REVIEW OF THE COST STATUS OF MAJOR TRANSMISSION PROJECTS IN ALBERTA

From The Transmission Facilities Cost Monitoring Committee

DECEMBER 2012 REPORT

Table of Contents

Message From The Chair

This is the fourth report from the Transmission Facilities Cost Monitoring Committee (TFCMC) to its stakeholders. The report provides a detailed and structured summary of cost, scope and schedule information on all transmission projects being monitored by the Committee on a monthly basis for the period of May 1, 2012 to October 31, 2012.

Detailed information on two new projects has been provided to the Committee by the Alberta Electric System Operator (AESO): the East Calgary Transmission Project and ENMAX Shepard Energy Centre Connection, with the cost estimated at just over $102 million, along with the Northwest of Fort McMurray Transmission Development Project, at a total estimated cost of $366 million. Details for these two projects can be found in Section 2 and in Appendix B and Appendix C. Section 2 also contains key observations made by the Committee while monitoring the progression of the 16 transmission projects that fall under its purview. During this reporting period, the Committee worked on comparing transmission project costs in Alberta to transmission costs experienced by other jurisdictions. A summary of this work is also included in this section. The developing theme from this work is that Alberta is incurring higher costs for its transmission developments projects than other jurisdictions.

Section 3 provides a status update on the Transmission Cost Recovery Subcommittee (TCRS) initiative. Alberta Energy has advised that it is recommending to the Government to proceed with the next step, to be conducted by the Alberta Utilities Commission, to examine transmission rate options.

Through the Committee's work is in monitoring project costs, it has identified many opportunities to control costs. Since the first report, the Committee has made recommendations to take advantage of these opportunities. Section 4 provides an update on the status of all previous recommendations. Around $100 million a month has been planned for transmission development in Alberta in the next decade and it is critical to take advantage of these opportunities now. Even though it is not within the Committee's ministerial mandate to make these recommendations, the TFCMC is heartened by the proactive responses from the AESO and Alberta Energy. The AESO is working on developing a robust benchmarking database that will benefit greatly in our collective efforts to be a leader in cost effectiveness. The AESO is also undertaking a stakeholder engagement effort to identify opportunities to improve cost accountability management. Alberta Energy recently advised that it is reviewing potential amendments to the Transmission Regulation and will consider the Committee's recommendation in that review.

Section 5 contains the Committee latest recommendation. It also outlines an important activity undertaken by the Committee during this reporting period: a one-day session held by the TFCMC to review its own effectiveness after two years of operation. The review highlighted the value of the Committee's work as well as identified opportunities to enhance its role. The framers of the TFCMC mandate envisioned that the Committee's work would "shine a light" on the cost effectiveness of the Province's transmission development projects. Some members of the Committee felt that the shining light needs to have a broader coverage in order to effect cost reductions before project expenditures are committed.

I would like to take this opportunity to acknowledge the significant contributions from Shan Bhattacharya, Vice President–Transmission at the AESO and Ian McKay, Executive Director, Infrastructure and Alternative Energy, at Alberta Energy. Both Shan and Ian are retiring from their current posts. Even though they were not direct members of the TFCMC, the influence they exercised in their respective organizations enabled the Committee to effectively carry out its mandate and more. They supported the Committee constructively and pro actively. The Committee will miss their presence. On behalf of all committee members, I would like to wish both gentlemen all the best in whatever ventures they choose to pursue in the future.

Thank you for your continuing support. The TFCMC's next report is scheduled for the second half of 2013. Your comments to improve the report will be much appreciated. Please email your comments to **TFCMC@gov.ab.ca**.

Henry Yip
Chair, Transmission Facilities Cost Monitoring Committee

1. Transmission Projects Covered Under The TFCMC's Mandate

The TFCMC has the authority to review records relating to the cost, scope and schedule of transmission facility projects that are expected to cost more than $100 million. These projects include all lines and substations, which make up the transmission facilities required to transfer power between generators and loads. The current list of 16 monitored projects, in alphabetical order, is:

- **ALBERTA INDUSTRIAL HEARTLAND BULK TRANSMISSION DEVELOPMENT (HBTD);** PROJECT 629 – Construction of a double-circuit 500 kV transmission line, which will connect the Heartland region (northeast of Fort Saskatchewan) to existing 500 kV transmission facilities in the Edmonton area.
- **CENTRAL EAST AREA TRANSMISSION DEVELOPMENT (CETD);** PROJECT 811 – Transmission development in Wainwright, Lloydminster, Provost, Vegreville and Cold Lake.
- **CHRISTINA LAKE AREA 240 KV TRANSMISSION DEVELOPMENT (CHL);** PROJECT 1101 – To establish transmission facilities to serve new oil sands developments and enhance reliability to existing oil sands operations.
- ***NEW* EAST CALGARY TRANSMISSION PROJECT AND ENMAX SHEPARD ENERGY CENTRE CONNECTION (ECTP);** PROJECT 719 – To serve growing demand for electricity in the Calgary and High River planning areas.
- **EDMONTON REGION 240 KV LINE UPGRADES (ERLU);** PROJECT 786 – Upgrading 240 kV lines in the Edmonton area; adding one 240 kV phase shifter at Dover substation.
- **ENMAX NO. 65 SUBSTATION (ESCS);** PROJECT 922 – New 240 kV substation in south Calgary and 138 kV development due to overloading in south Calgary.
- **FOOTHILLS AREA TRANSMISSION DEVELOPMENT – EAST PROJECT (FATD);** PROJECT 1117 – To meet growing demand in South Calgary, High River and the surrounding area.
- **FORT MCMURRAY AREA TRANSMISSION BULK SYSTEM REINFORCEMENT (FMAC);** PROJECT 838 – Construction of 500 kV transmission lines from the Edmonton region to the Fort McMurray area.
- **HANNA REGION TRANSMISSION DEVELOPMENT (HATD);** PROJECT 812 – Transmission development in Hanna, Sheerness and Battle River.
- **NORTH FORT MCMURRAY TRANSMISSION DEVELOPMENT (NFMD);** PROJECT 791 – Transmission development to relieve constraints and to serve forecast demand north of Fort McMurray.
- **NORTH SOUTH TRANSMISSION REINFORCEMENT (HVDC);** PROJECT 737 – Construction of two 500 kV HVDC transmission lines from the Edmonton area to the Calgary and south regions. **In late February 2012, this project received provincial government approval to proceed after previously being put under review by the government.**
- ***NEW* NORTHWEST OF FORT MCMURRAY TRANSMISSION DEVELOPMENT (NW FMM);** PROJECT 1180 – To provide service and connect future industrial customers in areas where there are no transmission facilities.
- **NORTHWEST TRANSMISSION DEVELOPMENT (NWTD);** PROJECT 535 – Transmission expansion and enhancement in northwest Alberta.
- **RED DEER REGION TRANSMISSION DEVELOPMENT (RDTD);** PROJECT 813 – Transmission system reinforcement in the Red Deer area.
- **SOUTHERN ALBERTA TRANSMISSION REINFORCEMENT (SATR);** PROJECT 787 – To accommodate wind generation in southern Alberta.
- **YELLOWHEAD AREA TRANSMISSION DEVELOPMENT (YATD);** PROJECT 671 – To serve increased electricity demand, replace aging infrastructure and improve reliability in the Drayton Valley, Hinton, Edson and Alberta Beach areas.

2. TFCMC Observations To Date

Each month as the TFCMC moves forward with its mandate to review the cost of major transmission projects, it embarks on an in-depth assessments of these undertakings[1] (in the case of new projects) or focuses on a more detailed analysis of existing ones based on the monthly reports[2] it receives.

The Committee has observed the following concerns and or issues during the six-month period covered by this report.

Observations On New Projects

Two new transmission projects – the East Calgary Transmission Project and ENMAX Shepard Energy Centre Connection, along with the Northwest of Fort McMurray Transmission Development – have been added to the list of the projects the TFCMC monitors. The Committee's observations on these new projects are as follows:

EAST CALGARY TRANSMISSION PROJECT AND ENMAX SHEPARD ENERGY CENTRE CONNECTION

Project 719

In August, the Alberta Electric System Operator (AESO) presented information on the East Calgary Transmission Project and the ENMAX Shepard Energy Centre Connection. The East Calgary 240 kV and 138 kV Transmission System Upgrades and the Shepard Energy Centre Connection Needs Identification Document (NID) was filed with the Alberta Utilities Commission (AUC) on May 10, 2011[3].

The AESO identified the need to develop the transmission system to serve growing demand for electricity, enable future generation facilities to reliably connect to the system, and maintain system reliability. The AESO has identified the need for the following system developments:

- Modification of the existing ENMAX No. 2 and East Calgary 5S substations;
- Modification of the existing ENMAX No. 23 substation;
- Modification of the existing Janet 74S substation;
- Utilizing the Provincial Government's favourable credit rating to reduce financing costs for certain transmission projects;
- Construction of a new switching station to connect the proposed Shepard 860 MW natural gas-fired electricity generator to the transmission system, and
- Reinforcement of various 138 kV and 240 kV transmission elements.

The target in-service date for this transmission development will occur between September 2013 and June 2015. The development and the target in-service dates are described in Appendix B.

The estimated[4] cost for the system related components of this project is $102,300,000[5].

1 New projects added to the TFCMC's purview receive an in-depth review in addition to being inserted into the Committee's month-to-month examination process.

2 The TFCMC continues to receive monthly reports from the AESO and the Transmission Facility Owners (TFOs) on all projects valued at $100 million and over.

3 The application number is 1607312 for the East Calgary 240 kV and 138 kV Transmission System Upgrades and the Shepard Energy Centre Connection Needs Identification Document.

4 The estimated costs for the East Calgary 240 kV and 138 kV Transmission System Upgrades and the Shepard Energy Centre Connection are based upon the Proposal to Provide Service (includes a +20/-10% cost estimate) prepared by AltaLink Management Ltd. (dated April 10, 2011) and ENMAX Power Corp. (dated April 26, 2011). The estimate included estimated costs for both customer and system related transmission components. The estimated cost for the customer related components of this project is $34,023,000.

5 The estimated cost for the system related components includes escalation and an allowance for funds used during construction (AFUDC). Without AFUDC, the estimated cost for the system related components is $97,118,649.

AltaLink Management Ltd. and ENMAX Power Company are the TFOs for this project and both have filed the associated Facilities Applications[6] (FAs) related to the NID. The AUC approved the development and issued Permit & License (P&L) on November 1, 2012.

NORTHWEST OF FORT MCMURRAY TRANSMISSION DEVELOPMENT

Project 1180

The AESO presented information from the Northwest of Fort McMurray 240 kV Transmission Development NID as well as a cost summary of the project. The NID was filed with the AUC on November 10, 2011 and approved by the AUC on June 18, 2012.

The AESO identified the need to expand the existing transmission system to serve developing electricity-intensive industrial growth. Oil sands extraction facilities and related industrial developments are proceeding into areas where there are currently no transmission system facilities to provide electrical service and connect future industrial customers.

The AESO forecasts that electricity demand in this area could be in the range of 250 MW to 450 MW by 2020. New industrial customers will require connection to the transmission system beginning as early as 2013. The proposed transmission system development includes a looped system extending west, the addition of two new 240 kV substations, approximately 125 km to 175 km of new transmission lines and modifications to existing facilities.

Project construction will occur in two stages with the first stage taking place in the second quarter of 2014 with expected costs of $180 million. The second stage, planned for second quarter of 2015, has an expected cost of $190 million.

ATCO Electric is currently preparing its Facilities Applications and anticipates filing with the AUC in the second quarter of 2013.

Eastern Alberta Transmission Line (EATL) Converter Station Costs

The TFCMC has been reviewing costs associated with the Eastern Alberta Transmission Line (EATL) project as part of the Committee's monitoring activities.

Information Requests (IR) were issued to ATCO Electric in our efforts to understand the makeup of the budgetary cost for this project. The Committee has also engaged a consultant to gather information on costs of similar projects in other jurisdictions.

Based on the above efforts, the Committee is alarmed that the budgetary cost of the converter station for the EATL project, at $453 million, appears to be at least about 80% higher than similar projects in other jurisdictions around the world. ATCO's IR responses confirmed that the converter stations will allow for future expanded capacity, but the current costs are principally for the 1000 MW of capacity. As such, the significant magnitude of cost difference from what has occurred in other jurisdictions warrants further detailed examination.

ATCO stated in its rebuttal evidence for the 2013-2014 General Tariff Application that it does not believe the costs of the converter stations are unusually high, noting that the costs for the EATL converter stations are largely driven by the technical requirements and the cost of construction in Alberta.

EATL and the corresponding Western Alberta Transmission Line (WATL), which is being built by AltaLink Management Ltd., combine to form the North South Transmission Reinforcement (HVDC) development, also referred to as Project 737 – the construction of two 500 kV HVDC transmission lines from the Edmonton area to the Calgary and south regions.

6 ENMAX Power Corp. submitted a Facilities Application (Application No. 1607400) on June 10, 2011 titled "EPC East Calgary Transmission Project/ENMAX Shepard Energy Centre Interconnection". AltaLink Management Ltd. submitted a Facility application (Application No. 16074446) on June 27, 2011 titled "East Calgary Transmission Project (ECTP)/ENMAX Shepard Energy Centre Interconnection".

HVDC Project Cost Comparisons

A review was conducted of major transmission projects currently underway or recently built in Newfoundland, Manitoba and Alberta. The intent was to develop a cost comparison of the projects in order to establish whether Alberta's costs were reasonable for similar voltage lines and substations.

It is difficult to compare projects, specifically due to the varying soil conditions and footing or anchor costs, transmission and station configurations, and weather design characteristics. Several projects reviewed involved special circumstances, which added to their complexity and costs, so they were omitted from further study.

CANADIAN HVDC PROJECTS

The EATL and WATL HVDC transmission lines in Alberta are in the estimating phase, as are similar projects in Manitoba and Newfoundland. The Manitoba project is 2000 MVA, + -500 kV, the Newfoundland project is 900 MVA, + -350 kV, and the two Alberta projects are planned for the first phase as 1000 MVA,+ -500 MVA, while the lines have been designed to carry 2000 MVA when Phase 2 is completed. The characteristics of the stations, towers, and conductors and equipment vary for each of the projects.

Despite the differences, an attempt has been made to compare projects on the basis of some of the project component parts, namely planned costs to construct the transmission lines, the converter station costs, the transmission line clearing costs, and the telecommunication costs.

The transmission lines are quite variable in length: 852 km in Alberta, 1,100 km in Newfoundland and 1,340 km in Manitoba. The unit costs to construct in Manitoba and Newfoundland were similar at $910,000 and $920,000 per kilometre, respectively. The Manitoba planned construction cost per kilometre is slightly lower, but the line has a higher voltage and higher carrying capacity. The Newfoundland project, although only a 900 MVA project, has been designed to carry 1,350 MVA indefinitely and 1,800 MVA for at least 10 minutes. The Alberta lines, EATL and WATL, are both designed to carry 1000 MVA initially but are upgradable to 2000 MVA at a future date without further transmission line expenditures, so they are also comparable to the Newfoundland (1800) and Manitoba (2000) projects.

The unit costs of the combined Alberta transmission projects, as planned, are in the vicinity of $1,540,000 per kilometre, which is substantially higher than the other two projects in Newfoundland and Manitoba. The costs are higher due to higher land and construction costs. Also the HVDC converter station costs, as planned in both Newfoundland and Manitoba, are approximately $280,000 per MVA whereas the Alberta converter costs are $420,000 per MVA. The TFCMC has been unable to establish why there is such a large variance and is continuing to investigate via information requests to the Transmission Facility Owners (TFOs).

A review of projected line clearing costs showed that Newfoundland was the highest of the three at $13,000 per kilometre; whereas Manitoba was $6,000 per kilometre and Alberta was $11,000 per kilometre. The variances are likely related to the amount of clearing required in the respective transmission line corridors and as such the variances were statistically insignificant in the context of the overall transmission line cost.

An analysis of telecommunication costs showed that all three projects were very similar in estimated cost. Costs ranged from $17 million to $21 million and there was no appreciable differentiation.

HVAC Project Cost Comparisons: 230 kV And Greater

The dual-circuit 315 kV project scheduled for Labrador, from Muskrat Falls to Churchill Falls, has been estimated to cost $795,000 per kilometre. Similarly, the 345 kV line built in North Dakota, between coal plants in the western part of the state and Grand Forks, has been built at about $700,000 per kilometre. Both of these lines are examples of reasonably priced projects for their carrying capacity.

By comparison the South Alberta Transmission Reinforcement (SATR) project has been estimated to cost approximately $1.4 million per kilometre. However, the North Dakota project is rated at 673 MVA whereas the SATR project is planned to be rated at 2000 MVA. Escalating the North Dakota line to factor in a comparable carrying capacity and escalating the costs to 2012 dollars would result in an estimated cost of $1.1 million per kilometre or 21% lower than the SATR project.

A series of 230 kV projects in Manitoba and Alberta were compared to see if there was any significant difference in unit costs. The costs on several Manitoba projects ranged from $326,000 to $383,000 per kilometre, whereas the costs on a series of Alberta projects ranged from $293,000 to in excess of one million dollars per kilometre. Thus, it was recognized that costs per kilometre in Alberta were in general substantially higher than those in Manitoba. As with the HVDC projects, there is no direct, simple comparison as each project is unique and conditions vary throughout the province. Benchmarking projects is a complex task, which requires considerable research and analysis. However, construction and land costs appear to make up a significant proportion of the higher costs of Alberta HVAC projects.

Transmission Cost Comparison: Center to Grand Forks vs. Cassils to Whitla

At the July 2012 TFCMC meeting, a presentation was made by the AESO comparing costs between a recently approved transmission project in the United States to the costs for the Cassils to Bowmanton and Bowmanton to Whitla (CBW) sections of the Southern Alberta Transmission Reinforcement (SATR) project.

In April of this year, the North Dakota Public Service Commission approved routing for the Center to Grand Forks project – a 345 kV transmission line running 260 miles. The primary driver for this project is to accommodate transmission of a generating facility in western North Dakota to Grand Forks, on the eastern border with Minnesota, as well as providing reliability support in the eastern parts of North Dakota.

The project was approved at a cost of $312 million resulting in an apparent cost of just $750,000 per kilometre. At the August TFCMC meeting an update on the two of the components of SATR (referenced as CBW) indicated a cost of $677.9 million for the 240 kV lines at a combined distance of 240 km or a cost of $2,825,000/km. The Committee needed to understand why a transmission project in similar terrain in Alberta was costing 3.8 times as much per kilometre as one in North Dakota with the appearance of greater capacity at 345 kV versus 240 kV.

The North Dakota project, to be constructed and operated by Minnkota Power, was required to meet the need to transmit the 455 MW of capacity at the second unit of the Milton R. Young generating station due to the recently acquired Power Purchase Agreement (PPA) for this output. In return, Minnkota gave up transmission rights on the existing HVDC line from the power station to Duluth, Minnesota. The new line also provides reliability and voltage support to the North Dakota grid.

Of interest is that the line uses monopole towers with an average height of 120 feet and a ground footprint of around 80 square feet compared to the dual-circuit 240 kV towers used on the CBW project with a height nearing 150 feet and ground footprint of more than 800 sq ft. Minnkota Power also provides a significant amount of information on the project on the website http://www.minnkotacgf.com, including real time maps on construction as a service to affected landowners.

As was presented by the AESO at the July meeting, these are not ‘apple to apple’ comparative lines as they have differing MVA ratings, and differing carry capacities. However the cost differential is significant and there are lessons to be gleaned from an ongoing examination of the Minnkota project.

Brooks/Cassils Substation Tower Weight Observations: Tower Design – CBW Transmission Line

TFCMC members and independent engineers observed that the dead-end and angle towers used on the Southern Alberta Transmission Reinforcement (SATR) project – near the Cassils substation on the Cassils-Bowmanton-Whitla (CBW) lines – are much larger and heavier and as a result, more costly compared to towers used for similar applications elsewhere in Canada, which are subject to comparable climatic conditions.

Information Requests (IRs) have been drafted to the Transmission Facility Owner (TFO) to gain clarification and ensure that the towers are the most appropriate for the application. The towers have been designed for heavy icing conditions combined with high wind loads.

The size of the towers would indicate that they may have been intended for use in weather zone "A" as opposed to the region in which they are being deployed. However, local weather conditions in the vicinity of the station may dictate that towers designed for zone "A" may be more appropriate. Alternatively, these zone "A" towers may have been readily available and were substituted to expedite construction schedules.

The design follows standards established by the AESO, however there is insufficient information available to know if the towers have been sized to accept future interconnections and/or additional conductors.

Black Fly to McLelland Observations

As a follow-up to the North Fort McMurray Transmission Development (Project 791) cost increases identified in January 2012, the AESO reviewed options that might mitigate the cost increase on the northern portion of the project, known as the Black Fly to McLelland line.

The Salt Creek to Black Fly line was under construction in the winter of 2011/2012 when ATCO identified three major issues resulting in an increased cost estimate. These issues included geotechnical issues that changed the original foundation design assumptions, increasing labour costs as compared to original estimates, and a shortened construction season due to warm weather delaying freeze up – the Black Fly to McLelland line segment is now planned to be constructed during the winter of 2012/2013. Committee members speculated that a change in tower design might reduce foundation costs for the Black Fly to McLelland line. In addition, deferring construction of the line would delay the costs being included in the Transmission Facility Owner (TFO) rate base and transmission rates would then benefit by the lower rate base.

The AESO presented its review findings to the TFCMC in October 2012. The AESO concluded that deferral of the project was not acceptable, as customers' connection requests continue to drive the need for regional transmission development in the area. Deferring these regional lines will delay customer in-service dates. Detailed design for the Black Fly to McLelland line segment has already been completed and changing the design at this late stage would increase costs further. The AESO noted that ATCO's January cost-change order included the cost impacts to the Black Fly to McLelland portion of the line.

Comparison of Fort McMurray to Christina Lake and Northwest of Fort McMurray

The Christina Lake Area 240 kV Transmission Development (Project 1101) and the Northwest of Fort McMurray 240 kV Transmission Development (Project 1180), are located in areas where muskeg is present and may be subject to similar cost pressures occurring in the North Fort McMurray Transmission Development (Project 791).

These cost pressure issues include geotechnical issues that changed the original foundation design assumptions, increasing labour costs as compared to original estimates and a shortened construction season due to warm weather delaying freeze up. At the October 2012 TFCMC meeting, the AESO presented a comparison of cost estimates between the three projects. The newer estimates have higher costs per kilometre. Labour costs are forecast to increase, as is the total effort required to complete these projects.

For TFCMC purposes, the legislation that drives transmission line siting preferences was discussed. These preferences include maximizing the efficient use of rights-of-way and providing staged transmission capacity increases that reduce the need to access rights-of-way for subsequent capacity increases — even if they result in additional costs. These preferences have resulted in AESO proposals with higher capacity double-circuit lines in many transmission projects. A double-circuit line often results in a narrower right-of-way. Two higher capacity circuits on the towers helps reduce the need to access those rights-of-way, when capacity increases are required at a later date. In some projects, the second circuit is planned to be added at a later date and, in others, both lines are installed in one construction period. From a ratepayer perspective, near-term transmission rates will be impacted. This is due to the higher costs of developing narrow rights-of-way and building high-capacity lines in order to defer returning to the right-of-way if future capacity increases are needed.

For the Christina Lake Area 240kV Transmission Development (Project 1101) and the Northwest of Fort McMurray 240kV Transmission Development (Project 1180), the AESO is considering options to attempt to mitigate increasing cost through changes to the transmission line design. In addition, the use of single-circuit lines on some line segments of Project 1180 is being considered.

Customer connections for industrial load growth, primarily oil sands production and pipelines, continue to drive electric load growth and the need for increased transmission capacity in all three of these projects.

3. The TCRS: An Update

This initiative, whose genesis dates back to 2011, arose out of an opportunity where the TFCMC saw a chance to help the province find ways to potentially minimize projected rate increases from Alberta's major electrical transmission build.

At the end of April 2012, the TFCMC accepted a report prepared by its Transmission Cost Recovery Subcommittee (TCRS), along with the accompanying simulation model developed by the subcommittee to evaluate the various options outlined in the report. The report and the simulation model were then submitted to Alberta Energy.

The TFCMC has since been informed by Alberta Energy that it will recommend to the Government to engage the Alberta Utilities Commission to examine transmission rate options. Alberta Energy anticipates that the decision on its recommendation could be made early in 2013. The TCRS report is expected to be released to stakeholders in the same time frame.

In order to proceed with the contemplated work, the TFCMC advised the Energy Minister that creative rate-setting solutions needed to be explored. The TFCMC submitted a formal request for a mandate extension, which was approved in late June 2011. The TFCMC then formed the TCRS, with select members of the TFCMC taking part as well as representatives from the AESO, AltaLink Management Ltd., ATCO Electric Ltd., ENMAX Power Corp. and EPCOR Distribution and Transmission Inc. A more detailed look at the work of the TCRS was published in the TFCMC June 2012 Report.

4. Results to Date: Status of Previous TFCMC Recommendations

In the three previous semi-annual reports, the TFCMC made a total of nine recommendations. The Committee believes that these recommendations, if implemented, will enhance the management of transmission costs.

Of the nine recommendations, seven were directed to the Alberta Electric System Operator (AESO) and two have been made to the Alberta Department of Energy.

The following recommendations made to the AESO have been implemented. They are:

- That the AESO improve future NID estimates by including fully loaded costs – allowance for funds used during construction (AFUDC), escalation, engineering and supervision, and owners' cost *(June 2011 Report)*;
- That the AESO improve the estimates in the AESO Long-Term Transmission Plan by employing third-party cost estimates or cost estimate verification as well as from benchmark data being compiled by AESO *(June 2011 Report)*;
- That the AESO enhance compliance of the material procurement provisions of Rule 9.1 *(June 2011 Report)*.

These recommendations to the AESO are in the process of being implemented:

- That the AESO develop a transmission cost benchmarking competency and database *(June 2011 Report)*;
- Initiate a review process on the current framework for cost accountability *(June 2011 Report)*;

The AESO has expanded the following recommendation into the broader context of the cost accountability recommendation; to coordinate with the Alberta Utilities Commission (AUC) on the development of a reporting protocol with respect to the reporting of transmission project costs.

- That for each Direct Assigned project, the AESO provide to the Alberta Utilities Commission (AUC) a summary of the scope changes authorized by the AESO for that project including the following:
  - I. The AESO's assessment on whether each scope change was needed;
  - II. A summary of the alternatives available to meet each scope change;
  - III. The AESO's assessment on whether the alternative recommended by the TFO to address each needed scope change was the most appropriate alternative, and
  - IV. The AESO's assessment on whether the cost of each scope change as estimated by the TFO was reasonable.

This information would form part of the AUC's consideration, under section 25(4) of the Transmission Regulation, in determining the TFO's prudence in managing the cost of the Direct Assigned project *(December 2011 Report)*.

The most recent recommendation directed to the AESO came about as the TFCMC believes the information from a benchmarking database will be of assistance in the regulatory approval process for transmission projects. The recommendation stated:

- That for each Direct Assigned Capital project estimated to cost in excess of $100 million[7] at the Needs Identification Document stage, the AESO will publish a cost benchmarking report at the time the Transmission Facility Owner files its Facility Application with the Alberta Utilities Commission for approval. To the extent that there are significant project cost changes between the Proposal to Provide Service stage and the TFO's application before the AUC for rate base approval, the AESO will update and publish its cost benchmark report (*June 2012 Report*).

The AESO has responded positively and will post an overall benchmark report before starting to benchmark individual projects.

AESO Transmission Cost Accountability Recommendation Update

Based on recommendations from the TFCMC in its first semi-annual report (June 2011), the AESO began a review of the cost accountability framework in November 2011.

The review started with the publication of a discussion paper, which addressed several key areas of focus for the review, and included stakeholder sessions to request comments and feedback.

The AESO recommended making adjustments within the current cost accountability framework based on the following considerations: stakeholder comments received on the discussion paper, public policy, and the current legislative and regulatory framework.

The recommended adjustments to the current framework included: developing a suitable reporting protocol with the Alberta Utilities Commission (AUC), continuing work with the TFCMC, enhancing cost estimating quality and reporting, and initiating changes to *ISO Rule Section 9.1*.

