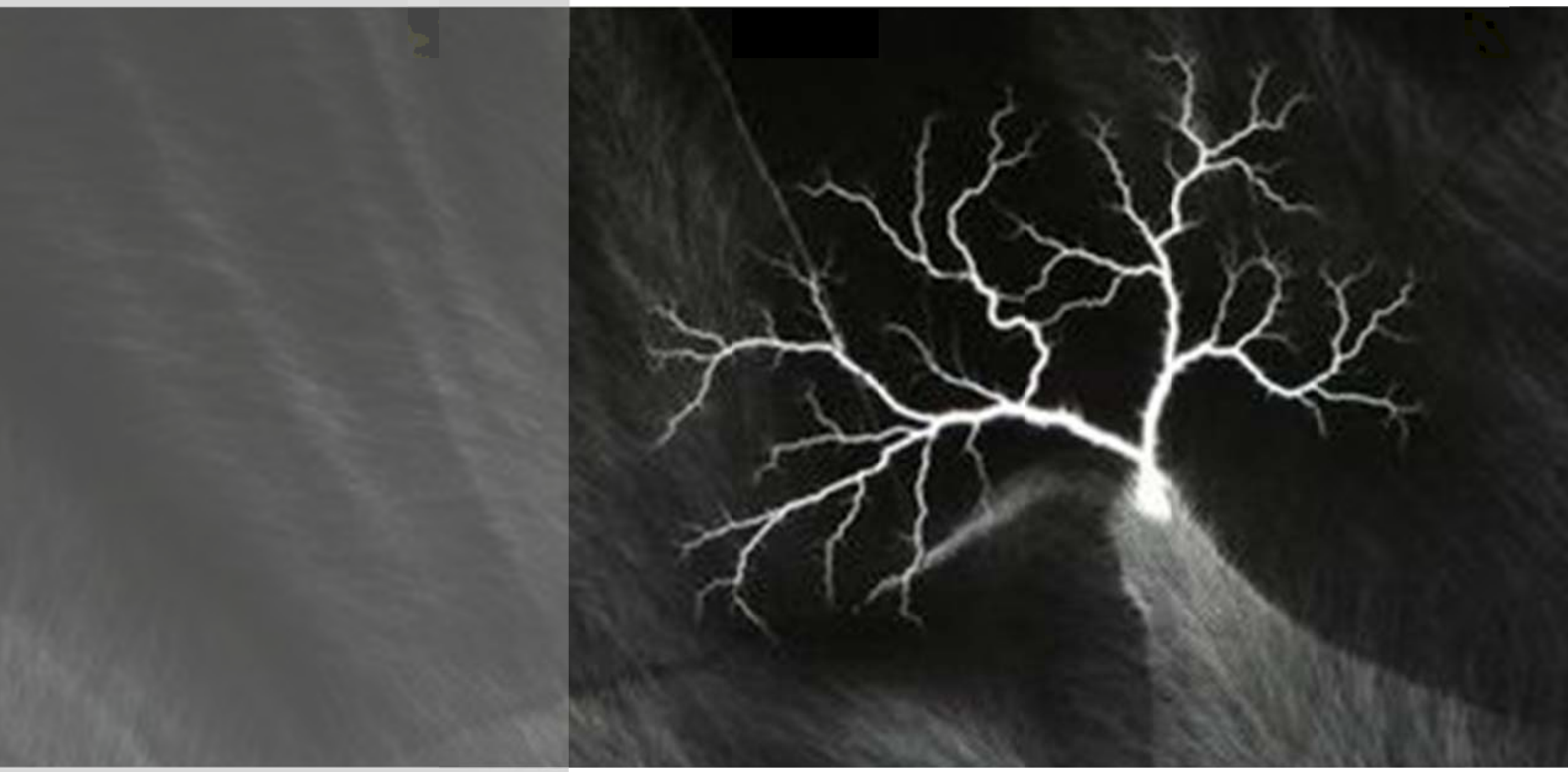
Oil Sands Co-generation Report
July 2012

The Oil Sands Developers Group

Co-generation and Power Infrastructure Committee



Prepared for the OSDG by Genalta Power Inc.

Executive Summary

This report is the 13th annual summary of a survey on the state and future expectations of electricity demand and generation by oil sands developers in Alberta. Oil sands production and extraction is an electric intensive undertaking and increased development of the oil sands region requires forward looking analysis to ensure sufficient supplies of electricity and transmissions capacity are available, whether through on-site generation or by consuming power from the Alberta grid. Oil sands related co-generation currently provides large amounts of base load supply to the Alberta power market. Over time, as more oil sands developments are commissioned, areas like Fort McMurray will move from being a net supplier (or net exporter) of electricity to a net importer.

The objectives of the co-generation survey are:

- Determine the key factors influencing oil sands developer's decisions to build co-generation.
- Provide policy makers with an overview of issues that may be promoting or hindering the development of oil sands related co-generation.
- Provide a quantitative overview of the current and historical on-site electricity demand, oil sands co-generation capacity, potential exports to the provincial grid, and stand-by requirements (for those projects with on-site supply).
- Provide an estimate of the forecast bitumen electricity intensity.

The survey results were compiled from 24 oil sands companies reporting on 135 oil sands projects, of which, 46 projects have developed or are expecting to develop on-site co-generation. Mining projects amounted to 20% of all projects reported with the remaining 80% of projects are in-situ developments.

Compared to the 2011 survey results, there was a 20% increase in company participation and a 6% increase in terms of the number of projects. Not all oil sands developers completed the survey and hence this report should be viewed as somewhat conservative. It is anticipated that over 95% of the potential oil sands projects have been captured in the 2012 survey. The survey was completed during Q1-2012 with the results reflecting a more positive view of future developments relative to previous years. Recall, all-time highs in forward oil prices in 2008 were almost immediately followed by a global economic downturn and recession, remnants of which still impact the economy today. The survey results reflect the known changes in project schedules and scopes for those companies who chose to participate. Year-over-year changes could include the addition or cancellation of projects, advancements or delays to timing, and increases or decreases to on-site demand and/or co-generation assumptions.

The 2012 survey respondents have identified delivered price of power versus cost of generating on-site as the most important factor influencing the decision to build on-site generation. This result is a change from the previous year's study, which identified delivered price of power as the second most influential factor. The increase in importance of delivered power costs directly reflects changes in the Alberta market since the previous year's survey. Increased electricity demand in the province, driven in part by oil sands development and overall economic recovery, combined with a tightening supply mix, has resulted in higher and more volatile power prices in Alberta. In addition, transmission tariffs costs were revised mid-2011, increasing the cost of delivering power to the oil sands regions. For most, both the price of power and cost of delivery are anticipated to continue to increase.

Reliability of power from the grid dropped to the second most influential factor in the 2012 survey (was first in 2011) followed by GHG emissions/regulations which moved up from fourth position in 2011. All of the factors were deemed to be of high importance to some of the survey respondents, with at least two participants listing Internal Fuel Use (the lowest ranked factor) of high importance when making the decision to develop co-generation.

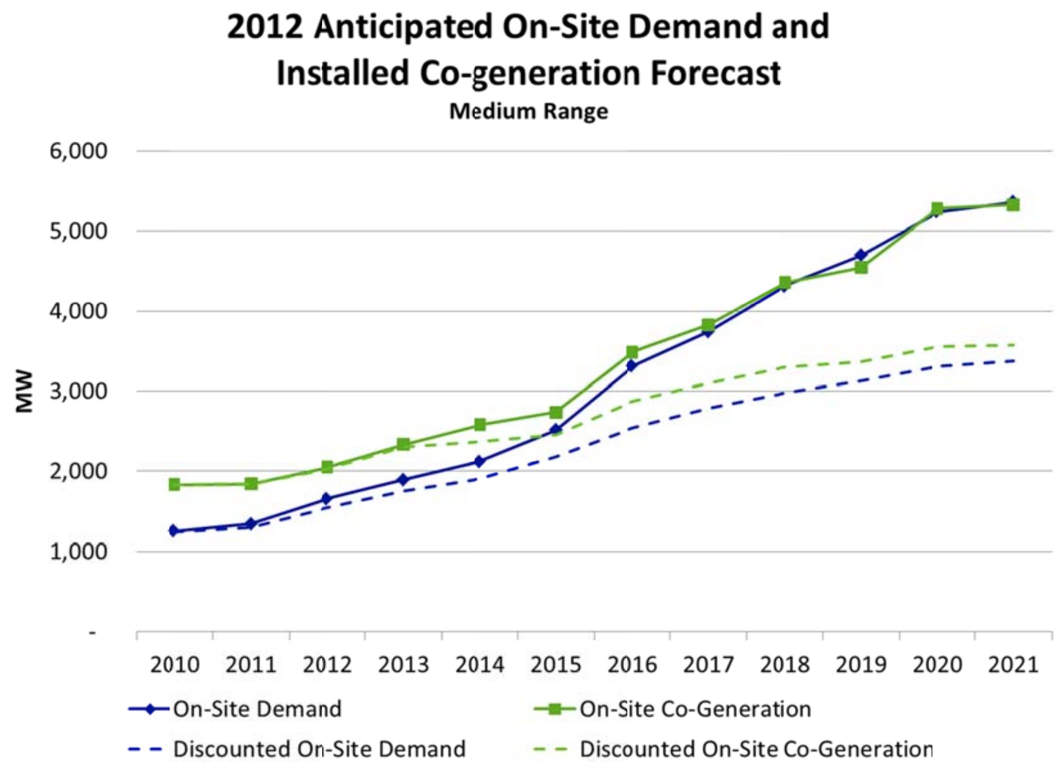
Over the course of the year, factors influencing the development of co-generation can quickly change, potentially impacting future development expectations. Some examples of influential factors that have changed since the previous OSDG study include long term transmission plans, electricity costs, and commodity (oil and natural gas) prices. While near term projects (i.e. next five years) are less flexible to react, significant changes to influential factors may have a substantial impact on longer term oil sands demand and co-generation expectations.

While some factors influencing the development of on-site co-generation are outside the direct control of policy makers others can be influenced to a greater extent. The following outlines some factors policy makers could influence, potentially assisting on-site co-generation decision making:

- Reduce security of supply and reliability risks and improve transmission access by ensuring that additional transmission capacity to/from the Fort McMurray and Cold Lake areas are developed in advance of industry requirements.
- Provide greater certainty on the cost of new critical transmission development projects and the potential tariff impacts on oil sands projects both with and without on-site co-generation.
- Reduce environmental risks by providing clarity on future greenhouse gas emissions compliance obligations and credit allowance.
- Reduce development timelines with streamlined AESO connection and AUC approval processes and make changes to Section 101 of the *EUA,* to remove the requirement that transmission connected projects need approval from the local distribution company.

Similar to survey results over the past three years, almost half of the respondents (49%) plan to use both on-site co-generation and purchased power from the grid to meet their power needs. Around 42% of the projects plan to directly purchase electricity from the grid with the remaining 10% developing on-site co-generation only. In terms of MWs, almost 70% of on-site demand reporting plans for utilizing both co-generation and purchases from the grid with 27% intending to rely on direct purchases from the grid (no co-gen) and the remaining 3% relying on co-generation only. Figure 1 illustrates the Medium Range on-site demand and on-site co-generation survey results along with the corresponding discounted forecast.

Figure 1 - Anticipated On-Site Demand & Installed Co-Generation Forecast (Medium Range)



In the Medium Range, on-site demand has an annual average growth rate of about 15% over the forward term while on-site co-generation is anticipated to record around 11% annual growth. Around 2016, co-generation capacity and on-site demand begin to approach each other as on-site power demand begins to increase at a greater rate than installed co-generation capacity. There is a significant number of smaller oil sands in-situ projects proposed to come on-line over the forecast period. These smaller projects are less likely to develop on-site co-generation and in aggregate amount to a significant amount of demand.

Planned transmission reinforcements, concerns over increasing capital and operating costs, and future electricity supply and cost implications will all continue to influence the decision whether or not to develop on-site co-generation. Future surveys will provide insight into the evolving position of oil sands developers and their influence on Alberta's electricity market.

The discounted forecasts in Figure 1 drastically reduce the amount of forecast on-site demand and installed co-generation, with an average discount of just over 50% applied to both forecasts. Over half of the projects included in this year's study are in the conceptual or announced phase, receiving the heaviest discounts. The more heavily discounted projects tend to be scheduled to come on-line in the latter years of the forecast period.

Relative to the previous study, there was a 36% (or 12 project) increase in the number of co-generation projects expected to come on-line over the forecast period. Most of this increase is the result of more oil sands developments included in this year's study, supported by stronger economics and higher future oil prices as well as increased survey participation.

Throughout the following report, the 2012 results are compared with survey responses from the past five years. Minor changes in near term expectations imply prior surveys have been relatively accurate such that anticipated demand and co-generation capacity five years out has not materially changed. However, there have been significant increases in on-site demand and co-generation capacity forecast over the back end of the forecast period, post 2015.

Similar to last year, about 95% of all exports from oil sands projects are expected to be non-price responsive, that is, the net exports will be created based on factors other than the wholesale market price for electricity. This includes the Generator Must Run and Dependent on Oil Sands Operations categories. This is a significant result as it indicates most oil sands developers are not building excess generation capacity to actively participate in the wholesale electricity market.

The report includes detailed analysis of the potential impact of anticipated oil sands development projects on the Alberta transmission system serving the Fort McMurray area. The analysis suggests near term electricity flows will continue to approach the existing export and import transmission line capacities. Currently, the AESO has plans to reinforce the reactive power capability which is expected to increase the maximum export limit to 630 MW and the import limit to 440 MW. In the past, the main concern has been export transmission capacity limiting flows out of Fort McMurray; however, this analysis suggests over time, the key transmission limitation may be insufficient transmission capacity for imports (i.e. electricity flowing into the Fort McMurray area).

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Introduction

Co-generation has been employed by the oil sands industry to assist with the production of bitumen since the mid 1970's. Over the past 40 years, co-generation capacity has grown as more projects come on-line and operators seek self-sufficiency, improved electric reliability, and optimization of on-site steam and electricity needs. The Oil Sands Developers Group (OSDG) began tracking and forecasting the growth in co-generation starting in 1999 with the objective of providing information to operators, the Alberta Electric System Operator (AESO), and Alberta government policy makers on issues related to co-generation and transmission development.

The *2012 Oil Sands Co-Generation Report* contains the results of the 2012 co-generation survey of companies operating or planning to operate oil sands mines and in-situ operations within the province of Alberta, Canada. The purpose of the survey is to determine the current and potential electrical capacity of co-generation plants located within oil sands projects. The OSDG Co-generation and Power Infrastructure Committee manage the annual survey and issue this report. The committee looks at accessing and addressing the electricity transmission needs of the oil sands producers and its linkages throughout the province. Each year the committee provides a forecast report on Co-generation and Power Infrastructure. The mandate of the committee is to:

- Provide a forum to share, discuss, and disseminate information about electricity transmission capabilities and delivery in the oil sands region of the province ensuring capacity needs to oil sands producers are met.
- Assure that government regulatory processes are recognized and support the potential for new electrical generation in concert with oil sands developer (the committee does not participate in regulatory proceedings).
- Explore issues, opportunities, and new technologies in relation to the development and operation of co-generation and transmission in the oil sands region and province by engaging with the OSDG membership and key stakeholders.

