The Impact of a Cost Rebate on the Economics of Solar Power in Canada

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1. Abstract

Incentives have been implemented in countries like Canada, the United States of America, and China, among others, to stimulate the deployment of solar power. Electricity from solar energy is one source of renewable energy that can reduce greenhouse gas emissions. Achieving a widespread adoption of solar projects depends on both the current subsidy for solar power and determining the ideal geographic location for solar insolation.

This paper analyzes the impact of various systems cost incentives on the economics of residential solar projects in Western Canada. Eighteen cities across three provinces were analyzed for both photovoltaic and concentrated photovoltaic projects with start dates of 2016, 2018, and 2020. Additionally, this research looked at the impact of optimizing a PV system and how this impacts generated revenue. The internal rate of return (IRR) and discounted net present value (NPV) were calculated for each city under various cost incentive scenarios. The internal rate of return was then mapped for a visual estimate of the most economically viable location in which to install a solar system.

This research finds that the internal rate of return for PV and CPV projects increases over time and shows the extent to which the application of additional systems cost incentives impacts this economic measurement. In order to make solar projects profitable to homeowners in Western Canada (IRR > 7%) the government needs to subsidize systems costs by 30%. The results also show that the value of the discount rate used has an impact on the net present value over time, and that the net present value generally increases over time, with the application of additional cost incentives. Moreover, the findings recommend deferring a solar project until the year 2020 where systems costs will decline and the price of electricity will rise, making solar projects an attractive investment.

2. Introduction

The OECD Green Growth Strategy (OECD, 2011) recommends that green growth policies should encourage innovation to enhance efficiency in the use of natural capital and provide new economic opportunities from the emergence of new green activities. Various types of government policies, the declining cost of many renewable energy technologies, changes in the prices of fossil fuels, an increase of energy demand and other factors have encouraged the increase in use of renewable energy (IPCC, 2011). Some renewable energy technologies are broadly competitive with existing market energy prices (IPCC, 2011). Many of the other renewable energy technologies can provide competitive energy services in certain circumstances, for example, in regions with favourable resource conditions or that lack the infrastructure for other low-cost energy supplies (IPCC, 2011).

In the United States, the federal government and many states have adopted policies to promote the development of various renewable energy technologies including tax subsidies, direct subsidies, loan guarantees, purchase obligations, and long-term contracting requirements (Joskow, 2011). For instance, under the Economic Stabilization Act of 2008, new solar installations receive a 30% tax credit, which means that the taxpayer’s corporate income tax liability is reduced by 30% of the initial investment (Reichelstein & Yorston, 2013). In most regions of the world, policy measures are still required to ensure deployment of renewable energy sources. Electricity from solar energy is one such source of renewable energy that can reduce greenhouse gas emissions. This energy resource does not require ongoing extraction from the Earth and its price does not fluctuate according to market forces; it is always free of charge (Tomosk, 2016). The most recent period of PV technology development from the 1990’s to the present day has been positive for the industry with the increase in energy-producing companies and the growth of commercialized renewable energy products (Fontana, 2012). During this time period, Japan, China and Europe surpassed the United States in domestic PV usage on account of new government programs and policies, which enticed individuals and businesses to adopt solar energy technology (Lamont, 2012). The success of renewable energy policies in these countries has helped to enact similar policies in other countries (Stokes, 2013). During the period 2000-2012, there was 16.9 GW of solar PV capacity in Europe, which represented 57% of the global total installed capacity (Sahu, 2015). Asia (including Japan, China, India, Korea, Taiwan, and Thailand) was placed in second position during this time period with a total new installed solar PV capacity of 7 GW, while North America (United States and Canada) was third, adding a new installed capacity of 3.6 GW (Sahu, 2015). The International Electricity Agency (IEA) forecasts that by 2050, solar electricity could account for 27% of the world's energy mix; if this forecast is accurate, solar electricity will become the leading source of electricity worldwide (International Energy Agency, 2014).

In Canada, there are currently no federal policies specific to solar power; however, some provinces offer their own policies and rebate programs. A number of direct support policy measures have been put in place across Canada, but the most significant PV-specific support measure is in Ontario, most notably, the feed-in tariff (FIT) program that was implemented in 2009 under the Ontario Green Energy Act (International Energy Agency, 2015). This program has broad objectives of increasing the capacity of renewable energy supply, reducing emissions of GHGs, attracting new investment, and enabling green industries (Yatchew & Baziliauskas, 2011). The FIT program is regulated by the Independent Electricity System Operator (IESO) and applies to 10-500 kW wind, hydropower, biomass, biogas, landfill gas and solar energy sources (IESO, 2016a). The FIT program provides a long-term, fixed price for the electricity generated by renewable energies (i.e. solar) over 20 years (Lipp, 2007). For renewable energy sources under 10 kW (i.e. residential rooftop solar panels), Ontario has a micro-FIT program which is similar to the FIT program (IESO, 2016b). By setting a long-term fixed price, the financial risk for developers is reduced and long-term market stability is established for investors (Lipp, 2007). PV power capacity grew in Canada at an annual rate of 98% in 2011, 48% in 2012, 54% in 2013 and 52% in 2014 due to the Ontario FIT program (Poissant, Dignard-Bailey, & Bateman, 2016). This is one example of a provincial program that is offered in Canada, which aims to encourage more people to invest in clean renewable energy sources. It should also be noted that Ontario has one of the highest amounts of solar PV installed across Canada (International Energy Agency, 2015). Table 1 shows Ontario grid-connected electricity production by fuel type from 2013 to 2015. An interesting observation is the phase out of coal, which was completed in 2015.

Table 1: The energy production from various fuel types in Ontario from 2013 – 2015 (IESO, 2016c).

Year	**Nuclear**	**Hydro**	**Coal**	**Gas/Oil**	**Wind**	**Biofuel**	**Solar**
2015	92.3 TWh 60%	36.3 TWh 24%	N/A N/A	15.4 TWh 10%	9.0 TWh 6%	0.45 TWh <1%	0.25 TWh <1%
2014	94.9 TWh 62%	37.1 TWh 24%	0.1 TWh <1%	14.8 TWh 10%	6.8 TWh 4%	0.3 TWh <1%	0.0185 TWh <1%
2013	91.1 TWh 59%	36.1 TWh 23%	3.2 TWh 2%	18.2 TWh 12%	5.2 TWh 3%	0.2 TWh <1%	N/A N/A

This table shows the increase in embedded generation solar and wind power, although these are not yet the main source of electricity in Ontario. With this being said, solar energy continues to struggle for widespread adoption against traditional fuel sources, such as oil and diesel (for small, off grid communities), and nuclear, wind, natural gas, and coal (for grid generation) because of the variable supply of energy and the seemingly high investment costs. Achieving cost competitiveness with these carbon intensive energy sources depends crucially on both the subsidies for solar power and an ideal geographic location for solar insolation (Reichelstein & Yorston, 2013). The research question that this project aims to answer is what impact a government cost incentive would have on the economics of solar power in Canada, focusing on the internal rate of return. This research will analyze the extent to which a federal or provincial rebate would improve the internal rate of return for solar power, therefore reducing the need for carbon-intensive sources of energy.

3. Literature Review

Solar Power

Electricity from solar energy is renewable and carbon-free. There are three methods employed to transform solar energy into a useable output (National Renewable Energy Laboratory, 2013). One method, photovoltaics, transforms solar energy into electricity for use in electrical and electronic devices (National Renewable Energy Laboratory, 2013). The second method is solar thermal, which converts radiation from the sun into heat, which can be used to warm up water tanks within residential and commercial buildings (Mills & Schleich, 2009). A third option is concentrated solar power (CSP), where solar energy is concentrated by mirrors to boil water, and the steam is then used to drive a turbine and electrical generator (National Renewable Energy Laboratory, 2016a). While all of the aforementioned methods are valuable, this research will focus solely on solar photovoltaics (PV). PV can be further split into traditional photovoltaics and concentrated photovoltaics (CPV). CPV is an advanced form of PV technology, which uses mirrors, or transparent pieces of glass to focus light from the sun onto specifically designed solar cells capable of absorbing concentrated sunlight (National Renewable Energy Laboratory, 2010; Sala & Luque, 2007). Traditional solar cells absorb sunlight without external focusing materials and can be installed in a variety of settings such as residential rooftops, commercial buildings, or on land surrounding these properties (Canadian Solar Industries Association, 2011). This project will be analyzing financial results from the use of both PV and CPV installations, however, the literature review will focus on PV technology since there is more published material compared to CPV technology. Additionally, our research will be based on crystalline silicon solar cells since this material is more efficient at generating electricity, and more capable of withstanding the elements; this translates into a longer lifespan and slower degradation of the solar cells (Moore, 2010). Consequently, crystalline silicon solar cells are more appropriate for outdoor solar modules that provide electricity to a home, business, or the existing power grid (Tomosk, 2016). The lifecycle of crystalline silicon PV modules is assumed to be within 25-30 years, thus, in this work, the lifetime of the module and the investment is assumed to be equal to 25 years (Ito et al., 2003; Sanchez-Friera et al., 2011; Rodrigues et al., 2016).

Like any technology, solar PV has advantages and disadvantages. Examples of advantages, as noted by Foster, Ghassemi, and Cota (2009), is that the fuel source is stable over long-term, operation and maintenance costs are reasonable, no staff are required on-site to generate electricity, the energy created is clean, and the technology supports 20 or more years of operation. Some disadvantages of solar PV technology are that the upfront cost of installation is typically large, and the amount of energy produced is variable since weather conditions may negatively impact the availability of the energy source (Foster, Ghassemi, & Cota, 2009). Examples of these weather conditions are temperature, and cloud cover; these uncontrolled variables impact the amount of solar energy produced, which is why there may be some hesitation to switch to solar power over traditional sources of electricity, which is readily available even in inclement weather conditions (Reichelstein & Yorston, 2013). The various costs and degradation rates that will be used for this research are presented later in this report (Table 5).

Economics of Solar Power

This study will focus on residential net-metering installations in Western Canada since, for residential customers, the value of the power is determined directly by the published electricity tariff in $/kW (MacDougall, Tomosk, & Wright, 2016). There is also the assumption that there is no storage since all electricity is either used or sold back to the grid at the same rate as the current electricity price. With British Columbia and Saskatchewan as exceptions, many Canadian provinces have not yet announced net-metering policies; therefore, there is currently no rate available. However, Ontario is developing a net-metering program so an assumption of this research is that a program will be implemented soon, and that other provinces will follow suit. The economics of solar power depends on the dollar value of the power generated. It is important to note that this study is focused on the private financial return, rather than the social return on investment, although this is an area of research that provinces could pursue in the future. The social return on investment is a method of accounting for economic, environmental, and social values of a project (Social Impact Scotland, 2016). For example, if a household installs a solar panel, their electricity bill which includes the fixed costs of the system (i.e. wires, etc.) goes down, whereas other customers who do not have solar panels must pay more, even though the household with solar panels is still relying on the grid for backup. This study is focused on the homeowner's perspective by analyzing the financial viability of solar power to the homeowner with current electricity tariffs. There are various methods of measuring the economics of solar power such as the levelized cost of electricity (LCOE), net present value (NPV) and the internal rate of return (IRR). The LCOE is a common way of reporting the present value of the cost of an energy project. It is a measure of the average cost of producing electricity over the lifetime of the system, and it can be used to compare among other alternative power-generation technologies (Branker, Pathak, & Pearce, 2011). This method is useful for comparing energy producing technologies that sell electricity to the energy marketplace at a consistent price over their operational lifetimes (Tomosk, Wright, Hinzer & Haysom, 2015). However, this method is not useful for residential projects since solar is usually the only option available, and because the value of the power generated may vary with month and hour, for instance, under the time of use tariff in Ontario (MacDougall, Tomosk, & Wright, 2016; Hydro Ottawa, 2016).

The net present value (NPV) method discounts future cash flows to their present value using the organization’s cost of capital as the discount rate (Brigham & Daves, 2007). The present value of the future cash flows is then compared to the initial investment. A positive NPV represents the future cash flows exceeding the amount of the initial investment; this means that the project’s future cash flows will exceed the amount necessary to repay the invested capital and provide a rate of return on the capital (Swift, 2013). A zero NPV occurs when the present value of the future cash inflow equals the initial investment. This means that the project’s future cash flows are exactly sufficient to repay the invested capital (Swift, 2013). Therefore, an investment with a positive NPV is usually deemed to be a worthy investment. This is an appropriate measure for business investments, where a discount rate is readily available, but this method is less suitable for a residential scale project (MacDougall, Tomosk, & Wright, 2016). The discount rate can also take into account the amount of risk that is involved for a particular investment. A higher discount rate will represent a higher risk investment, compared to a lower discount rate for an investment with less risk. For example, one household could receive a loan or mortgage at one interest rate (i.e. 3.9%), and their neighbour could have a different interest rate on their loan or mortgage (i.e. 2.8%). These two discount rates would result in different NPV values. Various discount rates have been reported in the literature for both PV and CPV installations. For this study, a 7% discount rate was applied to PV systems (Bazilian et al., 2013; Barbrose et al., 2013; REN21, 2013; Swift 2013). However, since CPV technology is relatively new and not as widespread as PV technology, an exact discount rate for CPV was difficult to obtain at the present time. Poullikkas et al. (2013) performed a sensitivity analysis using a span of discount rates for a prospective CPV installation, so this research will use both a 7% and a 9% discount rate. The 7% follows the same discount rate used for PV systems, and 9% will account for the higher risk involved due to more moving parts that may require increased maintenance. NPV results will be presented for this study to provide an additional perspective on various methods of calculating the economic value of a project.

The internal rate of return method is closely related to the NPV method. The IRR is used to evaluate the attractiveness of a project by quantifying the long-term profitability, by providing a rate of return from an investment, rather than using a cost of capital in the calculation (Swift, 2013). It is defined as the rate of return, or discount rate, that forces the NPV of the investment to equal zero (Swift, 2013). Generally speaking, the greater the project's IRR, the more desirable the project, and if the IRR is greater than the discount rate, the project should be pursued. The IRR is an appropriate measure for residential solar projects because it gives the customer a measure of the return they are getting on their investment and it avoids having to know each customer's discount rate (MacDougall, Tomosk, & Wright, 2016). Therefore, we will be focusing mainly on the IRR for the present study.

With the decline in PV module and systems cost, the cost of electricity from solar sources is in decline. In Canada, prices for solar modules (panels) decreased from approximately CAD 10.70Wp to CAD 1.15/Wp between the years 2000 and 2012, with a nearly 50% decline between 2010 and 2012 alone (Luukkonen et al., 2013). Grid-connected PV systems 10kW or less were priced at CAD 20.00/Wp in 2000, whereas the same sized system had a price that ranged from CAD 3.00-5.00/Wp in 2012 (Luukkonen et al., 2013). The IEA published a national survey report of PV solar applications in Canada for the year 2014 which included a table presenting the decline in systems costs (CAD) for different applications of PV over time, as shown in Figure 1. The report noted that the price of a residential PV system was CAD 20.00/Wp, but the International Energy Agency (2015) did not report the price in years 2001-2003. Therefore, this data point was not shown in Figure 1. The gap in commercial PV data (year 2008) is due to the IEA not reporting the price in this year. Ground-mounted utility prices were not reported by the IEA (2015) until the year 2010. Figure 1 is a visual representation of declining systems costs over time.