The AESO issued a recommendation paper on August 7, 2012, which included the AESO's recommendations and next steps for moving forward with this initiative. Based on the feedback received, the AESO believes there is general stakeholder support to move forward with the recommendations to make adjustments within the current cost accountability framework.

The recommendations included:

1. Developing a suitable reporting protocol with the AUC;
2. Continuation of work with the TFCMC;
3. Enhancing cost estimating quality and reporting; and
4. Initiating changes to *ISO Rule Section 9.1*.

These recommendations were structured into three work streams:

1. Reporting and Oversight Protocol (AESO and AUC);
2. AESO Cost Benchmarking (TFO Direct Assign Transmission Projects); and
3. Changes to *ISO Rule Section 9.1* (NID & PPS Estimates, reporting including Change Orders, Procurement).

The following sections provide an update on the AESO's progress concerning these three areas of work.

7 According to Section 10 of Ministerial Order 64/2010, the mandate of the TFCMC is to review all Transmission Facility Projects forecast to cost in excess of $100 million. In a letter dated January 12, 2011, the Minister of Energy clarified that the starting point for the TFCMC when reviewing cost variances is the estimate in place when a project is approved by an Order in Council for Critical Transmission Infrastructure (CTI) projects, or, the estimate in place when the Needs Identification Document (NID) is approved by the Alberta Utilities Commission (AUC). The AESO, of course, is at liberty to file benchmarking cost reports with various stakeholders, including the AUC, in respect of projects below the $100-million threshold.

AESO Reporting and Oversight Protocol Update

In October 2012, the AESO posted a paper on its website outlining a proposal to further develop a joint AUC/AESO transmission project reporting and oversight protocol. The scope of the proposal included the following activities:

- AUC/AESO to jointly review existing reporting and oversight practices – *completed*;
- AUC/AESO to jointly propose additional reporting and oversight practices – *currently being finalized*; and
- AUC/AESO to consider rule revisions – *in progress – ISO Rule 9.1* changes.

Additional reporting and oversight practices will see three future reporting practices between the AESO and the AUC, which allow the AUC to determine prudence closer to the time of an expenditure and prior to the project completion.

First, the AESO will provide (to the AUC) Proposals to Provide Service (PPS) that are updated six months after Permit and License (P&L) has been issued by the AUC. Second, when project costs are outside the ISO rule threshold, the AESO will provide information to the AUC concerning these costs. Third, the AESO will send the AUC final cost reports six months after energization of each transmission project. The AESO and AUC will implement these reporting practices once process details have been finalized.

AESO Cost Benchmarking Recommendation Update

The AESO provided an update on this initiative to the TFCMC in mid-2012.

As discussed, the AESO intends to publish a cost benchmark report in the first quarter of 2013, which will include benchmarks for transmission development within Alberta and a template for a benchmark report for individual projects. Additional project detail will be required to enable the AESO to provide proper comparisons for future transmission projects, and will therefore be addressed in the consultation process for *ISO Rule Section 9.1* (Estimating and Reporting).

In addition, the AESO has been working with an external consultant to develop benchmark data for transmission projects external to Alberta, and anticipates publishing a report reflecting this data early in the second quarter of 2013.

Transmission project cost benchmarking data will support the AESO's efforts with respect to testing for "cost reasonableness" and will provide Alberta stakeholders with an enhanced level of transmission facility cost estimate comparisons. The AESO also expects that the benchmarking data will contribute to continuous improvement in the AESO's planning process by providing feedback with respect to the cost impacts of planning decisions.

This initiative is based on a recommendation from the TFCMC, in its June 2011 Report, to develop a cost benchmarking database that will enable the AESO to further assess the reasonableness of the costs proposed by Transmission Facility Owners (TFOs) in the Needs Identification Document (NID) and Proposal to Provide Service (PPS) stages of a transmission development project.

ISO Rule Section 9.1 Consultation

The AESO formed an industry working group to review and recommend changes to *ISO Rule Section 9.1*. The main areas within *ISO Rule Section 9.1* to be reviewed by the working group are:

- NID and PPS estimates;
- Cost reporting including change orders; and
- Project procurement.

The review will also include potential changes to AESO transmission project templates, business practices and information documents.

The AESO held a working group meeting with stakeholders in November 2012 to establish the scope of the consultation, the main areas for review, and the approach for the review and the schedule. A staged approach was determined as appropriate, commencing with consultation on NID and PPS estimates, followed by reporting and change orders and concluding with project procurement. Each stage will include a recommendation of policy changes, the development of draft rule language and other non-rule changes, and the filing of the draft rule changes with the AUC. The intended result will be three separate ISO rules.

The AESO will commence working group sessions with stakeholders in mid-January 2013 and anticipates filing the last of the *ISO Rule 9.1* changes by fall 2013. The AESO will continue to look for efficiencies in the process in order to file recommended changes to *ISO Rule Section 9.1* with the AUC earlier, if possible.

Recommendations To The Government

During the course of its operations, the TFCMC has directed two recommendations to the Alberta Department of Energy through its semi-annual reports. Of these, one[8] was considered premature by the Department given the implementation of the other recommendations from the June 2011 Report.

In the December 2011 Report[9], the TFCMC made a second recommendation for the Department to consider. It reads:

- That the Minister of Energy modify the Transmission Regulation to require TFOs to seek AESO authorization of CTI pre-construction expenditures incurred prior to AUC approval of the Facility Application.

In a letter to the Committee, dated November 20, 2012, the Minister advised that Alberta Energy will consider this recommendation as it reviews potential amendments to the Transmission Regulation over the next few months.

8 The recommendation reads: That for non Critical Transmission Infrastructure (CTI) projects, the Department of Energy consider legislative changes to require a second approval stage by the AUC if cost estimates exceed a pre-determined limit. The TFCMC recognizes the need to avoid unnecessary project delays due to factors outside the control of the TFOs.

9 The December 2011 Report was actually released in early 2012 to accommodate the input of additional information. As well, a new provincial cabinet was named in 2012 and a new minister was appointed to the Energy portfolio.

5. TFCMC Conclusions & Recommendations

This section contains the TFCMC's latest recommendation, for the AESO to undertake a case study on cost changes and the cost-change management process based on the experience with the just completed Yellowhead Area Transmission Development project. The section also outlines the highlights of a one-day strategic planning session held by the Committee to review its own effectiveness after two years of operation. The review looked at the value of the Committee's work as well as identified opportunities to enhance its role.

Also of note during this reporting period, the Committee worked on comparing transmission project costs in Alberta to transmission costs experienced by jurisdictions and a summary of this work can be found in Section 2. The developing theme from this work is that Alberta is incurring higher cost for its transmission developments projects than other jurisdictions.

Strategic Planning Session

On July 19, 2012 Fleishman-Hillard (FH) facilitated a strategic planning session for the TFCMC. Prior to the session, the TFCMC had determined an underlying question they believed to be affecting its efficacy: can the committee productively achieve its goals under its current mandate and structure, or does the mandate need to be changed?

The goal of the workshop was to help the TFCMC gain insights and develop recommendations to improve the effectiveness of its role by assisting in the achievement of the following two objectives:

1. Develop recommendations for the TFCMC (operations, resources), within its current mandate, and find out whether or not these recommendations need a consensus and/or majority support.
2. Develop recommendations for changes to the TFCMC's mandate. These may include consensus recommendations and non-consensus recommendations for the Minster to consider.

Each committee member was provided with a Strengths, Weaknesses, Opportunities and Threats analysis (SWOT) to fill out as well as a questionnaire asking members to reflect on the Committee's fundamental objectives. In facilitating the session, FH identified some common points of agreement, most notably that the TFCMC unanimously believes they are the proper vehicle for pursuing the opportunities and objectives in their current mandate, and are the right organization to address some of the key opportunities and issues identified in the SWOT analysis.

While there was consensus on many key topics, it was also identified that there is a diverse range of views on many points, and that this diversity of views is at the core of the challenges facing the Committee. There was general agreement that the Committee needs to add value to the process and ultimately help reduce costs, but opinions on the means for achieving this vary ranging from one end of the spectrum to the other: a need for significant enhancement to the Committee's official mandate to just minor enhancements that enable greater effectiveness.

A large majority of TFCMC members feel the Committee should not be responsible for managing costs, and should remain in its current role as a cost monitoring committee. They cite the fact that the TFCMC recommendations have successfully influenced the AESO, TFOs, and AUC practices and there is no reason to believe this will not continue.

For other members, a review of governance is in order and it is contended that success and productivity is restricted under the existing mandate. Suggesting a change in mandate, these members seek to "get ahead" of costs, thus ensuring better transparency and prudence, which can help the province as a whole and lower costs for ratepayers.

Identifying the Committee's achievements, for example, is difficult because of a lack of processes to measure outcomes. It was largely agreed that improving the monitoring process can ultimately help to reduce costs.

Effective cost oversight through transference of risk to TFOs, reduction of the regulatory burden to ratepayers, and the reduction of transmission project costs are considered to be indicators of success by many TFCMC members. Opinions within the Committee vary on how much project costs should be reduced, ranging between one per cent and 10 per cent. Measurably doing so would demonstrate the Committee's ability to provide value to ratepayers, and can be achieved by increasing resources and sharing expertise with organizations such as the AUC and the AESO.

The TFCMC also identified the potential to take on the role of "thought leader," researching best practices and appropriate methods for monitoring and reducing transmission costs, but believes this can only be accomplished under an extended mandate.

There is a consensus within the TFCMC that value needs to be added to its processes to ultimately help reduce transmission costs. But there is no consensus on whether or not the Committee should expand its mandate to enhance cost transparency, challenge prudence and inform ratepayers through the monitoring of projects. Because of these differing views, the Committee needs to develop support from internal and external stakeholders and build on the success it has achieved under its current mandate in order to move forward.

The TFCMC's Work and General Tariff Applications

One of the TFCMC's purposes is for consumer groups to be able to monitor costs prior to regulatory hearings.[10] It was and is anticipated that access to this information will improve the efficiency and the effectiveness of these hearings. Currently, ATCO Electric is in the process of seeking approval for its requested revenue requirement via the ATCO Electric 2013-2014 General Tariff Application (GTA). Four consumer groups that are members of TFCMC have been active in ATCO Electric's GTA.

These consumer groups have benefited from the information provided to the TFCMC in the preparation of information requests, conducting cross-examination of ATCO Electric panels, and in the preparation of evidence.

Some examples of information provided to the TFCMC that has proven valuable in the ATCO GTA hearings are:

- HVDC Converter Station cost analysis and presentations from TransGrid Solutions Ltd., a consultant to the TFCMC;
- Responses to information requests on converter stations from ATCO Electric;
- A presentation on cost increases on the North Fort McMurray project from ATCO Electric;
- Monthly cost reports from ATCO Electric provided to the AESO and circulated to the TFCMC;
- Clarification from the AESO on the accuracy and components of cost estimates provided by the TFOs such as ATCO Electric;
- Benchmarking studies prepared by the AESO and presented to the TFCMC, including comparisons of engineering and other overhead costs to other costs such as materials and labour; and
- Clarification of the contents of the Final Cost Reports required under *ISO Rule 9.1.3.6* and specifically requirements for disclosure on detailed engineering.

In summary, the work undertaken by the TFCMC has made a significant contribution towards more effective and efficient interventions by the consumer groups who are members of the TFCMC.

10 Ministerial Order 64/2010, August 5, 2010; Covering letter from the Government of Alberta.

Recommendations

Construction work and energizations for Project 671, Yellowhead Area Transmission Development, are now complete, however, the 69 kV line and substation salvaging is only expected to be finished by March 2013. During its deliberations, the Committee noted that there was a change order for an amount of more than $15 million submitted retroactively to the AESO for this project.

The overall cost for Project 671 was forecast at $88 million at the Needs Identification Document (NID) stage while the Proposal to Provide Service (PPS) came in at $126 million, including $17.5 million for contingency. The project cost ultimately increased to $148 million.

The Committee invited representatives from AltaLink to assist in gaining a better understanding of the factors that caused the cost escalation. From its review and monitoring efforts, with inputs from the AESO and AltaLink, the Committee has developed the opinion that the experience of this project offers several learning and improvement opportunities for the future; such as:

- Visibility of change order details to the TFCMC;
- Clarity of contingency requirement and use;
- Information flow process between TFOs and the AESO, and the TFCMC; and
- The project cost trade-off process during implementation.

Given the above, the TFCMC recommends that:

1. The AESO, with assistance from TFCMC consultants, undertake a case study concerning the cost changes for Project 671 – from the NID through to the PPS and the authorized budget – and this should include lessons learned from the Yellowhead project and lessons about reporting under *ISO Rule 9.1* (Compliance Monitoring).

Appendix A: About The TFCMC

Origin And Composition Of The Transmission Facilities Cost Monitoring Committee

The Government of Alberta created the Transmission Facilities Cost Monitoring Committee (TFCMC) on July 31, 2010 through a Ministerial Order issued by the Honourable Ronald Liepert, then Minister of Energy, in order to make sure Albertans have the benefit of increased transparency on the cost of transmission projects.

According to the Ministerial Order, number 64/2010, the TFCMC can consist of up to 13 individuals as follows:

- the **Alberta Association of Municipal Districts and Counties** may appoint one member;
- the **Alberta Chambers of Commerce** may appoint one member;
- the **Alberta Direct Connect Consumers Association** may appoint one member;
- the **Alberta Federation of Rural Electrification Associations** may appoint one member;
- the **Alberta Urban Municipalities Association** may appoint one member;
- the **Consumers' Coalition of Alberta** may appoint one member;
- the **Canadian Federation of Independent Business** may appoint one member;
- the **Industrial Power Consumers Association of Alberta** may appoint one member;
- the **Independent Power Producers Society of Alberta** may appoint one member;
- the Minister may also appoint up to two ***independent members*** with technical, regulatory, transmission facility development or other experience that, in the opinion of the Minister, will benefit the Committee;
- the **Independent System Operator** ("Alberta Electric System Operator") shall appoint one member, and
- the **Office of the Utilities Consumer Advocate** shall appoint one member.

The TFCMC's Mandate

The TFCMC's mandate is to review records that relate to the cost, scope, schedule and variances of Alberta transmission facility projects forecast to cost in excess of $100 million. This may include more than one transmission facility, if it is a part of a contiguous transmission facility project. The Alberta Electric System Operator (AESO), a not-for-profit entity that is responsible for the safe, reliable and economic planning and operation of Alberta's transmission system (also known as the Alberta Interconnected Electric System) determines which transmission facilities are part of a transmission facility project.

In a letter dated January 12, 2011, the Minister of Energy clarified that the starting point for the TFCMC when reviewing cost variances is the estimate in place when a project is approved by an Order in Council for Critical Transmission Infrastructure (CTI) projects, or, the estimate in place when the Needs Identification Document (NID) is approved by the Alberta Utilities Commission (AUC). The TFCMC, therefore, does not review any of the projects from an initial prudence, need, technology choice or staging perspective.

The TFCMC cannot delay or slow the development of transmission facility projects.

In late June 2011, the Minister of Energy provided his support of a request from the TFCMC to explore and develop innovative approaches to cost recovery for new transmission facilities in Alberta. The TFCMC was asked to undertake this initiative on a priority basis, together with the Transmission Facility Owners (TFOs), the AESO and Alberta Energy. The findings of this initiative were submitted in April 2012 to the Assistant Deputy Minister, Electricity, Alternative Energy and Carbon Capture and Storage, for consideration and action.

Since the TFCMC began its work, the Committee has monitored a total of 17 different transmission projects, which includes one now completed project, the Southern Alberta Transmission Development (SATD). During the period covered by this report, the TFCMC monitored 16 projects.

The TFCMC's Members

The 11 organizations and two independents named in the Ministerial Order forming the TFCMC represent a cross-section of industry, consumer and business groups with ties to Alberta's electricity sector.

Organizations and independent members are listed alphabetically:

Alberta Association of Municipal Districts and Counties (AAMDC)

The AAMDC advocates on behalf of the province's 69 municipal districts and counties. The association assists its members in achieving strong, effective local government. The AAMDC representative on the TFCMC is **Dwight Oliver, a Past Director for AAMDC District 2**.

Alberta Chambers of Commerce (ACC)

The ACC is a federation of 126 Chambers of Commerce, which in turn represents more than 23,000 businesses. The ACC ensures its members' business interests are improved through the development and advocacy of policy to the provincial and federal governments. The ACC representative on the TFCMC is **Ken Kobly, ACC President & CEO**.

Alberta Direct Connect Consumers Association (ADC)

The ADC represents nine large industrial consumers who have facilities directly connected to the transmission system. The ADC members represent the key sectors of forestry, chemical and cement manufacturing. The aggregate electricity demand of the membership represents about 7% of the Alberta load. The ADC representative on the TFCMC is **Colette Chekerda, ADC Executive Director**.

Alberta Electric System Operator (AESO)

The AESO is a not-for-profit entity, is independent of any industry affiliations, and owns no transmission or market assets. It is responsible for the safe, reliable and economic planning and operation of the Alberta Interconnected Electric System. The AESO representative on the TFCMC is **Jerry Mossing, AESO's Vice President, Transmission Planning and Performance**.

Alberta Federation of Rural Electrification Associations (AFREA)

The AFREA is a not-for-profit cooperative association representing member Rural Electrification Associations (REAs) who provide rural power services throughout Alberta. It is committed to promoting the economic welfare and value of its cooperative members by providing strong representation to government and industry stakeholders with one voice. The AFREA representative on the TFCMC is **Dan Astner, AFREA 2nd Vice President**.

Alberta Urban Municipalities Association (AUMA)

The AUMA represents Alberta's 277 urban municipalities including cities, towns, villages, summer villages, and specialized municipalities. AUMA represents and advocates the interests of its members to the provincial and federal governments. The AUMA representative on the TFCMC is **Andre Chabot, Director, Cities Over 500,000**.

Canadian Federation of Independent Business (CFIB)

The CFIB is an association representing small- and medium-sized businesses across Canada that takes direction from its more than 109,000 members, providing independent businesses a voice at all levels of government. The CFIB representative on the TFCMC is **Richard Truscott, the CFIB's Director of Provincial Affairs, Alberta and Northwest Territories**.

Consumers' Coalition of Alberta (CCA)

The CCA is comprised of the Consumers' Association of Canada (Alberta Division) and the Alberta Council on Aging. The CCA, a coalition of two public interest groups, participates as a collective in public utility hearings to ensure rates, tolls and charges for residential customers are just and reasonable. The CCA representative on the TFCMC is **Azad Merani, CCA Consultant.**

Independent Power Producers Society of Alberta (IPPSA).

The IPPSA represents Alberta's power producers. IPPSA is a forum for dialogue among Alberta's power producers and a proponent of competition in Alberta's electricity market. The IPPSA representative on the TFCMC is **Evan Bahry, IPPSA's Executive Director**.

Industrial Power Consumers Association of Alberta (IPCAA)

The IPCAA is an organization representing large industrial customers, including such key sectors as oil & gas, forest products, petrochemicals and steel. Its mission is to take a leadership role in achieving a fair, open and efficient marketplace for electricity sales and service in Alberta. The IPCAA representative on the TFCMC is **Sheldon Fulton**.

Office of the Utilities Consumer Advocate (UCA)

The UCA is the voice of small consumers in Alberta's electricity and gas markets. The UCA advocates on behalf of Alberta's low-volume or smaller users of electricity and natural gas, those being residential, small business and farm utilities consumers, and helps them to make informed choices. As well, the UCA represents and protects their interests by participating in utility hearings and inquiries. The UCA representative on the TFCMC is **Wayne Taylor**.

TFCMC Independent Members:

Allen Snyder, of Winnipeg, brings a background and a wealth of knowledge in the electricity sector to the TFCMC. He held several key executive positions with Manitoba Hydro including Vice President of Transmission & Distribution, Power Supply and Corporate Services over the past 20 years. He also established a very successful Manitoba Hydro International with sales of software and services to more than 60 countries worldwide. Currently, he is Vice President of Energy Services for Wood West & Associates.

Henry Yip is a senior business executive with more than 30 years of broad business experience in Canada and the USA. He has held senior executive positions in large corporations and entrepreneurial business enterprises, and has advised governments in the area of city planning, strategy development, technology commercialization, international business collaboration and grant application approval. His current business interests include Executive Chair at Nirix Technology, and President of C'andcee Development. He is a past Chair of the Board at Edmonton Economic Development Corporation.

The Operations Of The TFCMC

The TFCMC meets monthly, alternating between the cities of Calgary and Edmonton. The primary purpose of the meetings is to review reports provided by the AESO on the cost status of transmission projects that are within the Committee's purview. The first meeting took place in September 2010.

The TFCMC reviews the reasons for cost variances of all these projects. When appropriate, it retains external experts to prepare Information Requests (IRs) to the AESO and the Transmission Facility Owners (TFOs) for further illumination on the reasons for the variances.

Each calendar year, the TFCMC is required to provide at least two reports to the member organizations represented on the committee as well as at least one report to the Ministers of Energy and Service Alberta. The reports summarize the records it reviews and the status of the transmission facility projects.

The TFCMC strives for consensus in its decision-making process but a simple majority of those present at a meeting is the minimum threshold for agreement.

Independent member Henry Yip chairs the TFCMC. The TFCMC secretary is Lorena Munteanu, engaged through the Office of the Utilities Consumers Advocate (UCA).

The TFCMC will also form subcommittees from time to time to facilitate the workings of the Committee. There were two active subcommittees in operation during the period of this report:

- A standing subcommittee to monitor and approve expenditures incurred by the members of the TFCMC during the course of discharging its mandate. Sheldon Fulton chairs this subcommittee.
- The Information Request (IR) subcommittee. This group develops appropriate questions for the TFOs in order to get clarifications on information previously provided by the TFOs on the cost status of the various transmission projects. This subcommittee is supported by external expert advisors when required. Allen Snyder chairs this subcommittee.

Appendix B: The Transmission Projects At A Glance

1. **ALBERTA INDUSTRIAL HEARTLAND BULK TRANSMISSION DEVELOPMENT (HBTD);** PROJECT 629 – Construction of a double-circuit 500 kV transmission line, which will connect the Heartland region (northeast of Fort Saskatchewan) to existing 500 kV transmission facilities in the Edmonton area.

   THE PROJECT: The Alberta Industrial Heartland Bulk Transmission Development calls for the construction of a double-circuit 500 kV transmission line, which will connect the Heartland region (northeast of Fort Saskatchewan) to existing 500 kV transmission facilities on the south side of Edmonton. This upgrade is to respond to the growing demand for power in this region. The Heartland project will form the foundation of electricity supply into northeast Alberta and will support oil sands development, local demand in the Heartland area and strengthen the entire provincial network.

   THE COMPONENTS: A 500 kV AC double-circuit transmission line connecting the 500 kV system on the south side of Edmonton to the new Heartland 12S Substation (the 500 kV Line Project); a 240 kV/500 kV Heartland 12S Substation, located approximately 15 kilometres northeast of Edmonton in the Gibbons-Redwater region (the Heartland 12S Substation Project), and a 240 kV double-circuit transmission line connecting the existing 240 kV system in the area to the new Heartland 12S Substation (the 240 kV Line Project). The Industrial Heartland region includes parts of Sturgeon, Strathcona and Lamont counties.

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
500 kV 1206L/1212L	Sixty-five kilometres of 500 kV double-circuit line from Ellerslie to Heartland substation	September 30, 2013
Heartland 12S Ellerslie 89S and 1054L/1061L	Heartland 500 kV sub and 22 kilometres of 240 kV lines to tie in the existing system	September 30, 2013

   THE TRANSMISSION FACILITY OWNER(S): AltaLink Management Ltd. and EPCOR Distribution & Transmission Inc.

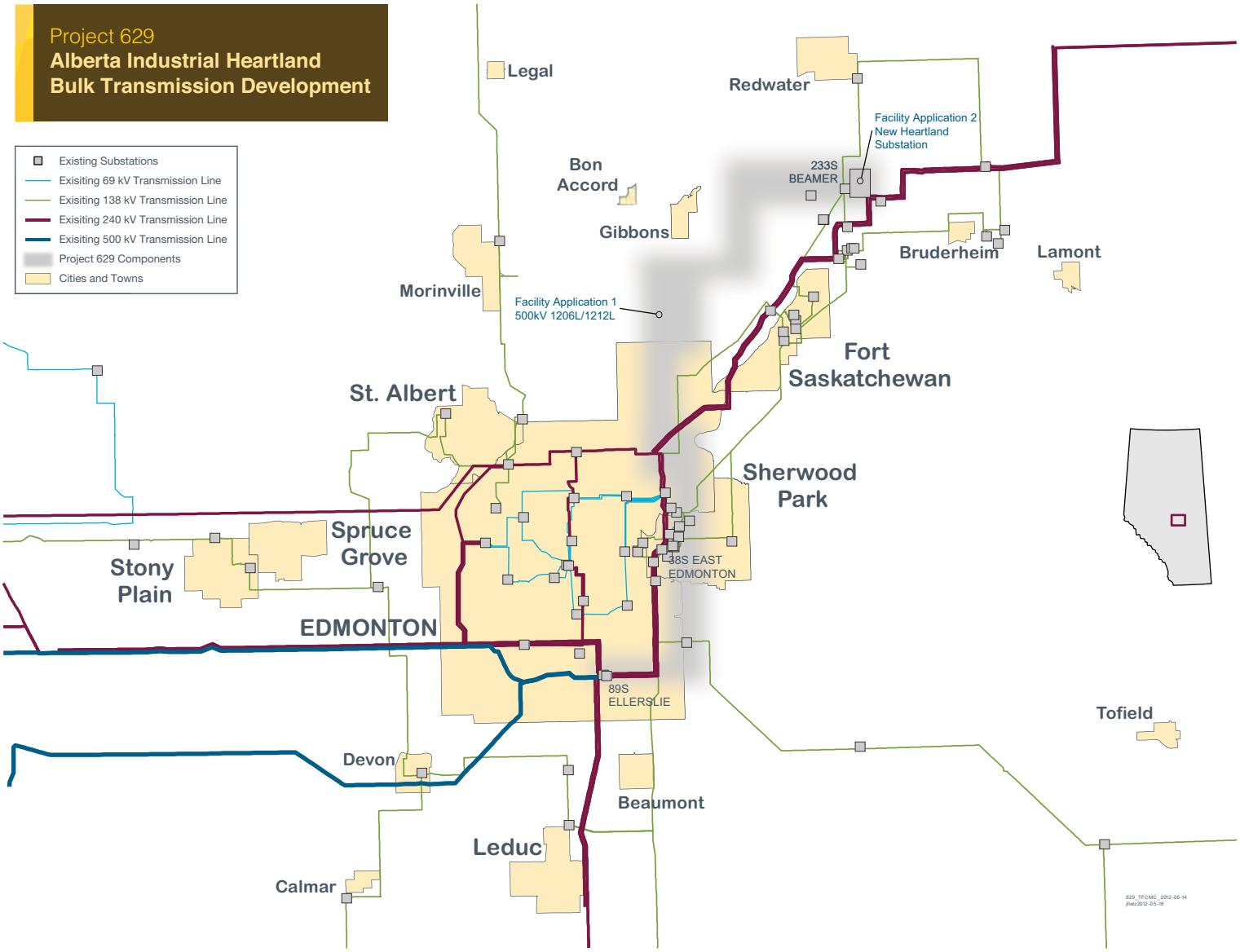
   PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Alberta Industrial Heartland Bulk Transmission Development	$537 Million (2011$ without escalation)	$589 Million (ISD$ with escalation)[11]

   CURRENT STATUS: The Alberta Utilities Commission (AUC) approved the Heartland Transmission Project in November 2011. The approved east route for the line skirts the city of Edmonton to the south and east and travels through an existing Transportation Utility Corridor (TUC) for roughly half the line's length.

   An allowance for funds used during construction (AFUDC) Reduction Change Proposal was approved in November 2012, resulting in a reduction of approximately $33 million from the estimated cost. The project is currently under construction.

11 As per the information provided in the Cost Committee Monthly Summary in the December 2012 TFCMC meeting, which is based upon the TFO's October 2012 Monthly Project Progress Report.


