REVIEW OF THE COST STATUS OF MAJOR TRANSMISSION PROJECTS IN ALBERTA

From The Transmission Facilities Cost Monitoring Committee

JUNE 2015 REPORT

Industry Abbreviations Commonly Found In This Report

Alberta Electric System Operator . . . . . (AESO)

Alberta Utilities Commission . . . . . (AUC)

AltaLink Management Ltd. . . . . (AltaLink)

ATCO Electric Ltd. . . . . (ATCO)

Critical Transmission Infrastructure . . . . . (CTI)

Direct Assign Capital Deferral Account . . . . . (DACDA)

Distribution Facility Owner . . . . . (DFO)

ENMAX Power Corp. . . . . (ENMAX)

EPCOR Distribution and Transmission Inc. . . . . (EDTI)

EPCOR Utilities Inc. . . . . (EPCOR)

Facility Application . . . . . (FA)

General Tariff Application . . . . . (GTA)

High Voltage Direct Current. . . . . (HVDC)

In-Service Date . . . . . (ISD)

Long-Term Plan . . . . . (LTP)

Needs Identification Document. . . . . (NID)

Proposal to Provide Service . . . . . (PPS)

Permit and Licence . . . . . (P&L)

TransAlta Corp. . . . . (TransAlta)

Transmission Facilities Cost Monitoring Committee. . . . . (TFCMC)

Transmission Facility Owner . . . . . (TFO)

Transportation Utility Corridor . . . . . (TUC)

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Message From the Chair

This is the ninth report from the Transmission Facilities Cost Monitoring Committee (TFCMC) to its stakeholders. The report provides a detailed and structured summary of the cost, scope and schedule information of the transmission projects monitored by the Committee on a monthly basis for the period of November 1, 2014 to April 30, 2015.

During this period, the Committee examined the progression of 13 major transmission projects, with the total cost of these projects estimated at just over $8.6[1] billion. A listing of the 13 projects can be found in Section 1, while details for these projects are contained in Appendices B and C.

Section 2 of this report contains summaries of several project reviews provided by the AESO including a new project, Thickwood Hills 240 kV Transmission Development (Project 1186). Several key learnings and observations made by the Committee while monitoring the progress of the transmission projects are also included:

- A presentation by Dr. Eugene Beaulieu from the University of Calgary on the impact of the oil price crash on the labour market;
- Inputs from AltaLink Management Ltd. and Al Snyder, an independent member of the Committee, on the subject of transmission line conductor optimization, and
- A final status report on the AESO's review of its technical requirements for bulk transmission lines (ISO Rule 502.2).

Through the TFCMC's work in monitoring transmission project costs, it has and continues to identify opportunities to control costs. Since its inception, the Committee has made recommendations to take advantage of these opportunities. Section 3 provides an update on the status of all previous recommendations. The Committee is encouraged by the proactive responses from the AESO and Alberta Energy. The AESO's continuing work in enhancing the benchmarking database and in strengthening Rule 9.1 in the areas of cost estimating, cost reporting and procurement are just some examples of their positive responses to the Committee's recommendations.

There are no new recommendations contained in this edition of the TFCMC report.

The ministerial order that created this Committee required that a review of the Committee be undertaken by the end of 2015 on whether the Committee's mandate continues to be relevant and whether the Committee is effective and efficient in fulfilling its mandate. The Committee has been working collaboratively with Alberta Energy to implement this requirement. Alberta Energy advised the Committee in June 2015 that Solas Energy Consulting of Calgary has been selected through a public tendering process. Solas is undertaking this review with the objective of submitting a report to the Minister of Energy at the beginning of October 2015.

I would like to take this opportunity to mention that during this reporting period, Steven Flavel, Director, Generation, Transmission and Wholesale Policy has replaced Vinson Banh as the Alberta Energy representative on the Committee. The Committee would like to express its appreciation for Vinson's contribution during his tenure.

In addition to issuing a limited quantity of hard copies of this semi-annual report, the report will be posted on the Utilities Consumer Advocate's website for access by any interested parties.

1 This figure does not include costs for Project 838 – Fort McMurray Area Transmission Bulk System Reinforcement (FMAC) – as this project falls under a competitive procurement process. If the cost of Project 838 is included, the 13 projects would be valued at just over $10.101 billion.

Thank you for your continuing support. The TFCMC's next semi-annual report is scheduled for release in the spring of 2016. 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 expected to cost more than $100 million. These transmission projects include all lines and substations, which make up the transmission facilities required to transfer power between generators and loads. For this edition, and for easier reference, project cost figures have been added to the listings.

Monitored Projects

The TFCMC monitored 13 projects valued at a total of just over $8.668 billion[2] (based solely on the current estimated costs noted in Appendix B of this report).

The monitored projects, in alphabetical order, are:

- **CENTRAL EAST AREA TRANSMISSION DEVELOPMENT (CETD);** PROJECT 811 – Transmission development in Wainwright, Lloydminster, Provost, Vegreville and Cold Lake. **| Current Estimated Cost: $344 million |**
- **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. **| Current Estimated Cost: $512.95 million |**
- **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 and to interconnect the ENMAX Shepard Energy Centre. **| Current Estimated Cost: $164.26 million |**
- **EDMONTON REGION 240 KV LINE UPGRADES (ERLU);** PROJECT 786 – Upgrading 240 kV lines in the Edmonton area and adding one 240 kV phase shifter at Livock substation to gain more capacity out of the existing 240 kV network. **| Current Estimated Cost: $178 million |**
- **FOOTHILLS AREA TRANSMISSION DEVELOPMENT (FATD) – EAST PROJECT;** PROJECT 1117 – To meet growing demand in South Calgary, High River and the surrounding area. **| Current Estimated Cost: $523.91 million |**
- **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. **| Current Estimated Cost: $1.433 billion |**
- ***COMPLETED* HANNA REGION TRANSMISSION DEVELOPMENT (HATD);** PROJECT 812 – 240/144 kV transmission development in the Hanna, Sheerness, Wainwright, Provost and Battle River areas. **| Current Estimated Cost: $969 million[3] |**
- **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. **| Current Estimated Cost: $3.569 billion |**
- **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 of Fort McMurray. **| Current Estimated Cost: $235.1 million |**
- **RED DEER REGION TRANSMISSION DEVELOPMENT (RDTD);** PROJECT 813 – 240/138 kV transmission system reinforcements in the Red Deer area. **| Current Estimated Cost: $392.4 million |**

2 This figure does not include costs for Project 838 – Fort McMurray Area Transmission Bulk System Reinforcement (FMAC) – as this project falls under a competitive procurement process. If the cost of Project 838 is included, the 13 projects would be valued at just over $10.101 billion.

3 While this project has been completed, the amount of $969 million does not include final project numbers. The AESO expects to receive the final project cost later in 2015 but it currently estimates the final project cost at $997.3 million.

- **SOUTH AND WEST OF EDMONTON TRANSMISSION DEVELOPMENT (SWEATR);** PROJECT 850 – Transmission system reinforcement to the 138 kV systems south and west of the City of Edmonton. **| Current Estimated Cost: $172 million |**
- **SOUTHERN ALBERTA TRANSMISSION REINFORCEMENT (SATR);** PROJECT 787 – To accommodate wind generation in southern Alberta. **| Current Estimated Cost: $1.417 billion |**
- ***NEW* THICKWOOD HILLS 240 KV TRANSMISSION DEVELOPMENT AND REACTIVE POWER REINFORCEMENT (THTD);** PROJECT 1186 – To connect the Fort McMurray West 500 kV transmission project to the existing transmission system in the Thickwood Hills area, west of Fort McMurray. **| Current Estimated Cost: $190.80 million |**

2. TFCMC Observations To Date

As the Transmission Facilities Cost Monitoring Committee (TFCMC) moves forward with its mandate to review the cost of major transmission projects, it embarks on in-depth assessments of these undertakings (in the case of new projects)[4] or focuses on a more detailed analysis of existing ones and relevant issues based on the monthly reports[5] it receives.

This section describes some of the substantive observations made by the Committee during the six-month period covered by this report.

Central East Transmission Development Update

The Alberta Electric System Operator (AESO) provided the TFCMC with a program update on the Central East Transmission Development (CETD); primarily, details on the recent Needs Identification Document (NID) amendment filing with the Alberta Utilities Commission (AUC).

The broad scope of the project was a requirement for regional transmission development in the Central region of the province from Cold Lake to the Wainwright area. The need for the transmission update is driven by industrial load and generation increases for the period of 2012 to 2017. The NID estimate (+/-30%, 2009$) was $370 million. This included:

- Stage 1: In-Service Date (ISD) - 2012, $310 million, and
- Stage 2: ISD - 2017, $60 million.

After further review of the Central East planning areas it was determined that some of the 138 kV developments should be cancelled in favour of 240 kV development.

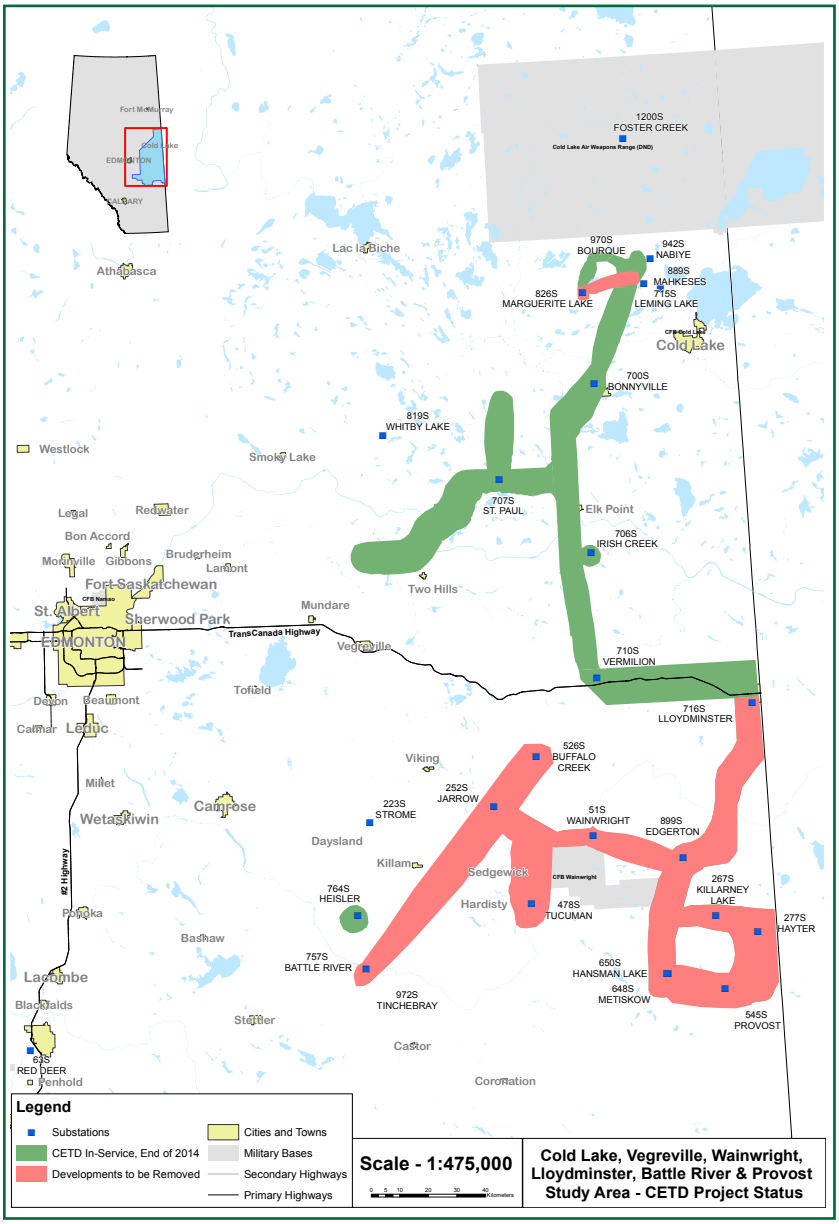
The following projects and facilities development were put on hold in March 2013 and cancelled in December 2014 (amendment) after system validation studies were completed:

- CETD Stage 1:
  - Provost Area:
    - Rebuilding lines 7L749, 749L, 749AL, 748L, 715L, and
    - A new 138 kV line between Provost and Hayter.
  - Wainwright Area:
    - Rebuilding lines 704L and 704AL, and
    - A new 138 kV line between Wainwright and Edgerton.
  - Lloydminster and Bonnyville–St. Paul Areas:
    - Line clearance mitigations for 7L14 and 7L53.
- CETD Stage 2:
  - Rebuilding line 7L50, and
  - A new 240 kV line between Bourque and Marguerite Lake.

4 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.

5 The TFCMC continues to receive monthly reports from the AESO, which originate from the TFOs, on all projects valued at $100 million and over.

The following map illustrates the facilities completed in 2014, and those that were removed as a result of the amendment.



The new proposed 240 kV development for the Central Region includes the following:

- 240 kV transmission line interconnecting Gaetz 87S (Red Deer Area) and Tinchebray 972S;
- 240 kV transmission line interconnecting Tinchebray 972S and Drury 2007S (Vermillion Area);
- 240 kV transmission line interconnecting Hansman Lake 650S and Edgerton 899S (Provost Area), and
- Addition of Shunt Capacitor Banks at Strome 223S, Irish Creek 706S and Whitby Lake 819S.

In August 2013 the AESO started the Vermillion to Red Deer, and Edgerton to Provost 240 kV Transmission Development (the Vermilion to Red Deer, Edgerton to Provost Transmission Development (VREPTD) Project).

At the time of this presentation (January 2015), the AESO planned to file the NID in March or April 2015 and the Cost Oversight Manager (COM) pilot team had initiated its review of the project. Since the time of the presentation, the AESO is reassessing the need and timing of the 240 kV development.

Ells River Benchmark Comparison

The AESO provided the TFCMC with a presentation on its cost review of the Proposal to Provide Service (PPS) received from ATCO Electric (ATCO) regarding Project 1180, Northwest (of) Fort McMurray Transmission Development. The presentation focused on the Ells River portion of the project.

The scope of the Ells River substation and the in-and-out on lines 9L08 includes:

- Construction of the Ells River Substation;
- Extension of line 9L08; 60 km of 240 kV single-circuit towers in-and-out from existing 9L08;
- Line 9L76; 60 km of 240 kV single-circuit towers in-and-out from existing 9L08;
- Protection upgrades to nearby substations, and
- Communication upgrades required to integrate this project.

(Note that the 9L08 and 9L76 lines will be the only source supplying the Ells River area.)

The PPS estimate is $199 million, with an ISD of March 1, 2017. The NID estimate was $156 million, a 28% variance. The increase between the NID and the PPS estimate is attributed to an escalation of $11 million, Engineering and Supervision (E&S) cost increases of $10 million, and construction labour cost increases of approximately $23 million.

The main cost-increase drivers can be further explained by the following benchmarking analysis:

- 9L08 and 9L76 240 kV single circuit lines:
  - Per km cost is higher than the benchmark cost by 74%;
  - Major differences are in the site preparation cost and construction costs;
  - 9L08 and 9L76 site preparation costs of $265,000 per km while the benchmark average cost is $45,000 per km, and
  - 9L08 and 9L76 construction costs of $401,000 per km while the benchmark average cost is $270,000 per km.
- Ells River 2079S 240 kV substation:
  - The Ells River substation cost is 94% higher than the benchmark average;
  - Major differences are in site preparation and construction costs:
    - Site preparation costs of $5 million while the benchmark average cost is $3 million, and
    - Construction costs of $5 million while the benchmark average cost is $3 million.
- Non-facility costs:
  - E&S as well as escalation costs are higher than projects of similar size and scope.

The AESO made the following observations and recommendations as a result of the cost review and benchmarking analysis:

- The +20/-10% PPS cost estimate is 28% or $43 million higher than NID cost estimate;
- A second source for the Ells River substation has been postponed; this is the 9L95 240 kV line;
- The length of the two lines increased from 52 km in the NID to 60 km in the PPS (per km cost has decreased from $1.036 million/km to $0.993 million/km);
- The changes in the cost estimate do not impact the planning decision to continue with the Northwest Fort McMurray Transmission Development Project, and
- The AESO is currently reviewing and discussing staging options based on customer ISDs.

Review of Project 850 – South and West of Edmonton Transmission Development

The AESO conducted its PPS review of the South and West of Edmonton Transmission Development project and provided the TFCMC with an update.

The need for Project 850 is a result of existing transmission constraints in the area south and west of Edmonton. The demand for electricity in the Edmonton region is forecast to increase by 800 MW over the next 10 years, which represents a 3.4% average annual growth from the current demand of 2,127 MW. The electrical system in this area will lack sufficient capacity to handle this growth without a number of system developments.

Overall, the +20/-10% PPS cost estimate was approximately $151 million (88%) higher than the $172.2 million NID cost estimate, although this comparison is based on different year dollars (2015 dollars for the NID and 2017 dollars for the PPS). AltaLink has provided an escalation of $18.8 million from 2015 to 2017, meaning the project cost would be approximately $304.5 million in 2015 dollars (i.e., $323.3 million – $18.8 million) or approximately 77% higher than the NID cost estimate.

Distributed cost shows the highest increase – approximately $62 million – followed by line cost, with an increase of approximately $41 million. Costs increases in distributed cost and line cost account for approximately $100 million of the total cost increase, or about two-thirds of the approximate $151-million increase compared to the NID cost estimate. Within the distributed cost, the direct management cost for project and construction is $48.3 million. AltaLink attributed the high Project Management/Construction Management cost to the large number of work sites. The key reasons for increased costs of major facilities and equipment can be summarized as:

- Pipeline mitigation;
- Right-of-way preparation, and
- Longer 240 kV line distance due to a different substation siting assumption.

The AESO has continued its due diligence given the cost increases, and is reassessing the various aspects of the project. Also at the time of presentation (earlier in 2015), the COM was still reviewing the costs of the project as part of the COM pilot project[6] . Because of the review and further analysis, the filing of the Facility Application (FA) was delayed from spring to late summer.

6 The COM pilot project is part of an initiative by the Alberta Energy aimed at improving the management of transmission costs.

Potential Impact of Lower Oil Prices on Labour Markets in Alberta

Not that long ago when oil prices were in excess of $100 per barrel, TFOs reported significant upward pressure on labour rates for Alberta's transmission projects. In an attempt to gain an understanding of the potential impact of the recent and significant reduction in oil prices on labour markets in Alberta, the TFCMC invited Dr. Eugene Beaulieu of the University of Calgary to share his views on this issue.

The question put to Dr. Beaulieu, a professor in the Department of Economics and the Director of International Economics in the School of Public Policy was: would labour rates in the electricity sector fall as a result of the reduction in oil prices?

In short, Dr. Beaulieu stated that the economy in Alberta had been through a long period of tight labour markets and while there will be a delay in the impacts of falling oil prices, layoffs in the energy sector are beginning to affect other sectors and labour rates will likely weaken for transmission projects.

The rationale for Dr. Beaulieu's opinion is based on the following facts, presented to the TFCMC in March 2015:

- The price of West Texas Intermediate (WTI) is down more than 50% to approximately $40 per barrel (at the time of the presentation);
- The rapid decline in oil prices since the fourth quarter of 2014 has dramatically altered the economic climate in Alberta;
- The Organization for Economic Development Co-Operation and Development (OECD) revised its forecast of Canadian economic growth from 2.6% to 2.2% for 2015 and from 2.4% to 2.1% for 2016, due to the lower oil prices;
- Firms in the energy sector are adjusting operational plans, delaying or cancelling projects, reducing capital outlays and increasing layoffs; and
- There has been an increase in labour supply for other sectors and workers have begun relocating to other regions in Canada.

Dr. Beaulieu also noted that the sharp rise in oil prices since the early 2000s is known as a "super-cycle" and that the historical average WTI price (in U.S. dollars) from 1972 to 2013 was a shade under $50. Oil prices, he said, will continue to remain low – or around the historical average in the medium term.

Transmission Line Development Optimization

Transmission line development intends to minimize the net present value (NPV) of transporting energy from generation sources to end users of electricity. Planning features include route selection, attainment of easements and an assessment of local geological conditions including ground conditions, as well as wind, snow and icing considerations.

Conductor selection is a key part of the process and includes voltage class, number of circuits and conductor sizing in concert with industry standards. Powerflow and basic loss optimization are carried out during this planning stage. The process is iterative, with further design phase optimizations reinserted into analytical planning models to refine powerflow and loss calculations

Design then considers appropriate foundation types and tower structures (wood or steel) to carry the conductors selected. Present and future load considerations are factored into the design. Tower spotting programs are then deployed to minimize the number of towers while ensuring compliance with minimum line clearances.

At the invitation of the Committee, the AltaLink team shared their work on transmission line conductor optimization – one segment of overall transmission line development – using their actual study for the Chapel Rock to Castle Rock Ridge project, part of Project 787, Southern Alberta Transmission Reinforcement. The February 2015 presentation showed that:

- A conductor selection study is an iterative process intended to determine which conductor configuration is the most economic for a given project.
- Although ISO Rule 502.2 requires the use of ACSR or ACSR/TW conductor, AltaLink evaluated additional conductor types to determine the potential cost savings.
- The range of conductor size has negligible impact on the loading of tangent structures. However, the quantity and type of conductor can be significant.
- Twin 1234 kcmil Yukon conductor was determined to be the optimum configuration compliant with Rule 502.2 requirements for 1000/1200 MVA capacity.

Options considered:

- Twin 1033 kcmil Curlew ACSR was considered feasible, if the summer capacity requirements could be marginally reduced.
- Single 1927 kcmil ACSS/TW conductor, also non-compliant with Rule 502.2 has a 30% higher impedance than the twin Curlew option, making it unacceptable.

The AESO considered the original recommendation and the savings that could be achieved by the options offered and accepted AltaLink's proposal for the 1033 kcmil Curlew.