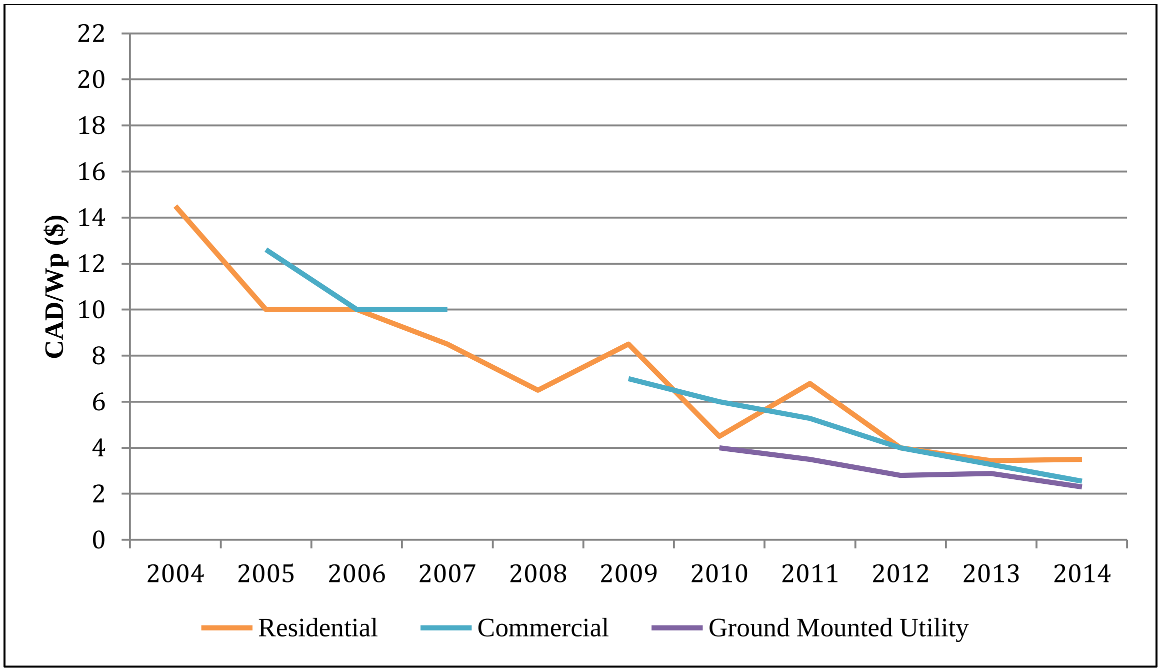
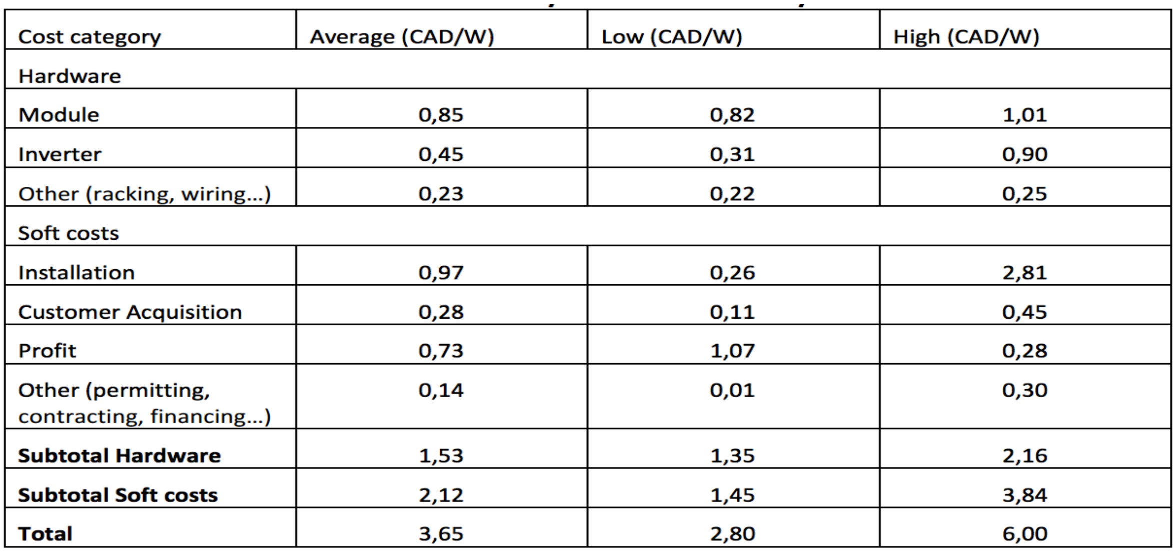


Figure 1: Trends in Canadian systems prices (2015 dollars) for various PV applications (International Energy Agency, 2015).

The report also displayed the findings for a cost breakdown of a residential PV system, in Canadian dollars (CAD) per watt (W), in the year 2014 (see Figure 2).



Cost category	Average (CAD/W)	Low (CAD/W)	High (CAD/W)
Hardware			
Module	0,85	0,82	1,01
Inverter	0,45	0,31	0,90
Other (racking, wiring...)	0,23	0,22	0,25
Soft costs			
Installation	0,97	0,26	2,81
Customer Acquisition	0,28	0,11	0,45
Profit	0,73	1,07	0,28
Other (permitting, contracting, financing...)	0,14	0,01	0,30
Subtotal Hardware	1,53	1,35	2,16
Subtotal Soft costs	2,12	1,45	3,84
Total	3,65	2,80	6,00

Figure 2: Cost breakdown for a residential PV system (under ten kilowatts) in 2014 (International Energy Agency, 2015).

This table shows a low, high, and average cost category, along with various soft costs, which can differ by region. While these amounts are in Canadian dollars, this study will be conducted in American dollars for easier comparison between published studies and industry reports. Additionally, Canadian systems costs are only reported up to the year 2014, where we are projecting costs for projects starting in 2016. Data presented in Figures 1 and 2 show only up until 2014, where published studies (i.e. NREL (2016b)) give a 2016 cost value. The output values from our model will be converted using a monthly average exchange rate from the Bank of Canada website (Bank of Canada, 2016). Table 5 shows various cost inputs we will use for PV and CPV systems, in USD. It should also be noted that operation and maintenance costs are incurred annually and depend on the size of the PV system. While system prices are declining, electricity prices are on the rise. For example, in the United States, the price of electricity generation, excluding transmission and distribution, for residential customers is expected to increase from USD 0.061/kWh in 2014 to USD 0.097/kWh in 2032 (U.S. Energy Information Administration, 2014). Comparatively, Ontario's Long-Term Energy Plan indicates that the average electricity generation price for residential customers will increase from approximately CAD 0.098/kWh in 2014 to CAD 0.13/kWh in 2032 (Ontario Power Authority, 2014). These pricing figures exclude transmission and distribution charges, and indicate that solar generated electricity could become cost competitive with, if not less expensive in some cases than, grid-produced electricity in the near future. This is due to the falling cost of solar panels coupled with the rising price of electricity. Compared to other fuel sources such as uranium, coal, and natural gas, all of which may experience price fluctuations in the future due to the cost of these resources, solar power has zero fuel cost (Neal, 2016). This zero fuel cost can be expected to result in more stable electricity prices for solar power compared to other sources that depend on fuels that have variable costs. The economic feasibility of residential solar projects will be evaluated in this study for cities in Western Canada assuming a total investment amount of $100,000.

Mapping the Economics of Solar Power

While maps of solar irradiance are quite common, there have been fewer studies that look at mapping the economics of solar power projects. Lave & Kleissl (2011) have mapped the optimal tilt orientation for solar panels, which is optimized for maximum energy yield rather than any financial measures. Haysom, Hinzer & Wright (2015) discussed the impact of electricity tariffs on the optimal orientation of PV modules and found that optimal orientation adds 4-19% to the cost savings, which could potentially impact the economic feasibility of a PV installation. In terms of mapping the economic feasibility of solar power, Rodrigues et al. (2016) performed a study that looked at thirteen countries (Australia, Brazil, China, Germany, India, Iran, Italy, Japan, Portugal, South Africa, Spain, United Kingdom, and the United States of America) under various PV energy consumption scenarios, and employed economic assessments in order to determine which country presents the most attractive small scale (either 1kW or 5kW) solar PV system investment, from the investor's perspective. The authors took into account each country's current solar policies, electricity tariffs, system costs, and annual solar production value, to name a few. A 5kW PV system was found to present better economic results compared to a 1kW PV system mainly due to the higher investment costs per installed Watt in a 1kW PV system (Rodrigues et al., 2016). Figure 3 below shows the IRR for the 1kW PV system according to the various consumption scenarios. Figure 4 shows the same results but for the 5kW PV system. These are graphical representations of their findings, which show that the 5kW PV system (Figure 4) has better economical values.

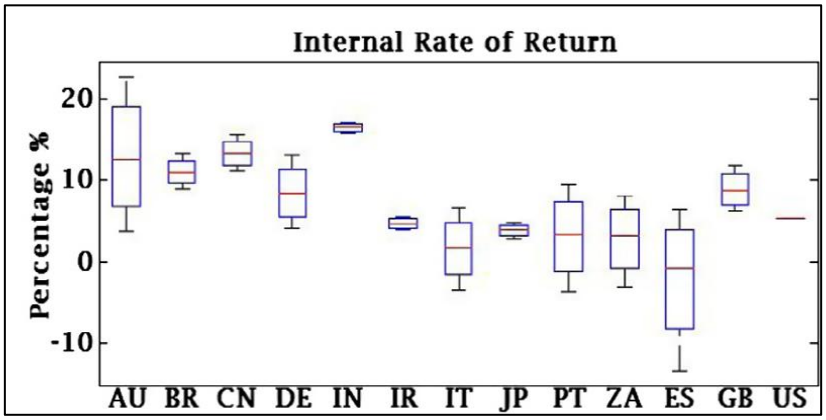


Figure 3: The IRR for the 1kW PV system over the various consumption scenarios for each country (Rodrigues, 2016). The countries that have median IRR values higher than 10% are Australia, Brazil, China, and India.

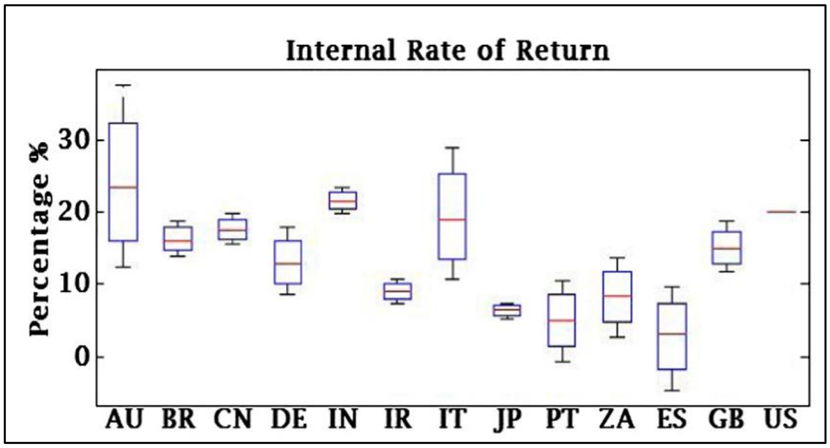


Figure 4: The IRR for the 5kW PV system over the various consumption scenarios for each country (Rodrigues, 2016). The countries that have median IRR values higher than 10% are Australia, Brazil, China, Germany, India, Italy, the UK, and the USA.

It was also found that when using a 5kW PV system, the countries that present the possibility to quadruple the investment include Australia, Germany, and Italy, and countries that can offer to triple the investment include China, India, and the United States (Rodrigues et al., 2016). Moreover, the results show that the viability of a PV system project largely depends on a combination of the investment cost, electricity tariff, government incentives, and solar radiation (Rodrigues et al., 2016). These factors will be taken into account for our study and will be used to perform a similar analysis to determine which location is the most financially viable for residential solar investment in Canada.

4. Methodology

Data Collection

This quantitative project is focused on the financial impact (not including social costs) of a cost rebate on residential solar power projects across three provinces in Canada; Alberta, Saskatchewan, and Manitoba. These provinces were chosen based on the medium/high levels of solar irradiance and population density (Ecosmart, 2016). The data used for this project was irradiance and weather measurements available hourly for 52 years from ground monitoring stations via the Canadian Weather, Energy and Engineering Datasets (CWEEDS), which is publically available (Government of Canada, 2015). Peruchena et al. (2016) stated that "a minimum of 11 years of GHI and 15 of DNI will be recommended for an accurate statistical characterization," therefore, our study of 18-52 years will meet this recommendation. Within each province, two cities representative of different levels of solar irradiance were selected, for a total of 18 cities (see Table 2 and Figure 5). Moreover, the 18 cities were chosen based on the availability of data from CWEEDS; the most recent year of data collection in the database is 2005. Hence, large cities that had data measurements until 2005 were included in the study.

Table 2: List of cities within each province used for this study, the level of solar irradiance, and the number of years worth of data (YoD) available from CWEEDS.

Irradiance	Alberta	YoD	Saskatchewan	YoD	Manitoba	YoD
High	Medicine Hat	52	Regina	52	Brandon	46
	Lethbridge	52	Estevan	52	Dauphin	50
Medium	Edmonton	51	Saskatoon	52	Winnipeg	52
	Calgary	52	Prince Albert	52	The Pas	52
Low	Fort McMurray	52	La Ronge	28	Churchill	52
	Peace River	46	Stony Rapids	18	Thompson	37

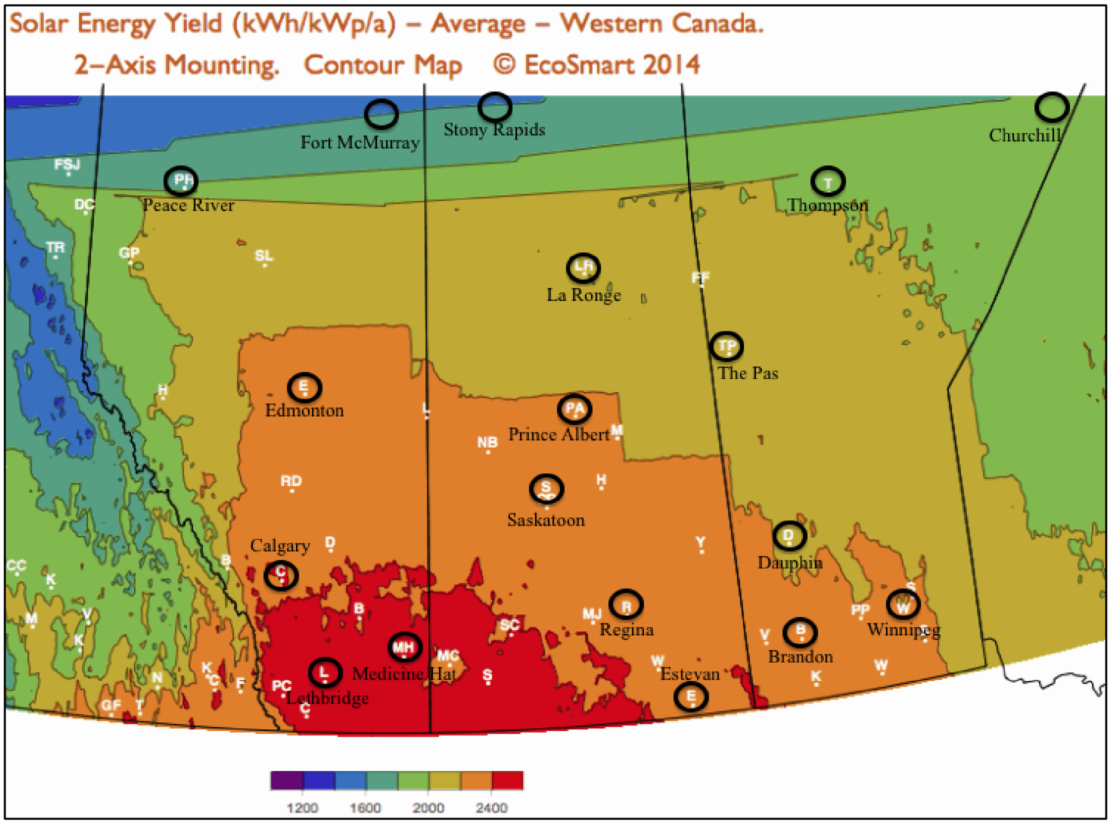


Figure 5: Map of Alberta, Saskatchewan, and Manitoba with the 18 respective cities that this paper will focus on (Ecosmart, 2016).

The data (i.e. irradiance readings) were downloaded from CWEEDS and imported into an energy model that has been developed and designed by Tomosk (2016), in order to determine CPV and PV output. The energy model contains multiple factors for both PV and CPV technologies, as listed in Table 3 below.

Table 3: A list of various factors included in the energy yield models for each month and hour of the year (Tomosk, 2016).

