

August | 09



Bill 50: Implications and Concerns

Executive Summary

Bill 50, the Electric Statutes Amendment Act, 2009, was introduced on June 1st in the Alberta Legislature. It proposes to amend three existing Acts in order to facilitate a new and immense transmission infrastructure regime for Alberta.

The basis for the Bill was established in the Provincial Energy Strategy, released in December 2008. Bill 50 designates and provides for the future designation of new transmission facilities as Critical Transmission Infrastructure ("CTI"), as determined by government. By so doing, it is intended to expedite the development of key transmission in Alberta, thus better ensuring the electricity system is "*capable of meeting long-term load growth throughout the province.*"

Industrial electricity consumers have four primary concerns with Bill 50 as it is currently proposed:

1. The **removal of the “needs” application process** will mean no public and transparent cost-benefit analysis is conducted to examine the routing of the lines and the technology choices;
2. The lack of any detailed justification for the **selection of HVDC technology** within Alberta’s integrated electrical system will result in cost over-runs, missed in-service dates and an inability to capture any meaningful line loss benefits;
3. The **lack of an effective cost oversight process** will result in added and unnecessary expense to ratepayers. A pro-active cost oversight process is vital in ensuring that transmission projects will be constructed in a prudent manner. This is particularly relevant considering that both incumbent Transmission Facility Owners (“TFOs”) have relied on expensive out-of-province suppliers without due regard for existing competitive procurement rules; and
4. The **allocation of the CTI projects to incumbent monopolies**, instead of competitive sourcing, is decidedly *un-Albertan*. Albertans deserve cost-competitive infrastructure and Alberta companies deserve the ability to compete for business opportunities if they have the capacity to deliver the required infrastructure in the required timeframes. We have a proven track record of competitive, large-scale industrial project delivery – this capability should be put to work saving ratepayer dollars.

In order to address these concerns, we urge the government to consider four adjustments to Bill 50 to ensure cost effective and responsible investment in transmission projects in Alberta:

1. Initiate an immediate and independent **cost-benefit assessment** of the overall rationale for the proposed CTI expenditures as well as a project-by-project review;
 - At this time there is considerable uncertainty as to the potential benefits that will accrue from the overall transmission development plan and whether the timing and siting is optimal for future electricity costs.
2. Employ **alternative and competitive sourcing** for all CTI projects open to all potential transmission suppliers;
 - It is imperative that the new CTI lines be sourced in a fully competitive environment open to all transmission suppliers to ensure the costs and in-service dates are set by competitive factors;
 - The actions taken by the government on August 25 are unethical and premature. The government has no authority to tell ATCO Electric and AltaLink to begin making expenditures on behalf of ratepayers before Bill 50 has been passed. The Alberta Electric System Operator (“AESO”) is not currently in a position to designate the HVDC lines as CTI, and as such the government cannot rely on AESO advice to direct TFO monopolies to begin work on these lines.
3. Introduce **time and cost penalties and bonuses** for all project builds;
 - Both target cost and firm in-service dates need to be embodied in the bid terms such that the transmission suppliers have both incentives to meet targets and penalties to their shareholders for missing targets;
4. Implement a **Ratepayer Oversight Committee** with access to engineering and accounting expertise to monitor procurement and costs during all phases;
 - Ultimately it is the ratepayer that pays for the new transmission capacity – not the taxpayer – and as such the ratepayer needs a central role in the sourcing and monitoring of the CTI projects.

If transmission costs increase substantially without commensurate benefits in lower energy costs, the economic viability of current and future industrial operations in Alberta will be severely impacted. As such, industrial power consumers require input into the decision-making process that will determine the design of infrastructure, procurement mechanisms and cost allocation for which they will be ultimately be responsible.

The Provincial Energy Strategy calls for electricity to be an enabling industry for development of Alberta's rich oil, gas, and renewable power resources. The transmission lines that are to be designated as CTI will have the opposite effect on the development of these resources. The added costs for transmission will further constrain investments in the oilsands.

Forcing a new transmission build program on existing Ratepayers that will treble and potentially quadruple transmission costs in the next ten years, without any cost control or oversight mechanisms and in the absence of any meaningful cost benefit assessments and consultations with the industrial energy sector, is contradictory to the intent of the Provincial Energy Strategy.

As it is currently established, Bill 50 will result in power costs that limit new oil and gas project viability and force other industries to relocate to jurisdictions where electricity is much more cost-competitive. If Bill 50 passes without modifications, large-scale Alberta industry will look to self-generate electricity, leaving residential and commercial consumers to pay for a considerably larger portion of this new and largely unnecessary transmission infrastructure.

Introduction

The Industrial Power Consumers Association of Alberta (“IPCAA”) is an organization of large industrial electricity customers, including such key sectors as oil and gas, agriculture, petrochemicals and steel. IPCAA’s members constitute approximately 35% of the provincial electricity consumption, and contributed approximately \$3 Billion in electricity revenue in 2008. IPCAA members have an active interest in promoting a competitive electricity market and in taking a leadership role in the Alberta electricity marketplace.