If you have any comments on this report please contact:

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Trends in the Use of Co-Generation

The development of co-generation associated with oil sands operations has gone through a few build cycles. The earliest oil sands developments began in the late 1960s and involved on-site electricity generation and steam production, typically burning coke to heat boilers and run steam generators. As oil sands operations were developed throughout the 1970s to 1990s various co-generators have come on-line. At times these units were developed in partnership with electric utilities or independent power producers, eventually leading to some oil sands companies creating internal co-generation divisions. During this period, co-generators were typically sized to on-site steam requirements, resulting in excess electricity being produced, almost as a by-product.

The deregulation of the Alberta electricity market was, in part, influenced by the desire for a visible and open system to sell co-generated electricity at a market-established price. The change in trend to develop power generation primarily to satisfy on-site power needs was first noted in the *2005 Co-Generation Report*. This trend, of sizing on-site generation closer to electricity needs (rather than steam requirements) appears to have persisted through to 2012. However, this year's survey results may point to the start of a new trend, in which on-site co-generation development is part of the majority of oil sands projects. Trends in the development of on-site co-generation are discussed throughout the report and specifically illustrated in Figure 16 on page 29 in which the survey results for 2012 have been compared to the annual survey responses from 2002 to 2011.

In 2010, the *Electric Statues Amendment Act* included an initiative to allow for the advancements of additional transmission capacity to the Fort McMurray area. This initiative and additional changes to government policy, specifically clarification on Greenhouse Gas (GHG) emissions regulatory requirements, is expected to influence co-generation build decisions, potentially reversing the trend back to building on-site generation with excess electricity capacity.

Methodology

The *2012 Oil Sands Co-Generation Report* summarizes the results of a survey of oil sands companies conducted during Q1-2012. The survey requested actual and forecasted values for co-generation operating capacity, on-site demand, requirements for stand-by power from the grid, and potential power sales or net exports. The data was requested for three ranges; low, medium, and high. The ranges were defined as:

- **Low Range –** project would be built to the minimum anticipated scope. This may reflect a minimum capital spend, lower oil prices, higher priced emissions compliance costs, and/or poor economic conditions.
- **Medium Range –** project would be built to the most probable or planned scope in a business-as-usual environment.
- **High Range –** project would be built to the maximum anticipated scope. This may relate to a larger capital spend, higher oil prices, lower priced emissions compliance costs, and/or more robust economic conditions.

The survey data was complied, analyzed and adjusted by Genalta Power and shared with a representative of the AESO. The results of the study were compiled from 24 oil sands companies reporting on 135 oil sands projects, of which, 46 projects have developed or are expecting to develop on-site co-generation. Relative to the previous year, there was a 20% increase in company participation or a 6% increase in response, in terms of the number of projects.

The report contains forward-looking information. Actual results could differ due to market conditions, different laws or government policies, changes in operating conditions and costs, advancements/delays in projects schedules, operating performance, demand for oil and natural gas, commercial negotiations, or other technical and economic factors. The results included in this report reflect the information shared by those companies that chose to participate. Not all oil sands companies completed the 2012 survey and hence the information provided in this report is not inclusive of all potential oil sands projects in Alberta.

Presentation of the Data

The results of the 2012 survey are summarized throughout the report in two ways. The first reflects the un-adjusted values of the survey respondents, assuming all projects will proceed at their announced capacity and timing. While the second applies a percentage-based adjustment to the survey responses creating a discounted data set. This discount is applied based on the development status of each project, focusing particularly on the regulatory application/approval process. Table 1 illustrates each development stage and its corresponding discount.

Table 1 – Development Stage Discounts

Status	Discount
Cancelled	0%
Conceptual	10%
Announced	25%
Approved	60%
Regulatory	90%
Construction	100%
Operating	100%

The discounted results reflect a more likely outcome as those projects at the initial stages of development have been adjusted to incorporate the increased risk of delays or cancellations. As many of the oil sands projects included in the 2012 study are at the earlier stages of development, there is a significant difference between the un-adjusted survey responses and the discounted analysis. This difference increases over the forecast period as projects scheduled for the second half of the forecast tend to be in earlier stages of development and therefore receive heavier discounts.

Typically, the Medium Range survey responses are discussed throughout with most figures illustrating the results of all three cases. Five-year comparisons of survey responses are included for some result areas.

In this study oil sands development of carbonate reservoirs containing bitumen have been excluded. While the concept of producing oil from carbonates has existed for many years, the extremely large amounts of electricity required to extract bitumen from these formations, using electric heating technologies has, in part, prevented its development. Several companies have expressed an interest in carbonate oil sands projects with estimates of 500 MW to 5,000 MW of on-site generation required. For now, carbonate developments have been excluded from the survey while projects remain in the early stages.

The use of electricity for bitumen extraction from carbonate reservoirs would have a significant impact on the Alberta electricity market, as multiple, large on-site natural gas-fired generation developments, most likely combined-cycle, would be required to meet the large down hole electrical heating loads. These projects may elect to secure firm transmission supply contracts (AESO DTS) for a portion of their requirements which may require some form of transmission upgrades. This study will continue to monitor oil sands carbonates and ensure future forecasts acknowledge and/or incorporate these potential developments.

There are some non-carbonate oil sands projects, in the early stages of development, proposing to use electricity-based bitumen extraction techniques. These oil sands related projects have been included in the study.

Survey Results

Critical Factors Influencing the Decision to Develop Co-Generation

Survey respondents were asked to indicate the level of importance of 13 factors over five categories that could impact their decision whether or not to build co-generation. Table 2 lists the 13 factors in their 5 categories and provides a brief overview of each factor.

Table 2 – Factors Influencing Co-Generation Development Decisions

Category	Factor	Description
Security of Supply & Reliability	Reliability of power from grid	Transmission system is inadequate to provide the level of “up time” required for oil sands projects.
	Balance load & co-generation	Ability to balance load and generation within oil sands projects, including steam balance considerations.
Environmental	GHG emissions/regulations	Consideration of GHG cost and regulation compliance (uncertainty and potential positive/negative impacts).
	Internal fuel use	Ability to provide fuel from the oil sands operations, (e.g. syn-gas fueled or turbine fuel source).
Transmission Access	Timing	Certainty (or uncertainty) to when transmission capacity will be available for oil sands projects.
	Customer owned substation	Ability to design, build, and/or own the substation and control the development/construction process.
Market Fundamentals	Delivered price of grid power versus cost of generating power	Cost of electricity from co-generation plus stand-by transmission charges compared to purchasing from third party suppliers plus transmission charges.

	Natural gas prices versus power pool prices	Risks associated with the correlation between natural gas and electricity prices, or system heat rate (positive/negative).
	Transmission Charges	AESO wires charges for delivery of electricity and/or stand-by capacity from the grid.
	Industrial System Designation (ISD)	Potential AESO tariff savings associated with ISD (e.g. net metering).
Regulatory	DISCO Section 101 approvals	Ability (or inability) to obtain approval from the distribution company to become an AESO direct connect customer.
	Alberta Utilities Commission (AUC) approvals	Ability (or inability) to obtain approval from the distribution company to become an AESO direct connect customer.
	Industrial System Designation	Consideration of time and resources required to obtain approvals from the AUC for an ISD.

The following chart (Figure 2) shows the survey results graphically sorted based on the sum of a hierarchical value assigned to each level of importance[1]. The 2012 survey respondents have identified delivered price of power versus cost of generating on-site as the most important factor influencing the decision to build on-site generation, with 13 oil sands companies (out of the 22 companies which provided responses to this section of the survey) indicating this factor was of high importance. This result is a change from the previous year's study, which identified delivered price of power as the second most influential factor.

The increase in importance of delivered power costs directly reflects changes in the Alberta market since the previous year's survey. Increased electricity demand in the province, driven in part by oil sands development and overall economic recovery, combined with a tightening supply mix, has resulted in higher and more volatile power prices in Alberta. In addition, transmission tariffs costs were revised mid-2011, increasing the cost of delivering power to the oil sands regions.

[1] Note, this methodology prevents ranking of importance purely based on those factors with the most number of "high importance" responses. Consequently, there is potential for a factor with a number of "medium importance" responses to have a higher overall ranking than a factor with the same or larger number of "high importance results".

Figure 2 – Factors Influencing Decision to Build Co-Generation

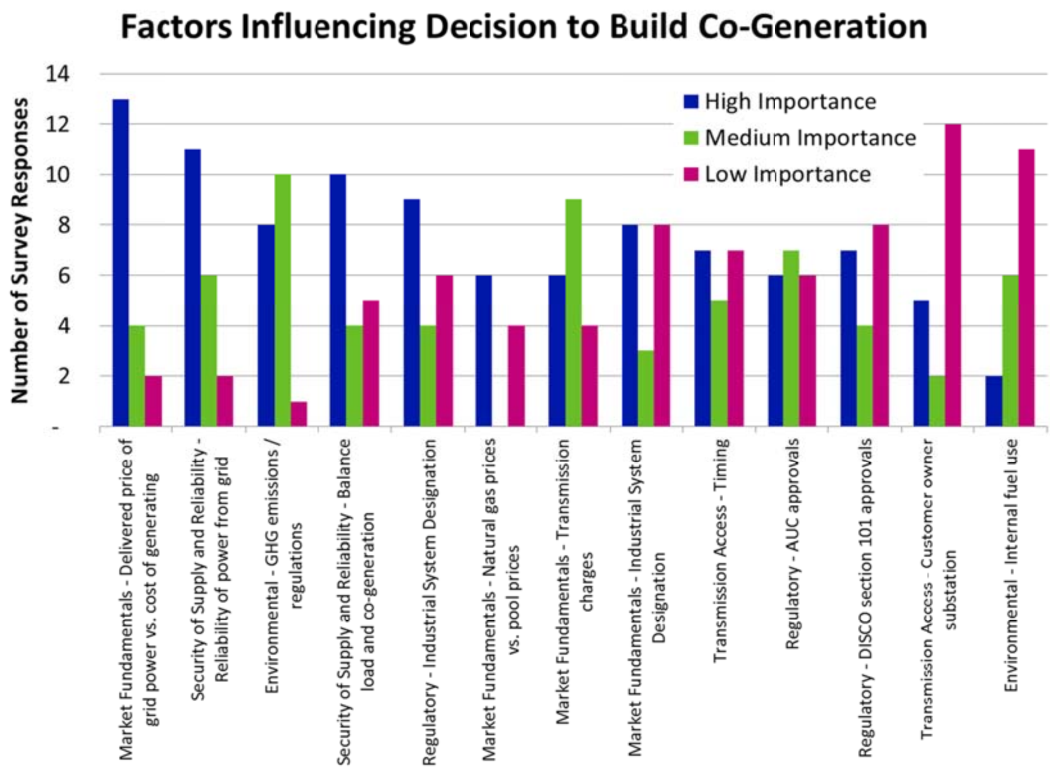
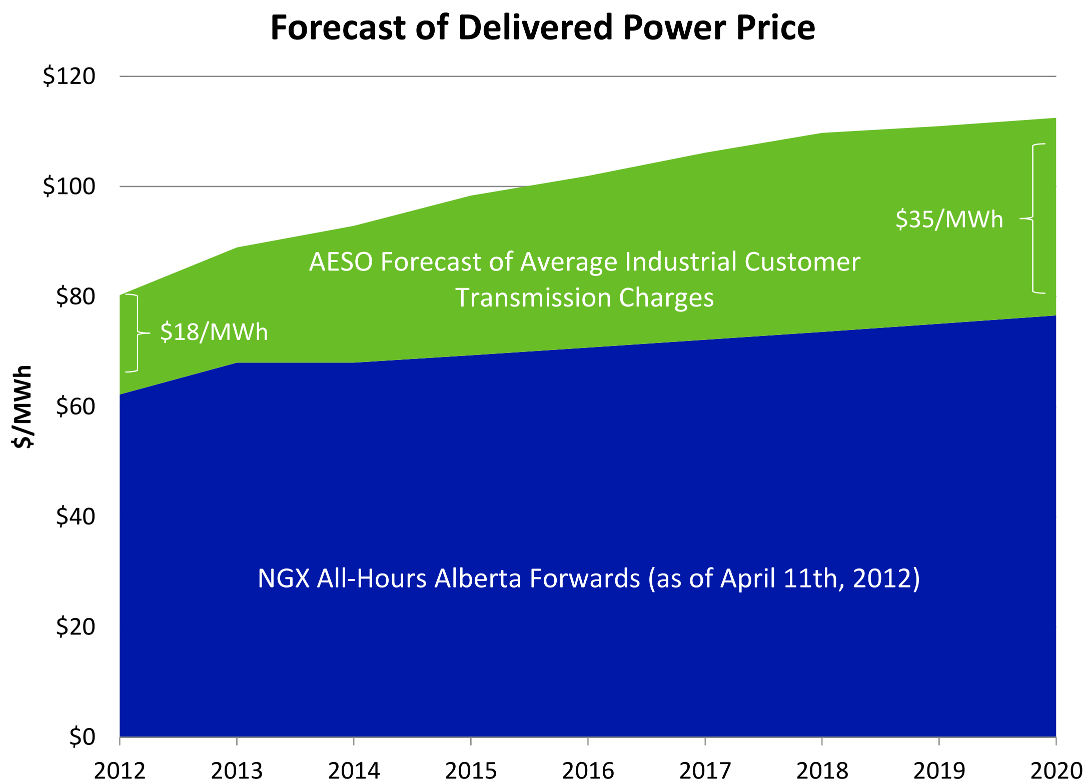


Figure 3 illustrates the expected increase in delivered price of power over the forecast period influenced by higher anticipated pool prices and increased industrial customer transmission charges. The Alberta all-hours forward market[2]reflects a tighter near term supply demand balance supporting prices despite low natural gas price. The AESO has published its forecast of future transmission costs that show a significant increase in transmission charges over the next ten years.[3] This increase in delivery costs incorporates the cost of developing Critical Transmission Infrastructure projects, including two 500 kV lines to the Fort McMurray area planned throughout the next decade, and capital maintenance projects totaling about $20 billion over the next eight years. Over the past five years, average transmission charges for load customers have increased about 50%. Overall, higher delivered power prices are expected to incent the development of co-generation as oil sands producers investigate on-site alternatives for power supply.

[2] Source: NGX All-Hours Alberta AESO Settlement as of April 11th, 2012. Forward market values for 2012-2014, escalated at 2% thereafter.

[3] See http://www.aeso.ca/downloads/Transmission_Rate_Impact_Analysis_-_2011-2020_Draft_(2011-07-18A).xls

Figure 3 - AESO Forecast of Average Industrial Customer Transmission Charges



Reliability of power from the grid dropped to the second most influential factor in the 2012 survey (was first in 2011) followed by GHG emissions/regulations which moved up from fourth position in 2011. Note, Reliability of power from the grid can be a regional issue having different impacts or influences on co-generation development depending on the area. All of the factors were deemed to be of high importance to some of the survey respondents, with at least two participants listing Internal Fuel Use (the lowest ranked factor) of high importance when making the decision to develop co-generation.