PV (fixed)	CPV (tracking)
Global Horizontal Irradiance (GHI), Direct Normal Irradiance (DNI), reflected irradiance	Direct Normal Irradiance (DNI)
Temperature	Temperature (which has a minor effect)
Degradation	Degradation rate (minor effect)
Dependence of efficiency on angle of incidence	Dependence of efficiency on zenith angle as a proxy for spectrum
Tilt and azimuth to calculate angle between direct beam and plane of array	Dependence of efficiency on concentration

The output from this model resulted in a DC output kWh for each hour, month, and year after installation of the system, and this data was then used as input to the financial model. The DC rating for CPV was 0.32 kW/m^2 and 0.156 kW/m^2 for PV. The financial model and its respective macros analyzed three main variables: system energy output, measured in kilowatt-hours; electricity tariffs, measured in dollars per kilowatt-hour; and revenue generated from solar energy production, measured in dollars (Tomosk, 2016). The required quantitative values were gathered from a variety of sources. For instance, solar installation costs, operation and maintenance fees, inverter replacement charges, and an expense for dismantling and recycling the solar modules at the end of their useful life were obtained from journals, conference proceedings, and industry reports. The electricity tariff data, electricity rate increase per year, and any government incentives (shown in Table 4) were obtained from official websites of each province, for example, Manitoba Hydro (Manitoba Hydro, 2016). Table 5 provides a summary of the various sources of input data that was used for this research.

Table 4: Provincial residential tariff and government incentive data*.

	Electricity Tariff ($/kWh)	**Government Incentive (if applicable)**	**Electricity Rate Increase/year**	**Source**
Alberta	0.048665	N/A for residential	3.5	Enmax Corporation (2016)
Saskatchewan	0.13267	One time rebate, 20% of eligible costs	5%	SaskPower (2016)
Manitoba	0.07930	$1/W installed, up to 200kW	3.95%	Manitoba Hydro (2016)

*Electricity prices are subject to change based on demand. These values are based on August 2016 rates.

Table 5: Input data for residential PV and CPV projects (USD).

Cost		**PV**	**CPV**	**Source**
Systems, capital costs ($/W)	2016	3.89	3.86	National Renewable Energy Laboratory (2016b); Feldman et al. (2015); Haysom et al. (2014).
	2018	3.57	3.11	
	2020	3.42	2.60	
Operating and Maintenance Costs ($/kW/year)		21.0	32.0	National Renewable Energy Laboratory (2016c); Drury et al. (2014); Klise et al. (2014); Hernandez-Moro & Martinez-Duart (2013).
Degradation rate (%)		0.81%	0.3%	Phinikarides et al. (2014); Hernandez-Moro & Martinez-Duart (2013); Gerstmaier et al. (2011).
Inverter replacement cost ($/W)		0.098		Perez et al. (2014)
Recycling cost ($/m^2)		15.15		Di Francia (2013)

Capital costs of residential solar projects are not available for the project start dates required for this study (2016, 2018, 2020). In order to determine which costs to use in the model, various calculations were performed. The capital costs displayed in Table 5 were obtained by initially comparing the values presented by Feldman et al. (2015) where five different industry estimates and projections of residential PV systems costs until the year 2020 were presented. The average percent change between each year was noted and also applied to the CPV values presented by Haysom et al. (2014). Through further analysis of the literature, a more recent documentation of capital costs was found. The average Feldman et al. (2015) PV values were then compared to the most updated <10kW PV installed costs presented by NREL (2016b), where it was shown that $3.89/W is the capital cost for 2016. This value then acted as the baseline to compare to the average values of years 2018 and 2020 from Feldman et al. (2015). Percent changes were applied and PV capital costs for the years 2018 and 2020 were estimated, as shown in Table 5 (Appendix A). As stated previously, this study implemented all cost inputs in USD, rather than CAD, due to availability of the most current data. In order to determine the updated capital costs for CPV systems, the percent change that occurred between 2016 in the PV NREL (2016b) study was applied to values of CPV capital costs presented by Drury et al. (2014). This gave updated estimated values of capital costs for the years 2018 and 2020 (see Appendix A for a sample calculation of this process). These systems prices include modules, racking, installation, and the tracking system for the CPV system.

The operations and maintenance costs were presented by NREL (2016c) where the most updated operation and maintenance cost for a PV system <10kW was $21/kW/yr. The operations and maintenance (O&M) cost for a CPV system was stated as $32/kW/yr by Drury et al. (2014). Since CPV is a more recent technology, there are fewer studies that observe O&M costs; the estimate Drury et al. (2014) provides is higher than the O&M cost for PV since CPV systems require a tracking system with moving parts that require more maintenance. Notably, the degradation rate plays a large role when determining the revenue of a PV or CPV system since the degradation of the solar modules reduces the efficiency of the system over time. The degradation rate for PV systems was found to be 0.81% by Phinikarides et al. (2014) and the degradation rate for CPV systems was found to be 0.3% as shown by Gerstmaier et al. (2011) and Hernandez-Moro & Martinez-Duart (2013). A solar panel installation is assumed to have a life span of 25 to 30 years; however, the warranty on the inverters required to convert direct current (DC) to alternating current (AC) is 10-15 years (Perez et al., 2014). Therefore, the inverter replacement cost was incurred halfway through the life of the system. At the end-of-life of the system, the glass and framing of the solar modules can be sold for recycling, however, there is a dismantling cost that is incurred, therefore, this cost was incorporated into the model (Di Francia, 2013). As noted in the literature review, a 7% discount rate was applied for PV systems, and CPV systems were analyzed using a 7% discount rate and a 9% discount rate (Bazilian et al., 2013; Barbrose et al., 2013; Poullikkas et al., 2013; REN21, 2013; Swift 2013).

Data Analysis

Once all variables were accounted for in the financial model, each city was analyzed by looking at the IRR and NPV under a range of possible cost rebates for projects starting in the years 2016, 2018, and 2020, assuming a total investment amount of $100,000. The "No incentive" scenario refers to the status quo, where no additional incentive is applied in addition to what is already in place in each province. The 10%, 20%, and 30% incentive scenarios all refer to an additional cost incentive that is applied after the provincial incentive is taken into account. It is important to note that the provincial incentive was applied prior to incorporating the additional 10%, 20% and 30% cost incentive. At the end of the analysis, each city produced IRR and NPV values over time under each of the four rebate percentage scenarios. The differences in IRR were analyzed in order to determine what impact an additional cost rebate would have on the financial viability for residential solar projects. This analysis was performed on both CPV and optimized PV technology. For clarity, the term "optimized PV" refers to the tilt and azimuth of the system being set at a certain degree in order to optimize the total dollar value of annual solar power generated. The climate model contained an optimization table to calculate the appropriate values for tilt and azimuth; for the majority of this paper, we focus on the optimized PV system, which assumes the system can be optimized to an accuracy of plus/minus two degrees, rather than solely facing south, with the tilt set just below the latitude. This will be discussed in detail in the following results section.

Additionally, the IRR results were plotted on solar irradiance maps of Canada, creating IRR contours based on irradiance patterns. Figure 6 and 7 show irradiance maps of the three provinces that were analyzed; these maps come from satellite measurements, which are less accurate than CWEEDS ground station monitoring. Figure 6 shows the irradiance map for PV technology (fixed mounting), while Figure 7 shows irradiance measurements for CPV technology (2-axis mounting).

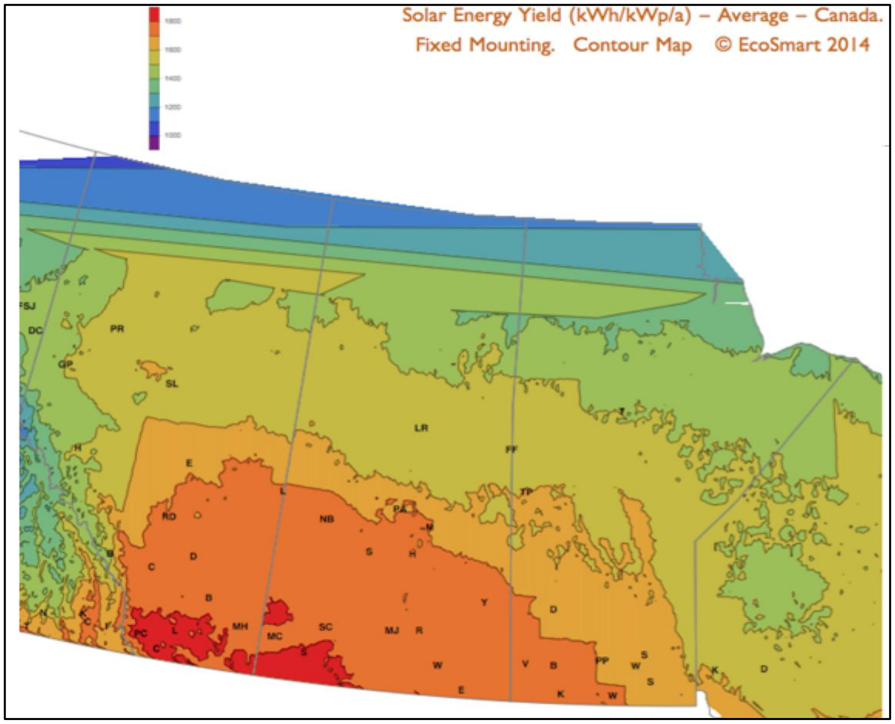


Figure 6: A solar irradiance map of Alberta, Saskatchewan, and Manitoba for PV technology (Ecosmart, 2016).

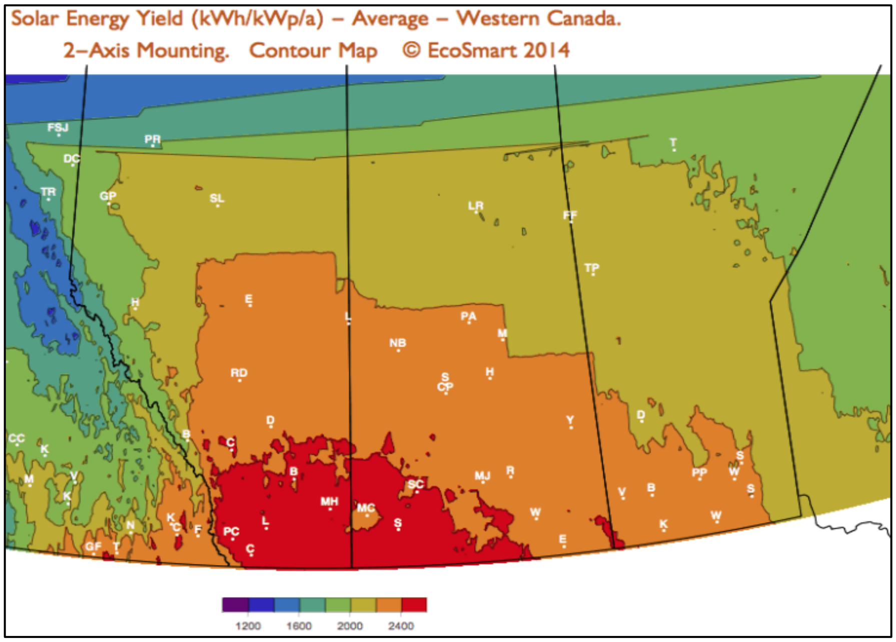


Figure 7: A solar irradiance map of Alberta, Saskatchewan, and Manitoba for CPV technology (Ecosmart, 2016).

A total of 14 maps were created, each looking at a specific incentive scenario for projects starting in a particular year. These maps will be presented in the results section and will aid in drawing conclusions about locations in Canada where solar projects are the most financially viable.

5. Results

5.1. Internal Rate of Return Results

This research presents internal rate of return results for two types of solar systems: CPV, and PV with tilt and azimuth values chosen to optimize the amount of the solar power generated. The discount rate did not impact the IRR values of CPV when the discount rate was changed from 7% to 9%, therefore, only two IRR graphs per city will be presented in this paper (all graphs are shown in Appendix B). The results for all 18 cities are presented for project start dates of 2016, 2018, and 2020, under four possible cost incentive scenarios (all graphs are found in Appendix B). These results quantify the extent to which the IRR is improved over time.

Edmonton, the capital of Alberta, will serve as an example from this province, which does not offer a residential solar incentive at the provincial level. Out of the three provinces, Alberta has the lowest electricity tariff of $0.048665/kWh (Enmax Corporation, 2016). The combination of a low electricity tariff and lower irradiance levels (EcoSmart, 2016), contributes to the IRR being negative for all six cities across Alberta. The results in Figure 8 show the impact of a 10%, 20% and 30% systems cost incentive on the IRR of a residential CPV system. For CPV technology, IRR values range from -5.7% to -3.7% in 2016, -4.5% to -2.4% in 2018, and in 2020 the IRR values range from -3.5% to -1.2% (as seen in Figure 8). The average IRR in 2016, 2018, and 2020, across all incentive scenarios, is -3.5%. A 10% reduction in CPV systems costs results in a 10-18% increase in IRR, where a 20% reduction in systems costs results in a 22-40% increase in IRR. When there is a 30% reduction in CPV systems costs, the IRR increases between 35% and 65%. It should be noted that these percent increases in IRR is a percent of a percent, since the IRR is itself a percentage.

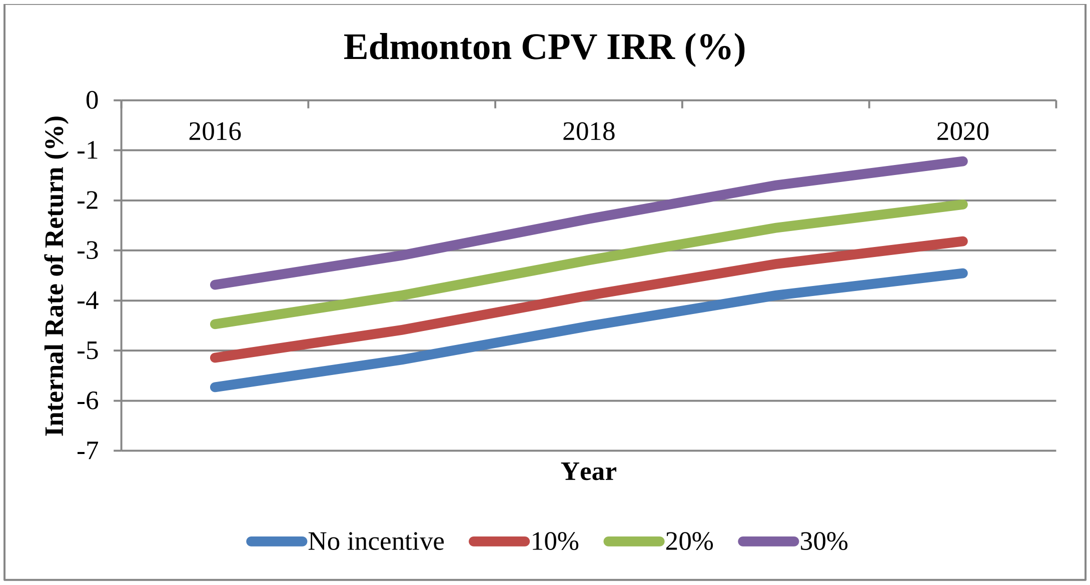


Figure 8: Internal rate of return for CPV under various cost incentives in Edmonton.

To show the extent to which a higher incentive benefits the IRR of a CPV system, the average IRR of all six cities in Alberta are displayed in Figure 9. In 2020 for example, the average IRR is -2.4% with a 10% incentive (red line), compared to an IRR value of -0.7674% under a 30% incentive (purple line).