Transmission Rate Impact Project (TRIP) Update

The TFCMC received a presentation from John Martin, the AESO's Director, Tariff Applications, in April 2015, providing the Committee with a preview of the 2015 update to the Transmission Rate Impact Projection (TRIP).

This update incorporated:

- The latest data from various Transmission Facility Owner (TFO) tariff filings;
- The Rate DTS energy forecast from the AESO's 2014 Long-Term Outlook;
- All relevant transmission project changes;
- AESO costs as budgeted for 2015 (escalated by inflation in subsequent years), and
- The pool price from the 2014 fourth quarter EDC Associates forecast.

The Committee was told the next steps to finalize the TRIP model update included:

- Addressing the residential delivered cost of electricity calculation:
  - Distribution system owners have applied for a 2015 capital tracker K-factor adjustment of about 14% for the PBR formula;
  - Increase not expected to be sustained over long term, and
  - Consider shaping the K-factor to reflect transmission capital adjustments.
- Consider concerns raised in the Industrial Power Consumers Association of Alberta (IPCAA) review of the TRIP model in November 2014.
- Finish the updating of inputs and review and validation of formulas.

The Committee provided various inputs during the presentation. The finalized, updated TRIP model was expected to be made public shortly.[7]

7 The TFCMC was later advised that the AESO has decided to postpone their update to the TRIP model until early 2016.

ISO Rule 502.2 Review Update

ISO Rule 502.2 sets out the technical requirements for bulk transmission lines. The current rule became effective on January 1, 2012. The AESO established a Technical Panel to review ISO Rule 502.2. The Technical Panel's mandate was to provide the following recommendations to the AESO:

1. The Technical Panel will recommend modifications to the existing ISO Rule 502.2.
2. The Technical Panel will provide recommendations to enhance conductor and line optimization.
3. The Technical Panel will review the AESO's latest regional transmission plans and, if appropriate, identify new towers that should be designed.
4. The Technical Panel will review upcoming transmission projects and, if appropriate, identify existing towers that should be redesigned.

At the June 2015 TFCMC meeting, the AESO provided a summary of the recommendations of the Technical Panel.

The Technical Panel recommended to the AESO the following changes to the rule:

1. Incorporate additional permitted conductor types;
2. Incorporate additional detail regarding line optimization studies;
3. Clarify footing requirements related to sequence of failure;
4. Allow for the removal of the shield wire in certain circumstances;
5. Eliminate the requirement for 240 kV lines to be able to operate at a temperature of 100 degrees Celsius; and
6. Clarify clearance requirements to the edge of the right of way.

No changes were recommended related to galloping requirements or to weather loading requirements for radial customer connections.

Based on a review of the AESO's latest transmission plans, there are no planned 240 kV double-circuit transmission projects with a capacity requirement of 1,100 MVA per circuit (the design standard for the current family of 240 kV towers). However, there are two potential 240 kV double-circuit projects with a capacity requirement of 500 MVA per circuit. Preliminary assessments indicate that a large single conductor per circuit may be optimal for these two projects. The Technical Panel recommended that the AESO direct the TFOs to undertake staged line optimization and tower design for these projects to ensure that lighter, less expensive, towers are available in time to be used for these projects.

The AESO advised that they intend to initiate their formal stakeholder consultation process for changes to ISO Rule 502.2 this summer and that they plan to submit their proposed changes to the rule to the AUC this fall.

Observations On New Projects

One new project was added to the TFCMC's roster of monitored projects during the period covered by this report.

Thickwood Hills 240 kV Transmission Development and Reactive Power Reinforcement (THTD) – Project 1186

The Thickwood Hills 240 kV Transmission Development and Reactive Power Reinforcement project is now a part of the projects that are reviewed by the TFCMC. This 240 kV transmission system development requires a northern termination point for two single-circuit 500 kV AC transmission facilities (500 kV Lines) that will run from the Edmonton region to the Fort McMurray area.

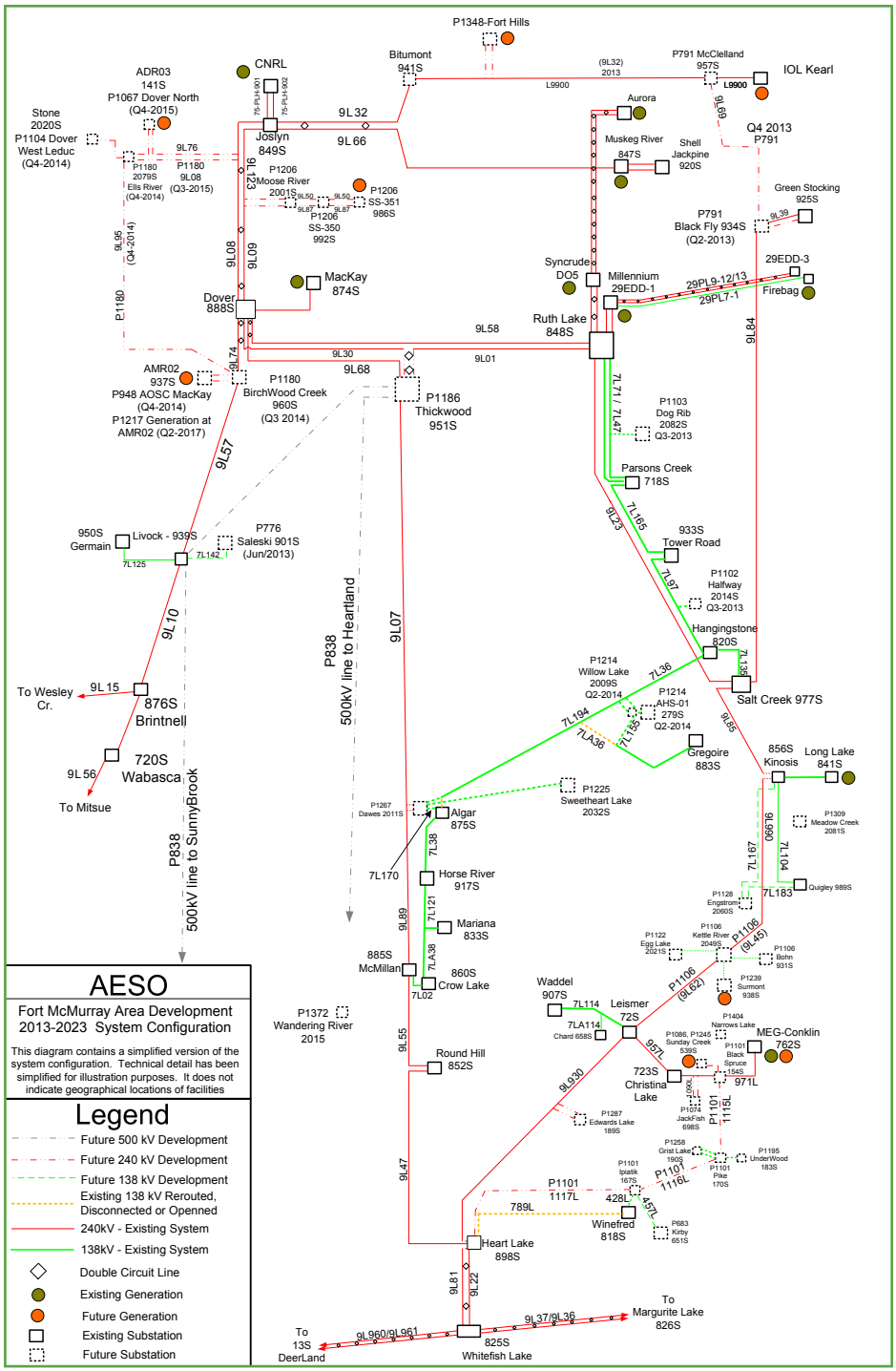
- The 240 kV transmission developments are required to integrate the 500 kV Fort McMurray facilities into the Alberta Interconnected Electric System (AIES).
- The first of the 500 kV lines will run from the Wabamun area west of Edmonton to the Thickwood Hills area west of Fort McMurray (Fort McMurray West Line) and is expected to be in service by approximately June 2019.
- The second of the 500 kV lines will run from the Heartland 12S substation northeast of Edmonton to the Thickwood Hills substation (Fort McMurray East Line) and is expected to be in service after 2020.

The scope of the project is as follows. The 240 kV transmission developments required to enable integration of the Fort McMurray West Line include:

- The 240 kV portion of the 500/240 kV Thickwood Hills 951S substation (Thickwood Hills substation), including a +200/-100 MVAr Static Var System (SVS) and capacitor banks with a capacity totaling 100 MVAr, and
- New 240 kV transmission circuits connecting the Thickwood Hills substation to the existing transmission system.

The second of the 500 kV Lines will run from the Heartland 12S substation northeast of Edmonton to the Thickwood Hills substation (Fort McMurray East Line) and includes:

- A second bank of capacitors totaling 100 MVAr, to enter service commensurate with the ISD of the Fort McMurray East Line.



The NID was filed with the AUC on December 16, 2014, and was approved on March 12, 2015. These facilities are required to be in service (approximately) in the third quarter of 2018 to facilitate commissioning, testing and integration of the Fort McMurray 500 kV West Line. A second bank of capacitors totaling 100 MVAr will enter service commensurate with the ISD of the Fort McMurray 500 kV East Line (after 2020).

The NID cost estimates are as follows:

- Stage 1: ISD 2018, $196 million, and
- Stage 2: ISD 2021, $6 million.

Completed Projects

The AESO considers the following project as closed and will no longer report on it to the TFCMC. Where a project may have some work outstanding, such as pipeline mitigation, the AESO will advise the TFCMC as necessary.

Hanna Region Transmission Development (HATD) – Phase 1; Project 812

This project is now in service, and the AESO is currently reviewing the Final Cost Report for the Hanna Region Transmission Development – Phase 1.

All FAs related to Phase 1 of the project have been completed, including the Lanfine Static Var Compensator. The ISD for this development was April 13, 2015.

Final costs for all AltaLink developments on this project have been received and were acknowledged by the AESO in May 2015. The 150-Day Final Cost Report for ATCO developments was received in June 2015. The AESO is currently reviewing the report. In the last monthly TFO Report (April 2015), the Actual Cost to Date was $5-million lower than the Authorized Budget.

Monthly reports are no longer available for this project. If there are significant variances in the Final Cost Report as compared to the Authorized Budget, the AESO will advise the TFCMC.

The AESO is reassessing the timing of and the need for Phase 2 of the Hanna project as part of the long-term planning assessment. Both ATCO and AltaLink have been requested to cease all work on the project until further notice.

Based on the current system work plan, a review of Hanna Phase 2 is being deferred until 2016 due to other priorities. The AESO will bring forward a new project and project number to the TFCMC if and when Phase 2 commences.

3 TFCMC Results to Date | Recommendations

Eight semi-annual reports containing 11 recommendations – all with the goal of enhancing the monitoring and management of transmission costs in Alberta – have been previously released. Nine of these recommendations were directed to the Alberta Electric System Operator (AESO) and two have been made to Alberta Energy.

Instead of recommendations, the TFCMC's June 2013 report focused on a list of the Committee's Top 5 transmission priorities. This list came about as Alberta Energy initiated a review of its transmission cost management policy and sought input from leaders in the electricity sector[8].

Recommendations to the Alberta Electric System Operator

The AESO has been proactive in its response to recommendations made by the Committee, adopting a majority of the TFCMC's recommendations. The TFCMC, continues to be encouraged by the overall direction and response that the AESO has taken in regards to these recommendations.

Recommendations already implemented:

- **JUNE 2011 REPORT, RECOMMENDATION NUMBER 1:** 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, RECOMMENDATION NUMBER 2:** 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, RECOMMENDATION NUMBER 3:** That the AESO develop a transmission cost benchmarking competency and database.
- **JUNE 2011 REPORT, RECOMMENDATION NUMBER 4:** That the AESO enhance compliance of the material procurement provisions of Rule 9.1.
- **JUNE 2011 REPORT, RECOMMENDATION NUMBER 6:** Initiate a review process on the current framework for cost accountability.
- **DECEMBER 2012 REPORT, RECOMMENDATION NUMBER 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).
- **DECEMBER 2013 REPORT, RECOMMENDATION NUMBER 1:** The Committee recommends that the AESO take the necessary steps to change the relevant rules so that it is clear that it will only review change orders for scope and in-service date changes.

The remaining AESO recommendations

The AESO has expanded the following recommendation into the broader context of the TFCMC's earlier cost accountability recommendation. The AESO's goal is still to coordinate with the Alberta Utilities Commission on the development of a reporting protocol with respect to the treatment of transmission project costs.

8 To see the TFCMC's Top 5 Transmission Priorities in their entirety, please consult the TFCMC's June 2013 semi-annual report.

- **DECEMBER 2011 REPORT, RECOMMENDATION NUMBER 2:** That for each Direct Assigned project, the AESO provide to the Alberta Utilities Commission 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.

The AESO considers the following recommendation closed.

- **JUNE 2012 REPORT, RECOMMENDATION NUMBER 1:** That for each Direct Assigned Capital project estimated to cost in excess of $100 million[9] 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.

The AESO notes that the AUC has not expressed any interest in receiving or using such a report. The AESO has established a protocol with the AUC for transfer of cost information when projects exceed the cost estimate threshold. The cost information includes reports gathered under AESO Rule 9.1 and if pertinent, AESO benchmarking analysis.

Further, the AESO has made the cost benchmarking report available to the public. Therefore any interested party may create their own benchmarking report, for example, if they are intervening in a TFO proceeding. The AESO processes for cost estimate reviews also include a benchmarking analysis. These processes have been shared with the AUC and the TFCMC.

Cost Accountability Recommendation: Status of ISO Rule 9.1 Development

Between May 5, 2015 and May 20, 2015, the AESO consulted with stakeholders on the proposed new Section 504.5, Service Proposals and Cost Estimates, along with associated new and amended definitions proposed for inclusion in the AESO Consolidated Authoritative Documents Glossary.

ISO Rule 504.5 will replace the current ISO Rule 9.1.2, TFO Obligations to Provide Estimates and Proposals. The AESO is currently reviewing stakeholder comments and may need to make revisions to the proposed rule and re-consult with stakeholders. The AESO expects to file the rule with the AUC in the summer of 2015.

The AESO issued a recommendation paper on Project Procurement and has received comments from stakeholders. It will provide comments to stakeholders in the third quarter of 2015. The AESO is targeting early 2016 for filing of a revised ISO Procurement rule.

9 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.

Input to Rule 9.1.5 Working Group

The TFCMC received the AESO's recommendation paper regarding transmission project procurement (ISO Rule 9.1.5). The recommendation paper outlined three options:

1. Revisions to Existing Project Procurement Rule; these revisions may include the following:
   - Clarity on the AESO definition of terms relating to project procurement;
   - Enhancing rules ensuring the receipt of competitive bids;
   - Reporting of exceptions in the monthly project report;
   - Documentation of non-compliant bids, rejected bids, bids received from affiliates and sole sourced bids;
   - Providing flexibility to the TFOs to procure based on total life system costs and consideration of bulk contracts, and
   - Changes to the project thresholds.
2. ISO Rules and Project Procurement Principles; examples of procurement principles may include:
   - Value for money;
   - Competitive tendering;
   - Accountability;
   - Transparency;
   - Impartiality, and
   - Service.
3. No Changes to Existing Project Procurement Rule

The TFCMC understands that in consideration of comments received from the Industry Working Group, the AESO recommends Option 2. Under this option, the Project Procurement Rule would include procurement principles derived from industry best practices, rather than contain specific detailed requirements as per the current rule. The stated principles, as contained in Option 2, along with the TFOs development of best practices to adhere to these principles, would address a majority of the working groups' comments.

The TFCMC engaged Bema Enterprises (and their sub-consultant, FTI Consulting) to review the AESO's recommendations and provide their views on:

1. The feasibility of AESO options 1 and 2;
2. Some of the pitfalls or concerns that need to be addressed with the current AESO recommendation (i.e. Option 2), and
3. Other insights on these two options that could assist the TFCMC in their assessment of these options.

FTI Consulting highlighted the following concerns with the current AESO recommendation:

> There is no explanation in the recommendation paper that demonstrates that the AESO has given sufficient consideration to, or balanced the concerns of all Stakeholders with respect to the concern for excessive capital costs that can arise from defective/deficient procurement practices versus the effort required to comply with a revised procurement rule that compels competition, transparency and accountability of the TFO's purchasing function for transmission materials, equipment and other construction services.

Of the three options proposed by the AESO, FTI recommended Option 1 as the preferred alternative to improve the Project Procurement Rule for the following reasons:

- The advantage of Option 1 is that the specific requirements, which are an enhancement to the existing rule, would not require many months to refine and codify.
- Option 2 does not address ratepayer concerns that the Project Procurement Rule should be expanded in its application to include engineering and design services that can cost millions of dollars on transmission facility projects, particularly when those services are procured externally to the TFO.
- Option 2 falls seemingly short of what is required to ensure fair, open and transparent procurement practices that results in market efficiency and competitive pricing for materials, equipment and professional services.
- The benefits of a more principled and possibly flexible process, the principle benefit of Option 2 can be captured through an exception mechanism.

The views of FTI were provided to the AESO for their consideration. The Committee did not take a position on the views expressed by FTI.

Transmission Cost Accountability Recommendation: Reporting and Oversight Protocol

With regards to the AUC's Approved Cost Estimate (ACE) initiative – arising out of new transmission cost management legislation approved by the Government of Alberta in September 2014 – the AUC is currently working on a bulletin that is expected to be released later this year with details of the initiative.

The COM Pilot concluded at the end of June 2015 with a submission of the COM Pilot's report to the COM Pilot Subcommittee. The subcommittee reviewed and provided the COM Pilot's report to the Department of Energy for further review and next steps.

Meanwhile, the AESO will hold a second round of consultation on Rule 504.5 (Cost Estimating) in the fall of 2015. A number of revisions to the draft rule were made, based on feedback received from industry stakeholders on the first round of consultation. The AESO is targeting filing of the new rule with the AUC before the end of 2015, with an effective date of January 2016.

Cost Benchmarking Recommendation Update

The AESO's Cost Benchmarking initiative is now complete. The benchmarking database is available on the AESO's website (www.aeso.ca/transmission/28352.html) and continues to be used for cost estimating by the AESO and the industry.

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

Recommendations to the Provincial Government

The TFCMC has directed two recommendations to the Alberta Energy through its semi-annual reports. One[10] of the two, **Recommendation Number 5 in the June 2011 Report**, was considered premature by the Department given the implementation of the other recommendations from the same semi-annual report.

The TFCMC made a second recommendation for the Department to consider. This one, **Recommendation Number 1 in the December 2011 Report**, reads as follows:

- 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.

The Minister, in a letter to the Committee, advised that Alberta Energy would consider this recommendation as it reviews potential amendments to the Transmission Regulation, and Alberta Energy has considered this recommendation as part of its review. Changes to the Transmission Regulation Amendment were made in September 2014.

New Recommendations

The Committee has no additional recommendations at this point.

10 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.

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 ensure 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.

The TFCMC's Members

The organizations and 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. Their 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. Their 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. Their 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. Their representative on the TFCMC is **Kelly Yagelniski, AESO's Director, Transmission Program Support.**

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. Their representative on the TFCMC is **Dan Astner, AFREA President – 2014 Board of Directors.**

Alberta Urban Municipalities Association (AUMA)

The AUMA represents Alberta's 271 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. Their representative on the TFCMC is **Andre Chabot, AUMA Director, Cities Over 500,000.**

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. Their 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. Their 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. Their representative on the TFCMC is **Vittoria Bellissimo, IPCAA's Executive Director.**

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.

Former Members

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 resigned in early 2014, stating it believes its involvement is no longer necessary due to the re-establishment of an independent regulatory review process and the repeal of Bill 50.

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 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 Laura Severs, engaged through Alberta Energy; she also serves as the Committee's technical writer.

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. Evan Bahry 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

Facility Applications for each project are sorted by the forecast or actual in-service date (ISD). The Facility Application number column in each project's initial chart is provided as an easy reference to its location on the accompanying map. Please note that due to updated information, some dates and items may have changed from previous TFCMC reports.

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

THE PROJECT: To accommodate load and generation in central Alberta, additional substations and upgrades to existing facilities are required. The Alberta Electric System Operator (AESO) has outlined the need for the 138/144 kV augmentation and upgrade, with two stages of implementation. The Central East project serves the dual purpose of meeting the growing demand for electricity for pipelines moving oil sands production, and 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, compels the substantial rebuild of the 138 kV and 144 kV systems, and the decommissioning of aging 69 kV and 72 kV lines.

THE COMPONENTS: Originally, there were two stages to this project, however, Stage 2 has been cancelled and the current Needs Identification Document (NID) is being amended to address the cancellations. Additionally, a new project is being developed to address system constraints.

The major components for Stage 1 of the project are: a new 144/25 kV Watt Lake substation; the conversion of three existing 72/25 kV substations to 144/25 kV; a new 240 kV switching station in the Cold Lake area, 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 one 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 existing 144 kV lines by mitigating line clearances and discontinuing the use of existing 72 kV equipment at existing substations or lines.