Both Regulatory ISD and Market Fundamental ISD factors moved significantly higher relative to the 2011 survey results. Recall the regulatory ISD factor involves the time and resources required to obtain AUC approval for an ISD while the market fundamentals ISD factor centers on the potential tariff savings available for ISDs.

Consistent with the previous year, DISCO Section 101 approvals, Customer owned substations, and Internal Fuel Use were deemed to be the least influential factors in the decision to develop on-site co-generation.

Some of the factors within each category are outside the direct control of policy makers, such as wholesale natural gas and electricity prices, whereas other factors, like increased transmission costs, via legislative requirements in the *Electric Statues Amendment Act (EUA)*, can be influenced to a greater extent. The following outlines some additional factors that policy makers could influence, potentially assisting on-site co-generation decision making:

- Reduce security of supply and reliability risks and improve transmission access by ensuring that additional transmission capacity to/from the Fort McMurray and Cold Lake areas are developed in advance of industry requirements.
- Provide greater certainty on the cost of new critical transmission development projects and the potential tariff impacts on oil sands projects both with and without on-site co-generation.
- Reduce environmental risks by providing clarity on future greenhouse gas emissions compliance obligations and credit allowance.
- Reduce development timelines with streamlined AESO connection and AUC approval processes and make changes to Section 101 of the *EUA,* to remove the requirement that transmission connected projects need approval from the local distribution company.

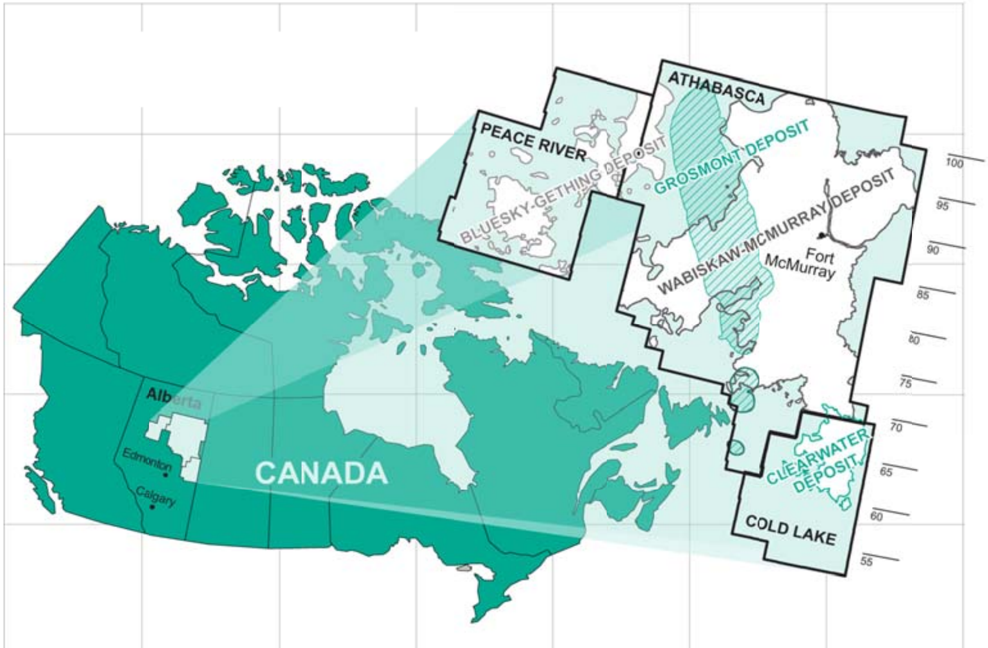
Detailed Survey Results

The following presents the results for each question of the 2012 survey. The results were compiled from 24 oil sands companies reporting on 135 oil sands projects, of which, 46 projects have developed or are expecting to develop on-site co-generation. 20% of the projects reported on were identified as mining projects with the remaining 80% a form of in-situ development based on the number of projects. While oil sands mines may represent a smaller number of projects they are typically larger than in-situ projects, both in terms of on-site power demand and production (bbl/d). Some oil sands projects are multi-phase developments, adding demand and potentially on-site co-generation through a staged approach. The impact of multi-phase developments can be seen throughout the forecast influencing forecast results even though the base project is already on-line. In a change from last year, general information about the participating companies will be discussed first (location, project status), followed by detailed discussion of the demand and supply results.

Your project is located in the following region:

There are three Alberta oil sands regions; Athabasca, Cold Lake, and Peace River (shown in Figure 4). The original oil sands projects are located in the Athabasca region with both mining and in-situ developments in the area. The Athabasca region is the largest and so for the purposes of this study has been divided further into three areas; North of Fort McMurray and East of the Athabasca River, North of Fort McMurray and West of the Athabasca River, and South of Fort McMurray. The Cold Lake region is found to the southeast while the Peace River region is located to the west. Both areas have a tendency towards in-situ operations. The Wabasca and Red Earth/Other regions contain those few outliners not located in traditional oil sands areas.

Figure 4 – Alberta's Oil Sands Areas[4]



The results of this question assist the AESO in planning for future transmission growth by identifying the location and number of existing and forecast co-generation units as well as the anticipated co-generating operating capacity in each region. Values shown in the table below reflect Medium Range survey results.

Table 3 – Location & Number of Co-Generation Projects, Installed Generation & Operating Capacity

Project Location	No. of Projects with Co-Gen		Installed Generation Capacity 2021 (MW)	Operating Capacity (MW)	
	2011	2021		2011	2021
Athabasca Region -					
South of Fort McMurray	3	14	1,335	278	1,049
North of Fort McMurray & East of the Athabasca Ri	4	16	2,235	959	2,156
North of Fort McMurray & West of the Athabasca Ri	2	8	1,137	285	985
Wabasca Area	-	-	-	-	-
Cold Lake Area	3	7	645	317	597
Peace River Area	-	1	540	-	540
Other Areas	-	-	-	-	-
Total	**12**	**46**	**5,892**	**1,839**	**5,327**

As can be seen from Table 3, the majority of projects are located in the Athabasca region, followed by the Cold Lake area. Survey respondents indicated there were 12 projects with co-generation operating in the province in 2011, amounting to over 1,800 MW of operating capacity. By 2021, the number of projects with on-site co-generation is expected to almost quadruple, with over 5,300 MW of operating capacity from 46 projects with an aggregate nameplate capacity of almost 6,000 MW.

[4] Source: Energy Resources Conservation Board (ERCB). ST98-2011: Alberta's Energy Reserves 2010 and Supply/Demand Outlook 2011-2020. June 2011.

Relative to the previous study, there was a 39% (or 13 project) increase in the number of co-generation projects expected to come on-line over the forecast period. Most of this increase is the result of more oil sands developments included in this year's study, supported by stronger economics and higher future oil prices as well as increased survey participation. This can include advanced timelines of some projects previously outside of the study scope. In addition, concerns over the cost and reliability of power delivered through the grid, as reflected in response to the influential factors section, have encouraged the development of on-site generation.

What is the status of your project as of January 1st, 2012?

The purpose of this question is to gather information on the development status of the various co-generation units. As any developer knows, there is a significant difference between a conceptual project and steel in the ground. The status of each co-generator provides insight into both the timing and probability of the project coming on-line. Table 4 lists the nameplate capacity for the Medium Range in 2021 as well as the number of co-generation units.

Table 4 –Status of Co-Generation, Installed Generation Capacity, & Number of Units (Medium Range, 2021)

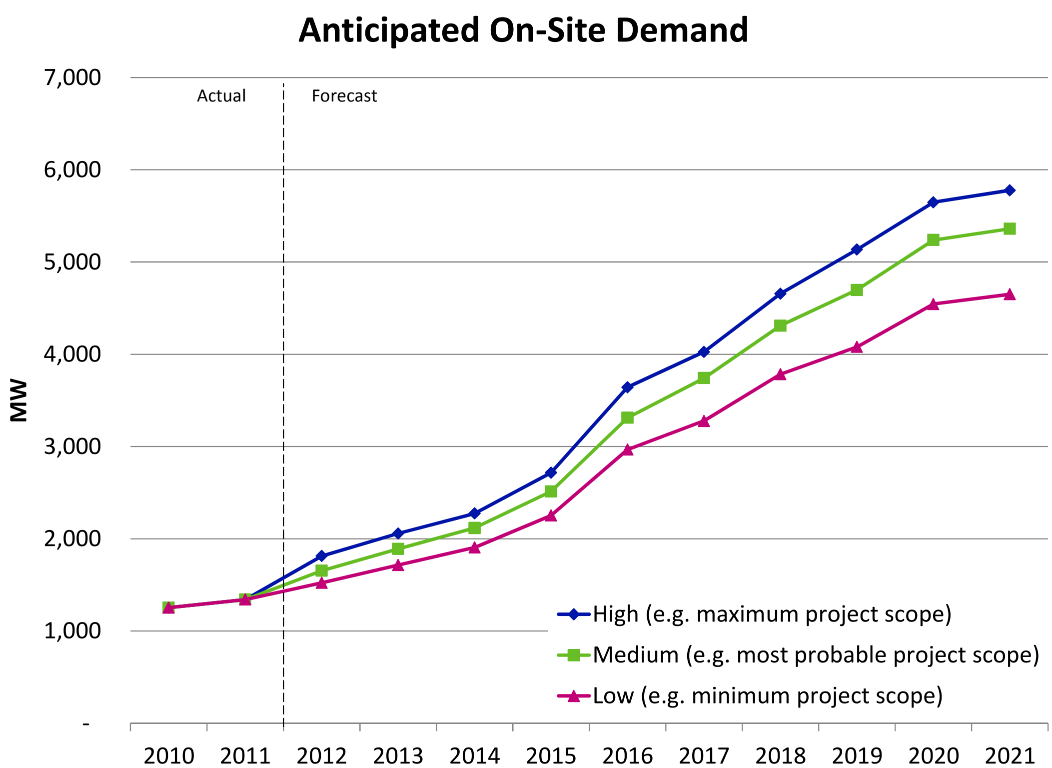
Status	Installed Generation Capacity (MW)	No. Co-gen Units
Built &/or Operating	2,542	37
Under Construction	170	2
Full Regulatory Approval	573	8
Full Company Approval	186	4
In Approval Stage	385	8
Announced	705	5
Conceptual	1,331	32
Total	**5,892**	**96**

The 2012 survey results imply that almost 6,000 MW of co-generation is planned to be operating by 2021. Currently, these co-generators are in various stages of development from existing operations to conceptual projects. Note, the number of co-generation units reflects more than one co-generator located at a single facility or project. Compared to the 2011 survey results, both installed generation capacity and number of units are significantly higher. Again, this is assumed to reflect an increased number of projects included in the survey as well as year-over-year changes in the Alberta market, further exemplifying the oil sands developers concerns over delivered electricity costs and reliable delivery of power, especially to the Fort McMurray area, as shown in Figure 2.

What is the expected range of on-site demand for each year?

The 2012 survey results show a significant increase in on-site demand over the forecast period 2012-2021 (Figure 5). The Medium Range annual demand growth averages about 17% per year until 2016 when a 32% year-over-year growth spike is forecast. This coincides with the expected start-up of 8 oil sands projects, including a large oil sands mining operation and a large in-situ project. From 2017 on, a lower annual average growth rate of 10% is forecast. Over the full term, anticipated on-site demand is expected to record a 15% annual growth rate.

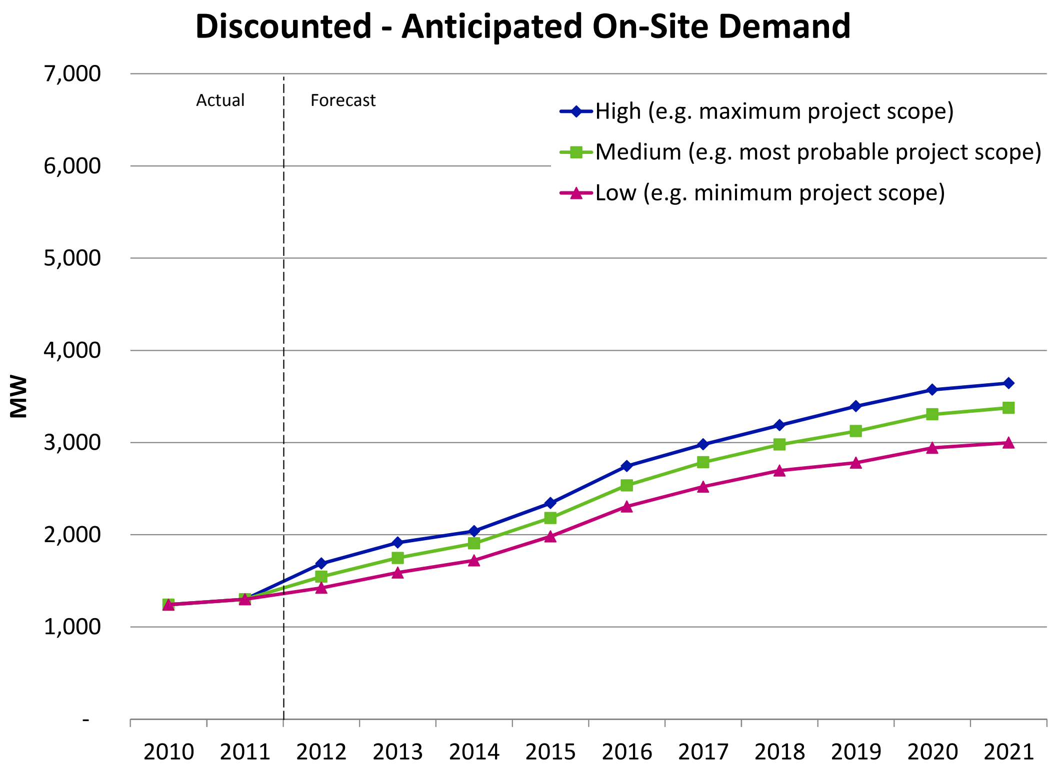
Figure 5 – Anticipated On-Site Demand



Oil sands developers with on-site co-generation may choose to contract with the AESO for some amount of anticipated on-site demand to ensure adequate capacity is available when on-site generation units are off-line (i.e. DTS contract capacity). Figure 5 illustrates anticipated on-site demand in aggregate. In reality, there will be very few instances where the majority of developers would be consuming electricity from the grid at their highest anticipated on-site demand capacities at the same time (i.e. not all on-site generators will be off-line at the same time). The Duration Curve Analysis section shows electricity flows over the year, showing that demand in the hour is typically lower than anticipated on-site demand for oil sands projects that have on-site co-generation.

