comparably-sized, vertically integrated utilities commonly combine. Some distinctive factors apply here *e.g.*, the dc design of the LIL and the need to account for Hydro Quebec's rights in addressing Churchill Falls organization and resources. Nevertheless, promising lines of inquiry exist, and will be reviewed in detail in Phase Two, including:

- The significant number of executive and senior management positions in related areas
- Broad duplication of organizations with and activities having a high degree of commonality
- Repetition of service partners (*e.g.*, HR, Finance and Accounting, IT) embedded to carry out day-to-day functions in multiple organizations.

The extremely-wide geographic dispersal of both customers and key facilities complicates Nalcor's staffing challenges, and will require careful consideration to ensure that apparent cost savings opportunities do not produce unintended service consequences.

Nalcor identifies a total complement of some 1,700 full-time equivalent persons including temporary personnel. Even a five percent cut in resources, not an unreasonable assumption from the data we have (but not provable before Phase Two work) would reduce revenue requirements in the range of $15 million per year depending on the associated cost of resources, which includes wages or salary, benefits and other direct and indirect costs of supporting an employee. We therefore propose examination of consolidation opportunities at all Nalcor organizations conducting direct and support activities. Below we describe a number of specific cost reduction opportunities within Hydro. They focus less on consolidation and more on planning and executing work within Hydro or in cooperation between Hydro and Newfoundland Power.

5. Improving Hydro Efficiency

We began this engagement with knowledge, albeit now dated, about Hydro's internal transmission and distribution operations and, to a lesser, but still material degree, those of Newfoundland Power. Our work here included updating that knowledge, examining existing and forecasted capital and O&M expenditures, looking at total personnel and their distribution by department, and performance metrics. The opportunities that look most attractive, based on our initial effort are:

- Combination of functions and operations with Power Supply (addressed above)
- Examining the transfer of responsibility (from operations through ownership) of all or some retail operations to Newfoundland Power
- Finding ways to address circuit breaker PCB remediation and to extend air blast circuit breaker replacement
- Enhancing the focus on, structure of, and accountability for work planning and management, on productivity, and on craft work scheduling and overtime
- Economically optimizing the balance between employee and contractor use (internally and combined with Power Supply)
- Identifying opportunities for common Hydro/Newfoundland Power field work performance or support facilities and equipment.

The options involving Newfoundland Power arise from areas of territorial proximity. They also derive from the greater focus that Newfoundland Power, as an electric distribution company, places on infrastructure, systems, and organizations that get electricity from transmission substations to the meter, supported by a large customer service organization. A primary source of engagement with Newfoundland Power will concern Hydro's distribution customers. The Phase Two work in this area will address Hydro costs avoided by a transfer of some level of control over its retail operations, and resulting onsets to Newfoundland Power costs. Phase Two work will also consider likely changes in service reliability and quality. As one example, a change with nominal cost reduction benefits may produce a significant expected improvement in customer service.

Another point of engagement with Newfoundland Power will occur as part of our search for common contracting opportunities between Hydro and Nalcor. Adding Newfoundland Power to the pool of available work may offer contractors work volume, scheduling, resourcing, or other advantages that may allow the reduction of costs to all three "customers."

We did not encounter a strong Hydro focus on work execution productivity. Work planning and management is dispersed, its systems and methods are not as strong as we have seen elsewhere, productivity metrics are not robust, work measurement and data analysis do not appear to be "central" elements of cost management, and accountability for productive performance is not well-placed. The Hydro organization is large enough to make this issue matter - - each two percent improvement in productivity (a modest assumption here) has a value well in excess of $1 million per year.

6. Generation Facilities O&M

While additional analysis is required to validate the accuracy of the comparisons, the initial findings indicate there may be opportunities to reduce O&M costs for certain of Hydro's generating stations.

Information about Churchill Falls staffing and costs was received late, and has yet to undergo rigorous examination. There does not appear to be strong potential for reducing Churchill Falls costs based on the review to date. More rigorous analysis will be completed in Phase Two to confirm whether this is correct. Preliminary data places Muskrat Falls costs above those of a peer group of similarly sized hydroelectric plants we examined. Some obvious reasons stand out, including Impact and Benefit Agreement (IBA) payments, the Water Power Fee, and environmental costs. In any event, cost comparisons involving Muskrat Falls and the other units warrant more detailed analysis before concluding about their ability to undergo reduction.

The Muskrat Falls IBA payments and Water Power Fees grow to over $20 million per year after commissioning. The Water Power Fee, payable to the Provincial government accounts for about 75 percent of this amount. This non-cost-based fee included in Hydro’s revenue requirements appears therefore to offer another source of potential mitigation. In any event, significant growth in expected MFP O&M costs and the comparative position of Muskrat Falls O&M costs make them a sound choice for Phase Two examination.

Hydro’s other, smaller hydro facilities show competitive costs, but their data also requires more vetting. The Holyrood Plant and all combustion turbines non-fuel O&M costs also appear higher in comparison with the peer groups we assembled. We propose Phase Two work that will further refine the peer group analysis, after which we will select plants that show the greatest promise for cost reductions.

II. MFP Financing Costs

A. Background

The following table shows the expected total sources of MFP funding at commissioning in 2020. The current level of Emera investment in the LIL stands at $0.4 billion.

MFP Funding Sources (in billions)

	Muskrat Falls	LTA	LIL	Total
FLG1 & FLG2 Debt	$3.7	$0.7	$3.5	$7.9
Nalcor/NL Equity	$2.7	$0.4	$0.6	$3.7
Emera Equity	$	$	$0.6	$0.6
AFUDC	$	$	$0.4	$0.4
Total	$6.4	$1.2	$5.1	$12.7

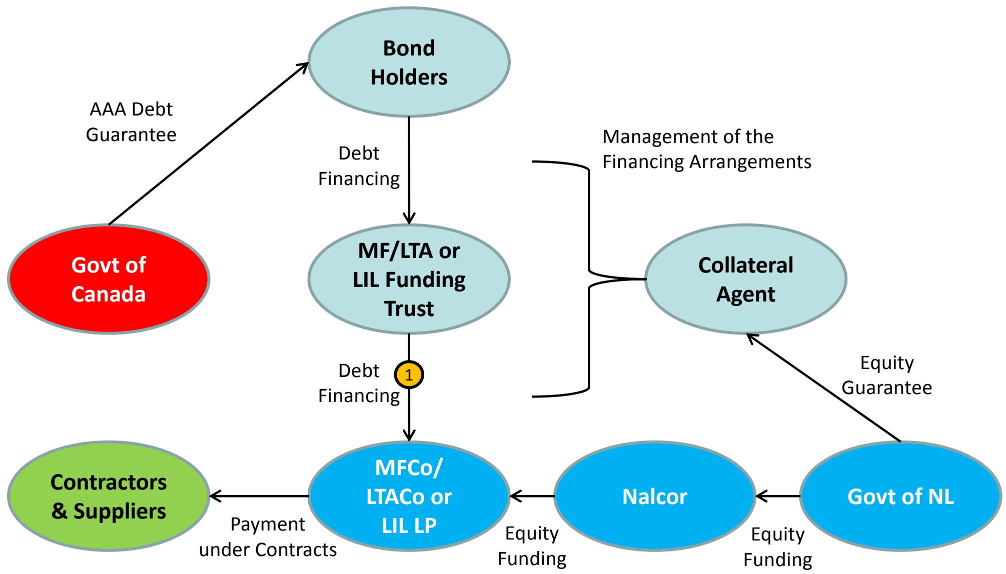
Financing costs incurred to fund MFP construction form the largest driver of expected increases in Hydro rates. MFP financing costs will account for more than 50 percent of the total Hydro revenue requirement in the years following project commissioning, making them the primary area to examine for potential revenue requirements mitigation for Hydro customers. MFP costs are estimated to reach $12.7 billion at commissioning (including $0.4 billion in reserves), and include the following primary drivers of financing costs:

- Nalcor "dividends" produced by its return of and on the MFP capital cost equity component
- Interest on MFP debt payable to bondholders
- Sinking fund payments on MFP debt principal.