Project 629
Alberta Industrial Heartland
Bulk Transmission Development
Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Exisiting 500 kV Transmission Line
Project 629 Components
Cities and Towns
Legal
Redwater
Facility Application 2
New Heartland
Substation
233S
BEAMER
Bon
Accord
Gibbons
Bruderheim
Lamont
Morinville
Facility Application 1
500kV 1206L/1212L
Fort
Saskatchewan
St. Albert
Sherwood
Park
Spruce
Grove
Stony
Plain
38S EAST
EDMONTON
EDMONTON
89S
ELLERSLIE
Tofield
Devon
Beaumont
Leduc
Calmar

2. **CENTRAL EAST AREA TRANSMISSION DEVELOPMENT (CETD);** PROJECT 811 – Transmission development in Wainwright, Lloydminster, Provost, Vegreville and Cold Lake.

THE PROJECT: The Central East project serves the dual purpose of meeting the growing demand for electricity from oil sands development and pipelines, and will enable the connection of more than 500 MW of proposed gas-fired generation and wind farms in the eastern region of Central Alberta. Aging infrastructure, overloads and low voltages in the large area east of Edmonton from Cold Lake in the Northeast region to Hardisty necessitate the substantial rebuild of the 138 kV and 144 kV systems, and the decommissioning of aging 69 kV and 72 kV lines.

THE COMPONENTS: There are two stages of transmission development for the project.

The major components for Stage 1 of the project are: a new 144/25 kV Watt Lake substation; the conversation of three existing 72/25 kV substations to 144/25 kV; a new 240 kV switching station in the Cold Lake Area that will be energized at 144 kV initially; a new double-circuit 144 kV line from the existing Mahihkan 837S to the new switching station; a new 240 kV double-circuit line (one side strung) from the new switching station to the existing Bonnyville 700S and initially energized at 144 kV; a new single-circuit line from the existing Wainwright 51S to the existing Edgerton 899S; a new 144 kV capacitor bank at Vermilion 710S; the addition of a 138/72 kV transformer at the existing Wainwright 51S; rebuild six existing 138 kV or 144 kV lines to increase capacity, and restore ratings of the existing 144 kV lines by mitigating line clearances and discontinuing the use of existing 72 kV equipment at existing substations or lines.

The major components for Stage 2 of the project are: rebuild one existing 144 kV line to increase capacity and a new 240 kV double-circuit line (one side strung) from the new switching station to the existing Marguerite Lake 826S.

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Cold Lake Area Reinforcements (Except Bonnyville to Bourque)	New 144 kV switching station (Bourque 970S), new 144 kV double-circuit line from existing Mahihkan 837S to new 144 kV switching station and rebuild existing 144 kV lines (7L87, 7L74 and 7L83)	October 1, 2013
Cold Lake Area Reinforcements – Bonnyville	New 240 kV double-circuit line (one side strung) from new 144 kV switching station to existing Bonnyville 700S and initially energized at 144 kV	July 1, 2014
St. Paul Area Upgrades – Watt Lake, 7LA92	New 144/25 kV Watt Lake and new 144 kV line from Watt Lake to existing 7L92	July 1, 2013
St. Paul Area Upgrades – St. Paul 707S, Whitby Lake 819S & 7L139/7L70	Rebuild St. Paul 707S from 72/25 kV to 144/25 kV substation, new 144 kV double-circuit line from St. Paul 707S to existing 7L70 creating an in and out configuration	April 1, 2014

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Vermilion 710S Substation Upgrade	Addition of 144 kV 25 VAr capacitor bank; addition of a new 144/25 kV transformer; relocation of existing 144/72/25 kV transformer to Heisler 764S; discontinue use of existing 72 kV equipment at Vermilion 710S and discontinue use of 6L06 (Kitscoty 705S to Vermilion 710S)	May 1, 2013
Heisler Area Upgrades	Convert Heisler 764S from 72 kV to 144 kV; addition of 144/72/25 kV transformer from Vermilion 710S; new 144 kV single-circuit line from Heisler 764S to existing 7L701 and discontinue use of existing 6L05	April 28, 2013
Kitscoty Area Upgrades	Convert Kitscoty 705S from 72 kV to 144 kV; addition of 144/72/25 kV transformer from Heisler 764S, new 144 kV double-circuit line from Kitscoty 705S to existing 7L14	December 1, 2013
7L749 Replacement	Rebuild existing 749L/7L749 from Metiskow 648S to Lloydminster 716S	March 1, 2015
Line Clearance Mitigations	Restore ratings of existing 144 kV lines by mitigating line clearances	December 31, 2012 – April 2013
Provost & Wainwright Area Upgrades	New single-circuit line from existing Wainwright 51S to existing Edgerton 899S, addition of a 138/72 kV transformer at existing Wainwright 51S; rebuild three existing 138 kV lines to increase capacity	March 1, 2015

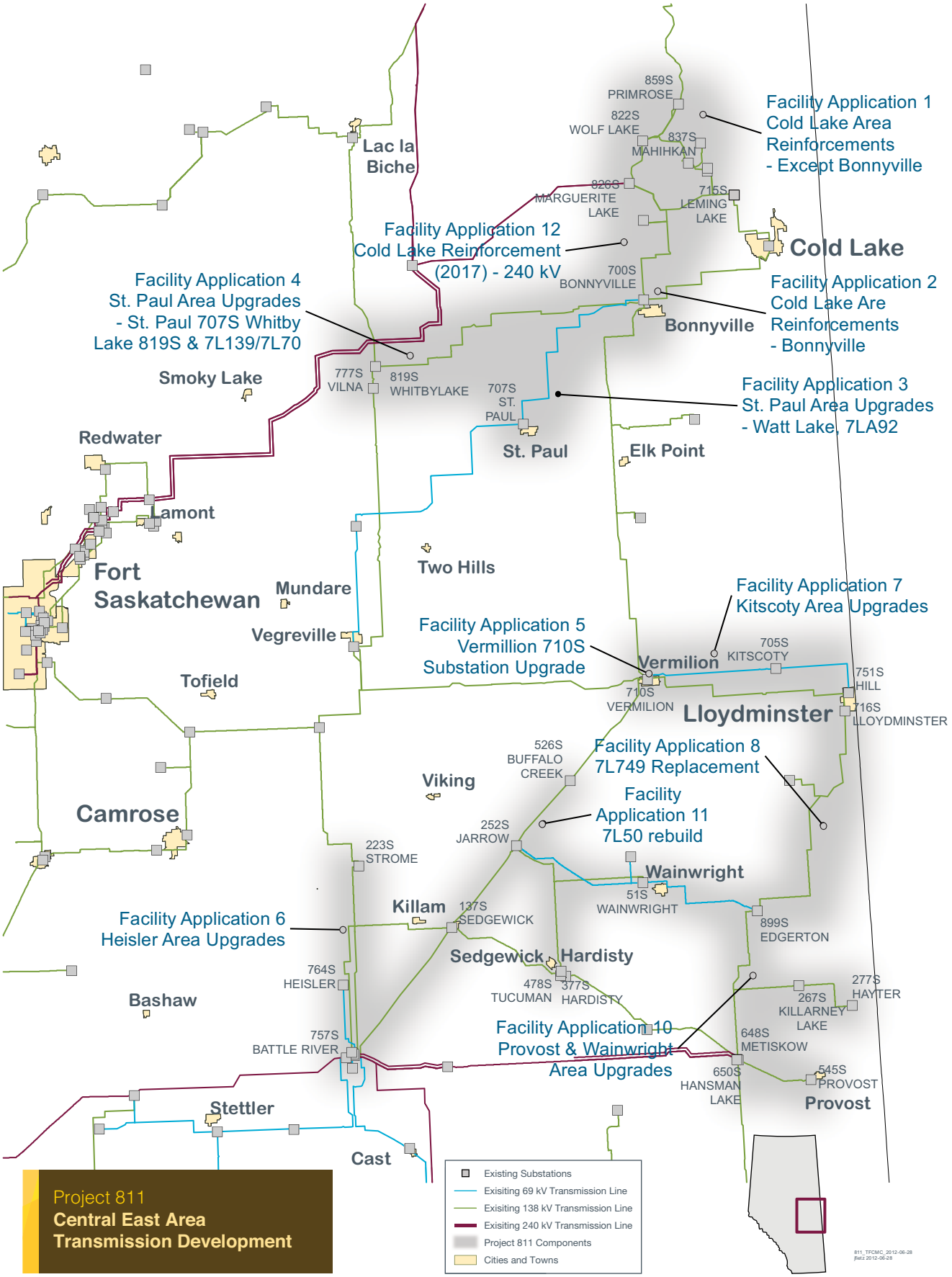
THE TRANSMISSION FACILITY OWNER(S): AltaLink Management Ltd. and ATCO Electric Ltd.

PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Central East Area Transmission Development	**$352 Million** (2011$ without escalation)	**$515 Million** (ISD$ with escalation for Stage 1)[12]

CURRENT STATUS: The AUC approved the Central East Transmission Development Needs Identification Document (NID) in February 2011. For Stage 1 of the Central East Transmission Development, ATCO has received AUC approval for four Facility Applications (FAs) – 7L701 Clearance mitigation, Heisler 764S, Whitby Lake and Vermilion 710S – and is moving through the construction phase. As well four FAs, Watt Lake, 7L87 rebuild, Bourque substation and associated lines, and Bonnyville substation and Bonnyville to Bourque, have been filed with the AUC, and it is expected that ATCO will now be filing the remaining Facility Applications in 2013. Further, the Alberta Electric System Operator (AESO) has identified the need to advance the 7L50 upgrade as a result of a generation connection project that will affect this line.

12 As per the information provided in the Cost Committee Monthly Summary in the December 2012 TFCMC meeting, which is based upon the TFO's October 2012 Monthly Project Progress Report. The $515 million is broken down as follows:
- $277 Million PPS estimate for the ATCO Stage 1
- $238 Million based on the NID estimate of AML Stage 1 and ATCO Stage 2.


859S
PRIMROSE
822S
WOLF LAKE
837S
MAHIHKAN
826S
MARGUERITE
LAKE
715S
LEMING
LAKE
Facility Application 1
Cold Lake Area
Reinforcements
- Except Bonnyville
Lac la
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Facility Application 12
Cold Lake Reinforcement
(2017) - 240 kV
Cold Lake
700S
BONNYVILLE
Facility Application 4
St. Paul Area Upgrades
- St. Paul 707S Whitby
Lake 819S & 7L139/7L70
Facility Application 2
Cold Lake Are
Reinforcements
- Bonnyville
Bonnyville
Smoky Lake
777S
VILNA
819S
WHITBYLAKE
707S
ST.
PAUL
Facility Application 3
St. Paul Area Upgrades
- Watt Lake, 7LA92
Redwater
St. Paul
Elk Point
Lamont
Fort
Saskatchewan
Mundare
Two Hills
Facility Application 7
Kitscoty Area Upgrades
Vegreville
Facility Application 5
Vermillion 710S
Substation Upgrade
705S
KITSCOTY
Vermilion
751S
HILL
Tofield
710S
VERMILION
Lloydminster
716S
LLOYDMINSTER
526S
BUFFALO
CREEK
Facility Application 8
7L749 Replacement
Viking
Facility
Application 11
7L50 rebuild
Camrose
252S
JARROW
223S
STROME
Wainwright
51S
WAINWRIGHT
Killam
137S
SEDGEWICK
Facility Application 6
Heisler Area Upgrades
899S
EDGERTON
Sedgewick
Hardisty
764S
HEISLER
478S
TUCUMAN
377S
HARDISTY
277S
HAYTER
Bashaw
267S
KILLARNEY
LAKE
Facility Application 10
Provost & Wainwright
Area Upgrades
648S
METISKOW
757S
BATTLE RIVER
650S
HANSMAN
LAKE
545S
PROVOST
Provost
Stettler
Cast
Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Project 811 Components
Cities and Towns
Project 811
Central East Area
Transmission Development

3. **CHRISTINA LAKE AREA TRANSMISSION DEVELOPMENT (CHL);** PROJECT 1101 – Reinforcing transmission facilities for oil sands developments and enhanced reliability to existing oil sands operations.

THE PROJECT[13]: Strong oil sands development, including Steam Assisted Gravity Drainage (SAGD) and pump station facilities, in the Christina Lake area, located approximately 140 km south of the City of Fort McMurray and 100 km to the northeast of Lac La Biche, is driving this development. This project would ensure the area's transmission network is reinforced to support current load and to ensure adequate capacity to connect customers in the near-and-long term. The Christina Lake plan will reinforce the existing 138 kV network in the southern part of the area through the development of the new CHL2 240/138 kV substation, and will reinforce the 240 kV network in the north of the Christina Lake area by closing the loop through the existing Heart Lake A898S substation.

THE COMPONENTS: The AESO has proposed a transmission development plan for the area that includes developing a 240 kV looped transmission system, including three new 240 kV substations; approximately 100 km to 150 km of new 240 kV transmission line, and modifications and expansion of existing transmission substations in the area. The project consists of a new 240 kV switching station and a new 240/138 kV substation.

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Black Spruce substation and 240 kV lines	Black Spruce substation and interconnecting 240 kV lines	June 2013
Pike substation and 240 kV lines	Pike substation and interconnecting 240 kV lines	June 2014
Pike to Ipiatik to Heart Lake and 240 kV lines	240 kV line from Ells River to Birchwood Creek substation	June 2015
Heart Lake expansion	Expand Heart Lake substation for the termination of 9L930 in/out and the new 240 kV line to Ipiatik	September 2015[14]

THE TRANSMISSION FACILITY OWNER(S): AltaLink Management Ltd. and ATCO Electric Ltd.

PROJECT COST:

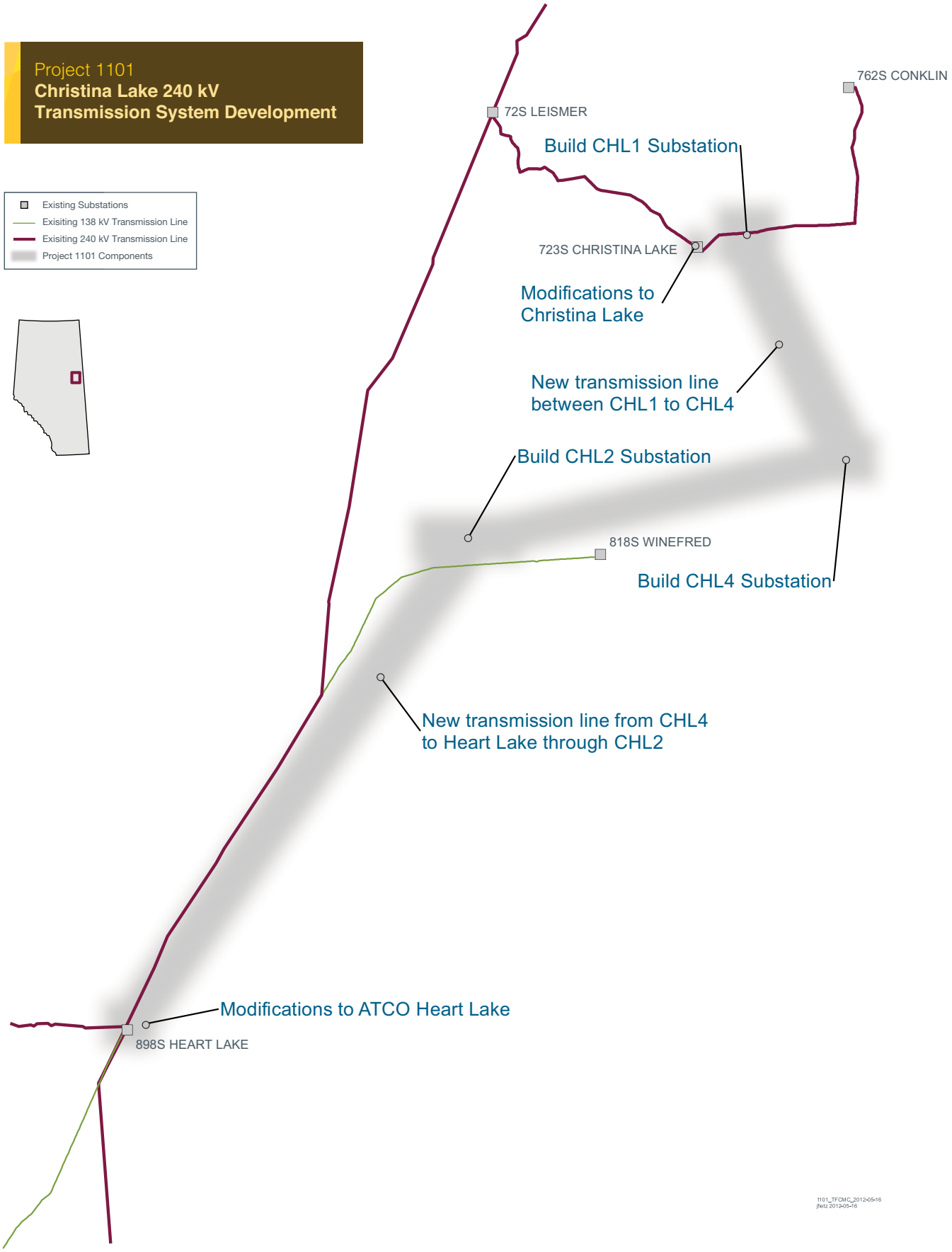
TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Christina Lake Area Transmission Development	**$358 Million** (2011$ without escalation)	**$407 Million** (ISD$ with escalation)[15]

CURRENT STATUS: The NID was approved by the AUC on April 24, 2012. The Black Spruce FA was filed on July 23, 2012. Permit and License (P&L) was received December 24, 2012. AltaLink and ATCO have begun siting and routing work, including preparing Proposal to Provide Service (PPS) estimates for the remaining FAs.

13 The Christina Lake Area 240 kV Transmission Development and the Heart Lake expansion project identified in the AESO's Long-term Transmission Plan (filed June 2012) were combined into one Needs Identification Document.

14 ATCO has indicated the Heart Lake expansion will be completed in September 2015.

15 The project cost is based upon the Needs Identification Document (NID) estimates (±30%) used in the NID dated October 2011.


Project 1101
Christina Lake 240 kV
Transmission System Development
Existing Substations
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Project 1101 Components
762S CONKLIN
72S LEISMER
Build CHL1 Substation
723S CHRISTINA LAKE
Modifications to
Christina Lake
New transmission line
between CHL1 to CHL4
Build CHL2 Substation
818S WINEFRED
Build CHL4 Substation
New transmission line from CHL4
to Heart Lake through CHL2
Modifications to ATCO Heart Lake
898S HEART LAKE
1101_TFCMC_2012-05-16
jfeitz 2012-05-16

4. ***NEW* EAST CALGARY 240 KV AND 138 KV TRANSMISSION SYSTEM UPGRADES AND THE SHEPARD ENERGY CENTRE CONNECTION (ECTP);** PROJECT 719 – To serve growing demand for electricity in the Calgary and High River planning areas.

THE PROJECT: The East Calgary Transmission Project and the ENMAX Shepard Energy Centre Connection is required to serve growing demand for electricity in the Calgary and High River planning areas, enable future generation facilities to reliably connect to the system, and maintain system reliability.

THE COMPONENTS: Modifications to existing East Calgary 5S and ENMAX No.2 substations (including the addition of one 240/138 kV – 240/320/400 MVA transformer); new 138 kV transmission line between ENMAX No. 23 and ENMAX No. 2; new 138 kV transmission line between Janet 74S and ENMAX No. 23; modifications to the existing 240 kV double-circuit towers (to maintain the connection between Janet 74S and East Calgary 5S); removal of line terminations at East Calgary 5S and Janet 74S; new 240 kV double-circuit 240 kV transmission line (985L/1003L) from Janet 74S to ENMAX No. 25; addition of a 240 kV switching station (ENMAX No. 25) for connection to the transmission system and Shepard Energy Centre; addition of a second 240/138 kV – 240/320/400 MVA transformer at East Calgary 5S.

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
East Calgary 240 kV and 138 kV transmission system upgrades and Shepard Energy Centre Connection (ENMAX FA)	Modifications to existing ENMAX No. 2 and No. 23 substations, addition of new ENMAX No. 25 substation	August 2013
East Calgary 240 kV and 138 kV transmission system upgrades and Shepard Energy Centre Connection (AltaLink FA)	Rebuild East Calgary 5S substation; upgrade AltaLink owned infrastructure from structure 26 to Janet 74S; build D/C 240 kV transmission line between Janet 74S and ENMAX No. 25 substations, replace existing transformer at East Calgary 5S	September 2013

THE TRANSMISSION FACILITY OWNER(S): ENMAX Power Corp. and AltaLink Management Ltd.

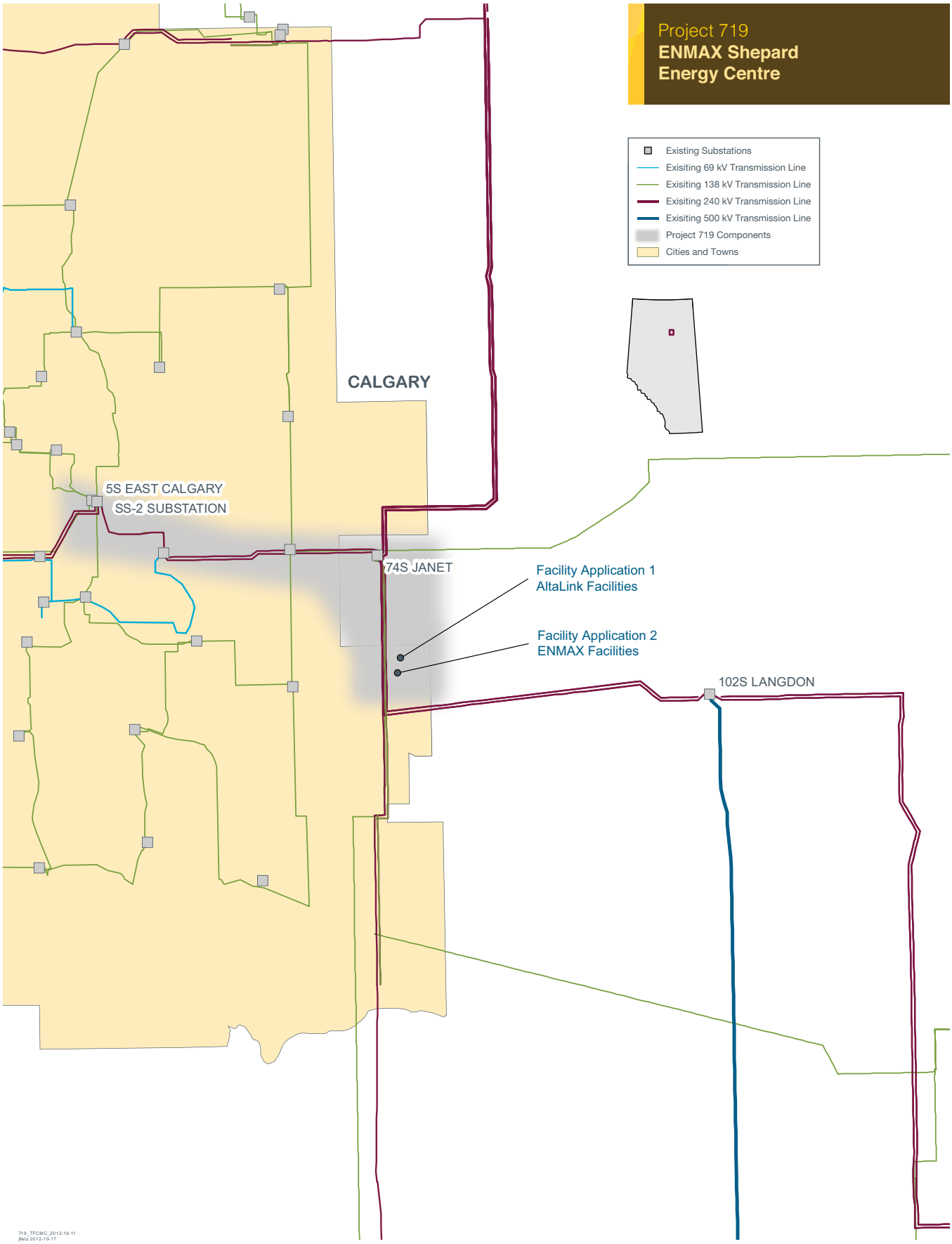
PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
East Calgary 240 kV and 138 kV Transmission System Upgrade and Shepard Energy Centre Connection	**$711 Million*** (2011$ without escalation)[16] *entire FATD plan	**$102 Million*** (includes escalation and AFUDC)[17] *East Calgary Transmission Project and the ENMAX Shepard Energy Centre Connection portion

CURRENT STATUS: The AESO filed the NID with the AUC on May 10, 2011. Subsequently, ENMAX and AltaLink filed FAs with the AUC on June 10, 2011 and June 27, 2011, respectively. The AUC approved the development and issued P&L on November 1, 2012.

16 The AESO's Long-term Transmission Plan identified the need for the Foothills Area Transmission Development. The East Calgary 240 kV and 138 kV transmission system upgrades is one of four components of the overall Foothills Area Transmission Development. The four components of the Foothills Area Transmission Development are:
a. East Calgary 240 kV and 138 kV transmission system upgrades and Shepard Energy Centre Connection;
b. Foothills Area Transmission Development – East Region;
c. Third 138 kV Circuit from ENMAX No. 65 to existing ENMAX No. 54 and ENMAX No. 41; and
d. Foothills Area Transmission Development – West Region.

17 This is the estimated cost for the system related components of the East Calgary 240 kV and 138 kV transmission system upgrades and Shepard Energy Centre Connection based upon the information provided in the Cost Committee Monthly Summary of the TFCMC's December 2012 meeting, which is based upon the TFO's October 2012 Monthly Project Progress Report.


Project 719
ENMAX Shepard
Energy Centre
Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Exisiting 500 kV Transmission Line
Project 719 Components
Cities and Towns
CALGARY
5S EAST CALGARY
SS-2 SUBSTATION
74S JANET
Facility Application 1
AltaLink Facilities
Facility Application 2
ENMAX Facilities
102S LANGDON
719_TFCMC_2012-10-11
jfietz 2012-10-17

5. **EDMONTON REGION 240 KV LINE UPGRADES (ERLU);** PROJECT 786 – Upgrading 240 kV lines in the Edmonton area; add one 240 kV phase shifter at Dover substation.

THE PROJECT: More than 4000 MW of base load generation that serves as the main source of electricity for the majority of the province is situated near Wabamun Lake in the Edmonton region. This generation supports central and south Alberta loads, northwest region loads, Edmonton area loads and major industrial loads located in the Fort Saskatchewan area. There are major thermal overloads of transmission facilities throughout the Edmonton region. The 138 kV transmission paths from Wabamun to North Calder, East Edmonton to Nisku, and from East Edmonton to the Fort Saskatchewan area are weak during peak load conditions and voltage violations occur in those two areas due to weak system support.

THE COMPONENTS: The 240 kV transmission system developments in the area include a rebuild of some sections of the existing transmission line, an increase in capacity of the lines by replacing conductors, the reconfiguration of the system, building new line, and the installation of a special protection scheme for multiple contingencies to ensure system reliability in the area. Also, a 240 kV phase shifter transformer will be installed at Livock 939S in the Fort McMurray area.

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
AML Rebuild 240 kV 904L (1043L)	Rebuild approximately 50 km of the existing 240 kV line 904L between Jack Fish Lake in west of Edmonton and Petrolia 816S; salvage the existing 240 kV structures, conductor and hardware; build a new section of approximately 12 km of 240 kV line utilizing double-circuit structures with one side strung to connect Keephills 320P substation to the rebuild of 904L – renumbered to 1043L. (Keephills 320P to Petrolia 816S)	March 2013
AML 902L Restring & 909L Retermination	Restring eight km of 902L at each line end, Wabamun 19S and Sundance 310P substations	March 2013
	Retermination of the existing 240 kV 909L at Sundance 310P (Ellerslie 89S to Sundance 310P)	
AML 908L, 909L Restring	Restring four km of 908L and 909L outside Sundance 310P substation (first four km of the lines); 908L is renumbered to 1045L	March 2011
EPCOR Jasper, Petrolia	Upgrade bus work and protections	June 2011
EPCOR 1044EL, 1045EL	Restring approximately 24 km of existing 904L at Jasper 805S – in/out line section; Renumber EPCOR's portion of the line to 1044EL (going to Petrolia 816S) and 1045EL (going to Sundance 310P)	October 2011
ATCO Phase Shifter	Add 600 MVA phase shifting transformer at Livock 939S	May 2013
TransAlta 902L, 1043L	Delegate the work to AML	March 2013

THE TRANSMISSION FACILITY OWNER(S): AltaLink Management Ltd. and EPCOR Distribution & Transmission Inc., ATCO Electric Ltd. and TransAlta Corp.