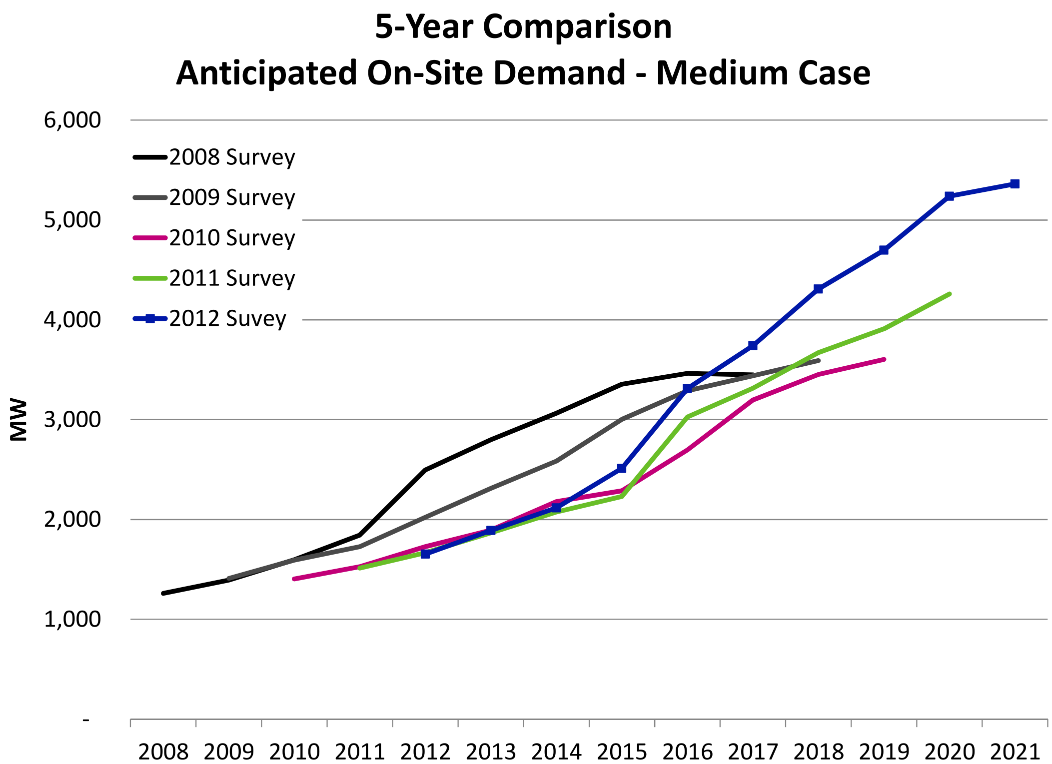
With discounting, the 2012 survey anticipated on-site demand has a considerably lower annual growth rate, averaging 10% in the Medium Range over the forecast period (Figure 6). The average discount applied to oil sands projects is around 50% with over half the projects in the conceptual or announced stage receiving the largest adjustments. The 2012 survey results are in line with 2011 survey results (2020, Medium Range)

Figure 6 - Discounted - Anticipated On-Site Demand



The five year comparison of annual surveys (Figure 7) shows that for the first couple years of the forecast, anticipated on-site demand is relatively close to the forecast results from the previous study. Starting around 2015 and elevated by the large growth planned for 2016, the results of the two studies begin to diverge with the 2012 on-site demand forecast expected to be higher than the previous year's expectations. This continues for the remainder of the period, resulting in total demand being almost 1,000 MW higher by 2020 in the Medium Range. Starting in 2017, the 2012 survey results are the highest forecast of anticipated on-site demand out of the historical survey results shown.

Figure 7 – 5-Year Comparison of Anticipated On-Site Demand



Again, the higher forecast relative to the previous study is the result of more projects included in this year's forecast, overall higher anticipated on-site demand, and the advancement of some projects to earlier start dates.

What options for power supply are being considered?

Similar to survey results over the past three years, almost half of the respondents (49%) plan to use both on-site co-generation and purchased power from the grid to meet their power needs. Around 42% of the projects plan to directly purchase electricity from the grid with the remaining 10% developing on-site co-generation only. The results are presented in Table 5. Note, the options are not mutually exclusive with some respondents choosing more than one option for a project.

Table 5 – Options for Power Supply (Number of Projects)

Options for Power Supply	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Co-Generation Only (no stand-by)	-	-	-	1	2	5	5	5	6	7	8	8
Direct Purchase from Grid (no co-gen)	11	10	13	16	23	29	27	28	32	34	35	36
Both of the Above	13	13	15	15	17	20	26	32	34	38	41	42

In this study, more projects have indicated plans to develop on-site co-generation only, an increase of about 5% relative to last year's responses. Direct purchases recorded a year-over-year decrease of about 4% with 1% fewer projects considering both options.

Table 6 shows the electricity source for the quantum of demand in terms of MW, with 27% of demand reported planning to make direct purchases from the grid and 3% to develop on-site cogeneration only.

Again the vast majority of demand is planning on some combination of supply ("Both of the Above") with almost 70% of on-site demand reporting plans for utilizing co-generation and purchases from the grid. Around 27% intend to rely on direct purchases from the grid (no co-gen) while the remaining 3% will be served by co-generation only (i.e. do not intend to draw power from the grid).

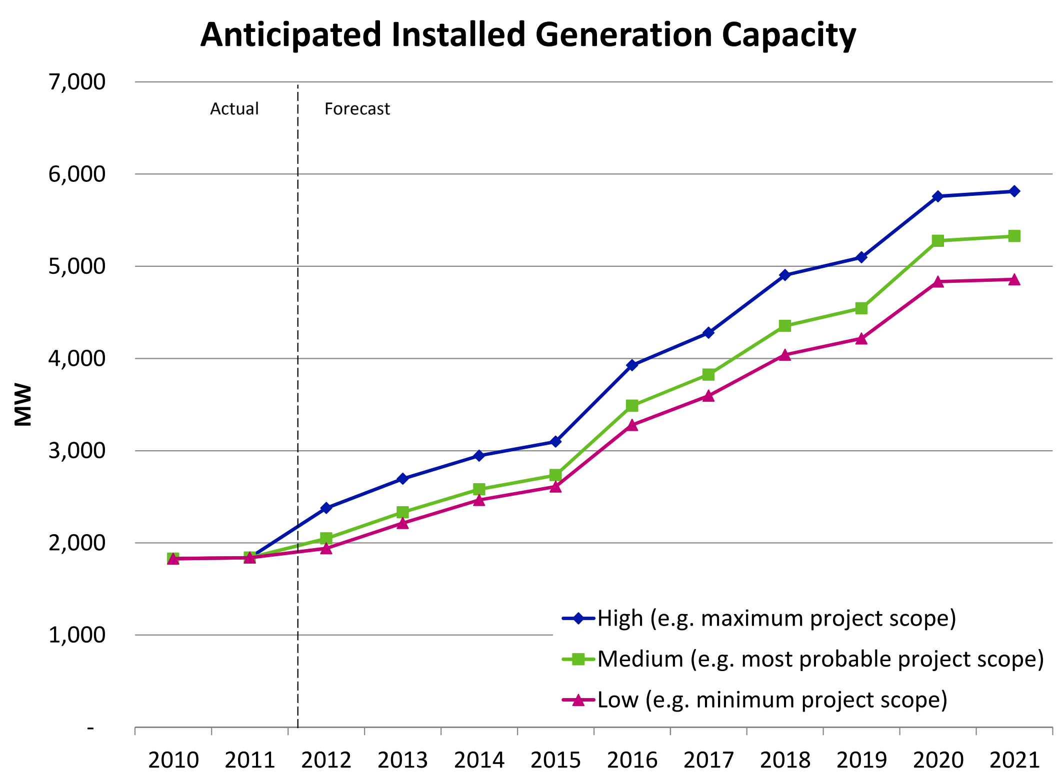
Table 6 – Options for Power Supply (Quantum of Demand Reported)

Demand for Power Supply (MW)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Co-Generation Only (no stand-by)	-	-	-	6	36	78	74	74	96	143	173	173
Direct Purchase from Grid (no co-gen)	73	106	200	283	311	481	818	877	1,103	1,306	1,488	1,552
Both of the Above	1,197	1,232	1,476	1,604	1,813	1,998	2,478	2,884	3,203	3,431	3,751	3,866

If installing on-site co-generation power supply, please provide the anticipated range of your installed generating capacity.

Figure 8 illustrates the forecast of installed co-generation capacity. As can be seen by the figure, the Medium Range of the forecast is skewed towards the Low Range for most of the term. Sizing of on-site co-generation is less flexible and constrained by the physical capacities of generators, often resulting in differences between on-site demand and supply.

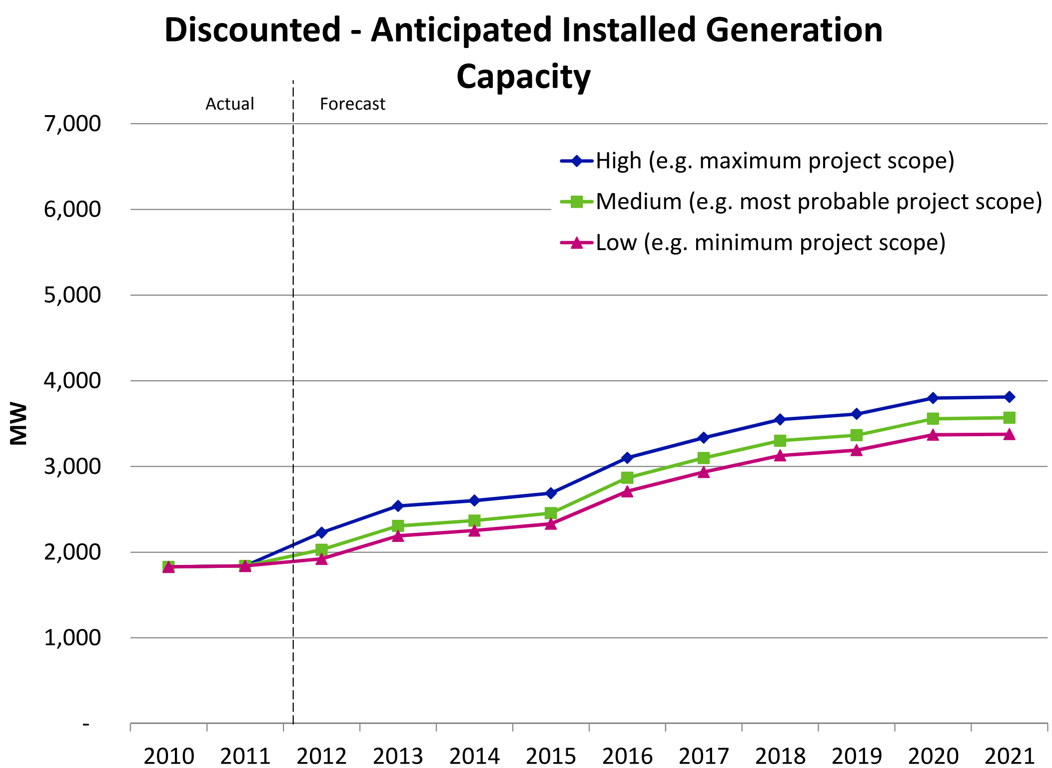
Figure 8 – Anticipated Installed Generation Capacity



In the Medium Range, the anticipated installed generation capacity forecast has an average annual growth rate of 11% with a two notable increases in capacity. The first occurs in 2016, with the commissioning of eight projects adding almost 450 MW of supply, and second in 2020 when four projects are scheduled to come on-line with over 250 MW of cogeneration supply. In both instances, multi-phase developments also have aspects coming on-line those years, further adding to the forecast growth.

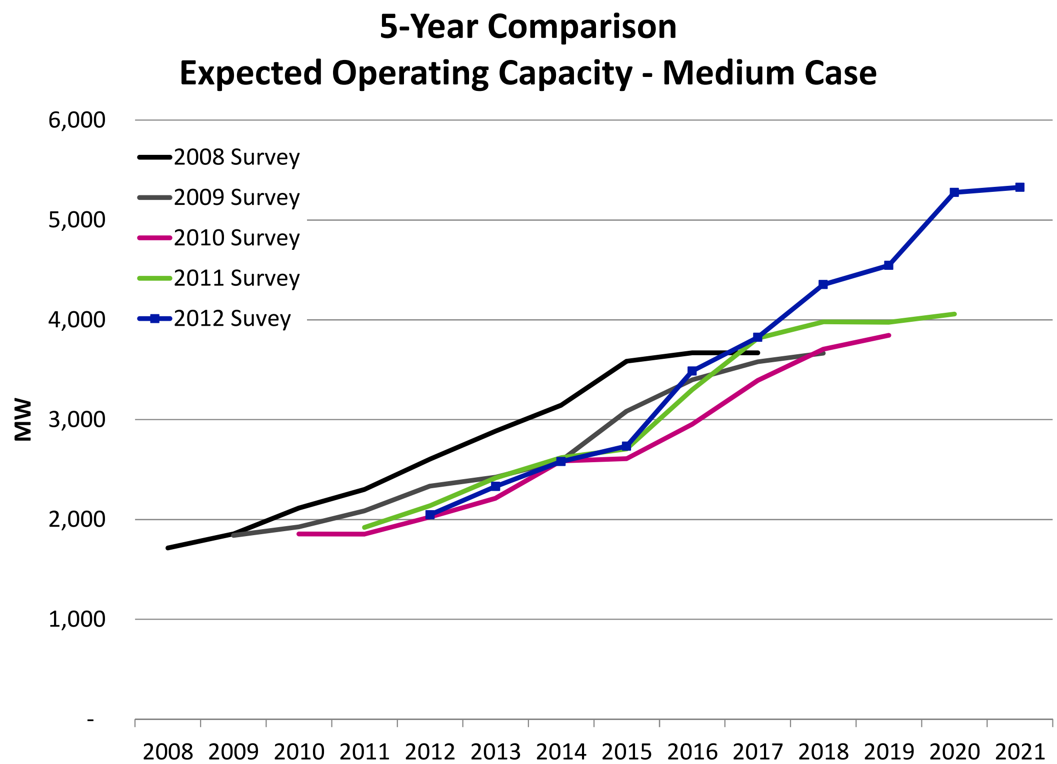
Discounted results (Figure 9) drastically reduce the amount of installed co-generation with an average discount of just over 50% applied to the forecast. Again, over half of the projects planning to develop on-site co-generation are in the conceptual or announced phase.

Figure 9 – Discounted – Anticipated Installed Generation Capacity



For most of the forecast term, the 2012 survey forecast of operating co-generation capacity is very similar to previous survey results (Figure 10). It is not until 2018, when the installed generation forecast from the 2012 survey eclipses the values reported in years past. This increase at the back of the forecast period is the result of more projects considering co-generation developments to meet all or a portion of on-site demand, driven by some of the influential market factors discussed with Figure 2, as well as a large number of generators increasing the planned capacity of their developments year-over-year. These results are consistent with patterns and changes in the anticipated and discounted on-site demand forecasts.