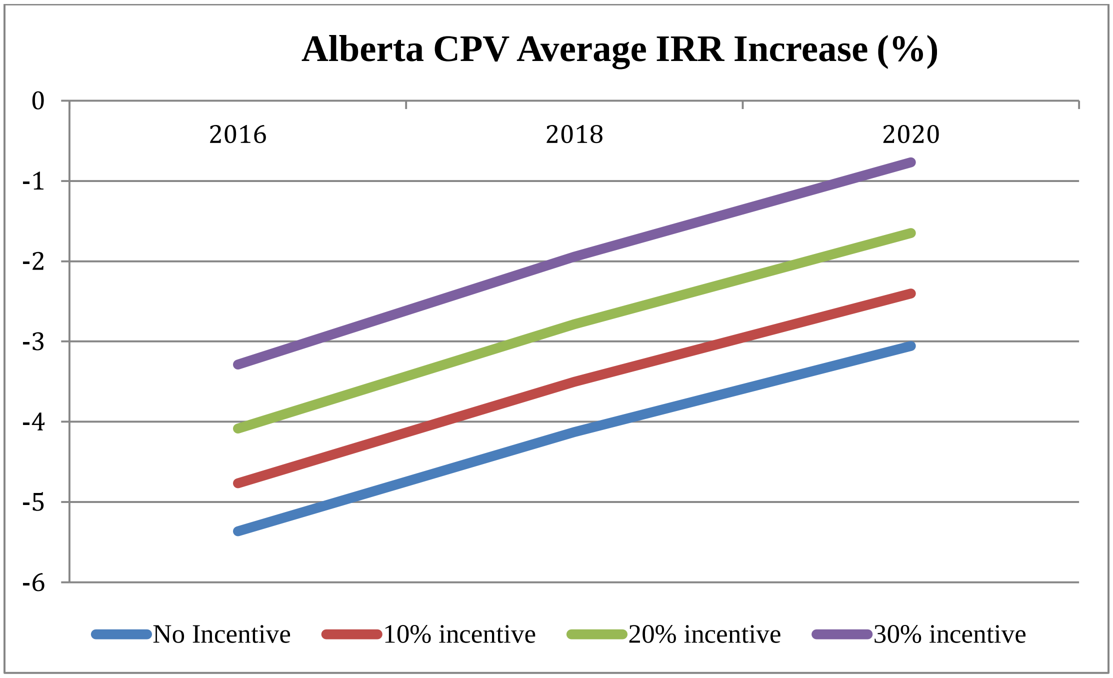


Figure 9: The incremental improvement of IRR for CPV in Alberta, averaged across all six locations.

Figure 10 below shows the impact of the various cost incentives on the IRR of an optimized PV system in Edmonton. In 2016, the IRR for a PV system is between -5.8% to -3.6%. In 2018, the IRR ranges between -5.3% to -3.1%, and from -5 to -2.8% in 2020. The average IRR across all incentive scenarios in 2016, 2018 and 2020 is -4.3%. A 10% reduction in systems cost results in an increase in IRR of -10% to -12%, where a 20% reduction in systems costs results in a -23% to -27% increase in IRR. When there is a 30% reduction in systems cost, the IRR increases by -37% to -45%. In this case, the range of percent increase of IRR for CPV systems is greater than those for PV. For instance, the effect of a 30% reduction in systems costs of a PV system results in a -37% to -45% increase in IRR compared to the -35% to -65%

increase in IRR for CPV. This may be due to the fact that the CPV IRR is higher to begin with, since systems costs are initially lower.

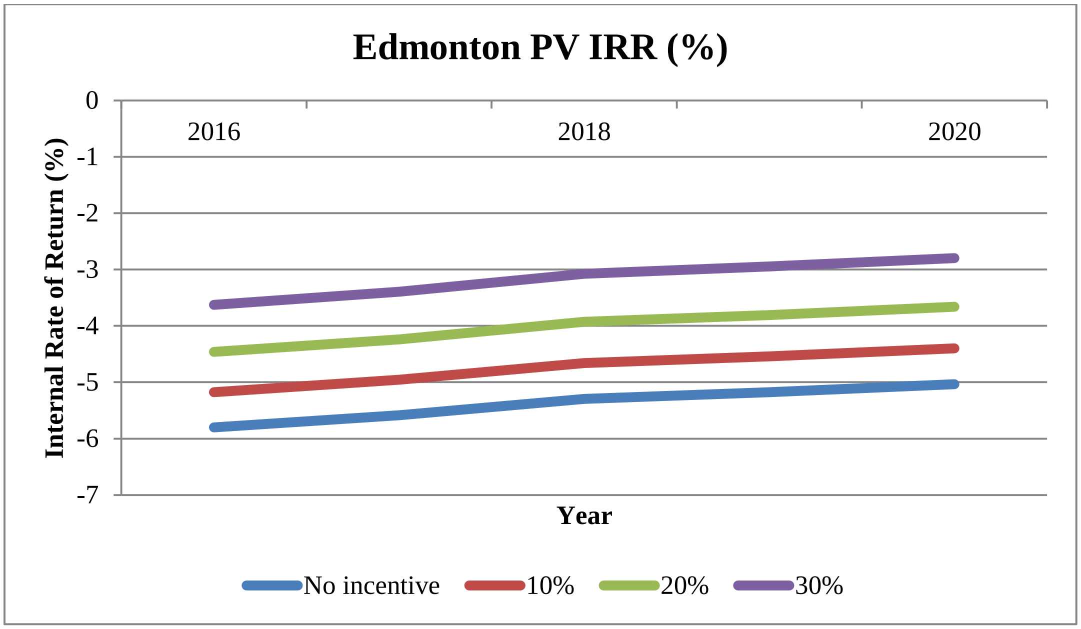


Figure 10: Internal rate of return for an optimized residential PV system under various cost incentives in Edmonton.

The incremental benefit of higher incentives for PV systems averaged across all six locations in Alberta is shown in Figure 11. This shows the extent to which a higher incentive impacts the IRR. For instance, in 2020, under a 30% incentive scenario, the IRR is -3% compared to -5.2% with no additional incentive.

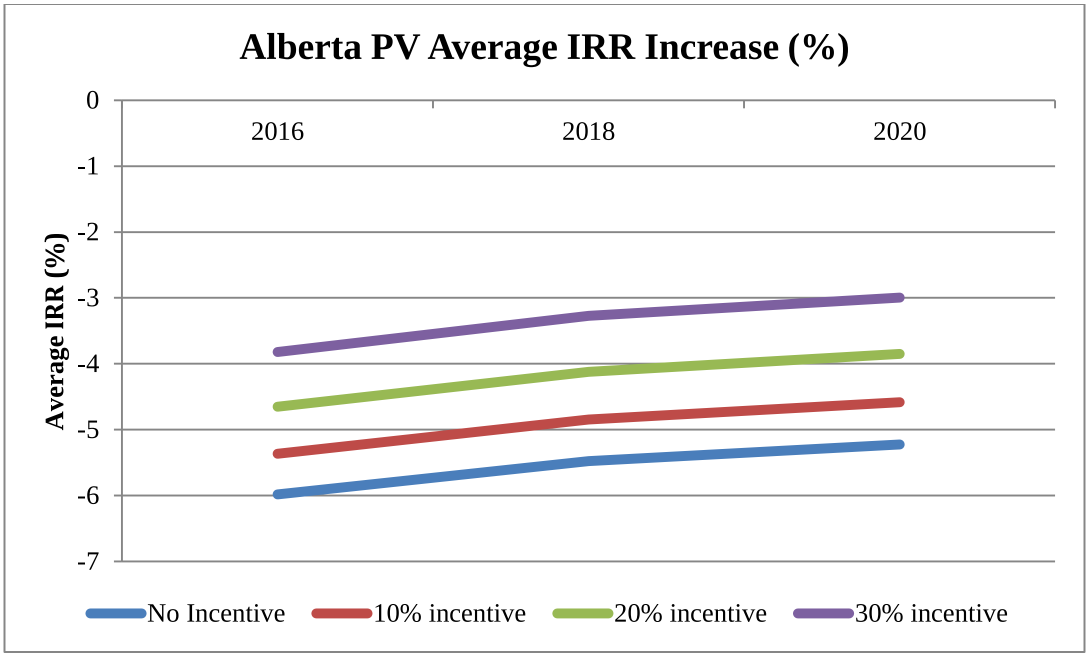


Figure 11: The incremental benefit of additional higher incentives on PV IRR averaged across all six cities in Alberta.

The province of Saskatchewan currently offers a one-time rebate to residents, farms, and businesses, equivalent to 20% of eligible costs to a maximum of $20,000 for an approved and grid connected net metering project (SaskPower, 2016). Saskatchewan also has the highest electricity tariff between the three provinces that were analyzed for this study, $0.13267/kWh. The combination of high electricity prices, decreasing systems costs, high levels of solar potential, and the provincial cost rebate that is currently offered are all factors which contribute to a positive IRR for all six cities in Saskatchewan. Regina is the capital of Saskatchewan and has the highest yearly PV potential (kWh/kW) in Canada (EcoSmart, 2016). Figure 12 presents the IRR results for a CPV system in Regina under the four cost incentive scenarios.

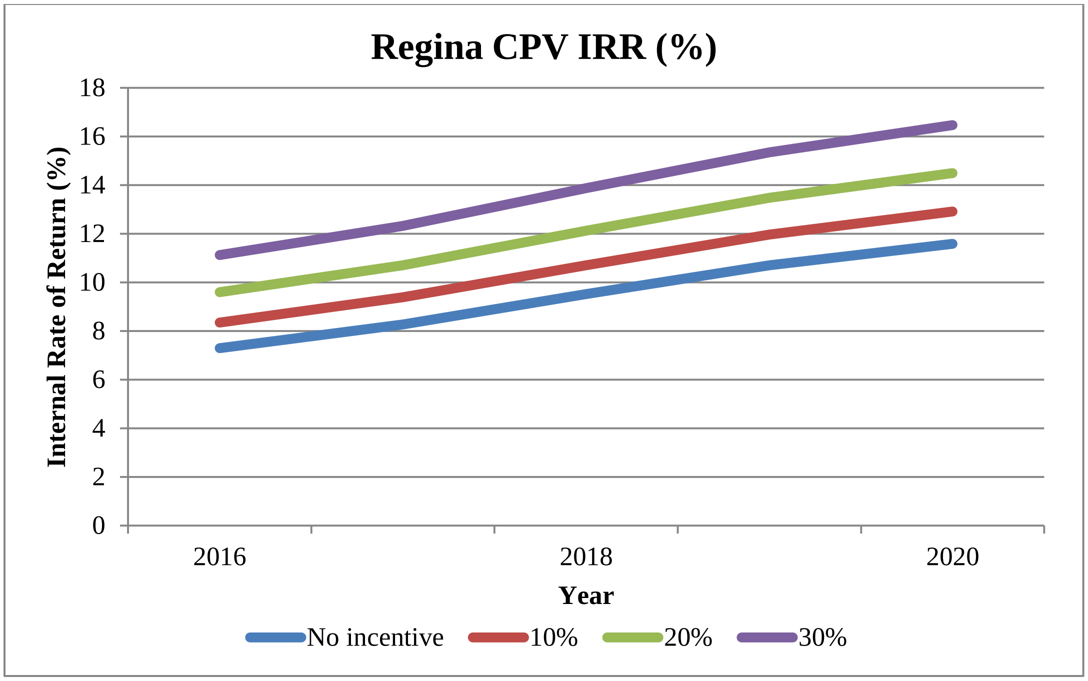


Figure 12: Internal rate of return for a CPV system in Regina under various cost incentives.

The IRR values in 2016 range from 7.3% (with no additional incentive) to 11.1% (under a 30% cost incentive scenario), and in 2018 these values range from 9.5% to 13.9%. In 2020, the IRR values are highest, ranging from 11.6% to 16.5%. The average IRR across the three years and over all incentive scenarios is 11.5% for CPV technology. When a 10% cost incentive is implemented, the IRR increases by 11.4% to 14.5% over 2016, 2018, and 2020. A 20% reduction in systems costs results in a 25.2% to 31.7% increase in IRR, and a 30% reduction in systems cost showed an increase in IRR by 42.1% to 52.6%. In all incentive scenarios, the IRR increases over time. The average IRR for CPV systems across all six cities in Saskatchewan was calculated and the incremental benefit of applying increasing incentives is shown in Figure 13.

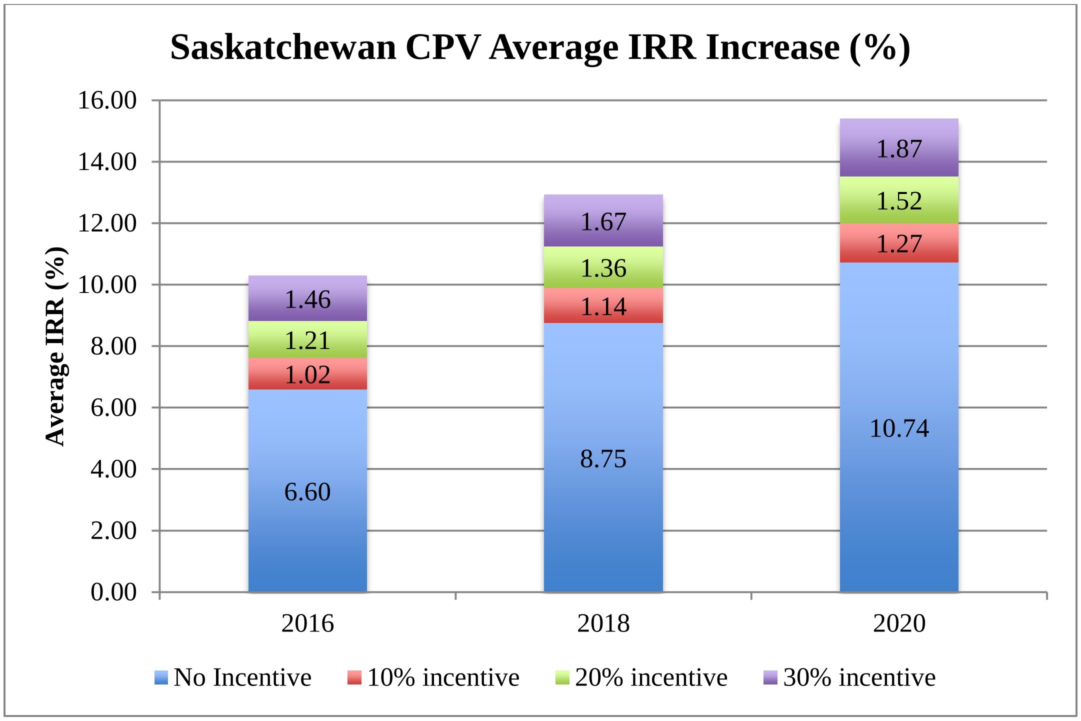


Figure 13: The average IRR for CPV projects in all six cities in Saskatchewan averaged, showing the incremental benefit of increasing incentives.

Figure 13 shows the incremental benefit of higher incentives for a CPV system for the average of all six cities in Saskatchewan. For example, in the year 2020, a 30% incentive will provide a 1.87% increase in IRR compared to implementing a 20% incentive. The data labels on the graph demonstrate the extent to which the IRR would increase when a higher incentive is applied across all six cities in Saskatchewan for a CPV project. The value in each “no incentive” stack is the IRR value if there was no additional incentive applied; values in the stacks above are the incremental increases (%) between incentive scenarios.

Figure 14 shows the IRR results for PV technology in Regina under all four incentive scenarios. The IRR ranges between 6.7% (no incentive) and 10.5% (30% incentive) in 2016, 7.6% to 11.6% in 2018, and 8% to 12.2% in 2020. The average IRR for 2016, 2018, and 2020 across all incentive scenarios is 9.3%.

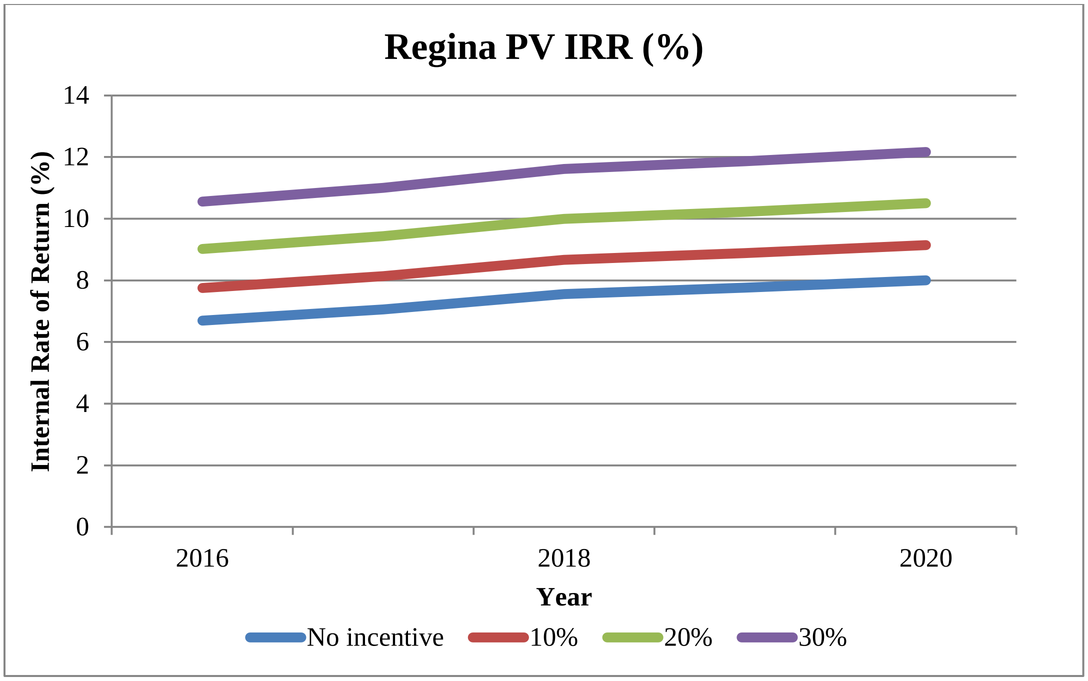


Figure 14: Internal rate of return for PV under various cost incentives in Regina.