B. MFP Transaction Structure

The debt and equity costs of financing $12.7 billon in MFP costs arise under a tailored transaction structure that includes debt and equity commitments and associated governmental guarantees, revenue agreements obligating Hydro to pay amounts including financing costs, and a number of related debt financing agreements that have specific payment requirements. Two sets of financing transactions (in each 2013 and 2017) have created that structure. The next illustration offers a simplified version of the structure applicable to financing structures for each of the Muskrat Falls Corporation (MFCo), Labrador Transmission Corporation (LTACo) and Labrador Island Limited Partnership (LIL LP) projects.

MFP Financing Transaction Structure



Equity funding and guarantees provided by the Province form the foundation for the transaction structure. The Province provides the equity portion of financing to Nalcor, which uses the amounts to fund the projects, in accordance with equity support agreements. The Province backs its equity commitments with equity guarantees obligating it to providing a mandated base equity level and all further, contingent equity required to ensure achievement of the projects' completion and commissioning. The Province/Nalcor equity funding is expected to reach a total of $3.7 billion for the MFP. An Emera entity participating in the LIL will provide an additional $0.6 billion in equity.

The debt portion of MFP capital is structured as a "flow-through" project financing. External "Bond Holders" provide financing to MF/LTA and LIL "Funding Trusts," which in turn lend the proceeds of the debt financing to the two MFP special purpose project entities (one for MF and LTA and one for LIL). One set of financing agreements governs the relationship, rights, and obligations between Bond Holders and the Funding Trusts. A second set of agreements between the Funding Trusts and the MF/LTA and LIL project entities (the "Project Financing Agreements") do the same for their relationship that permits the external financing to flow through to the project entities. This second set of agreements requires payment streams to the Funding Trusts (the internal level), who must then satisfy the payment streams of the Funding Trusts to their respective external Bond Holders (the external level). The Bond Holders have received an unconditional and irrevocable guarantee from the Government of Canada ("Canada") for the debt payment obligations of the Funding Trusts.

An original $5.0 billion of debt financing for the MFP ("FLG1") was completed in December 2013. It came through a series of six long-term bonds issued to the external Bond Holders by the Funding Trusts. Canada's guarantee enables each of these bond series to carry Canada's AAA credit rating. A supplemental debt financing in May 2017 ("FLG2") came in the form of $2.9 billion of additional Canada-guaranteed debt. It employed the same funding trust structure as FLG1. The internal Project Financing Agreements (between MF/LTA and LIL and Funding Trusts) require sinking fund payments on all six FLG1 bond series. No such requirements exist in the external agreements, leaving the external Bond Holders with no interest or say in their continuation - - a distinction with important consequence in seeking revenue-requirements mitigation opportunities.

C. MFP Financing Options for Producing Mitigation

The MFP structure was initially developed in a "commercial project financing" mode. It included substantial equity investments from the Province (at least 35 percent for MF and LTA and 25 percent for LIL), returns on equity for Nalcor and the Province, and project finance debt to be sold to the debt investment community. The federal debt guarantees and the flow-through financing structure components of the final structure came after this initial development. The additions were made to increase the marketability of the MFP FLG1 and FLG2 debt. The Canada debt guarantees effectively place MFP financing in "government project" mode, with equity also guaranteed by the Province. Equity levels and returns for the Province more typical of a "commercial financing" approach remained, raising questions about their continuing need or costs they might add after the federal guarantees.

The transaction financing structures and related payments for the MFP offer the consideration of a variety of alternatives to provide substantial rate mitigation. They take the following four major forms:

- Nalcor Returns and Dividends
- FLG Sinking Fund Payments
- FLG Interest Payments
- Changes in the MFP Capital Structures.

Nalcor's $3.7 billion of Nalcor/Province equity contributions (like those of Emera for its contribution to LIL equity) are slated to earn substantial returns - - directly related to the amount of those equity contributions. The "revenue agreements" obligating Hydro pay the Nalcor entities holding MF/LTA, and LIL interests incorporate long-term returns similar to those an investor-owned utility generally might expect.

Forecasts show Nalcor's MFP equity returns growing at a high rate. Increases in Power Purchase agreement (PPA) "Energy Sales" from Muskrat Falls to Hydro also increase substantially, with Hydro paying a supply price that escalates over time.

Recapture of MFP equity returns to Nalcor and of the margins from sales of energy from Muskrat Falls dwarf all other potential sources of rate mitigation. Nalcor had planned to dividend the entire amounts of MFP equity returns to the Province - - hence the term "Nalcor dividends." Such recapture in effect would return to customers moneys directly recoverable from them (equity returns) in utility rates or operating as an offset to the costs forming such rates (margins from off-system energy sales).

D. Payments Associated with Federal Loan Guarantees

Substantial pre-funding of principal repayment at maturity accompanies both the MF/LTA, and LIL debt (FLG1) issuances. The sinking fund cash requirements comprise a large portion of Hydro revenue requirements associated with MFP debt. Depending on the debt tranche involved, the

MF/LTA payments extend across durations ending between 2029 and 2048. LIL payments extend across durations ending between 2029 and 2053.

Reducing or removing sinking fund payments could lower Hydro's revenue requirements significantly. Any change is subject to agreement with the federal government.

E. Capital Structure Options

The final major category for rate mitigation is MFP Capital Structure alternatives. The maximum debt/equity ratios permitted for FLG1 and FLG2 issuances stand at 65/35 for MF/LTA and 75/25 for LIL. One way to alter the MFP capital structures to generate rate mitigation would be to bring MF/LTA, and LIL funding to the limits of the debt/equity by issuing additional debt. The timing of access to FLG1 and FLG2 funds and their relation to required Cost Overrun Equity funds ("COREA") from the Province should cause final equity levels at MFP commissioning to well exceed the required minimum levels. The MF/LTA capital structure at commissioning is expected to contain about 41 percent equity, and the LIL project more than 30 percent. Each of the projects has significant "headroom" to increase debt.

New, federally-guaranteed ("FLG3") debt issuances bringing MF/LTA and LIL to their maximum permitted debt levels offer one example for tapping this potential. The additional FLG3 debt issued could be substantial, depending on how the proceeds are applied. A potential rate mitigation application of such FLG3 debt lies in when and how to apply its proceeds. With the MFP dividends discussed above expected to increase over time, there are less of them to provide revenue requirements mitigation in early years.

It could prove useful to "advance" the availability of funds to smooth out rate reductions by increasing MFP borrowing and applying the proceeds to rate mitigation in the first several years after MFP commissioning. For example, the proceeds could be applied to the FLG1 sinking funds over a limited horizon to reduce Hydro revenue requirements.

There are a number of potential permutations for altering the capital structure for MF/LTA and for LIL. The FLG3 debt can involve a variety of sizes, maturities, conditions and terms, including whether or not to require sinking funds. The application of the proceeds from any FLG3 debt issuance to sinking funds could also: (a) reduce equity levels in MF/LTA and LIL, or (b) directly go to rate mitigation for Hydro customers.

Further exploration of capital structure changes requires consideration along with the other financing options, and may have particular value as a means for shifting the timing of funds availability for rate mitigation from "richer" to "leaner" periods expected across the coming years. Moreover, we consider it useful to consider debt levels even higher than those currently permitted, given that the stakeholder with whom increased debt guarantees would have to be negotiated is the federal government. For instance, the impacts of changing the MFP capital structures to 85 percent and even 100 percent debt could also be analyzed.

F. Other Financing Alternatives

We considered a number of other alternatives, finding that Nalcor personnel have performed a number of initial screening analyses of a broad range of them. Their initial analysis determined that some alternatives had relatively minor impact and did not "move the needle" in providing rate mitigation. These other types of financing alternatives were found to have much lesser impacts on Hydro revenue requirements, causing the rate mitigation focus to turn to the financing alternatives with greater rate mitigation potential, as described above.