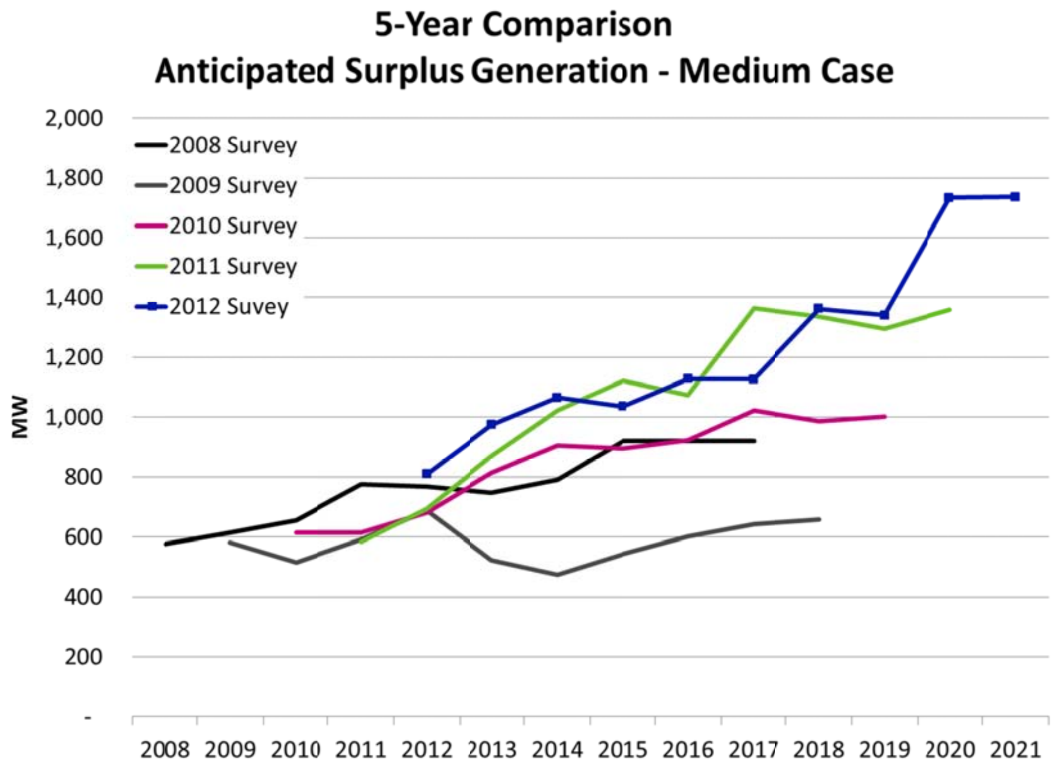
Figure 10 – 5-Year Comparison of Expected Installed Operating Co-Generation Capacity



If installing co-generation, please provide the anticipated range of surplus generation.

As to be expected, the significant increase in on-site electricity demand and installed co-generation capacity has resulted in an increase in forecasted surplus generation to the provincial grid. Figure 11 shows the results of the 2012 survey as well as the forecast values from the previous four years. For most of the forecast period, the 2012 survey results vibrate around the 2011 values, with any significant year-over-year differences the result of changes to project assumptions, such as timing.

Figure 11 - 5-Year Comparison of Anticipated Surplus Generation



Overall, there is more surplus generation expected by the end of the forecast period. The large increase shown in 2020 is the result, in part, of projects coming on-line and more significantly, changes to projects that commissioned over the forecast period. Some oil sands projects are multi-phase developments, adding demand and potentially on-site co-generation. Throughout the forecast period, the impact of multi-phase developments influences the forecast results; however, in the case of surplus generation, this is especially noticeable in the increase in 2020. Note, the surplus generation results reflect electricity capacity available for export and do not take into consideration hourly flows in and out of the Fort McMurray area (see Duration Curve Analysis section for this analysis).

If anticipating power exports how do you plan to operate?

Currently, the majority of co-generation net exports from the oil sands are non-price responsive, in that excess capacity is offered into the Alberta market near the $0/MWh floor. This ensures excess electricity produced on-site will be used and co-generation operations will not be ramped up and down in response to hourly spot market prices. This question was added to the survey in 2011 to gain insight into future bidding behaviour of oil sands co-generators.

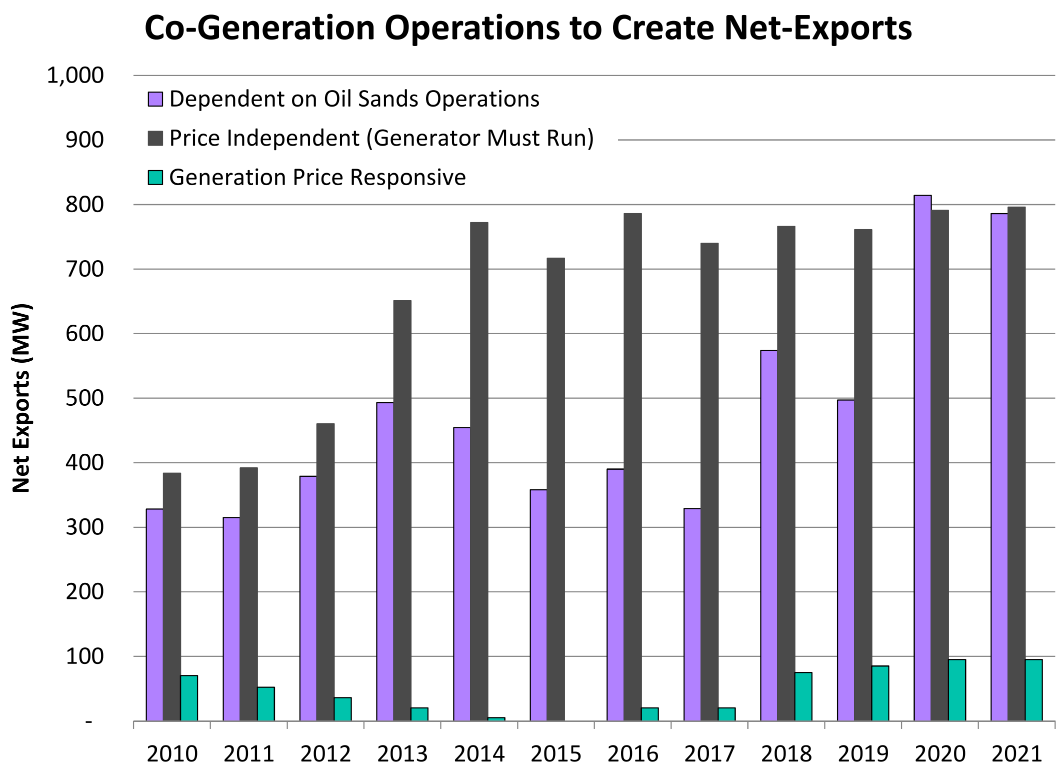
Oil sands developers with export capabilities where asked how the electricity would be bid into the market. Three options were provided:

1. Price Independent (Generator Must Run) – net exports to the grid will continue regardless of the power pool price (net exports are "price takers" bidding near the $0/MWh floor).

2. Generation Price Responsive – net exports to the grid will generally increase when pool prices are high (e.g. pool price is above variable costs) and generally decrease when pool prices are low (e.g. pool price is below variable costs).
3. Dependent on Internal Oil Sands Operations – the quantum of net exports will be a function of internal operations and may or may not change with power pool prices.

The survey results are shown in Figure 12.

Figure 12 – Co-Generation Operations to Create Net Exports



Similar to last year, about 95% of all exports from oil sands projects are expected to be non-price responsive, that is, the net exports will be created based on factors other than the wholesale market price for electricity. This includes the Generator Must Run and Dependent on Oil Sands Operations categories.

This is a significant result as it indicates most oil sands developers are not building excess generation capacity to actively participate in the wholesale electricity market. Only three oil sands developers reported that they plan to be price responsive with a portion of their co-generation capacity. From an electric system operation perspective, the non-price responsiveness of excess co-generation capacity implies there will be significant supplies of zero or low priced power, potentially leading to lower off-peak prices. As well, this can serve as an indication to the market that increased generation output from oil sands co-generators should not be expected or relied upon during times of high market prices.

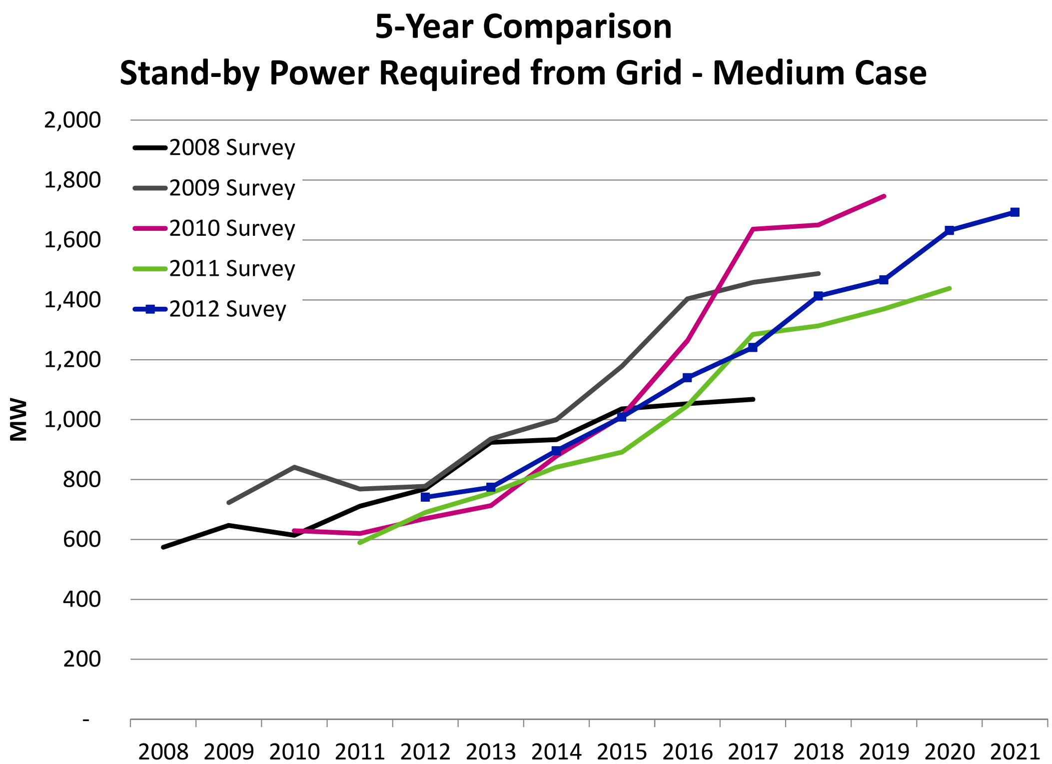
If you are planning to construct a co-generation plant, how much stand-by power or back-up do you require from the grid each year?

Stand-by or back-up power requirements refer to the amount of capacity each project would be required to operate if any on-site generation was unavailable. This variable is measured by anticipated DTS contract capacity and is difficult to quantify as the amount of power required can vary significantly for any given day in a year. These results must be interpreted with caution as each project's stand-by power requirements are not fully additive with other projects. The use of stand-by supplies from the transmission system is infrequent and the likelihood of all projects requiring stand-by capacity at the same time is remote. Please see the Duration Curve Analysis section which suggests the average Medium Range co-incident requirement from all loads net of generation in the Fort McMurray area will average about 600 MW in 2021 under the 100% case (Figure 23, black 2021 line) and about 125 MW under the discounted case (Figure 24, black 2021 line), compared to over 1,500 MW in Figure 13 (Medium Range, 2021).

Compared with 2011 survey results, stand-by requirements are relatively similar over the first half of the forecast period. However, starting around 2018, there is an uptick in the stand-by power requirements, mostly reflecting the stand-by requirements of oil sands projects expected to begin operations that year. Stand-by power requirements are also susceptible to changes as the result of multi-phase developments, which could increase or decrease stand-by requirements as demand, and potentially on-site generation come on-line. Again, this does not mean that all stand-by capacity forecast will be required at any one time. Rather, this is the cumulative stand-by requirement from over 30+ projects.

Note, stand-by requirements have a direct impact on the transmission tariff costs of an oil sands operation. Around mid-2011, transmission tariffs were increased, a trend which is anticipated to continue and grow at a steep pace, as tariffs begin to incorporate the cost of proposed transmission infrastructure builds planned over the next 5 to 8 years (Figure 3). As evident from the factors influencing the decision to build co-generation discussion (Figure 2) oil sands developers may be re-evaluating the cost of stand-by capacity versus the risk of reduced production during generation outages.

Figure 13 – 5-Year Comparison of Stand-by Power Requirements

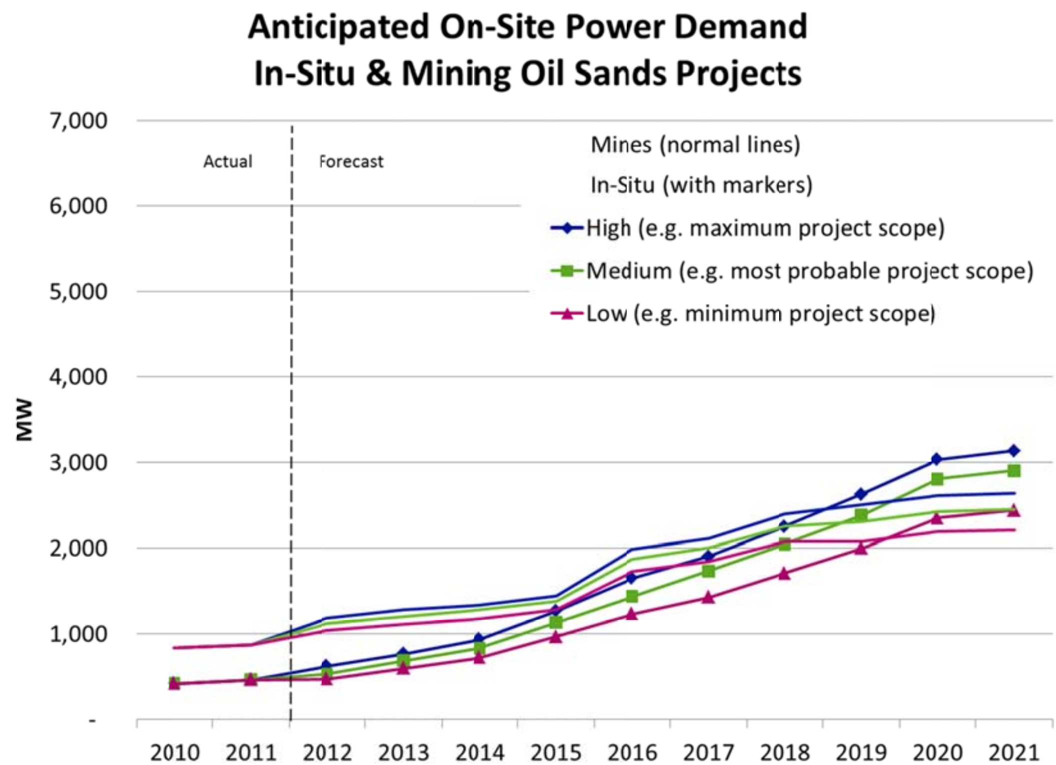


Similar to trends seen from the other 5-year forecast graphs above, the quantum of stand-by required is relatively in-line with 2011 estimates over the first half of the forecast period, rising beyond the 2011 forecast starting around 2018. The fact that the 2012 forecast results are surrounded by previous years' expectations of stand-by requirements implies that there has been a shift towards more conservative estimates since 2008-2010 when it comes to estimated stand-by requirements for oil sands operations. While most developers are planning to develop on-site co-generation there are those whom still rely, in part or fully, on power supplied by the Alberta grid.