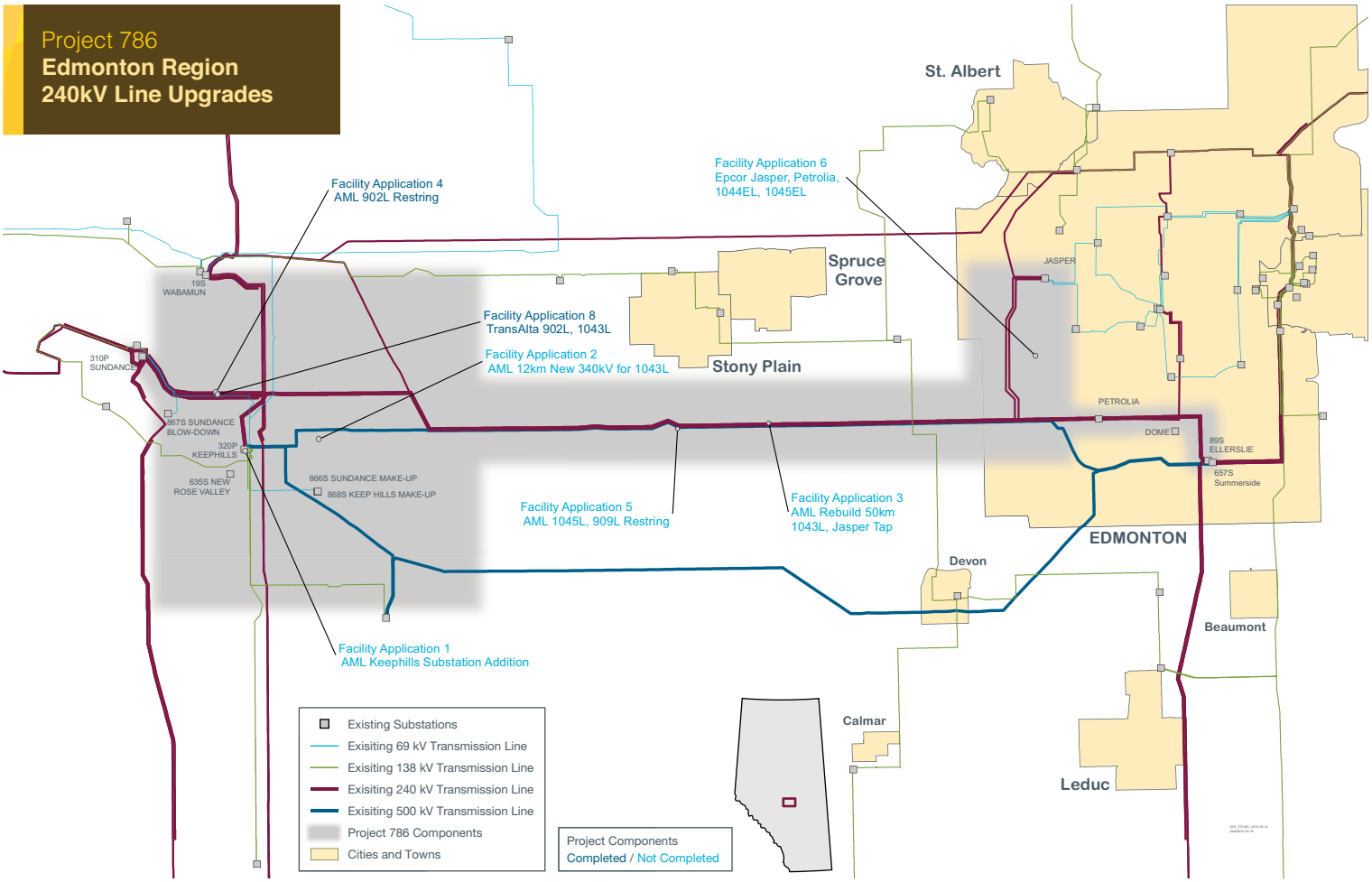
PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Edmonton Region 240 kV Line Upgrades	**$153 Million** (2011$ without escalation)	**$169 Million** (ISD$ with escalation)[18]

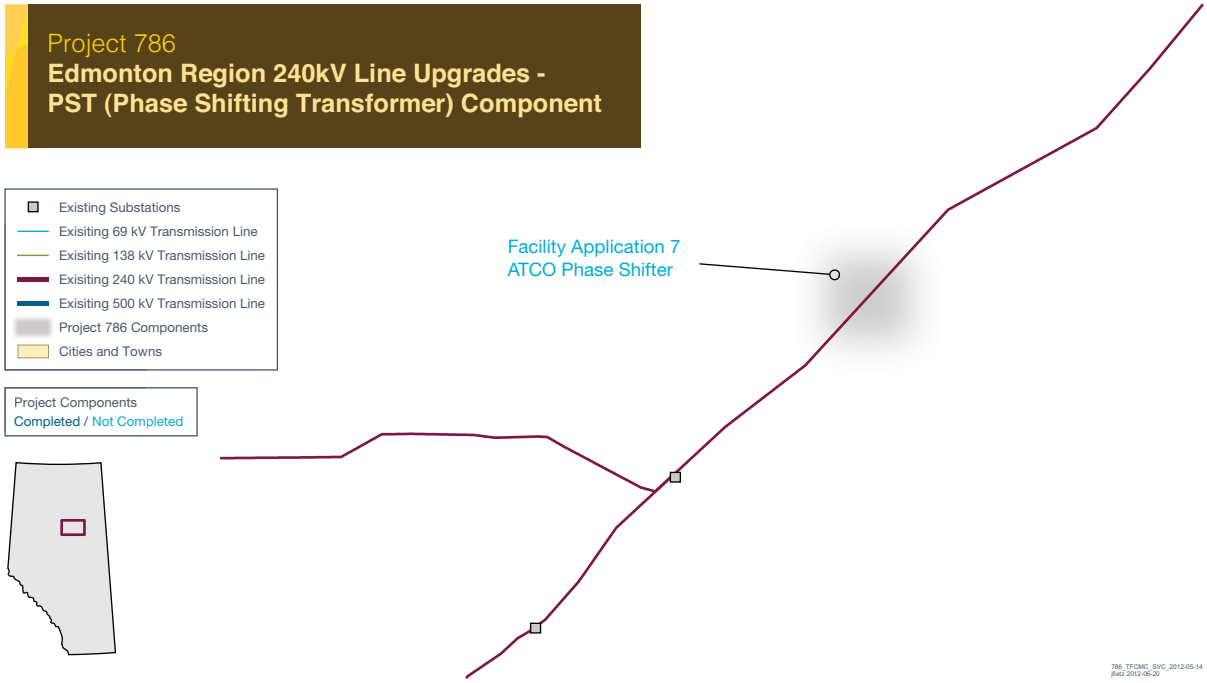
CURRENT STATUS: AltaLink received P&L for the 904L rebuild on September 30, 2011 and plans to complete the work in early 2013. The FA for the 902L restring was submitted to the AUC in early August 2011. A public AUC hearing was held in Spruce Grove in April 2012. Regulatory delays have contributed to delaying the target in-service date for the entire project to March 2013.

Construction required to complete a small portion of the 1043L transmission line has been delayed due to land access issues. An in-service date for the 1043L transmission line cannot be determined at this time, but stakeholders will be advised of next steps once new information is available. The delivery of a phase shifter has also been delayed, resulting in a delay in the ISD from March 2013 to May 2013.

18 As per the information provided in the Cost Committee Monthly Summary in the December 2012 TFCMC meeting, which is based upon the TFO's October 2012 Monthly Project Progress Report.


Project 786
Edmonton Region
240kV Line Upgrades
St. Albert
Facility Application 6
Epcor Jasper, Petrolia,
1044EL, 1045EL
Facility Application 4
AML 902L Restring
Spruce
Grove
JASPER
19S
WABAMUN
Facility Application 8
TransAlta 902L, 1043L
Facility Application 2
AML 12km New 340kV for 1043L
Stony Plain
310P
SUNDANCE
PETROLIA
867S SUNDANCE
BLOW-DOWN
DOME
320P
KEEPHILLS
89S
ELLERSLIE
657S
Summerside
635S NEW
ROSE VALLEY
866S SUNDANCE MAKE-UP
868S KEEP HILLS MAKE-UP
Facility Application 5
AML 1045L, 909L Restring
Facility Application 3
AML Rebuild 50km
1043L, Jasper Tap
EDMONTON
Devon
Beaumont
Facility Application 1
AML Keephills Substation Addition
Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Exisiting 500 kV Transmission Line
Project 786 Components
Cities and Towns
Project Components
Completed / Not Completed
Calmar
Leduc

Project 786
Edmonton Region 240kV Line Upgrades - PST (Phase Shifting Transformer) Component



6. **ENMAX NO. 65 SUBSTATION (ESCS);** PROJECT 922 – New 240 kV substation in south Calgary and 138 kV developments due to overloading in south Calgary.

THE PROJECT: The AESO has recommended transmission reinforcement in the South Calgary area. The ENMAX No. 65 Substation is to serve significant load growth due to the increasing population in this sector of the city. The proposed development includes a new 240/138 kV substation located east of 88 Street SE and north of Highway 22X, with about one km of double-circuit 138 kV transmission line that ties into an existing 138 kV transmission line, and a double-circuit 240 kV transmission line from the current 911L to connect into the existing transmission system.

THE COMPONENTS: The proposed development includes the aforementioned new 240/138 kV substation located east of 88 Street SE and north of Highway 22X, and associated 138 kV and 240 kV lines to interconnect into the existing system.

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
New 240/138 kV Substation	New ENMAX No. 65 Substation and about one km of 138 kV transmission line to connect the new substation to the existing transmission system	September 2013
ENMAX No. 65 Substation Interconnection	Addition of double-circuit line from existing 911L to create an in and out configuration into the new ENMAX No. 65 Substation	September 2013 – substation to the AltaLink 911L

THE TRANSMISSION FACILITY OWNER(S): ENMAX Power Corp. and AltaLink Management Ltd.

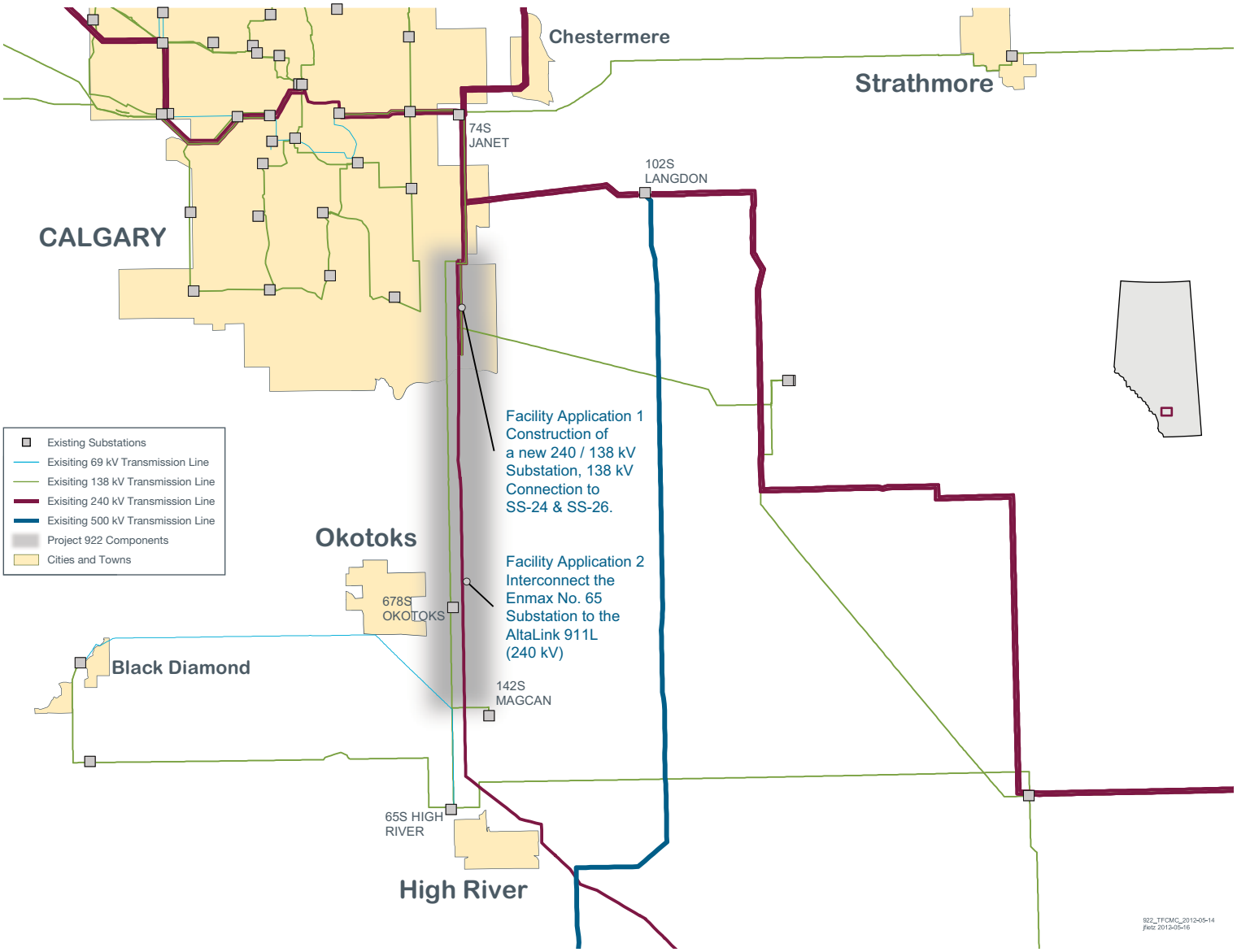
PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
ENMAX No. 65 Substation	**$37 Million** (2011$ without escalation)	**$37 Million** (ISD$ with escalation)[19]

CURRENT STATUS: On November 3, 2011, the AUC approved the FA and issued the P&L for the project. Construction started in April 2012 and the forecasted in-service date has now been moved to September 2013.

19 As per the information provided in the Cost Committee Monthly Summary in the December 2012 TFCMC meeting, which is based upon the TFO's October 2012 Monthly Project Progress Report.

Project 922
ENMAX No. 65 Substation Transmission Development



7. **FOOTHILLS AREA TRANSMISSION DEVELOPMENT – EAST PROJECT (FATD);** PROJECT 1117 – To meet growing demand in South Calgary, High River and the surrounding area.

THE PROJECT: The AESO has forecasted that transmission reliability constraints in the south Calgary and High River areas will occur within the 2014 to 2019 time frame. The FATD East development will ensure the transmission system will serve growing electricity demand in Calgary, High River, and the surrounding area, enable new generation facilities to connect, and maintain system reliability. The development will also facilitate wind generation development within adjacent areas and mitigate thermal overloads and voltage violations.

THE COMPONENTS: The project has both a 240 kV and 138 kV scope. The 240 kV scope consists of building a new 240/138 kV substation designated Foothills 237S; adding a new 240 kV double-circuit line from the proposed Foothills 237S substation to the future ENMAX SS-65; a new 240 kV double-circuit line from the existing Langdon 102S to the existing the Janet 74S; a new 240 kV double-circuit line from Langdon 102S to East Calgary 5S using a combination of existing lines; a 240 kV double-circuit line between the future ENMAX SS-65 substation to the proposed ENMAX SS-25 substation; and the de-energization of sections of existing transmission lines.

The 138 kV scope consists of adding a new 138 kV single-circuit line from the proposed Foothills 237S to the existing Okotoks 678S; a new 138 kV single-circuit line from Foothills 237S to the existing High River 65S; a 138 kV single-circuit line from Okotoks 678S to Carseland 525S, and the de-energization of transmission lines and modifications to lines in the area.

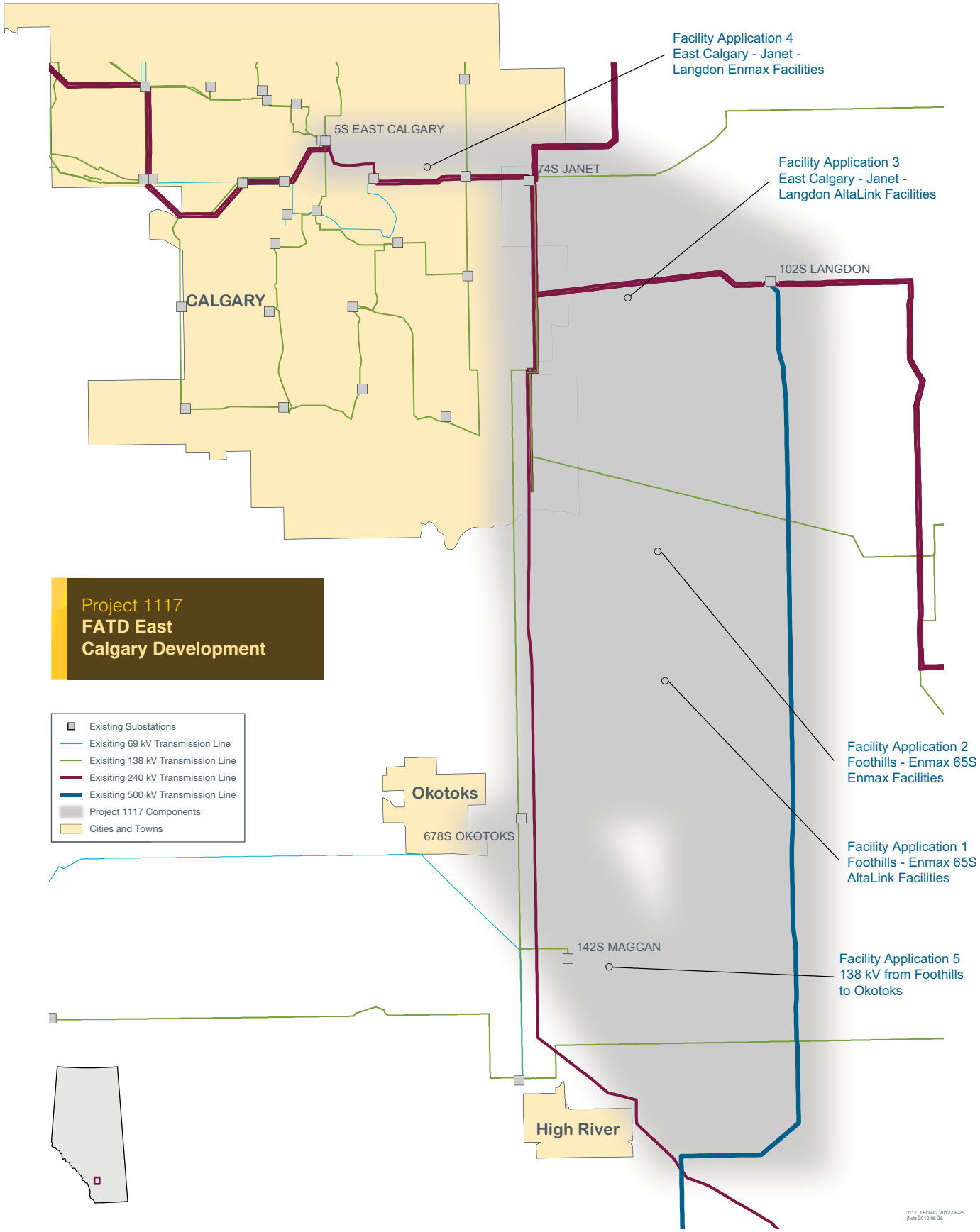
FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
North Foothills Transmission Project	Construction of Foothills 235S 240/138 kV switching station, and construction of approximately 52 km of 240 kV double-circuit transmission line from Foothills 237S to ENMAX SS-65	July 2015
Langdon to Janet Project	Construction of approximately 18 km of 240 kV double-circuit transmission line from Langdon 102S to Janet 74S; expansion of Janet 74S substation; removal of terminations at Janet 74S resulting in two new circuit terminals at East Calgary 5S and Crossing 511S, and salvage of approximately six km of 240 kV transmission line from Janet 74S to ENMAX SS-25	July 2015
Foothills 138 kV Project	Addition of two 240/138 kV transformers at Foothills 237S; construction of approximately 14 km of 138 kV double-circuit transmission line from Foothills 237S to High River 65S; rebuild of approximately seven km of existing transmission line to 678S, and salvage of approximately 30 km of existing line from Janet 74S to Okotoks 678S	October 2015
ENMAX No.25 Substation 240 kV Line Additions and ENMAX No.65 Substation 240 kV Line Additions	Interconnection of two new AltaLink Management Ltd. 240 kV transmission lines at ENMAX SS-25, and termination of three new AltaLink Management Ltd. 240 kV transmission lines at ENMAX SS-65	June 2015

THE TRANSMISSION FACILITY OWNER(S): AltaLink Management Ltd. and ENMAX Power Corp.

PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Foothills Area Transmission Development – East Project	**$711 Million*** (2011$ without escalation) *entire FATD plan	**$417 Million*** (ISD$ with escalation) *FATD East PPS

CURRENT STATUS: The AESO filed the NID with the AUC for approval in July 2012. The AUC announced a hearing for May 13, 2013.


Facility Application 4
East Calgary - Janet -
Langdon Enmax Facilities
5S EAST CALGARY
74S JANET
Facility Application 3
East Calgary - Janet -
Langdon AltaLink Facilities
102S LANGDON
CALGARY
Project 1117
FATD East
Calgary Development
Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Exisiting 500 kV Transmission Line
Project 1117 Components
Cities and Towns
Okotoks
678S OKOTOKS
Facility Application 2
Foothills - Enmax 65S
Enmax Facilities
Facility Application 1
Foothills - Enmax 65S
AltaLink Facilities
142S MAGCAN
Facility Application 5
138 kV from Foothills
to Okotoks
High River
1117_TFCMC_2012-06-25
jfietz 2012-06-25

8. **FORT MCMURRAY AREA TRANSMISSION BULK SYSTEM REINFORCEMENT (FMAC);** PROJECT 838 – Construction of 500 kV transmission lines from the Edmonton area to the Fort McMurray area.

THE PROJECT: The Fort McMurray area transmission project is to serve load from the expected growth of the oil sands industry in the northeastern part of the province. The AESO has recommended a 500 kV AC line from the Genesee generating station to a new 500 kV substation in the Fort McMurray area and a 500 kV AC line from the new Heartland substation to the new Fort McMurray area 500 kV substation.

THE COMPONENTS: The major components for Stage 1 of the project (West 500 kV Line) are: approximately 500 km of 500 kV single-circuit transmission line from Thickwood Hills 951S to Sunnybrook 510S; a 500 kV substation switchyard at Thickwood Hills 951S to terminate the north end of the West 500 kV line; modifications to the Sunnybrook 510S substation to terminate the south end of the West 500 kV line, and a 500/240 kV 1200 MVA transformer bank at Thickwood Hills 951S.

The major components for Stage 2 of the project (East 500 kV Line) are: approximately 400 km of 500 kV single-circuit transmission line from Thickwood Hills 951S to Heartland 12S; modifications to the Thickwood Hills 951S substation to terminate the north end of the East 500 kV line; modifications to the Heartland 12S substation to terminate the south end of the East 500 kV line, and a second 500/240 kV 1200 MVA transformer bank at Thickwood Hills 951S.

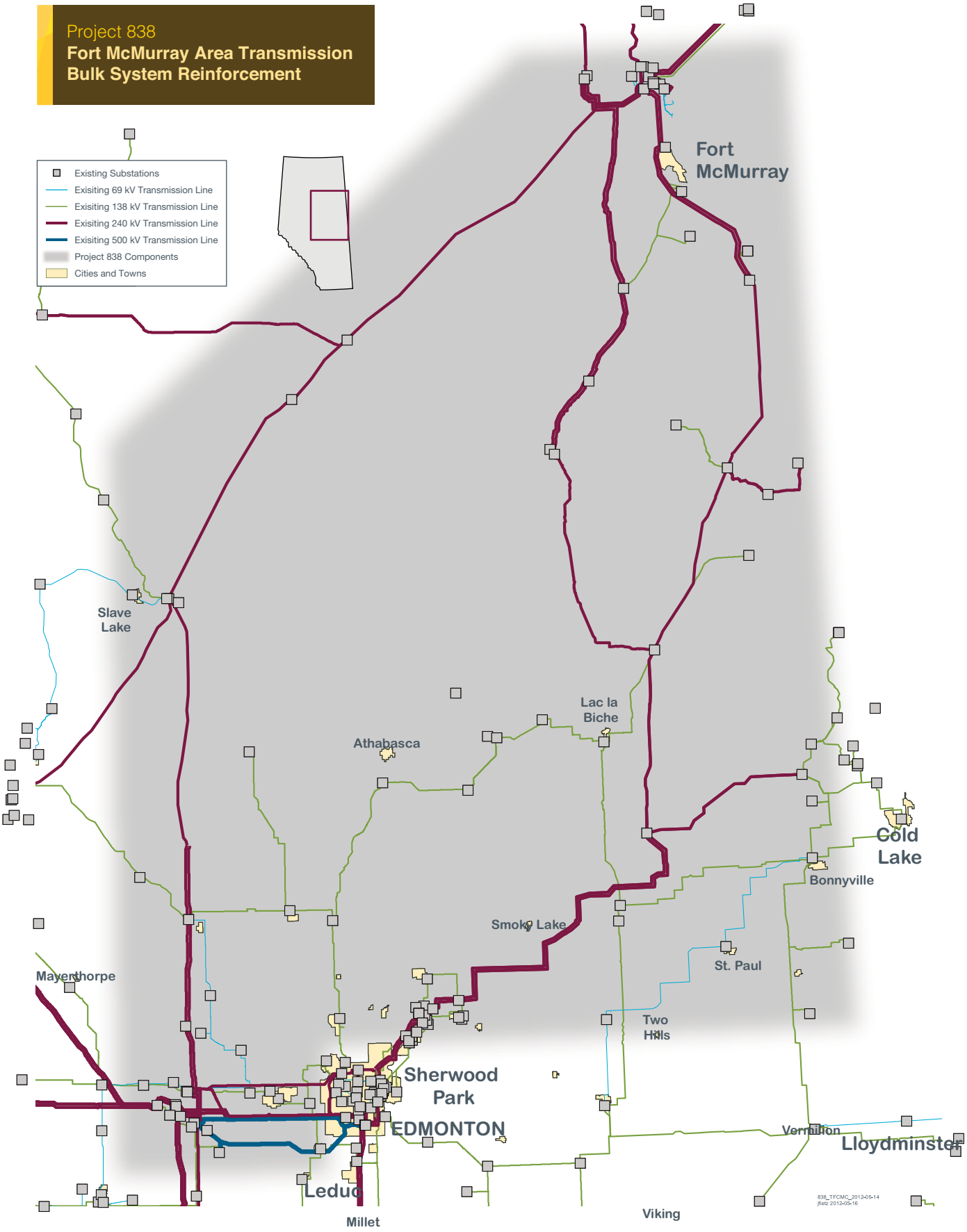
FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Fort McMurray Area Bulk System Development Stage 1 – West Line	One 500 kV transmission line will be constructed from a new substation at Thickwood Hills to the Genesee area, called the West 500 kV line	2018
Fort McMurray Area Bulk System Development Stage 2 – East Line	A second 500 kV transmission line will be constructed from a new substation at Thickwood Hills to the Heartland area, called the East 500 kV line	2020

THE TRANSMISSION FACILITY OWNER(S): The Transmission Facility Owner (TFO) will be determined through the Competitive Process.

PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Fort McMurray Area Transmission Bulk System Reinforcement	***Stage 1:*** **$1.649 Billion** (2011$ without escalation) ***Stage 2:*** Not Available	Not Available

CURRENT STATUS: The Fort McMurray Area Transmission Bulk System Reinforcement will utilize the competitive process. The AESO's Competitive Process Application was filed with the AUC on September 15, 2011. The written hearing started on September 17, 2012. The hearing was closed in November 20, 2012, with AUC approval of the competitive process expected during the first quarter of 2013.