This paper outlines the critical concerns that industrial power consumers have with Bill 50 as it is currently presented. In a further effort to assist, once these concerns have been identified, a series of solutions are offered which we believe would facilitate the general intent of Bill 50 in a more cost-efficient manner. IPCAA has worked with industrial, commercial and residential power consumers, as well as other electricity stakeholders to develop the concerns and recommendations included in this paper.

As illustrated in Figure 1, below, industrial power consumers pick up 61% of the electricity transmission costs in Alberta. If these transmission costs are going to increase substantially, industrial power consumers require input into the decision-making processes that will determine the design of infrastructure, procurement mechanisms and cost allocations for which they ultimately pay.

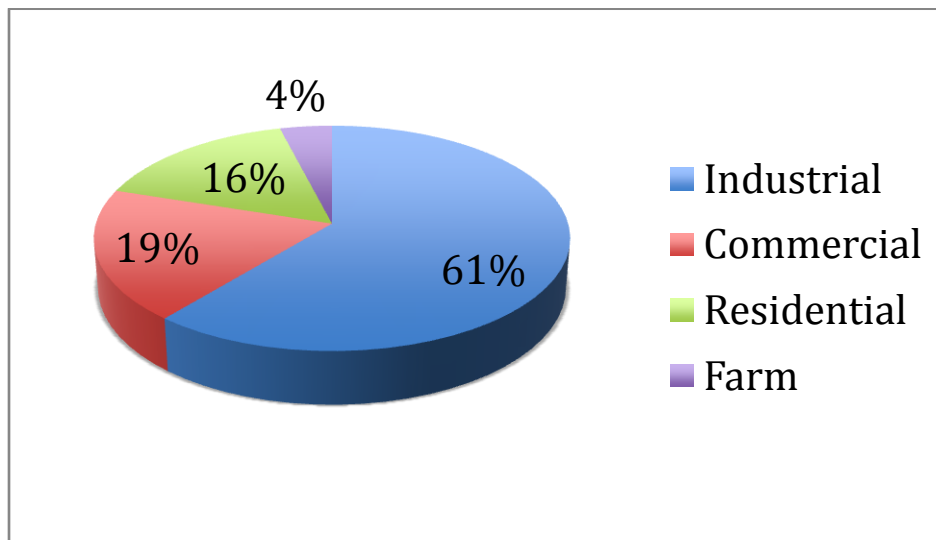


Figure 1: Allocation of Transmission Costs by Customer Class

Background Information

Bill 50, the Electric Statutes Amendment Act, 2009, would amend the following three Acts:

1. The Alberta Utilities Commission Act
2. The Electric Utilities Act
3. The Hydro and Electric Energy Act

Under Bill 50, the Government of Alberta will identify the need for CTI. Siting of transmission projects will be determined by Alberta Utilities Commission (“AUC”). *Electric Utilities Act* amendments include authorizing the need for the first group of CTI projects and establishing a legislative approval process for future projects. CTI Projects are illustrated in Figure 2, and include the transmission lines in the following table, identified as Tier 1 Projects. Tier 2 Projects are additional infrastructure projects in the works:

	Project	Description	Cost (in \$M)
Tier 1 Projects	Edmonton to Calgary	Two HVDC lines that will carry more power to customers in central and southern Alberta	3,135
	Heartland to Edmonton	A 500 kV AC line to address the power needs of industry	387
	Fort McMurray to Edmonton/ Heartland	Two 500 kV AC lines to support ongoing oil sands development and enable the connection of industrial cogeneration into the provincial transmission system	2,045
	Southern Alberta (wind)	Two double-circuit 240 kV lines along with a new 500 kV substation to increase the ability of the southern system to connect new wind farms. <i>Already in front of the AUC.</i>	2,454
	South Calgary Reinforcement	An upgrade of the system in and around the City of Calgary. The upgrade is required to carry additional electricity and provide stronger connections and power service to the city and nearby towns	100
	SUBTOTAL		
Tier 2 Projects (Interties)	1	B.C. intertie	200
	2	Alberta/ Saskatchewan/ Manitoba intertie	760
	3	Saskatchewan intertie	350
	4	U.S. Pacific Northwest intertie	815
	SUBTOTAL		
Tier 2 Projects (Intra-Alberta)	Northwest	Transmission to renewable and low-emission energy zones	500
	Northeast	Transmission to renewable and low-emission energy zones	1,400
	SUBTOTAL		
Other	Underway	Bulk transmission system infrastructure currently underway	570
	Long-Term	Long-term regional transmission system plan	3,872
OVERALL TOTAL			16,588