Oil Sands Mining vs. In-Situ Developments

Survey respondents were also asked to identify the type of oil sands development; mining or in-situ. Out of the 135 projects included in this study, 20% were mining projects with the remaining 80% a form of in-situ development. Figure 14 presents the results of the 2012 survey with respect to on-site demand separated by oil sands development. Forecast power demand for mining operations are shown by straight lines while in-situ projects are illustrated by lines with markers.

Figure 14 – Anticipated On-Site Power Demand – Mines & In-Situ

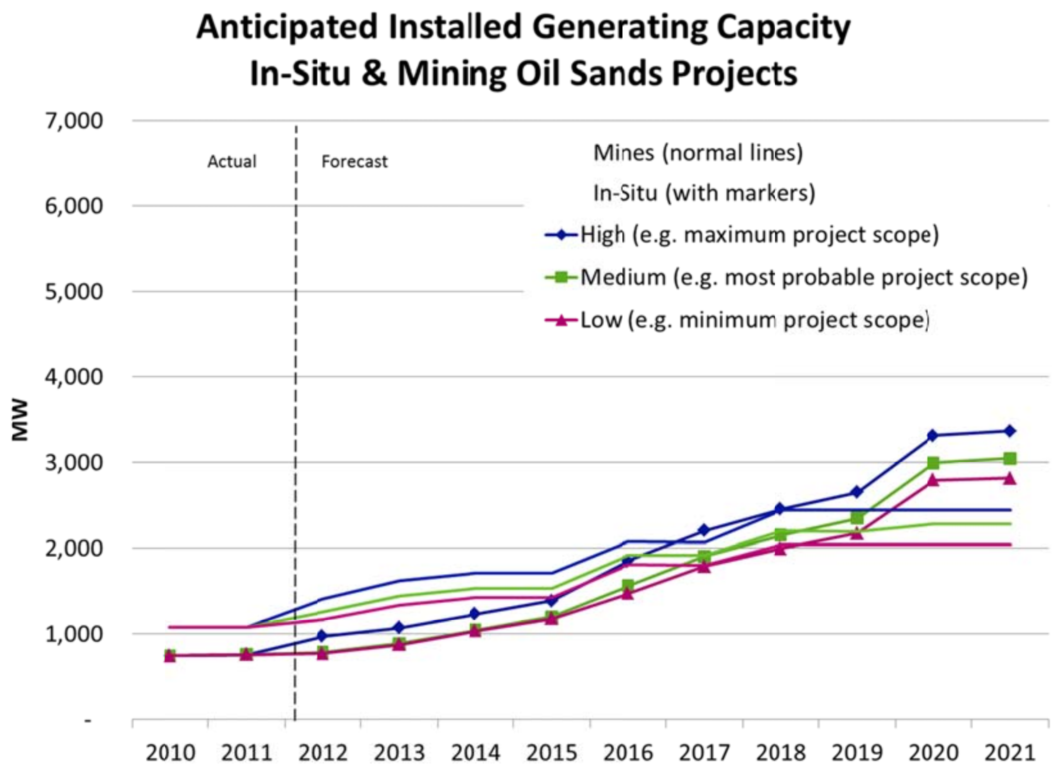


Currently, oil sands mines account for the majority of the electricity demanded from oil sands projects from about six existing mining operations. This trend continues until around 2015/2016 when additional in-situ developments begin to overtake the forecast for mining power demand.

Figure 18 provides insight into the electricity intensity of oil sands developments. While in-situ operations tend to be less electricity intensive (i.e. require less power to produce a barrel of oil), in-situ operations account for almost all future development activities. By 2019, in-situ projects are anticipated to account for the majority of power demand from the oil sands.

Figure 15 shows the breakdown of on-site co-generation developments based on oil sands process. As can be seen from the figure, the difference between mining and in-situ on-site co-generation development is a lot closer than the spread between power demand. Again, it isn't until 2015/2016 when in-situ projects begin to overtake mining operations as the majority of the installed generation capacity.

Figure 15 – Anticipated Installed Generating Capacity – Mines & In-Situ



Net Export Potential

Net exports of co-generated power to the Alberta grid can have benefits to both the Alberta power market and generation owners. Typically, excess co-generated power is supplied to the Alberta market at low prices, a trend which is likely to continue based on the results shown in Figure 12. In aggregate, low priced co-generation can amount to a significant quantity of base load power supply. For co-generation owners, additional electricity produced can be done so with relatively little increase in the overall use of natural gas and would generate power market revenues that could help offset the cost of developing on-site generation.

The potential for net exports has, in part, influenced the trends in on-site co-generation development. In the early 2000's, power pool prices were generally higher and a transmission build, to move power out of the Athabasca region was anticipated. During this time, oil sands developers planned for excess co-generation capacity from oil sands projects to take advantage of these favourable market conditions. However, in the latter part of the last decade, it became apparent that transmission capacity to export surplus power from the Fort McMurray region was limited and power pool prices were more volatile. Developers responded by sizing their co-generation projects closer to on-site conditions, effectively lowering the forecast of net exports from oil sands developments to the provincial grid.

Looking forward, oil sands developers are faced with higher forecast power prices, increasing transmission tariff costs, and promise of a significant transmission build, including a higher import limit by 2017 from the first of two new 500 kV lines from the Edmonton area to Fort McMurray (currently planned for 2017 and 2023).

Developing on-site co-generation can represent a significant undertaking, in a potentially non-core area, with no guarantee of stable returns or transmission capacity to move generation in or out of Fort McMurray. While the *Electric Statutes Amendment Act* has passed, there is still some uncertainty regarding the potential cost and timing of the proposed 500 kV transmission upgrades within Alberta. It is anticipated oil sands developers will move with caution when deciding whether or not to build on-site co-generation and will seriously investigate the pros and cons of excess supply.

Figure 16 shows the survey results for the 2012 year from the survey responses from 2002 to 2011 and demonstrates the change in on-site demand and co-generation capacity forecasts. In general, the annual forecasts over the past 10 years show a "tightening" of demand and supply, starting with the year 2007 survey results. The gap began to widen starting in 2009 and continued through to the 2012 survey response.

Figure 16 – 2012 Forecasts from Surveys Forecasts (2002 to 2011)

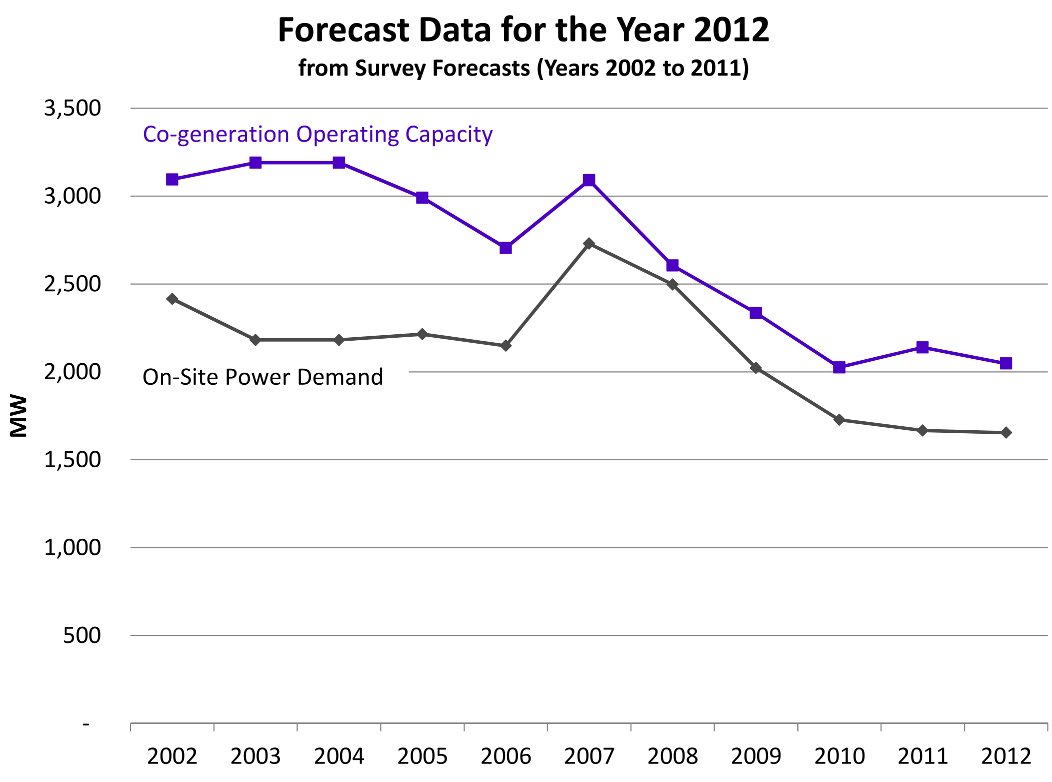
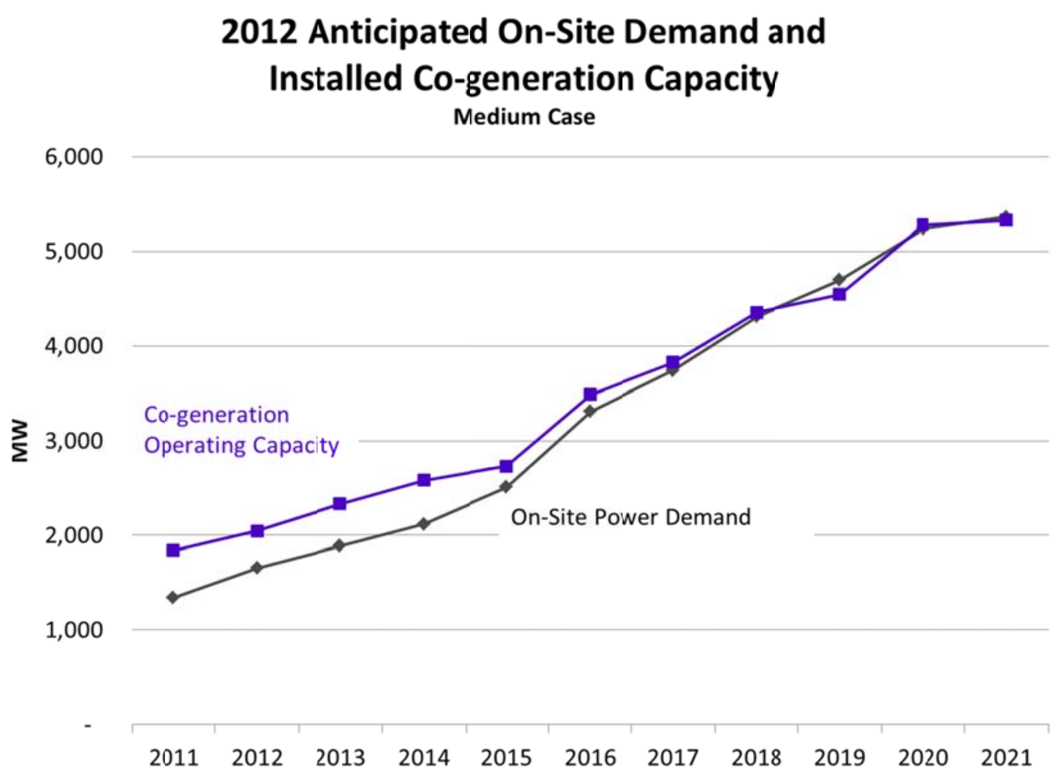


Figure 16 also provides a glimpse into the accuracy of prior forecasts. In general, if the lines were relatively flat, it would suggest there may not have been material changes in the survey results from year to year. Note, both on-site power demand and co-generation operating capacity are well below forecasts from 10-years ago, potentially reflecting caution when developing oil sands projects. Both timelines and estimates of electricity needs seem to have become more conservative over time, as key learnings from initial developments provide experience moving forward. In addition, changing economic conditions since 2002 will have significantly impacted the forecast outlooks. Recall, all-time highs in forward oil prices in 2008 were almost immediately followed by a global economic downturn and recession, remnants of which still impact the economy today. At the same time, oil sands developers in Alberta were faced with higher capital and operating cost estimates. These factors are just some of the few that will have influenced oil sands development decisions over the past 10 years.

Figure 17 demonstrates the 2012 survey results for on-site demand and co-generation operating capacity in relation to net exports (from the Medium Range). Looking forward, developers anticipate additional projects will be built with co-generation and both co-generation operating capacity and on-site demand will increase over the forecast period.

Figure 17 – 2012 On-Site Demand & Co-generation Capacity



Around 2016, co-generation capacity and on-site demand begin to approach each other as on-site power demand begins to increase at a greater rate than installed co-generation capacity. There is a significant amount of smaller oil sands in-situ projects (i.e. less than 25 kbpd) proposed to come on-line over the forecast period. These smaller projects are less likely to develop on-site co-generation and have an average power demand of around 50 MW. In aggregate, these smaller projects can become significant and could decrease the amount of net exports out of the Fort McMurray area.

Net exports are anticipated to increase by almost 375 MW or 28% by the end of the forecast period. Planned transmission reinforcements, concerns over increasing capital and operating costs, and future electricity supply and cost implications, will all continue to influence the decision whether or not to develop on-site co-generation. Future surveys will provide evolving insight into the position of oil sands developers and their potential influence on spot prices in Alberta's electricity market.

Regulatory Approvals

Figure 2 outlined those factors oil sands developers believe are influential when making the decision to build on-site cogeneration. In the 2012 survey, both Regulatory ISD and Market Fundamental ISD factors were of more significant relative to the 2011 survey results. Recall the regulatory ISD factor involves the time and resources required to obtain AUC approval for an ISD while the market fundamentals ISD factor centers on the potential tariff savings available for ISDs. On the other hand, DISCO Section 101 approvals remained as one of the least influential factors. The following summarizes oil sands developer's intentions with regards to Section 101 and ISD filings.

Section 101 of the *EUA* states sites must arrange for distribution service from the distribution system owner in the area. If the site wishes receive service directly from the transmission system, approval from the distribution system owner and the AESO must be obtained. Some consider Section 101 to be a deterrent to the development of co-generation. Wire owners are reluctant to provide Section 101 approval unless the oil sands developer has an ISD from the AUC. Recent regulatory precedents suggest an ISD can only be obtained once a generating unit has been ordered. Acquiring an ISD order can be an onerous and inefficient process, potentially resulting in process delays creating scheduling constraints. In addition, once distribution or transmission lines are built by a wire owning utility the value of a future ISD can be diminished. These constraints could force a developer to scale back the scope of a co-generation facility or cancel the co-generator altogether. Streamlining Section 101 approvals as they pertain to ISD's would enhance the efficient integration of co-generation facilities into an oil sands development.

As part of the 2012 survey, developers were asked to indicate if they have a Section 101 approval, have filed for a Section 101 approval, or plan to file for an approval. Of the 45 projects with plans for co-generation, Table 7 shows the *EUA* Section 101 stage for 33 respondents.

