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An Economic and Policy Assessment for a more Sustainable Electricity Grid in Alberta

by

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Abstract:

This research investigates whether integrating distribution connected generation projects is more sustainable than transmission connected generation projects in Alberta. To test if incorporating more distribution connected projects into the electricity grid was in the best interest of Albertans, a case study of a 20MW solar project was tested via a transmission and distribution grid tie in. Additionally, a benefit cost analysis was performed to assess if deferring the cost of long-term transmission upgrades with distribution system upgrades was a superior option. Finally, a survey of stakeholders was conducted to see if there was support for changes to the tariff system to support additional distribution connected projects. Results showed it was less expensive to upgrade the distribution system and produce electricity via distribution-connected projects. Survey results show that Albertans support changes to the tariff system to promote distribution connected projects making the electricity grid more sustainable in the long term.

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List of Abbreviations

AESO: Alberta Electric System Operator

Alberta: Province of Alberta

AUC: Alberta Utilities Commission

BCA: Benefit-Cost Analysis

C°: Celsius Degrees

CAN: Canadian Dollars

CAPX: Capital Costs Expenditure

CO2 : Carbon Dioxide

DCG: Distribution Connected Generator

GHG: Greenhouse Gas

EV: Electric Vehicle

IRR: Internal Rate of Return

kW: Kilowatt

kWh: Kilowatt-hour

LCA: Life Cycle Assessment

MISO: Midcontinent Independent System Operator

MWh: Megawatt-hour

NPV: Net-Present Value

NREL: National Renewable Energy Laboratory

OPEX: Operation Cost Expenditure

PPA: Power Purchase Agreement

PV: Photovoltaics

SAM: System Advisor Model

SMP: System Marginal Price

UN: United Nations

USD: United States of America Dollars

W: Watt

Wdc: Watt direct current

Chapter 1: Introduction

The electricity generation market in Alberta is undergoing a massive change. The traditional model of centralized electricity generation, connecting consumers through their transmission and distribution partners is being displaced with small, decentralized generation projects connected directly to the distribution grid. These Distribution Connected Generation (DCG) projects represent a rapidly emerging segment of the electricity supply in Alberta (Patel, 2020). Renewable energy projects are taking up a larger share of the total new electricity generation capacity in Alberta and DCG projects are expected to increase in both size and number the future (Doluweera et al., 2020). In a DCG project the electricity is used locally by consumers within the local distribution network and does not use or enter the transmission system.

Every ratepayer in Alberta is charged a for the use of the transmission system regardless of whether the electricity they consumed ever used the transmission network (AESO 2022a). This study will attempt to understand if the current tariff system for electricity billing in Alberta is just or if transmission companies are being unfairly supported for a service they have not provided.

On June 7, 2021, the Alberta Utilities Commission (AUC) released decision 26090-D01-2021 which requires that credits given to DCGs be suspended (Alberta Utilities Commission, 2021). DCG credits are intended to compensate small generators that are not connected to Alberta's transmission grid for supplying electricity to utilities (Fortis Alberta, 2018). The credits were implemented initially as an incentive to small electricity generators to produce electricity directly into the local distribution grid where they reduced the burden on the transmission grid and subsequently reduce friction loses in transmission (Wirfs-Brock, 2015). In return for not using the transmission grid, many utilities pay DCGs a DCG Credit. These credits are intended make up the difference between what the utility would have paid for electricity off the transmission grid and what it actually paid by using the DCGs' power (Chapman, 2021). As a result of the suspension of DCG credits transmission scale generation projects (>25MW) became significantly more economic as the cost of transmission is paid disproportionately by the consumer. Transmission scale projects may not necessarily be more economic than distribution projects when the total cost electricity is compared because there are significant capital costs associated with building the transmission lines and there are significant losses in the transmission network as electricity is moved over long distances (Wirfs-Brock, 2015). As a result of the abolishment of DCG Credit program the consumers of distribution scale electricity generators are forced to pay for transmission charges regardless of if the electron travels 1km using only the distribution network or via a 1000km of transmission infrastructure. The nature of distribution grid connections means that the electricity is generally used in the local area therefore, in essence, the ratepayers are effectively subsidising the transmission companies as transmission charges are added to every ratepayers electricity bills regardless whether or not the electricity was transported via regional transmission lines.

1.1 Background

Transmission infrastructure is both environmentally degrading and capital intensive. Transmission line corridors create long linear disturbances on the landscape that affect both animal, such as woodland caribou (DeCesare, 2012) and bird populations and migration habits (Ferrer et al., 2020). The visual appearance of transmission lines negatively impact the appearance of the landscape (Sullivan, 2014) and the building of tower suspended lines is receiving increasing resistance from land owners and environmental groups (Ross, 2021). As a result of this local resistance, transmission lines are being rerouted or in some cases in Europe even buried underground. The capital cost associated with these subterranean lines are substantial (globaltransmission, 2016) and the costs are eventually passed back to the ratepayer. Additionally, from a full life cycle perspective the GHG emissions and environmental degradation form the mining of metals required for the transmission towers and cables is significant (Harrison, 2010).

In Alberta, there is a need to expand the electricity system to meet the needs of consumers as the energy transition intensifies. Electric vehicles (EV) and electric heating in addition to the expanding population base requires significant upgrades to the electricity system (AESO, 2022b). These changes include the expansion of the transmission system to connect remote large scale utility renewable energy projects to the grid. As a result of these expansion projects the cost of transmission rates in Alberta has increased five-fold from $5MWh in 2004 to $25MWh today (Government of Alberta, 2022). Additional transmission infrastructure is currently planned to bring on more renewable energy projects. The cost for this infrastructure is paid predominantly by the ratepayer, as the generators connection fees are refunded over the first 10 years of the project (Electric Utilities Act, 2003).

Electricity costs in Alberta are divided into three components, firstly the cost of electricity, secondly the cost of distribution and thirdly the cost of transmission. Based on the authors personal residential utility bills for a property on the border of the City of Calgary, these components make up 38%, 30% and 22% of electricity cost respectively. Considering that just over one third of the total cost of a ratepayer's bill is the electricity cost, it is critically important to ensure that the cost of delivering electricity is managed as efficiently as the generation of the electrons themselves. As the Smart Grid, EVs, battery storage and DCG project's roll out across the electricity network, questions must be raised whether the existing tariff system is fit for purpose. The current tariff system that supported development of hydro or coal fired generation in the hinterlands of the province, linked to a transmission and distribution system to move the electricity to market originated in the Edwardian era and may not be appropriate to support the electricity grid of the future (Yergin, 2011). All decisions that the AUC makes are framed within the context of the hub and spoke grid and the tariff system that support it. The AUC acknowledges that there are alternative systems in other jurisdictions that "recognise the value of distributed energy resources based on avoided cost" however, the confines of the existing government regulatory framework "would likely require government policy direction, as well as amendments to the regulatory framework" to implement (Alberta Utilities Commission, 2021).