Project 838
Fort McMurray Area Transmission Bulk System Reinforcement
Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Exisiting 500 kV Transmission Line
Project 838 Components
Cities and Towns
Fort McMurray
Slave Lake
Lac la Biche
Athabasca
Cold Lake
Bonnyville
Smoky Lake
St. Paul
Mayerthorpe
Two Hills
Sherwood Park
EDMONTON
Vermilion
Lloydminster
Leduc
Millet
Viking
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jfeitz 2012-05-16

9. **HANNA REGION TRANSMISSION DEVELOPMENT (HATD);** PROJECT 812 – Transmission development in Hanna, Sheerness and Battle River.

THE PROJECT: Transmission reinforcement in the Hanna region (East Central Alberta) will allow for the connection of up to 700 MW of wind power and serve demand of about 970 MW, largely driven by industrial development in the area. The AESO's system studies indicate that the key drivers for the project are to provide transmission capacity to meet growth (load and generation), improve the reliability of the transmission system and alleviate transmission constraints that can result in generation curtailment in the region.

THE COMPONENTS: There are two stages of transmission development for the project.

The major components for Stage 1 of the project are: a new 240/144 kV substation near Hardisty with a 240 kV double-circuit line connecting the new substation to the 240 kV line between Cordel and Hansman Lake, and a 138 kV double-circuit line connecting the new substation to the existing Tucuman 478S; a 240 kV doublecircuit line from Anderson to a new 240 kV switching station south of Anderson 801S; a 240 kV double-circuit transmission line (one side strung) from the new 240 kV switching station to existing Hansman Lake 605S and two new 240/144 kV substations near Oyen and Monitor; addition of -100/+200 VAr static var compensators at existing Hansman Lake 650S and new Lanfine 959S substations; a double-circuit 240 kV line (one side strung) west from the new 240 kV switching station to a new 240/144 kV substation near the Hand Hills area, and various local area 138 kV or 144 kV enhancements.

The major components for Stage 2 of the project are: string conductor on the open side of the 240 kV lines from the 240 kV switching station south of Anderson 801S to Hansman Lake 650S; string conductor on the open side of the 240 kV line west from the 240 kV switching station south of Anderson 801S to the new 240/144 kV station in the Hand Hills area; addition of a second 240/144 kV transformer at source substations near Oyen, Monitor and Hand Hills, the addition of -100/+200 VAr static var compensator, and various local area 138 kV and 144 kV enhancements.

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Youngstown 772S Capacitor Bank addition	Youngstown 772S – Capacitor Bank addition, 144 kV breaker and communication tower	October 6, 2011
Battle River 757S Capacitor Bank addition	Battle River 757S – 72 kV Capacitor Bank addition, 144 kV circuit breaker and substation alterations	October 3, 2011
New Lanfine 240/144 kV substation	New 240/144 kV substation designated Lanfine 959S	March 30, 2013
Lanfine 959S 200 VAr SVC	Addition of a -100/+200 VAr SVC at Lanfine 959S	May 31, 2013
Lanfine-Oyen 144 kV S/C Line 7L132	Double-circuit 144 kV line (one side energized) from Lanfine 959S to Oyen 767S	May 31, 2013
Relocate 7L98 Oyen 767S – Lanfine 959S	Decommission and salvage of transmission line 7L98 and 7LA98	May 31, 2013
Oakland 946S 240 kV S/S combined with Anderson-Oakland line	New 240 kV double-circuit transmission line (designated as 9L70/9L97) from Anderson 801S to Oakland 946S, Oakland 946S substation and related alterations	May 30, 2013
Oakland-Lanfine 240 kV S/C line 9L924	New 240 kV double-circuit transmission line (one side strung) designated 9L24, from Oakland 946S to Lanfine 959S and alterations to Oakland 946S	March 30, 2013

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Coyote Lake 963S 240 kV S/S combined with Oakland-Coyote line	New 240/144 kV Coyote Lake 963S; new 240 kV double-circuit transmission line (one side strung) designated as 9L29 from Oakland 949S to Coyote Lake 963S and alteration to Oakland 946S	April 30, 2013
Coyote Lake 963S – Michichi Creek 802S 144 kV SC Line 7L128	New single-circuit transmission line designated as 7L128 from Michichi Creek 802S to Coyote Lake 963S and alterations to existing Michichi Creek 802S	May 31, 2013
Pemukan 932S 240 kV Substation	New 240/144 kV substation designated Pemukan 932S	May 31, 2013
New Lanfine-Pemukan 240 kV S/C Line 9L46	New 240 kV double-circuit transmission line (one side strung) designated 9L46, from Pemukan 932S to Lanfine 959S and alterations to Lanfine 959S	March 31, 2013
144 kV Capacitor Bank and circuit breaker additions at Three Hills Substation 770S	Three Hills 770S 144 kV Capacitor Bank addition; 144 kV circuit breaker and substation alterations	December 13, 2011
Hansman Lake-Pemukan 240 kV S/C Line 9L966	New 240 kV double-circuit transmission line (one side strung) designated 9L966, from Pemukan 932S to AltaLink's service territory and alterations to Pemukan 932S	May 31, 2013
Pemukan 932S-Monitor 774S 144 kV S/C Line 7L127	Double-circuit 144 kV line (one side energized) from Pemukan 932S to Monitor 774S	May 31, 2013
Relocate 7L79 line from Monitor 774S – Pemukan 932S	Retermination of existing 7L70 from Monitor 774S to Pemukan 932S and alterations to Pemukan 932S	May 31, 2013
Heatburg 948S – Three Hills-Nevis 144 kV D/C Line 7L16/7L159	New 144/25 kV Heatburg 948S substation; new 144 kV double-circuit transmission line from Heatburg 948S to existing 7L16; modification of 7L16 to create an in and out configuration to Heatburg 948S and alterations at existing substations	May 31, 2012
Rowley 768S – Michichi-Three Hills 144 kV DC Line 7L25	Expansion and rebuild of existing Rowley 768S substation; construction of about 13 km of new 144 kV double-circuit transmission line designated as 7L25 and 7L137 and alterations at existing substations	June 1, 2012
Stettler 769S – Nevis 768S 144 kV S/C Line 7L143	New 144 kV single-circuit transmission line from Nevis 766S to Stettler 769S; alterations to Nevis 766S and alterations to Stettler 769S	May 31, 2013

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Nilrem 574S combined with D/C 240 kV 953L – 1047L and Tucuman 478S combined with D/C 138 kV 679L-680L	New 240/138 kV Nilrem 574S; new 240 kV double-circuit transmission line (designated as 953L/1047L) from connection point on existing 240 kV line 953L to Nilrem 574S; alteration to existing 953L; new 139 kV double-circuit transmission line (679L/680L) from Tucuman 478S to Nilrem 574S and alterations to existing Tucuman 478S	March 30, 2013
Hardisty 377S Substation Capacitor Bank	138 kV Capacitor Bank addition at Hardisty 377S substation and other associated work	June 30, 2012
New 240 kV line 966L from Pemukan 932S – Hansman Lake 650S	New 240 kV double-circuit transmission line (one side strung) designated 966L, from Hansman Lake 650S to ATCO's service territory and alterations to Hansman Lake 650S	May 30, 2013
Hansman Lake 650S Substation SVC Addition	Addition of a -100/+200 VAr SVC at Hansman Lake 650S	October 15, 2012
New 240 kV line 1060L from Ware Junction 132S – West Brooks 28S	New 240 kV single-circuit transmission line (designated 1053L) from Ware Junction 132S to Cassils 324S; alterations to Ware Junction 132S and alteration to Cassils 324S	September 1, 2013

THE TRANSMISSION FACILITY OWNER(S): AltaLink Management Ltd. and ATCO Electric Ltd.

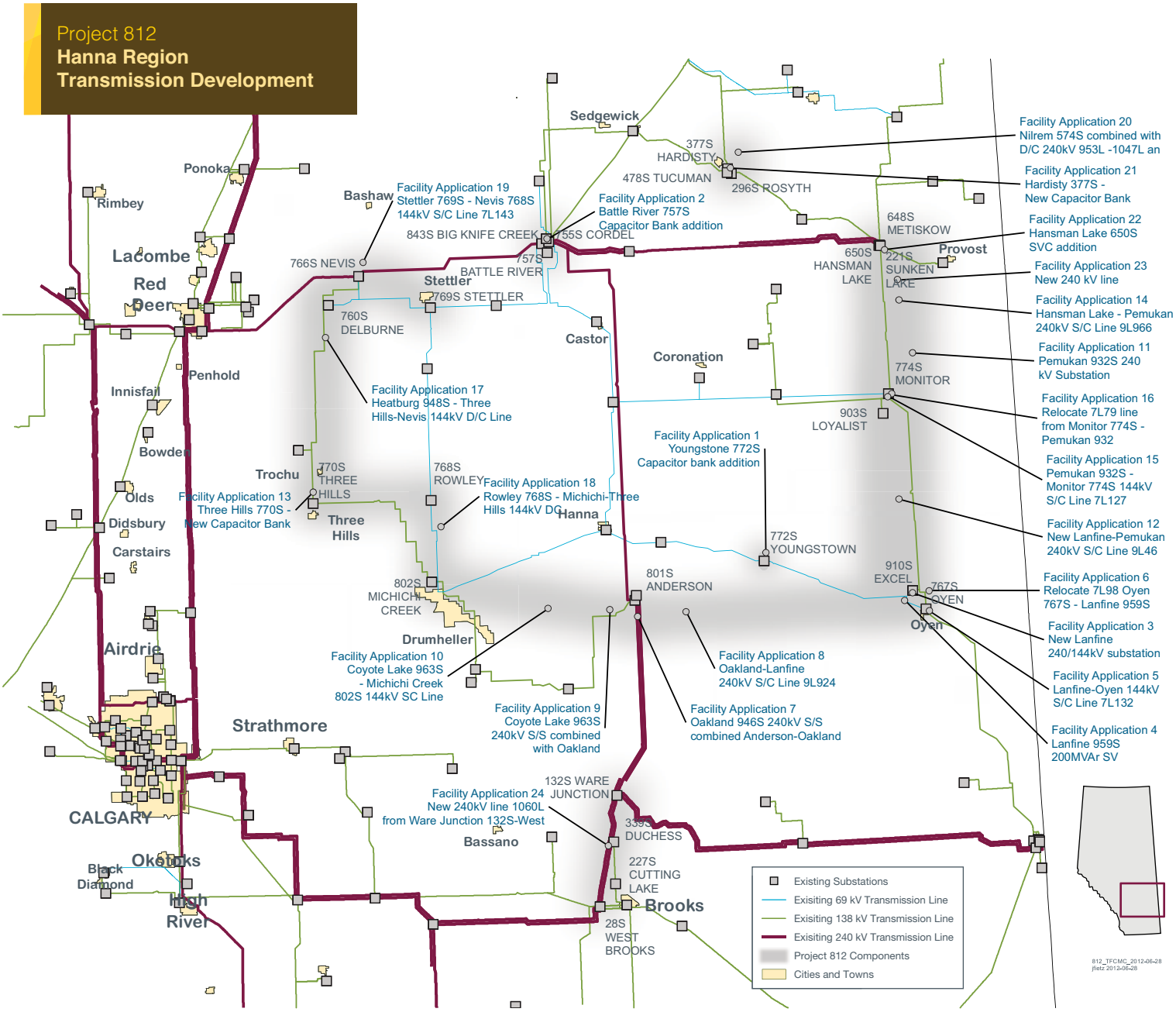
PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Hanna Region Transmission Development	**$909 Million** (2011$ without escalation)	**$897 Million** (ISD$ with escalation for stage 1)[20]

CURRENT STATUS: The Hanna Region Transmission Development NID was approved April 29, 2010. All FAs related to Stage 1 of the project have been approved by the AUC with the last FA for the Heatburg 948S and Three Hills-Nevis 144 kV D/C transmission line being approved on June 13, 2012. All components are moving through the construction phase of development.

The AESO is currently working on Stage 2 of the Hanna project; the NID identified that this development is required by 2017.

20 As per the information provided in the Cost Committee Monthly Summary in the December 2012 TFCMC meeting, which is based upon the TFO's October 2012 Monthly Project Progress Report.


Project 812
Hanna Region
Transmission Development
Sedgewick
377S HARDISTY
478S TUCUMAN
296S ROSYTH
Facility Application 20 Nilrem 574S combined with D/C 240kV 953L -1047L an
Facility Application 21 Hardisty 377S - New Capacitor Bank
Facility Application 22 Hansman Lake 650S SVC addition
Facility Application 23 New 240 kV line
Facility Application 14 Hansman Lake - Pemukan 240kV S/C Line 9L966
Facility Application 11 Pemukan 932S 240 kV Substation
Facility Application 16 Relocate 7L79 line from Monitor 774S - Pemukan 932
Facility Application 15 Pemukan 932S - Monitor 774S 144kV S/C Line 7L127
Facility Application 12 New Lanfine-Pemukan 240kV S/C Line 9L46
Facility Application 6 Relocate 7L98 Oyen 767S - Lanfine 959S
Facility Application 3 New Lanfine 240/144kV substation
Facility Application 5 Lanfine-Oyen 144kV S/C Line 7L132
Facility Application 4 Lanfine 959S 200MVAr SV
Facility Application 19 Stettler 769S - Nevis 768S 144kV S/C Line 7L143
Facility Application 2 Battle River 757S Capacitor Bank addition
Facility Application 17 Heatburg 948S - Three Hills-Nevis 144kV D/C Line
Facility Application 1 Youngstone 772S Capacitor bank addition
Facility Application 18 Rowley 768S - Michichi-Three Hills 144kV DC
Facility Application 13 Three Hills 770S - New Capacitor Bank
Facility Application 10 Coyote Lake 963S - Michichi Creek 802S 144kV SC Line
Facility Application 9 Coyote Lake 963S 240kV S/S combined with Oakland
Facility Application 8 Oakland-Lanfine 240kV S/C Line 9L924
Facility Application 7 Oakland 946S 240kV S/S combined Anderson-Oakland
Facility Application 24 New 240kV line 1060L from Ware Junction 132S-West
Ponoka
Rimbey
Bashaw
843S BIG KNIFE CREEK
755S CORDEL
766S NEVIS
757S BATTLE RIVER
Stettler
769S STETTLER
Lacombe
Red Deer
760S DELBURNE
Castor
Coronation
Provost
648S METISKOW
650S HANSMAN LAKE
221S SUNKEN LAKE
774S MONITOR
903S LOYALIST
Penhold
Innisfail
Bowden
Olds
Didsbury
Carstairs
Trochu
770S THREE HILLS
Three Hills
768S ROWLEY
Hanna
772S YOUNGSTOWN
910S EXCEL
767S OYEN
Oyen
801S ANDERSON
802S MICHICHI CREEK
Drumheller
Airdrie
Strathmore
CALGARY
Okotoks
Black Diamond
High River
132S WARE JUNCTION
Bassano
335S DUCHESS
227S CUTTING LAKE
Brooks
28S WEST BROOKS
Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Project 812 Components
Cities and Towns
812_TFCMC_2012-06-28
jfietz 2012-06-28

10. **NORTH FORT MCMURRAY TRANSMISSION DEVELOPMENT (NFMD);** PROJECT 791 – Transmission development north of Fort McMurray.

THE PROJECT: The North Fort McMurray Transmission Development Project is to relieve transmission constraints and to serve forecast electrical demand as industrial load (oil sands) continues to grow in the area north of Fort McMurray.

THE COMPONENTS: The project calls for a 240 kV double-circuit line from Kearl Lake to Salt Creek; addition of the McLelland 240 kV switching station near Kearl Lake, and a 240 kV switching station at Black Fly.

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
North Fort McMurray Transmission Development	Double-circuit 240 kV line from Kearl Lake to Salt Creek; addition of the McLelland 240 kV switching station near Kearl Lake; and a 240 kV switching station at Black Fly	April 2013

THE TRANSMISSION FACILITY OWNER(S): ATCO Electric Ltd.

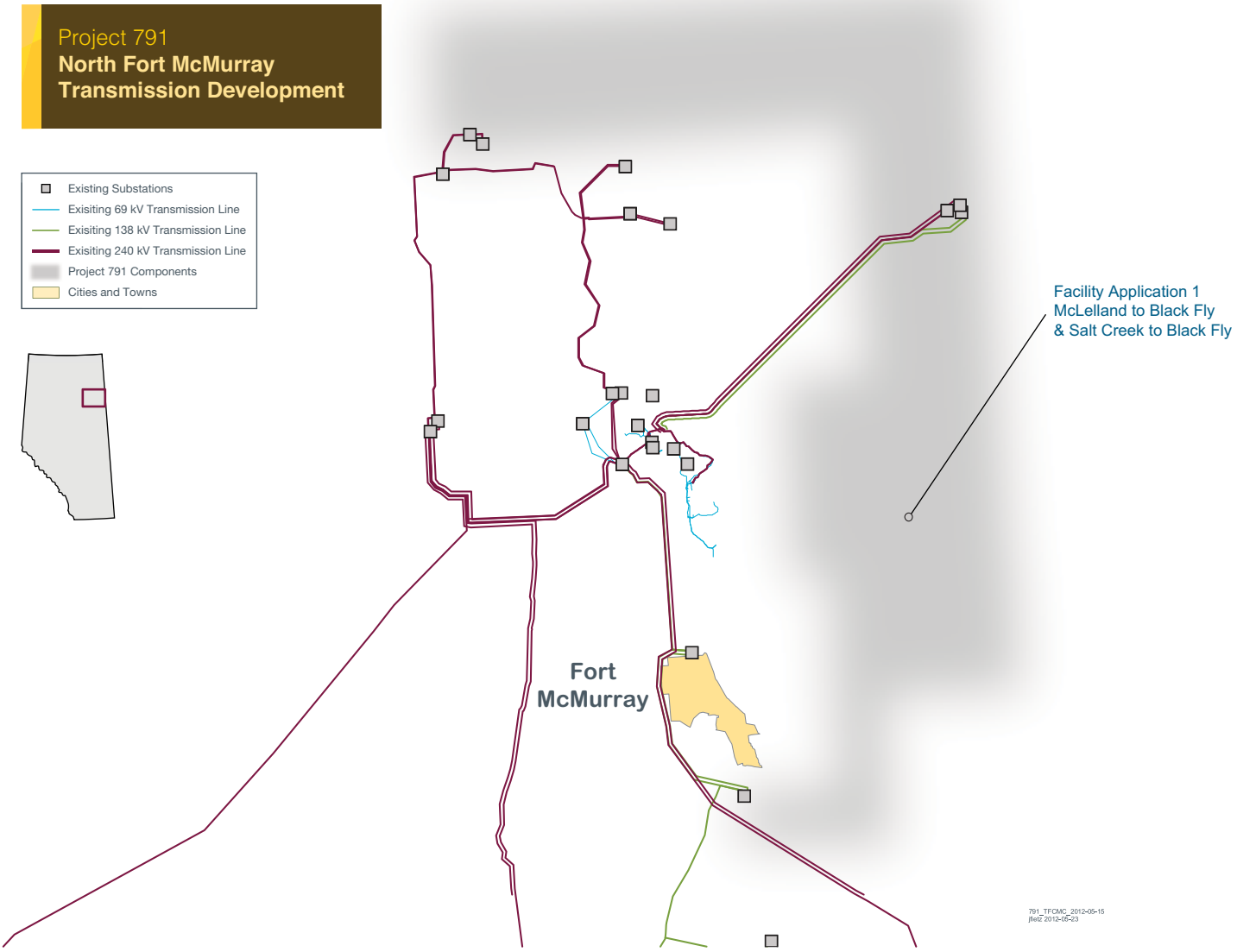
PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
North Fort McMurray Transmission Development	**$197 Million** (2011$ without escalation)	**$328 Million** (ISD$ with escalation)[21]

CURRENT STATUS: The North Fort McMurray NID was approved June 24, 2011. On July 28, 2011 the AUC approved the south portion of the FA and on December 23, 2011 granted approval to the overall project. Line 9L84, the 240 kV line from Salt Creek to the location of the new Black Fly substation, was commissioned on May 15, 2012. The north part of the project, Black Fly Substation, 9L69 from Black Fly to McLelland and McLelland substation, is scheduled for completion on April 1, 2013.

The AESO submitted a letter on March 13, 2012 to the AUC that highlighted an increase in the cost for the North Fort McMurray Transmission Development exceeding the accuracy tolerance identified in the NID.

21 As per the information provided in the Cost Committee Monthly Summary in the December 2012 TFCMC meeting, which is based upon the TFO's October 2012 Monthly Project Progress Report.


Project 791
North Fort McMurray
Transmission Development
Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Project 791 Components
Cities and Towns
Facility Application 1
McLelland to Black Fly
& Salt Creek to Black Fly
Fort
McMurray
791_TFCMC_2012-05-15
jfleiz 2012-05-23

11. **NORTH SOUTH TRANSMISSION REINFORCEMENT (HVDC);** PROJECT 737 – Construction of two 500 kV HVDC transmission lines from the Edmonton area to the Calgary and south regions.

THE PROJECT: The North South Transmission Reinforcement is to address increased demand in southern and central Alberta, mitigate issues with reliability, maximize efficiency, accommodate long-term growth and lead generation decisions. The project calls for two high-capacity lines between Edmonton and Calgary to reinforce the backbone of the grid and replace aging 240 kV lines. One line will be located on the west centre portion of the province, connecting to the existing Wabamun Lake hub west of Edmonton to the Calgary area hub near Langdon. The second line will be located on the east side of the province connecting the Heartland hub northeast of Edmonton to a southern hub in the Brooks area.

THE COMPONENTS: The new lines will be 500 kV high-voltage direct current (HVDC) technology and will be built to transfer up to 1000 MW of power. The lines and stations will be upgradable to 2000 MW at a future date. Four HVDC converter stations will be required, one at the source and one at the destination point, to convert AC power to DC and DC to AC.

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
EATL Facility Application – ATCO	Application to construct and operate a high voltage DC line from Heartland to West Brooks	2014
WATL Facility Application – AltaLink	Application to construct and operate a high-voltage DC line from Genesee to Langdon	2015

THE TRANSMISSION FACILITY OWNER(S): AltaLink Management Ltd. will build the Western Alberta Transmission Line (WATL) and ATCO Electric Ltd. will build the Eastern Alberta Transmission Line (EATL).

PROJECT COST:

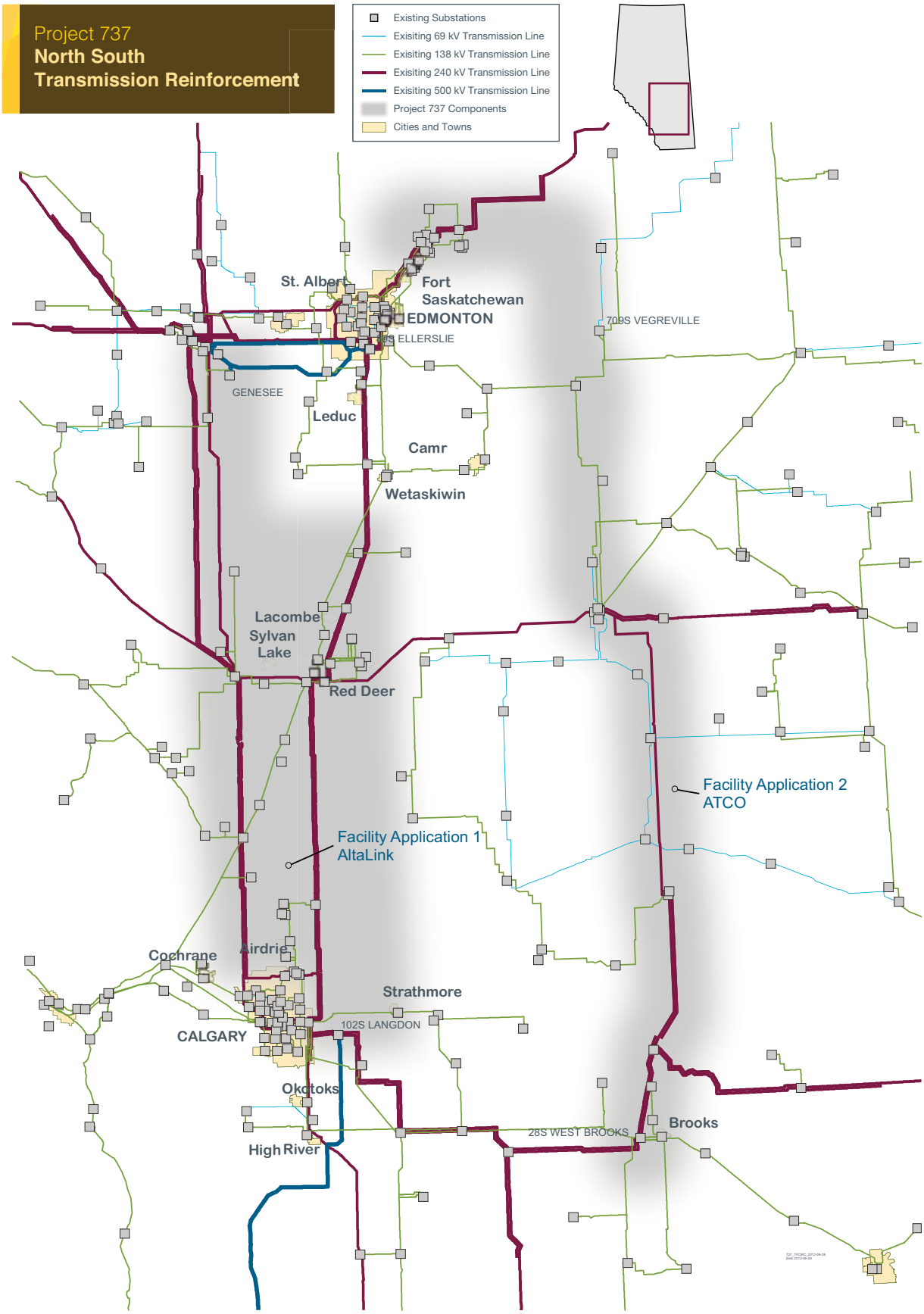
TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
North South Transmission Reinforcement – EATL	**$1.622 Billion** (2011$ without escalation)	**$1.651 Billion** (ISD$ with escalation)[22]
North South Transmission Reinforcement – WATL	**$1.329 Billion** (2011$ without escalation)	**$1.442 Billion** (ISD$ with escalation)[23]

CURRENT STATUS: The AUC public hearing for AltaLink's WATL application was closed on September 10, 2012. P&L was issued December 6, 2012. The WATL in-service date is scheduled for early 2015.

The AUC public hearing for ATCO's EATL application was closed August 20, 2012. The AUC issued P&L on November 15, 2012 for FAs from ATCO, AltaLink and EPCOR. The EATL in-service date is scheduled for late 2014.

22 As per the information provided in the Cost Committee Monthly Summary in the December 2012 TFCMC meeting, which is based upon the TFO's October 2012 Monthly Project Progress Report.

23 As per the information provided in the Cost Committee Monthly Summary in the December 2012 TFCMC meeting, which is based upon the TFO's October 2012 Monthly Project Progress Report.


Project 737
North South
Transmission Reinforcement
Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Exisiting 500 kV Transmission Line
Project 737 Components
Cities and Towns
St. Albert
Fort
Saskatchewan
EDMONTON
ELLERSLIE
709S VEGREVILLE
GENESEE
Leduc
Camr
Wetaskiwin
Lacombe
Sylvan
Lake
Red Deer
Facility Application 2
ATCO
Facility Application 1
AltaLink
Cochrane
Airdrie
Strathmore
102S LANGDON
CALGARY
Okotoks
High River
28S WEST BROOKS
Brooks

12. ***NEW*** **NORTHWEST OF FORT MCMURRAY TRANSMISSION DEVELOPMENT (NW FMM);** PROJECT 1180 – To provide service and connect future industrial customers in areas where there are no transmission facilities.

THE PROJECT: The Northwest of Fort McMurray 240 kV Transmission Development includes a 240 kV looped system extending west from existing transmission facilities between the Dover 888S and Joslyn 849S substations as well as two new 240 kV substations. This expansion will serve electricity intensive industrial growth, as oil sands extraction facilities and related industrial developments are proceeding into areas where there are currently no transmission facilities.

THE COMPONENTS: A new 240 kV switching substation (Birchwood Creek 960S); existing 9L57 line in/out at Birchwood Creek 960S; new 240 kV switching station (Ells River 2079S); 9L08 Joslyn to Dover line in/out at Ells River 2079S (approximately 50 km of 240 kV double-circuit line, designated as 9L08/9L76); approximately 80 km of 240 kV double-circuit line (9L95), one-side strung between Ells River 2079S and Birchwood Creek 960S.