Table 1: Tier 1 and 2 CTI Projects

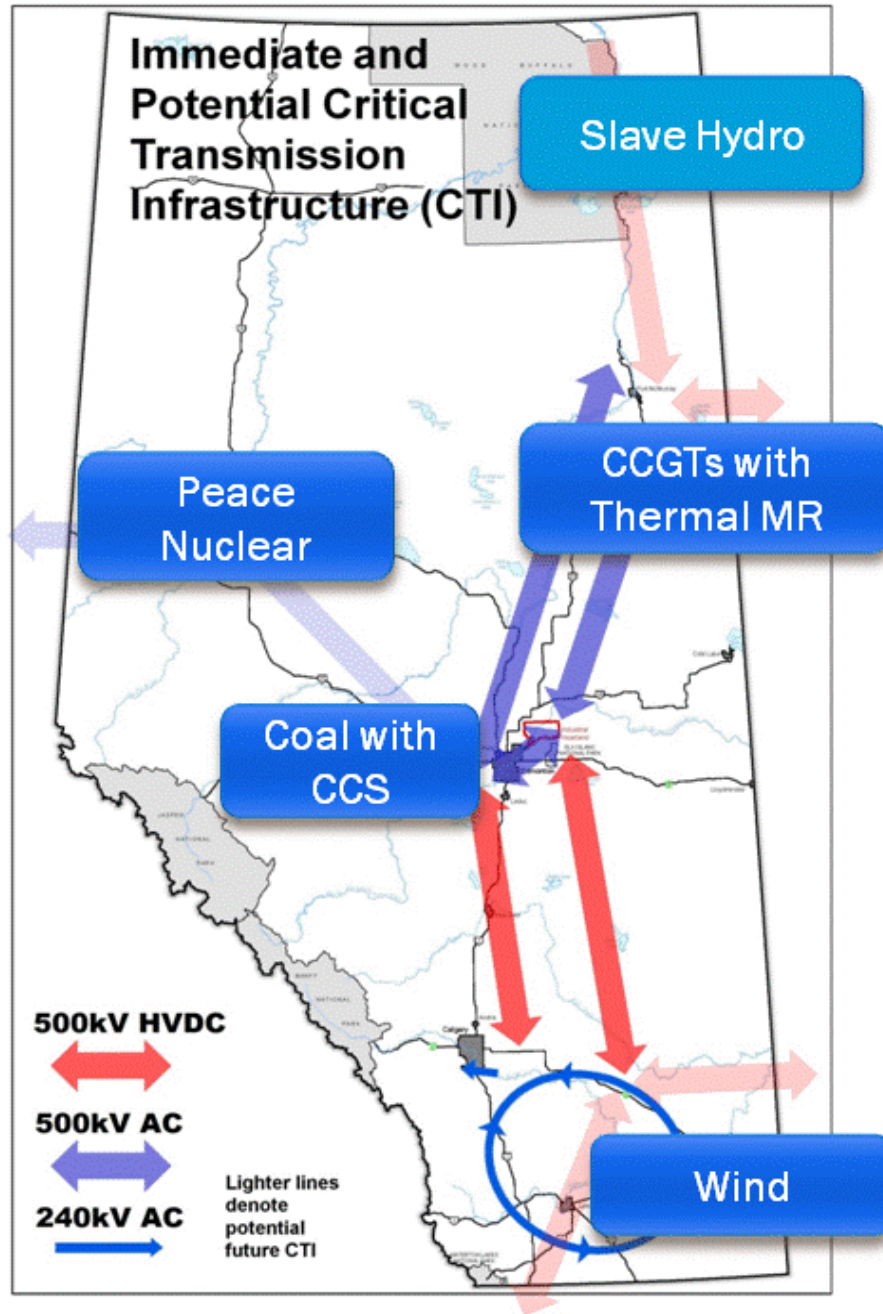


Figure 2: Map of Critical Transmission Infrastructure under Bill 50

Imposed on the map in Figure 2 are the five contemplated generation sources that require large-scale transmission access. However, each of these sources present problems including: generation costs, time to build and availability of surpluses requiring large-scale transmission. Any cost-benefit assessment of transmission has to deal with the probabilities and costs for potential generation builds. In order for any new transmission to bring value to consumers, it is vital to consider the new generation sources that will accompany the transmission.

Cost Implications

In an effort to assess the cost implications of the proposed transmission infrastructure build under Bill 50, a basic costing model has been developed. To the extent possible, publicly available information is used for model inputs. An overview of the cost parameters, the key assumptions that are used and the resulting cost implications for Alberta electricity consumers is included in Appendix A.

Table 2 indicates the total costs, total tariff impacts, costs per MWh of consumption and total annual costs to industrial consumer resulting from the implementation of Bill 50.