1.2 Goals, Objectives and Interdisciplinary Aspects

This project will investigate if the expansion of distribution scale generation projects could help reduce the total cost of electricity in Alberta while still providing a highly reliable electricity grid. From a sustainability perspective, does better utilizing the existing distribution infrastructure helps reduce or defer the need for new transmission projects? Thereby reducing both the social and environmental burden of electrical costs which promotes a strong robust economy (Batlle, et al., 2012). This research will integrate economics, energy, and the environment into multidisciplinary study on the electricity grid in Alberta. The UN sustainable development goals that will be addressed are Affordable and Clean Energy (#7), Decent Work and Economic Growth (#8), and Sustainable Cities and Communities (#11).

Chapter 2: Methodology

This research will assess the private economics of a utility scale solar project, a social benefit cost analysis (BCA) and a survey/interview of stakeholders in the electricity system in Alberta to understand if DCG projects are a more sustainable alternative to transmission connected generation projects. The first phase of this research will investigate the economic performance of a commercial scale 20 MW photovoltaic solar project connected to the electricity grid via either the distribution or transmission networks. The distribution connected project will be tested with and without the DCG credit applied. As a result, three economic models will be evaluated. An economic comparison of the three projects will be conducted using SAMs (Blair et al., 2018) renewable energy modeling software. The key difference in the distribution versus the transmission connected projects arises from the costs associated to tying the project to the grid. The distribution connection requires the upgrading of the existing distribution line network whereas the transmission tie-in requires the buildout of a short transmission spur line. A comparison of the economics of these alternative projects will then be undertaken.

The second phase of the study will undertake a Social Benefit Cost Analysis (BCA) of the distribution connected versus transmission connected generation projects. The BCA looks at the benefit or cost of replacing the need for long term transmission system upgrades with an increased penetration of distribution connected electricity projects. The bases of the economic parameter used in the BCA are from the AESO "2022 Transmission Rate Projection" document (AESO 2022b). This projection shows that between 2022 and 2042 the cost of providing transmission services for Albertan Ratepayers will increase by 45%. The BCA will investigate if displacing the long-term transmission upgrade costs with a greater proportion of distribution connected generation projects would be of net benefit for Albertan ratepayers. For this study only the long-term transmission upgrade costs from 2032 to 2042 were evaluated, the near term and medium-term costs were unchanged. The BCA will not only look at direct electricity cost but also address less quantifiable issues such as reliability, life cycle costs, GHG emissions, ecological impacts, and employment rates.

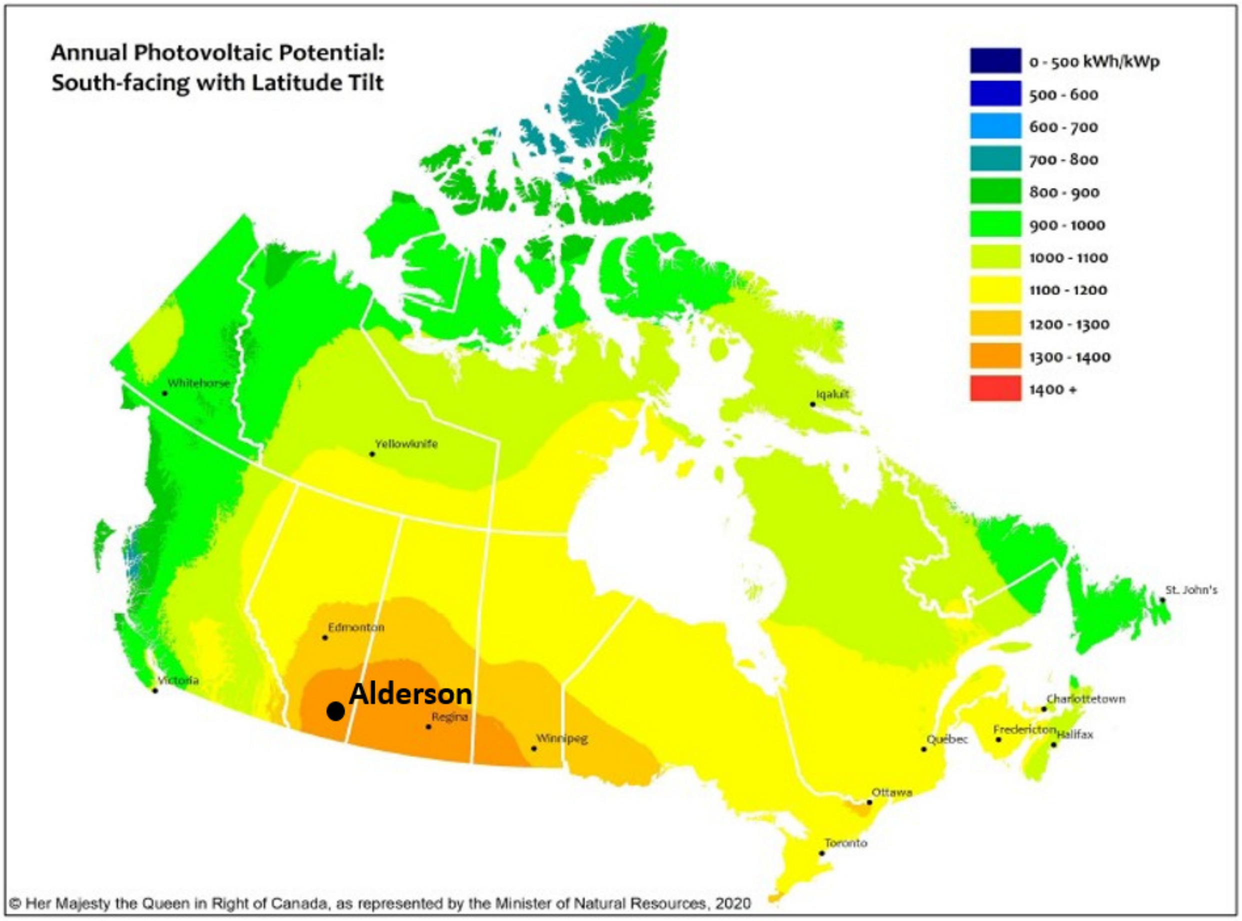
The final aspect of the study is a survey and interview of various stakeholders in the electricity system in Alberta. The survey and interview attempt to address if there is support for alternative methods of providing electrical services other than through transmission connected projects, and if there is support for smaller DCG projects connected to the distribution grid. Finally, the survey asks if stakeholders would support changes to the existing tariff scheme to increase the sustainability of the electricity grid in Alberta. The survey and interviews were conducted on a spectrum of stakeholders and include residential ratepayers, industrial ratepayers, generators, and integrated electrical service companies.