In terms of the impact of various incentives, a 10% reduction in systems costs results in a 14.3% to 15.9% increase in IRR, a 20% reduction results in a 31.2% to 34.8% increase in IRR, and a 30% reduction shows a 52% to 57.8% increase in IRR over time. In this case, the effect of the incentive applied has a larger impact on PV compared to CPV, since a 30% reduction results in a 42.1% – 52.6% increase for CPV compared to a 52% – 57% increase in IRR for PV. The impact of percent increases of IRR for CPV systems are less marked than those for PV systems, since CPV IRR is higher to begin with. Additionally, it is important to note that the percentage impact on IRR is greater than the percentage required to create it (i.e. a 10% reduction causes a 14.3% – 15.9% increase in IRR), making this investment viable.

Figure 15 shows the incremental increase for higher incentive scenarios that is averaged across all six cities in Saskatchewan for PV systems. For a project start date in year 2018, the IRR will increase by 1.06% under a 10% incentive, compared to no additional incentive. A 20%

incentive will result in an IRR increase of 1.26%, and a 30% incentive will result in an IRR increase of 1.54%.

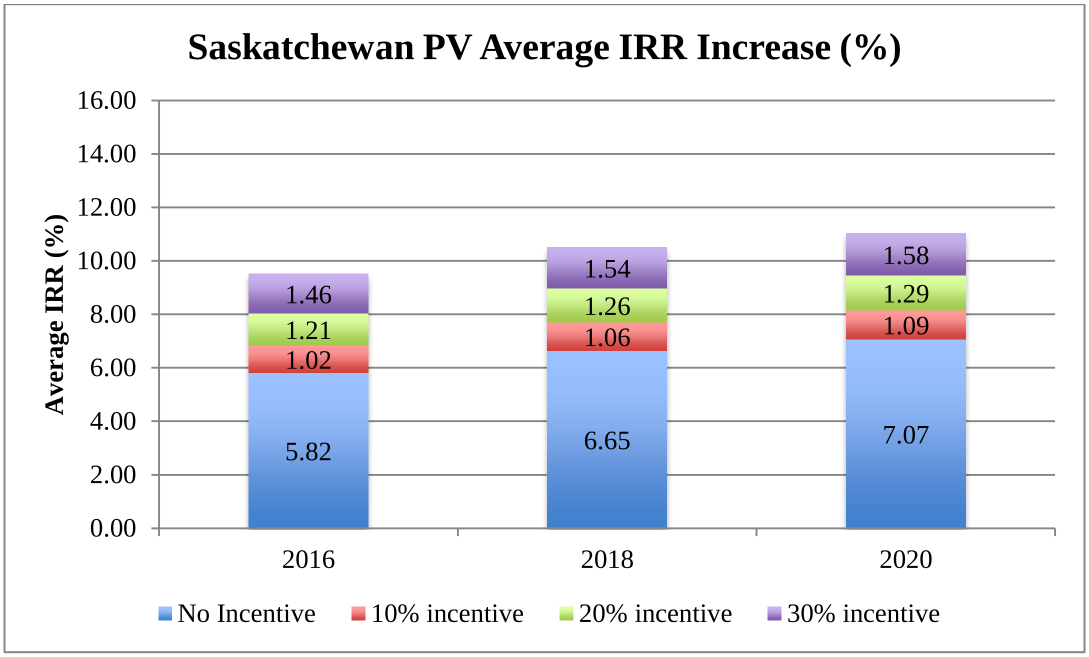


Figure 15: The average IRR incremental benefit of higher incentives across all six cities in Saskatchewan for PV systems.

Manitoba offers an incentive of $1/W, up to 200 kW, through their Solar Energy program (Manitoba Hydro, 2016). This incentive is offered at the residential level and was incorporated into the model by reducing the initial system costs prior to applying the 10%, 20%, and 30% incentives. Manitoba also has an electricity tariff of $0.07930/kWh and has lower levels of solar irradiance compared to Saskatchewan (Ecosmart, 2016). Figure 16 shows the IRR results for CPV in Dauphin, where the average IRR for all incentive scenarios in 2016, 2018, and 2020 is 6.3%.

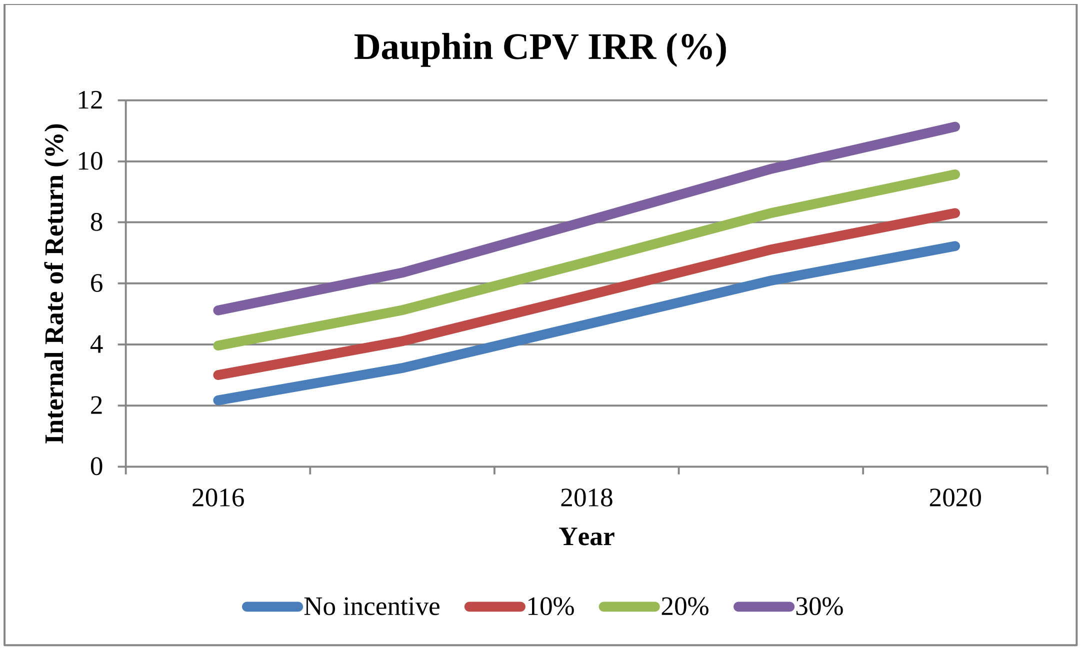


Figure 16: Internal rate of return for CPV under various cost incentives in Dauphin.

The IRR for CPV in 2016 ranges from 2.2% (with no additional incentive) to 5.1% (with a 30% incentive). In 2018, the IRR ranges from 4.7% to 8.0%, and in 2020 ranges from 7.2% to 11.1%. The impact of a 10% systems cost reduction increases the IRR by a range of 14.8% to 38.2%, while a 20% reduction in systems costs increases the IRR by 32.5% to 82.8% over time. A 30% reduction in systems cost increases the IRR by a range of 54.0% to 136%. As can be seen, the IRR increases over time, and is the highest under the 30% cost incentive.

As shown in Figure 17, there are incremental benefits of higher incentives for the IRR values of CPV systems, averaged over six cities in Manitoba. For a project start date in 2020, the IRR will increase by 0.98% under a 10% incentive, compared to the no additional incentive scenario. A 20% incentive will result in an IRR increase of 1.16%, and a 30% incentive will result in an IRR increase of 1.40%.

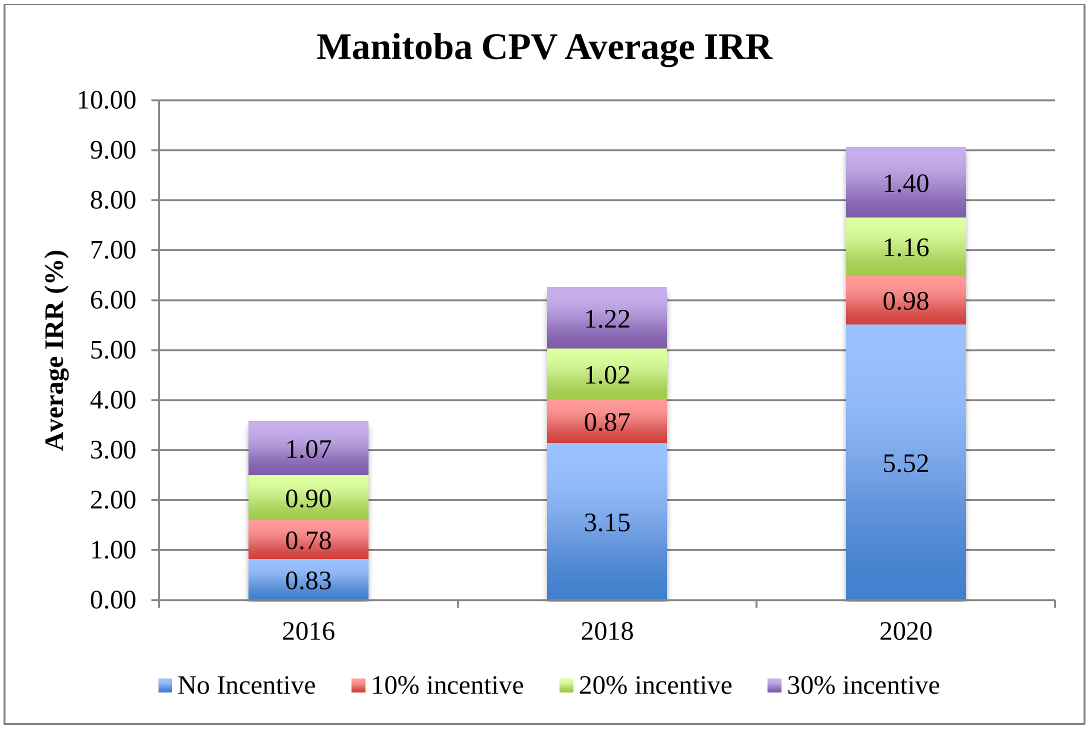


Figure 17: IRR averaged over all six locations in Manitoba showing incremental benefit of higher incentives for CPV systems.

Figure 18 shows the IRR results for PV technology in Dauphin, where the average IRR (across all incentive scenarios over time) is 3.1%. What is immediately noticeable in Figure 18 is that the IRR for a PV system is much lower compared to the CPV IRR shown in Figure 16.

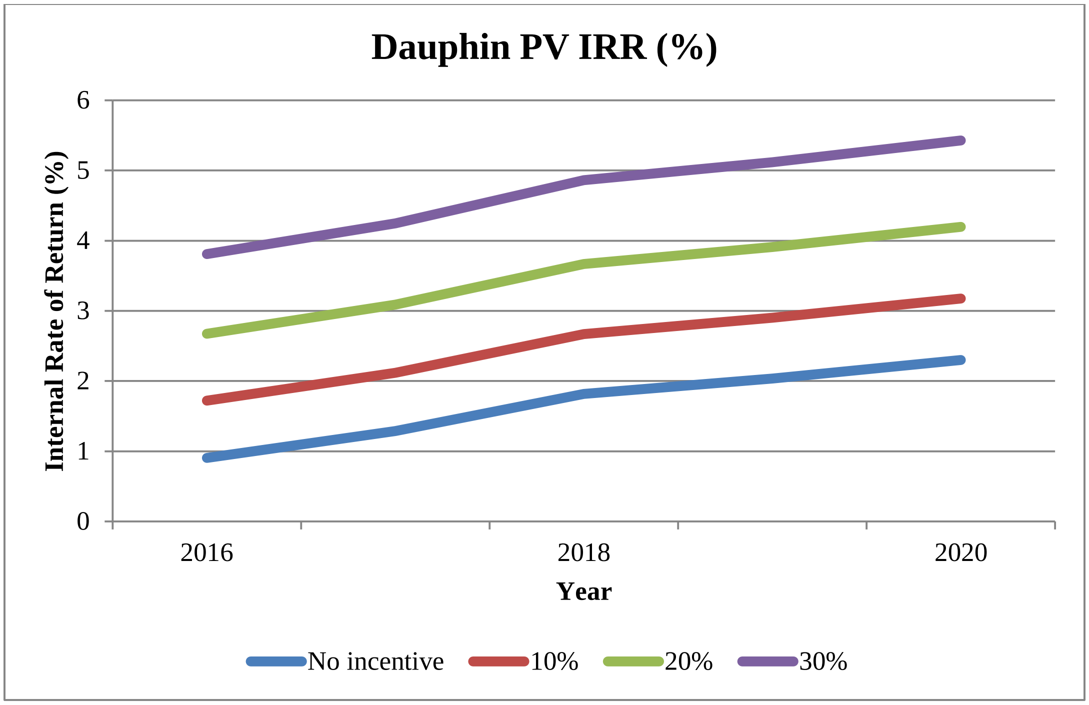


Figure 18: Internal rate of return for PV under various cost incentives in Dauphin.

For PV technology, the IRR in 2016 ranges from 0.91% (no incentive) to 3.8% (30% incentive). In 2018, these values range from 1.8% to 4.9%, while the IRR is highest in 2020 with a range of 2.3% to 5.4%. In terms of the impact an incentive has on the IRR, a 10% reduction in systems cost resulted in a 38% to 90% increase in IRR, a 20% reduction resulted in a 82% to 195% increase in IRR, and a 30% reduction increases the IRR by a range of 136% to 320%. These large percent increases are due to the very low IRR numbers (i.e. 0.91%). For instance, the actual increase in IRR due to a 10% reduction in systems cost is 1.38 – 1.9% but the percent increase in IRR is 38% - 90%.

Figure 19 shows the PV IRR averaged over all six locations in Manitoba showing the incremental benefit of higher incentives. For a project start date in 2016, the IRR will increase by 0.80% under a 10% incentive, compared to the no additional incentive scenario. A 20% incentive will result in an IRR increase of 0.93%, and a 30% incentive will result in an IRR increase of 1.10%.

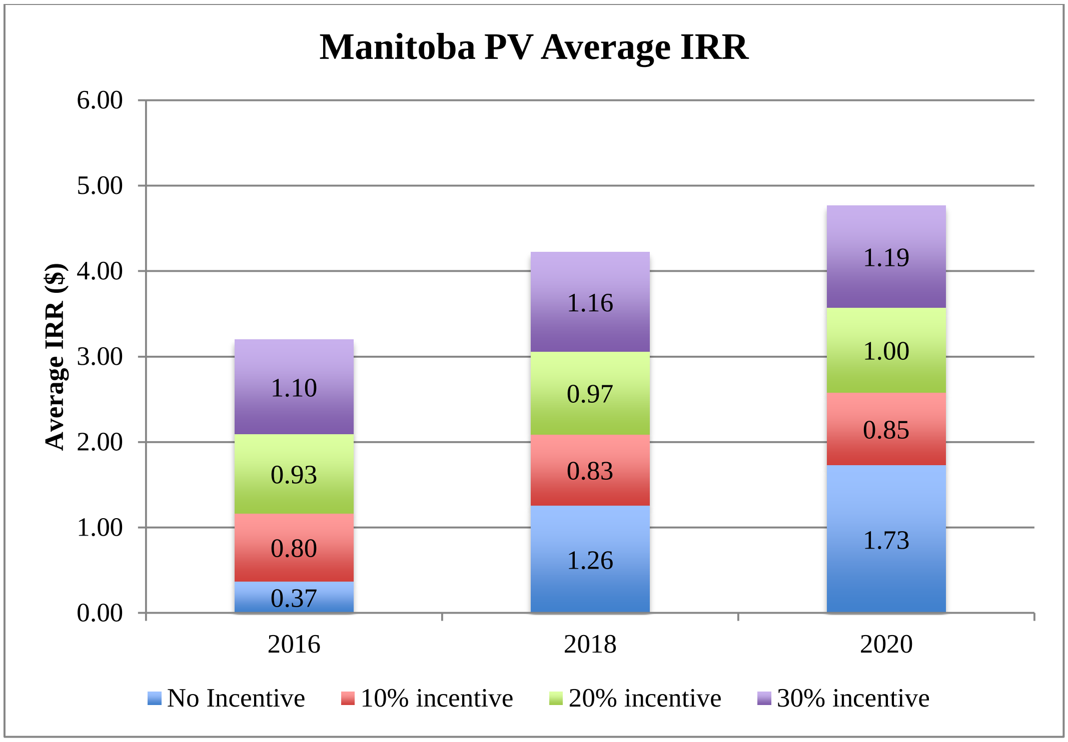


Figure 19: The average IRR incremental benefit of higher incentives for PV systems across all six cities in Manitoba.