FACILITY APPLICATION NAME	FACILITY APPLICATION NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Line Clearance Mitigation	10	Restore ratings of existing 144 kV lines by mitigating line clearances	July 18, 2012
Heisler Area Upgrades	7	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	July 27, 2013
Vermilion 710S Substation Upgrade	6	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)	September 15, 2013
St. Paul Area Upgrades – Watt Lake, 7LA92	3	New 144/25 kV Watt Lake and new 144 kV line from Watt Lake to existing 7LA92	December 12, 2013

FACILITY APPLICATION NAME	FACILITY APPLICATION NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Cold Lake Area Reinforcements (Except Bonnyville to Bourque)	1	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)	January 30, 2014
St. Paul Area Upgrades – Whitby Lake	5	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/out configuration	June 25, 2014
Kitscoty Area Upgrades	8	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	November 30, 2014
St. Paul Area Upgrades	4	St. Paul 707S and 7L139/7L70 in/out	April 1, 2016
Cold Lake Area Reinforcements – Bonnyville	2	New 240 kV double-circuit line (one-side strung) from new 144 kV switching station to existing Bonnyville 700S, initially energized at 144 kV	May 31, 2016
Line Clearance Mitigations	11,12	Restore ratings of existing 144 kV lines by mitigating line clearances	Cancelled
Wainwright Upgrades	13	25 km of single-circuit line from Wainwright 51S to 704L	Cancelled

Note: For Facility Application (FA) #8, the In-Service Date (ISD) was adjusted from November 30, 2014 to December 4, 2014; FA #4 ISD is moved from July 12, 2015 to April 1, 2016; and FA #2 is moved from December 1, 2015 to May 31, 2016.

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

PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JANUARY 2014) ESTIMATED COST	CURRENT ESTIMATED COST
Central East Area Transmission Development	**$246 Million** (2013$)	**$344 Million**[11] (ISD$ with escalation for Stage 1)

CURRENT STATUS: Two facilities remain under construction and are expected to be completed in the third quarter of 2016.

The AESO identified 12 project components from the NID approval that are no longer needed or have been rendered inappropriate by changing needs in the Central East sub-region. A NID amendment to address project cancellations was filed with the Alberta Utilities Commission (AUC) on December 23, 2014 (AUC Proceeding 3605).

ATCO and TransCanada submitted a Statement of Intent to Participate in the proceeding and expressed concerns regarding the lack of attention being paid to system constraints in the region. The AESO is currently working on a Need Cancellation validation, to be completed by the end of July 2015.

In order to address stakeholder concerns, the AESO requested the AUC to refrain from establishing further process steps until the AESO has addressed this issue through a subsequent submission.

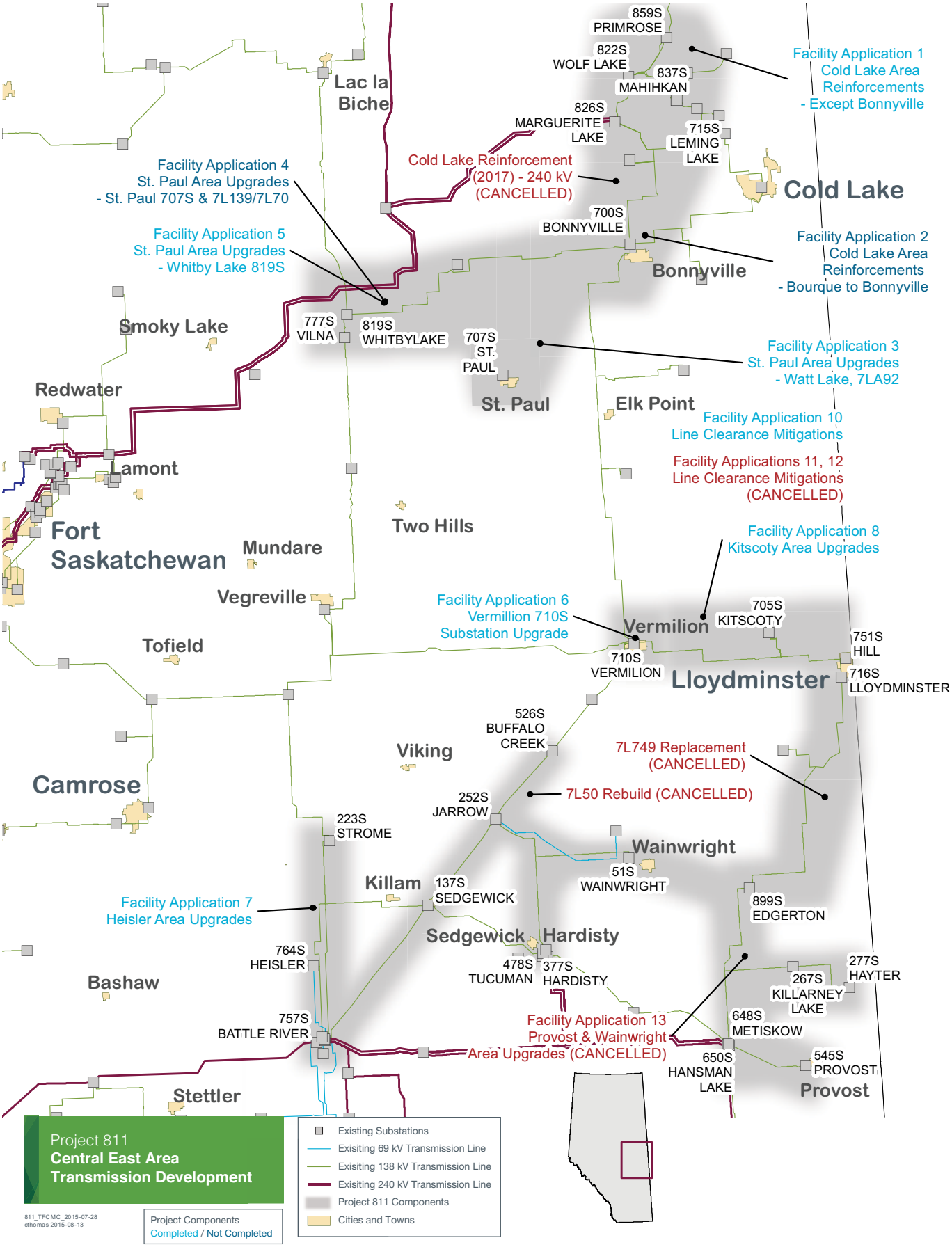
PROJECT RISKS

Concerning the NID Amendment Cancellations, ATCO and TransCanada submitted a Statement of Intent to Participate in the proceeding.

Although the AESO has had conversations with both stakeholders to clarify their concerns and is working on a Need Cancellation validation, the NID amendment may end up in a hearing if the Need Cancellation validation recommendation is to proceed with the cancellations as filed.

There were no significant risks identified on the remaining facilities that are under construction.

11 The current estimated cost decreased by $34 million due to the cancellation of FA 99.


859S
PRIMROSE
822S
WOLF LAKE
837S
MAHIHKAN
826S
MARGUERITE
LAKE
715S
LEMING
LAKE
Facility Application 1
Cold Lake Area
Reinforcements
- Except Bonnyville
Lac la
Biche
Cold Lake Reinforcement
(2017) - 240 kV
(CANCELLED)
Cold Lake
Facility Application 4
St. Paul Area Upgrades
- St. Paul 707S & 7L139/7L70
700S
BONNYVILLE
Facility Application 5
St. Paul Area Upgrades
- Whitby Lake 819S
Facility Application 2
Cold Lake Area
Reinforcements
- Bourque to 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
Facility Application 10
Line Clearance Mitigations
Lamont
Facility Applications 11, 12
Line Clearance Mitigations
(CANCELLED)
Fort
Saskatchewan
Mundare
Two Hills
Facility Application 8
Kitscoty Area Upgrades
Vegreville
Facility Application 6
Vermillion 710S
Substation Upgrade
705S
KITSCOTY
Vermilion
Tofield
751S
HILL
710S
VERMILION
Lloydminster
716S
LLOYDMINSTER
526S
BUFFALO
CREEK
Viking
7L749 Replacement
(CANCELLED)
Camrose
7L50 Rebuild (CANCELLED)
252S
JARROW
223S
STROME
Wainwright
51S
WAINWRIGHT
Killam
137S
SEDGEWICK
899S
EDGERTON
Facility Application 7
Heisler Area Upgrades
Sedgewick
Hardisty
764S
HEISLER
478S
TUCUMAN
377S
HARDISTY
277S
HAYTER
Bashaw
267S
KILLARNEY
LAKE
757S
BATTLE RIVER
Facility Application 13
Provost & Wainwright
Area Upgrades (CANCELLED)
648S
METISKOW
650S
HANSMAN
LAKE
545S
PROVOST
Provost
Stettler
Project 811
Central East Area
Transmission Development
811_TFCMC_2015-07-28
cthomas 2015-08-13
Project Components
Completed / Not Completed
Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Project 811 Components
Cities and Towns

2. **CHRISTINA LAKE AREA 240 KV TRANSMISSION DEVELOPMENT (CHL);** PROJECT 1101 – Reinforcing transmission facilities for oil sands developments and enhanced reliability to existing oil sands operations.

THE PROJECT:[12] 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 two new 240/138 kV substations and will reinforce the 240 kV network by closing the loop from the new Black Spruce 154S substation to 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 NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Black Spruce substation and 240 kV lines	1	Black Spruce substation and interconnecting 240 kV lines	July 10, 2013
Pike substation and 240 kV lines	2	Pike substation and interconnecting 240 kV lines to Black Spruce	June 30, 2014
Heart Lake expansion	4	Expand Heart Lake substation for the termination of 9L930 in/out and the new 240 kV line to Ipiatik	June 27, 2015
Pike to Ipiatik to Heart Lake and 240 kV lines and modifications to Christina Lake 723S	3	New Ipiatik substation, new 240 kV line from Pike to Ipiatik to Heart Lake substation and modifications to Christina Lake 723S	September 25, 2015

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

PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JANUARY 2014) ESTIMATED COST	CURRENT ESTIMATED COST
Christina Lake Area 240 kV Transmission Development	**$390 Million** (2013$)	**$512.95 Million**[13] (ISD$ with escalation)

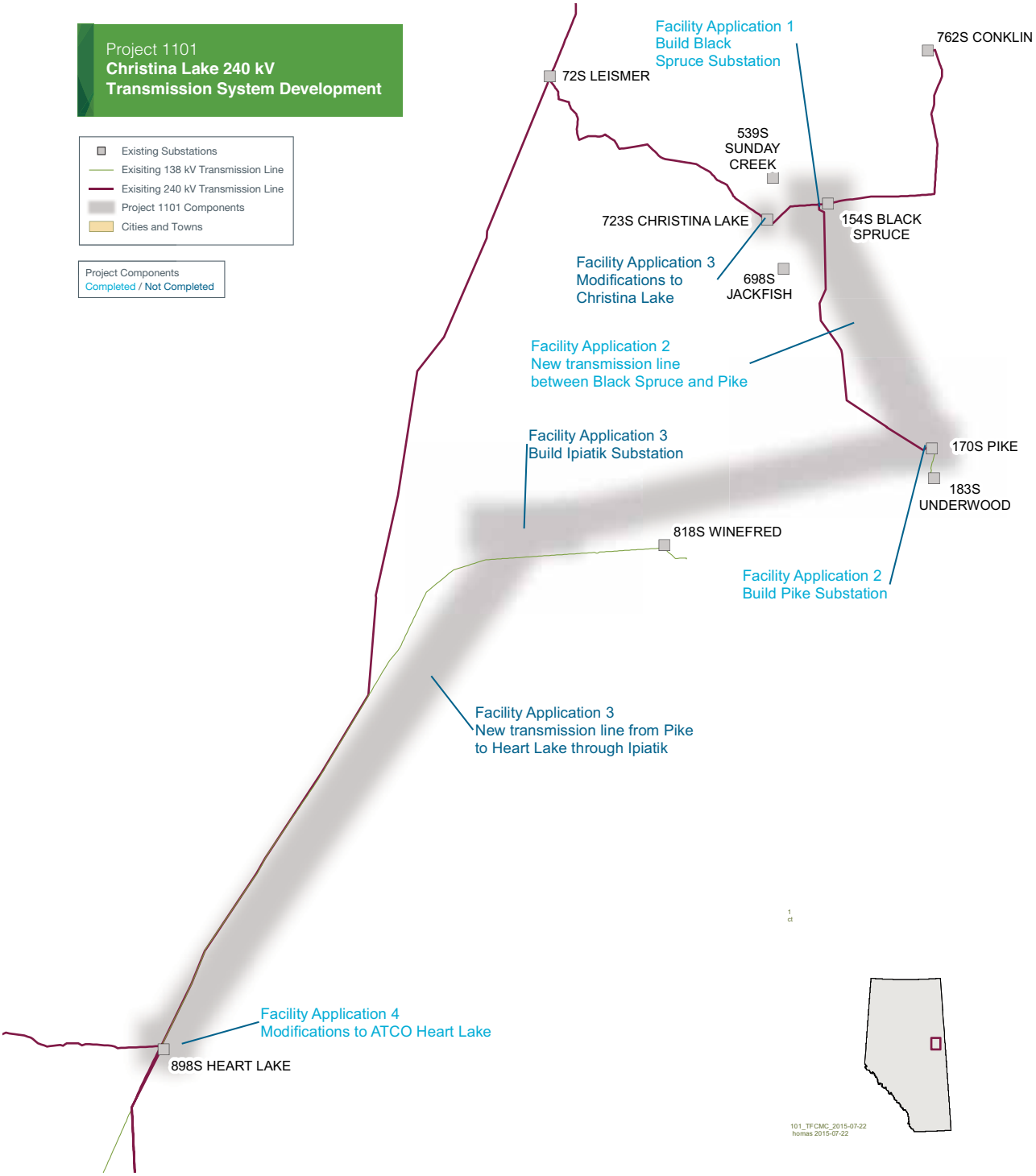
CURRENT STATUS: The Black Spruce substation and lines to the Pike substation are energized. The Ipiatik to Heart Lake development (1116L/1117L) is under construction, with an ISD of August 21, 2015. The Heart Lake development was completed on June 30, 2015. The remaining work at the Christina Lake substation is expected to be completed by October 2015. A change proposal for hot line work to eliminate the lengthy outage of four to five days to reconnect Winefred and Kirby Lake has been approved.

12 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 NID.

13 The current estimated cost decreased by $8.61 million from $521.56 million.

PROJECT RISKS

Several pipeline operators have failed to implement either temporary or permanent AC mitigations. This has resulted in a delay in the ISD of six weeks, and there is a risk of further delays.



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

THE PROJECT: The East Calgary Transmission Project and the ENMAX Shepard Energy Centre Connection is required to serve growing demand for electricity in the southeast Calgary area and enable new generation facilities to reliably connect to the system. The project supports the connection of the ENMAX Shepard Energy Centre Connection, a new 850 MW combined-cycle generation facility via a new substation – ENMAX No. 25.

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); a new 138 kV transmission line between ENMAX No. 23 and ENMAX No. 2; a 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; a new 240 kV double-circuit 240 kV transmission line (985L/1003L) from Janet 74S to ENMAX No. 25; the addition of a 240 kV switching station (ENMAX No. 25) for connection to the transmission system and the Shepard Energy Centre; addition of a second 240/138 kV – 240/320/400 MVA transformer at East Calgary 5S.

FACILITY APPLICATION NAME	FACILITY APPLICATION NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
East Calgary 240 kV and 138 kV transmission system upgrades and Shepard Energy Centre Connection (AltaLink Facility Application)	1	Rebuild East Calgary 5S substation; upgrade AltaLink-owned infrastructure 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 30, 2015
East Calgary 240 kV and 138 kV transmission system upgrades and Shepard Energy Centre Connection (ENMAX Facility Application)	2	Modifications to existing ENMAX No. 2 and No. 23 substations, addition of new ENMAX No. 25 substation; construct new 138 kV line between ENMAX No. 23 and Janet 74S substations	September 30, 2015

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

PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JANUARY 2014) ESTIMATED COST	CURRENT ESTIMATED COST
East Calgary 240 kV and 138 kV Transmission System Upgrade and ENMAX Shepard Energy Centre Connection	***$921 Million**[14] (2013$) *entire FATD plan	***$164.26 Million** (includes escalation and AFUDC) *ECTP and Shepard Energy Centre PPS only

CURRENT STATUS: The Shepard Energy Centre started commercial operation in March 2015. Remaining system work includes an upgrade of the transformer at the East Calgary substation and salvaging of the old buswork at ENMAX No. 2 substation. This work is scheduled to be completed by the end of September 2015.

PROJECT RISKS

Risk includes general construction challenges due to brownfield development.

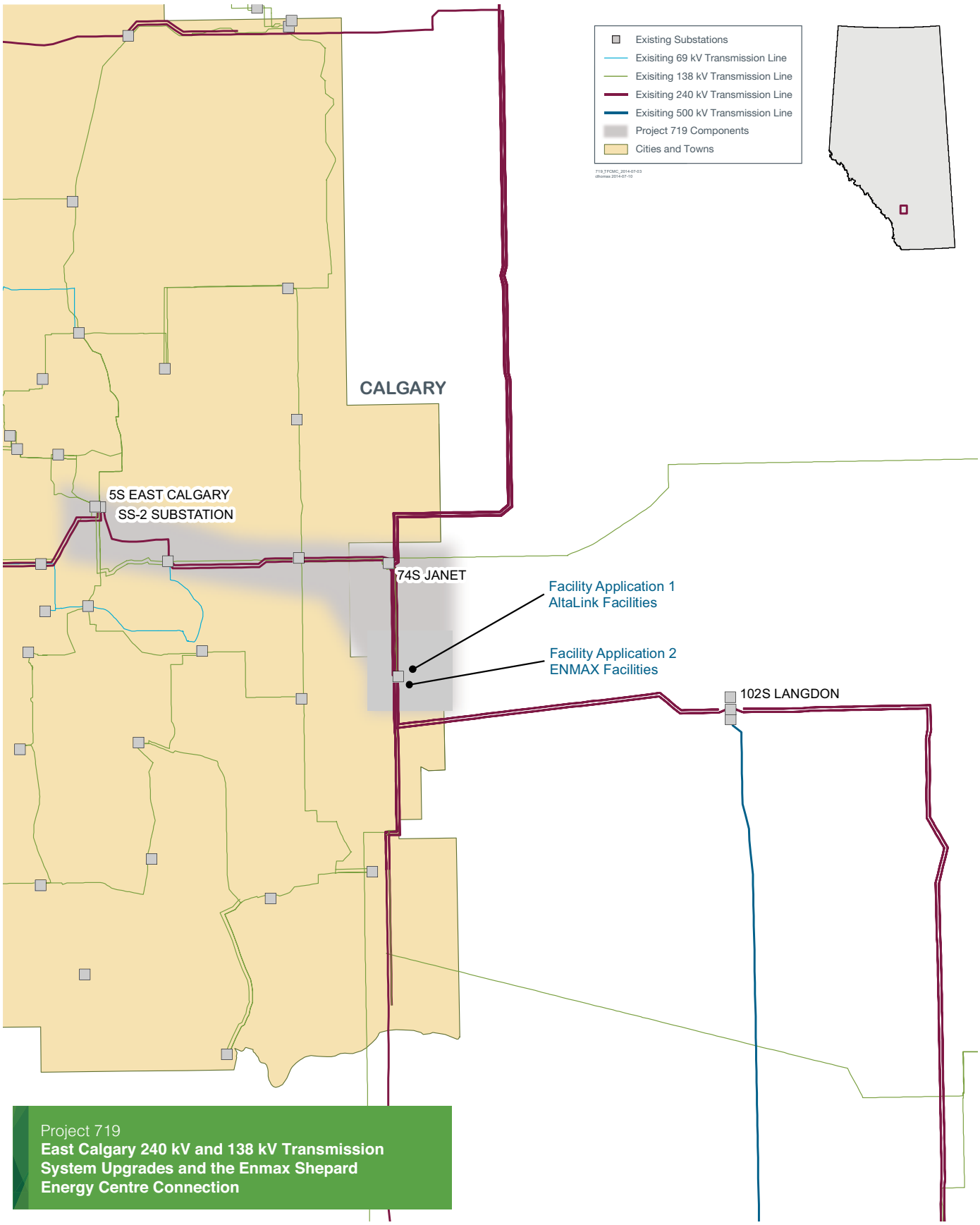
14 The AESO's Long-Term Transmission Plan identified the need for the Foothills Area Transmission Development. The East Calgary 240 kV and 138 kV transmission system upgrades are one of four components of the overall Foothills Area Transmission Development. The four components of the Foothills Area Transmission 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 41; and

d. Foothills Area Transmission Development – West Region.



Project 719
East Calgary 240 kV and 138 kV Transmission System Upgrades and the Enmax Shepard Energy Centre Connection

4. **EDMONTON REGION 240 KV LINE UPGRADES (ERLU);** PROJECT 786 – Upgrading 240 kV lines in the Edmonton area and adding one 240 kV phase shifter at the Livock substation to gain more capacity out of the existing 240 kV network.

THE PROJECT: More than 4,000 MW of baseload 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 regional 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 and 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 lines and the installation of a special protection scheme for multiple contingencies to ensure system reliability in the area. Additionally, a 240 kV phase-shifter transformer will be installed at Livock 939S in the Fort McMurray area.

FACILITY APPLICATION NAME	FACILITY APPLICATION NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
AltaLink Keephills Substation addition	1	Additions at Keephills	July 31, 2010
AltaLink 1045L, 909L Restring	5	Restring four km of 908L and 909L outside Sundance 310P substation (first four km of the lines); 908L is renumbered to 1045L	March 20, 2011
EPCOR Jasper, Petrolia	6	Upgrade bus work and protections	June 14, 2011
EPCOR 1044EL, 1045EL	3	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)	February 29, 2012
ATCO Phase Shifter	7	Add 600 MVA phase shifting transformer at Livock 939S	August 20, 2013
TransAlta 902L	8	Rebuild portion of 902L	November 12, 2014
AltaLink Rebuild 240 kV 904L (1043L) TransAlta 902L, Re-terminate 909L at Sundance	2 and 4	Delegate the work to AltaLink for re-termination of the existing 240 kV 909L at Sundance 310P (Ellerslie 89S to Sundance 310P); rebuild approximately 50 km of the existing 240 kV line 904L between Jackfish Lake 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)	July 31, 2017

THE TRANSMISSION FACILITY OWNER(S): AltaLink, EDTI and ATCO.