Chapter 3: The Alderson Solar Project

Alderson is located in southeast Alberta between Medicine Hat and Brooks on the Canadian Pacific Railway Mainline and the Trans Canada Highway. This region is one of the sunniest and driest parts of Canada and has an excellent solar resource. Figure One shows that Alderson is in Canada's best solar resources zone with 1300-1400kWh/kWp. This region of Southern Alberta has numerous new solar projects, and the development of these projects is part an economic diversification of this region's economy (Jones, 2022)

Figure 1:

Map of the Solar potential in Canada with the Alderson Solar Facility indicated

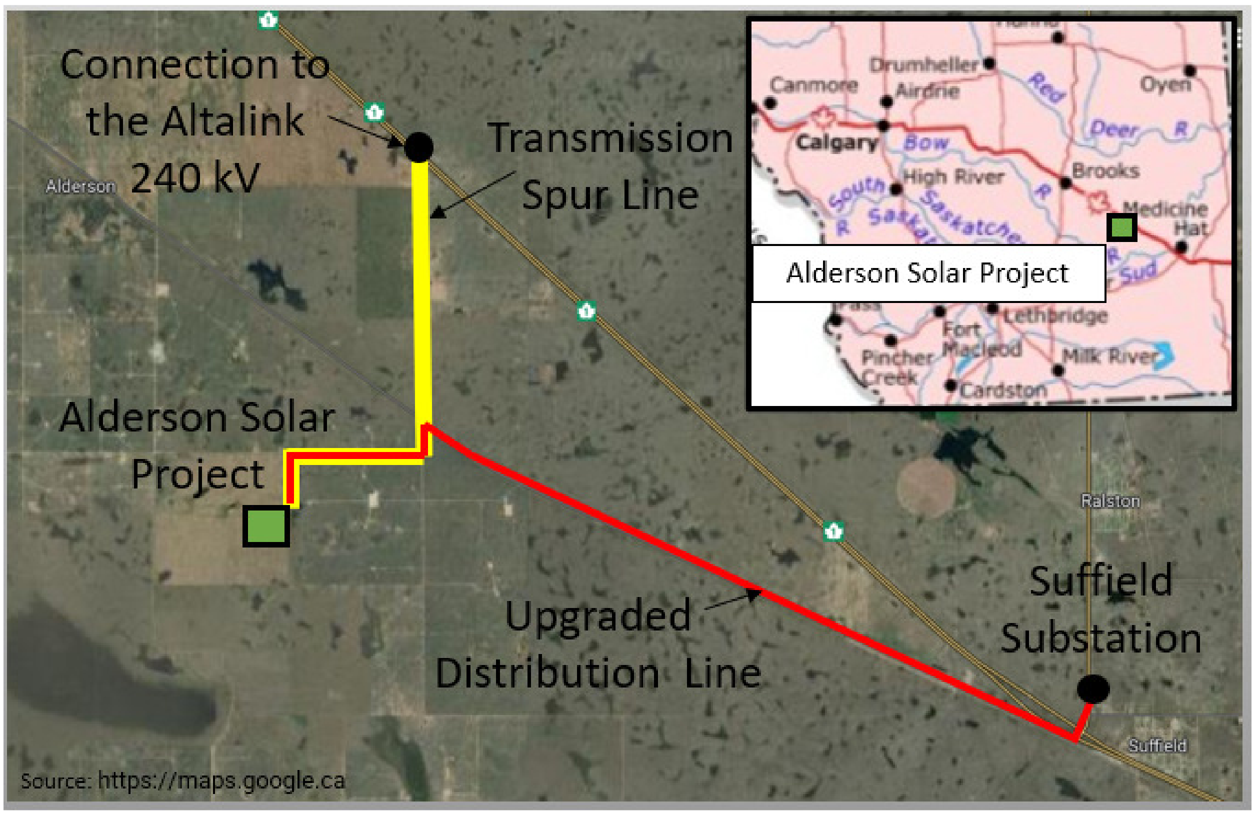


Note: Canadian Ministry of Natural Resources 2020.

The location of the 20 MW solar field is 4km south and 2.5km east of Alderson, Alberta on the Southeast Quarter of Section 9 township 15 Range 10 West of the 4^{th} Meridian. The Latitude of 50.25N and -111.3E Longitude was used to calculate the solar resource in the SAMs model (Blair et al., 2018). The map in Figure 2 shows the location of the Alderson Solar project area and existing transportation infrastructure in the area.

Figure 2:

Map of the Alderson and Suffield region showing the Section 9-15-10W4 and the project area within it.



Note: Author (2022). The location of the Trans Canada Highway and CP Mainline indicated on the map.

3.1 SAMs model

The System Advisor Model (SAM) is a free techno-economic software model that allows for planning and the economic assessment of renewable energy projects and is one of the key software modeling tools used in the renewable energy industry (Blair et al., 2018). SAM is developed in United States by the National Renewable Energy Laboratory (NREL) and is funded by the US Department of Energy. The program has a wide range of uses but the Solar model is well established and trusted in the industry to analyse the solar potential and the economics of a photovoltaic solar energy project.

Being a US product one of the key elements in using the program is that it uses US dollars as its currency. Therefore, for use in Canada all inputs and the resulting economic forecast need to be converted from US to Canadian dollars. An exchange rate of 1.3 CAN/USD was used to convert between currencies. The input to the models themselves is tested against industry standards and adjusted frequently to reflect the changing cost of products and services such as construction and installation to reflect inflationary pressure and supply chain affects. The key parameters affecting the performance of the solar field include the solar module, inverter, tracking system, interest rates, Capital (capex) and operational (opex) costs and depreciation. For the purpose of this study the majority of these parameters have been kept constant across between the projects with the exception of the costs associated with the grid connection via the transmission or distribution network. A description of these parameters and why they were selected is listed below.

3.2 Solar Module

The choice of Solar Module used was guided by what other solar operators have chosen in the area. Bi-facial modules mounted on a single axis tracking mount are most common. The bi-facial modules help capture the reflected light onto the back of the module. This is particularly beneficial in the winter when there is snow on the ground and the light is reflected towards the sky. The dual faces of the module allow this reflected light to be captured rather than returning to space as shown in Figure 3.

The choice of what specific module to uses was guided by the industry sponsors for this project that had done specific research on what the optimal module is for the climate in SE Alberta. This module is the LONGi Green Technology Co. Ltd. LR5-72HBD-540M. This uses monocrystalline silica and has excellent nominal efficiency at 21.72% and has a loss of -1.747 W/C° or -0.323 %/ C°.

The modules are mounted on a single axis tracking mechanism orientated at 180° or North-South, allowing the modules to pivot catching the sun as it traverses across the sky each day from east to west.

Figure 3:

Example of bifacial photovoltaic solar modules mounted on single axis tracking systems.

Note: From Bluearth Renewables (2021)

3.3 Inverter

The inverter choice was again advised from industry partners based on their experience. The Sungrow Power Supply Co Ltd. SG250HX – US (800V) was chosen based on performance and cost. It has a CEC weighted efficiency of 98.691% and an exceptionally flat rated output power curve.

3.4 System Design

To reach a name plate capacity of 20 MWdc a total of 36,972 modules and 73 inverters are used. The modeling software in SAM optimises the layout and design of the array so that 26 modules are arranged in each string. These modules are arranged to make 1,422 strings in parallel. This arrangement creates a solar module array totaling 92,060 m^2 or 49.3 acres or 9.21 hectares.

3.5 Soiling and Degradation

To adjust the soiling model to reflect the fact that snow will often cover the panels in winter months the default system parameters of 2% soiling were adjusted. The soiling factor for the months of November, December, January, February, and March were increased to 10% to allow for snow cover and frost. In April and October, the soiling factor was increased to 5%. For the remainder of the year, May through September the soiling factor was kept at the default of 2% to reflect that dust, insects, and bird droppings effect output. The average soiling factor for the year was 5.8%.