In order to easily relay the range of average IRR values across all 18 cities, Figure 20 shows the average values for both PV optimized and CPV technology. For all cities, the CPV technology provides a higher IRR compared to PV. This is in part due to lower initial systems costs for CPV compared to systems costs for PV. Additionally, CPV is dependent on GHI measurements, which are different than DNI measurements. The relative importance of these two factors is analyzed in Table 6 below.

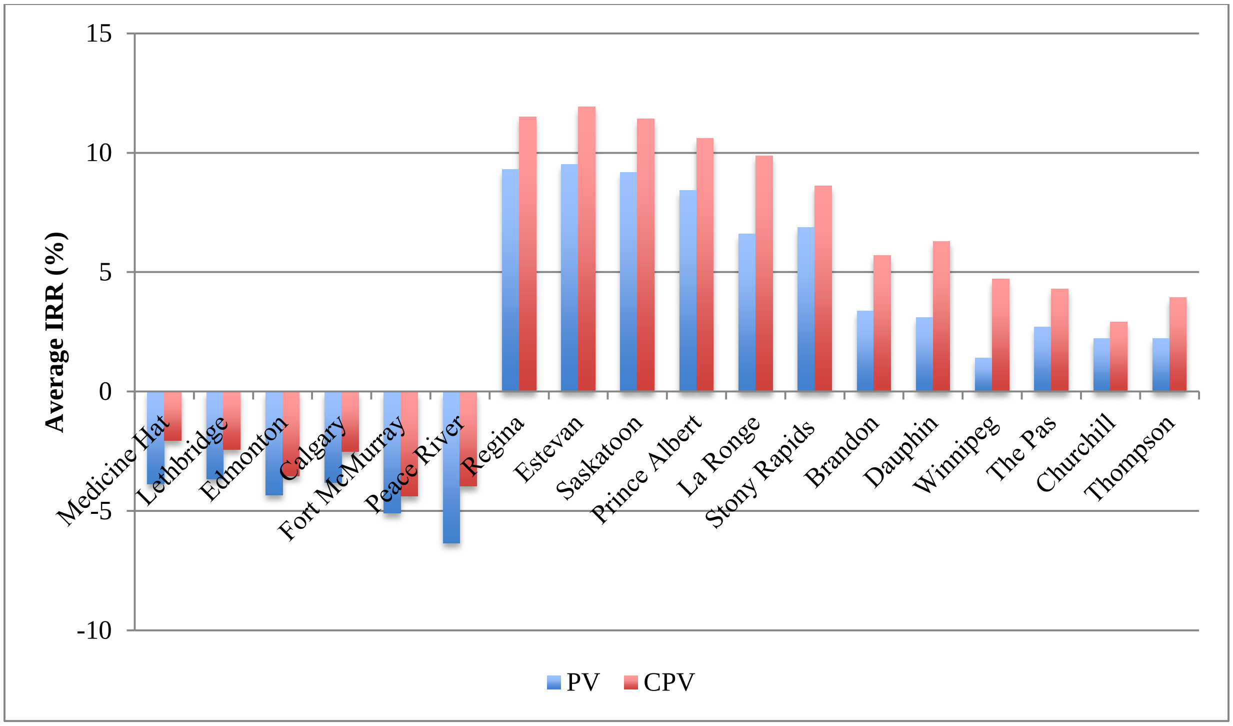


Figure 20: Graphical representation of the average IRR across all 18 cities for optimized PV and CPV technology. This includes the average IRR values from all four incentive scenarios for projects starting in 2016, 2018, and 2020.

Table 6 shows the extent to which CPV provides a higher IRR than optimized PV systems, averaged across all 18 cities. It demonstrates that the difference in systems cost between the two technologies is a major factor that contributes to the difference in IRR, since systems costs are very similar in 2016 but are very different in 2020 (Table 5). From this, it can be seen that CPV is especially superior for project start dates of 2020, with CPV IRR values being just more than 3% higher than PV IRR values. For project start dates in 2016, the difference in IRR between CPV and optimized PV is less than 1%, meaning that either technology will produce similar IRR values.

Table 6: The extent to which CPV has a better IRR than PV optimized, averaged over all 18 cities (IRR (CPV) – IRR (PV)).

	No incentive	**10% incentive**	**20% incentive**	**30% incentive**
2016	0.61%	0.61%	0.58%	0.55%
2018	1.8%	1.8%	1.9%	1.9%
2020	3.2%	3.3%	3.5%	3.6%

Another aspect of this research analyzed the IRR improvement between optimized PV and south facing PV, where the azimuth is set to 0° and the tilt angle is equal to the latitude. These results are presented in Table 7.

Table 7: The average IRR improvement when a PV system is optimized (tilt and azimuth are optimized for maximum revenue). This table shows the impact of PV optimization on IRR. The average IRR values are rounded for readability.

City	**Average IRR PV Optimized (IRRo)**	**Average IRR PV South Facing (IRRs)**	**Average IRR improvement (%) (IRRo/IRRs)-1**
Medicine Hat	-3.88%	-3.97%	2.27%
Lethbridge	-3.67%	-3.76%	2.39%
Edmonton	-4.33%	-4.43%	2.26%
Calgary	-3.80%	-3.90%	2.56%
Fort McMurray	-5.09%	-4.16%	2.24%
Peace River	-6.34%	-6.47%	2.01%
Regina	9.30%	9.18%	1.31%
Estevan	9.51%	9.82%	3.16%
Saskatoon	9.19%	9.06%	1.43%
Prince Albert	8.42%	8.27%	1.81%
La Ronge	6.59%	6.44%	2.33%
Stony Rapids	6.88%	6.67%	3.15%
Brandon	3.37%	3.28%	2.74%
Dauphin	3.10%	3.02%	2.65%
Winnipeg	1.42%	3.14%	5.49%
The Pas	2.71%	2.58%	5.04%
Churchill	2.23%	2.06%	8.25%
Thompson	2.22%	2.10%	5.71%

The values show the extent to which IRR is improved when optimizing a PV system. For instance, optimizing a PV system in Edmonton results in a 2.26% increase in IRR, a 1.31%

increase in Regina, and a 2.65% increase in Dauphin. Optimizing PV systems seems to be quite favourable in Manitoba, where IRR improvement ranges from 2.65% to 8.25%. This information could be beneficial to households since it verifies the fact that a solar project would be more financially viable when the tilt and azimuth of a PV system are optimized for maximum revenue. The different optimization values for each city will be discussed in detail in a following section.

5.2 Mapping IRR Results

The majority of this research focused on analyzing the IRR for PV and CPV residential solar projects. This research focused on 14 incentive scenarios, as shown in Table 8.

Table 8: The incentive scenarios and project start dates that were focused on for the IRR mapping.

PV	**CPV**
2018 with no additional incentive	2018 with no additional incentive
2018 with a 10% additional incentive	2018 with a 10% additional incentive
2018 with a 20% additional incentive	2018 with a 20% additional incentive
2018 with a 10% additional incentive	2018 with a 20% additional incentive
20% additional incentive in 2016	20% additional incentive in 2016
20% additional incentive in 2018	20% additional incentive in 2018
20% additional incentive in 2020	20% additional incentive in 2020

This section will present 8 out of 14 graphs, which show the IRR for all 18 cities. The remaining graphs can be found in Appendix C. The maps show estimated contour lines that represent the IRR; these contour lines were drawn based off of the solar irradiance map patterns from Figures 6 and 7 (Ecosmart, 2016). Since this study only looked at 18 cities, these maps are in no way an exact representation of IRR across the three provinces; they can only serve as an estimate that can act as a stepping-stone for adding other cities, therefore increasing the sample size, within each province. The legend at the top of each graph represents the IRR range of values, the purple and blue colours are very low, and the pink and red values are high values.

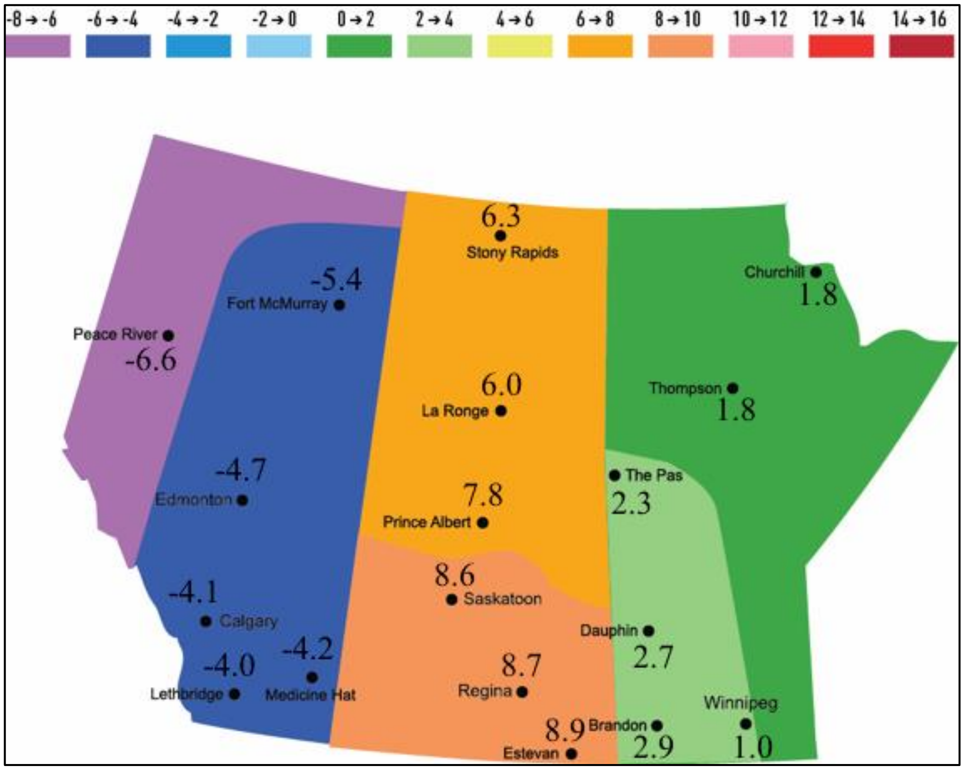


Figure 21: PV 2018 with a 10% additional incentive.

Figure 21 shows the PV optimized IRR in all cities in the year 2018 with a 10% additional incentive. Figure 22 shows the CPV IRR in 2018 with a 10% additional incentive. These maps provide an easy way to visually see the difference in IRR between PV and CPV technology.

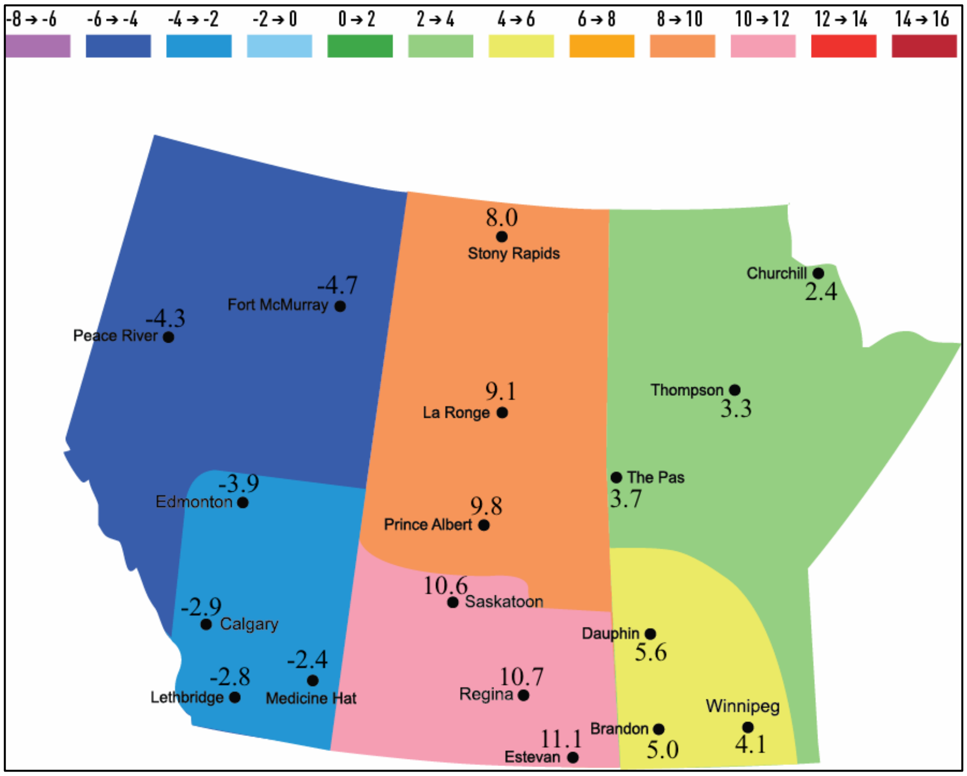


Figure 22: CPV 2018 with a 10% additional incentive.

Figure 23 shows PV projects starting in 2018 with an additional 30% incentive, and Figure 24 shows CPV projects starting in 2018 with a 30% incentive. Figure 25 shows PV projects with a 20% additional incentive with a project start date of 2016, and Figure 26 shows the same except for CPV technology. Figure 27 shows PV projects with a 20% additional incentive with a project start date in the year 2020 and Figure 28 shows CPV projects with an additional 20% incentive with a start date of 2020.

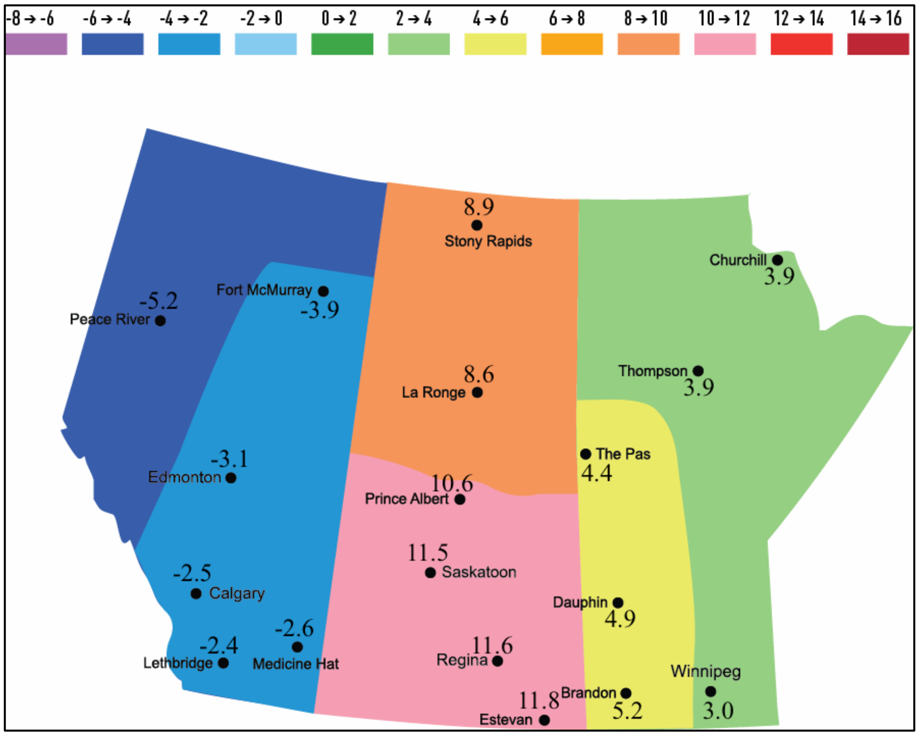


Figure 23: PV 2018 with a 30% additional incentive.