PROJECT COST:

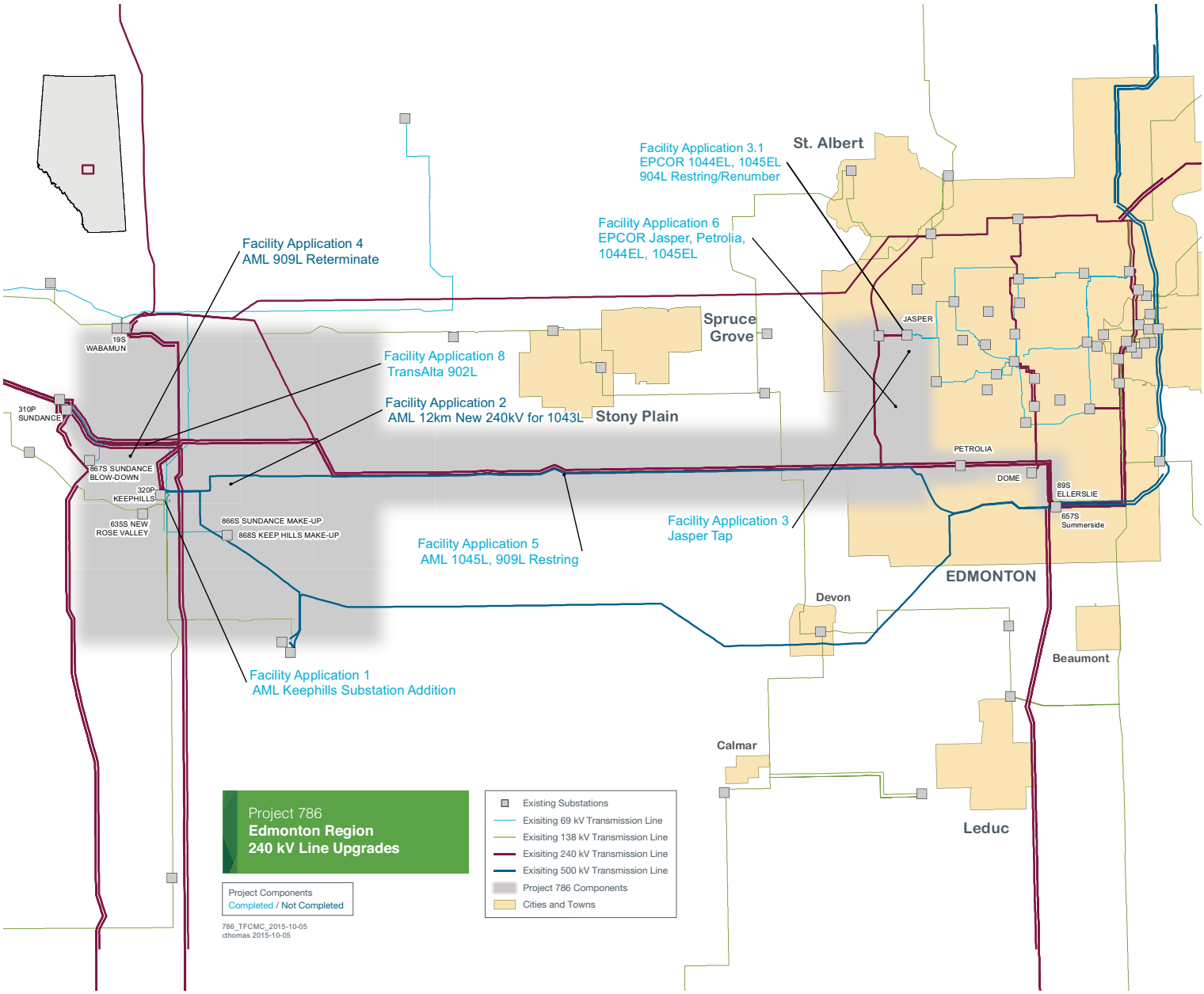
TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JANUARY 2014) ESTIMATED COST	CURRENT ESTIMATED COST
Edmonton Region 240 kV Line Upgrades	**$182 Million** (2013$)	**$178 Million** (ISD$ with escalation)

CURRENT STATUS: All facilities, with the exception of 1043L, are in service.

The construction required to complete a small portion of the 1043L transmission line has been delayed due to land access issues. A firm ISD for the 1043L transmission line and re-termination of 909L cannot be determined at this time until land access issues are resolved. A change proposal from TransAlta Utilities extending the Permit and License (P&L) to July 2016 has been approved.

PROJECT RISKS

The completion of 1043L is at risk of not being completed. It is unknown when negotiations between the Enoch First Nations and TransAlta will be completed. If negotiations fail, a re-route of the line going around the Enoch First Nations would need to occur. A change proposal from AltaLink to begin work on the reroute option has been approved by the AESO. An estimated ISD would be in 2018. The cost estimate for the re-route has not been provided.


Facility Application 3.1
EPCOR 1044EL, 1045EL
904L Restring/Renumber
St. Albert
Facility Application 6
EPCOR Jasper, Petrolia,
1044EL, 1045EL
Facility Application 4
AML 909L Reterminate
Spruce Grove
JASPER
19S
WABAMUN
Facility Application 8
TransAlta 902L
Facility Application 2
AML 12km New 240kV for 1043L
Stony Plain
310P
SUNDANCE
PETROLIA
867S SUNDANCE
BLOW-DOWN
DOME
320P
KEEPHILLS
89S
ELLERSLIE
635S NEW
ROSE VALLEY
866S SUNDANCE MAKE-UP
868S KEEP HILLS MAKE-UP
657S
Summerside
Facility Application 3
Jasper Tap
Facility Application 5
AML 1045L, 909L Restring
EDMONTON
Devon
Beaumont
Facility Application 1
AML Keephills Substation Addition
Calmar
Leduc
Project 786
Edmonton Region
240 kV Line Upgrades
Project Components
Completed / Not Completed
786_TFCMC_2015-10-05
cthomas 2015-10-05
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

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

THE PROJECT: The FATD East development will ensure the transmission system will serve growing electricity demand in Calgary, High River, and the surrounding areas, and enable future generation facilities to reliably connect to the system. It 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 ENMAX SS-65; a new 240 kV double-circuit line from the existing Langdon 102S to the existing 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 ENMAX SS-65 substation to the new ENMAX SS-25 substation, and the de-energization of sections of existing transmission lines.

The 138 kV scope consists of 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 NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
North Foothills Transmission Project	1	Construction of Foothills 235S 240/138 kV switching station, and construction of approximately 52 km of double-circuit 240 kV transmission line from Foothills 237S to ENMAX SS-65	May 25, 2015
Langdon to Janet Project	3, 4	Construction of approximately 18 km of double-circuit 240 kV transmission line from Langdon 102S to Janet 74S; expansion of Janet 74S substation; removal of terminations at Janet 74S resulting in two new circuits 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 31, 2015
ENMAX No.25 substation 240 kV line additions and ENMAX No.65 substation 240 kV line additions	2	Interconnection of two new AltaLink 240 kV transmission lines at ENMAX SS-25, and termination of three new AltaLink 240 kV transmission lines at ENMAX SS-65	November 1, 2015
Foothills 138 kV Project	5	Addition of two 240/138 kV transformers at Foothills 237S; construction of approximately 14 km of double-circuit 138 kV 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	November 1, 2015

THE TRANSMISSION FACILITY OWNER(S): AltaLink and ENMAX.

PROJECT COST:

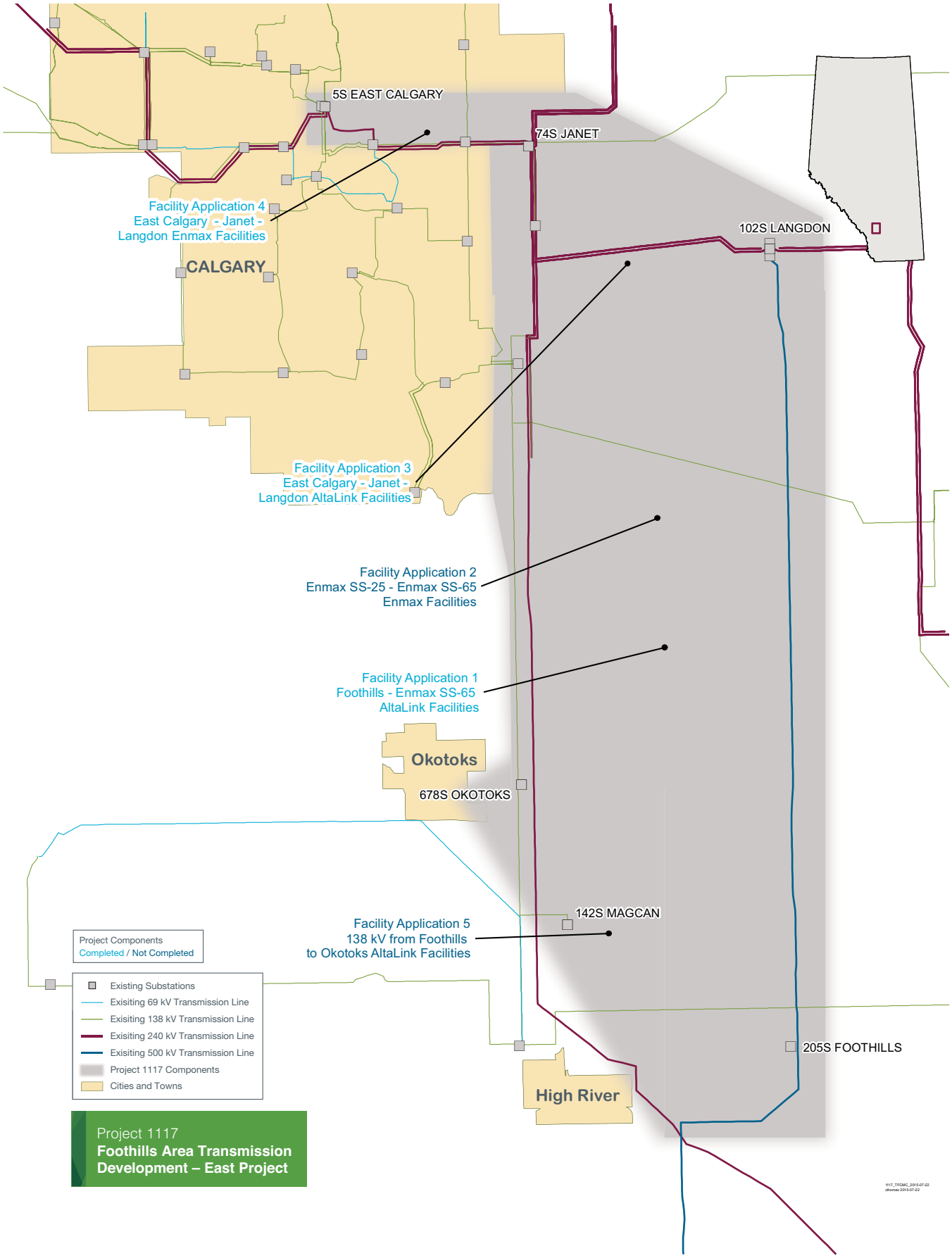
TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JANUARY 2014) ESTIMATED COST	CURRENT ESTIMATED COST
Foothills Area Transmission Development – East Project	***$921 Million** (2013$) *entire FATD plan	***$523.91 Million**[15] (ISD$ with escalation) *FATD East

CURRENT STATUS: The following energizations were completed in May 2015: 240 kV 1064L/1065L; reconfiguration of 240 kV 937L from the Langdon substation to the East Calgary 5S substation; Foothills substation and the 240 kV 1106L/1107L from the Foothills substation to the ENMAX No. 65 substation. The project is expected to be fully completed by November 2015.

PROJECT RISKS

Risk includes outage conflicts with concurrent projects (East Calgary Transmission Project, Western Alberta Transmission Line, Red Deer Area Transmission Development and Southern Area Transmission Reinforcement). These risks may impact project schedules.

15 The current estimated cost increased by $1.9 million from $522 million.


5S EAST CALGARY
74S JANET
102S LANGDON
Facility Application 4
East Calgary - Janet -
Langdon Enmax Facilities
CALGARY
Facility Application 3
East Calgary - Janet -
Langdon AltaLink Facilities
Facility Application 2
Enmax SS-25 - Enmax SS-65
Enmax Facilities
Facility Application 1
Foothills - Enmax SS-65
AltaLink Facilities
Okotoks
678S OKOTOKS
142S MAGCAN
Facility Application 5
138 kV from Foothills
to Okotoks AltaLink Facilities
205S FOOTHILLS
High River
Project Components
Completed / Not Completed
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
Project 1117
Foothills Area Transmission
Development – East Project

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

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 NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Fort McMurray Area Bulk System Development Stage 1 – West Line	1	One 500 kV transmission line will be constructed from a new substation at Thickwood Hills to the Genesee area, referred to as the West 500 kV line	2019
Fort McMurray Area Bulk System Development Stage 2 – East Line	2	A second 500 kV transmission line will be constructed from a new substation at Thickwood Hills to the Heartland area, referred to as the East 500 kV line	Deferred

THE TRANSMISSION FACILITY OWNER(S): The Transmission Facility Owner (TFO) for the West line is Alberta PowerLine Ltd. (APL). The TFO for the East line will be determined through the Competitive Process.

PROJECT COST:

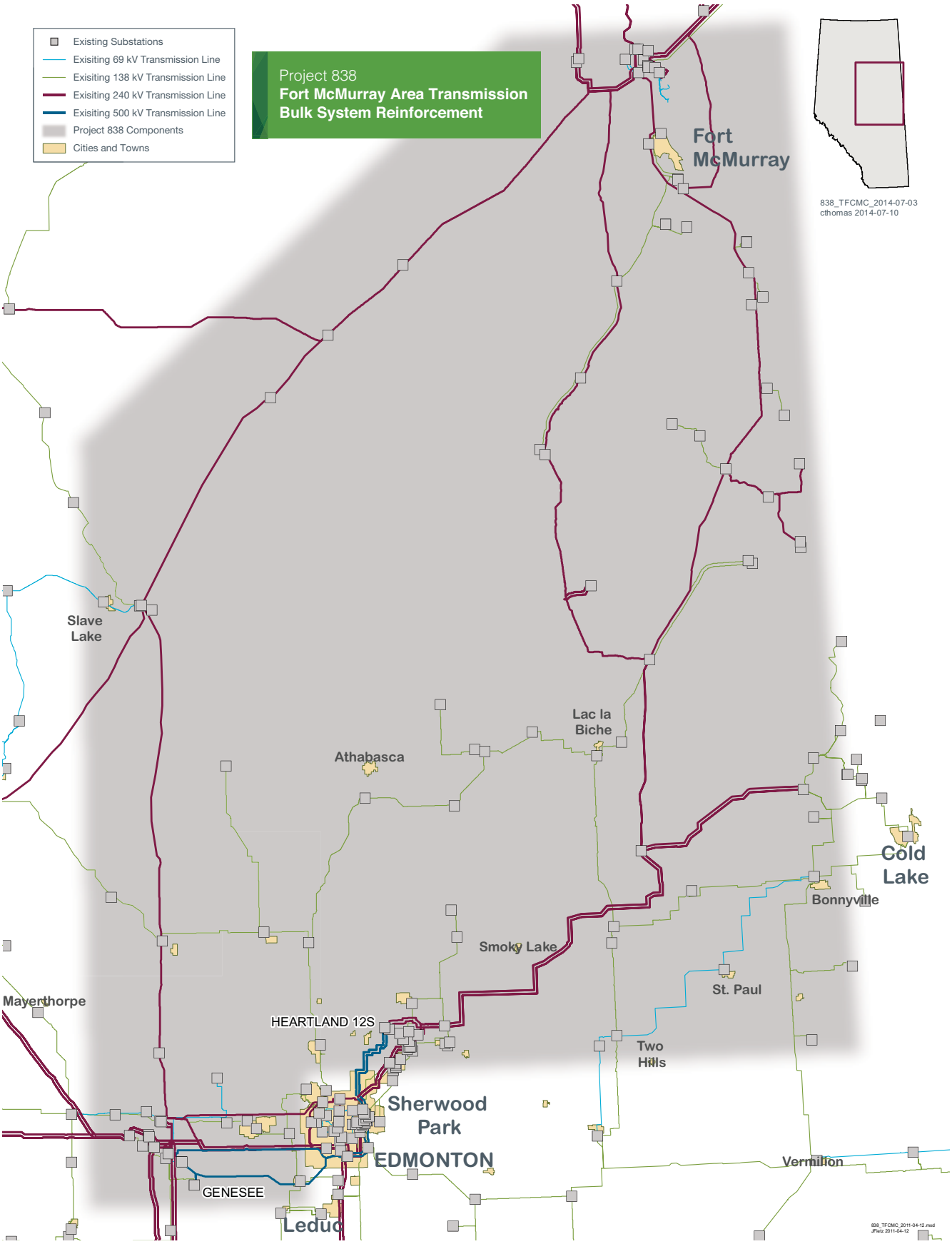
TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JANUARY 2014) ESTIMATED COST	CURRENT ESTIMATED COST
Fort McMurray Area Transmission Bulk System Reinforcement	**$1.796 Billion** (2013$) **Stage 1: $1.796 Billion** (2013$) **Stage 2:** To Be Determined	**Stage 1: $1.433 Billion**

CURRENT STATUS: In December 2014 APL was the successful proponent of the Fort McMurray West 500 kV transmission project, with a fixed price of $1.433 billion. APL is currently consulting with stakeholders on its alternate and preferred routes, with a targeted filing of the FA with the AUC by the end of 2015. The target ISD for the project is June 2019.

Based on the current economic environment and sustained low oil prices, the AESO is deferring the launch date of the Fort McMurray East 500 kV Transmission Project. The AESO will release its next forecast in early 2016 and at that time will be in a better position to provide an update on Stage 2 of the project.

PROJECT RISKS

Risks, such as the regulatory process, adverse weather conditions, construction activities, land rights or access, and other stakeholder issues, may delay the ISD beyond June 2019.


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
Project 838
Fort McMurray Area Transmission
Bulk System Reinforcement
838_TFCMC_2014-07-03
cthomas 2014-07-10
Fort McMurray
Slave Lake
Lac la Biche
Athabasca
Cold Lake
Bonnyville
Smoky Lake
St. Paul
Mayerthorpe
HEARTLAND 12S
Two Hills
Sherwood Park
EDMONTON
Vermilion
GENESEE
Leduc
838_TFCMC_2011-04-12.mxd
JFietz 2011-04-12

7. ***COMPLETED* HANNA REGION TRANSMISSION DEVELOPMENT (HATD);** PROJECT 812 – 240/144 kV transmission development in the Hanna, Sheerness, Wainwright, Provost and Battle River areas.