G. Summary

Rate mitigation from the financing structure of the MFP has enormous potential (dwarfing other alternatives in magnitude). Costs for financing the $12.7 billion MFP investment will drive more than half of future revenue requirements. The following MFP financing opportunities have the most merit:

- Return of MFP dividends from Nalcor and the Province:
    - The Nalcor/Province contribution of dividends provides a substantial foundation for packages around which other mitigation alternatives can be shaped and layered
    - Additional detailed analysis is needed on the components of energy sales that drive the rapidly increasing Muskrat Falls earnings and dividends. Analysis of the probabilities and risks of various energy sales and dividend levels as well as refined schedules for the dividends is required to solidify this key rate mitigation component
- Alterations in FLG required payments:
    - Sinking fund payments apply to all three Tranches of the $5.0 billion FLG1 debt, and debt amortization payments apply to FLG2 debt
    - Sinking fund/amortization payments significantly inflate debt service revenue
- MF/LTA and LIL capital structure changes:
    - "Topping Up" debt levels at both MF/LTA and LIL (to 65 percent and 75 percent) may be accomplished by issuing "FLG3" guaranteed debt, and applying the proceeds to the sinking fund requirements that form a component of costs recovered from Hydro customers
    - Agreement of the federal government would be required for any change
    - A key assumption on using FLG3 debt to increase the leverage of MFP capital structures is the application of the debt proceeds, which possibly could be timed to meet the greatest rate mitigation needs
    - Further exploration of capital structure changes should be performed, expanding on the basic tenant that increased MFP leverage will further reduce revenue requirements
    - Increased leverage above the maximum levels included in FLG1 and FLG2 debt financing would have even greater rate mitigation potential, but, like other aspects of the financial agreements, would require significant concessions from Canada.

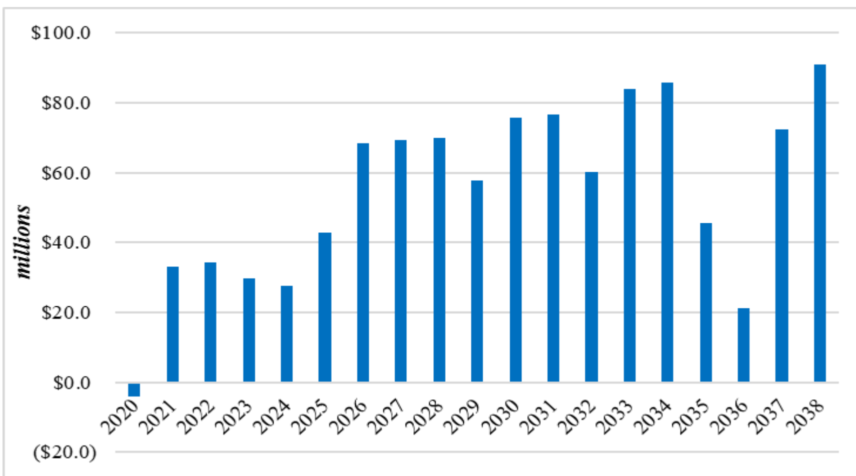
III. Other Nalcor Dividends

A. Background

Nalcor earnings and dividends from several other elements of its utility businesses operations also offer potential sources of Hydro revenue requirements mitigation. Nalcor expects material dividends from the Hydro utility operations subject to Board regulation. It expects dividends from non-regulated businesses as well. We addressed the MFP equity returns in the preceding chapter. Export power sales managed by Nalcor Energy Marketing are expected to produce very large margins after Muskrat Falls enters operation. Churchill Falls will produce consistent but much smaller margins, with almost all of its production supporting power to Hydro Quebec.

Similar to many holding companies, Nalcor will generate significant corporate and support service costs - - *i.e.*, overheads that produce no separate revenue streams. These roughly $20 million in annual costs offset dividend streams from the businesses that generate revenues. The next chart and table show the projected dividends, corporate holding company costs and net dividends from these sources for 2020 through 2038, unmitigated. Our Phase Two work will continue to address estimates of the contributors, analyzing additional information for impacts on their magnitudes.

Net Other Dividends



B. Muskrat Falls Exports

Muskrat Falls generation will be sold to Hydro in accordance with Schedule 2 of the PPA. Generation above the sales to Hydro become available for sale in export markets. Nalcor has "base case" projections of export sales, earnings generated from these sales, and related dividends produced. External markets and the opportunities they present for mitigation are also being evaluated by other consultants as part of this review. We have limited our review in Phase One to identifying their magnitude as estimated by management.

C. Churchill Falls

The Churchill Falls 5,400 MW hydroelectric station in Labrador was commissioned in the late 1960s. Nalcor holds two thirds of the shares in Churchill Falls, with nearly all the output sold to

Hydro Quebec under a contract running to 2041. The resulting earnings and dividend streams forecast by Nalcor represent steady but small positive economic returns from 2020-2030.

D. NL Hydro Regulated

Nalcor's dividends from Hydro come from the rate of return required to be built into rates to its customers. They follow the return-on-equity approach typical in utility regulation, except that they are modeled on rates that include a return for private equity holders. Hydro has no such equity holders. The Hydro return rate is applied to its net investment in capital assets, using the allowed return on the equity capital set in rate proceedings.

Nalcor's earnings and dividends from this, its regulated sector, remain strong. However, Nalcor proposes for the immediate future to devote all dividends generated from Hydro to building its equity position to targeted levels, which it believes will not happen until 2025.

E. Nalcor Corporate Expenses

Nalcor nets its corporate service costs at the holding company level against these three sources of dividends. These expenses are primarily related to the labor and benefits expenses of headquarters staff, such as executives, treasury, legal, accounting and other support services. Nalcor estimates that its annual corporate expenses will steadily grow from $17 to $25 million from 2021 through 2038.

F. Summary

The "net dividends" from the Muskrat Falls exports, Churchill Falls, and Hydro regulated less Nalcor corporate expenses are in the $27 to $33 million range per year from 2021-2025. These are estimates of dividends before mitigation. Those estimates will be influenced by additional work in Phase Two, warranting continuing assessment of their valuation.

IV. Re-Integrating Nalcor

A. Nalcor' Businesses

Nalcor operates in two industries:

- Electric utility: A traditional, vertically integrated electric utility supply and delivery company, including the functions of generation, transmission, distribution, and customer service
- Off-shore oil and gas: Exploration, development, production, and sale of oil and gas, and an industrial fabrication site.

Nalcor expects to divest the latter in the very near term. Power Development, part of the current organizational structure, focuses on the construction of the MFP. With the MFP approaching completion, the future of Power Development appears to be in question.

Divesting the oil and gas business will leave Nalcor with essentially one business - - but one that it has split in two. These two arms conduct similar businesses, but separated between what has been determined to date to be "regulated" and "non-regulated" sectors. Vertically integrated electric utilities plan, construct, and operate supply, transmission, and distribution facilities. Nalcor's regulated business (Hydro) does all of these functions. Hydro's rates and services for doing so fall under the rates and service quality and reliability jurisdiction of the Board. The two business units that fall within the traditional definition of a vertically integrated electric service, but which Nalcor treats as not "regulated" by the Board are:

- Power Supply (hydro generation construction and operation and electricity transmission)
- Off-System Power and Energy Purchases and Sales.

A major asset within Power Supply, Churchill Falls generating station, pre-dates the creation of the current electricity corporate and regulatory structure in the Province. However, the remainder of the operations of these two business units:

- Are very new in origin - - both the generation and transmission facilities and the ability to make significant out-of-province power and energy transactions
- Predominately rely on support from Hydro and its customers for support through responsibility for most of the costs of the facilities involved
- Comprise generation and transmission and power market operations that fall squarely within the traditional responsibilities of a vertically integrated utility.

Many jurisdictions in North America, particularly in the U.S., have restructured the industry to eliminate the concept of a vertically integrated utility. Those conditions do not exist in the Province, and will not for what is likely any extended period of time. Therefore, it remains appropriate to look at Hydro as a vertically-integrated utility, calling into question the effectiveness and efficiency of separating a portion of traditional responsibilities and powers - - particularly when Hydro remains responsible for so much of the costs and the creation of the opportunities that Nalcor has separated from Hydro.

In the context of rate mitigation for Hydro, the structure that Nalcor has created by establishing a significant, non-utility, utility-like sector becomes important for two reasons:

- The production of large revenue streams ("dividends") passing (in some cases through Hydro) to Nalcor from "non-regulated" operations - - revenue streams supported by Hydro's rates to its customers
- The wide-spread duplication of corporate, support, technical, and operating organizations among sometimes four areas of business operation - - Churchill Falls, Power Supply, Hydro, and Energy Marketing.