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Birchwood Creek Substation and 9L57 In/Out	New 240 kV switching substation (NW FMM South); existing 9L57 line in/out at NW FMM South (Birchwood Creek)	May 2014
Ells River Substation and 9L08	New 240 kV switching station (NW FMM North) (Ells River); 9L08 Joslyn to Dover line in/out at NW FMM North (approximately 50 km of 240 kV double-circuit line)	May 2014
Ells River to Birchwood Creek Line 9L95, 240 kV line between Ells River and Birchwood Creek	Approximately 80 km of 240 kV double-circuit line, one side strung between Ells River and Birchwood Creek and NW FMM North	January 2015

THE TRANSMISSION FACILITY OWNER(S): ATCO Electric Ltd.

PROJECT COST:

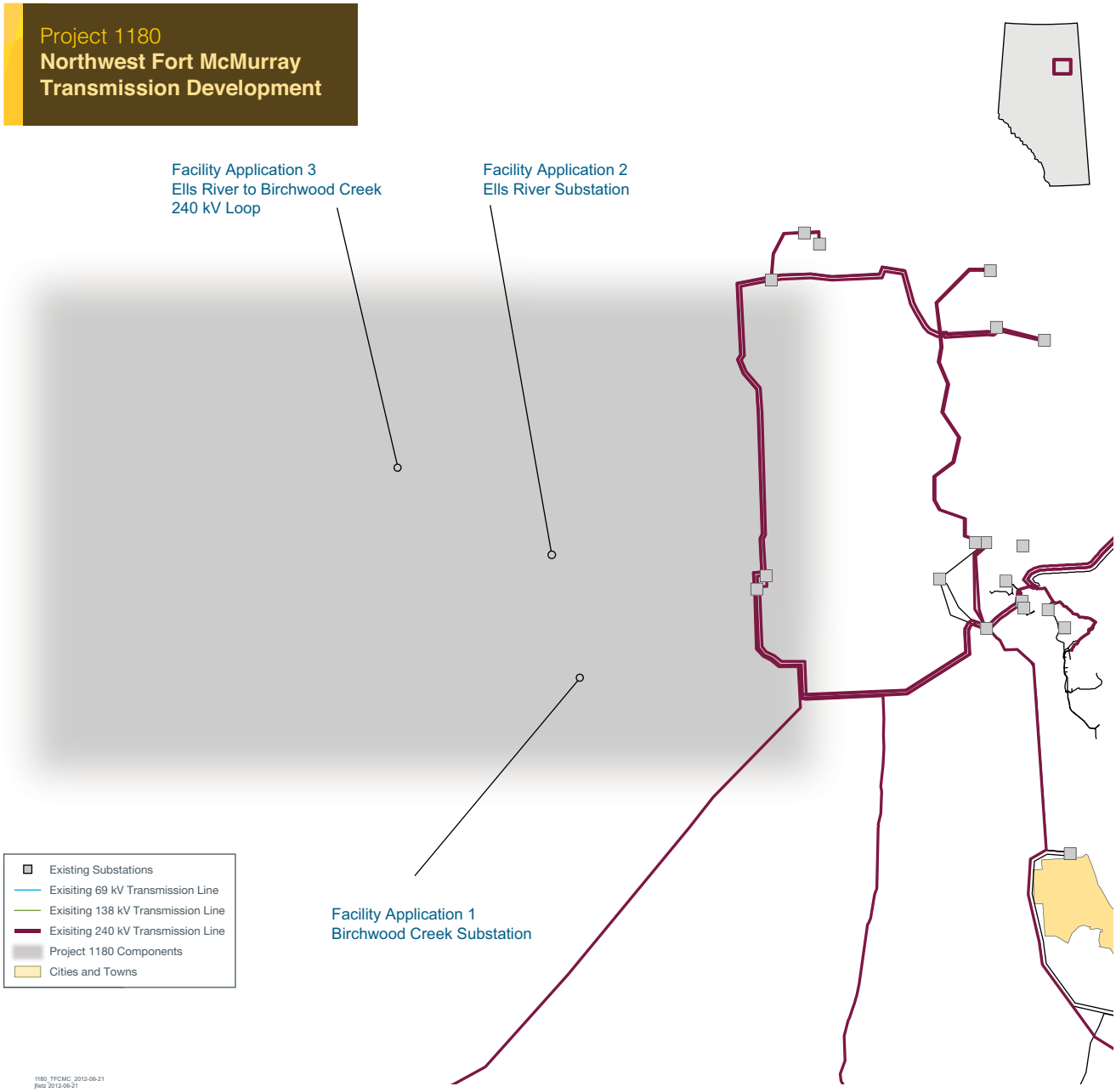
TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Northwest of Fort McMurray 240 kV Transmission Development	**$342 Million** (2011$ without escalation)[13]	**$366 Million** (ISD$ with escalation)[14]

CURRENT STATUS: This is a brand new project. On June 18, 2012, the AUC approved the NID for the Northwest Fort McMurray 240 kV Transmission Development. ATCO is developing their FAs, which includes route and site selection for the proposed development and anticipates their filing in the second quarter of 2013.

24 Referenced as "240 kV double-circuit line from Livock to Joslyn Creek" in the Long-term Transmission Plan that was filed in June 2012.

25 The cost is based upon the information provided in the Cost Committee Monthly Summary in the TFCMC's December 2012 meeting, which is based upon the TFO's October 2012 Monthly Project Progress Report.

Project 1180
Northwest Fort McMurray Transmission Development



13. **NORTHWEST TRANSMISSION DEVELOPMENT (NWTD);** PROJECT 535 – Transmission development in northwest Alberta.

THE PROJECT[26]: The Northwest (Alberta) Transmission Development identifies transmission issues in three areas of the Northwest region.

THE COMPONENTS: The transmission development includes adding new 240/144 kV transformers, capacitor banks and reactive support devices, a 240 kV line from Brintnell to Wesley Creek, and the addition of four new 144 kV transmission lines.

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
9L15 240 kV Wesley Creek 834S 240 kV single-circuit line	9L15 energized Wesley Creek to Brintnell 876S, two 300 MVA transformers at Wesley Creek	March 19, 2010
7L131/7L106 – 144 kV D/C line CTs Wesley Creek to Meikle 905S	144 kV double-circuit line from Wesley Creek to new Meikle	September 29, 2010
7L133 -144 kV S/C line Sulphur Point 828S to High Level 786S	144 kV single-circuit line from Sulphur Point 828S to High Level 786S	March 19, 2011
High Level 786S +1- 30 VAr SVC	High Level +1- 30 VAr Static VAr Compensator	June 30, 2010
7L113-144 kV S/C line Ring Creek 853S to New Arcenciel 930S	144 kV single-circuit line from Ring Creek to new Arcenciel 930S substation and 1 – 30 VAr Capacitor Bank at Arcenciel	December 19, 2011
Arcenciel 930S -30 +50 VAr synch conductor	Arcenciel 930S -30 +50 VAr synchronous condenser	May 2013
Arcenciel 930S +1- 30 VAr	Arcenciel 930S +1- 30 VAr Static VAr Compensator	September 7, 2011
Little Smoky 813S-install +/-100 VAr SVC & two 144 kV VAr Static VAr Compensator and breakers	Little Smoky 813S +/-100 VAr SVC and two 144 kV VAr Static VAr Compensator and breakers	March 31, 2010

THE TRANSMISSION FACILITY OWNER(S): ATCO Electric Ltd.

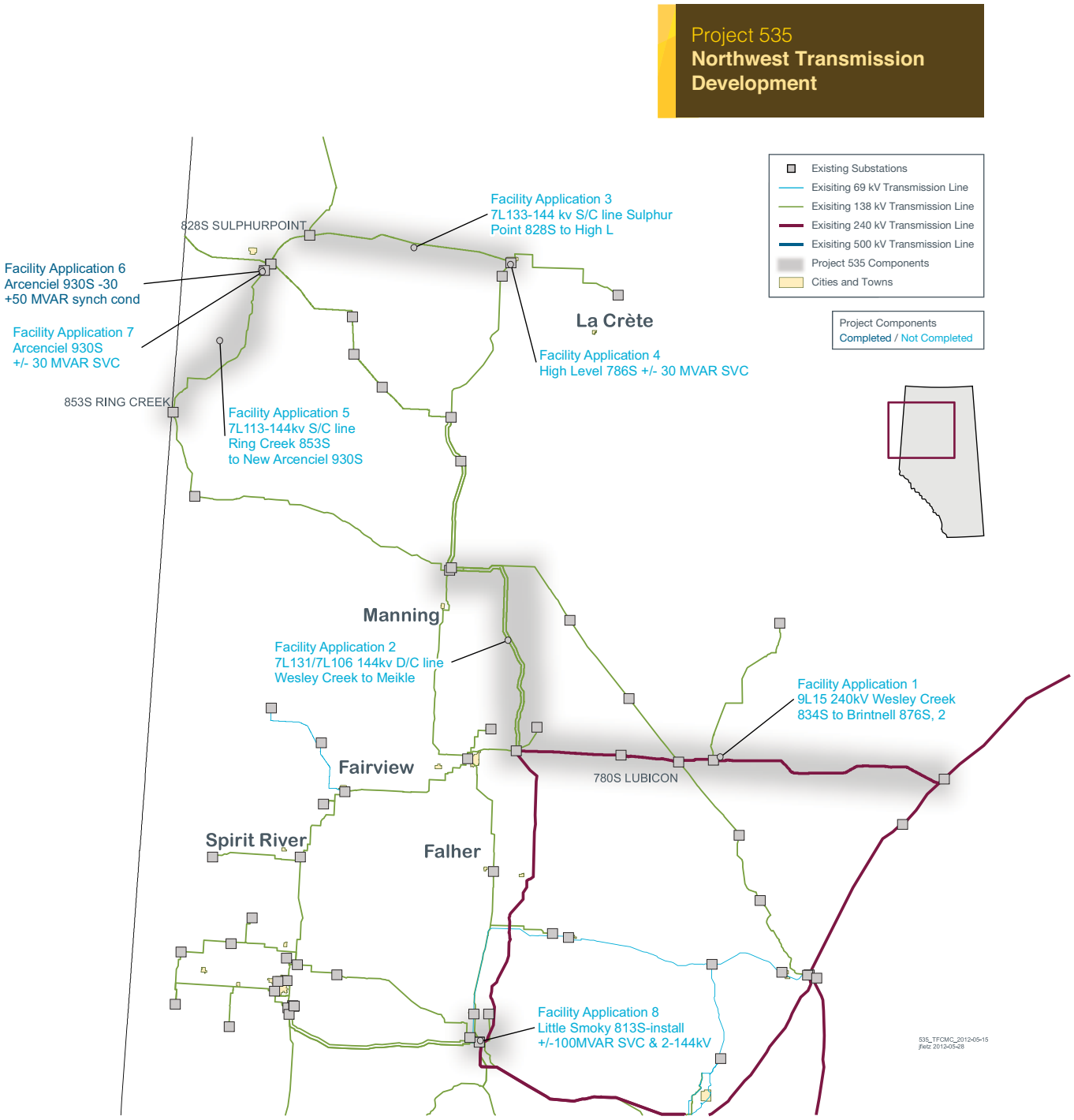
PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Northwest Transmission Development	Not estimated in 2011 Long-Term Transmission Plan	**$583 Million** (ISD$ with escalation)[27]

CURRENT STATUS: The Northwest Transmission Development will be completely in-service by May 2013 when a synchronous condenser is energized at the Arcenciel 930S substation.

26 This project was not included in the AESO's Long-term Transmission Plan (filed June 2012) as it was expected to be completed at the time of publication. The revised ISD for this project is May 2013.

27 As per the information provided in the Cost Committee Monthly Summary in the December 2012 TFCMC meeting, which is based upon the TFO's October 2012 Monthly Project Progress Report.


Project 535
Northwest Transmission Development
Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Exisiting 500 kV Transmission Line
Project 535 Components
Cities and Towns
Project Components
Completed / Not Completed
Facility Application 3
7L133-144 kv S/C line Sulphur Point 828S to High L
828S SULPHURPOINT
Facility Application 6
Arcenciel 930S -30 +50 MVAR synch cond
Facility Application 7
Arcenciel 930S
+/- 30 MVAR SVC
La Crète
Facility Application 4
High Level 786S +/- 30 MVAR SVC
853S RING CREEK
Facility Application 5
7L113-144kv S/C line
Ring Creek 853S
to New Arcenciel 930S
Manning
Facility Application 2
7L131/7L106 144kv D/C line
Wesley Creek to Meikle
Facility Application 1
9L15 240kV Wesley Creek
834S to Brintnell 876S, 2
Fairview
780S LUBICON
Spirit River
Falher
Facility Application 8
Little Smoky 813S-install
+/-100MVAR SVC & 2-144kV
535_TFCMC_2012-05-15
jfietz 2012-05-28

14. **RED DEER REGION TRANSMISSION DEVELOPMENT (RDTD);** PROJECT 813 – Transmission system reinforcements in the Red Deer area.

THE PROJECT: Growing demand from industrial, commercial, farming, and residential, along with existing constraints on the system, have created the need to strengthen the transmission system in the Red Deer region.

THE COMPONENTS: There are two stages of transmission development for the project.

The major components for Stage 1 of the project are: building new 240/138 kV substations near Didsbury, Ponoka and Innisfail; upgrading substations near Benalto and West Lacombe; adding approximately 150 km of new and rebuilt transmission line, and salvaging more than 100 km of existing transmission line.

The only component left for Stage 2 of the project is building a third 138 kV line from Gaetz to Joffre.

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Red Deer Area Transmission Development Stage 1 – Brownfield	Split 768L and 778L; 240/138 kV transformer at Benalto 17S, Capacitor Banks at Joffre 535S, Prentiss 276S and Ellis 332S	April 2013
Red Deer Area Transmission Development Stage 1 – Rebuilds	Rebuild 80L from S. Red Deer 194S to N. Red Deer 217S; rebuild 80L from S. Red Deer 194S to Red Deer 63S; rebuild 755L from Red Deer 63S to Piper Creek 247S to Joffre 535S, and rebuild 717L from Red Deer 63S to Benalto 17S	November 2014
Red Deer Area Transmission Development Stage 1 – New Builds	New Johnston 240/138 kV substation and new transmission lines; 138 kV line from NE Lacombe 212S to Ellis 322S; new Wolf Creek 240/138 kV substation and new transmission lines; new Hazelwood 240/138 kV substation and new transmission lines, and salvage 80L from Red Deer 63S to Innisfail 214S to Olds 55S	January 15, 2015
Red Deer Area Transmission Development Stage 1 – Salvage	Salvage 80L from Ponoka 331S to West Lacombe 958S, and salvage 716L from Wetaskiwin 40S to Ponoka 331S	June 13, 2015
Red Deer Area Transmission Development Stage 2 – Rebuild 166L	Rebuild 166L from Didsbury 152S to Harmattan 256S	July 2014
Red Deer Area Transmission Development Stage 2 – Gaetz to Joffre	138 kV line from Gaetz 87S to Joffre 535S	November 2017

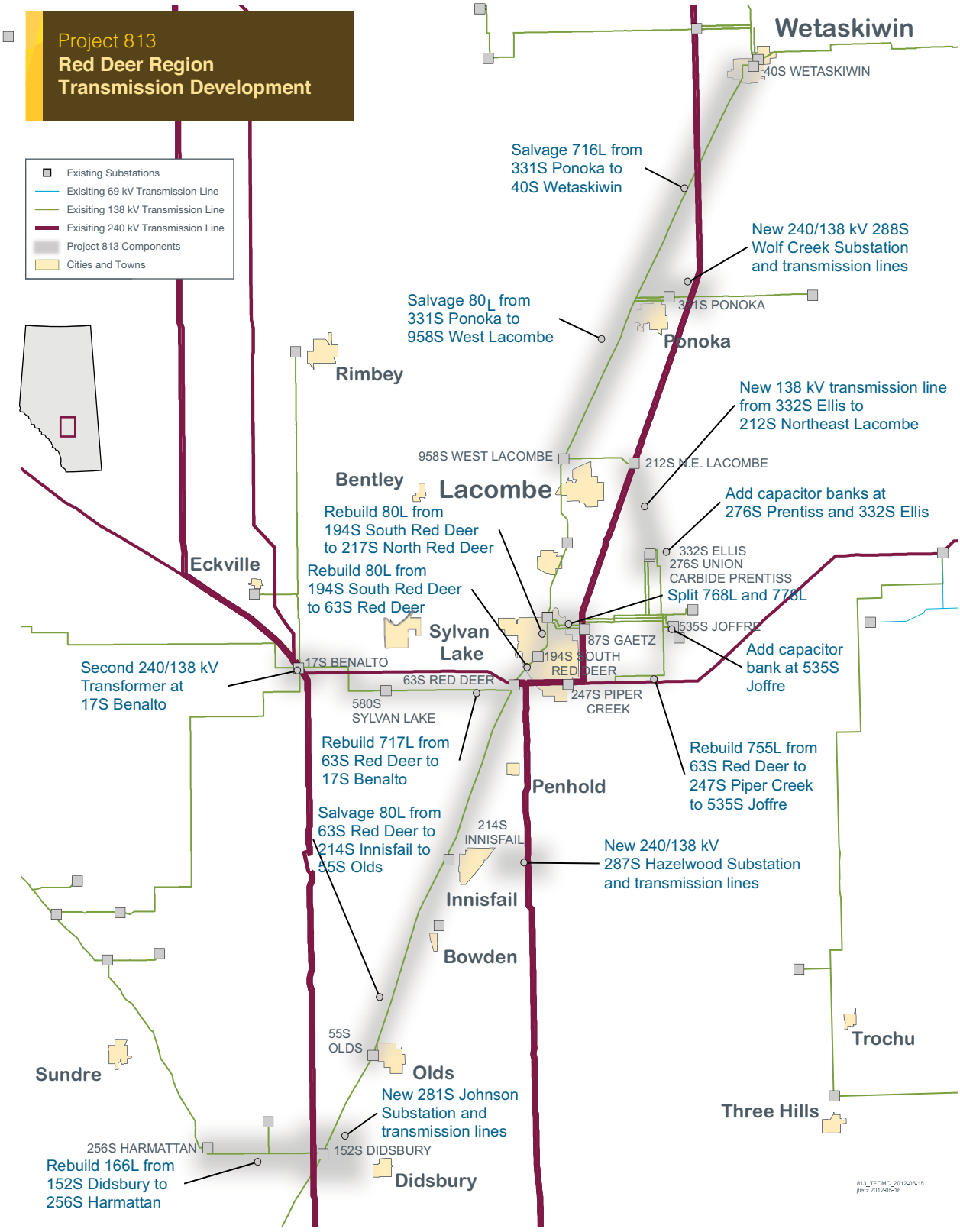
THE TRANSMISSION FACILITY OWNER(S): AltaLink Management Ltd.

PROJECT COST:

TRANSMISSION APROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Red Deer Transmission Development	**$204 Million** (2011$ without escalation)	**$300 Million** (ISD$ with escalation)[28]

CURRENT STATUS: AltaLink filed the first FA for Brownfield on September 26, 2011 and received approval on September 27, 2012. AltaLink will be filing Facility Application Rebuilds and Facility Application New Builds in January 2013. Stage 2 development related to the rebuild of 166L has been advanced to 2014 to facilitate the connection of a generation facility in the Harmattan area.

28 The cost is based upon the information provided in the Cost Committee Monthly Summary in the TFCMC's December 2012 meeting, which is based upon the TFO's October 2012 Monthly Project Progress Report.


Project 813
Red Deer Region
Transmission Development
Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Project 813 Components
Cities and Towns
Wetaskiwin
40S WETASKIWIN
Salvage 716L from 331S Ponoka to 40S Wetaskiwin
New 240/138 kV 288S Wolf Creek Substation and transmission lines
331S PONOKA
Ponoka
Salvage 80L from 331S Ponoka to 958S West Lacombe
Rimbey
New 138 kV transmission line from 332S Ellis to 212S Northeast Lacombe
958S WEST LACOMBE
212S N.E. LACOMBE
Bentley
Lacombe
Add capacitor banks at 276S Prentiss and 332S Ellis
Rebuild 80L from 194S South Red Deer to 217S North Red Deer
332S ELLIS
276S UNION CARBIDE PRENTISS
Split 768L and 778L
Eckville
Rebuild 80L from 194S South Red Deer to 63S Red Deer
Sylvan Lake
87S GAETZ
535S JOFFRE
194S SOUTH RED DEER
Add capacitor bank at 535S Joffre
Second 240/138 kV Transformer at 17S Benalto
17S BENALTO
63S RED DEER
247S PIPER CREEK
580S SYLVAN LAKE
Rebuild 717L from 63S Red Deer to 17S Benalto
Rebuild 755L from 63S Red Deer to 247S Piper Creek to 535S Joffre
Penhold
Salvage 80L from 63S Red Deer to 214S Innisfail to 55S Olds
214S INNISFAIL
New 240/138 kV 287S Hazelwood Substation and transmission lines
Innisfail
Bowden
Trochu
55S OLDS
Olds
Sundre
New 281S Johnson Substation and transmission lines
Three Hills
256S HARMATTAN
152S DIDSBURY
Rebuild 166L from 152S Didsbury to 256S Harmattan
Didsbury

15. **SOUTHERN ALBERTA TRANSMISSION REINFORCEMENT (SATR);** PROJECT 787 – To accommodate wind generation in southern Alberta.

THE PROJECT: The existing capacity of the transmission system in southern Alberta is insufficient to provide adequate system access for the interconnection of additional wind-powered generation. Additional substations and upgrades to existing facilities are required. The AESO has outlined the need for a 240 kV AC looped system with three stages of implementation.

THE COMPONENTS: The project includes the following three stages of development.

Stage 1: Planned to reinforce the 240 kV system in the Fort MacLeod and the Brooks–Medicine Hat corridor.

Stage 2: Planned to reinforce the 240 kV and 138 kV systems in the Glenwood, Lethbridge, Blackie and City of Medicine Hat areas, including a 240 kV system loop connection to the 500 kV Langdon–Cranbrook line.

Stage 3: Planned to interconnect the Ware Junction–Langdon area via a 240 kV line.

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
911L Line Replacement	Build new 240 kV lines from Foothills substation to Windy Flats substation	June 13, 2015
Milo Junction Switching Station	Build a switching station at Milo Junction	October 31, 2011
PST Addition at Russell 632S	Phase shifting transformer and new Russell substation	April 25, 2012
Cassils to East Medicine Hat	240 kV lines from Cassils to Bowmanton	March 25, 2014
East Medicine Hat to Whitla 240 kV Transmission Line	240 kV lines from Bowmanton to Whitla	March 31, 2014
Medicine Hat Area 138 kV Line Development	138 kV system upgrades in the Medicine Hat area	July 31, 2015
240 kV lines from Goose Lake to Crowsnest/ Chapel Rock substation	240 kV Line from Goose Lake to Chapel Rock and new Chapel Rock 500 kV substation	May 14, 2017
Etzikom Coulee S/S and 240 kV line to MATL S/S	240 kV line from Journault to Picture Butte (formerly called MATL) substation	February 28, 2016
Goose Lake S/S to Etzikom Coulee S/S 240 kV Line	240 kV line from Goose Lake to Journault substation	September 30, 2016
Etzikom Coulee S/S to Whitla 240 kV Line	240 kV line from Journault to Whitla substation	February 28, 2016
Blackie Area 138 kV Upgrade	138 kV system upgrade in the Blackie area	July 31, 2014
Cypress Reactive Power Addition	Reactive power addition at Cypress substation	October 31, 2014
Ware Junction Substation Upgrade	933L line in/out at Ware Junction	July 15, 2013

THE TRANSMISSION FACILITY OWNER(S): AltaLink Management Ltd.

PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Southern Alberta Transmission Reinforcement	**$2.287 Billion** (2011$ without escalation)	**$2.82 Billion** (ISD$ with escalation)[29]

CURRENT STATUS: On December 30, 2008 the AESO applied to the AUC for approval of a NID for transmission reinforcement in Southern Alberta (SATR NID). AUC Approval No. U2009-340 was issued to the AESO on September 17, 2009.

On December 7, 2009 the AESO filed the finalized milestones and monitoring process with the AUC pursuant to their direction in Decision 2009-126 (SATR NID). AUC Approval No. U2010-264 was issued to the AESO on July 19, 2010.

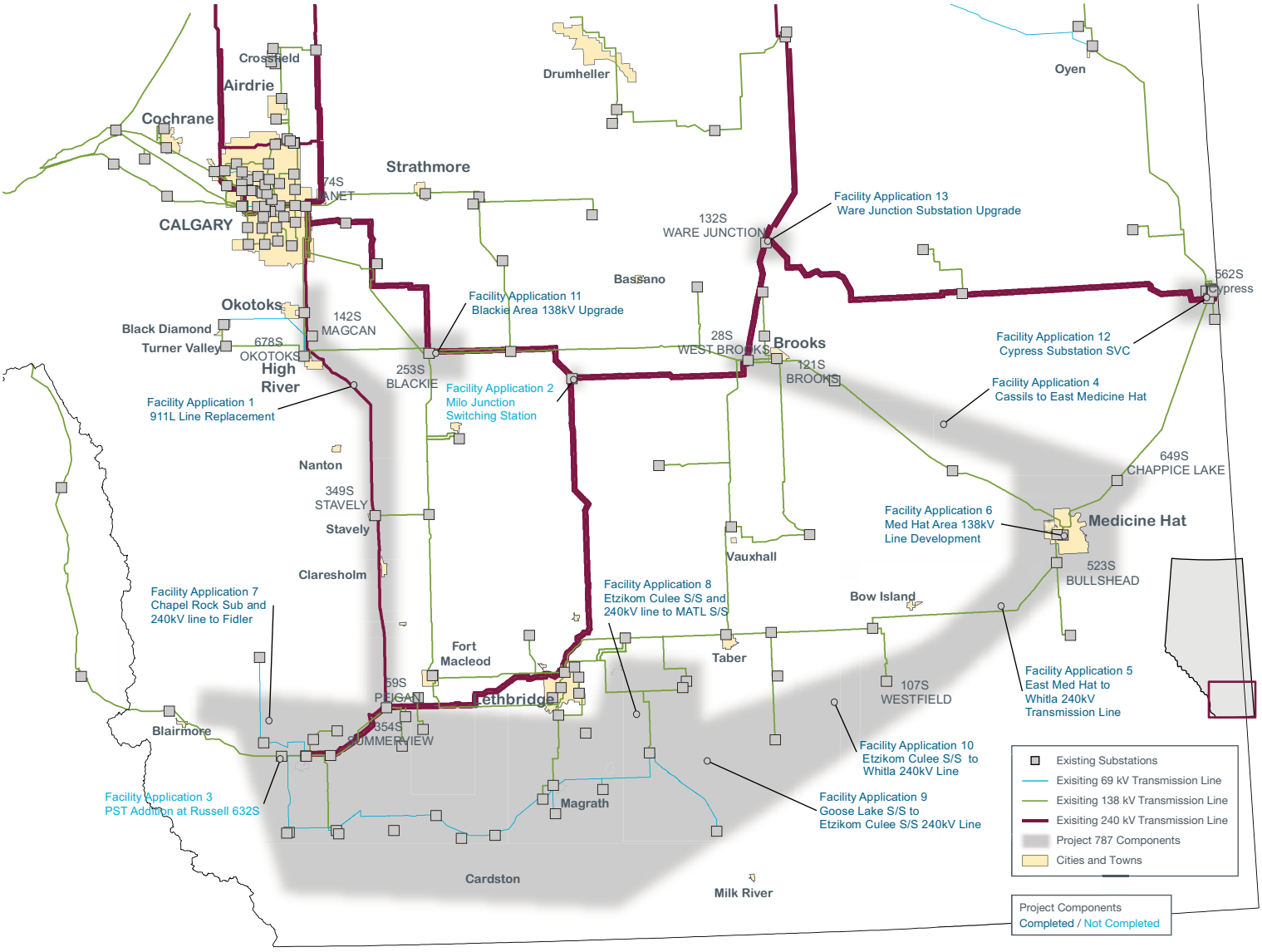
On December 14, 2012 the AESO filed the Goose Lake to Chapel Rock Amendment to the AUC SATR Approval No. U2011-115.