THE PROJECT: Transmission reinforcement in the Hanna region (East Central Alberta) allows for the connection of up to 700 MW of wind power and to 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 double-circuit 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 the existing Hansman Lake 605S and two new 240/144 kV substations near Oyen and Monitor; addition of -100/+200 VAr static var compensators at the 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 NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Battle River 757S Capacitor Bank addition	2	Battle River 757S–72 kV Capacitor Bank addition; 144 kV circuit breaker and substation alterations	October 3, 2011
Youngstown 772S Capacitor Bank addition	1	Youngstown 772S–Capacitor Bank addition; 144 kV breaker and communication tower	October 6, 2011
144 kV Capacitor Bank and Circuit Breaker additions at Three Hills substation 770S	13	Three Hills 770S 144 kV Capacitor Bank addition; 144 kV circuit breaker and substation alterations	December 13, 2011
Rowley 768S–Michichi–Three Hills 144 kV DC Line 7L25	18	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
Hardisty 377S substation Capacitor Bank	21	138 kV Capacitor Bank addition at Hardisty 377S substation and other associated work	June 28, 2012
Hansman Lake 650S substation SVC addition	22	Addition of a -100/+200 VAr SVC at Hansman Lake 650S	October 5, 2012

FACILITY APPLICATION NAME	FACILITY APPLICATION NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Heatburg 948S–Three Hills–Nevis 144 kV D/C Line 7L16/7L159	17	New 144/25 kV Heatburg 948S substation; new double-circuit 144 kV transmission line from Heatburg 948S to existing 7L16; modification of 7L16 to create an in/out configuration to Heatburg 948S and alterations at existing substations	January 25, 2013
Oakland 946S 240 kV S/S combined with Anderson–Oakland line	7	New double-circuit 240 kV transmission line (designated as 9L70/9L97) from Anderson 801S to Oakland 946S, Oakland 946S substation and related alterations	March 25, 2013
Stettler 769S–Nevis 768S 144 kV S/C Line 7L143	19	New single-circuit 144 kV transmission line from Nevis 766S to Stettler 769S; alterations to Nevis 766S and alterations to Stettler 769S	April 21, 2013
Coyote Lake 963S 240 kV S/S combined with Oakland–Coyote line	9	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	May 17, 2013
New Lanfine 240/144 kV substation	3	New 240/144 kV substation designated Lanfine 959S	May 20, 2013
Oakland–Lanfine 240 kV S/C line 9L924	8	New double-circuit 240 kV transmission line (one-side strung) designated 9L24, from Oakland 946S to Lanfine 959S and alterations to Oakland 946S	May 21, 2013
Pemukan 932S 240 kV substation	11	New 240/144 kV substation designated Pemukan 932S	June 1, 2013
New Lanfine-Pemukan 240 kV S/C Line 9L46	12	New double-circuit 240 kV transmission line (one-side strung) designated 9L46, from Pemukan 932S to Lanfine 959S and alterations to Lanfine 959S	June 1, 2013
Relocate 7L98 Oyen 767S–Lanfine 959S	6	Decommission and salvage of transmission line 7L98 and 7LA98	June 1, 2013
Relocate 7L79 line from Monitor 774S–Pemukan 932S	16	Re-termination of existing 7L70 from Monitor 774S to Pemukan 932S and alterations to Pemukan 932S	June 12, 2013
Pemukan 932S–Monitor 774S 144 kV S/C Line 7L127	15	Double-circuit 144 kV line (one-side energized) from Pemukan 932S to Monitor 774S	June 15, 2013
Coyote Lake 963S–Michichi Creek 802S 144 kV SC Line 7L128	10	New single-circuit transmission line designated as 7L128 from Michichi Creek 802S to Coyote Lake 963S and alterations to existing Michichi Creek 802S	July 12, 2013

FACILITY APPLICATION NAME	FACILITY APPLICATION NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Lanfine-Oyen 144 kV S/C Line 7L132	5	Double-circuit 144 kV line (one-side energized) from Lanfine 959S to Oyen 767S	July 15, 2013
Hansman Lake-Pemukan 240 kV S/C Line 9L966	14	New double-circuit 240 kV transmission line (one-side strung) designated 9L966, from Pemukan 932S to AltaLink's service territory and alterations to Pemukan 932S	August 21, 2013
New 240 kV line 966L from Pemukan 932S–Hansman Lake 650S	23	New double-circuit 240 kV transmission line (one-side strung) designated 966L, from Hansman Lake 650S to ATCO's service territory and alterations to Hansman Lake 650S	August 21, 2013
Nilrem 574S combined with D/C 240 kV 953L–1047L and Tucuman 478S combined with D/C 138 kV 679L–680L	20	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	August 30, 2013
New 240 kV line 1060L from Ware Junction 132S–West Brooks 28S	24	New single-circuit 240 kV transmission line (designated 1053L) from Ware Junction 132S to Cassils 324S; alterations to Ware Junction 132S and alteration to Cassils 324S	November 29, 2013
Lanfine 959S 200 VAr SVC	4	Addition of a -100/+200 VAr SVC at Lanfine 959S	April 13, 2015

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

PROJECT COST:

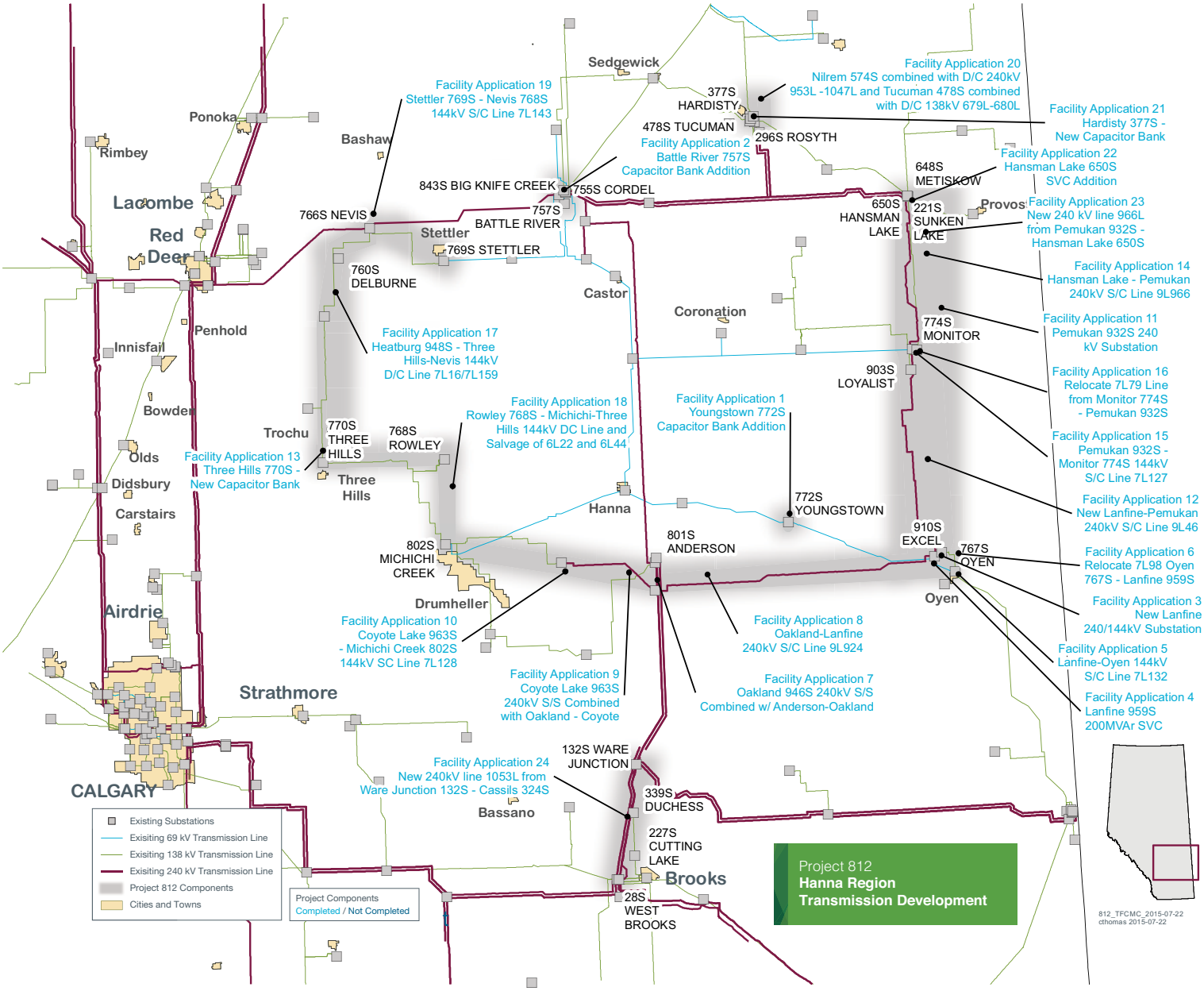
TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JANUARY 2014) ESTIMATED COST	CURRENT ESTIMATED COST
Hanna Region Transmission Development	**$895 Million** (2013$)	**$969 Million** (ISD$ with escalation)

CURRENT STATUS: All FAs related to Phase 1 of the project have been completed, including the Lanfine Static Var Compensator. The ISD for this development was April 13, 2015.

Final costs for AltaLink developments were received and reviewed by the AESO in May 2015. Final Costs for ATCO developments were received in June 2015. The AESO is reviewing these costs.

PROJECT RISKS

The AESO is re-evaluating the timing and the need for Phase 2 of the Hanna project. Based on the current system work plan, the review of Hanna is being deferred until 2016 due to other priorities. Both ATCO and AltaLink have been requested to cease all work on the project until further notice.


Sedgewick
Facility Application 19
Stettler 769S - Nevis 768S
144kV S/C Line 7L143
Facility Application 20
Nilrem 574S combined with D/C 240kV
953L -1047L and Tucuman 478S combined
with D/C 138kV 679L-680L
377S
HARDISTY
Facility Application 21
Hardisty 377S -
New Capacitor Bank
Ponoka
Rimbey
Bashaw
478S TUCUMAN
Facility Application 2
Battle River 757S
Capacitor Bank Addition
296S ROSYTH
Facility Application 22
Hansman Lake 650S
SVC Addition
648S
METISKOW
843S BIG KNIFE CREEK
755S CORDEL
Lacombe
766S NEVIS
757S
BATTLE RIVER
650S
HANSMAN
LAKE
221S
SUNKEN
LAKE
Provost
Facility Application 23
New 240 kV line 966L
from Pemukan 932S -
Hansman Lake 650S
Red
Deer
Stettler
769S STETTLER
760S
DELBURNE
Castor
Facility Application 14
Hansman Lake - Pemukan
240kV S/C Line 9L966
Coronation
Penhold
Innisfail
Facility Application 17
Heatburg 948S - Three
Hills-Nevis 144kV
D/C Line 7L16/7L159
774S
MONITOR
Facility Application 11
Pemukan 932S 240
kV Substation
903S
LOYALIST
Facility Application 16
Relocate 7L79 Line
from Monitor 774S
- Pemukan 932S
Bowden
Facility Application 18
Rowley 768S - Michichi-Three
Hills 144kV DC Line and
Salvage of 6L22 and 6L44
Facility Application 1
Youngstown 772S
Capacitor Bank Addition
Trochu
770S
THREE
HILLS
768S
ROWLEY
Olds
Facility Application 13
Three Hills 770S -
New Capacitor Bank
Facility Application 15
Pemukan 932S -
Monitor 774S 144kV
S/C Line 7L127
Didsbury
Three
Hills
Carstairs
Hanna
772S
YOUNGSTOWN
Facility Application 12
New Lanfine-Pemukan
240kV S/C Line 9L46
910S
EXCEL
801S
ANDERSON
767S
OYEN
Facility Application 6
Relocate 7L98 Oyen
767S - Lanfine 959S
802S
MICHICHI
CREEK
Oyen
Airdrie
Drumheller
Facility Application 3
New Lanfine
240/144kV Substation
Facility Application 10
Coyote Lake 963S
- Michichi Creek 802S
144kV SC Line 7L128
Facility Application 8
Oakland-Lanfine
240kV S/C Line 9L924
Facility Application 5
Lanfine-Oyen 144kV
S/C Line 7L132
Facility Application 9
Coyote Lake 963S
240kV S/S Combined
with Oakland - Coyote
Facility Application 7
Oakland 946S 240kV S/S
Combined w/ Anderson-Oakland
Strathmore
Facility Application 4
Lanfine 959S
200MVAr SVC
132S WARE
JUNCTION
Facility Application 24
New 240kV line 1053L from
Ware Junction 132S - Cassils 324S
CALGARY
Bassano
339S
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
Project Components
Completed / Not Completed
Project 812
Hanna Region
Transmission Development
812_TFCMC_2015-07-22
cthomas 2015-07-22

8. **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, the Western Alberta Transmission Line (WATL), 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 the Langdon area. The second line, the Eastern Alberta Transmission Line (EATL), will be located on the east side of the province connecting the Heartland hub northeast of Edmonton to a southern hub near the Brooks area.

THE COMPONENTS: The two new lines will be 500 kV high-voltage direct current (HVDC) technology and will be built to transfer up to 1000 MW of power each. Each line and converter station can be upgraded to 2000 MW at a future date. For each line, two 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 NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Eastern Alberta Transmission Line Project Facility Application – AltaLink	3	Application to construct and operate an interface for the EATL converter stations	September 2015
Western Alberta Transmission Line Project Facility Application – AltaLink	2	Application to construct and operate a high-voltage DC line from Genesee to Langdon	October 2015
Eastern Alberta Transmission Line Project Facility Application – ATCO	1	Application to construct and operate a high-voltage DC line from Heartland to West Brook	November 2015

THE TRANSMISSION FACILITY OWNER(S): AltaLink is the designated TFO to build WATL and ATCO is the designated TFO to build EATL.

PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JANUARY 2014) ESTIMATED COST	CURRENT ESTIMATED COST
North South Transmission Reinforcement – EATL	**$1.665 Billion** (2013$)	**$1.90 Billion** (ISD$ with escalation)
North South Transmission Reinforcement – WATL	**$1.499 Billion** (2013$)	**$1.669 Billion** (ISD$ with escalation)

CURRENT STATUS: ATCO is forecasting the EATL ISD to be mid fourth quarter 2015; AltaLink is forecasting the WATL ISD to be in the late part of third quarter of or the early part of the fourth quarter of 2015.

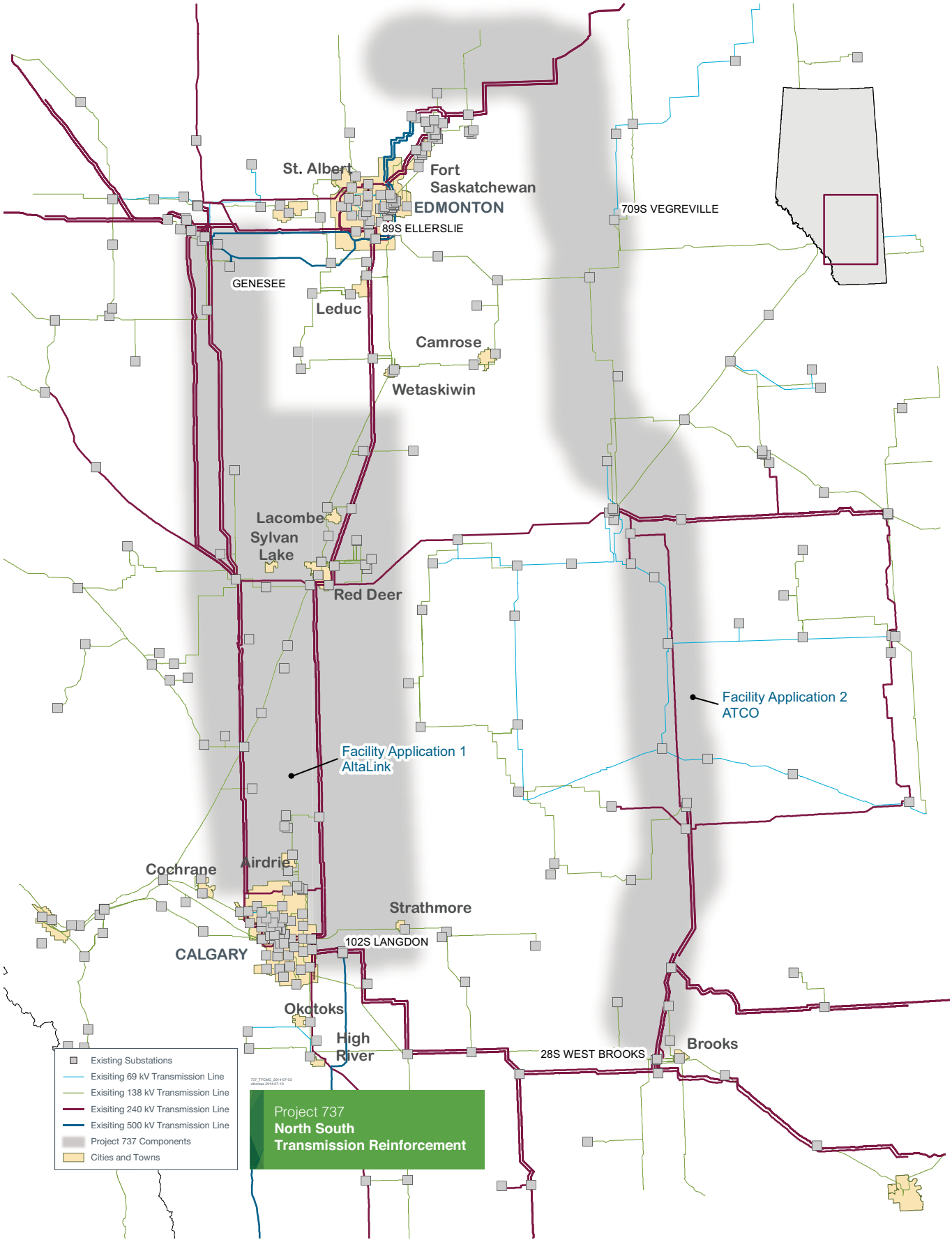
The remaining work on both projects is termination of wires within the converter stations, pre-commissioning of all equipment and sub-systems, and commissioning of the end-to-end system.

PROJECT RISKS

Project risks include construction outages and inter-dependencies with other concurrent projects (i.e., FATD, ECTP, SATR) that may impact commissioning of facilities and the ISDs.

Commissioning studies completed so far show that no market impacts are expected during the commissioning of the facilities. Risks that could change this are unplanned outages that occur on the system.

There is the risk of increased project costs if further delays occur. The AESO meets monthly with both TFOs to discuss commissioning and outage planning to attempt to mitigate these risks.


St. Albert
Fort Saskatchewan
EDMONTON
89S ELLERSLIE
709S VEGREVILLE
GENESEE
Leduc
Camrose
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
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
Project 737
North South
Transmission Reinforcement

9. 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 of Fort McMurray.

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, including the addition of two new 240 kV substations. This expansion of the transmission system will serve developing (electricity intensive) industrial growth as oil sands extraction facilities and related industrial developments are proceeding into areas where there are currently no transmission facilities to provide service, and connect future industrial customers.

THE COMPONENTS: Major components include a new 240 kV switching substation (Birchwood Creek 960S-NW FMM South); existing 9L57 line in/out at Birchwood Creek 960S; a new 240 kV switching station (Ells River 2079S-NW FMM North); 9L08 Joslyn to Dover line in/out at Ells River 2079S (approximately 50 km of 240 kV double-circuit line, designated as 9L08/9L76), and approximately 80 km of 240 kV single-circuit line (9L95), between Ells River 2079S and Birchwood Creek 960S.

FACILITY APPLICATION NAME	FACILITY APPLICATION NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Birchwood Creek substation and 9L57 in/out.	1	Birchwood Creek: new 240 kV switching substation; existing 9L57 line in/out at Birchwood Creek	March 10, 2015
Ells River substation, 9L76 and 9L08, in/out 240 kV double-circuit line from existing 9L08 to Ells River substation	2	9L08, Joslyn to Dover line in/out at Ells River (approximately 50 km of 240 kV double-circuit line)	Second quarter 2017
Ells River to Birchwood Creek Line 9L95, 240 kV line between Ells River and Birchwood Creek	3	Approximately 80 km of 240 kV double-circuit line, one-side strung, between Ells River and Birchwood Creek	Fourth quarter 2017

THE TRANSMISSION FACILITY OWNER(S): ATCO.

PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JANUARY 2014) ESTIMATED COST	CURRENT ESTIMATED COST
Northwest (of) Fort McMurray 240 kV Transmission Development	**$343 Million** (2013$)[16]	**$235.1 Million** (ISD$ with escalation)

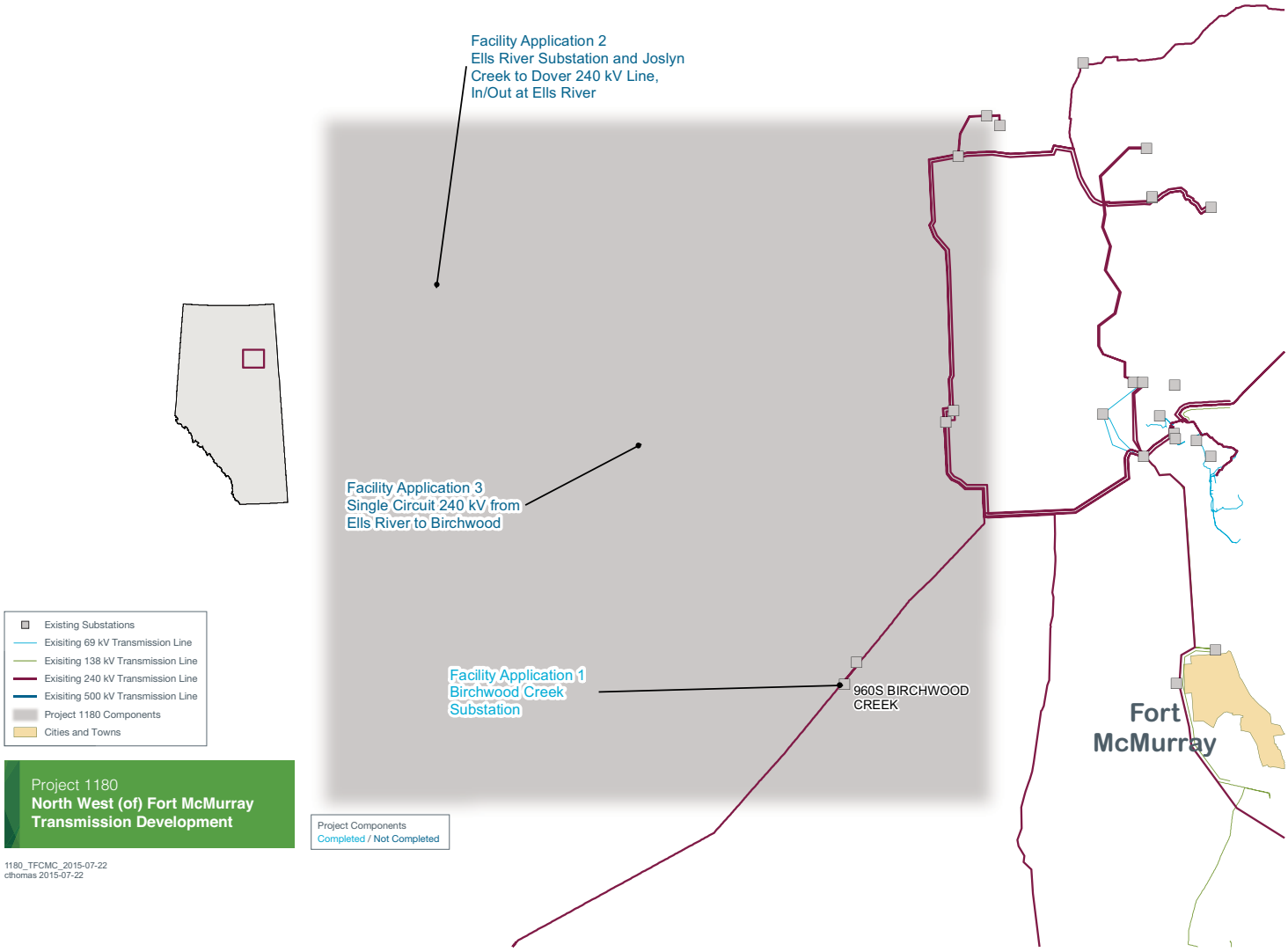
CURRENT STATUS: The Birchwood Creek switching substation and 9L57 240 kV in/out was energized on March 9, 2015. The FA for the Ells River substation and 9L76/9L08 240 kV in/out double circuit was expected to be filed in the second quarter of 2015, however, system studies have been initiated as a result of changes in the timing of customer system access requests in the area. Reassessment work is expected to recommence in 2016. ATCO has been notified to stop work until the AESO reassessment is complete.