Therefore, it becomes useful to consider the fully vertically-integrated model as a means for examining how the Province may succeed in reducing future Hydro revenue requirements as major new facilities approach completion under what at present is an artificially bifurcated construct.

Reasons for separation before now have existed. The 5,400 MW of capacity at Churchill Falls, Canada's second largest hydro generation facility, is nearing a half century of operation as a prodigious producer of hydroelectric energy, largely for sale to Hydro Quebec. It operates under an ownership and management structure unique to its circumstances, but has shared services with Hydro. The introduction of Muskrat Falls raises the need for close attention to whether additional cost efficiency and sharing of services should be considered.

It is understandable that owners and managers of projects of the size and complexity of MFP, when faced with significant challenges, restructure to better address project completion needs. Nalcor did so in 2016, focusing organizational and leadership accountability and responsibility, likely at the cost of higher total resource needs. The need for concerted measures to complete the MFP will pass in the reasonably-near future. Continuation of the present structure will produce a split of normally integrated functions within what remains a small, vertically integrated utility. We examined opportunities for structural realignment that would, after MFP completion, bring together organizations now performing related functions across the utility operations of Nalcor, whether at or supporting Churchill Falls, Muskrat Falls, the LIL, Hydro, or Energy Marketing. The organizations affected include those performing planning, engineering and design, operations, corporate, and administrative support functions.

B. Organization and Staffing Overview

Offshore Development, which includes Bull Arm Fabrication, operates in fundamentally different business areas and its divestiture in the near- term is planned. Our examination considers integrating functions now split between Hydro and Power Supply fully or in major part. The corporate functions of the Finance and General Counsel organizations remain critical but narrowed in scope and potentially affected by consolidation of aspects of Hydro and Power Supply operations. For example, Finance now embeds personnel in both Hydro and Power Supply.

Nalcor identifies its operating structure as follows:

- Hydro
  - Hydro Regulated - Provides for sales of electricity (primarily at wholesale to Newfoundland Power, industrial customers, and to many small groups of retail customers within the Province and under regulation by the Board)
  - Hydro Non-Regulated - Sells power purchased from Churchill Falls to mining operations, and manages operations of certain facilities (*e.g.*, Exploits) not subject to Board regulation

- Power Development - Performs MFP development activities that will become part of Power Supply upon completion of Muskrat Falls
- Power Supply
    - MFP Transmission - Constructs and will operate the Labrador-Island Link (LIL) and Labrador Transmission Assets (LTA)
    - Churchill Falls - Owns and operates a hydroelectric generating facility that sells electricity to Hydro-Québec and Hydro
    - Other - Includes revenues and costs associated with the operation of the Menihek Generating Station, the Maritime Link, administration and community development costs related to Power Supply, and costs associated with the management of MFP construction.
- Energy Markets
    - Energy Trading - Sells to export markets in Eastern Canada and the northeastern U.S. available excess energy, at present primarily Recapture (*i.e.*, excess energy from the 300 MW block of electricity that Churchill Falls has agreed to sell and deliver to Hydro); will manage all Power Supply and Hydro power and energy transactions in and out of the Province after Muskrat Falls completion
    - Commercial and Other - Costs associated with Gull Island and business development activities related to exploring additional markets and sources for future energy generation and transmission.
- Offshore Development
    - Oil and Gas - Engages in exploration, development, production, transportation and processing sectors of the oil and gas industry
    - Bull Arm Fabrication - Makes available an industrial fabrication site for sublease to third parties.
- Corporate - Includes corporate support and shared services functions.

Energy Markets organizationally reports to Power Supply but comprises a separate legal entity.

Nalcor Energy Structure: Operating and Organizational

Nalcor Energy Operating Structure
Hydro
Regulated
Non-Regulated
Power Development
Power Supply
LCP Transmission
Churchill Falls
Other
Energy Markets
Energy Trading
Commercial & Other
Offshore Development
Oil & Gas
Bull Arm
Corporate

Nalcor Energy Organizational Structure[1]	
Hydro	*Power Supply*
Engineering	Engineering
Transmission & NLSO	Trans. & Community Affairs
Production	Production & Energy Mrkt
Financial Services	Financial
Reg. Affairs & Corp. Services	Safety, Health & Sustain.
General Counsel	Transition to Operations
Mng Interconnection Integr.	
Finance	*General Counsel & Secretary*
Accounting	
Plan., Treasury, Risk Mng	
CIO	
Corporate Affairs	
Commercial MNG & Strategy	

[1] Excludes Power Development and Offshore Development

The Operating structure, shown on the left of the preceding chart, depicts how Nalcor publicly reports operating results. This portion shows Energy Marketing operationally reporting independently of Power Supply, but Energy Marketing is shown in the Organizational structure on the right as part of Power Supply's Production group. Also, Churchill Falls, which operationally is a distinct sub-unit of Power Supply, is embedded within the Power Supply's Production group from an organizational perspective.

The differences between the Operating and Organizational structures become important because Nalcor displays personnel (full-time equivalents, or "FTEs") and costs in different categories. The lack of consistency makes it difficult to grasp readily where and how functions interrelate among the operations for purposes of gauging consolidation opportunities.

We analyzed staffing by rolling up positions as they appear in organization charts associated with the "Organizational Structure" portion of the preceding figure. We sought to generate a quantifiable comparison of the organizational units within Nalcor (*e.g.*, the number of engineering staff in Hydro compared to the number in Power Supply, or the relative size of the production organizations.) Summary information received toward the end of Phase One showed FTEs more aligned with the Operating Structure (center box) than the Organizational Structure (right box), a less useful (at this stage) point of comparison, but one that might be helpful in Phase Two.

However, there is at least one major point of distinction when comparing results using Liberty's "bottom's up" FTE count under the "organizational structure" versus FTE information provided by Nalcor under the "operational structure." The tables below present FTE counts using both frameworks. They show different numbers, raising the question of how to reconcile them.

Operational vs. Organizational Nalcor Structure

Operational Structure			
	2018 FTEs		
	Permanent	*Temp*	*Total*
Hydro			
Regulated	790	111	901
Unregulated	47	11	58
Sub-total	837	122	959
Power Supply			
LCP	135	61	196
Churchill Falls	237	90	327
Energy Marketing	25	--	25
Other - Power Supply	46	8	54
Sub-total	443	159	602
Corporate			
Exec., Finance & IS, Corp. Systems & Strat. Plan.	144	3	147
Bus. Systems Trans.	--	13	13
Sub-total	144	16	160
Total	1,424	297	1,721

Organizational Structure	
2018 FTEs	
President and CEO	1
Exec Ass't	1
General Counsel & Corp. Secretary	8
Power Suppy	486
NL Hydro	868
Finance / CFO	105
Total	*1,469*

The total FTE count of 1,469 using Liberty's "bottom's up" approach comes close to the FTE count of "permanent" staff - 1,424 - under the operational structure. The minor difference in FTE count likely results from inconsistent treatment of vacant positions between the two management counts shown in the preceding table. We counted them in our bottom-up approach.

However, we did find problematic the 297 "temporary" FTEs shown in the operational-structure view of Nalcor. Management described these temporary FTEs as spread throughout Nalcor. They include seasonal workers and co-op students. Management projects constant "temporary" FTE levels in 2019, and perhaps well longer. More analysis and dialogue with management is required on temporary FTEs to determine their use and effectiveness.

The "operational structure" view of FTEs also does not make clear the functions that resources perform. Comparing functions at detailed level (for example, Power Supply Engineering FTEs versus Hydro FTEs) will take substantial effort. Our bottom-up database may make comparison easier.

C. Hydro and Power Supply

Hydro and Power Supply comprise by far the largest Nalcor organizations. They operate under reasonably comparable overall organization structures. Engineering, transmission, finance, and production are common to both and, not surprisingly, to most utility organizations. There are important distinguishing features to consider. For example, Power Supply transmission staff operating the LIL are apt to have more specialized skills given the LIL's operation as a high voltage direct current transmission line. There remains much commonality in operating and maintaining them, however.