Table 7 – *EUA* Section 101

EUA Section 101

Stage	Projects	
Planned	14	42%
Filed	3	9%
Approved	16	48%
Total	**33**	

Relative to the 2011 survey, five more projects have obtained Section 101 approval with nine more projects indicating plans to obtain Section 101 approval. This further supports the findings that ISDs have become an increasingly influential factor in developing oil sands co-generation.

Oil sands developers were also asked to indicate if they have an approved ISD, have filed an ISD application with the AUC, or plan to file. Of the 136 identified projects (some of which include more than one phase of development), 46 indicated a response with respect to an ISD (Table 8).

Table 8 - Industrial System Designation (ISD)

Industrial System Designations

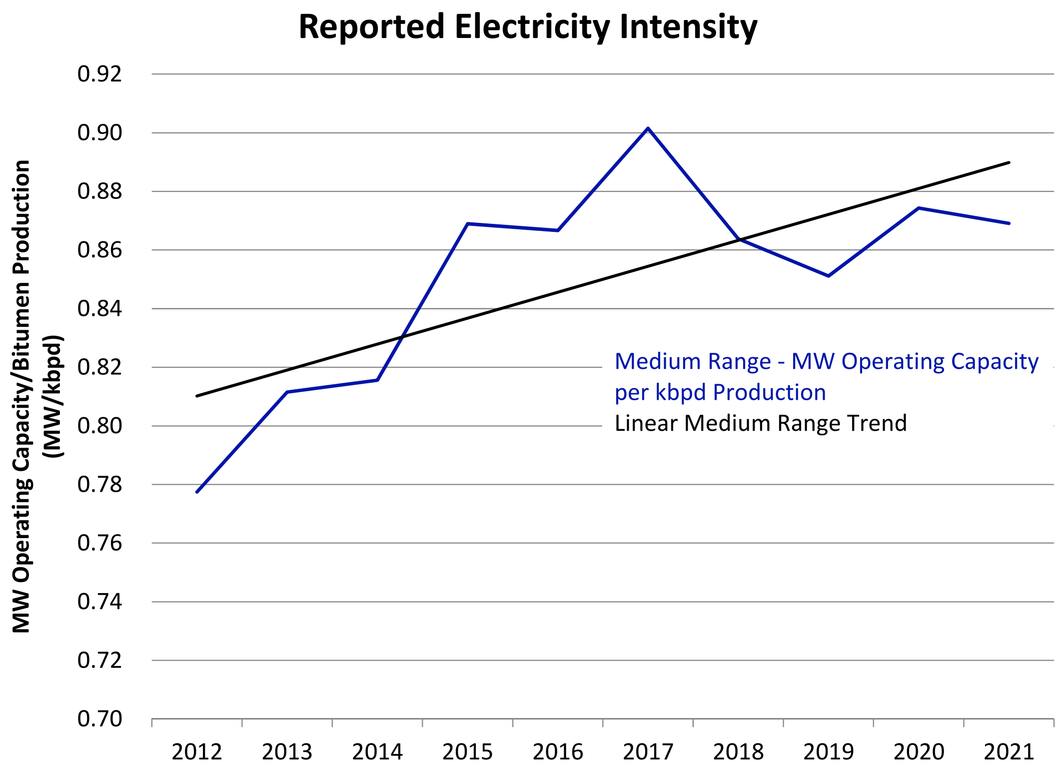
Stage	Projects	
Planned	23	50%
Filed	6	13%
Approved	17	37%
Total	**46**	

Half of the respondents indicated plans to obtain an ISD with 17 projects with an approved ISD. Note, these statistics may be skewed by projects being reported in phases. In most instances, all loads on a project site, which could include more than one phase, would be part of a single ISD. The number of projects planning on having an ISD has increased by ten from the 2011 survey results.

Bitumen Production

As part of the 2012 survey, oil sands developers were asked to provide estimated bitumen production under the High, Medium, and Low Ranges. In the Medium Range, bitumen production is expected to record an annual average growth rate of 20%. Some survey respondents chose not to provide a bitumen production forecast and as a result caution should be used when interpreting the growth rate and resulting electric intensity. Figure 18 illustrates the electricity intensity per thousand barrels per day for projects which provided a response.

Figure 18 – Reported Electricity Intensity



Note, the results were calculated based on the corresponding demand forecast for those projects which provided a bitumen forecast. As shown in Figure 18, the average electricity demand per thousand barrels of bitumen production per day (kbpd) is about 0.85 MW/kbpd. Over the forecast horizon, the electric intensity of bitumen production is anticipated to increase. This increase reflects more electric intensive production technologies, such as the introduction of water treatment technologies that have higher electrical intensity, offsetting any declines in newer and more efficient oil sands operations. The mix between mining and in-situ projects is also felt to influence electricity intensity year to year.

Duration Curve Analysis

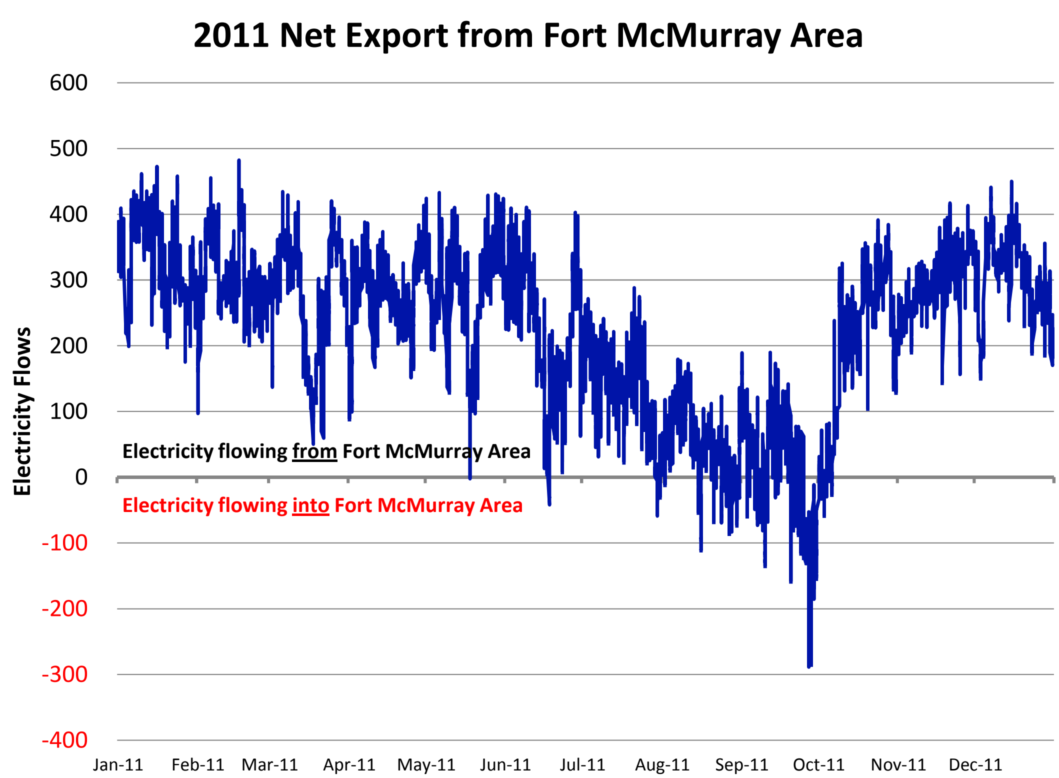
One of the shortcomings of the co-generation survey is the static nature of the reported data. Oil sands developers are asked to provide supply and demand capacities, which often reflect the value needed during a single occurrence, and can misrepresent typical operation levels. For example, a developer may forecast the need for 50 MW of stand-by capacity from the transmission grid; however, this stand-by capacity may only be required in a few hours per year. As the number of on-site co-generators increases to over 40 units by the end of the forecast horizon, there is a corresponding increase in the differential. It is extremely unlikely all 40+ projects will require stand-by capacity at the same time hence planning for transmission capacity for stand-by assuming all co-generators will rely on the transmission grid at the same time is not reasonable. Since co-generation units tend to be in service 95% or more of the time, the reliance on the transmission grid for stand-by is significantly less than the survey numbers may indicate.

Conversely, net export statistics out of the Fort McMurray area may be more indicative of day-to-day operations since, from Figure 11 it is clear there is excess co-generation capacity. In this study, net exports have been separated into two categories; Surplus Net Exports and Merchant Net Exports.

Surplus Net Exports typically occur regardless of the price for electricity. This could occur when an oil sands co-generator is required to run for on-site operations, with electricity in essence a by-product. If the co-generation capacity is greater than on-site demand, the surplus electricity is sold to the power pool as a "price-taker". On the other hand, Merchant Net Exports tend to be more closely tied to power pool prices. When power pool prices rise above the variable cost of electricity production, co-generators have profit motive to increase net exports. There are some generation owners that behave this way today.

Planning for transmission capacity for net exports is difficult as oil sands operations dictate if net exports will occur. To provide further insight, hourly transmission data for electricity flowing into and out of the Fort McMurray area was obtained from the AESO for all hours in 2007 to 2011. Figure 19 shows a plot of the 2011 data versus time, showing the random nature of electricity flows.

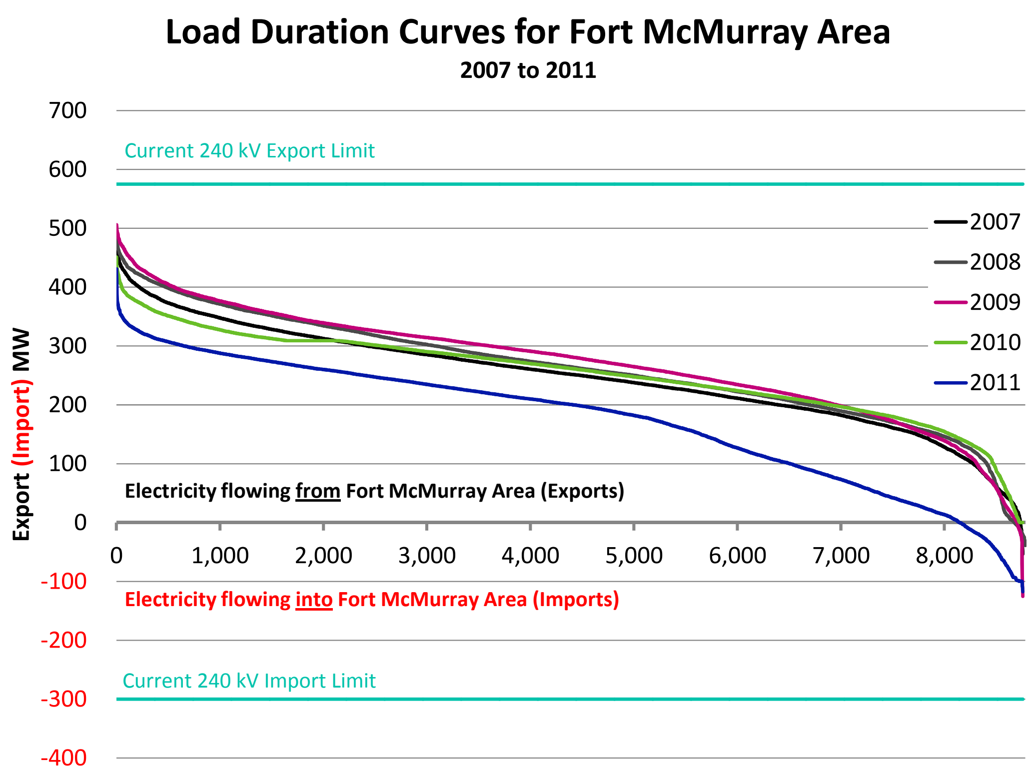
Figure 19 – 2011 Net Exports from Fort McMurray Area



The figure indicates electricity flows out of the Fort McMurray area most of the time; however, there was a significant amount of imports into Fort McMurray around Q3-2011. The 2011 net exports are different from previous years with considerably less net exports across the entire year and more net imports into Fort McMurray. At this time, it would be premature to characterize this as a shift in behavior with more years of data required to indicate a behavior change as opposed to a one-year event.

A more representative way to view this data is through a duration curve which orders data in descending order of magnitude plotted against the number of hours in the year. A duration curve can also be used to illustrate the relationship between transmission capacity and capacity utilization. The following duration curve (Figure 20) shows the same data as Figure 19 above, with data for 2007 to 2010 added for comparison purposes.

Figure 20 - Net Exports from the Fort McMurray Area Duration Curves

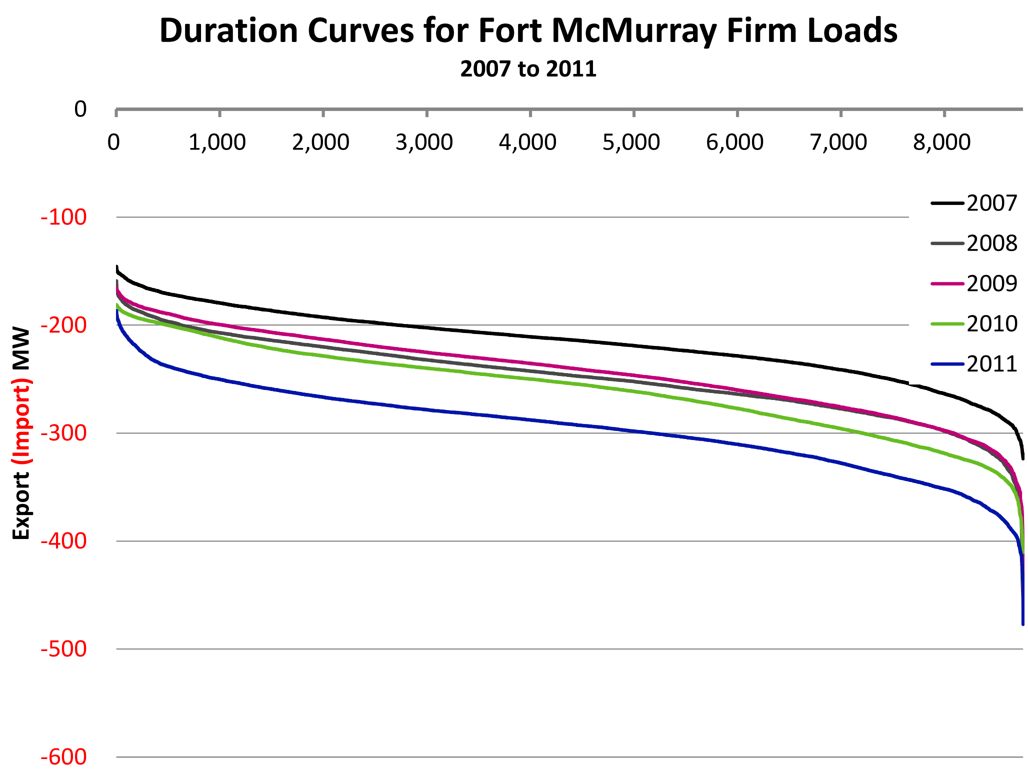


The duration curves in Figure 20 show that generation in the Fort McMurray area (mainly oil sands co-generation) is producing more electricity than the area's total demand over 93% of the time. For all but 7% of the hours per year, there were net exports of electricity out of the Fort McMurray area. Again, the overall decrease in net exports (and more hours of imports) in 2011 is not necessarily representative of a shift in behavior. This can indicate increased demand from firm loads, like the City of Fort McMurray, are being served by excess co-generation and/or reduced co-generation production in the Fort McMurray area is resulting in lower exports to the provincial grid. The duration curve also shows the significant quantities of co-generation available to the grid. In over half the hours in 2011, 200 MW+ was exported, most of which is from excess oil sands co-generation. If anything, the 2011 results further support the conclusion that exports from the Fort McMurray area are decreasing each year.