The Ells River ISD has been delayed from 2016 to 2017/2018 because of delays to customer projects. Further delays may mean a re-scoping of the project and a NID Amendment.

16 Referenced as the "240 kV double-circuit line from Livock to Joslyn Creek" in the Long-Term Transmission Plan filed in June 2012.

PROJECT RISKS

There are no significant risks to report at this time.



10. **RED DEER REGION TRANSMISSION DEVELOPMENT (RDTD);** PROJECT 813 – 240/138 kV 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 NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Red Deer Area Transmission Development Stage 1 – Brownfields	1	Split 768L and 778L; 240/138 kV transformer at Benalto 17S; Capacitor Banks at Joffre 535S, Prentiss 276S and Ellis 332S	November 28, 2013
Red Deer Area Transmission Development Stage 1 – Greenfields	3	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	July 20, 2016
Red Deer Area Transmission Development – New 423L	6	New 138 kV (423L) transmission line from 332S Ellis to 212S NE Lacombe	October 4, 2016
Red Deer Area Transmission Development Stage 1 – Rebuilds	2	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	March 1, 2017
Red Deer Area Transmission Development Stage I – Salvage	5	Salvage 80L from Ponoka 331S to West Lacombe 958S; salvage 80L from Red Deer 63S to Innisfail 214S to Olds 55S; salvage 716L from Wetaskiwin 40S to Ponoka 331S	April 13, 2017
Red Deer Area Transmission Development Stage 2 – Rebuild 166L	4	Rebuild 166L from Didsbury 152S to Harmattan 256S	May 3, 2017
Red Deer Area Transmission Development Stage 2 – 2017 Facilities	7	Component energizations	November 9, 2017

The ISDs for FAs #2, 3, 4 and 7 have all been updated.

THE TRANSMISSION FACILITY OWNER(S): AltaLink.

PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JANUARY 2014) ESTIMATED COST	CURRENT ESTIMATED COST
Red Deer Region Transmission Development	**$329 Million** (2013$)	**$392.4 Million**[17] (ISD$ with escalation)

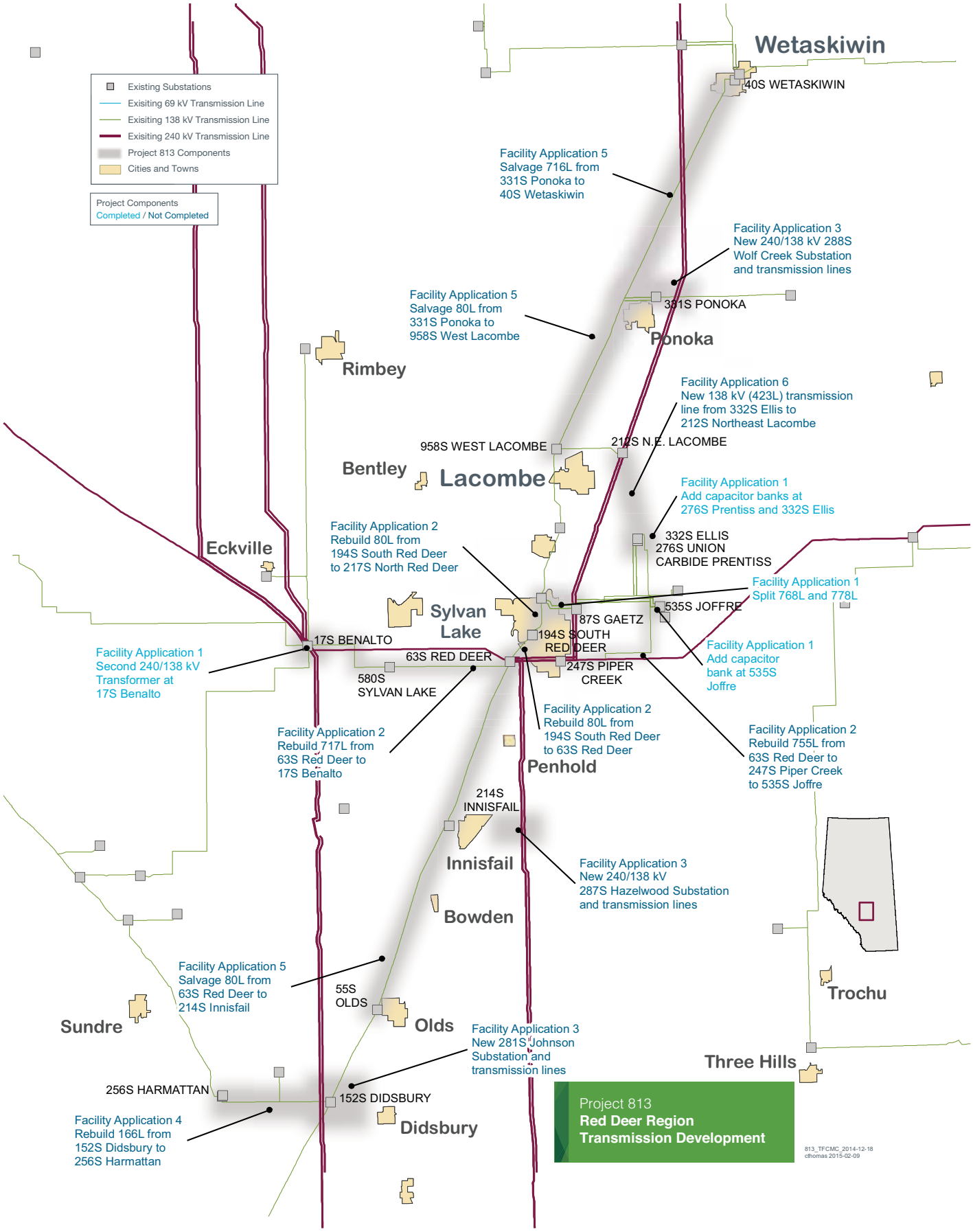
CURRENT STATUS: Stage 1 development included FAs for Brownfields, Rebuilds and Greenfields. The Brownfields were energized in 2013 while the Rebuilds and Greenfields are expected to be energized by 2016. Development of 423L was excluded from the AUC hearing (Rebuilds and Greenfields) and a new hearing is scheduled for September 2015.

Stage 2 development is the rebuild of 166L, which has been placed on hold until the AESO addresses advancement costs with respect to the 2014 ISO Tariff Application and 2013 ISO Tariff Update, along with any discussions with respect to connection of a generation facility in the Harmattan area.

PROJECT RISKS

Risks include outage coordination with other projects.

17 The current estimated cost increased by $31.4 million from the December 2014 TFCMC Report.


Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Project 813 Components
Cities and Towns
Project Components
Completed / Not Completed
Wetaskiwin
40S WETASKIWIN
Facility Application 5
Salvage 716L from
331S Ponoka to
40S Wetaskiwin
Facility Application 3
New 240/138 kV 288S
Wolf Creek Substation
and transmission lines
331S PONOKA
Ponoka
Facility Application 5
Salvage 80L from
331S Ponoka to
958S West Lacombe
Rimbey
Facility Application 6
New 138 kV (423L) transmission
line from 332S Ellis to
212S Northeast Lacombe
958S WEST LACOMBE
212S N.E. LACOMBE
Bentley
Lacombe
Facility Application 1
Add capacitor banks at
276S Prentiss and 332S Ellis
332S ELLIS
276S UNION
CARBIDE PRENTISS
Facility Application 2
Rebuild 80L from
194S South Red Deer
to 217S North Red Deer
Eckville
Facility Application 1
Split 768L and 778L
535S JOFFRE
Sylvan
Lake
87S GAETZ
194S SOUTH
RED DEER
17S BENALTO
63S RED DEER
247S PIPER
CREEK
Facility Application 1
Second 240/138 kV
Transformer at
17S Benalto
580S
SYLVAN LAKE
Facility Application 1
Add capacitor
bank at 535S
Joffre
Facility Application 2
Rebuild 80L from
194S South Red Deer
to 63S Red Deer
Facility Application 2
Rebuild 717L from
63S Red Deer to
17S Benalto
Facility Application 2
Rebuild 755L from
63S Red Deer to
247S Piper Creek
to 535S Joffre
Penhold
214S
INNISFAIL
Innisfail
Facility Application 3
New 240/138 kV
287S Hazelwood Substation
and transmission lines
Bowden
Facility Application 5
Salvage 80L from
63S Red Deer to
214S Innisfail
55S
OLDS
Olds
Sundre
Trochu
Facility Application 3
New 281S Johnson
Substation and
transmission lines
Three Hills
256S HARMATTAN
152S DIDSBURY
Facility Application 4
Rebuild 166L from
152S Didsbury to
256S Harmattan
Didsbury
Project 813
Red Deer Region
Transmission Development
813_TFCMC_2014-12-18
cthomas 2015-02-09

11. SOUTH AND WEST OF EDMONTON TRANSMISSION DEVELOPMENT (SWEATR); PROJECT 850 – Transmission system reinforcement to the 138 kV systems south and west of the City of Edmonton.

THE PROJECT: In preparation of the South and West Edmonton Plan, the AESO considered the specific needs and timing of existing and future transmission facilities in the South and West Edmonton area. There is insufficient transmission capacity in the South and West Edmonton area, and transmission reinforcements are required to provide the needed capacity to meet future load growth.

The South and West Edmonton Transmission Development will add two new 240/138 kV substations, one south of the town of Stony Plain and one close to the Nisku 149S substation; reconfigure the 138 kV network in the vicinity of the Cooking Lake 522S substation; rebuild portions of the 138 kV transmission lines, and modify existing substations in the area.

THE COMPONENTS: The list for the South and West of Edmonton Transmission System Development is as follows: a new 240/138 kV Harry Smith substation; a new 240/138 kV Saunders Lake substation; two new 138 kV lines between 780L and Cooking Lake, and reconfiguration; one 138 kV 27 MVAr capacitor bank at Leduc 325S; existing 138kV lines reconfiguration.

FACILITY APPLICATION NAME	FACILITY APPLICATION NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
New Capacitor Bank at Leduc 325S	5	One 138 kV 27 MVAr capacitor bank at Leduc 325S	December 1, 2017
Open 133L from Wabamun 19s to 234L tap	4	Operate 133L line from Wabamun 19S to 234L tap normally open (operating condition)	December 1, 2017
Two new 138 kV lines between 780L and Cooking Lake, and reconfiguration	3	Two new 138 kV circuits, 780L to Cooking Lake 522S, augmentation of Cooking Lake 522S Substation (upgrades existing bus, addition of circuit breakers with isolating switches)	December 1, 2017
New Saunders Lake Substation	2	New Saunders Lake 289S substation including two 240/138 kV 400 MVA transformers, modifications to Nisku 149S, Wetaskiwin 40S and Ellerslie 89S, four 240 kV lines, two 138 kV lines, and rebuild 780L and 858L between Nisku and Saunders Lake	December 1, 2017
New Harry Smith Substation	1	New 240/138kV Harry Smith 367S substation including two 240/138 kV 400 MVA transformers, modifications to Acheson 305S, Stony Plain 434S and Keephills 320P substations, and two new 240 kV lines and three new 138 kV lines	December 1, 2017
New EPCOR scope of work	N/A	P&C line renumbering	December 1, 2017

THE TRANSMISSION FACILITY OWNER(S): AltaLink.

PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JANUARY 2014) ESTIMATED COST	CURRENT ESTIMATED COST
South and West of Edmonton Transmission Development	**$194 Million** (2013$)	**$172 Million** (ISD$ with escalation)

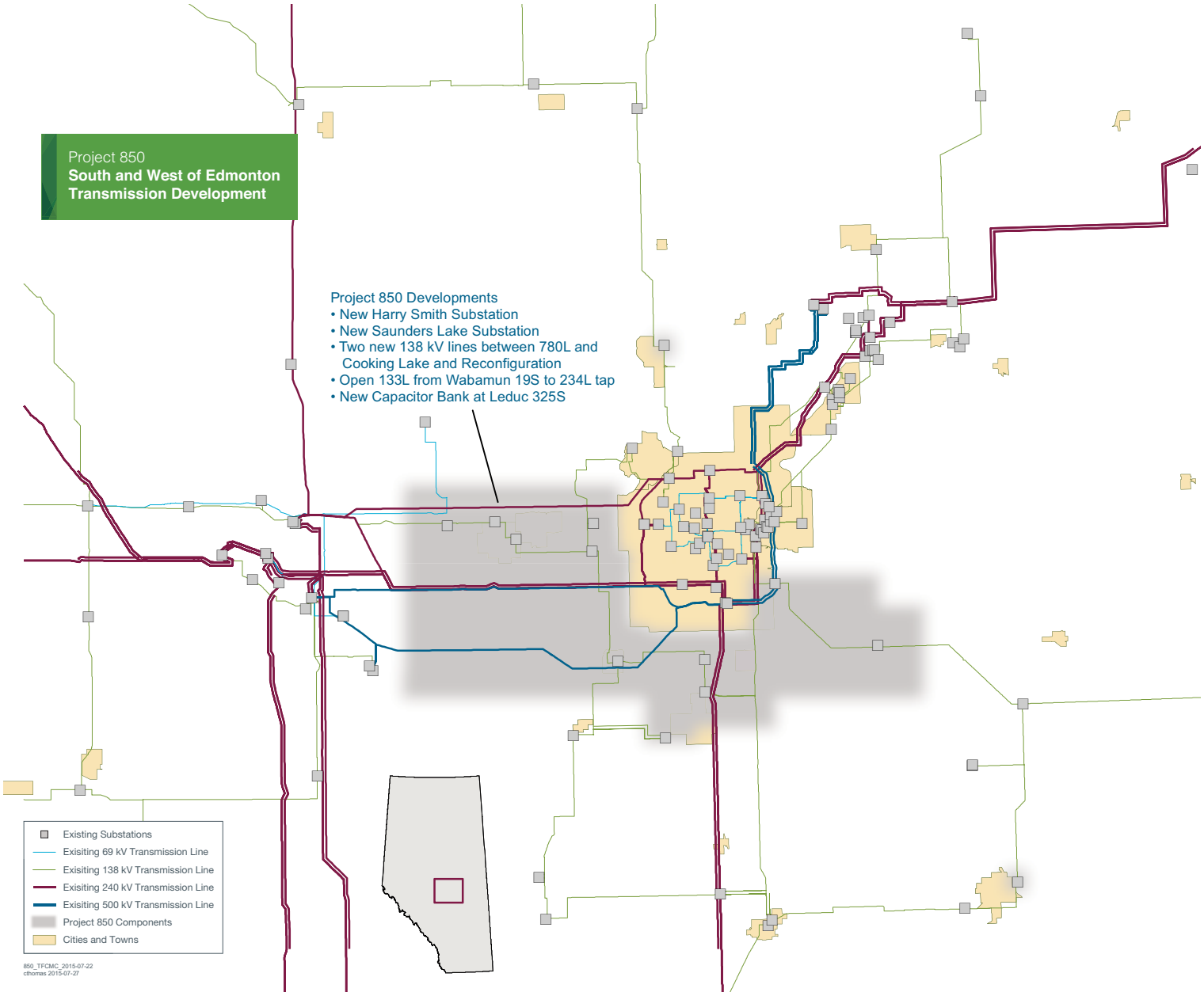
CURRENT STATUS: On June 2, 2015 AltaLink re-submitted its Proposal to Provide Service (PPS), Rev. 3, to the AESO for review as a result of a change in the preferred site for the Saunders Lake substation. The review has been completed.

Before the AESO issues a Notice to File Direction to AltaLink, the AESO needs to assess whether the Cooking Lake development can be deferred or staged. The completion of this assessment is targeted for August 2015.

AltaLink is planning to file its FAs in September or October 2015, or after the AESO's assessment of Cooking Lake. The delay in the Notice to File Direction has impacted AltaLink's FA filing dates and will likely impact the ISD. This will also have a cost impact to the project.

PROJECT RISKS

The ISD for 1043L as part of the Edmonton Region 240 kV Line Upgrades (Project 786) is currently unknown. As such, this places a risk on the Harry Smith substation development. If 1043L is re-routed, there is also a risk that the location of the Harry Smith substation may need to be reconsidered.


Project 850
South and West of Edmonton Transmission Development
Project 850 Developments
• New Harry Smith Substation
• New Saunders Lake Substation
• Two new 138 kV lines between 780L and Cooking Lake and Reconfiguration
• Open 133L from Wabamun 19S to 234L tap
• New Capacitor Bank at Leduc 325S
Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Exisiting 500 kV Transmission Line
Project 850 Components
Cities and Towns
850_TFCMC_2015-07-22
cthomas 2015-07-27

12. 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 originally outlined the need for a 240 kV AC looped system with three stages of implementation.

THE COMPONENTS: The project includes three stages of development.

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

Stage 2: 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: Interconnect the Ware Junction–Langdon area via a 240 kV line.

FACILITY APPLICATION NAME	FACILITY APPLICATION NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Milo Junction Switching Station	2	Build a switching station at Milo Junction	November 1, 2011
PST Addition at Russell 632S	3	Phase shifting transformer and new Russell substation	April 25, 2012
Ware Junction substation upgrade	13	933L line in/out at Ware Junction	October 4, 2013
Cassils to East Medicine Hat	4	240 kV lines from Cassils to new Bowmanton	November 27, 2013
East Medicine Hat to Whitla 240 kV Transmission Line	5	240 kV lines from Bowmanton to new Whitla	March 25, 2014
911L Line Replacement	1	Build new 240 kV lines from Foothills substation to Windy Flats substation	August 21, 2015
Medicine Hat Area 138 kV Line Development	6	138 kV system upgrades in the Medicine Hat area	April 30, 2016
Blackie Area 138 kV upgrade	11	138 kV system upgrade in the Blackie area	April 30, 2016
Cypress Reactive Power Addition	12	Reactive power addition at Cypress 562S substation	ON HOLD
Etzikom Coulee S/S and 240 kV line to Picture Butte S/S	8	240 kV line from Etzikom Coulee to Picture Butte (formerly called MATL) substation	ON HOLD
240 kV Line from Etzikom Coulee to Goose Lake	9	240 kV line from Etzikom Coulee substation to Goose Lake substation	ON HOLD
Castle Rock Ridge to Chapel Rock 240 kV line	7	240 kV Line from Goose Lake to new Chapel Rock 500 kV substation	October 31, 2018
Etzikom Coulee S/S to Whitla 240 kV Line	10	240 kV line from Journault to Whitla substation	ON HOLD

Note: FA #12 was updated to being ‘on hold’.

THE TRANSMISSION FACILITY OWNER(S): AltaLink.

PROJECT COST:

TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JANUARY 2014) ESTIMATED COST	CURRENT ESTIMATED COST
Southern Alberta Transmission Reinforcement	**$2.493 Billion** (2013$)	**$1.417 Billion**[18] (ISD$ with escalation)

CURRENT STATUS: The Stage 1 scope included five FAs that are all energized, with one exception. The remaining facilities under construction replace the existing 911L with higher capacity lines (1037L/1038L). The ISD for these facilities is scheduled for August 21, 2015.

The scope for Stage 2 included eight FAs. One FA has been energized; two FAs have received AUC approval and are under construction; one FA is currently being prepared by AltaLink, and four FAs have been stopped; the timing of these applications is being re-evaluated by the AESO.

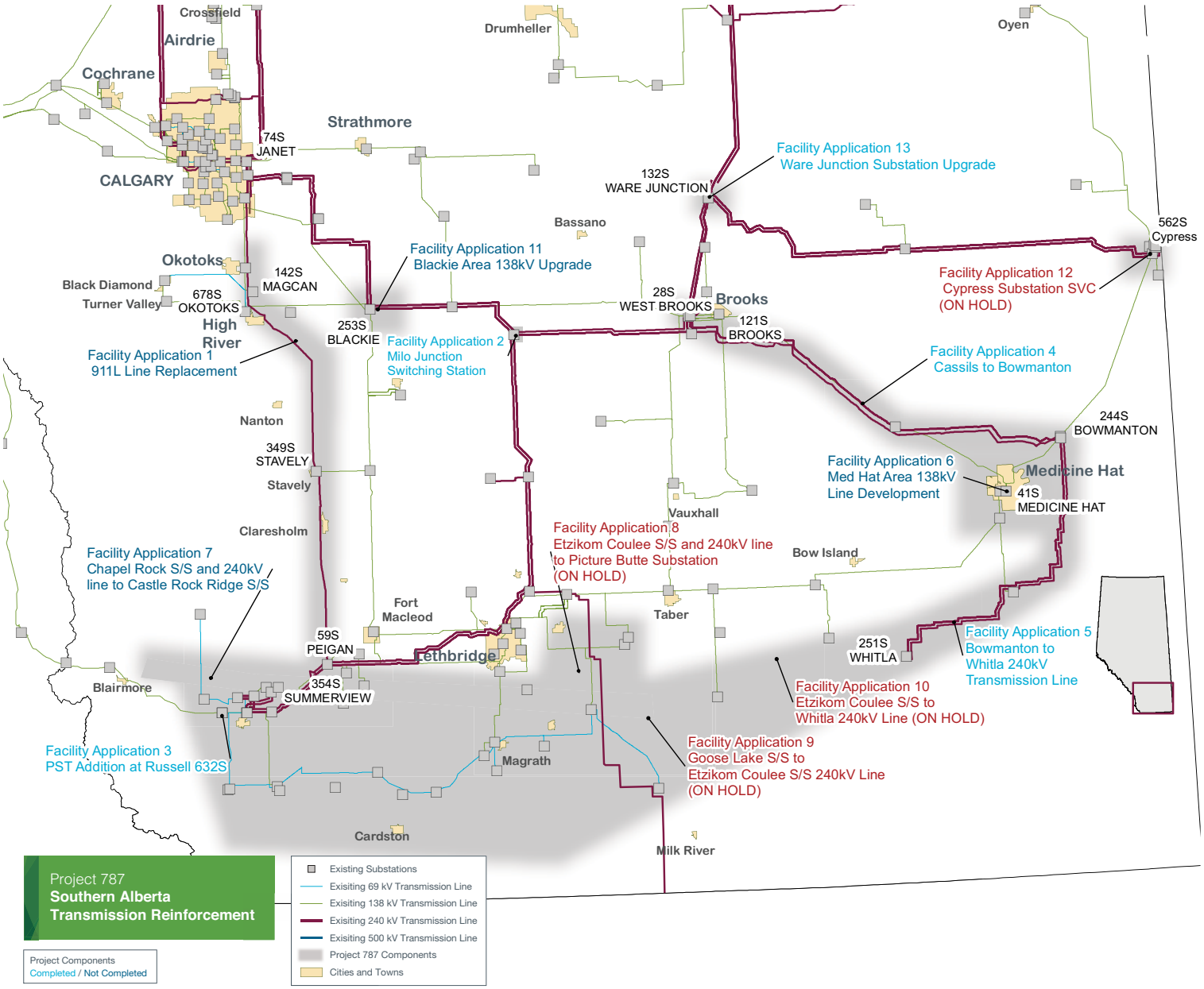
The scope for Stage 3 included the construction of a new double-circuit 240 kV transmission line connecting the Ware Junction substation to the Langdon substation. This project has been cancelled as a result of the EATL DC facilities (part of Project 737), which replaces the need for this line.