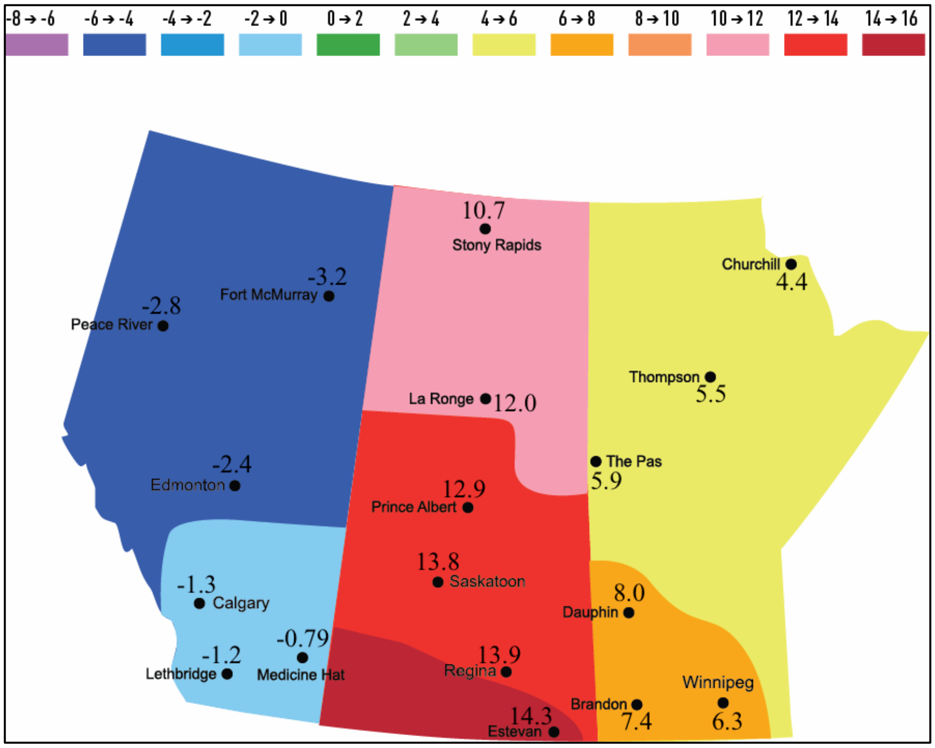


Figure 24: CPV 2018 with a 30% additional incentive.

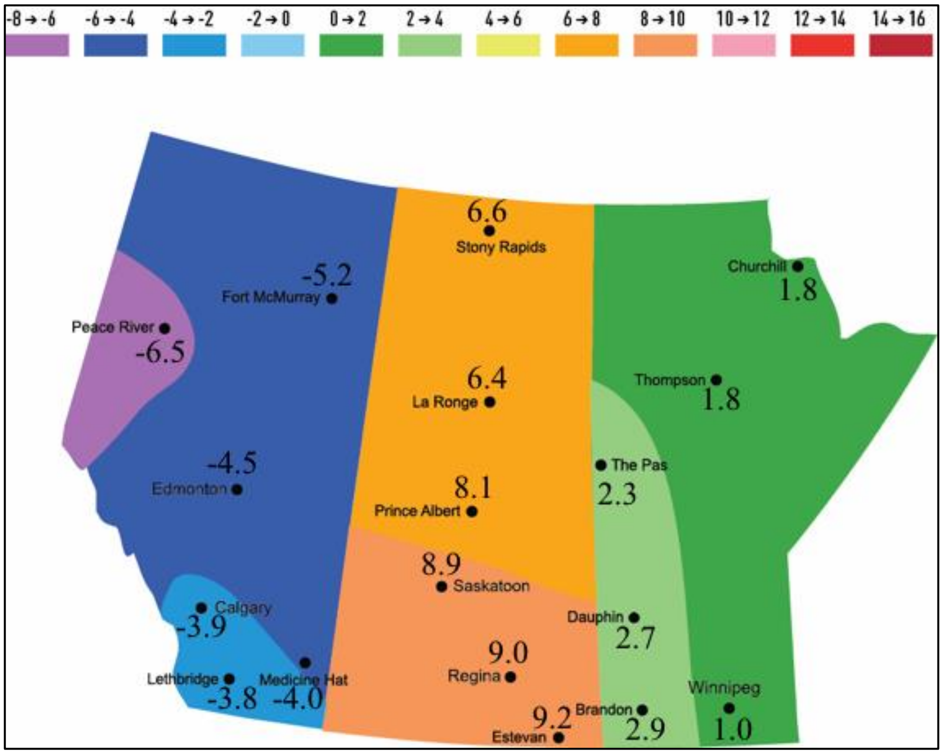


Figure 25: PV with an additional 20% incentive in 2016.

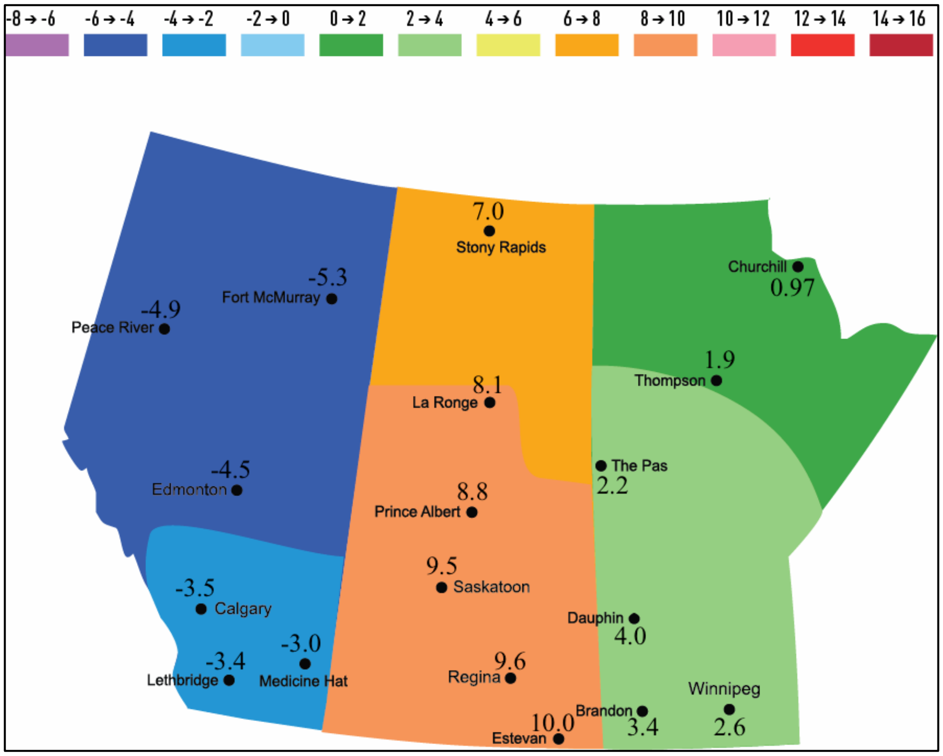


Figure 26: CPV with an additional 20% incentive in 2016.

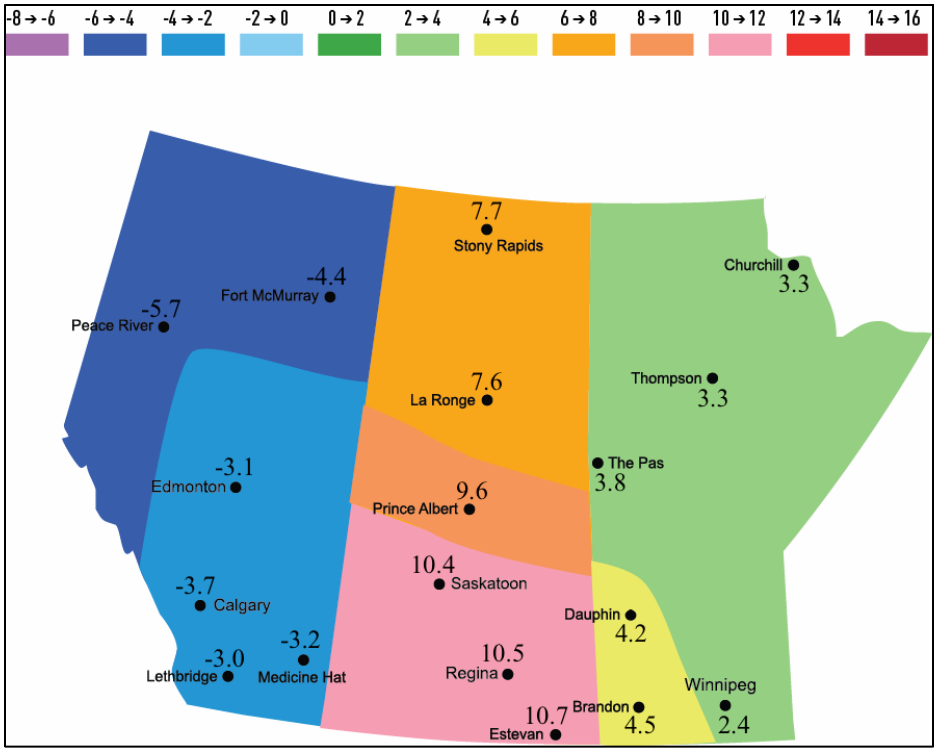


Figure 27: PV with an additional 20% incentive in 2020.

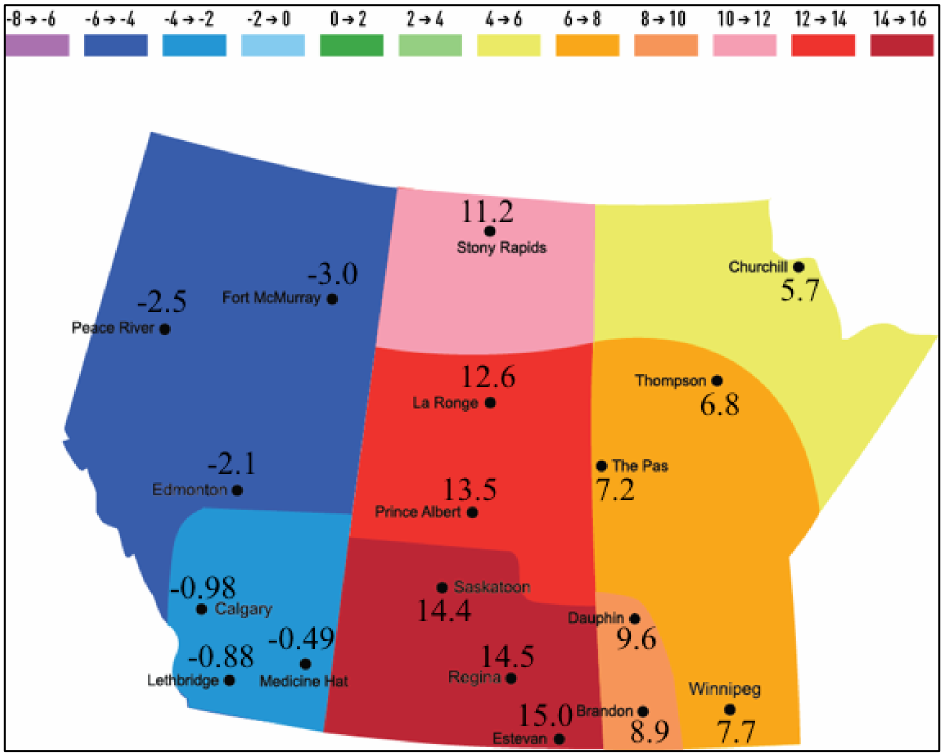


Figure 28: CPV with an additional 20% incentive in 2020.

From the figures above, it is clear that there is a difference in IRR between PV and CPV technologies. Additionally, the incentive scenario that is applied in a certain year has a large effect on the range of IRR across all cities. The above results, as well as the results in section 5.1 show that the IRR is highest in Saskatchewan and lowest in Alberta across all scenarios.

5.3 Net Present Value Results

This research also analyzed the impact of various cost incentives on the net present value of residential solar power in all 18 cities with project start dates of 2016, 2018, and 2020 for CPV and PV technologies (all graphs are found in Appendix B), using an assumed total investment of $100,000. For CPV technologies, a discount rate of 7% and 9% were applied to reflect the higher level of risk involved with more moving parts of the installation (Poullikkas et al., 2013); PV technologies used a 7% discount rate (Bazilian et al., 2013; Barbrose et al., 2013; REN21, 2013; Swift 2013). The NPV method is useful since it demonstrates exactly what year the NPV becomes positive and therefore a viable investment option. The following graphs quantify the extent to which NPV is impacted based on an additional incentive for both technologies. NPV values will be presented for one city in Alberta, Saskatchewan, and Manitoba below. The remaining cities and the respective NPV graphs can be found in Appendix B.

Edmonton, Alberta does not offer a residential solar incentive at the provincial level and has the lowest electricity tariff of $0.048665/kWh out of the three studied provinces (Enmax Corporation, 2016). The combination of a low electricity tariff and lower irradiance levels (EcoSmart, 2016), contributes to the NPV being negative for all six cities across Alberta, for all three technologies (PV, CPV with 9% discount rate, and CPV with 7% discount rate). The results in Figure 29 show the impact of a 10%, 20% and 30% systems cost incentive on the NPV of a residential CPV system using a 9% discount rate.

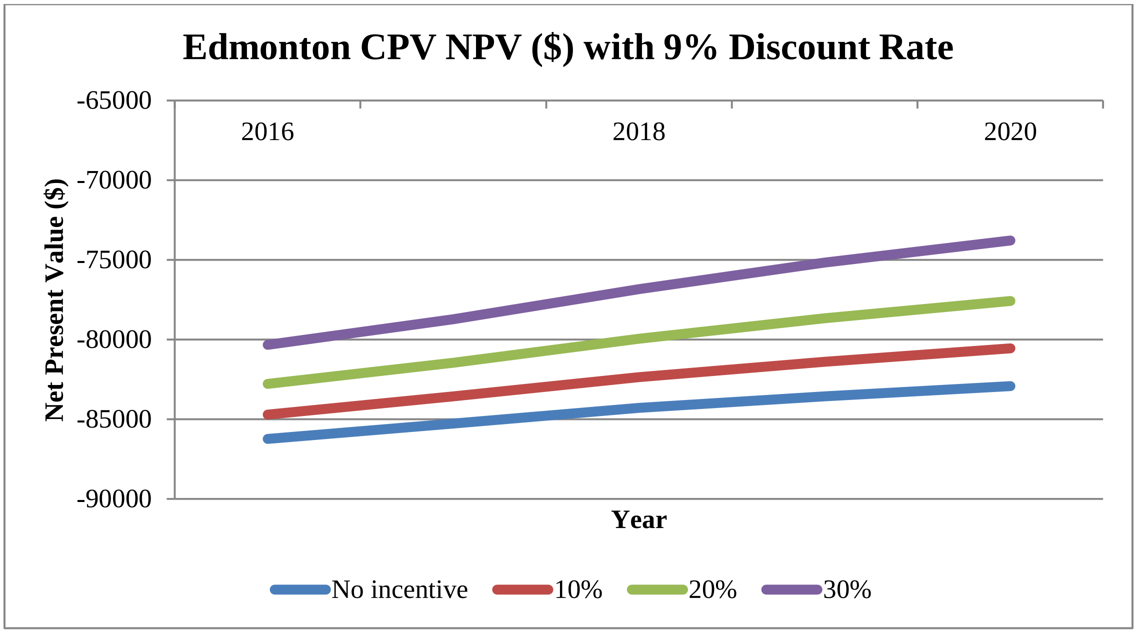


Figure 29: Net present value for a CPV system in Edmonton using a 9% discount rate.

As shown in the above figure, NPV values range from $-86,231.34 (with no incentive) to $-80,330.48 (with a 30% reduction in capital costs) in 2016. In 2018, NPV values range from $-84,284.64 to $-76839.40 and in 2020 the NPV values range from $-82,915.34 to $-73,785.24 (as seen in Figure 29). The average NPV in 2016, 2018, and 2020, across all incentive scenarios, is $-81,025.90. These large negative values are certainly undesirable from a homeowner standpoint, and can be attributed to a combination of a higher discount rate, low electricity costs, and the fact that the province of Alberta does not have any residential solar cost incentives. The NPV improved slightly when a lower discount rate of 7% was applied. These results are shown in Figure 30 below.