Also shown on Figure 20 are the current 575 MW export and 300 MW import limits from the three existing 240 kV lines into Fort McMurray. Currently, the AESO has plans to reinforce the reactive power capability by the end of 2012, forecast to increase the maximum export limit to 630 MW and the import limit to 440 MW.[5] Import and export capability is anticipated to be increased further in 2018 with the addition of the first, of two, 500 kV lines from the Edmonton area to Fort McMurray (the second 500 kV line is planned for 2023). If additional co-generation is developed (or load is reduced) increasing the need for transmission capacity before additional transmission becomes available, the AESO may have to restrict generation output or curtail load due to transmission capacity limitations.

To assist with projecting future transmission requirements and incorporate the 2012 survey results, the 2011 hourly load flow data was segregated into firm load (City of Fort McMurray load) and oil sands related load (including transmission connected loads). Figure 21 shows the duration curves of the firm loads from 2007 to 2011, which tends to vary between about 200 MW and 400 MW.

Figure 21 – Duration Curves for City of Fort McMurray Firm Loads



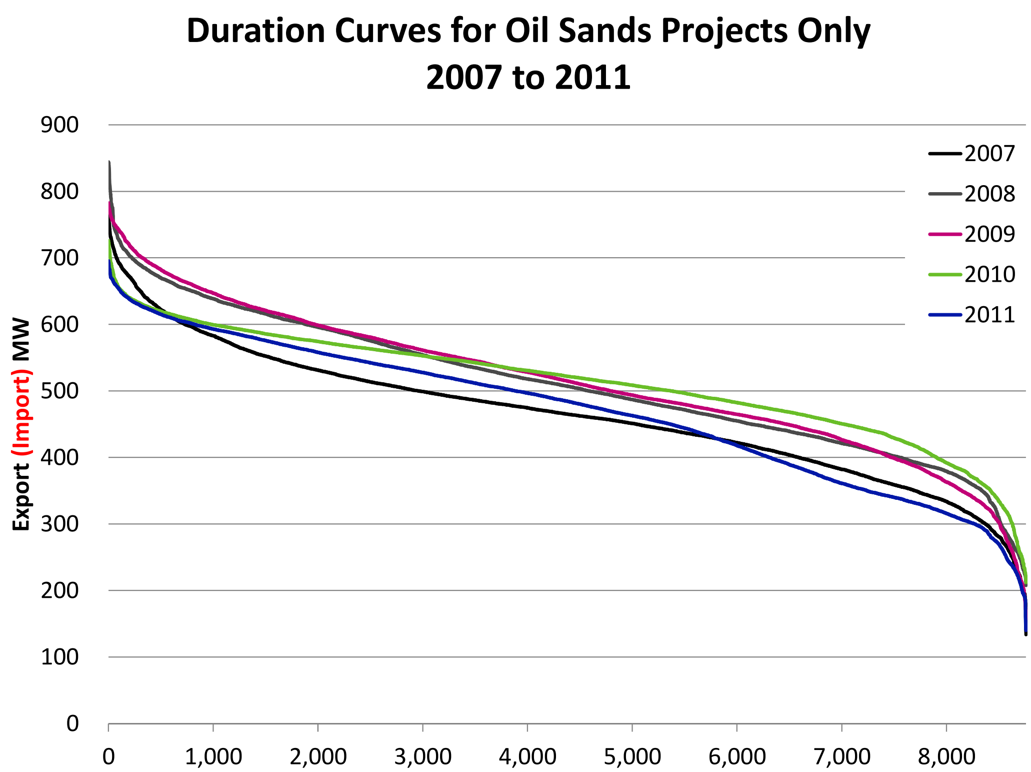
As to be expected, the firm load from the City of Fort McMurray is completely imported from the provincial grid. City of Fort McMurray firm load growth has recorded an average 8% annual growth rate since 2007.

The duration curves of oil sands related electricity flows (loads and generation) have the following shape (Figure 22), excluding firm loads. As can be seen from the figure, oil sands projects in the Fort

[5] See http://www.aeso.ca/downloads/24_Month_Reliability_March_2012_final.pdf, page 42

McMurray area provide net exports of electricity to the grid in every hour in 2007 to 2011, averaging just less than 500 MW. Note, the atypical behavior of the 2011 curve is, in part, the result of net export behavior out of the Fort McMurray area and does not reflect firm load behavior which tends to be relatively stable year-over-year.

Figure 22 – Duration Curves for Oil Sands Projects Only



Looking to the future, the 2012 survey forecasts for on-site demand and co-generation operating capacity were modeled against the 2011 hourly load flow data, to provide an estimate of hourly flows into and out of the Fort McMurray area in 2018 and 2021. The following outlines the methodology used to estimate these flows.

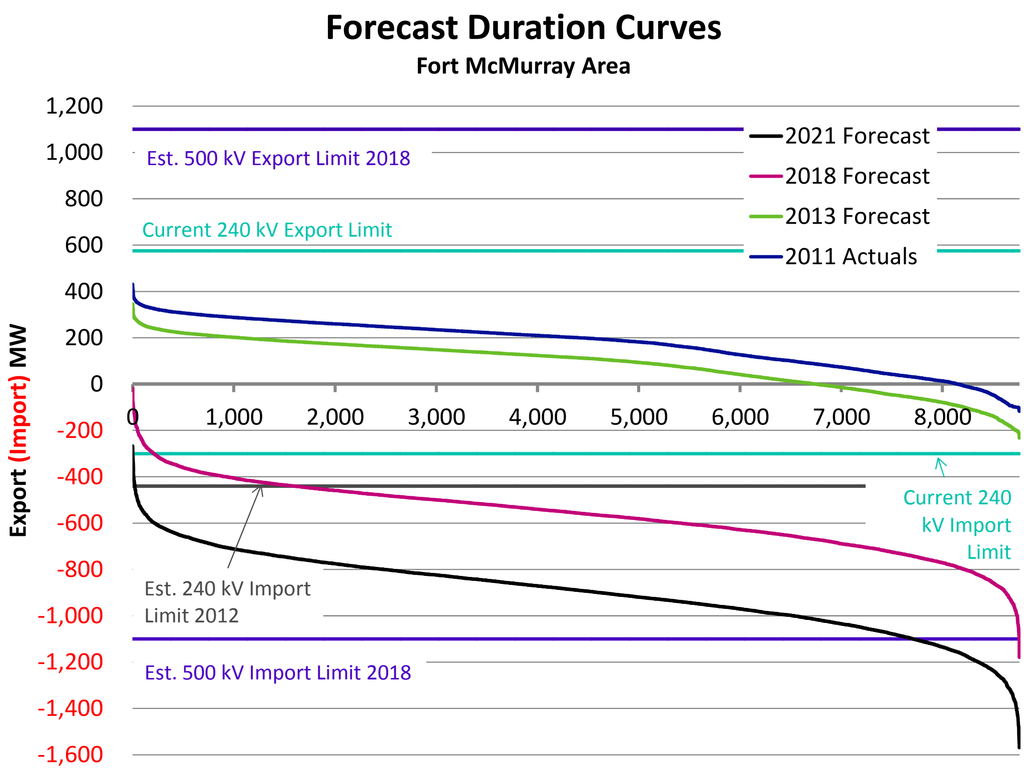
Based on the consistent nature of firm load from Fort McMurray over the past five years (Figure 21), it is assumed the firm load shape will not materially change over time and grow at 8% per year. Oil sands related load and generation hourly behavior and additions were derived from 2011 hourly flow data and the 2012 survey results, respectively. As well, the following assumptions were included:

- Each co-generation project operates 95% of the time (2.5% of the time down for planned maintenance and 2.5% of the time down for unplanned maintenance).
- Oil sands operations have a load factor of 85%.
- Capacity and timing of stand-by requirements and generation exports were determined hourly, on a probabilistic basis, for each load and generation project included in the 2012 survey (Medium Range).

- No consideration of wholesale power prices was allowed to influence the results (i.e. all net exports were assumed to be from surplus on-site generation behaving as price takers, with no additional electricity produced as a result of higher market prices).

The results of the analysis are shown in Figure 23 for the years 2013, 2018 (after first 500 kV line added) and 2021, with the 2011 data from Figure 20 shown for comparison purposes (including City of Fort McMurray firm load). The figure shows the results of the unadjusted on-site demand and co-generation values.

Figure 23 – Forecast Flow Duration Curves for Fort McMurray Area



The analysis suggests near term electricity flows will continue to approach the existing export and import transmission line capacities (illustrated by the teal "Current 240 kV Export/Import Limit" lines). In the past, the main concern has been export transmission capacity limiting flows out of Fort McMurray. The figure suggests over time, the key transmission limitation may be insufficient transmission capacity for imports (i.e. electricity flowing into the Fort McMurray area).

Recall the forecast duration curves include firm load (i.e. load from the City of Fort McMurray). This load, which is anticipated to record 8% growth over the forecast period, will likely be served from excess co-generation supply, reducing electricity flows from the Fort McMurray area to the rest of the province. Consequently, despite significant quantities of surplus generation forecast, net export electricity flows diminish over time.

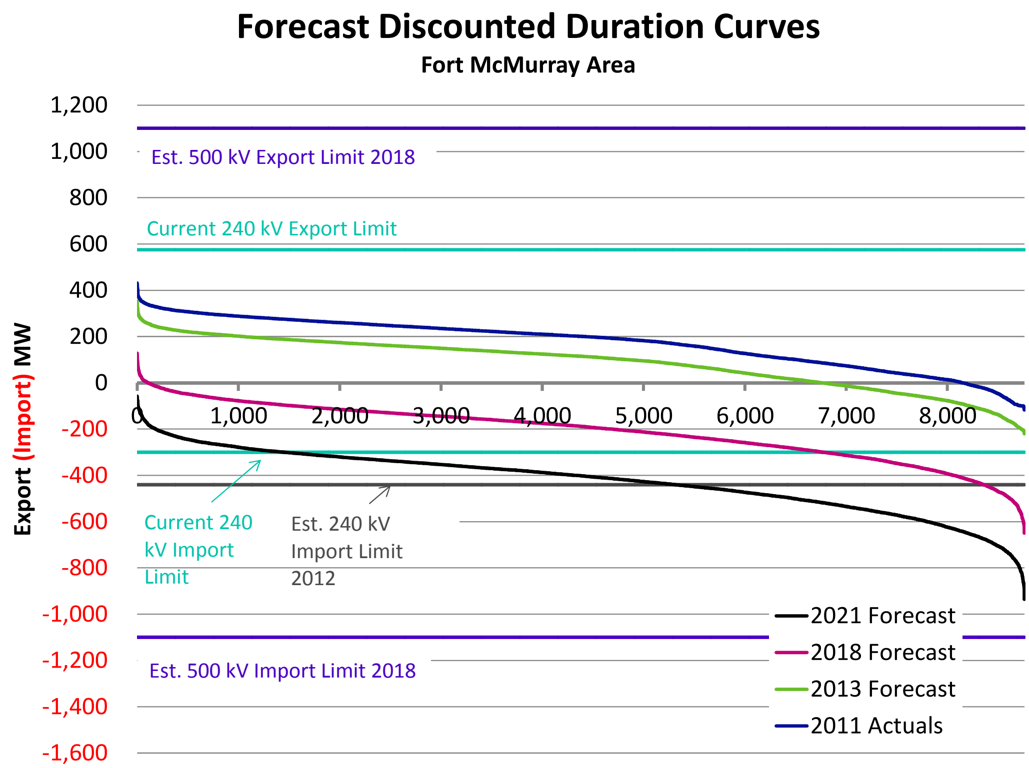
In 2013, the highest import value forecast is around 230 MW, approaching the current 300 MW import limit (green line approaching the teal line), suggesting there will be sufficient 240 kV transmission capacity for imports into the Fort McMurray. The addition of the reactive power capability will provide a significant buffer when the import limit is increased from the current 300 MW to the planned 440 MW, scheduled for Q1-2012 in the AESO's current timeline. The forecast anticipates an increase in the number of import hours, with 23% of the year exported to record imports into Fort McMurray.

Consistent with previous studies, more imports are anticipated over time (2018 and 2021 projections) as electricity demand in the Fort McMurray area grows at a faster pace than electricity co-generation additions. Table 5 and Table 6 showed that the majority of oil sands developers plan some form of on-site generation with support from the transmission grid serving a portion of on-site demand. Multi-phase projects can also influence electricity flows as there is often an energy imbalance as load or co-generation is over built until additional phases come on-line and use up the excess capacity. The increased reliance on imports from the grid could result in oil sands projects being required to, under AESO policy, involuntarily curtail load, potentially leading to reduced bitumen production.

The 2018 forecasts imports will be greater than the 440 MW limit over 80% of the year. However, with the commissioning of the first 500 kV line, the 1,100 MW import limit in place there will be sufficient transmission capacity for most of the year, with at least 1 hour recording imports greater than the first 500 KV import line limit. By 2021, there are slightly more forecast load additions in the Fort McMurray area than generation additions, with a large number projects or phases scheduled to come on-line at the end of the forecast period. This results in a 2021 forecast duration curve that suggests additional import capability will be required into the Fort McMurray area, beyond the first 500 kV line proposed for 2018. Note, the transmission line limits are based on N-1 contingencies; consequently, if one of the two 500 kV lines was out of service, load customers could be curtailed. Comparing the 2011 data (blue line) to the 2021 forecast (black line), imports into the Fort McMurray area are forecast to increase from about 7% of the time in 2011 to 100% of the time in 2021.

Figure 23 assumes all oil sands projects will proceed as reported in the 2012 survey. If projects are discounted (as discussed throughout) the forecast load duration curves show significantly lower levels of imports in 2018 and 2021 (Figure 24).

Figure 24 - Forecast Flow Duration Curves for Fort McMurray Area (Discounted Results)



The significant decrease in forecast electricity flows using the discounted data set further shows the impact of the average 50% discount applied to over half the projects. Similar to the previous figure, the 2013 discounted forecast duration curve is within the current export and import capabilities. In the latter years of the forecast, the impact of the discounting methodology is more pronounced as projects planned for those years are often in the early stages of development, receiving the largest discounts. The 2018 and 2021 discounted forecast duration curves exceed the current 240 kV lines import capacity of 440 MW in 5% of the hours and 40% of the hours, respectively. Even in the discounted case, the first of the planned 500 kV lines to Fort McMurray would be required to meet the 2018 and 2021 forecast import volumes.