The degradation factor used for the modules was kept at the default SAM parameter of 0.5%. As a result of this degradation in the efficiency of the panels total electricity production drops from 33,600 MWh/y in 2024 to 29,700 MWh/y in 2049.

3.6 Capital Cost (CAPEX) -Direct and Indirect

Capital costs for the Alderson solar project are separated into two distinct categories. First are the direct equipment cost and labour and other professional service costs required to design and construct the facility. These costs are constant across all three scenarios tested. The second type of cost is related to the grid interconnection. Due to the distance and route to connect to either the transmission lines or the Suffield Substation there are significant differenced to costs of grid connection.

Direct capital costs include $8.2 Million USD and $1.0 Million USD for the solar modules and inverters respectively. The balance of the system equipment is $4.0 Million USD.

Labour and professional services for the installation is $3.4 Million USD. For a total of $16.6 Million USD.

3.6.1 Transmission Connected CAPEX

Indirect capital cost includes $1.6 Million USD for engineering, permitting and environmental studies. The cost of the grid interconnection in SAM's assumes that the facility is directly adjacent to the transmission line or the distribution grid substation. The Alderson Solar facility is located 6km from the closest transmission connection (Figure 2). The cost to build a new spur transmission line is estimated at $4.5 Million USD based on a $750,000/km cost estimate (Lucas Duffield PNE Canada pers. com.) Therefore, the total indirect capital cost for the transmission connected project are $7.1 Million USD. Giving a total project capital cost including 3% contingency and tax of $25 Million USD. This translates to a cost of $1.25Wdc.

3.6.2 Distribution Connected CAPEX

Capex for the distribution connected project is identical to the Transmission connected project with the exception of the grid interconnection costs. The distribution connected project will upgrade the wiring on the existing power poles however, there is limited need to instal new poles. New wire will be strung along the 12.5 km route (Figure 2) at a cost of $300,000/km for a total cost of $3,750,000 Canadian Dollars or $2,887,500 USD.

3.7 Operating Cost (OPEX)

The operation cost for both the transmission and distribution connected models is the same and have been left with the default SAM parameters of $15 USD kW/year increasing by 2% annually. The cost to lease the land has also been included in the OPEX costs uses a value of $CAN 400/acre/year which is the known solar lease rate in the area. This is converted to USD for consistency in the SAMs model. The SAM calculated a total area of 50 acres to be occupied by the solar facility.

3.8 Financial Parameters

The analysis period for the project was set for 25 years and over this time the inflation rate was set to 2.5% and the real discount rate was set to 6.4% making the nominal discount rate 9.04%. For modeling purposes, the project is to be to be constructed in 2024 and put into operation in 2025. The module life span is 25 years so there are no expected material capital cost inputs until the decision to replace the modules or decommission the project is made in 2050.

Tax on the project is set to the current Canadian federal tax rate of 15% an additional 8% provincial tax rate payable to the province of Alberta is also included in the analysis. Property taxes are also payable to the County of Cypress and were calculated at 0.1% of the project value of $25 Million USD therefore the property tax payable is $25,000/year.

To finance the project 80% of the total $25 million was financed at an interest rate of 4%/year.

3.9 Revenue

The revenue for electricity sales via a Power Purchase Agreement (PPA) set at $77 Canadian dollars per MWh from internal IRRICAN Power forecasts. These prices generally align with public data shown by Barron, 2020 of $69 MWh Canadian. Since 2020 electricity prices have increased as a result of increasing natural gas prices and inflationary pressure so the $77MWh is largely in line with these 2020 numbers. IRRICAN also supplied a forecast carbon tax equivalent price that reflected the increase to $170/tonne of CO2. The average Carbon offsets price of $58.60MWh Canadian was used for the 2024 -2050 project life. Converting these two values to $98.06 USD/MWh or 0.09806 $/kWh for input into the SAM.

The $98.06 USD/MWh value was kept consistent in the Transmission connected and Distribution connected projects. However, in the distribution connected project with a Distribution Connected Generators credit applied an additional revenue stream needs to be added to the reflect this. Again, based of modeling work carried out by IRRICAN Power the expected average rebate received under the Fortis Option M (Fortis Alberta, 2018) program is $25.79 Canadian Dollars or $19.85 USD. Therefore, adding this value to the combined PPA and Carbon offset price above gives an input into the SAM of $117.91 MWh or $0.11791 kWh USD.

3.10 Depreciation

Renewable energy projects are eligible for an accelerated depreciation schedule under the rules set out by the CRA. These assets are depreciable by allowing 75% of the value to be credited in the first year followed by 50% of the remaining value for all subsequent years (Government of Canada, 2022). This schedule was entered into SAM and was used in all three test scenarios.

3.11 Results

Comparing between the distribution connected project and the transmission connected project the key difference is the increased cost of the transmission spur line to connect the project to the grid. As a result, the total transmission connected project cost is $32.5 Million compared to $30.4 Million for the distribution connected project. The addition $2.1 Million dollars for the transmission connected project significantly affects the project economics. Table 1 shows a comparison of the results from the modeled projects the NPV of the distribution and transmission connected projects are $10.77 Million and $9.63 Million respectively, indicating the distribution connected project have a greater value. The IRR of the distribution and transmission connected projects were 43.2% and 38.6% respectively, indicating that the distribution project would have higher rate of return. The total installed cost per capacity was also higher on the transmission connected project at $1.25/Wdc compared to $1.17/Wdc for the distribution connected project. In all these parameters the distribution connected project is superior and would be the best option.

In addition to the transmission and distribution projects a third model was conducted testing the impact on the economics of a project when the DCG credit was included. Adding this additional revenue into the project economic significantly improved the economic performance with the NPV increasing to $17.71 Million Dollars. The internal rate of return also increased to 59.4% or and increase of 16.2 percentage points over the distribution connected project with no credit applied. It is clear by the results how significant the DCG credit is for the private economics of distribution connected generators in Alberta (Table 1).

Table 1:

A comparison of the costs, revenue streams and economic performance of the three SAMs models.

	Transmission Connected Solar	Distribution Connected Solar	Distribution Connected Solar with DCG Credit
Total Project Cost	$32.5 Million	$30.4 Million	$30.4 Million
PPA plus Carbon Offsets	$127.60 MWh	$127.60 MWh	$127.60 MWh
Distribution Connected Generation Credit	NA	NA	$25.79 MWh
Combined price used in SAM	$127.60 MWh	$127.60 MWh	$153.39 MWh
Economic outputs from SAM			
NPV Net present value	$9.63 Million	$10.77 Million	$17.71 Million
IRR Internal rate of return	38.6%	43.2%	59.38%
Total installed cost per capacity	$ 1.25/Wdc	$ 1.17/Wdc	$ 1.17/Wdc

Note: Author (2022)

Chapter 4: Benefit Cost Analysis

The second phase of this study is to undertake a Benefit Cost Analysis (BCA) of replacing long-term transmission system upgrades with increased penetration of distribution connected generation projects. The scope of the BCA was to understand if it was more cost effective to mitigate the need for long-term transmission system upgrades and new infrastructure by implementing the strategic integration of DCG projects into the electricity grid. The BCA evaluates not only the direct cost of electricity services but also the impact on the environment and society.