PROJECT RISKS

The NID for the Medicine Hat 138 kV reconfiguration (Stage 2) needs to be amended to accommodate moving the City of Medicine Hat connection to the AIES. This amendment poses a risk to the ISD.

Concerning the New Chapel Rock substation and the 240 kV lines between Chapel Rock and Castle Rock Ridge substations (Stage 2), there is a risk that there will be a FA hearing, which may cause a delay to the ISD.

18 The current estimated cost increased from $1.407 billion to $1.417 billion since the December 2014 TFCMC Report.


Crossfield
Airdrie
Cochrane
CALGARY
Strathmore
74S
JANET
Drumheller
Oyen
Facility Application 13
Ware Junction Substation Upgrade
132S
WARE JUNCTION
Bassano
562S
Cypress
Facility Application 11
Blackie Area 138kV Upgrade
Okotoks
Black Diamond
Turner Valley
142S
MAGCAN
678S
OKOTOKS
High River
Facility Application 12
Cypress Substation SVC
(ON HOLD)
28S
WEST BROOKS
Brooks
121S
BROOKS
253S
BLACKIE
Facility Application 2
Milo Junction
Switching Station
Facility Application 1
911L Line Replacement
Facility Application 4
Cassils to Bowmanton
Nanton
244S
BOWMANTON
349S
STAVELY
Stavely
Facility Application 6
Med Hat Area 138kV
Line Development
Medicine Hat
41S
MEDICINE HAT
Vauxhall
Claresholm
Facility Application 8
Etzikom Coulee S/S and 240kV line
to Picture Butte Substation
(ON HOLD)
Bow Island
Facility Application 7
Chapel Rock S/S and 240kV
line to Castle Rock Ridge S/S
Fort
Macleod
Taber
59S
PEIGAN
Lethbridge
251S
WHITLA
Facility Application 5
Bowmanton to
Whitla 240kV
Transmission Line
Blairmore
354S
SUMMERVIEW
Facility Application 10
Etzikom Coulee S/S to
Whitla 240kV Line (ON HOLD)
Facility Application 3
PST Addition at Russell 632S
Magrath
Facility Application 9
Goose Lake S/S to
Etzikom Coulee S/S 240kV Line
(ON HOLD)
Cardston
Milk River
Project 787
Southern Alberta
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 787 Components
Cities and Towns
Project Components
Completed / Not Completed
787_TFCMC_2015-07-22
cthomas 2015-07-27

13. ***NEW* THICKWOOD HILLS 240 KV TRANSMISSION DEVELOPMENT AND REACTIVE POWER REINFORCEMENT (THTD);** PROJECT 1186 – To connect the Fort McMurray West 500 kV transmission project to the existing transmission system in the Thickwood Hills area, west of Fort McMurray.

THE PROJECT: This consists of a 240 kV substation and reactive power reinforcement for the 500 kV Fort McMurray West Line project. The present requested ISD is the fourth quarter of 2018, which is at least six months ahead of the 500 kV West Line.

THE COMPONENTS: The project includes the construction of a new 240 kV substation that will terminate four 240 kV lines and also includes the construction of approximately 20 km of new double-circuit 240 kV line.

FACILITY APPLICATION NAME	FACILITY APPLICATION NUMBER	FACILITY APPLICATION DESCRIPTION	FORECAST OR ACTUAL IN-SERVICE DATE
Thickwood	1	Construct a new 240 kV substation and 20 km of 240 kV double-circuit line	October 1, 2018

THE TRANSMISSION FACILITY OWNER(S): ATCO.

PROJECT COST:

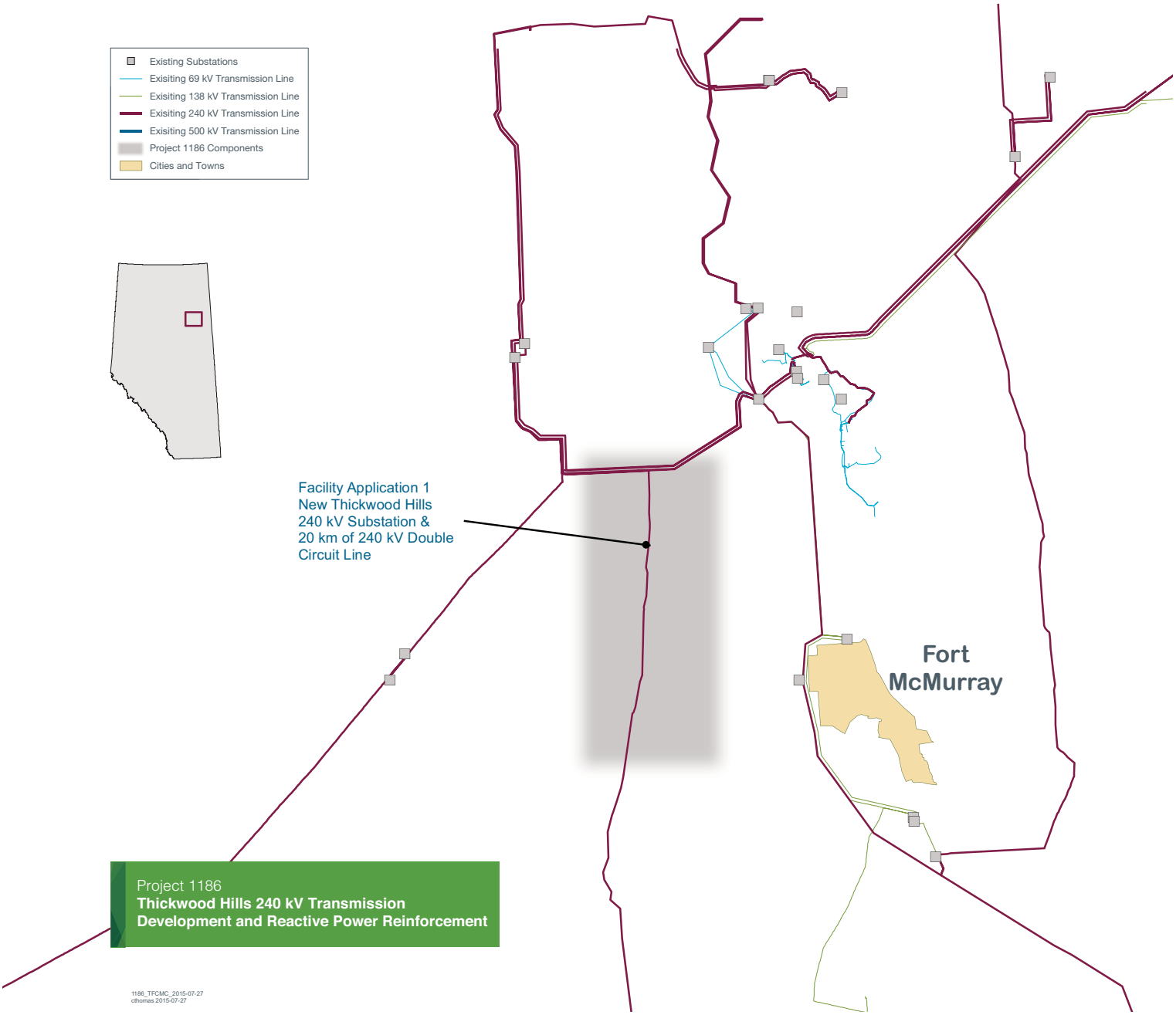
TRANSMISSION PROJECT	AESO LONG-TERM TRANSMISSION PLAN (FILED JANUARY 2014) ESTIMATED COST	CURRENT ESTIMATED COST
Thickwood Hills 240 kV Transmission Development and Reactive Power Reinforcement	**Not Applicable**[19]	**$190.80 Million** (ISD$ with escalation)

CURRENT STATUS: The AESO filed the NID on December 16, 2014, and received approval on March 12, 2015. ATCO is preparing the PPS estimate and the FA.

PROJECT RISKS

The FA must be filed in late 2015 to coincide with the Fort McMurray Area Transmission Bulk System Reinforcement (Stage 1) West 500 kV filing date.

19 The 'Not Applicable' entry is because the costs for this project were not broken out in the AESO Long-Term Transmission Plan that was filed in January 2014.


Existing Substations
Exisiting 69 kV Transmission Line
Exisiting 138 kV Transmission Line
Exisiting 240 kV Transmission Line
Exisiting 500 kV Transmission Line
Project 1186 Components
Cities and Towns
Facility Application 1
New Thickwood Hills
240 kV Substation &
20 km of 240 kV Double
Circuit Line
Fort
McMurray
Project 1186
Thickwood Hills 240 kV Transmission
Development and Reactive Power Reinforcement
1186_TFCMC_2015-07-27
cthomas 2015-07-27

Appendix C: Previously Monitored Projects

Since the TFCMC began its deliberations, the Committee has monitored a total of 19 different transmission projects. To date, seven of the projects have been completed or are in service and for the purpose of TFCMC reporting are considered closed. Those undertakings, and their final costs, are below. Projects are listed alphabetically.

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

  Estimated Final Project Cost: $713 million[20] | AESO 2012 LTP Estimated Cost: $537 million | Removed from monitoring: TFCMC December 2014 Report

- **ENMAX NO. 65 SUBSTATION (ESCS);** PROJECT 922[21] – New 240 kV substation in south Calgary and 138 kV development due to overloading in south Calgary.

  Final Project Cost: $45 million | AESO 2012 LTP Estimated Cost: $37 million | Removed from monitoring: TFCMC June 2014 Report

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

  Estimated Final Project Cost: $997.3 million[22] | AESO 2012 LTP Estimated Cost: $909 million | Removed from monitoring: TFCMC June 2015 Report

- **NORTH FORT MCMURRAY TRANSMISSION DEVELOPMENT (NFMD);** PROJECT 791 – Transmission development to relieve constraints and to serve forecast demand north of Fort McMurray.

  Final Project Cost: $352.3 million | AESO 2012 LTP Estimated Cost: $197 million | Removed from monitoring: TFCMC June 2014 Report

- **NORTHWEST TRANSMISSION DEVELOPMENT (NWTD);** PROJECT 535 – Transmission expansion and enhancement in northwest Alberta.

  Final Project Cost: $583 million | AESO 2012 LTP Estimated Cost: Not Estimated[23] | Removed from monitoring: TFCMC December 2013 Report

- **SOUTHERN ALBERTA TRANSMISSION DEVELOPMENT (SATD);** PROJECT 416 – Transmission development in Goose Lake-Peigan and North Lethbridge region.

  Final Project Cost: $238 million | AESO 2011 LTP Estimated Cost: $91 million | Removed from monitoring: TFCMC June 2013 Report

- **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.

  Final Project Cost: $141 million[24] | AESO 2012 LTP Estimated Cost: $123 million | Removed from monitoring: TFCMC December 2013 Report

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20 The AESO expects to receive the final project cost later in 2015. This amount will be updated once it is available.

21 The TFCMC monitored Project 922, ENMAX No. 65 Substation. While the project's value was below the $100-million TFCMC threshold, the original plans for this development had initially come in above that threshold.

22 Final costs for AltaLink developments were received and reviewed by the AESO in May 2015. Final Costs for ATCO developments were received in June 2015. The AESO is currently reviewing these costs.

23 In the June 2011 TFCMC Report it was reported that the need for this project was recognized in March 2006 and the need approval was granted in August 2006 with the total project scope envisioned at $262 million. However, due to project scope changes, the value increased to $463 million. In the December 2011 TFCMC Report, the PPS estimated cost was $508 million (ISD$ with escalation but that did not include project 603, the Arcenciel synchronous condenser).

24 The estimated final cost of this project was $148 million, as noted in the December 2013 TFCMC Report – at that time, final costs were not available. The actual final cost came in at $140,652,893.

Appendix D: TFCMC Working Documents

The TFCMC receives reports and cost summary updates, on a monthly basis, in order to 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 studies.

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.

As the documents on the following pages are an example, or working documents, of just some of the material the TFCMC reviews, there could be cost discrepancies between Appendices B and D on a particular project. Please refer to Appendix B for the most recent and accurate estimated cost figures.

Project Cost Reporting for TFCMC, Project 737: North South Transmission Reinforcement (HVDC); April 2015 Meeting

Project: 737 Cost Summary for [North South Transmission Reinforcement] Refreshed @ 09/04/2015 10:25:47

Project #	NID name	NID Filing Date	NID Approval Date	NID Estimated Cost	PPS Estimated Cost	Authorized Cost Change	Authorized Budget'	Total Changes	Percent Change of Auth
737	North South Transmission Reinforcement	CTI	2009-12-09	0.00M	3,058.41M	510.36M	3,568.77M	19	14.3%

Project 737 Details by FA

TFO	Cost Grouping	FA #	FA name	Stage	Facility Application Filing Date	Facility Application Approval Date	Overall Facility ISD	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget	No Of Changes'	Percent Change Of Auth'
AltaLink	3	3	Facility Application 3 - AltaLink East DC Facilities (Currently known to TFO as P961)	5	2011-05-01	2012-11-15	2015-08-03	39.35M	52.69M	92.04M	4	57.2%
ATCO	1	1	Facility Application 1 - ATCO East DC Facilities (Currently known to TFO as P961)	5	2011-03-29	2012-11-15	2015-08-03	1,598.76M	204.24M	1,802.99M	5	11.3%
AltaLink & EPCOR	2	2	Facility Application 2 - AltaLink West DC Facilities (Currently known to TFO as P962)	5	2011-03-01	2012-12-06	2015-06-26	1,420.19M	253.55M	1,673.73M	9	15.1%
EPCOR	4	4	Facility Application 4 - EPCOR East DC Facilities (Currently known to TFO as P961)	Null	2011-03-30	2012-11-15		0.12M	-0.11M	0.01M	1	-1845.5%

Comments

EATL: ATCO completed the stringing of the DC Transmission line earlier this year. The critical path for the project is the construction of the Converter Stations. The forecasted cost is $1.88B; comprised of ATCO's forecast of $1.80B and AltaLink's forecast of $74M. ATCO has spent $1.69B; while AltaLink has spent $60M on the project thus far. There are no pending Change Proposals at this time.

WATL: AltaLink has also completed the stringing of the DC Transmission line late last year. As well, the critical path for the project is the construction of the Converter Stations. The forecasted cost of $1.70B is $30M higher than the authorized budget of $1.67B. AltaLink has spent $1.47B to date. The AESO is expecting a Change Proposal from AltaLink for the trend variance of $36M. EPCOR has spent $7M on the project thus far and is forecast to be underspent by $4M.

Both projects have schedule risk due to the performance issues in the construction of the converter stations.

Project Cost Reporting for TFCMC, Project 786: Edmonton Region 240 kV Line Upgrades (ERLU); April 2015 Meeting

Project: 786 Cost Summary for [Edmonton Region 240 kV Line Upgrades] Refreshed @ 09/04/2015 10:25:47

Project #	NID name	NID Filing Date	NID Approval Date	NID Estimated Cost	PPS Estimated Cost	Authorized Cost Change	Authorized Budget'	Total Changes	Percent Change of Auth
786	Edmonton Region 240 kV Line Upgrades	2008-08-26	2009-02-24	125.41M	155.03M	23.31M	178.34M	25	13.1%

Project 786 Details by FA

TFO	Cost Grouping	FA #	FA name	Stage	Facility Application Filing Date	Facility Application Approval Date	Overall Facility ISD	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget	No Of Changes'	Percent Change Of Auth'
AltaLink	1,2,4,5	1	AML Keephills Substation Addition (Formerly P953)	6	2009-11-06	2010-03-19	2010-07-31	101.35M	12.66M	114.01M	19	11.1%
		2	AML Rebuild 240kV 904L (1043L)	5	2010-07-28	2011-08-12	2016-01-04					
		4	AML 902L Restring & 909L Retermination (Formerly P1057)	5	2011-08-05	2012-10-31	2016-01-01					
		5	AML 908L, 909L Restring (Formerly P1058)	6	2009-09-13	2010-02-10	2011-03-20					
ATCO	7	7	ATCO Phase Shifter (Formerly P957)	6	2009-09-14	2010-03-25	2013-08-20	31.52M	8.00M	39.51M	3	20.2%
EPCOR	3	3	EPCOR 1044EL, 1045EL (Formerly P955)	6	2010-10-15	2011-08-12	2012-02-29	7.97M	0.00M	7.97M	0	0.0%
	6	6	Epoch Jasper, Petrolia (Formerly P955)	6	2010-04-15	2010-06-16	2011-06-14	4.55M	2.65M	7.20M	3	36.8%
TransA..	8	8	TransAlta 902L	6	2011-08-05	2012-10-31	2014-11-12	9.65M	0.00M	9.65M	0	0.0%

Comments

FA 2, 4 are associated with 1043L. The work on 1043L and the re-termination of 909L from Keephills to Sundance is delayed because of land access negotiations. Change request for AltaLink to apply to AUC for P&L extension to ISD of July 31, 2015 has been approved.

Project Cost Reporting for TFCMC, Project 787: Southern Alberta Transmission Reinforcement (SATR); April 2015 Meeting

Project: 787 Cost Summary for [Southern Alberta Transmission Reinforcement] Refreshed @ 09/04/2015 10:25:47

Project #	NID name	NID Filing Date	NID Approval Date	NID Estimated Cost	PPS Estimated Cost	Authorized Cost Change	Authorized Budget'	Total Changes	Percent Change of Auth
787	Southern Alberta Transmission Reinforcement	2008-12-30	2009-09-17	3,442.90M	1,415.62M	(5.67M)	1,409.95M	37	-0.4%

Project 787 Details by FA

TFO	Cost Grouping	FA #	FA name	Stage	Facility Application Filing Date	Facility Application Approval Date	Overall Facility ISD	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget	No Of Changes'	Percent Change Of Auth'
AltaLink		7	Castle Rock Ridge to Chapel Rock 240 kV Line (Formerly P1034)	4	2015-09-08	2016-10-06	2018-10-31					
		8	Etzikom Coulee S/S and 240kV line to Picture Butte S/S (Formerly P1035)	4	2016-06-16	2017-06-16	2020-01-01					
		9	Goose Lake S/S to Etzikom Coulee S/S 240kV Line (Formerly P1036)	4	2016-11-19	2017-02-08	2020-01-01					
		10	Etzikom Coulee S/S to Whitla 240kV Line (Formerly P1037)	4	2017-07-14	2018-07-16	2020-01-01					
		12	Reactive Power Addition to Cypress 562S (Formerly P1039)	4	2016-04-14	2016-08-04	2017-04-28					
	1	1	911L Line Replacement (Formerly P882)	5	2012-09-25	2013-11-11	2015-09-22	440.17M	59.55M	499.72M	14	11.9%
	2	2	Milo Junction Switching Station (Formerly P883)	6	2009-12-21	2010-08-05	2011-11-01	29.70M	0.47M	30.17M	4	1.6%
	3	3	PST Addition at Russell 632S (Formerly P884)	6	2010-08-27	2011-01-12	2012-04-25	17.21M	-0.08M	17.13M	1	-0.5%
	4	4	Cassils to Bowmanton (Formerly P886)	6	2010-07-27	2011-06-08	2013-11-27	407.91M	-28.10M	379.81M	4	-7.4%
	5	5	Bowmanton to Whitla 240kV Transmission Line (Formerly P887)	6	2010-07-27	2011-06-08	2014-03-25	352.75M	-41.77M	310.98M	3	-13.4%
	6	6	Med Hat Area 138kV Line Development (Formerly P888)	5	2012-12-03	2013-10-18	2016-04-30	120.29M	3.80M	124.08M	8	3.1%
	11	11	Blackie Area 138kV Upgrade (Formerly P1038)	5	2014-09-11	2015-01-16	2016-04-30	41.45M	0.00M	41.45M	0	0.0%
	13	13	Ware Junction Substation Upgrade (Formerly P1040)	6	2011-04-05	2012-02-06	2013-10-04	6.13M	0.47M	6.61M	3	7.2%
Null		14	911L Salvage (Formerly P1619)	5	2015-05-22	2015-09-11	2016-03-11					

Comments

Null

Project Cost Reporting for TFCMC, Project 811: Central East Area Transmission Development (CETD); April 2015 Meeting

Project: 811 Cost Summary for [Central East Area Transmission Development] Refreshed @ 09/04/2015 10:25:47

Project #	NID name	NID Filing Date	NID Approval Date	NID Estimated Cost	PPS Estimated Cost	Authorized Cost Change	Authorized Budget'	Total Changes	Percent Change of Auth
811	Central East Area Transmission Development	2010-05-17	2011-02-10	431.00M	243.39M	100.59M	343.98M	10	29.2%

Project 811 Details by FA

TFO	Cost Grouping	FA #	FA name	Stage	Facility Application Filing Date	Facility Application Approval Date	Overall Facility ISD	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget	No Of Changes'	Percent Change Of Auth'
ATCO	1,2	1	FA 1 - Cold Lake Area 144 kV Reinforcements	6	2012-03-07	2012-12-11	2014-01-30	141.08M	54.83M	195.92M	3	28.0%
		2	FA 2 - Bonnyville 700S and 7L146	5	2012-04-27	2013-07-02	2016-05-31					
	3,4,5	3	FA 3 - St. Paul Area Upgrades - Watt Lake 956S	6	2011-12-23	2013-03-27	2013-12-12	50.85M	31.92M	82.77M	2	38.6%
		4	FA 4 - St. Paul Area Upgrades - St. Paul 707S and 7L139/7L70 in/out	5	2012-07-12	2013-12-20	2016-04-01					
		5	FA 5 - St. Paul Area Upgrades - Whitby Lake 819S 144kV CB Addition	6	2011-12-23	2012-04-20	2014-06-25					
	6	6	FA 6 - Vermillion 710S Substation Upgrade	6	2011-10-24	2012-05-16	2013-09-15	6.70M	2.92M	9.62M	1	30.4%
	7,8	7	FA 7 - Heisler Area Upgrades	6	2011-12-23	2012-02-27	2013-07-27	31.48M	10.91M	42.39M	4	25.7%
		8	FA 8 - Kitscoty Area Upgrades	6	2012-06-13	2013-01-02	2014-12-04					
Null	10	10	FA 10 - 7L701 Line Clearance Mitigation (Letter of Enquiry)	6	2011-10-24	Null	2012-07-18	13.28M	0.00M	13.28M	0	0.0%

Comments

ATCO Change Request #32 St Paul approved.
Change in ISD as a result of additional consultation and hearing required for a proposed re-route as well as increase in cost. New ISD April 2016.