	2010	2012	2015	2020	2025	2030
Total (Real) Costs \$M	\$ 599	\$3,331	\$ 10,909	\$16,567	\$19,201	\$20,440
Impact on AESO Tariff (Fixed Costs + O&M) \$M	\$ 90	\$ 500	\$ 1,636	\$ 2,485	\$ 2,880	\$ 3,066
Annual Impact (\$/MWh)	\$ 1.44	\$ 7.23	\$ 20.50	\$ 26.51	\$ 26.31	\$ 24.08
Annual Cost to Industrial Consumers (\$M)	\$ 54.8	\$ 304.8	\$ 998.2	\$ 1,515.9	\$ 1,756.9	\$ 1,870.2

Table 2: Bill 50 Costs to Consumers

The following items are particularly noteworthy (highlighted in green in the Table):

- Total capital costs of Bill 50 infrastructure is approaching \$20 billion by 2025;
- Annualized costs of Bill 50 are exceeding \$26.50/MWh (\$0.03/kWh) by 2020. This cost will apply to all Alberta consumers, including residential; and
- Industrial transmission bills are increasing by nearly 1 billion dollars by 2015 as a result of the implementation of Bill 50.

In comparison, the total transmission infrastructure in Alberta is currently valued at \$4 billion, the 2009 year-to-date power cost is just over \$45.00/MWh (4.5 cents/kWh) and industrial customers pay about \$1 billion/year in transmission tariffs.

Key Issues for Industrial Customers

1. Removal of Needs Application – inability to challenge design and costs

Clearly, without a Needs application the opportunity for stakeholders to question the need for a particular line or series of lines is removed. The question of ‘need’ includes not only whether a line is required, but also whether the design of the line is reasonable and optimal from a technical and cost perspective. As proposed, Bill 50 does not include milestones or metrics to ensure that any new generation will follow the development of the lines.

When establishing a route for CTI, the question remaining for the AUC is how to assemble the corridors as quickly as possible, not whether the optimal routes have been selected. Industrial customers have paid and will continue to pay for the majority of transmission costs. If Bill 50 goes forward without adequate design and cost controls, industrial customers will be on the hook for significant cost increases; most of which may be unnecessary.

The AESO and the government attempt to justify the massive capital expenditures set out for CTI projects on the basis of a number of factors that require a more detailed cost/benefit assessment before they can be accepted by industrial consumers as a valid rationale for such a significant cost imposition. Some of the key questions that need to be addressed with respect to the CTI objectives are included as follows. *Note that the objectives are taken from the AESO Long-Term Transmission Plan.*

1. Maintenance of system reliability

- Will HVDC lines have a de-stabilizing impact on reliability?
- Will increased renewable development (wind in particular) be feasible without compromising system reliability?
- Will ENMAX's 1100 MW of new gas turbine generators around Calgary provide greater reliability and more flexibility than large-scale DC lines?

2. Catch up to growth

- Will the AESO's projections for future growth in demand actually materialize given the impact of higher power costs on many industrial projects?
- Why was the AESO 2005 forecast of 7.7% growth from 2006 to 2008 out by 95% (actual growth was only 0.4%) during a period of high economic activity in Alberta?

3. Keep ahead of future growth

- How can we be confident that the AESO projections for 4.5% annual growth between 2010 and 2017 will actually occur given their dependence on growth in oilsands production and processing?
- How much of the load growth will occur in proximity to the proposed CTI lines?
- Will the oilsands load growth be served by local natural gas generation producing both steam and energy?

4. Enable renewable

- Does the current power market structure support investments in renewable when existing wind projects only capture 70% of the average prices?
- Will wind projects satisfy the need to offset carbon production from other energy activities in the province?
- If transmission is being built to renewable areas, how do we know that these renewable projects will be built, under the current market structure?

5. *Provide certainty to power generators and consumers*

- Given the most recent experiences with both major TFOs on delayed projects and cost over-runs, how can either generators or loads be confident that in-service targets will be met?
- How will the AESO ensure that new generation projects will be forthcoming if the transmission is built?

6. *Deliver the power we depend on now and into the future*

- How does the government reconcile the need for large-scale transmission projects with the growth in distributed generation in other electricity jurisdictions, as well as the environmental benefits of distributed generation?
- Does Bill 50 'lock-in' expensive and in-efficient future generation solutions for the next forty years in the absence of an integrated generation, regional load growth, fuel-source, and transmission plan?
- What are the comparative benefit/cost relationships between large-scale transmission and generation projects located at stationary fuel sources (hydro, wind, coal and likely nuclear) versus moving fuel (natural gas and shale gas through an existing and buried pipeline infrastructure to efficient gas turbine generators)?

7. *Minimize land-use impacts*

- How does the proposed HVDC technology result in a smaller 'footprint' than AC technology? Does it merely increase capacity on the existing 'footprint'?
- Are there more cost-effective solutions for farmers and ranchers in terms of land-use than those contemplated by CTI?
- Is the spacing between DC and AC towers the same, meaning that the benefit is simply a narrower right-of-way?
- Does not the use of existing gas pipelines moving fuel to generator source have an even lower land-use impact?

8. *Increase inter-tie capacity*

- How do the government and the AESO propose to deal with the reality of an existing BC inter-tie that is currently constrained to just 40% of its capacity?
- How do we gain confidence that new inter-tie capacity will actually result in effective inter-market price arbitrage within the current market design?
- Will the increase in inter-tie capacity cause increased exports that will result in higher energy prices for Alberta power consumers?
- Why should Alberta ratepayers pay for increased export capacity with no ability to recover the costs of these transmission additions?
- Should the seller of the export energy pay for added transmission capacity for exports in the same manner that oil and gas producers pay for the gas and oil pipelines that access US export markets?