The BCA is separated into two sets of costs and benefits, one for the planned build out of long-term transmission infrastructure and the associated cost and benefits to society that this creates. The second model tests the benefits and cost to society of upgrading the distribution network to allow for increased participation from DCG projects as an alternative to building additional transmission capacity. The DCG projects for the purpose of this study only replace the long-term expansion component of the transmission system. The existing and near to medium term transmission system and costs needed to build and maintain it are kept intact in both models.

The benefits and costs of the long term build out of transmission infrastructure include line losses, GHGs associated with the build out of the transmission system, the ecological impact of the transmission lines, the impact of new transmission lines on property values, the effect on system reliability and the employment and tax revenue associated with transmission infrastructure construction. The complete list of these benefits and costs are shown in Table 2.

The BCA for the implementation of the increased distribution connected generation projects is similar to those for transmission however, there were a number of different parameters that needed to be included, such as, costs to upgrade the distribution network, employment, and system reliability. Table 2 outlines the full list of all these parameters and their associated cost or benefit. How these factors were assessed, and the cost/benefit calculated is outline below.

4.1 BCA of Long-Term Transmission Upgrades

In the BCA analysis for the expansion of transmission system the largest single cost is for the long-term build out of transmission infrastructure. The AESO “2022 Transmision Rate Projection” document (AESO, 2022b) provides the basis for this cost assessment. This document breaks down upgrades to the transmission system in Alberta into three categories: near-term, medium-term, and long-term costs. For this study only the long-term costs from 2032 to 2042 were evaluated, the near term and medium-term costs were unchanged, this allows for the maintenance and expansion of the transmission system ensuring the reliability of the electricity grid. The mid-point date of 2037 was used for the 2032 to 2042 interval and an average increase of $8MWh was calculated for long term capital cost for transmission system build out.

The second largest factor affecting transmission costs are line losses. Wirfs-Brock (2015), calculated the average line loses in the United States at 2%. Calculating the value of energy lost in transmission at two percent of the electricity cost of $69MWh gives a cost of line loses at $1.38/MWh.

The third largest factor affecting the long term build out of transmission infrastructure and their associated utility scale generation projects is the positive impact on the economy from employment and the tax revenue generated form these activities. The MISO (2019) report shows that 5% of transmission project costs are labour for planning and permitting. An estimate of labour for the construction itself is at least another 5%. Therefore 10% of the project total is labour and of that approximately 30% is taxes that support the local community. To assess the net benefit of these activities in this study it is assumed that the employees were working in other industries before. Their employment change to support the transmission and electricity service industry was financial driven which resulted in an increase in real wages of 30%. Therefore, of the $8/MWh for transmission costs $0.80 is labour and tax revenue. Applying the 30% increase in real wages give a net benefit of $0.24/MWh that supports the local economy and provides funding for government programs. Additional employment benefits will result from the construction and operation of utility scale generation projects connected to the new transmission lines. Most of these new generation projects will be renewable in nature however, finding labour cost for these facilities was not possible. An estimate of labour cost for the construction and operation of these facilities is estimated to be three time those of static transmission lines and therefore the net benefit from these generation projects is estimated at $0.72MWh. Aggregating the transmission labour benefits with the generation projects benefits give a net benefit of $0.96MWh.

Other factors affecting the transmission projects are their impact on property values. These result from their visual impact on the landscape. Electromagnetic fields and the noise from transmission line have on properties adjacent the transmission line corridors. Bond et al., (2013) noted a decrease in property values along transmission line corridors. They noted multiple studies with a range of impacts from 0 to 10%. A total reduction in property values of 2% used for this assessment because most of the affected properties in Alberta would be agricultural land and would be less affected than studies which used a greater proportion of urban properties. The cost on property owners from the expansion of transmission was based on the $1.34 billion in capital transmission project cost (AESO, 2022a) of which ~50% are transmission lines. Using a

$4 million per mile of transmission line cost (MISO, 2019) equals 168 miles of transmission line. The average land price in Alberta is $4000 per acre (FCC, 2021) and therefore each section through which a transmission line passes will have damages of $51,000. The transmission lines would cross 168 sections of land. Therefore, the resultant damage would equal $8.6 million. Converting this $8.6 million value into dollars per MWh was done by converting it to a percentage of the total project cost, then using that percentage to compare it to the $8MWh (AESO, 2022b) projection of the cost of electricity services from the build out of long-term transmission capacity. Doing so results in a value of $0.048MWh.

Additional factors affect the indirect cost of electricity services and are captured in studies looking at the life cycle impact of the materials used to build, and the area disturbed as a result of transmission line construction. Doukas et al., (2011) reviewed the associated burdens of transmission systems. Based off their calculation 0.074g CO2 eq / KWh and a $170/Tonne Carbon price (Government of Canada, 2021) a cost of $0.013/MWh was calculated for the impact of CO_2 emissions from the production of steal, coper and other material needed for the construction of transmission infrastructure. Jorge and Hertwich (2014) conduct a Life Cycle Analysis (LCA) on transmission infrastructure and include an assessment of the cost from the degradation of non-renewable resources from the materials needed to build transmission infrastructure. Additionally, Doukas et al., (2011) in their LCA study associate the cost on society from the loss of natural habitat due the building of transmission line right of ways. Neither of these studies monetizes these values in a way that make it easy to convert them into a $/MWh cost. Therefore, for the purpose of this study an estimate based on the cost from CO_2 emissions has been used as a guide to estimate the societal cost from these factors. The cost for natural resource depletion is estimated at 50 percent of the cost of CO_2 emissions and the cost of ecological degradation from transmission line right of ways is estimated at 25 present of CO_2 emissions therefor based on this, values of \$0.06 and \$0.03 MWh, are used respectively.

The sum of all of the benefits and costs for upgrading the long-term transmission system results in a total cost of \$8.49MWh.

4.2 BCA of Distribution System Upgrades

As an alternative to the long-term expansion of the transmission network a benefit cost analysis (BCA) of the upgrading the distribution networks to allow for the expansion of more distribution connected generation projects is assessed. Upgrading the distribution system to allow for additional DCG requires the upgrades to the transformers, distribution lines and other infrastructure in the network. Porkar et al. (2011) calculated the cost to upgrade the distribution network to be \$3.012MWh USD. Converting this to Canadian dollars equates to \$3.92.

The second ranked factor in the BCA of distribution connected energy systems is cost associated due to loss of reliability. Distribution connected generation projects are known to improve system reliability for short to medium term outages but reduce reliability for long term outages (Baik et al,. 2017). As such the benefits from the reduction of short to medium term outages need to be balanced against the cost from long term outages. For this study three types of outage types were assessed short term, medium term and long term defined at one-, five- and one-hundred-hour duration respectively. The expected frequency of these events in a year are three one-hour outages and one five-hour outage. Additionally, one one-hundred -hour outage is expected every ten years. The implementation of distribution connected generation project is shown to mitigate the frequency of the short and medium term outages (Baik et al,. 2018) but increase the risk to long term outages. Therefore, for this study the benefits from the reduction of short and medium outages are subtracted from the cost from long term outages and in a ten-year period, and eighty hours of short-term benefits would be offset from one-hundred hours of long-term costs. Nooij et al., (2006) assessed the "average damage per unit of electricity not delivered due to an interruption" for all ratepayers at $11.18/kWh and applying this to the offsetting short term to long term cost above gives a net cost of $2.54MWh to be applied to the BCA.