It is unusual to employ two separate and distinct transmission and engineering organizations within the same network topology. This approach reflects management's desire to underscore the distinction between the regulated nature of Hydro's business and the unregulated nature of Power Supply's business. Whether that distinction is one that needs to be maintained, however, merits exploration. We recognize the complex nature of many of the agreements that govern the various elements of the MFP, and that regulatory, legislative, and other restrictions or conditions may affect corporate reorganization. Nevertheless, those restrictions, whatever their nature, would not seem to hinder, at the least, some material degree of functional combination. In fact, it appears that there is already a significant degree of cross-charging within Nalcor. The question, then, is whether careful consideration of combining certain functions will produce efficiency. Liberty believes it will.

D. Corporate Services

Enterprises of reasonable size and multiple operating entities generally find it beneficial to create functions, services, or organizations that can provide "shared" services and functions across multiple entities. Those services may be administrative in nature, such as payroll, compensation and benefits, labor relations, health and safety, or they may be financially oriented, such as treasury, accounting, and risk management. Shared services can also be technical or strategic in nature, such as information technology, regulatory relations, legal, and engineering.

Nalcor has adopted this general approach. For example, the Nalcor Finance/CFO organization provides a centralized responsibility center for key corporate functions, such as accounting, information technology, treasury and risk management, and internal auditing. The sizeable staff consists of:.

- Chief Information Officer (43)
- Chief Accounting Officer (19)
- Commercial, Treasury, Risk Mgmt. (18)
- Corporate Affairs (14)
- Internal Audit (7)
- Commercial Management & Strategy (3)

As shown earlier, the number of Finance function personnel under the Organizational structure totals 105 "permanent" FTEs, but the FTE count of Corporate staff in the Operational structure totals 160. The Finance organization likely does not reflect all of the functions embodied in the "corporate" group, but the differing counts need to be reconciled to address consolidation opportunities. The operative question is whether activities can be more efficiently performed via consolidation.

Nalcor's organizing to provide largely self-standing Hydro and Power Supply organizations, makes it very likely that total corporate and service functions support requirements have become sub-optimal. Moreover, the size and cost of the MFP relative to current revenues and asset base have led to a legal and operating structure both complex and highly unusual for a company this size. Such a structure has the distinct potential to introduce inefficiencies in staffing, cost-sharing, and service provision (*e.g.*, procurement), particularly with Nalcor so focused on MFP completion.

E. Summary

Our key findings regarding staffing and organization are as follows:

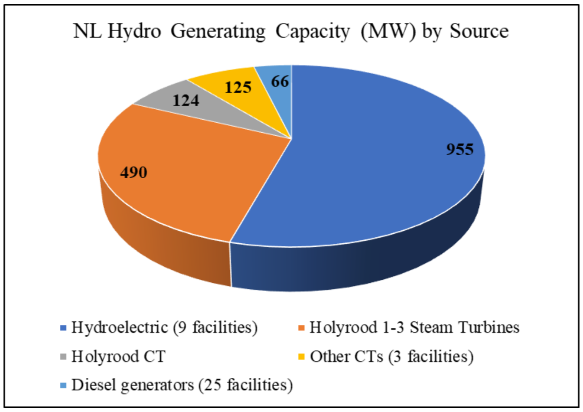
- Nalcor is a small company struggling to complete an enormous, and enormously expensive, capital project.
- The cost of the project is such that, notwithstanding good management, non-optimal spending or resource loading is much cheaper than jeopardizing schedule or operational readiness. Higher resource loading is almost certainly a consequence.
- A resource analysis showed numerous duplicative functions although the degree to which there is duplicative staff awaits examination.
- Liberty's bottom-up resource analysis did not identify almost 300 "temporary" staff because they were not included in the corporate organization charts.
- The relative size and seeming permanence, or at least stability, of the number of the "temporary" staff warrants examination.
- Permanent staff will begin to roll off special positions/functions (*e.g.;* Transition to Operations) as the MFP nears completion. How those FTEs will be dispositioned is a topic to be examined.
- Using a base over 1,700 FTEs, even a modest reduction of five percent would generate approximately $10 - $15 million in annual savings, depending on the associated costs of an FTE.

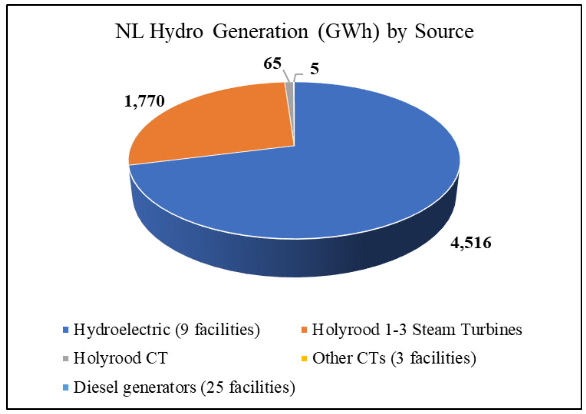
V. Generation Resources

A. Hydro's Generation Resources for the Province

The next table summarizes the capacity and energy contributions of Hydro's generating facilities on the Island Interconnected system in 2017.

Hydro Capacity and Energy Sources (2017)





Hydro supplements these resources with PPAs executed with a number of sources. Supply under these agreements comes primarily from wind and small hydroelectric facilities. Recall power from Churchill Falls has become a source of supply following energization of one of the poles of the LIL. In 2017, Hydro's hydroelectric generation made up 54 percent of the capacity and 71 percent of the energy produced by Hydro-owned assets. Hydro's oil-fired steam turbine plant, Holyrood, made up 28 percent of both the capacity and energy produced by Hydro. The gas turbines provided little energy, but serve as a source of capacity and limited energy, most importantly in remote locations in Labrador. The capacity and energy contributions by asset type are shown graphically in the charts above. The next table summarizes plant staffing at Hydro's generating units.

Hydro Generating Station Staffing

Function	Hydroelectric	Exploits Generation	Holyrood and GTs	Total
Operations	27	16	40	83
Work Execution	43	15	43	101
Long Term Asset Planning	6	4	11	21
Support Services	8	1	3	12
Safety, Health, and Environment	2	1	16	19
Senior Manager	1	1	2	4
Total	**87**	**38**	**115**	**240**

B. Churchill Falls

Nalcor's Power Supply organization operates a hydroelectric generating station, Churchill Falls, which dwarfs the Hydro fleet in size. Churchill Falls' 5,400 MW of generating capacity makes it the second largest hydroelectric plant in Canada. Almost all Churchill Falls output has gone to Hydro Quebec for decades, under agreements with long-continuing terms. Three hundred MW of recall power have been available for use in Labrador, with the LIL recently giving the Island access to that source. Churchill Falls is the only major generation now operated by Power Supply. Hydro Quebec has substantial rights with respect to operational, budget, and costs matters. Thus, any opportunities for cost mitigation involving those matters will have to consider the agreements that give Hydro Quebec such rights.

Upon completion of Muskrat Falls, Power Supply will operate both these two large Labrador hydroelectric generating stations. Muskrat Falls is much the smaller of the two. It will provide 824 MW of capacity and 4.9 TWh per year (at a 68 percent capacity factor). These amounts reflect just 15 percent of the capacity and just 14 percent of the energy that Churchill Falls offers.

C. Churchill Falls and Muskrat Falls Cost Drivers

The contrast in size, production, and vintage of the two large hydro generating facilities, makes their cost structures substantially different. Churchill Falls original costs have long since been fully recovered. Owners incur most hydroelectric plant O&M costs on a fixed basis; *i.e.*, not variable with plant output. The exception to this is the water power rental fee payable to the Province.

Muskrat Falls'capital investment (both extremely large and largely undepreciated) dominates its cost structure. Capital additions for the new plant are not likely to materially rise above those ultimately needed to achieve sustainable commercial operation, therefore not presenting substantial mitigation potential. Capital expenditures will be minimal going forward for many years, and will not likely factor into any mitigation measures. O&M expenses at both plants are substantial. Of particular interest are two areas. First, Muskrat Falls O&M estimates have risen substantially since the initial plans for the plant. Second, as a new plant, it will take time (likely on the order of a few years) for the uncertainty in actual O&M needs to level out as operation commences, matures, and stabilizes due to adjustments in staffing and plant operation.