9. *Increase efficiency by reducing costly and wasteful transmission losses*

- a. Are (1) distributed generation; and (2) siting gas generation proximate to load; better solutions to reducing transmission losses than massive transmission overbuild?
- b. How are the HVDC lines rationalized for 'line loss' savings when they are only contemplated to operate over 300 km and general engineering consensus is that at least 500 km of lines are required to make HVDC cost competitive with regards to losses?

Excerpt from ABB website on line losses

“HVDC transmission losses come out lower than the AC losses in practically all cases. An *optimized* HVDC transmission line has lower losses than AC lines for the same power capacity. The losses in the converter stations have *of course to be added*, but since they are only about 0.6 % of the transmitted power in each station, the total HVDC transmission losses come out lower than the AC losses in *practically all cases*. HVDC cables also have lower losses than AC cables. The diagram below shows a comparison of the losses for overhead line transmissions of 1200 MW with AC and HVDC.”

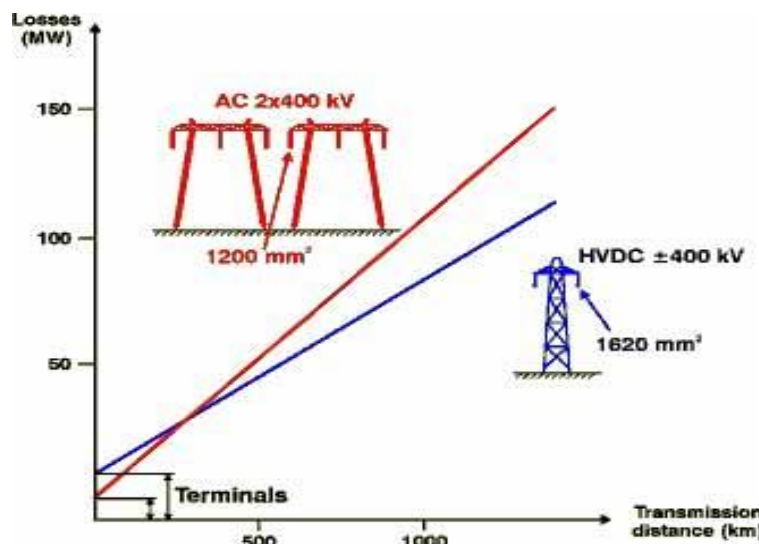


Figure 3: DC vs. AC line losses

- Does the concern for the short distances (300 km) and the line losses at each converter station (1.2% for 2 stations) not negate any potential benefits of HVDC with respect to losses?

Given the number of questions and concerns that have not been address with respect to the need for these CTI projects, industrial consumers urge the government to initiate an independent, third party cost-benefit assessment of these transmission projects as soon as possible, and in advance of any design work or action to implement construction. The terms of reference and consultant selection for this assessment should be subject to ratepayer approval, and the results of this assessment must be made public.

2. Technology Selection – prescribed solution brings high cost

The selection of High Voltage Direct Current (HVDC) technology for the two CTI lines planned between Edmonton and Calgary has never been justified on an economic basis. The rationale for selecting HVDC as opposed to HVAC lines is that the former uses a smaller footprint and will save on line losses. No data has been provided as to the costs associated with a larger footprint or the costs associated with line loss savings from using DC lines.

The Alberta Department of Energy ("ADOE") has indicated that line losses in 2008 were in the order of \$220 million and that the DC lines would result in savings. This creates the misleading impression that losses savings will be in the order of \$200 million – this value is for **all** transmission line losses in the province and for 2008. In 2009 line losses are estimated to fall to \$150 million.

The small incremental savings for DC versus AC would be a reduction from 4% to 2% and only for the electricity on these lines. Assuming that 30% of Alberta electricity flows north to south along these new CTI lines on an annual basis, the line loss savings would only amount to \$20 to \$30 million per year. To the extent the construction of HVDC lines between Edmonton and Calgary will serve to address this losses problem, it will do so both inadequately and in a far too costly manner.

Other jurisdictions have considered the use of HVDC for major transmission projects, including the Bruce-to-Milton line in Ontario, which is approximately 180 km. According to systems engineers, it would take a distance of well over 500 km (some studies indicate 1000 km) before DC lines would be cost comparable with AC lines, otherwise the losses and costs associated with AC-DC conversion will outweigh the benefits of a DC solution.

The system reliability impacts of integrating DC into the centre of the grid are currently unknown and untested. Even the government hydro monopolies in Manitoba and Québec have not attempted DC lines as proposed in Bill 50. Rather, in these jurisdictions, HVDC technology is used for moving electricity from far northern hydroelectric generators to export markets in the US.