The third most significant factor affecting the BCA of Distribution Connected generation systems is the positive impact that these facilities have on local employment and the associated spin-off benefits to the economy. These facilities would benefit rural areas to a greater extent as in many cases the source of energy is from agricultural activities for biodigesters or located in more rural areas in the case of micro-hydro, and wind resources. Solar may be the exception to this in that roof to solar is advantageous use of space in urban areas however that does not discount the possibility of utility scale solar project economically connecting to the distribution network as seen in part one of this study. The positive economic effect of DCG project has been demonstrated in other regions, for example Kemausuor et al., (2015) studied the positive economic impact of biogas production in Ghana. In the case of the Alderson Solar project there would be significant employment during the construction phase of the project as well as a number of full-time permanent jobs associated with the maintenance and operation of the facility. Other types of sustainable energy project would have an even greater positive employment effect. Biodigesters for example have labour costs of up to 30 percent of their operating budgets and they would have a significant positive affect on local economies (Kemausuor et al., 2015). Quantifying this into a $/MWh equivalent is difficult but intuitively a small-scale operating plant such as a biodigester would have significantly more labour needs than a static solar project therefore, it is estimated that the impact on the local community is 1.33 times that of resulting from the building and operation utility scale transmission generation.

Employment and tax benefits from utility scale transmission generation was calculated at $0.72MWh, therefore, a value of $0.96MWh has been used for this study.

Other factors such as the cost of associated GHG emissions and resources depletion from life cycle analysis perspective for the manufacturing of equipment from the upgrading of the distribution network was considered but was below the $0.01MWh threshold for inclusion in this analysis and was therefore not included.

The sum of all the benefits and costs for upgrading the distribution grid to allow for the build out of numerous distributions connected generating projects results in a total cost of $5.50MWh.

Table 2:

BCA summary table including net benefits to individual and all Albertan households.

Transmission Costs and Benefits	$/MWh
Long term Transmission upgrade construction costs	$8
Transmission Line Losses	$1.38
Transmission industry and utility scale energy projects jobs and tax revenue	-$0.96
Transmission Line impacts on property values, from Visual Impacts, Electromagnetic Fields, Noise etc.	$0.05
Transmission towers environmental impact ecological	$0.02
Total Cost of Transmission Connected Grid	**$8.49**
Distribution Costs and Benefits	**$/MWh**
Cost to upgrade the Distribution Network	$3.92
Aggregate cost of reliability changes	$2.54
Increase in local jobs and income from local distributed energy projects	-$0.96
Total Cost of Distribution Connected Grid	**$5.50**
Net Cost or Benefit	**$/MWh**
Total Saving (Total Transmission Connected Grid costs - Total Distribution Connected Grid costs=)	**$2.99**
Total Savings	**$**
Total Saving for the average Albertan household (7.2MWh/year)	**$21.53**
Total Saving for all Albertan Households (1,517,945 households)	**$32,681,355**

Note: Author (2022)

4.3: Benefit Cost Analysis Discussion and Results

The results from the BCA show that there is a net benefit from the implementation of upgrading the distribution grid versus building out the transmission grid. Comparing the BCA at a $/MWh basis shows that upgrading the distribution grid to allow for the build out of numerous distribution connected generation projects results in a net reduction in the total cost of electricity of $2.99MWh.

The average household uses 7.2MWh of electricity each year in Alberta and applying the differential savings of $2.99MWh associated to distribution connected grid upgrades results in a net savings of $21.53/year for each household in Alberta (Table 2). This results in a provincial savings of $32.7 Million dollars a year for the total residential population bases on 1,517,945 households in Alberta (Statistics Canada, 2016). These values do not include industrial ratepayers, but additional saving would be expected if these users were included.

Overall, the results from the BCA show that overall ratepayers in Alberta would benefit more from adding distribution connected generation projects than adding additional transmission capacity.

Chapter 5: Survey on the current and future electricity grid in Alberta

The third aspect of this study is a survey and interview of electricity generators, distributors, and ratepayers in Alberta. These stakeholders were asked how they view the cost of electrical services and grid reliability, distribution connected generation projects, transmission infrastructure and the future of the electricity grid in Alberta. Additionally, this survey assessed if changes to the tariff system that support the electricity grid were needed to develop a more sustainable electricity grid in Alberta. The interview component of the survey allowed the respondent the opportunity to elaborate on there answer to allow the researched to gain a perspective of how and why the respondent answered the question the way they did. The survey data is the primary source for this portion of the assessment however the interview component has been used to help guide the results and discussion.

The survey asked a series of questions on:

1. If the current electricity grid economically and reliably serves their needs?
2. The environmental impact of electricity infrastructure.
3. If there is support for local electricity generation and how it can support the local economy?
4. The cost of transmission infrastructure.
5. If changes to the current tariff scheme would promote more sustainable electricity development?

The survey started initially with twenty-two questions these questions have been narrowed down to eleven questions that address the key elements of the study and are listed below. Respondents were asked to answer the following questions on a scale of 1-10 where 1 represents strongly agree and 10 represent strongly disagree. Respondents were also given the option to not answer a particular question if they thought it may be damaging to themselves or their company or felt that they did not understand that aspect of the electricity industry enough to answer it in any meaningful way. Answers were recorded and compiled in a spread sheet to tabulate and assess the group results.

5.1: Survey Questions

The following are the questions that were used in this study.

1: Do you think that the current electricity grid economically serves you/your business?

2: Do you think that the current electricity grid reliably serves you/your business?

3: Would you support additional transmission tariff increases on your utility bill to support new transmission line development?

4: Would you be willing to pay more for sustainable electricity generation that supports local farms and business?

5: Would you be willing to support more smaller electricity generators in your local region?

6: Would you support the decoupling of transmission and distribution charges on your electricity bill? In this case decoupling means to separate the charges for electricity moved locally on the distribution network from electricity moved long distances over the transmission network.

7: Transmission and transformer losses can amount to >2% of the electricity moved on the transmission system. Would you support increased distribution connected generation capacity to mitigate these losses?

8: Do you think that transmission lines detract or degrade from the natural landscape?

9: Do you think that given the negative affect that transmission lines have on wildlife and endangered species that alternative methods of meeting the electricity needs of Albertans should be exhausted prior to building new transmission capacity?

10: Do you believe that instead of suspending the Distribution Connected Generation Credit program that an alternative solution could have been to decouple transmission and distribution charges and only pay transmission companies for the use of their infrastructure when it has been used?

11: Do you believe that increasing the number of Distribution Connected Generators (DCG) will reduce reliability of the electricity grid?