D. Muskrat Falls O&M Cost Projections

Estimates of total MFP O&M costs are significant, now at almost $100 million per year in 2021. The estimates do have supporting detail and we have had a chance to review some descriptions - - but not all the underlying data - - of the rationale for the estimates. However, the reasonableness of those estimates, their dependence on key assumptions (*e.g.*, is a 12 percent contingency too high or too low?), and the degree to which they are conditioned on subjective assessments (*e.g.*, the cost of a contract yet to be negotiated) is unknown. A thorough and detailed review of the cost categories by cost component (*i.e.*, the LIL, the LTA and Muskrat Falls) is required before an assessment can be made as to reasonableness.

The latest O&M cost projections for the MFP, which includes the LIL, the LTA, and Muskrat Falls show estimated annual total costs for the three components increasing from $47.3 million in 2019's budget to a forecast of $97.4 million in 2021. These most recent estimates of annual costs show declines of between $5.6 million and $9.0 million over the three-year forecast period (2019 – 2021). An earlier estimate of cost projections showed a budget for 2018 of $27.3 million.

Two of the three components of the MFP, the LTA and Muskrat Falls, show projected O&M cost increases from 2019 to 2021 of 21 percent (the LTA) and over 200 percent (Muskrat Falls). The Muskrat Falls cost increase occurs at the time it enters service. LIL total cost projections remain essentially flat over the three-year period. One significant reason for the increases is the transition from construction to operations - - when in commercial operations, some costs now capitalized will be accounted for as O&M.

During the LIL/LTA operation before Muskrat Falls is commissioned, Nalcor is charging most labor costs related to the operations staff to O&M, because they support delivery of recall power and other off-island purchases. During this same period, many corporate and engineering support services costs for these transmission assets will also be charged to O&M, with some to capital. Muskrat Falls generating station costs all go to capital until commissioned.

We have not had the opportunity to review the underlying data of the major cost categories comprising the MFP O&M cost projections, but below are details and descriptions of the major categories of costs.

System Equipment and Maintenance (SEM) - - SEM comprises the largest O&M cost category for all MFP components (excluding Water Power Rental and IBA for Muskrat Falls). For example, 2021 estimated SEM costs for the LIL of $16.7 million equate to 43 percent of the costs of operating the LIL. Similarly, SEM related costs for the LTA comprise almost 34 percent of its 2021 O&M costs. The SEM proportion of 2021 O&M costs for Muskrat Falls is lower at 18.8 percent, but that percentage is skewed lower by the inclusion of Water Power Rental and IBA costs in total costs. Excluding Water Power Rental and IBA costs, SEM-related costs for Muskrat Falls approximate 34 percent of the remaining O&M costs.

Corporate Support Services - - These costs are both large and increasing significantly from 2019 – 2021. Increases are a function of both increasing activity as well as accounting treatment.

Administration and Other Cost - - These budgets are based on estimates of categories such as training, travel, warehousing, equipment rentals and professional services. In some cases, certain specific costs, such as fees - - about $2.3 million - - become apparent only when the assets become operational (2021), similarly for estimates of insurance costs for Muskrat Falls, which jump almost $2 million between 2020 and 2021.

E. Initial Generation Cost Review

Our Phase One review sought to identify potential areas for cost reductions, with detailed exploration of them in Phase Two. A key concern for Phase Two will be balancing achievable cost savings initiatives with the need to maintain reliable service to Hydro's customers. In addition to concerns for reliability, there are other constraints to prospective mitigation measures, including contractual and legal concerns. For example, cost-cutting measures at Churchill Falls may not only impact reliability, but may need the approval of Hydro-Quebec.

In Phase One, we began with a high-level benchmarking exercise of operating costs at each generating facility. We benchmarked O&M costs between Nalcor and Hydro resources and those of an appropriate panel. Management did not provide O&M costs metrics ($/MWh and $/kW-yr.) that comprise standard benchmarking measures. We estimated them from management-provided data that we assumed reflect direct costs at each plant, and divided these into the appropriate denominator (energy in MWh or capacity in kW) depending on the asset type under review.

Smaller Hydroelectric Plants

O&M costs at hydroelectric generators are largely fixed and have no fuel component. The generally accepted approach to benchmarking the costs associated with hydroelectric generators is to divide the plant's total O&M into the electrical output, resulting in a $/MWh metric. We assembled panels of U.S. hydroelectric generators against which to compare Hydro's and Nalcor's plants. We chose U.S. plants because of the availability of O&M costs by plant for them. We then grouped them into categories defined by capacity (MW). The panels consisted of all hydroelectric plants (without pumped storage) of 40 MW capacity or more. These were then grouped into three capacity ranges (40-200 MW, 200-700 MW, and over 700 MW). The data was based on 2017 values and have been converted to CAD.

Many factors affect hydroelectric cost benchmarks, such as plant capacity, length of dams, age, number of units, number of gates, start/stop cycles, for example. For the purposes of this benchmark, we divided the panel solely by capacity ranges.

The key metric is weighted average O&M, with 2017 energy output (MWh) as the weighting factor. O&M for the 40-200 MW group was $9.22/MWh. For the 200-700 MW group, O&M falls to $6.00 per MWh. For the 700+ MW group, O&M falls further to $5.20 per MWh. The inverse correlation between capacity and O&M per MWh is as expected, reflecting the economies of scale in larger facilities.

We compared O&M in $/MWh for all of Hydro's small hydro units units , with those of plants in the 40-200 MW panel. This initial review shows that Hydro's small units compare well to the panel in terms of operating cost, but we have yet to validate commonality of O&M cost definition between Hydro and the peer group data. This does not mean that there are not cost-reduction opportunities within this group of assets, but that the benchmarking process did not flag any notable cost anomalies.

We compared O&M in $/MWh for Bay d'Espoir to plants in the 200-700 MW panel. This initial review shows that Bay d'Espoir compared well to the panel in terms of operating cost, again subject to validation.

Large Hydroelectric Plants

We compared both Churchill Falls and Muskrat Falls to the 700+ MW group. O&M in $/MWh for each was compared to the plants in the panel. This initial review shows a substantial difference in O&M costs between the two Nalcor facilities, each on the extreme ends of the spectrum of costs. Churchill Falls displays the lowest O&M cost relative to the panel, while Muskrat Falls (based on projections for 2021) is the highest. Again, more detailed analysis on the classification of costs as O&M is warranted.

Unlike Churchill Falls, the Muskrat Falls O&M costs well exceed the panel's weighted average. However, Muskrat Falls O&M costs include IBA and the Water Power Rental fee payments. Total 2021 O&M for Muskrat Falls is $48.5 million, with $5.8 million for the IBA and $15.6 million for the Water Power Rental fee. Removing these two charges brings Muskrat Falls O&M closer to the panel's median and the panel's weighted average. Environmental costs present another category where more detailed analysis will bear on differences.

It is important to put Power Supply's hydroelectric assets in perspective from the standpoint of operating cost. In order to compare the two, the annual cost of water rental fees at Churchill Falls must be added. In doing so, the 2019 O&M and rental fees amount to $71.8 M, as compared to $48.5 M at Muskrat Falls. Based on this, Churchill Falls requires only about 50 percent more in total O&M than Muskrat Falls, yet produces more than seven times the energy. This highlights just how expensive Muskrat Falls is from an O&M standpoint, further bolstering the need to identify any areas from which to reduce costs.

Hydro's Thermal Plants

Benchmarking oil-fired steam turbines is a difficult task, especially when attempting to assemble a field with large capacity and high capacity factor such as Holyrood. This is largely due to the fact that oil-fired steam turbines are inefficient and have high fuel costs, resulting in very high overall operating costs. This is further complicated by the costs of oil delivered in different regions.

Liberty was able to identify four oil-fired steam turbine plants that: (a) exceeded 100 MW in capacity, and (b) had capacity factors higher than 10 percent: two in Florida and two in Hawaii. In order to isolate controllable cost, we performed benchmarking on non-fuel O&M only. The four plants had an average capacity factor of 25 percent, and a weighted average non-fuel O&M of $8.40 per MWh. Liberty also calculated O&M as a function of capacity, producing a panel weighted average of $13.71 per kW-yr. By comparison, Holyrood's non-fuel O&M cost was much higher, again subject to validating the consistency of classification of costs as O&M.