Moreover, under current market rules and tariffs, line losses are paid for by generators, not by Alberta electricity consumers. If the new transmission infrastructure is intended to reduce line losses, it will bring a benefit to generators, while loads will incur significant new costs. This is a fundamental fairness concern that has not been addressed in the Provincial Energy Strategy or otherwise by the Alberta government.

With the current information provided by the ADOE, the incremental benefits of an HVDC solution with a price tag of \$3.5B compared to an HVAC alternative costing \$1.5 to \$2B are not at all apparent. A prescriptive technology choice, such as the required use of HVDC, may result in an unnecessary burden on Alberta ratepayers, and subsequently an uncompetitive environment for specific industries in the province.

3. Lack of Competitive Procurement and Dependence on Transmission Monopolies

One of the major concerns of ratepayers in the province is the lack of competitive sourcing in the assignment of major transmission projects. This concern remains and indeed is significantly increased under Bill 50 given the magnitude of the CTI projects contemplated. By granting the TFO monopolies the right to build the majority of the proposed Tier 1 transmission projects, the only cost control will be after the lines are built and in AUC hearings on cost prudence. This form of after-the-fact review is too late to ensure cost effectiveness.

Alberta's industrial consumers strongly recommend that all transmission providers be allowed to bid on provision on all elements of CTI and in particular the two North-South lines (should the HVDC technology prove to have a positive cost-benefit for consumers). Competitive bidding would have several key benefits:

- It would ensure that the total cost to provide the lines is competitively sourced with the commensurate benefits of competition on design, costs, cost management and time to delivery;
- It would ensure that the two North-South lines, (should they incorporate HVDC technology), would have no expensive duplication of engineering efforts by Alberta's incumbent TFOs neither of whom have any experience with DC construction or system integration of DC lines;
- It would provide for timely construction as competitive bid processes could incorporate incentives for early in-service, and penalties for delays, accruable to the TFO shareholder rather than the ratepayer (this will be described further in the subsequent section); and
- It would enhance opportunities for Alberta sourcing of engineering and construction. Local procurement for services can be stipulated as a bid criterion, as opposed to seeing the continued exporting of jobs as has been done by Alberta's incumbent TFOs.

Competitive procurement is also welcome and necessary in Alberta, given how current regulation has proven ineffective at limiting non-competitive EPCM (Engineering, Procurement, Construction, and Management) contracting between TFOs and their affiliates. Albertans deserve transparency and cost competitive solutions.

There are numerous companies in Alberta that have experience in multi-billion dollar infrastructure projects for oilsands development, pipeline construction, and electricity generation and transmission projects both domestically and internationally. The presence of this infrastructure project expertise makes Alberta ideally suited to provide competitive sourcing for CTI projects.

In order to allow for competitive procurement, it would be necessary to amend the monopoly franchise provisions of the current legislation. However, as the government is already in the process of amending several Acts through Bill 50, expansion of the Bill to allow for competitive sourcing for all CTI designated projects should be a relatively straightforward process. Incumbent franchise holders would obviously be allowed to bid, and if they have any competitive advantages, then they should be the successful supplier.

Several world-class transmission suppliers have indicated that they believe they could deliver the HVAC or HVDC infrastructure (if proven viable) contemplated within acceptable timeframes and at costs less than the budget estimated values set out in the AESO documents. Albertans deserve cost-competitive infrastructure and Alberta companies deserve the ability to compete for business opportunities if they have the capacity to deliver the required infrastructure in the required timeframes.

4. Need for Oversight and Correct Incentives

Oversight: Alberta ratepayers are also concerned with the lack of oversight for transmission project costs. This is particularly problematic where transmission EPCM services are provided through non-arm's length contracts with TFO monopolies. As with the concern regarding the lack of competitive sourcing, this concern regarding lack of cost oversight significantly increases under Bill 50 given the magnitude of the CTI projects contemplated.

A cost oversight mechanism needs to be incorporated into the legislation that will better ensure proactive control of costs and timetables. This oversight process should include a committee embodying the following features:

- The committee would consist of ratepayer associations that represent the interests of broad constituencies of consumers (such as the Utilities Consumer Advocate – UCA) and specific interest groups with at least 5% of total consumption such as IPCAA, the Alberta Direct Connect Consumers Association (ADC), the Consumers' Coalition of Alberta (CCA), and/or the Canadian Federation of Independent Business (CFIB);
- The committee would employ professional services from engineering and accounting firms to provide a continuous monitoring of design and costs, with reasonable access to the TFO actual cost expenditures;
- The committee would review all competitive procurement practices and oversee the actual procurement processes to ensure that competitive bidding is available for all engineering, equipment, construction and project management;
- The committee would negotiate the time and cost incentives and penalties for project completion, with such negotiated agreements to be filed with the AUC; and
- Costs for the committee and contracted professional services would be paid by the transmission developer, subject to review by the AUC.