5.2: Demographics of survey respondents

The survey was answered by four distinct stakeholder groups, made up of two respondents from the renewable energy generators, two respondents representing their companies as industrial ratepayers. Of these one represented a junior oil and gas producer and the other a business owner in the petfood space. One respondent represented an integrated energy utility working in their electricity distribution division. The final three respondent represented themselves as residential ratepayers. Efforts were also made to select stakeholders from across Alberta, with representation from respondents in Calgary, Red Deer, and Edmonton as well as rural communities near Devon and throughout Southeast Alberta.

Effort was taken to not overweight the statistics for the analysis with disproportionately more respondents than other stakeholder groups. There was an attempt made to get additional stakeholder groups or industries to partake in the survey but uptake to these requests was not successful. Surveys were conducted either in person or via Zoom or on the telephone.

5.3: Results

The results of the survey were complied, tabulated, and assessed. Table 3 shows the responses from each participant and the simple average for all respondents of that question. Participants names have been anonymized into four categories 1: Generators, 2: Integrated companies, 3: Industry ratepayers and 4: Residential ratepayers. Analysis of the values that participants choose indicates a high degree of conformity in questions 2 and 10. There was slightly more diversity in the responses in questions 1, 4, 5, 6, 7, and 8. However, question 3 and question 11 had a wide rage of responses. Looking a question 3 specifically it asked, "Would you support additional transmission tariff increases on your utility bill to support new transmission line development?" and reviewing the results showed very strong to strong support from industry#1 and the Intigrated#1 respondent. These individuals expressed that the increased reliability that additional transmission capacity could provide was valued greater than any potential cost savings than the alternative could provide, whereas other participants answered that they were not interested in paying more for their electricity services. Divergence in the results from question 9 "Do you think that transmission lines detract or degrade from the natural landscape?" reflect the subjective nature of the question.

Table 3:

Summary of participants answers to the survey questions with average results calculated

Participant	Question 1	Question 2	Question 3	Question 4	Question 5	Question 6	Question 7	Question 8	Question 9	Question 10	Question 11
Generator#1	2	4	10	1	1	1	1	8	5	1	10
Generator#2	2	2	5	2	2	5	3	4	N/A	1	10
Integrated#1	4	1	2	3	2	7	2	N/A	N/A	5	5
Industry#1	3	1	1	5	4	1	5	10	N/A	1	3
Industry#2	1	1	5	7	3	1	1	5	3	1	5
Residential#1	6	1	7	3	5	2	3	5	2	3	N/A
Residential#2	3	1	8	5	4	5	2	5	4	1	N/A
Residential#3	8	3	9	3	2	1	2	1	1	1	8
Average	**3.6**	**1.8**	**5.9**	**3.6**	**2.9**	**2.9**	**2.4**	**5.4**	**3.0**	**1.8**	**6.8**

Note: Author (2022)

5.4: Summary of Survey Results

The results of the survey have been compiled and are presented in Table 4. This table shows the question and the average answer from all respondents, additionally, a gauge used to indicate the level of support for the question. The gauge is based off the average response and is divided into five categories, very strong (0-2), dark green; Strong (2-4), light green; Moderate (4-6), yellow; poor (6-8), orange; and very poor (8-10), red.

When the results of the survey are assessed, there were four key themes or trends that emerged from the results. The first of these themes is started with question 1 and 2, which assessed how stakeholders believed that the current electricity grid support their needs from both an economic and reliability perspective. Question one asked if the current electricity grid economically serves you? There was strong support for this question with an average response of 3.6, however, several stakeholders in the residential sector answered with an 8 and a 6. Discussions with these individuals about electrical services indicated that they were concerned about the escalation of prices in recent years for both the cost of electricity itself but also the increasing cost of transmission and distribution charges. Question 2 addressed how reliable the existing electricity grid is. There was very strong support on average for the reliability of electrical services with an average response of 1.8 indicating that the current electrical grid reliability serves stakeholders in Alberta.

The second theme that expressed itself from the survey results is that stakeholders supported additional generation capacity from small distribution connected generation projects. Question 5 asked if there was support for small local electricity generation projects and respondents reported strong support with an average answer of 2.9. Respondents supported these projects even if there was an increase in the cost of electricity as was shown from Question 4 where the average response was 3.6 indicating strong support.

The third trend that was revealed in the analysis is that there was support from stakeholders to mitigate the environmental impact from the construction of transmission lines, their impact on wildlife and the landscape, and from the operation losses associated with their use. Question 7 asked if there was support to mitigate the losses associated to transmission line with additional DCG projects. Support was strong for this with the average response of 2.4. Question 9 asked if due the impact of transmission infrastructure on wildlife if alternative methods should be exhausted prior to building new transmission lines. Again, strong support was expressed with an average response of 3.0. Question 8 asked if respondents believed that transmission infrastructure detract or degrade from the natural landscape. Response to this question was split with an average response of 5.4. Examining the results from individuals and stakeholder groups showed that the generators and industry respondents did not believe that the infrastructure that supported their operations degraded that visual appearance of the landscape while residential ratepayers showed stronger support. These split results are not unexpected for this question however it is known that the visual appearance from transmission infrastructure does affect property values (Bond et al., 2013).

The fourth theme that was exposed from the survey was that there was strong and very strong support to decouple the transmission tariffs from other electricity services in question 6 and 10, respectively. Although similar question 6 and 10 had distinct differences in that question 10 asked specifically if decoupling transmission tariffs could have been an alternative to suspending the DCG credit. Discussing this question with the stakeholders in the interview a number of individuals stated that this decoupling mechanism may have been more equitable solution. This was because it prevents the double billing to ratepayers that the AUC determined was not the best interest of ratepayers while still giving an incentive to distribution connected generators.

In addition to the four major themes discussed the final remaining question number 12 assesses if survey respondents believed that increasing the number of distributions connected generation projects on the grid would reduce reliability. The average answer to this question was 6.8 indicating that the consensus of respondents did not believe that reliability would be significantly impacted by increased penetration of distribution connected generation projects.

Table 4:

Survey questions with the average answer shown.

Question	Average Answer	Gauge
1: Do you think that the current electricity grid economically serves you/your business?	3.6	
2: Do you think that the current electricity grid reliably serves you/your business?	1.8	
3: Would you support additional transmission tariff increases on your utility bill to support new transmission line development?	5.9	
4: Would you be willing to pay more for sustainable electricity generation that supports local farms and business?	3.6	
5: Would you be willing to support more smaller electricity generators in your local region?	2.9	
6: Would you support the decoupling of transmission and distribution charges on your electricity bill? In this case decoupling means to separate the charges for electricity moved locally on the distribution network from electricity moved long distances over the transmission network.	2.9	
7: Transmission and transformer losses can amount to >2% of the electricity moved on the transmission system. Would you support increased distribution connected generation capacity to mitigate these losses?	2.4	
8: Do you think that transmission lines detract or degrade from the natural landscape?	5.4	
9: Do you think that given the negative affect that transmission lines have on wildlife and endangered species that alternative methods of meeting the electricity needs of Albertans should be exhausted prior to building new transmission capacity?	3.0	
10: Do you believe that instead of suspending the Distribution Connected Generation Credit program that an alternative solution could have been to decouple transmission and distribution charges and only pay transmission companies for the use of their infrastructure when it has been used?	1.8	
11: Do you believe that increasing the number of Distribution Connected Generators (DCG) will reduce reliability of the electricity grid?	6.8	

Note: Author (2022). Gauge indicates very strong (0-2), Strong (2-4), Moderate (4-6), poor (6-8) and very poor (8-10).