The Cassils–Bowmanton, Bowmanton-Whitla and Ware Junction Substation portions of this development are currently under construction.

The Milo Junction Switching Station and Phase Shifting Transformer Addition at Russell Substation are in service.

29 The $2.82 billion estimate is based on two groups of sub-projects. The first group is based on the PPS cost estimate received to date, and the second group (no PPS to date) is based on the original NID estimate with an adjustment based on the cost ratio between the PPS received and the original NID cost.

Project 787
Southern Alberta Transmission Reinforcement



16. **YELLOWHEAD AREA TRANSMISSION DEVELOPMENT (YATD);** PROJECT 671 – To improve reliability in the Drayton Valley, Edson and Alberta Beach areas.

THE PROJECT: The AESO identified the need for a number of transmission system upgrades to replace facilities that have deteriorated with age in Drayton Valley, Edson, Hinton and the Alberta Beach areas, and to meet the growing residential and commercial demand for electricity in the region.

THE COMPONENTS: Conversion of the 69 kV systems to 138 kV from Wabamun to Drayton Valley and Wabamun to Barrhead, and re-configuration and enhancements to the 138 kV system in the Edson-Hinton area.

FACILITY APPLICATION NAME	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Hinton/Edson Area Transmission	Hinton/Edson Area 138 kV transmission upgrades	October 31, 2012
Cold Creek 602S 138 kV, 27 VAr Capacitor Bank	Cold Creek 602S 138 kV, 27 VAr Capacitor Bank	February 9, 2011
Cherhill Substation and 240 kV Interconnection	Cherhill substation and 240 kV interconnection	April 2, 2012
Drayton Valley Area 138 kV Transmission	Drayton Valley area 138 kV transmission development and cap bank Installations	December 21, 2011

THE TRANSMISSION FACILITY OWNER(S): AltaLink Management Ltd.

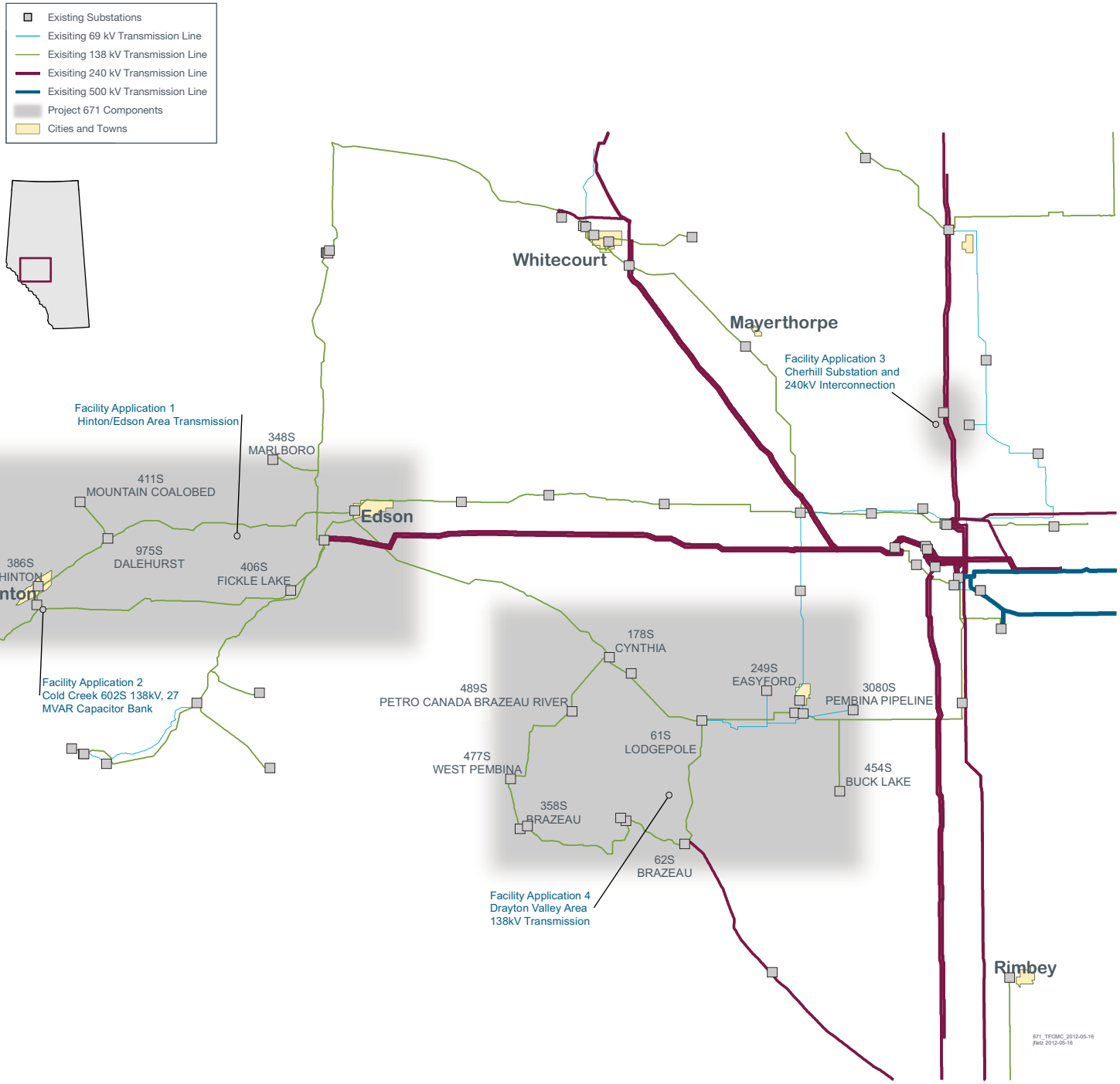
PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JUNE 2012) ESTIMATED COST	CURRENT ESTIMATED COST
Yellowhead Area Transmission Development	**$123 Million** (2011$ without escalation)	**$148 Million** (ISD$ with escalation)[18]

CURRENT STATUS: All construction work and energizations are complete. The 69 kV line and substation salvaging is expected to be completed by March 2013.

30 The cost is based upon the information provided in the Cost Committee Monthly Summary in the December 2012 TFCMC meeting, which is based upon the TFO's October 2012 Monthly Project Progress Report.

Project 671
Yellowhead Area Transmission Development



Appendix C: New Transmission Projects – A More Detailed Look At Costs

Project 719, the East Calgary Transmission Project and ENMAX Shepard Energy Centre Connection, and Project 1180, Northwest of Fort McMurray Transmission Development, have now been added to the list of transmission developments that the TFCMC monitors.

The TFCMC presented its observations on these two new projects earlier in this report in Section 2. Below, is a more detailed cost analysis based on presentations the Alberta Electric System Operator (AESO) made to the Committee.

East Calgary Transmission Project and ENMAX Shepard Energy Centre Connection (Project 719)

Required due to a growing demand for electricity in the Calgary and High River planning areas, this project was approved by the Alberta Utilities Commission (AUC) and Permit and License (P&L) was issued on November 1, 2012.

Major Components of ECTP

- East Calgary Transmission Project
  - Replace existing 336 MVA auto-transformer with two 400 MVA auto-transformers at East Calgary 5S
  - Modify ENMAX 2S to accept connection of two 400 MVA auto-transformers
  - Rebuild 138 kV lines 2.80L and 23.80L on separate structures to free up existing 240 kV towers
  - System capital cost is approximately $90 million (+20/-10%) from AESO NID May 10, 2011
  - Desired in service Q2 2014
  - Need and facility applications filed with AUC and pending approval or hearing

15

ENMAX Shepard Energy Centre Connection

- ENMAX Shepard Connection
  - Construct new 240 kV SS-25 station
  - Connect existing 911L in and out of SS-25
  - Build a new double circuit 240 kV transmission line from SS-25 to Janet 74S
  - Capital cost is approximately $50 million (+20/-10%) including cost in the order of $35 million to be charged to the market participant (AESO NID May 10, 2011)
  - Energization of SS-25 required by Q2 2013 to meet construction power requirements

16

ENMAX Shepard Energy Centre

- Plant Configuration and Location
  - Natural gas fired combined cycle power station
  - Two Mitsubishi 501G combustion gas turbines plus heat recovery steam generator
  - Total plant capacity approximately 860 MW
  - Located inside the City of Calgary at about 100 Street SE and about 1 km south of Glenmore Trail near existing major 240 kV transmission lines leading to Janet 74S
  - Currently under construction

11

ENMAX Shepard Energy Centre

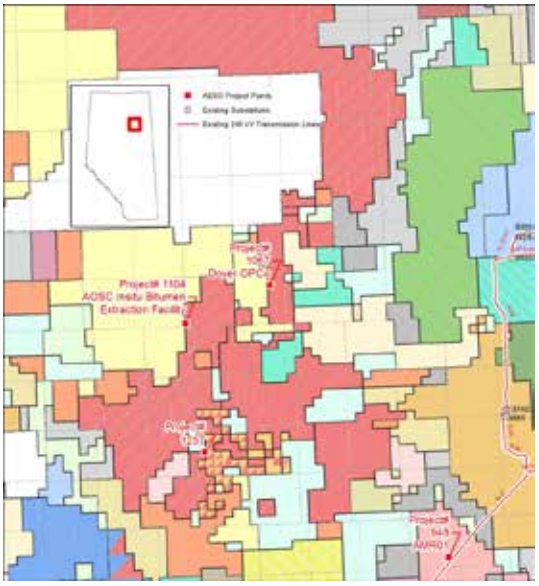
- Desired in service date and cost
  - ENMAX Shepard Inc. desires to be fully commissioned by Q1 2015 although some discussions to advance the date to 2014 have taken place
  - Installed cost of power station thought to be approximately $1.5 billion

12

Northwest of Fort McMurray Transmission Development (Project 1180)

This project is being driven by industrial growth in a portion of the northwest Fort McMurray region where there are no transmission facilities. The Needs Identification Document (NID) was filed with the Alberta Utilities Commission (AUC) on November 10, 2011 and approved by the AUC on June 18, 2012.

Need for NW FMM Development

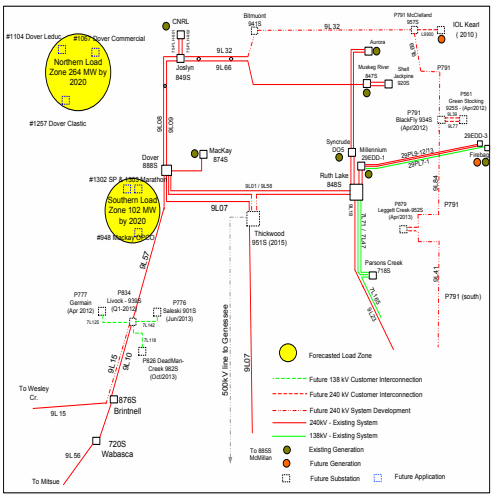


- NW FMM area estimated reserves of 318 bb (Grosmont reserves)
- SAGD/TAGD technology driving strong electric load growth projections for the area.
- 4 customer connection applications currently with AESO, 2 more anticipated shortly
- No existing transmission facilities in the area.

4

Need for NW FMM Development

- **NW FMM Area Load Forecast**
  - Forecast load by 2021
    - 260 – 320 MW (northern)
    - 100 – 130 MW (southern)
  - Long term forecast (2025 & beyond)
    - 580 – 1060 MW
- **NW FMM Area Generation Forecast**
  - New generation by 2021
    - Approx 255 MW



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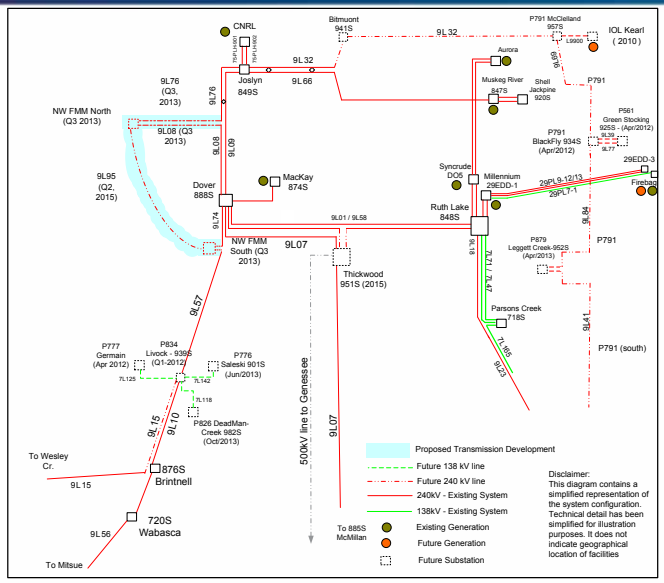
NW FMM Development Options Considered

- The alternatives for NW FMM transmission development were limited by the location and magnitude of the proposed / forecasted load and generation.
- Total load in the area could be from 366 MW to 450 MW, therefore 138 kV development was ruled out
- 500 kV development considered too big for the initial stages
- 240 kV transmission development has been sized and configured to reliably serve the short term requirements and the long term needs of the area.

6

NW FMM Development – 240 kV Loop



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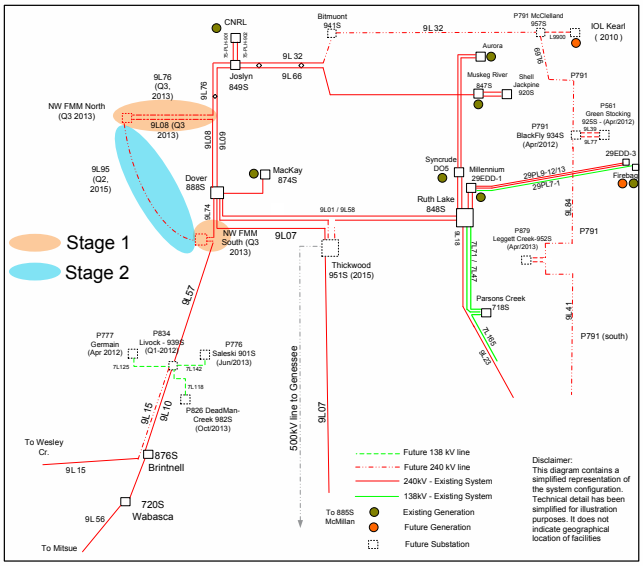
NW FMM Development – 240 kV Loop

- By Q3 2013
  - new 240kV switching substation referred to as NW FMM South
  - existing 9L57 in/out at NW FMM South
  - new 240kV switching substation referred to as NW FMM North
  - 9L08 Joslyn to Dover in/out at NW FMM North (approx 50 km of 240 kV double cct line)
- By Q2 2015
  - approximately 80 km 240 kV double cct line with one side strung between the new NW FMM South substation and the new NW FMM North substation

8

NW FMM Development - Costs

- Project construction in two stages to facilitate customer connections
- Stage 1 (Q3 2013)
  $180 Million
  (+/-30%, $2014)
- Stage 2 (Q2 2015)
  $190 Million
  (+/-30%, $2015)



Appendix D: TFCMC Working Documents

The TFCMC receives reports and cost summary updates, on a monthly basis, so that the Committee can better understand the costs and changes associated with the transmission projects it monitors. In this part of the report, samples of the cost summary updates are included to provide readers with a better insight as to the type of material the TFCMC reviews.

The cost summaries on the following pages are just a portion of the individual documents, which also include detailed information on authorized cost changes and cost estimate changes from the Needs Identification Document (NID) phase to the Proposal to Provide Service (PPS) stage.

Project Cost Reporting for TFCMC, Project 535: Northwest Transmission Development (NWTD); October 2012

Cost Committee Monthly Summary

Project 535: North West Transmission Development

Project Description:
North West Transmission Development

Month of TFCMC Meeting : 2012 / Oct
Report for the Month of : 2012 / Aug

NID Application			
Filing Date	Approval Date	TFO / Stage	NID Estimated Cost
06-Mar-06	Aug 17, 2006	ATCO	$312.0
		Total	$312.0

Facility					Costs		
Facility Application Number	Facility Application Name	Facility Application Filing Date	Facility Application Approval Date	Overall Facility In Service Date	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget
1	9L15 240kV Wesley Creek 834S to Brintnell 876S, 2 300MVA Tx P598 (Formerly P598)	Jun 19,2007	Nov 23,2007	Mar 19,2010	$208.33	-$1.10	$207.23
2	7L131/7L106 144kv D/C line Wesley Creek to Meikle 905S & CTs P599 (Formerly P599)	Jul 29,2008	Dec 19,2008	Sep 29,2010	$193.19	-$0.74	$192.45
3	7L133-144 kv S/C line Sulphur Point 828S to High Level 786S P600 (Formerly P600)	May 19,2009	Sep 11,2009	Mar 19,2011	$77.56	-$48.01	$29.55
4	High Level 786S +/- 30 MVAR SVC (Formerly P601)	Apr 14,2009	Sep 1,2009	Jun 30,2010	$12.30	$0.17	$12.47
5	7L113-144kv S/C line Ring Creek 853S to New Arcenciel 930S (Formerly P602,P604)	Jun 30,2010	Dec 2,2010	Dec 19,2011	$121.25	-$56.98	$64.26
6	Arcenciel 930S -30 +50 MVAR synch cond (Formerly P603)	Feb 3,2012	Apr 24,2012	May 31,2013	$23.15	$20.65	$43.81
7	Arcenciel 930S +/- 30 MVAR SVC (P605)	Jun 30,2010	Dec 2,2010	Sep 7,2011	$12.05		
8	Little Smoky 813S-install +/-100MVAR SVC & 2-144kV breakers (Formerly P606)	Jun 29,2009	Jun 29,2009	Mar 31,2010	$21.55		
				Total:	$669.4	-$86.01	$549.8

Project Comments:
• All cost numbers are in Million$ - Cost change on 1 and 2. Corrected costs in the data base.

Project Cost Reporting for TFCMC, Project 629: Alberta Industrial Heartland Bulk Transmission Development (HBTD); October 2012

Cost Committee Monthly Summary

Project 629: Alberta Industrial Heartland Bulk Transmission Development

Project Description:

The project includes a new Heartland 12S substation, a new 500 kV double circuit line from Ellerslie 89S to Heartland 12S and connecting to a new 240 kV double circuit line from Heartland 12S into 942L and 943L 240 kV lines.

Month of TFCMC Meeting : 2012 / Oct
Report for the Month of : 2012 / Aug

NID Application			
Filing Date	Approval Date	TFO / Stage	NID Estimated Cost
CTI	Dec 09, 2009		
		Total	

Facility					Costs		
Facility Application Number	Facility Application Name	Facility Application Filing Date	Facility Application Approval Date	Overall Facility In Service Date	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget
1	500kV 1206L/1212L (Formerly P629)	Sep 27,2010	Nov 1,2011	Sep 30,2013	$580.69	$41.46	$622.15
2	Heartland 12S Ellerslie 89S and 1054L/1061L (Formerly P1066)	Sep 27,2010	Nov 1,2011	Sep 30,2013			
				Total:	$580.7	$41.46	$622.1

Project Comments:

- All cost numbers are in Million$.
- Total $ includes salvage.

Project Cost Reporting for TFCMC, Project 671: Yellowhead Area Transmission Development (YATD); October 2012

Cost Committee Monthly Summary

Project 671: Yellowhead Area Transmission Development

Project Description:

Yellowhead Area Transmission Development - all NID work completed under P671

Month of TFCMC Meeting : 2012 / Oct
Report for the Month of : 2012 / Aug

NID Application			
Filing Date	Approval Date	TFO / Stage	NID Estimated Cost
09-Jun-09	May 12, 2010	AML	$87.8
		Total	$87.8

Facility					Costs		
Facility Application Number	Facility Application Name	Facility Application Filing Date	Facility Application Approval Date	Overall Facility In Service Date	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget
1	Hinton/Edson Area Transmission (Formerly P909)	Aug 5,2010	Apr 29,2011	Oct 31,2012	$51.36	$8.06	$59.42
2	Cold Creek 602S 138kV, 27 MVAR Capacitor Bank (Formerly P910)	Jul 8,2010	Aug 16,2010	Feb 9,2011	$2.25		$2.25
3	Cherhill Substation and 240kV Interconnection (Formerly P911)	Jul 26,2010	Apr 21,2011	Apr 2,2012	$30.50	$0.01	$30.51
4	Drayton Valley Area 138kV Transmission (Formerly P912)	Jul 30,2010	Apr 27,2011	Dec 21,2011	$41.86	$1.21	$43.07
				Total:	$126.0	$9.28	$135.3

Project Comments:

- All cost numbers are in Million$. - FA 1 isd delayed to Oct 31/2012 due to poor Spring weather.

Project Cost Reporting for TFCMC, Project 719: ENMAX Shepard Energy Centre (ECTP); October 2012

Cost Committee Monthly Summary

Project 719: ENMAX Shepard Energy Centre

Project Description:

800 MW Generation Facility and Associated Substation - 3 phase project includes system work at East calgary, Janet and associated transmission upgrades.

Month of Reporting : 2012 / Oct

Report for the Month of : 2012 / Aug

NID Application			
Filing Date	Approval Date	TFO	NID Estimated Cost
10-May-11	Nov 02, 2012	AML - 1	$37
		AML - 2	$34
		ENMAX	$66
		Total	$136

Facility					Costs		
Facility Application Number	Facility Application Name	Facility Application Filing Date	Facility Application Approval Date	Overall Facility In Service Date	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget
1	FA1 - AltaLink Facilities	Jun 27,2011	Jul 16,2012	Jun 30,2015	$70.77	na	na
2	FA2 - Enmax Facilities	Jun 10,2011	Jul 16,2012	Jun 30,2015	$65.55	na	na
				Total:	$136.32		

Project Comments:

1. All costs are in Millions$
2. Project Schedule:
• In-Service Dates delayed due to intervieners scheduled Hearing with the Alberta Utility Commission Scheduled for September 2012. Impact to ISD is 3-6 months.
Working with TFO's on recovery schedule:
• 1st ISD July 1, 2013 Shepard Interconnection
• 2nd ISD Aug 2013-5S expansion TX addition
• 3rd ISD- June 30, 2015-5S replacement
3. Project Costs:
• System Cost $102M & Customer Cost $34M
• Project remains within budget
4. Regulatory
• Awaiting AUC approval on NID and FAs

Project Cost Reporting for TFCMC, Project 737: North South Transmission Reinforcement (HVDC) – Eastern Alberta Transmission Line; October 2012

Cost Committee Monthly Summary

Project 737: North South Transmission Reinforcement - EATL

Project Description:

Construction of a +- 500KV bipolar HVDC transmission line from the vicinity of Heartland substation to the vicinity of West Brook substation. Initial development will be a monopole with at least 1000 MW transfer capacity.

Month of TFCMC Meeting : 2012 / Oct

Report for the Month of : 2012 / Aug

NID Application			
Filing Date	Approval Date	TFO / Stage	NID Estimated Cost
CTI			
		Total	

Facility					Costs		
Facility Application Number	Facility Application Name	Facility Application Filing Date	Facility Application Approval Date	Overall Facility In Service Date	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget
1	Facility Application 1 - ATCO East DC Facilities (Currently known to TFO as P961)	Mar 29,2011	Jan 15,2013	Dec 15,2014	$1,775.76	-$2.55	$1,773.20
3	Facility Application 3 - AltaLink East DC Facilities (Currently known to TFO as P961)	May 1,2011	Jan 31,2013	Dec 15,2014	$42.55	$15.73	$58.28
4	Facility Application 4 - EPCOR East DC Facilities (Currently known to TFO as P961)	Mar 30,2011	Jan 15,2013	Dec 15,2014	$0.12		$0.12
				Total:	$1,818.43	$13.18	$1,831.61

Project Comments:

• All cost numbers are in Million$
• This report only reflects the East HVDC line (aka EATL) of the North South Transmission Reinforcement

Project Cost Reporting for TFCMC, Project 737: North South Transmission Reinforcement (HVDC) – Western Alberta Transmission Line; October 2012

Cost Committee Monthly Summary

Project 737: North South Transmission Reinforcement - WATL

Project Description:

Construction of a 500kV HVDC transmission line from the vicinity of the Genesee substation to the vincinity of the Langdon substation. Initial development will be a monopole with 1000 MW transfer capacity.

Month of TFCMC Meeting : 2012 / Oct
Report for the Month of : 2012 / Aug

NID Application			
Filing Date	Approval Date	TFO / Stage	NID Estimated Cost
CTI			
		Total	

Facility					Costs		
Facility Application Number	Facility Application Name	Facility Application Filing Date	Facility Application Approval Date	Overall Facility In Service Date	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget
2	Facility Application 2 - AltaLink West DC Facilities (Currently known to TFO as P962)	Mar 1,2011	Oct 9,2012	Apr 22,2015	$1,542.19	$21.98	$1,564.17
				Total:	$1,542.19	$21.98	$1,564.17

Project Comments:

• All cost numbers are in Million$

Project Cost Reporting for TFCMC, Project 786: Edmonton Region 240 kV Line Upgrades (ERLU); October 2012

Cost Committee Monthly Summary

Project 786: Edmonton Region 240kV Line Upgrades

Project Description:

Upgrade 240kV transmission lines in Edmonton area; add one 240kV phase shifter at Dover substation

Month of TFCMC Meeting : 2012 / Oct
Report for the Month of : 2012 / Aug

NID Application			
Filing Date	Approval Date	TFO	NID Estimated Cost
26-Aug-08	Feb 24, 2009	AML	$77.26
		EPCOR	$9.47
		ATCO	$38.68
		TransAlta	
		Total	$125.41

Facility					Costs		
Facility Application Number	Facility Application Name	Facility Application Filing Date	Facility Application Approval Date	Overall Facility In Service Date	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget
1	AML Keephills Substation Addition **(Formerly P953)**	Nov 6,2009	Mar 19,2010	Jul 31,2010	$101.35	$11.08	$112.42
2	AML Rebuild 240kV 904L (1043L)	Jul 28,2010	Aug 12,2011	Jan 29,2013			
4	AML 902L Restring & 909L Retermination **(Formerly P1057)**	Aug 5,2011	Jan 11,2012	Mar 5,2013			
5	AML 908L, 909L Restring **(Formerly P1058)**	Sep 13,2009	Feb 10,2010	Mar 20,2011			
6	EPCOR Jasper, Petrolia **(Formerly P955)**	Apr 15,2010	Jun 16,2010	Jun 14,2011	$4.55	$2.60	$7.15
3	EPCOR 1044EL, 1045EL **(Formerly P955)**	Oct 15,2010	Aug 12,2011	Oct 13,2011	$7.97		$7.97
7	ATCO Phase Shifter **(Formerly P957)**	Jun 24,2011	Jul 14,2011	Mar-29-2013	$29.34	$6.11	$35.45
8	TransAlta 902L, 1043L **(Formerly P959)**	Jun 30,2010	Jan 27,2011	Mar 5,2012	$9.65		$9.65
				Total:	$152.85	$19.79	$172.64

Project Comments:

• All cost numbers are in Million$
• FA 7 - PST move to Livock, increase in transportation costs. Delay in isd due to moving restrictions for PST to site
•

Project Cost Reporting for TFCMC, Project 787: Southern Alberta Transmission Reinforcement (SATR); October 2012

Cost Committee Monthly Summary

Project 787: Southern Alberta Transmission Reinforcement

Project Description:
Re-enforcement of transmission system in Southern Alberta

Month of Reporting : 2012 / Oct
Report for the Month of : 2012 / Aug

NID Application			
Filing Date	Approval Date	TFO	NID Estimated Cost
30-Dec-08	Sep 17, 2009	Stage I	$830
		Stage II	$722
		Stage III	$279
		AFUDC & Escala	$1,612
		Total	$3,443

Facility					Costs		
Facility Application Number	Facility Application Name	Facility Application Filing Date	Facility Application Approval Date	Overall Facility In Service Date	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget
1	New Windy Flats and 240kV line (SFTP) (Formerly P882)	Sep 14,2012	Sep 6,2013	Jun 3,2015	$440.20		$440.20
2	Milo Junction Switching Station (Formerly P883)	Dec 21,2009	Aug 5,2010	Nov 1,2011	$29.70		$29.70
3	PST Addition at Russell 632S (Formerly P884)	Aug 27,2010	Jan 12,2011	Apr 25,2012	$17.21		$17.21
4	Cassils to Bowmanton (Formerly P886)	Jul 27,2010	Jun 8,2011	Mar 25,2014	$407.91		$407.91
5	Bowmanton to Whitla 240kV Transmission Line (Formerly P887)	Jul 27,2010	Jun 8,2011	Mar 31,2014	$352.75		$352.75
6	Med Hat Area 138kV Line Development (Formerly P888)	Oct 31,2012	Oct 31,2013	May 26,2014	$120.28		$120.28
7	Chapel Rock Sub and 240kV line to Fidler (Formerly P1034)	Aug 25,2013	Jul 22,2014	Apr 1,2016			
8	Etzikom Culee S/S and 240kV line to Picture Butte S/S (Formerly P1035)	Sep 1,2012	Sep 1,2013	Nov 1,2015			
9	Goose Lake S/S to Etzikom Culee S/S 240kV Line (Formerly P1036)	Jun 28,2013	Jul 28,2014	Sep 30,2016			
10	Etzikom Culee S/S to Whitla 240kV Line (Formerly P1037)	Sep 1,2012	Sep 27,2013	Sep 1,2015			
11	Blackie Area 138kV Upgrade (Formerly P1038)	Aug 10,2012	Feb 9,2013	Jul 15,2015			
12	Cypress Substation SVC (Formerly P1039)	Oct 17,2012	Apr 3,2013	Dec 15,2014			
13	Ware Junction Substation Upgrade (Formerly P1040)	Apr 5,2011	Feb 6,2012	Jul 15,2013	$6.13		$6.13
					$1,374.19		$1,374.19

Project Comments:

• All cost numbers are in Million$
FA#1: Four days delay in filing due to AESO's delay signing the South Region Reactive Study.
FA#6: FA Application delayed due to Landowner's issues. FA aproval date forecast by AESO assuming FA Hearing will occur. (Note: Actual FA approval depends of trhird party, i.e. AUC)
FA#12 Facility Application cancelled due to scope change as a result of the South Region Reactive Study outcome (SVC Cancellation and replacement by Shunt Capacitor Banks - New designe and PPS is required). Change will be reflected in future Monthly Report.