The intent is to ensure that ratepayers have full access to the costs of transmission builds well before they become general tariff applications and subject to review before the AUC. Access to costs and review of procurement practices will ensure a more efficient and accurate accounting of costs, as they become part of the overall transmission tariff for ratepayers.

Incentives: The use of time-based and cost-based incentives for major construction projects has a long and valued history in western Canada dating back to the incentive for railway and tunnel construction with the building of Canada's national railway infrastructure.

Incentives and penalties need to be reasonable, achievable and enforceable for them to result in meeting target costs and target in-service dates. As such, it is proposed that two sets of incentives be incorporated into the procurement for all CTI projects as set out in Figures 4 and 5 below.

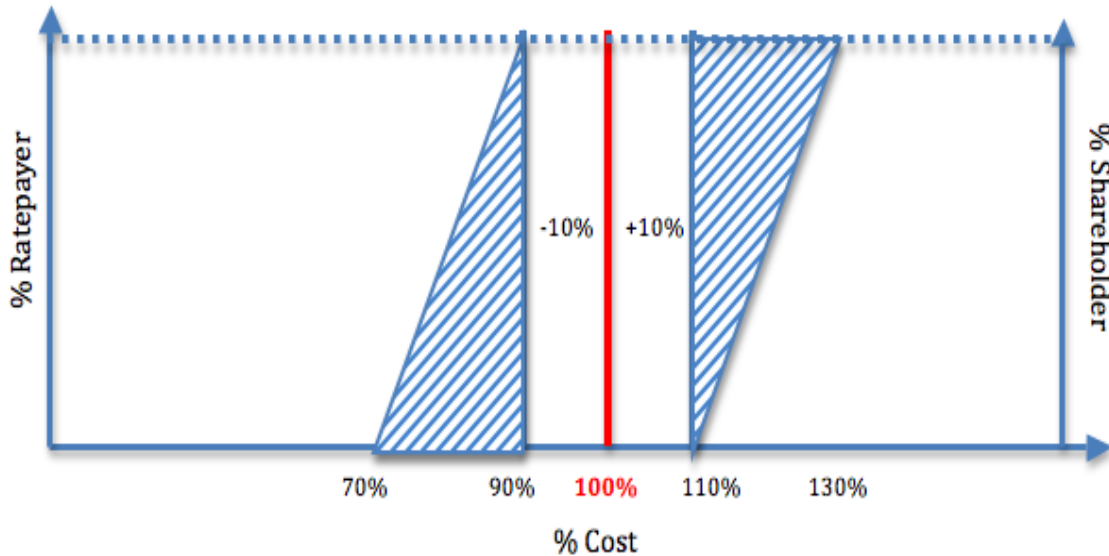


Figure 4: Risk Sharing on Cost Targets

Currently, cost over-runs accrue to ratepayers and require extensive post-event reviews, costly and time-consuming hearings, and engagement of competing teams of lawyers and expert witnesses. Figure 3 illustrates a more effective mechanism for cost control, requiring a target cost to be established in advance of construction. Cost variations of up to 10% above or 10% below the target will accrue to the ratepayer account. If costs end up at less than 90% of the target cost, a bonus mechanism will compensate the TFO shareholder. Similarly, if costs end up over 110% of the target cost, the TFO shareholder will be responsible to make up these costs according to a predetermined formula.

Beyond cost, loads and generators in Alberta are particularly concerned that new transmission projects are delivered in a timely manner, once the need has been established and a post benefit-cost ratio exists. Major generation builds and large-scale pipeline and oilsands projects can be adversely affected in the absence of timely provision of transmission infrastructure. As such, a second set of incentives is proposed for meeting targeted in-service dates.

Figure 5 illustrates this time-based incentive proposal. A target in-service date is established prior to construction, and if a TFO is able to deliver the project in advance of this date (by a pre-established time period, for example: 3 months), then the TFO shareholder is eligible for a bonus. On the other hand, if the TFO delivers the project after the target date (again by a pre-established period) then the TFO shareholder is subject to a penalty.