5.5: Discussion of Survey Results

Results from the survey have identified three key learnings with respect to the electricity generation, distribution, and transmission industry in Alberta. Firstly, the survey results exposed that the continuous and unlimited build out of transmission infrastructure as the only solution to providing reliable electricity services in Alberta is not supported by stakeholders. The environmental footprint of transmission infrastructure and their escalating costs question if alternative methods of providing electrical services are needed. The cost of transmission rates for residential ratepayers has increased five-fold between 2004 and 2021 (Government of Alberta 2022) and is expected to significantly increase through 2042 (AESO 2022b) as the electrification of the energy system intensifies in the energy transition (Canadian Energy Regulator 2021). The escalation of transmission costs is a predictable outcome with the expansion of solar and wind renewable energy projects. The unreliable nature of these projects means that their connecting transmission infrastructure is underutilised more frequently than conventional baseload generation projects and therefore proportionally more transmission infrastructure is needed to meet demand in the system than a comparable thermal or hydro baseload generation project. The survey results show there is significant stakeholder support for DCG projects as a means to mitigate the environmental impact, line loses, and escalating costs associated with transmission infrastructure.

The second key learning from the survey is that the existing tariff scheme may no longer be fit for purpose in the evolving electricity industry. Survey respondent strongly supported that the use of transmission infrastructure be decoupled from other electricity services. The decoupling of transmission services would help promote DCG projects. By decoupling the transmission tariff on ratepayers' utility bills significant environmental impacts, line losses and costs can be mitigated. By implementing a pay for use transmission tariffs in regions with high penetration rates of DCG projects, could result in a theoretical maximum saving rate of 25% for ratepayers.

The third key finding from the survey is that there is support for distribution connected generation projects as a means to support grassroots economic development and the local community. DCG projects are less capital intensive than utility scale transmission connected projects and are therefore a feasible undertaking for small business, farms, ranches, and community organisations. The implementation of battery storage as a generation type by the Alberta Government (ELECTRICITY STATUTES (MODERNIZING ALBERTA'S ELECTRICITY GRID) AMENDMENT ACT, 2022) opens up new opportunities for business to participate in the electricity industry. Energy storage and the implementation of the smart grid will be important components of a modern electricity grid. If there was a change in the tariff scheme to mitigate the burden of transmission infrastructure this would open up a lower cost alternative to ratepayers in the distribution network for locally DCG electricity providers.

Chapter 6: Integrated discussion and results

This study has investigated distribution connected generation (DCG) projects with an economic assessment case study and using a benefit cost analysis (BCA), to assess if there is a positive economic case for greater penetration of DCG projects within the electricity grid in Alberta. The results from both the case study on the Alderson solar project and the BCA show that DCG projects are superior to transmission connected projects and that utilising the distribution network more efficiently could significantly reduce the environmental and economic costs of providing electricity for Albertans.

The survey and interview component of the study showed that stakeholders were supportive of more DCG projects, and they would support additional projects to increase the sustainability of the electricity grid in Alberta. Increasing the sustainability would be achieved by reducing the environment impact associated with transmission infrastructure, supporting employment and grassroots economic growth within the distribution network, and reducing the financial burden of providing electricity to ratepayers by supporting DCG project that have superior total production costs.

The results from the survey also showed that to there was support to update the tariff scheme to make the electricity grid more sustainable. The survey showed strong support for decoupling transmission charges on ratepayer’s utility bills so that transmission charges become a pay for use service. These tariff changes would need to be organised through the AUC and ASEO to ensure that the existing transmission infrastructure is fully funded. Therefore, to ensure that the reliability of the grid is maintained it is unlikely that DCG projects would every be fully decoupled from transmission however, if even if the transmission tariff was reduced by half for DCG projects this would be a significant incentive for DCG developers. The intent of decoupling transmission services is not to defund the current transmission system but to promote DCG projects that have a lower environmental and economic cost. As discussed in the BCA analysis if DCG projects could slowly increase market share they may mitigate the need for the long-term expansion of the transmission system. These changes would gradually incentivise DCG projects which could locally market their electricity without the full transmission cost incurred by the ratepayers in that distribution network. From a sustainability perspective better utilising existing infrastructure while reducing the need for building new infrastructure is a win on all levels.

This research has demonstrated through an integrate economic case study, BCA analysis and survey that a more sustainable electricity grid is possible in Alberta through strategic development of DCG projects. These DCG projects will promote the UN sustainable development goals of Affordable and Clean Energy (#7), Decent Work and Economic Growth (#8), and Sustainable Cities and Communities (#11) (United Nations, n.d.). The results of this study show that increasing the proportion of DCG projects in the electricity grid broadly support the three pillars of sustainability. These DCG projects mitigate the environmental impact of new transmission infrastructure while positively supporting society with local employment and investment opportunities while reducing the total cost of electricity for Albertan ratepayers, thereby supporting positive economic growth.

With respect to the suspension of the Distribution connected generates credit program, changes to a government policy that significantly impacted the developers and investors is not positive to encourage investment in Alberta. However, the double billing that ratepayers for both transmission services and the repayment of the DCG credit was likely not in the long-term interest of Albertans. A more equable and simpler solution as suggested with this research is partially or fully decoupling transmission services to promote DCG development.

Chapter 7: Conclusion and recommendation for policy makers

The results of this research have shown that increasing the number and proportion of DCG projects in Alberta has the potential to mitigate environmental impacts, promote a more sustainable energy industry and reduce the cost of electricity for Albertian ratepayers. The Alderson solar case study demonstrated that DCG projects outperform similar scale transmission connected projects with superior NPV, IRR and total installed cost per capacity. The BCA shows that DCG projects can mitigate the overall environmental impact of the energy transition by limiting the need for new transmission infrastructure. The BCA also showed that there is the potential to mitigate the long term need to build additional transmission infrastructure by focusing on updating the distribution grid to support additional DCG projects. Results showed that if the long term costs allocated by AESO from 2032 to 2042 for upgrading the transmission system in Alberta were replaced by upgrades to the distribution network to support DCG projects, an overall cost saving of $3 MWh or $21.53 dollars per household would be achieved every year. That equates to $33 million dollars per year for all Albertan households. Finally, the survey component of the research confirmed that stakeholders of the electricity grid in Alberta support increased DCG projects to mitigate the environmental impact from transmission, support the local economy and support sustainable energy developments. To achieve these goals stakeholders support changes to the current tariff scheme to decouple the cost of transmission tariffs fully or partially. Making transmission services pay for use would be an incentive for DCG projects and thereby support a more sustainable energy grid.

Based on these results a recommendation for policy makers would be to investigate changes to the tariff scheme so that DCG projects are incentivised while still maintaining enough funding to ensure the reliability of the transmission system. It is understood that implementing these changes would require significant upgrades to the metering system to monitor loads across the grid. However, with the implementation of the smart grid coming in near future it is inevitable that these changes will be required anyway and the proactive choice for regulators and policy makers is to start the process of address these changes now.

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