Project Cost Reporting for TFCMC, Project 791: North Fort McMurray Transmission Development (NFMD); October 2012

Cost Committee Monthly Summary

Project 791: North Ft McMurray Transmission Development

Project Description:
North Ft McMurray Transmission Development

Month of TFCMC Meeting : 2012 / Oct
Report for the Month of : 2012 / Aug

NID Application			
Filing Date	Approval Date	TFO	NID Estimated Cost
12-Aug-10	Jun 24, 2011	ATCO	$237.44
		Total	$237.44

Facility					Costs		
Facility Application Number	Facility Application Name	Facility Application Filing Date	Facility Application Approval Date	Overall Facility In Service Date	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget
1	North Fort McMurray 240 kV Transmission Development	Sep 10,2010	Jul 28,2011	Apr 1,2013	$237.44	$90.96	$328.40
				Total:	$237.44	$90.96	$328.40

Project Comments:
• All cost numbers are in Million$.

Project Cost Reporting for TFCMC, Project 811: Central East Area Transmission Development (CETD); October 2012

Cost Committee Monthly Summary

Project 811: Central East Area Transmission Development

Project Description:
Transmission Development in Waiwright, Lloydminster, Provost, Vegreville Alliance/Battle River and Cold Lake

Month of TFCMC Meeting : 2012 / Oct
Report for the Month of : 2012 / Aug

NID Application			
Filing Date	Approval Date	TFO	NID Estimated Cost
17-May-10	Feb 10, 2011	Stage-1 ATCO	$166.41
		Stage-1 AML	$143.76
		Stage-2 ATCO	$60.14
		Escalation in NID	$60.68
		Total	$431.0

Facility					Costs		
Facility Application Number	Facility Application Name	Facility Application Filing Date	Facility Application Approval Date	Overall Facility In Service Date	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget
1	FA 1 - Cold Lake Area Reinforcements - Except Bonnyville	Mar 7,2012	Aug 31,2012	Mar 1,2013	$139.57		
2	FA 2 - Cold Lake Area Reinforcements - Bonnyville	Apr 27,2012	Dec 31,2012	Aug 1,2013			
3	FA 3 - St. Paul Area Upgrades - Watt Lake, 7LA92	Dec 15,2011	Sep 30,2012	Feb 28,2013	$50.85		
4	FA 4 - St. Paul Area Upgrades - St. Paul 707S, Whitby Lake 819S & 7L139/7L70	Jul 31,2012	Mar 31,2013	Dec 1,2013			
5	FA 5 - Vermillion 710S Substation Upgrade	Oct 24,2011	Jun 13,2012	Mar 1,2013	$6.70		
6	FA 6 - Heisler Area Upgrades	Dec 23,2011	Feb 28,2012	Mar 1,2013	$33.51		
7	FA 7 - Kitscoty Area Upgrades	Jun 19,2012	Dec 31,2012	Jul 1,2013			
8	FA 8 - 7L749 Replacement	Dec 31,2012	Jun 30,2013	May 22,2014	$33.17		
9	FA 9 - Double Circuit Line Clearance Mitigations (Letter Of Enquiry)	Oct 24,2011	Jun 13,2012	Dec 31,2012	$13.28		
10	FA 10 - Provost & Wainwright Area Upgrades	Aug 8,2012	Jun 20,2013	Sep 1,2014			
11	FA 11 - 7L50 Rebuild	Oct 19,2015	May 2,2016	Dec 1,2017			
12	FA 12 - Cold Lake Reinforcement (2017) - 240kV	Sep 7,2015	Mar 21,2016	Dec 1,2017			
				Total:	$277.1		

Project Comments:

Project Cost Reporting for TFCMC, Project 812: Hanna Region Transmission Development (HATD); October 2012

Cost Committee Monthly Summary

Project 812: Hanna Region Transmission Development

Project Description:
Transmission development in Hanna, Sheerness and Battle River

NID Application			
Filing Date	Approval Date	TFO	NID Estimated Cost
14-Aug-09	Apr 29, 2010	ALM	$228.1
		ATCO	$643.9
		Escalation in NID	$110.68
		Total	$982.7

Month of TFCMC Meeting : 2012 / Oct
Report for the Month of : 2012 / August

Facility					Costs		
Facility Application Number	Facility Application Name	Facility Application Filing Date	Facility Application Approval Date	Overall Facility In Service Date	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget
1	Youngstown 772S Capacitor bank addition (Formerly P977)	Aug 9,2010	Nov 15,2010	Oct 6,2011	$6.29	-$0.36	$5.93
2	Battle River 757S Capacitor Bank addition (Formerly P978)	Aug 9,2010	Aug 27,2010	Oct 3,2011	$3.00	-$0.17	$2.83
3	New Lanfine 240/144kV substation (Formerly P979)	Dec 21,2010	May 8,2012	Mar 29,2013	$38.75	-$2.20	$36.54
4	Lanfine 959S 200MVAr SVC (Formerly P980)	Mar 4,2011	May 8,2012	May 31,2013	$39.36	-$2.24	$37.12
5	Lanfine-Oyen 144kV S/C Line 7L132 (Formerly P982)	Mar 21,2011	May 8,2012	May 31,2013	$15.62	-$0.89	$14.73
6	Relocate 7L98 Oyen 767S - Lanfine 959S (Formerly P995)	Mar 21,2011	Dec 22,2011	May 31,2013	$12.77	-$0.73	$12.04
7	Oakland 946S 240kV S/S combined with Anderson-Oakland line (Formerly P996)	Nov 25,2010	May 8,2012	Mar 29,2013	$45.47	-$1.72	$43.75
8	Oakland-Lanfine 240kV S/C Line 9L924 (Formerly P998)	Dec 21,2010	May 8,2012	Mar 29,2013	$119.93	-$4.21	$115.71
9	Coyote Lake 963S 240kV S/S combined with Oakland-Coyote line (Formerly P999)	Feb 7,2011	May 8,2012	Apr 30,2013	$77.80	-$4.42	$73.38
10	Coyote Lake 963S - Michichi Creek 802S 144kV SC Line 7L128 (Formerly P1000)	Apr 8,2011	May 8,2012	May 31,2013	$39.25	-$2.23	$37.02
11	Pemukan 932S 240 kV Substation (Formerly P1001)	Jan 24,2011	May 8,2012	May 31,2013	$32.49	-$1.85	$30.64
12	New Lanfine-Pemukan 240kV S/C Line 9L46 (Formerly P1003)	Mar 4,2011	May 8,2012	May 31,2013	$97.24	-$5.53	$91.71
13	Facility Application 13 - 144kV Capacitor Bank and Circuit Breaker Additions at Three Hills Substation 770S (Formerly P1022)	Oct 8,2010	Dec 23,2010	Dec 13,2011	$27.04	-$1.54	$25.50
18	Rowley 768S - Michichi-Three Hills 144kV DC Line 7L25 (Formerly P1022)	Nov 22,2010	May 17,2011	Jun 1,2012			
14	Hansman Lake - Pemukan 240kV S/C Line 9L966 (Formerly P1011)	Jan 24,2011	May 8,2012	May 31,2013	$67.69	-$3.85	$63.84
15	Pemukan 932S - Monitor 774S 144kV S/C Line 7L127 (Formerly P1013)	Jan 24,2011	May 8,2012	May 31,2013	$14.31	-$0.81	$13.50
16	Relocate 7L79 line from Monitor 774S - Pemukan 932S (Formerly P1015)	Jan 24,2011	May 8,2012	May 31,2013	$10.26	-$0.58	$9.68
17	Heatburg 948S - Three Hills-Nevis 144kV D/C Line 7L16/7L159 (Formerly P1021)	Feb 15,2012	Jun 15,2012	May 31,2013	$14.84	-$0.84	$14.00
19	Stettler 769S - Nevis 768S 144kV S/C Line 7L143 (Formerly P1023)	Jun 3,2011	Dec 20,2011	May 31,2013	$41.29	-$2.35	$38.94
20	Nilrem 574S combined with D/C 240kV 953L -1047L and Tucuman 478S combined with D/C 138kV 679L-680L (Formerly P1024,P1025)	Nov 15,2010	Nov 10,2011	Mar 29,2013	$76.50	$5.21	$81.70
21	Hardisty 377S Substation Capacitor Bank (Formerly P1024,P1025)	Nov 29,2010	May 3,2011	Jun 30,2012			

Project Cost Reporting for TFCMC, Project 813: Red Deer Region Transmission Development (RDTD); October 2012

Cost Committee Monthly Summary

Project 813: Red Deer Area Transmission Development

Project Description:

Transmission system development that consists of new 240/138 kV substation developments, additions to existing substations, new 138 kV transmission line developments, 138 kV transmission line rebuilds and discontinued operation of existing 138 kV transmission lines

Month of TFCMC Meeting : 2012 / Oct
Report for the Month of : 2012 / Aug

NID Application			
Filing Date	Approval Date	TFO / Stage	NID Estimated Cost
20-Jul-11	Apr 10, 2012	AML Stage 1	$207.9
		AML Stage 2	$15.0
		Total	$222.9

Facility					Costs		
Facility Application Number	Facility Application Name	Facility Application Filing Date	Facility Application Approval Date	Overall Facility In Service Date	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget
1	Red Deer Area Transmission Development Stage I - Brownfield	Sep 26,2011	Sep 24,2012	May 31,2013	$20.72	$0.71	$21.43
2	Red Deer Area Transmission Development Stage I - Rebuilds	Dec 1,2012	Dec 1,2013	Nov 26,2014			
3	Red Deer Area Transmission Development Stage I - New Builds	Dec 1,2012	Dec 1,2013	Jan 15,2015			
4	Red Deer Area Transmission Development - Salvage	May 30,2013	Aug 30,2013	Jun 13,2015			
5	Red Deer Area Transmission Development Stage II	Jun 22,2012	Dec 19,2013	Jun 13,2015			
				Total:	$20.7	$0.71	$21.4

Project Comments:

Project Schedule:
• Filing of FA#2 and FA#3 delayed to December 2012 because re-design of 755L towers resulting in more consultation in area. PPS will also be resubmitted. Delay has also pushed ISD to Nov 2014.
• ISD for FA#1 pushed to May 2013 because AML cannot get plant outages in winter.

Project Cost Reporting for TFCMC, Project 922: ENMAX No. 65 Substation (ESCS); October 2012

Cost Committee Monthly Summary

Project 922: ENMAX No. 65 Substation

Project Description:

New 240kV / 13k kV substation in south Calgary and associated transmission facilities

Month of TFCMC Meeting : 2012 / Oct
Report for the Month of : 2012 / Aug

NID Application			
Filing Date	Approval Date	TFO / Stage	NID Estimated Cost
CTI	CTI		
		Total	

Facility					Costs		
Facility Application Number	Facility Application Name	Facility Application Filing Date	Facility Application Approval Date	Overall Facility In Service Date	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget
1	New 240/138 kV Substation	Dec 17,2010	Nov 3,2011	Aug 30,2013	$31.14		
2	ENMAX No. 65 I/C to 911L	Feb 16,2011	Nov 3,2011	Aug 30,2013	$6.90		
				Total:	$38.0		

Project Comments:

1. All costs are in Millions$
2. Project Schedule:
• ISD delayed from December 2012 to August/September 2013 for the reasons identified in the TFO monthly reports.
3. Project Costs:
• Project remains within budget

Project Cost Reporting for TFCMC, Project 1101: Christina Lake Area Development (CHL); October 2012

Cost Committee Monthly Summary

Project 1101: Christina Lake Area Development

Project Description:
Christina Lake Area Development

Month of TFCMC Meeting : 2012 / Oct
Report for the Month of : 2012 / Aug

NID Application			
Filing Date	Approval Date	TFO / Stage	NID Estimated Cost
20-Oct-11	Apr 24, 2012	AML	$394.9
		ATCO	$11.7
		Total	$406.60

Facility					Costs		
Facility Application Number	Facility Application Name	Facility Application Filing Date	Facility Application Approval Date	Overall Facility In Service Date	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget
1	CHL1	Jun 29,2012	Dec 14,2012	Jun 3,2013	$19.96		$19.96
2	CHL1 to CHL4	Aug 30,2012	Jun 3,2013	Feb 28,2014			
3	CHL4 to CHL2 to Heart Lake	Feb 20,2013	Nov 22,2013	Aug 28,2015			
4	ATCO Heart Lake	Feb 20,2013	Nov 22,2013	Aug 28,2015			
				Total:	$19.96		$19.96

Project Comments:
• All cost numbers are in Million$.

Project Cost Reporting for TFCMC, Project 1117: Foothills Area Transmission Development – East Calgary Development (FATD); October 2012

Cost Committee Monthly Summary

Project 1117: FATD - East Calgary Development

Project Description:
Project 1117 - East Calgary Development, including:

-New 240kV line(s) from Foothills 237S to Enmax 65S
-Re-energization of 850L from 65S to 102S
-Salvage 727L from 850L junction to Janet 74S

Month of Reporting : 2012 / Oct
Report for the Month of : 2012 / Aug

NID Application			
Filing Date	Approval Date	TFO	NID Estimated Cost
05-Jul-12		AltaLink	$413
		ENMAX	$4
		Total	$417

Facility					Costs		
Facility Application Number	Facility Application Name	Facility Application Filing Date	Facility Application Approval Date	Overall Facility In Service Date	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget
1	Facility Application 1 - Foothills-Enmax 65S AltaLink Facilities	Jul 13,2012	Jul 12,2013	Jul 30,2015	$247.94		
2	Facility Application 2 - Foothills-Enmax 65S Enmax Facilities	Jul 13,2012	Jul 12,2013	Jul 30,2015	$86.59		
3	Facility Application 3 - East Calgary-Janet-Langdon AltaLink Facilities	Jul 16,2012	Jul 15,2013	Aug 14,2015	$104.64		
4	Facility Application 4 - East Calgary-Janet-Langdon Enmax Enmax Facilities	Jul 13,2012	Jul 12,2013	Aug 14,2015	$3.48		
5	Facility Application 5 - 138kV from 237S to Okotoks	Jul 16,2012	Jul 15,2013	Oct 9,2015	$0.91		
				Total:	$443.55		

Project Comments:
1) All Project costs are in Millions$

2) Project Schedule:
The NID and all Facility Applications were filed July 5, 2012 and July 13, 2012 respectively.
3) Project Costs:
The project currently remains on budget within the PPS level estimates provided by the Transmission Facility Owners.
• Variance between NID Filed Costs and PPSs Amount: $417 Million(NID filed) vs $443 Million (PPS amount) due to the removal of AFUDC cost.
4) Regulatory:
The project is under regulatory review by the Alberta Utility Commission, for construction permit and license.

Project Cost Reporting for TFCMC, Project 1180: Northwest of Fort McMurray Transmission Development (NW FMM); October 2012

Cost Committee Monthly Summary

Project 1180: NW Ft McMurray Transmission Development

Project Description:
NW Ft Mac Transmission Development

Month of TFCMC Meeting : 2012 / Oct
Report for the Month of : 2012 / Aug

NID Application			
Filing Date	Approval Date	TFO / Stage	NID Estimated Cost
10-Nov-11	Jun 19, 2012	Stage I	$21.0
		Stage II	$156.1
		Stage III	$189.2
		Total	$366.3

Facility					Costs		
Facility Application Number	Facility Application Name	Facility Application Filing Date	Facility Application Approval Date	Overall Facility In Service Date	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget
1	Facility Application 1 - Birchwood Creek	Nov 21,2012	Apr 10,2013	May 8,2014			
2	Facility Application 2 - Ells River Sub/Transmission	Dec 5,2012	Jun 19,2013	May 1,2014			
3	Facility Application 3 - Ells River to Birchwood Creek 240 kV Loop	Mar 27,2013	Oct 9,2013	Apr 22,2015			
				Total:			

Project Comments:

• All cost numbers are in Million$.

Appendix E: Transmission Facility Owners Responses

Under the TFCMC's mandate, the Committee shall allow Transmission Facility Owners (TFOs) to review and provide written comments on any report produced that references a TFO or a project a TFO is developing. The following responses were received in regards to the December 2012 Report.

ALTALINK | 2611– 3rd Avenue SE, Calgary, Alberta T2A 7W7 | www.altalink.ca

February 13, 2013

Henry Yip, Chair
Transmission Cost Monitoring Committee
Email:hcyip@teleus.net

Henry,

Thank you for the opportunity to comment on your fourth semi-annual Transmission Cost Monitoring Committee Report. AltaLink continues to be supportive of providing greater transparency to the industry practices which determine how transmission projects are built.

Section 2 of your report, *TFCMC Observations to Date,* summarizes the challenges of benchmarking transmission projects across jurisdictions. As a general principle, we would agree that it is difficult to compare transmission projects as costs are significantly impacted by functional specifications, geotechnical conditions, weather, market conditions and compliance to regulatory processes. Proper benchmarking analysis needs to be sophisticated enough to account for the impact of the factors listed above.

In the case of the HVDC converter stations for both EATL and WATL, the converters meet with the same functional specification, comply with the same regulatory process and were bid in the same market conditions. It should be noted by the Committee that the resultant cost between the projects should be more comparable than comparisons with other jurisdictions. It is difficult to put projects from other jurisdictions into context given the significant variation of the cost drivers associated with each project.

The Committee has also noted that the dead end towers near the Cassils substation are much larger and heavier than towers in a similar application elsewhere in Canada. AltaLink would like to reiterate that the towers we have used on the CBW project meet the functional specification identified by the AESO and that the AESO has certified such to the AUC as part of the facilities application process. Dead end structures are heavier in nature versus tangent towers as they serve a different function and are under significantly more load forces than a tangent tower. AltaLink would like to confirm that the dead end towers will not have additional interconnections or additional lines added other than those planned as part of CBW.

More observations can be drawn from the Christina Lake review that was performed. It is important to note that the risk profile for projects attempted in this geographical region is higher than other regions of the province. The Committee highlighted their awareness of geotechnical issues and the short construction window. In actual fact, most construction can only occur in the winter period when conditions are frozen. The construction window continues to shrink due to climate change and new environmental caribou regulations. As such, project execution strategies which take a longer range view of construction execution risk are more cost effective for rate payers in the long term.

Transmission Facility Owners Responses

ALTALINK

In Section 5 of your report, *TFCMC Conclusion and Recommendations*, you have suggested that the Committee would like to add to its objectives to target cost reductions to transmission projects. This objective is outside the bounds of the "monitoring" mandate of the Committee. It should be noted that the Committee or its members in no way bare the risk in the execution of transmission projects, are not involved in the day to day execution of the projects and as such are not in a position to assess the appropriate cost reduction opportunities.

We appreciate the desire of the Committee and its members to have the TFO's reconcile project costs to the NID estimate however, we maintain that NID estimates are screening estimates and as such are used to determine which technical solution would be best presuming all field execution risk factors were the same between options. The PPS estimate confirms the technical solution and the execution solution (ie. route) for the project and is the most appropriate comparator for project costs.

Given the above, we do not believe that much more can be gained from a case study of the Yellowhead project. As noted in your report, AltaLink has already provided a detailed update to the Committee regarding the Yellowhead project. It should be noted that the Yellowhead development is within 11% of the original PPS estimate, with 3 of 4 projects under the PPS original estimate. The one segment of the project development (Hinton Edson) that exceeded budget, exceeded budget due to the actions required to mitigate severe weather and environmental impacts that were encountered as the project was in the field. The AESO was consulted regarding the appropriateness of our mitigation solution and agreed to the reasonableness of the actions taken by AltaLink to complete the project. In addition, we would suggest that the issue of traceability of costs from the NID to actual costs is already being addressed through the AESO Industry Working Group. As such it would not be recommended to have the TFCMC duplicate effort.

In closing, AltaLink appreciates that the TFCMC has taken the time to understand the challenges of benchmarking transmission projects across jurisdictions. The exercise has brought attention to the significant differences in the cost drivers that impact the cost of building projects in Alberta versus other jurisdictions. As the industry has come to realize, the standard of consultation, environmental stewardship, scope definition and regulatory due process have a substantial impact on cost and schedule. We look forward to exploring these factors with industry participants through the AESO Industry Working Group.

Thank you again for the opportunity to comment on your report. If you have any questions relative to these comments, please don't hesitate to call me at 403-267-6133.

Regards,

Johanne Picard-Thompson
SVP Projects, AltaLink

.cc Jerry Mossing, VP AESO

Transmission Facility Owners Responses

ATCO Electric

February 13, 2013

Henry Yip
Chair, Transmission Facilities Cost Monitoring Committee
1701 TD Tower
10088 – 102 Avenue
Edmonton, AB T5J 2Z1

Dear Sir:

Subject: Review of the Cost Status of Major Transmission Projects in Alberta – December 2012 Report

Thank you for the opportunity to review and comment on the Transmission Facility Cost Monitoring Committee's (TFCMC) fourth report dated December 2012.

As mentioned in our comments to the June 2012 report, ATCO Electric (ATCO) remains committed to cooperating with all interested parties and working on a collaborative basis to help the TFCMC achieve its mandated objectives. ATCO is, however, concerned with some of the wording contained in the following sections of the report:

- Message From the Chair:

  During this reporting period, the Committee worked on comparing transmission project costs in Alberta to transmission costs experienced by other jurisdictions. A summary of this work is also included in this section. The developing theme from this work is that Alberta is incurring higher costs for its transmission developments projects than other jurisdictions.

- Section 2, Eastern Alberta Transmission Line (EATL) Converter Station Costs:

  Based on the above efforts, the Committee is alarmed that the budgetary cost of the converter station for the EATL project, at $453 million, appears to be at least about 80% higher than similar projects in other jurisdictions around the world.

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Transmission Facility Owners Responses

ATCO Electric

- Section 2, HVDC Project Cost Comparisons:

> *The unit costs of the combined Alberta transmission projects, as planned, are in the vicinity of $1,540,000 per kilometre, which is substantially higher than the other two projects in Newfoundland and Manitoba.*

The forecasts for ATCO's projects are derived entirely in accordance with the ISO Rules, which require a competitive bidding process. Using benchmarks, particularly from other jurisdictions, is an inappropriate test of reasonableness as there are several factors that can cause significant differences in costs. Projects from other jurisdictions are not necessarily comparable in scope, design and geography to those being constructed by ATCO in Alberta. Transmission lines and substations are all unique, and the cost of a specific line or substation may be significantly different from those in other jurisdictions. The project costs identified by Interveners for Newfoundland/Labrador and Manitoba in ATCO Electric's GTA hearing were estimates and it was noted in the Intervener evidence that estimated costs such as those used for the Newfoundland/Labrador and Manitoba projects are not as reliable as costs from a competitive bidding process.

As such, ATCO Electric follows the ISO's competitive procurement rules to select the lowest compliant bidder and ensure project costs are prudent.

Both the Alberta Department of Energy and the AESO are currently undertaking a review of cost accountability, as recommended by the TFCMC, including the potential for both Alberta and non-Alberta transmission development cost benchmarking. ATCO Electric looks forward to participating and assisting with the development of workable and effective cost procurement and cost benchmarking processes. In ATCO Electric's view, the latter needs to reflect current demand, growth and inflation trends in Alberta and be fully capable of ensuring that TFOs can fulfill their duties to the AESO to meet Alberta's transmission needs and network reinforcement requirements in a timely and effective manner.

Please contact me directly at 780-420-7434 if you have any questions or require any clarification to the comments included herein.

Yours sincerely,
ATCO ELECTRIC

Dennis A. DeChamplain, C.A.
Vice President, Controller

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Transmission Facility Owners Responses

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February 15, 2013

Henry Yip, Chair
Transmission Facilities Cost Monitoring Committee
Email: hcyip@telus.net

RE: **TFCMC December 2012 Report**

Dear Mr. Yip,

EDTI appreciates the opportunity to comment on the December 2012 Report from the Transmission Facilities Cost Monitoring Committee ("TFCMC" or the "Committee"). EDTI continues to be supportive of the committee and its efforts to understand Alberta transmission infrastructure projects and the various factors that can impact the cost, scope and schedule of these projects.

EDTI has reviewed the report with specific attention to Section 2 TFCMC Observations to Date and Section 5: Conclusions and Recommendations; EDTI has the following comments:

EDTI notes that throughout section 2 of the TFCMC report the Committee continues to comment on technical specification and technology choice and in one case even appears to question the need of a particular project[1]. As noted by both EDTI and AltaLink in responses to the June 2012 TFCMC report, it is outside the mandate of the TFCMC to review any projects from an initial prudence, need, technology choice or staging perspective. This mandate was clarified by the Minister of Energy in a letter to the TFCMC dated January 12, 2011 and restated in Appendix A of this report.

Although EDTI appreciates the efforts by the TFCMC in undertaking an internal review of the value of its work and opportunities to enhance its role, EDTI notes that Ministerial Order 64/2010 establishing the TFCMC described the manner in which such a review is to occur. The Committee may recommend a party to conduct the review, but the review is to be undertaken by an independent person determined by the Minister of Energy. EDTI respectfully suggests that the mandate and desired outcomes of the TFCMC's activities is best set by the Minister after an independent review that allows the opportunity for other stakeholders such as Alberta TFOs to provide comments.

[1] TFCMC December 2012 Report – pg. 12 – Black Fly to McLelland Observations

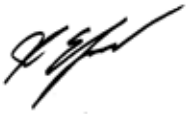
Transmission Facility Owners Responses

EDTI would agree with the majority of TFCMC members that the Committee should not be responsible for managing costs but should continue in its intended capacity which is to monitor costs. The other (minority) TFCMC members' suggestion that its mandate should be shifted from monitoring project costs to a focus on a reduction in transmission project costs is a fundamental change in the role of the Committee that should not be taken lightly. Furthermore, the increased costs of operating the Committee in an expanded role as well as the increased costs to TFOs and the AESO of responding to the TFCMC should also be weighed against any perceived benefits prior to initiating such a change in mandate. In addition such a change in mandate would potentially result in a duplication of effort among the various entities already involved in transmission projects in the province today.

EDTI also notes that the TFCMC report states that one indicator of success from its perspective is "transference of risk to TFOs"[2] which appears to imply that the TFCMC believes that a shift in the risk profile of the utilities is required. Such a change in risk to the TFOs would need to be taken into account when setting the appropriate capital structure and return on equity of the TFOs.

If you have any questions, please do not hesitate to contact me at 780.441.7154.

Regards,



John Elford
Director, EDTI Regulatory Affairs

[2] TFCMC December 2012 Report – pg. 21

DECEMBER 2012 REPORT

TFCMC@gov.ab.ca

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