Hydro also operates four oil-fired combustion turbines (CTs). Such units have low capacity factors, typically, due to their high heat rates. They are generally run for peaking purposes and for system reliability, not for overall economic dispatch of energy. Therefore, benchmarking the costs of gas turbines becomes difficult, with the best metric fixed O&M, in $/kW-yr. We assembled a panel of 795 U.S. CTs, and calculated a weighted average cost of $6.60 per kW-yr for the panel. Based on how CTs are staffed and utilized, typically with a single operator, and how they are deployed, typically for capacity and only occasionally for energy, it is assumed that all non-fuel costs are fixed. As such, Liberty finds that when fuel costs are removed from Hydro's CT's, fixed O&M expenses are much higher than those for the panel.

F. Summary

The Water Power Rental fees are not cost-based. They present another opportunity for examining how proceeds to the Province similar to those arising from dividends discussed above might be used to generate revenue requirement mitigation. The fees form part of costs recovered from utility customers.

We leveraged the knowledge we have gained in recent years about the Hydro fleet from previous consulting engagements with the Board. These insights and the data gathered in Phase One call for review of the units and their support resources and services. This assessment will cover:

- Personnel organization, types, and numbers
- Review of key operating metrics
- Site visits and interviews with management and operators
- Outsourcing approach and providers of non-standard maintenance and specialized services
- Centralized control opportunities
- Review thermal plant fuel costs, fuel management, hedging, and optimization
- The economic merits of asset closure versus continued operation.

VI. Hydro's Internal Operations

A. Background

We examined the potential for opportunities to mitigate revenue requirements arising from costs incurred by organizations operating under the senior management of Hydro's Vice President of Engineering and Hydro's Vice President of Transmission, & Distribution (T&D) & NLSO. The Vice President of Engineering has responsibility for the senior management of all Engineering Services departments. The Vice President of T&D and NLSO has responsibility for senior management of the NLSO (System Operator) organization, the Transmission and Rural Operations (the TRO Regions) organizations, and the Generation and Rural Planning organization.

Budgeted 2019 TRO O&M spending of $42.3 million shows a decrease from actual 2017 spending of $45.6 million. Management projects that capital spending will increase from the 2019 budget of $27.5 million to $39.6 million in 2023.

B. Engineering Services

The Engineering Services organization operates from St. John's but remotely locates project-oriented and Information Technology (IT) and Operations Technology (OT)-oriented professionals. We counted 140 combined permanent engineering and technical employees (not including IT and OT positions) in the Engineering Services organization, in the Regional LTAP organization, in the Regional Scheduling and Support Services organization, in the NLSO Transmission Planning organization, and in the Generation and Rural Planning organization. We excluded Non-Hydro and Muskrat Falls engineering and technical positions. Hydro employs 251 "wrench" (execution-oriented) FTEs in its Northern, Labrador and Western & Eastern TRO Regional Operations and Work Execution organizations, and in the TRO Support Services Organization.

Best practice permanent "technical to wrench" ratios are between 0.25 and 0.33 for large to medium-sized utility owned operations. Hydro's ratio of 0.56 indicates a notably-high number of permanent engineering and technical employees when compared to the execution units they support. Moving the permanent ratio to even a still comparatively-high 0.40 value would call for outsourcing a number of Engineering Services positions. Contracting at fully-loaded contractor rates could reduce costs by more than $1 million annually, assuming no reduction in net FTEs (employee plus contractor). A reduction there could add substantially to this amount.

C. Changing Responsibility for Retail Service Operations

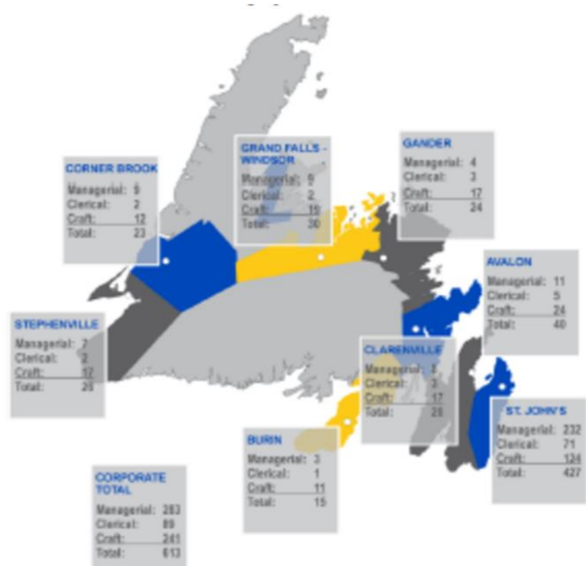
We reviewed a number of options for changing responsibility for Hydro's retail operations. They could take the form of divestiture or some form of service contracting. Transferring responsibility for Hydro's current distribution operations to Newfoundland Power also has the potential for changing service quality levels (perhaps improving them). Moreover, costs saved by Hydro would be offset by costs assumed by the transferee. Therefore, this option requires consideration of the net cost effects for customers and of potential changes in service quality.

Hydro Distribution Customers

Distribution System	Customers
Island Interconnected	22,910
Labrador Interconnected	11,210
Total Interconnected	34,120
Island Isolated	795
Labrador Isolated	3,679
Total Isolated	4,474
Total Distribution Customers	38,594

Hydro serves predominantly at wholesale, in major part to Newfoundland Power, which in turn is the supplier to the vast majority of retail customers on the Island. Hydro does, however, serve almost 40,000 customers at retail, through distribution systems dispersed across the rural and isolated areas of Newfoundland and Labrador. Hydro's retail customers include the residents of 21 remote communities using small diesel generator plants and associated local distribution systems.

Newfoundland Power Facilities



The map shows Newfoundland Power facility locations. Hydro's Western & Eastern TRO Region lies in the center of Newfoundland Power's distribution system as the following map shows (Hydro in blue shading, Newfoundland Power in yellow). Newfoundland Power has offices located around the eastern, northern, and western parameters of that Hydro TRO Region.

Hydro and Newfoundland Power Retail Serving Regions

Given the nature and location of Newfoundland Power's operations with respect to those of Hydro, consideration should be given to transferring some or all of Hydro's distribution assets. Specific options to consider in transferring retail service operating responsibility or ownership include:

- Western & Eastern Region Distribution Assets - - Newfoundland Power's territory surrounds Hydro's Central Region on the East, North, and West
- Entire 21 diesel plant and Isolated Distribution Assets - - Hydro's regional organizations maintain and operate these diesel plants and their local distribution systems, requiring line workers, diesel mechanics, and mechanical maintenance personnel not otherwise required for the interconnected distribution systems
- All Hydro Interconnected and Isolated Distribution Assets, Including Diesels - - This option would allow Hydro management and operations to focus only on its generation facilities , and its transmission system lines and terminal stations.

D. Building and Fleet Maintenance

Outsourcing of some or all of generic building and facilities maintenance to facilities management and maintenance contractors is a common utility practice. For example, it is common to see essentially all non-routine vehicle maintenance contracted to dealerships or other automotive and equipment service providers based on economic analysis of external versus fully loaded internal costs.

Contractors can frequently provide facilities management and maintenance work at favorable costs. We have not yet secured Hydro's O&M budget and actual data at a sufficiently detailed level to isolate the costs involved. Similarly, it is often economically desirable to enter contracts with vehicle repair service providers (mechanical, electrical and body shop) based on online labor and material and parts tools that can be specifically customized to the makes and models of vehicles and equipment within the fleet, paying for repairs when necessary and eliminating salaries and salary-related overhead costs of a standing fleet maintenance organization. We will in Phase Two perform additional analysis to determine if cost savings can be achieved by outsourcing building and fleet maintenance.

E. Work Management, Job Scheduling, and Crew Productivity Improvement

We did not find at Hydro the strong focus on active productivity management or on processes for establishing, communicating and measuring job level productivity expectations that industry experience would suggest. There appears to be an opportunity for savings from improving productivity and efficiency improvements. O&M productivity expectations and metrics at the corrective or preventive work order level do not appear to be emphasized. Accountability rests with first line supervisors for crew and individual worker success, using the supervisor's subjective judgment. This macro level approach does not employ clear, granular productivity expectations and Key Performance Indicator metrics, making it difficult to measure or improve crew-level productivity. Without good measurement, productivity generally tends to fall to levels below that obtainable through a more structured, rigorous approach to productivity management.