Awaiting AUC decision on NID Amendment (Cancellations).

Two energizations remain to complete the project: Energization #4 St Paul Area Upgrades and Energization #25 Bonnyville 700S Transformer addition. Energization #25 has dependencies with Energization #4. Expected ISD Q2-2016.

Project Cost Reporting for TFCMC, Project 812: Hanna Region Transmission Development (HATD); April 2015 Meeting

Project: 812 Cost Summary for [Hanna Region Transmission Development] Refreshed @ 09/04/2015 10:25:47

Project #	NID name	NID Filing Date	NID Approval Date	NID Estimated Cost	PPS Estimated Cost	Authorized Cost Change	Authorized Budget'	Total Changes	Percent Change of Auth
812	Hanna Region Transmission Development	2009-08-14	2010-04-29	983.00M	940.89M	28.43M	969.32M	34	2.9%

Project 812 Details by FA

TFO	Cost Grouping	FA #	FA name	Stage	Facility Application Filing Date	Facility Application Approval Date	Overall Facility ISD	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget	No Of Changes'	Percent Change Of Auth'
AltaLink	20,21	20	Nilrem 574S combined with D/C 240kV 953L -1047L ..	6	2010-11-12	2011-11-10	2013-08-30	76.50M	12.84M	89.34M	5	14.4%
		21	Hardisty 377S Substation Capacitor Bank (Formerly ..	6	2010-11-29	2011-05-03	2012-06-28					
	22,23	22	Hansman Lake 650S Substation Static VAR Compe..	6	2010-11-29	2011-04-27	2012-10-05	82.36M	16.53M	98.89M	3	16.7%
		23	New 240 kV line 966L from Pemukan 932S -Hansma..	6	2010-12-06	2012-05-08	2013-08-21					
	24	24	New 240kV line 1053L from Ware Junction 132S-Ca..	6	2011-04-05	2012-02-06	2013-11-29	78.66M	30.52M	109.17M	3	28.0%
ATCO	1	1	Youngstown 772S Capacitor bank addition (Formerly..	6	2010-08-09	2010-11-15	2011-10-06	6.29M	-0.36M	5.93M	1	-6.0%
	2	2	Battle River 757S Capacitor Bank addition (Formerly..	6	2010-08-09	2010-08-27	2011-10-03	3.00M	-0.17M	2.83M	1	-6.0%
	3	3	New Lanfine 240/144kV substation (Formerly P979)	6	2010-12-21	2012-05-08	2013-05-20	38.75M	-2.20M	36.54M	1	-6.0%
	4	4	Lanfine 959S 200MVAr SVC (Formerly P980)	5	2011-03-04	2012-05-08	2015-03-31	39.36M	-2.24M	37.12M	1	-6.0%
	5	5	Lanfine-Oyen 144kV S/C Line 7L132 (Formerly P982)	6	2011-03-21	2012-05-08	2013-07-15	15.62M	-0.89M	14.73M	1	-6.0%
	6	6	Relocate 7L98 Oyen 767S - Lanfine 959S (Formerly ..	6	2011-03-21	2011-12-22	2013-06-01	12.77M	-0.73M	12.04M	1	-6.0%
	7	7	Oakland 946S 240kV S/S combined with Anderson-..	6	2010-11-25	2012-05-08	2013-03-25	45.47M	-1.72M	43.75M	2	-3.9%
	8	8	Oakland-Lanfine 240kV S/C Line 9L924 (Formerly P..	6	2010-12-21	2012-05-08	2013-05-21	119.93M	-3.05M	116.88M	3	-2.6%
	9	9	Coyote Lake 963S 240kV S/S combined with Oaklan..	6	2011-02-07	2012-05-08	2013-05-17	77.80M	-4.42M	73.38M	1	-6.0%
	10	10	Coyote Lake 963S - Michichi Creek 802S 144kV SC ..	6	2011-04-08	2012-05-08	2013-07-12	39.25M	-2.23M	37.02M	1	-6.0%
	11	11	Pemukan 932S 240 kV Substation (Formerly P1001)	6	2011-01-24	2012-05-08	2013-06-01	32.49M	-1.85M	30.64M	1	-6.0%
	12	12	New Lanfine-Pemukan 240kV S/C Line 9L46 (Forme..	6	2011-03-03	2012-05-08	2013-06-01	97.24M	-5.15M	92.09M	2	-5.6%
	13,18	13	Facility Application 13 - 144kV Capacitor Bank and C..	6	2010-10-08	2010-12-23	2011-12-13	27.04M	-1.54M	25.50M	1	-6.0%
		18	Rowley 768S - Michichi-Three Hills 144kV DC Line 7..	6	2010-11-15	2011-05-17	2012-06-01					
	14	14	Hansman Lake - Pemukan 240kV S/C Line 9L966 (F..	6	2011-01-24	2012-05-08	2013-08-21	67.69M	-0.34M	67.35M	2	-0.5%
	15	15	Pemukan 932S - Monitor 774S 144kV S/C Line 7L12..	6	2011-01-24	2012-05-08	2013-06-15	14.31M	-0.81M	13.50M	1	-6.0%
	16	16	Relocate 7L79 line from Monitor 774S - Pemukan 93..	6	2011-01-24	2012-05-08	2013-06-12	10.26M	-0.58M	9.68M	1	-6.0%
	17	17	Heatburg 948S - Three Hills-Nevis 144kV D/C Line 7..	6	2012-02-13	2012-06-13	2013-01-25	14.84M	-0.84M	14.00M	1	-6.0%
	19	19	Stettler 769S - Nevis 768S 144kV S/C Line 7L143 (F..	6	2011-06-03	2011-12-20	2013-04-21	41.29M	-2.35M	38.94M	1	-6.0%

Comments

- Only 1 more energization for the Hanna region left to complete: Energization 4 - Lanfine 959S 200MVAr SVC - ATCO plans to energize on April 30, 2015.
-Final Costs received for AltaLink scopes of work are currently in review with the AESO. AESO had additional inquiries and AML plans to provide responses by April 9, 2015.

Project Cost Reporting for TFCMC, Project 813: Red Deer Region Transmission Development (RDTD); April 2015 Meeting

Project: 813 Cost Summary for [Red Deer Area Transmission Development] Refreshed @ 09/04/2015 10:25:47

Project #	NID name	NID Filing Date	NID Approval Date	NID Estimated Cost	PPS Estimated Cost	Authorized Cost Change	Authorized Budget'	Total Changes	Percent Change of Auth
813	Red Deer Area Transmission Development	2011-07-20	2012-04-10	222.80M	337.50M	54.18M	391.69M	56	13.8%

Project 813 Details by FA

TFO	Cost Grouping	FA #	FA name	Stage	Facility Application Filing Date	Facility Application Approval Date	Overall Facility ISD	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget	No Of Changes'	Percent Change Of Auth'
AltaLink		4	RDATD Facility Application 4 - 166L Rebuild	4	2015-10-01	2016-01-01	2016-07-01					
		5	RDATD Facility Application 5 - Salvage	4	2015-02-24	2015-10-06	2017-04-13					
		7	RDATD Facility Application 7 - Stage II 2017 Facilities	4	2016-10-27	2017-05-11	2017-11-09					
	1	1	RDATD Facility Application 1 - Brownfields	6	2011-09-26	2012-09-27	2013-11-28	20.72M	10.96M	31.68M	16	34.6%
	2	2	RDATD Facility Application 2 - Rebuilds	5	2013-06-18	2014-07-28	2016-09-01	179.48M	4.85M	184.33M	12	2.6%
	3,6	3	RDATD Facility Application 3 - Greenfields	5	2013-06-18	2014-07-28	2016-07-20	137.30M	38.38M	175.68M	28	21.8%
		6	RDATD Facility Application 6 - 423L	4	2013-06-18	2015-10-30	2016-10-04					

Comments

- A portion of Development D21 (637L) energized on March 25, 2015.
- Development D10 (80L North) scheduled to energize on April 5, 2015.
-Development D3 (423L) was excluded from the AUC hearing for FA2&FA3 and a new hearing is scheduled for June 22-26, 2015.
-P&L approved August 3, 2014 for FA#2 submission. An amendment to the P&L is being developed by AML for submission to the AUC in April 2015.
- FA#2 was combined as one submission to the AUC for Line Rebuilds and Greenfields by AML.
- FA#4 filing of FA has been delayed - on hold until AESO addresses advancement costs with respect to the 2014 ISO Tariff Application and 2013 ISO Tariff Update, along with any discussions with respect to facilitating the connection of a generation facility in the Harmattan area.

Project Cost Reporting for TFCMC, Project 850: South and West of Edmonton Transmission Development (SWEATR); April 2015 Meeting

Project: 850 Cost Summary for [South and West of Edmonton Transmission Development] Refreshed @ 09/04/2015 10:25:47

Project #	NID name	NID Filing Date	NID Approval Date	NID Estimated Cost	PPS Estimated Cost	Authorized Cost Change	Authorized Budget'	Total Changes	Percent Change of Auth
850	South and West of Edmonton Transmission Development	2012-12-14	2014-05-05	172.17M	0.00M	0.00M	0.00M	0	0.0%

Project 850 Details by FA

TFO	Cost Grouping	FA #	FA name	Stage	Facility Application Filing Date	Facility Application Approval Date	Overall Facility ISD	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget	No Of Changes'	Percent Change Of Auth'
AltaLink		2	Facility Application 2 - New Saunders Lake 240/138kV Substation; re-terminate 910L, 914L, 780L & 858L at Saunders Lake; build lines between Nisku & proposed Saunders Lake; and reconfiguration of affected substations.	4	2015-05-04	2016-05-05	2016-12-30					
		3	Facility Application 3 - New 138kV Lines from 780L to Cooking Lake & 174L; and reconfiguration of affected substations	4	2015-05-04	2016-05-05	2016-12-30					
		4	Facility Application 4 - Open 133L from Wabamum to 234L tap	4	2015-05-04	2016-05-05	2016-12-30					
		5	Facility Application 5 - New Capacitor Bank at Leduc 325S	4	2015-05-04	2016-05-05	2016-12-30					
Null		6	Facility Application 6 - EPCOR scope of work[P&C and line renumbering]	4	2015-04-02	Null	2016-12-30					

Comments

AltaLink submitted its PPS on March 5, 2015. AltaLink is currently addressing AESO comments on the PPS sent to AltaLink on March 20, 2015.

AltaLink is also preparing the Facility Application.

Project Cost Reporting for TFCMC, Project 1101: Christina Lake Area Development (CHL); April 2015 Meeting

Project: 1101 Cost Summary for [Christina Lake Area Development] Refreshed @ 09/04/2015 10:25:47

Project #	NID name	NID Filing Date	NID Approval Date	NID Estimated Cost	PPS Estimated Cost	Authorized Cost Change	Authorized Budget'	Total Changes	Percent Change of Auth
1101	Christina Lake Area Development	2011-10-20	2012-04-24	406.61M	418.89M	107.53M	526.42M	19	20.4%

Project 1101 Details by FA

TFO	Cost Grouping	FA #	FA name	Stage	Facility Application Filing Date	Facility Application Approval Date	Overall Facility ISD	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget	No Of Changes'	Percent Change Of Auth'
AltaLink	1	1	Facility Application 1 - CHL1 Black Spruce 154S	6	2012-07-23	2012-12-24	2013-07-10	19.96M	11.77M	31.73M	10	37.1%
	2	2	Facility Application 2 - Black Spruce 154S to Pike 170S	6	2013-01-18	2013-06-28	2014-06-30	116.15M	18.24M	134.39M	3	13.6%
	3	3	Facility Application 3 - Pike 170S to Ipiatik Lake 167S/1116L/1117L	5	2013-03-28	2013-11-01	2015-11-02	256.74M	82.31M	339.05M	5	24.3%
ATCO	4	4	Facility Application 4 - ATCO Heart Lake 898S/9L930/9L81	5	2013-10-10	2014-01-06	2015-06-30	26.05M	-4.79M	21.25M	1	-22.5%

Comments

FA 3 Ipiatik - Ipiatik, 1116L 1117L and work at Heart Lake (FA4) all have an in-service date of June 30, 2015. In-service date for reconnection of Winefred and Kirby is being reviewed to determine best way to perform the work. Work at Christina Lake is expected to be complete in November 2015.

Project Cost Reporting for TFCMC, Project 1117: Foothills Area Transmission Development – East (FATD); April 2015 Meeting

Project: 1117 Cost Summary for [Foothills Area Transmission Development - East] Refreshed @ 09/04/2015 10:25:47

Project #	NID name	NID Filing Date	NID Approval Date	NID Estimated Cost	PPS Estimated Cost	Authorized Cost Change	Authorized Budget'	Total Changes	Percent Change of Auth
1117	Foothills Area Transmission Development - East	2012-07-05	2013-10-07	0.00M	443.45M	80.46M	523.91M	22	15.4%

Project 1117 Details by FA

TFO	Cost Grouping	FA #	FA name	Stage	Facility Application Filing Date	Facility Application Approval Date	Overall Facility ISD	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget	No Of Changes'	Percent Change Of Auth'
AltaLink	1	1	Facility Application 1 - North Foothills Transmission Project - AltaLink Facilities	5	2012-07-13	2013-10-07	2015-05-25	247.94M	-19.45M	228.49M	6	-8.5%
	3	3	Facility Application 3 - Langdon to Janet - AltaLink Facilities	5	2012-07-16	2013-10-07	2015-06-01	81.98M	55.80M	137.77M	10	40.5%
	4	4	Facility Application 4 - Janet to Langdon - Enmax Facilities (By AltaLink)	Null	2012-07-13	2013-10-07		22.66M	0.00M	22.66M	0	0.0%
	5	5	Facility Application 5 - Foothills 138kV - AltaLink Facilities	5	2012-07-16	2013-10-07	2015-11-01	86.59M	44.10M	130.69M	6	33.7%
ENMAX	2	2	Facility Application 2 - Enmax SS-65 and SS-25 Additions - Enmax Facilities	5	2012-07-13	2013-10-07	2015-11-01	4.29M	0.00M	4.29M	0	0.0%

Comments

- Construction ongoing. Initial energizations at Janet (985L) and East Calgary (936L Janet bypass) substations were completed in Fall 2014. Next energizations pending in May 2015 include the Foothills substation, 1106L/1107L 240 kV lines from Foothills to Sub 65, 1064L/1065L 240 kV lines from Langdon to Janet, as well as the second Janet bypass (937L from Langdon to East Calgary substations).
- Total change proposals approved to date is $80 million.

Project Cost Reporting for TFCMC, Project 1180: Northwest Fort McMurray Transmission Development (NW FMM); April 2015 Meeting

Project: 1180 Cost Summary for [NW Ft McMurray Transmission Development] Refreshed @ 09/04/2015 10:25:47

Project #	NID name	NID Filing Date	NID Approval Date	NID Estimated Cost	PPS Estimated Cost	Authorized Cost Change	Authorized Budget'	Total Changes	Percent Change of Auth
1180	NW Ft McMurray Transmission Development	2011-11-10	2012-06-19	366.29M	235.09M	0.00M	235.09M	0	0.0%

Project 1180 Details by FA

TFO	Cost Grouping	FA #	FA name	Stage	Facility Application Filing Date	Facility Application Approval Date	Overall Facility ISD	PPS Estimated Cost	Authorized Cost Changes	Authorized Budget	No Of Changes'	Percent Change Of Auth'
ATCO		3	Facility Application 3 - 9L95	4	2015-03-10	2015-08-25	2016-12-01					
	1	1	Facility Application 1 - Birchwood Creek	6	2013-10-31	2014-01-08	2015-03-10	35.60M	0.00M	35.60M	0	0.0%
	2	2	Facility Application 2 - Ells River/9L08/9L76	4	2015-04-20	2015-10-05	2016-09-19	199.49M	0.00M	199.49M	0	0.0%

Comments

Birchwood Creek was placed in-service March 9, 2015. The AESO received ATCO's PPS for Ells River December 5, 2014 and is reviewing. 9L95 PPS is pending with a likely in-service date of 2018.

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 June 2015 Report.

ALTALINK
A BERKSHIRE HATHAWAY ENERGY COMPANY

2611 3rd Ave SE, Calgary, Alberta, T2A 7W7 | www.altalink.ca

November 5, 2015

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

Subject: 9th Semi Annual Transmission Cost Monitoring Committee Report

Henry,

Thank you for the opportunity to review the TFCMC's ninth semi-annual Transmission Cost Monitoring Committee Report. AltaLink continues to be supportive of reviewing project progress with the TFCMC in order to provide customer associations more visibility to project costs.

In your section on Transmission Line Development Optimization, it is important to emphasize that conductor selection is an optimization of many factors, and not just selecting the most economic conductor as the Chapel Rock to Castle Rock Ridge line optimization showed. Other factors can include: electrical characteristics (i.e. impedance), capacity requirements, tension/sag characteristics (which can impact structure heights/quantities), the availability of specialist stringing equipment and tooling (for installation and repairs), and market availability of the conductor (now and in the future). These are all factors that need to be considered in optimizing conductor selection.

Given that the report covers the period November 1, 2014 to April 30, 2015, we would like to note some developments which have occurred on a few projects since this timeframe:

- North South Transmission Reinforcement (Project 737- WATL/EATL)
  - The delay in the EATL project to Q3/Q4 2015 has impacted the outage planning and the ISD for the Red Deer Project (Project 813)
  - AltaLink continues to work with ATCO to get a clearer understanding of the EATL project completion date

We note from your report that Alberta Energy have commissioned a review of the Committee's mandate. AltaLink looks forward to being invited to contribute to this review.

Thanks you again for the opportunity to comment on the report.

Regards,

Johanne Picard-Thompson
SVP Projects, AltaLink

cc Jerry Mossing, VP AESO

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Transmission Facility Owners Responses

2000 – 10423 101 St NW, Edmonton, AB
T5H 0E8 Canada
epcor.com

November 4, 2015

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

Dear Mr. Yip:

RE: TFCMC June 2015 Report

EDTI appreciates the opportunity to review and comment on the June 2015 Report from the Transmission Facilities Cost Monitoring Committee (the "Committee").

As stated in our comments to the December 2014 Report, EDTI remains 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.

If you have any questions about EDTI's comments, please do not hesitate to contact me at 780-441-7111.

Regards,

<original signed>

Jay Baraniecki
Director, EDTI Regulatory Affairs

Transmission Facility Owners Responses

ATCO Electric

November 9, 2015

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 – June 2015 Report

Thank you for the opportunity to review and comment on the Transmission Facilities Cost Monitoring Committee's (TFCMC) ninth report dated June 2015. ATCO Electric Transmission (ATCO) remains committed to working on a collaborative basis with all industry participants to increase the levels of trust within, as well as the understanding of our complicated industry.

ATCO, however, is concerned that the TFCMC continues to portray a simplistic comparison of the estimated costs between projects as some sort of valid "benchmarking analysis". In Section 2: TFCMC Observations to Date: Ells River Benchmark Comparison (page 9), the TFCMC again comments on the cost of one project in relation to others. ATCO continues to emphasize that each project is unique and that there are numerous factors that lead to significant differences in costs to execute any one specific project.

As the industry is aware, there are numerous factors that cause differences in costs to complete any one project. Examples of project specific factors that quite often lead to significant differences in costs include, but are not limited to, economic conditions at the time the project material and services are tendered, terrain, structures, geography, land use, environmental and agricultural considerations. The combined impact of all project-specific factors should be carefully identified and analyzed before inferring or drawing any conclusions on the relative cost of any project or component thereof. Comparisons based on the estimates included in the AESO cost database should only be utilized in assessing the reasonableness of these estimates for the purpose of transmission system planning decisions.

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Transmission Facility Owners Responses

Please contact me 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.
Senior Vice President, Finance and Regulatory

Notes

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JUNE 2015 REPORT
TFCMC@gov.ab.ca

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