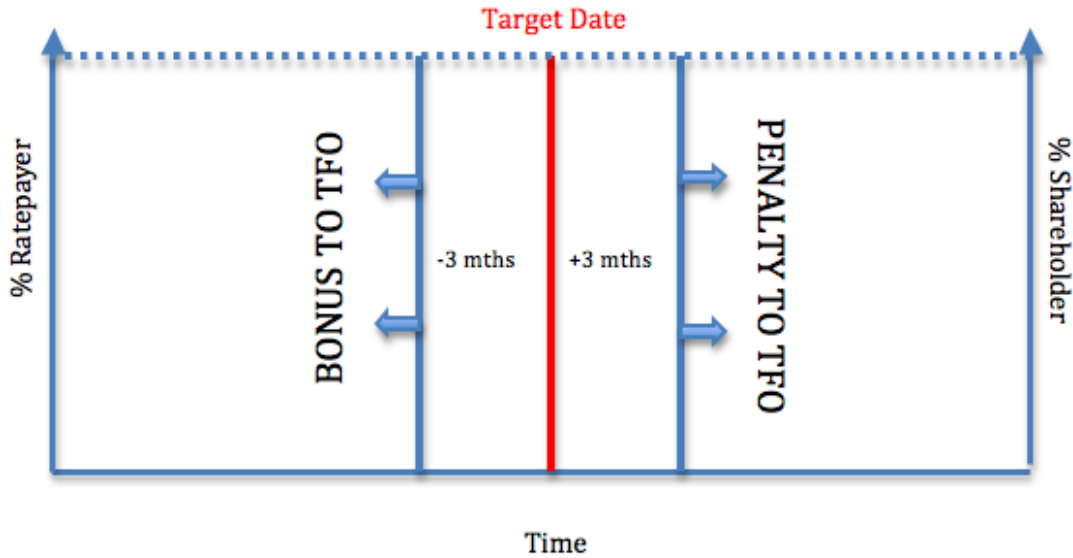


Figure 5: Risk Sharing on In-Service Dates

It needs to be noted that incentives and penalties for large-scale projects will only work in concert with fully competitive sourcing for the respective CTI projects. Target cost and in-service dates would be part of the bid acceptance criteria. The greater the risk the bidder is willing to take on behalf of his shareholders the more desirable that bid from a ratepayer perspective.

There are several examples of large-scale infrastructure projects that make effective use of oversight committees and incentive programs. One interesting case study is the Toll Bridge Seismic Retrofit Program in San Francisco Bay area of California. This project employed both cost and construction incentives and the creation of the Toll Bridge Program Oversight Committee (TBPOC) to provide regular monitoring and project tracking.

Quarterly reports for this project are available from:

<http://baybridgeinfo.org/tbpoc/overview>

Recommendations

Industrial consumers recommend that the government incorporate the following activities into Bill 50:

1. Initiate an ***immediate and independent cost/benefit assessment*** of the overall rationale for the proposed CTI expenditures as well as on a project-by-project review;
2. ***Employ alternative and competitive sourcing*** for all CTI projects open to all potential transmission suppliers;
3. ***Introduce time and cost penalties*** and bonuses for all project builds – contingent on competitive procurement;
4. ***Implement a Ratepayer Oversight Committee*** with access to engineering and accounting expertise to monitor procurement and costs during all phases;

It is critical that these recommendations are all implemented in a timely manner. These four activities complement one another and should be initiated in parallel to ensure the greatest value to ratepayers.

Alberta's industrial ratepayers believe in transparency, effective consultation and the value of competition in the marketplace. IPCAA is willing to work with the government to understand the objectives of Bill 50 and develop cost-effective mechanisms for achieving these objectives.

It is vital that the companies who will pay for the majority of this proposed transmission infrastructure have input into the decision-making process. The absence of this input will result in unnecessary expenditures, a weaker Alberta economy, and a strained relationship between the public sector and private enterprise.

Appendix A – Cost Model

Inputs

The Alberta Interconnected Electric System (“AIES”) annual energy forecast is used to measure impact through time. The Alberta Internal Load (“AIL”) numbers often cited for load growth are significantly larger, due to behind-the-fence load and generation. However it is anticipated that load which is met by behind-the-fence generation will not be responsible for paying for any additional transmission costs under the AESO tariff. The AIES load forecast is taken from the 2009 AESO Long-term Transmission System Plan and is summarized in Table 3, as follows:

	2010	2012	2015	2020	2025	2030
AESO Load Forecast (AIES) GWh	62,364	69,139	79,833	93,794	109,462	127,350

Table 3: Alberta Load Forecast

Table 4 indicates a possible phasing for the CTI projects that are contemplated and the estimated 2008 capital costs as provided by the AESO.

CTI Capital Expenditures	Estimate (2008 \$M)	2010	2012	2015	2020	2025	2030
Tier 1 Projects	\$8,121		\$2,000	\$6,000	\$8,121	\$8,121	\$8,121
Tier 2 (Interties)	\$2,125			\$200	\$550	\$1,365	\$2,125
Tier 2 (Renewables)	\$1,900			\$950	\$1,900	\$1,900	\$1,900
Under development	\$570	\$570	\$570	\$570	\$570	\$570	\$570
Long-term Regional	\$3,872		\$500	\$1,872	\$2,872	\$3,872	\$3,872
TOTAL	\$16,588	\$570	\$3,070	\$9,592	\$14,013	\$15,828	\$16,588
Capital Cost Escalator	2.5%/yr	1.051	1.104	1.189	1.345	1.522	1.722

Table 4: CTI Costs Going Forward

In an attempt to reflect the future capital costs an annual escalator of 2.5% is used. This allows the future costs to be reflected in the year of construction rather than in 2008 dollars.

These cumulative capital costs are then represented as a yearly cost based on a 15% annual factor. This value represents the fixed costs for the investments (depreciation, return on equity and debt servicing) as well as the O&M costs associated with the new investments. This factor has been as high as 20% in recent years; however a more conservative approach has been applied to the CTI projects.