The costs at stake are substantial. Combined 2017 O&M salary costs plus overtime for the two TRO operating departments (Western & Eastern) and (Northern & Labrador) exceeded $43.5 million. Assuming two thirds of the positions in those two departments to be craft employees, a seven percent improvement would generate over $2 million in annual O&M savings, even before counting support costs on top of salary and salary burdens. Additional savings would result from improvements in capital work productivity.

Each TRO Region conducts its own short-term work planning and scheduling, and there is not a process for addressing workload and resource management holistically, across Department boundaries. Centralizing the workload management function, at least across the two TRO regions, would standardize both the process and productivity expectations. Developing a Corporate level Work Management Organization would enable centralizing and consolidating TRO work planning and scheduling, establishing consistent practices across operating areas, and optimizing the movement of workload and resources across departmental boundaries. There is potential for Hydro to reduce O&M costs if it were to improve work management alone. Those savings would be multiplied if work management was improved across Hydro and Power Supply.

Centralized work management would also relieve TRO Region management from work planning and scheduling responsibilities (reducing local Regional personnel), better enabling supervisors to focus on managing crews and enabling productivity improvements. We will in Phase Two perform detailed analysis to determine cost savings achievable by work management and scheduling.

F. Optimizing Employee/Contractor Resources

Hydro's approach has been to fully load company resources first, and then contract out work remaining. After establishing an Annual Work plan for each TRO Department, management baseloads it with internal TRO craft employees first, with attention paid to increasing the diversity of assignments in order to maintain currency and proficiency in a wide range of job skills and qualifications. Annual plan work elements that remain after internal resources are fully loaded are then outsourced to contractors. As a result, management often commits highly qualified, comparatively expensive internal resources to work that may be outsourced at significantly less overall cost.

It is preferable to choose the least expensive, most efficient fully qualified resource for each type or discipline of work. Doing so promotes best economic use of available contractors, especially for high volume non-complex work and the most cost efficient use of existing, multi-qualified, highly paid company resources to perform the most complex/most expensive roles in the total workload. This process appropriately matches expensive resources for expensive work.

Wood-pole inspection and treatment offers an example. Management addresses almost 3,000 wood poles each year, using Line Worker "A" personnel in two- and three-person crews. 2018 Inspection and Treatment costs are expected to run at about $1 million. We have observed similar programs operated at fractions of this cost. A second opportunity arises from line and terminal worker retirements and other exits. As field personnel retire or leave Hydro, it may prove economical to use more contractor crews to supplement transmission and terminal work, and distribution work during fair-weather months. Some utilities maintain a ratio of contactors to regular line workers, during at least the summer months. This should be especially considered if Hydro implements a centralized work management organization.

In Phase Two we will examine Hydro's crew productivity and hourly costs, including direct overhead, and compare them to contractor crew productivity and costs to determine the potential for cost savings.

G. Oil and Air Blast Circuit Breaker Replacement

Canadian polychlorinated biphenyl (PCB) mitigation environmental regulations prompted Hydro to accelerate its replacement of oil circuit breakers (OCBs) with SF_6 circuit breakers. System outages caused by air blast circuit breaker (ABCBs) failures prompted Hydro to replace all of its ABCBs with SF_6 circuit breakers. Hydro is also working toward use of a standardized circuit breaker type to improve reliability and minimize maintenance and spare parts costs.

Planned OCB and ABCB replacements have forecasted capital costs of about $10 million per year. Examining costs saved by changing the programs is warranted. That examination should address the change in annual costs produced against any reliability decrease or maintenance cost consequences. Alternative methods of complying with environment requirements for the OCBs and deferring the completion of ABCB-replacement to at least 2028 should be examined.

We will in Phase Two undertake a more detailed analysis to determine if there are potential cost savings with this initiative.

H. O&M Asset Maintenance Programs, Performance, and Budgets

Management is considering a number of opportunities for improving TRO asset preventive maintenance management and for reducing spending, including:

- Increasing the 120-day cycle for terminal station inspections, unless criticality is an issue;
- Eliminating or reducing manual oil sampling on transformer units that have online gas monitoring systems
- Increasing maintenance cycles based on asset age, condition, and criticality
- Identifying opportunities to deploy resources between regions rather than outsource during the development of the Annual Work Plan.

In Phase Two we propose to assess the pace and effectiveness of these and other measures to determine their benefits and potential cost savings.

I. Asset Corrective Maintenance (CM) Programs

Hydro is currently considering a number of opportunities for improving its CM task management and reducing spending for its TRO CMs, including:

- Better packaging work and manage risk to allow work to be coordinated (bundled), where possible with other preventative maintenance and capital work, even if this means moving CM work in another Annual Work Plan year
- Supplementing resources between regions rather than outsource during the development of the Annual Work Plan
- Advancing and packaging work in areas where travel is costly, such as the coast of Labrador
- Reviewing priority definitions and consider extending timeframes for completion of certain work.

The actions Hydro is considering for reducing its future O&M costs for preventive and corrective maintenance work are reasonable and consistent with good utility practices. We will in Phase Two do further analysis to determine their potential cost savings.

VII. Conclusion

Our Phase One work has identified a broad series of measures that warrant Phase Two exploration. Those related to Nalcor returns, the proceeds of export sales, and MFP financing are clear and massive in impact, but require policy decisions - - some of them engaging the federal government. Others have promise, and may produce lesser, but still material reductions in costs. A number of them come from looking at Nalcor, post oil and gas business divestiture, as a vertically integrated utility - - a view that we believe holds considerable merit.

The following list identifies the measures we identified in our Phase One work. We state them all as clear propositions, but wish to make clear that:

- All remain contingent on further analysis required to validate the size of their revenue requirements reduction
- A number depend on participation of parties outside Nalcor and Hydro
- Many require detailed evaluation to verify that any impediments or barriers to implementation can be addressed so as to allow execution after Phase Two completion.

The opportunities for cost savings and revenue optimization that we propose for Phase Two examination are:

- Treat export sales from MFP assets whose costs Hydro's ratepayers bear as an offset to revenue requirements
- Eliminate or reduce Nalcor's return on equity in the MFP financial structure, correspondingly reducing Hydro PPA payments, to reflect the absence of outside equity investors in Nalcor
- Eliminate or reduce a second source of equity return to Nalcor - - built into the rates Hydro charges to its customers for utility service, again to reflect the lack of outside equity investors in Nalcor
- Reduce payments required by the financing agreements which will require the agreement of the federal government,
- Issue additional MFP debt and structure its repayment window to transfer more robust mitigation opportunities of later years to earlier ones, when opportunities are leaner
- Capture some or all Nalcor dividends received from Churchill Falls, an asset typical of vertically integrated utilities
- Combine leadership and commonly provided corporate and administrative service across Nalcor's entities and organizations, reflecting a re-integration (whole or partial) of Hydro and Nalcor, which, particularly after oil and gas business divestiture, will have an operational scope matching that of a vertically integrated utility
- Combine material or all portions of the planning, engineering, design, construction, operations, and customer services functions now split between Power Supply and Hydro
- Better identify the generating plants with costs and performance raising questions; analyze personnel, technical, equipment, and other drivers of performance at those determined to be outliers
- Transfer operational responsibilities or ownership of some portion or all of Hydro's retail operations to Newfoundland Power, recognizing the latter's location and expertise in providing retail service

- Combine responsibility for performance or contracting of operations functions between Power Supply and/or Hydro with Newfoundland Power
- Change the planning for, optimization of, and management of Hydro's use of a variety of contracted personnel and services
- Change the approach, organization, methods, and techniques applied to managing and incenting productivity at Hydro
- Change oil breaker and extend air blast breaker replacement programs to lower costs and defer capital expenditures to later years, when other sources of revenue requirements mitigation become more robust
- Identify those Hydro asset management and maintenance changes "under consideration" that have significant potential for cost reduction; establish specific implementation plans, schedules, and likely costs reductions for each.