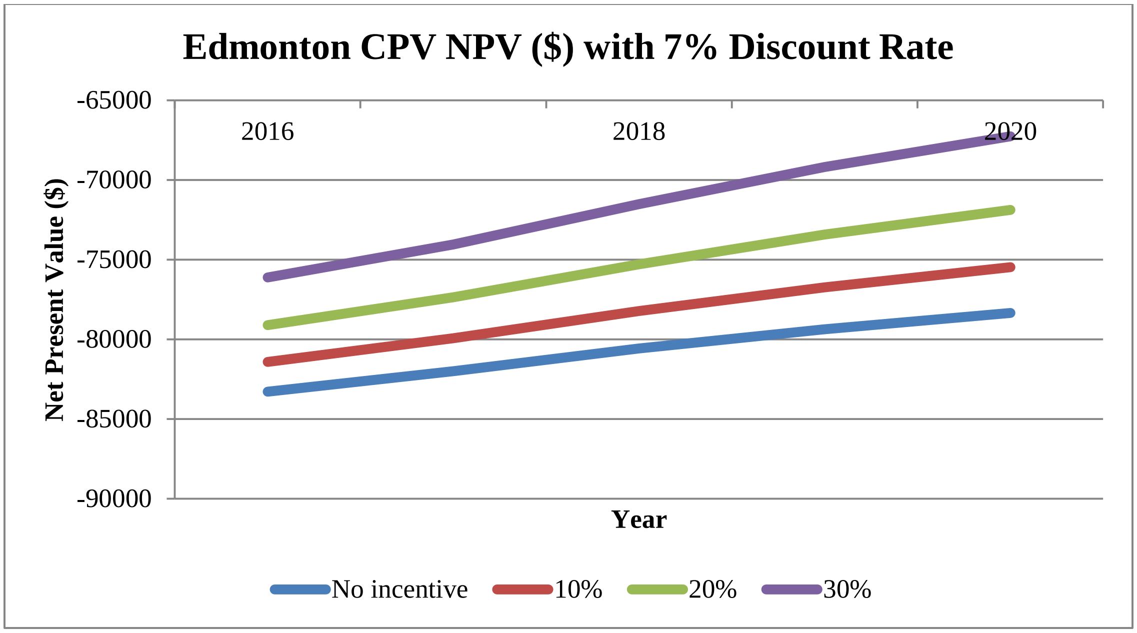


Figure 30: Net present value of a CPV system using a 7% discount rate in Edmonton.

In 2016, the NPV values range from $-83,282.02 (with no incentive) to $-76,117.17 (with a 30% incentive), while in 2018, the values range from $-80,563.42 to $-71,523.378. In 2020, the NPV values are highest across all incentive scenarios, ranging from $-78,352.02 to $-67,266.21. The average NPV across all incentives over three years is $-76,542.02.

The NPV results for PV technology in Alberta are rather interesting and noticeably different from the CPV results. As shown in Figure 31 and in Appendix B, the trend in NPV increases or decreases on a case-by-case basis, based on the city, the year of the investment, and the incentive that is applied. Using Edmonton as an example, the NPV values in 2016 range from $-81,381.29 (with no incentive) to $-73,401.85 (with a 30% incentive). In 2018, these values increase to $-81,033.12 to $-72,194.37. However, in 2020, NPV values decline to $-82,148.04 (with no incentive) to -$72,689.09 (with a 30% incentive). Another important result to highlight is that the 2020 NPV value is less than the value in 2016 under a no incentive and when a 10% incentive is implemented. When a 20% or 30% systems cost incentive is implemented, the NPV value in 2020 is higher than the value in 2016, although lower than the value in 2018. This demonstrates that 2018 would be the suggested year, out of the three given years, to invest in PV technology in Edmonton.

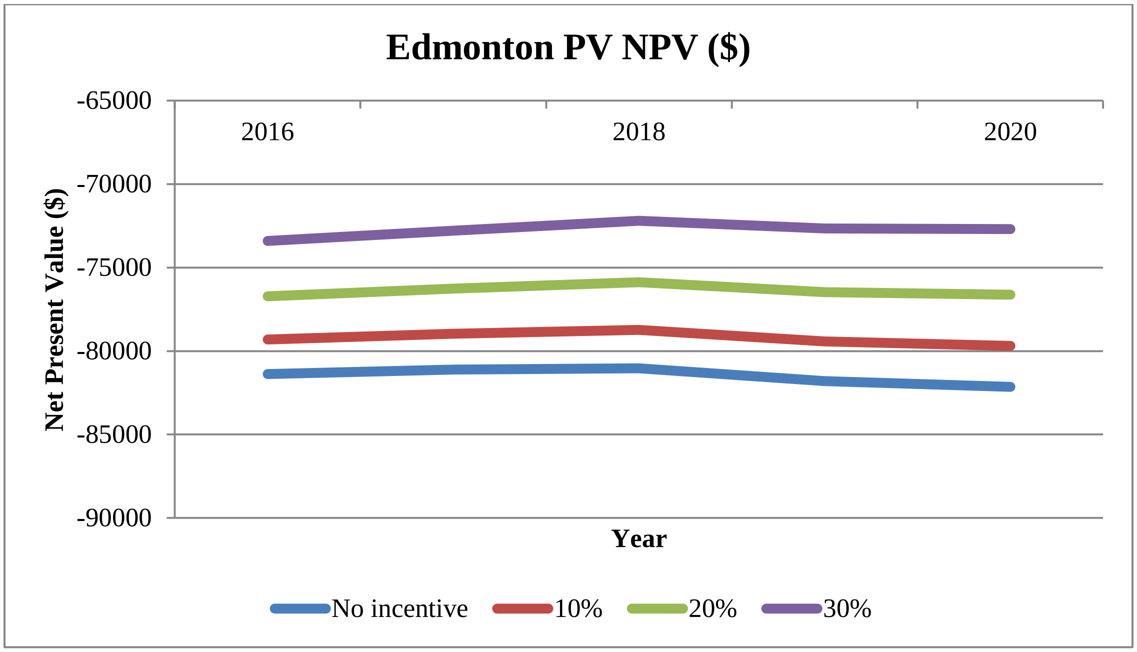


Figure 31: Net present value for PV in Edmonton under various cost incentives.

Across all six cities in Alberta, on average, the NPV decreases over time when there is no cost incentive or a 10% cost incentive applied (see Alberta NPV graphs in Appendix B). This means that over time, under these two incentive scenarios, the NPV actually decreases, meaning that this would not be a financially favourable investment. However, under a 20% or 30% cost incentive, the NPV in 2020 is higher than the NPV in 2016, although still lower than the NPV value in 2018. This pattern is specific to the province of Alberta, which may be due to the low electricity tariff and the low (compared to the other provinces in Table 4) electricity rate increase per year, 3.5%. This will be touched upon again in the discussion section of this paper.

Regina, Saskatchewan is a city where the province has a high electricity tariff, large amounts of solar radiation, and a provincial rebate program to reduce systems costs of residential solar installations. The results for CPV NPV are presented below in Figure 32.

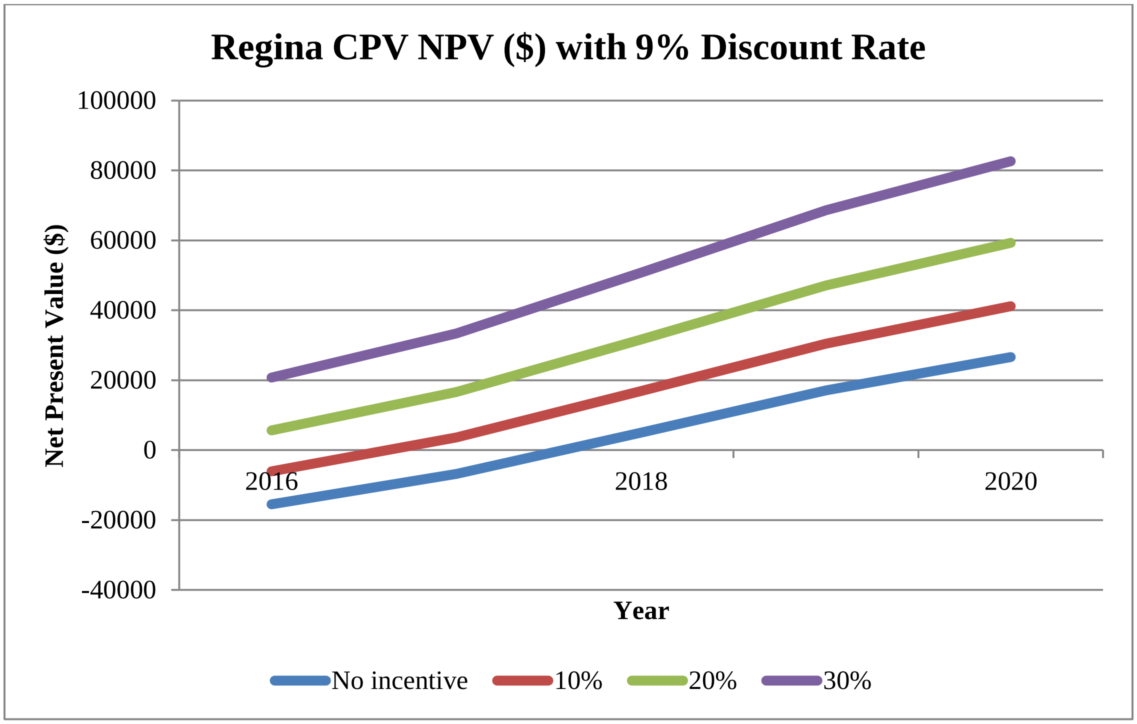


Figure 32: Net present value for CPV technology in Regina using a 9% discount rate.

As shown in Figure 32, NPV values range from $-15,450.93 (with no incentive) to $20,784.38 (with a 30% reduction in capital costs) in 2016. In 2018, NPV values range from $5,020.54 to $50,739.43, and in 2020 the NPV values range from $26,599.63 to $82,664.72. The average NPV in 2016, 2018, and 2020, across all incentive scenarios, is $26,582.52. When a lower discount rate of 7% was applied, the NPV values improved, since the discount rate is inversely related to NPV. The values did not fall below zero and increased over time under all incentive scenarios. Figure 33 shows this data.

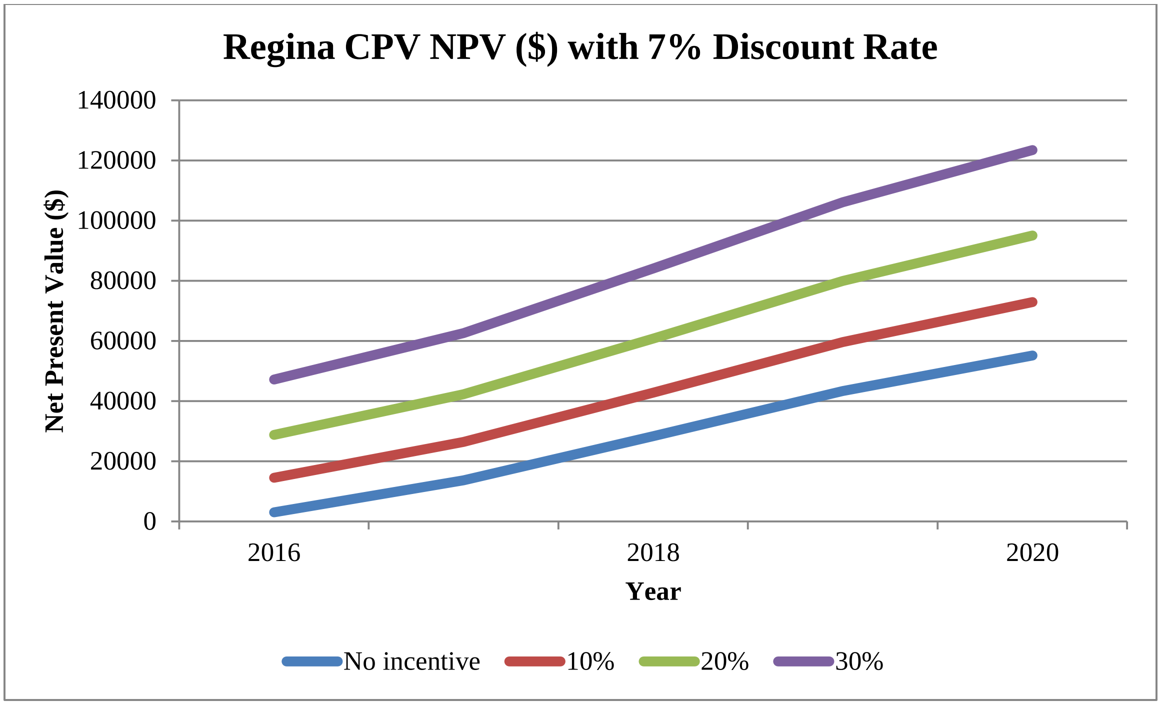


Figure 33: Net present value for a CPV system in Regina with a 7% discount rate.

In 2016, the NPV values range from $3,016.39 (with no incentive) to $47,166.27 (with a 30% incentive), while in 2018, the values range from $28,321.17 to $84,026.04. In 2020, the NPV values are highest across all incentive scenarios, ranging from $55,173.20 to $123,484.10. The average NPV across all incentives over three years is $54,658.65. This highlights the impact of a lower discount rate, since all NPV values are positive in Figure 33 compared with the 9% discount rate values in Figure 32, where some values are negative.

NPV values for a PV system in Regina are similar to the results of CPV with a 9% discount rate in that both sets of data contain both negative and positive values over time. The average NPV for PV project start dates of 2016, 2018, and 2020 is $3,374.72. Figure 34 below shows the trend over time across all incentive scenarios.

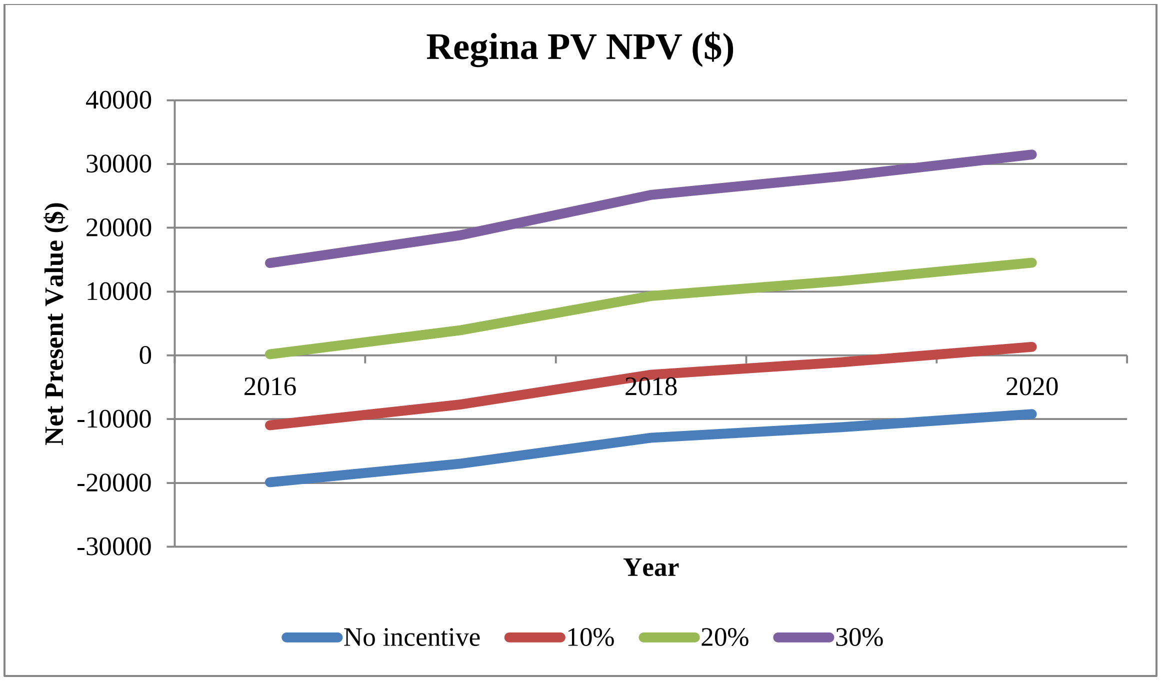


Figure 34: Net present value for a PV system in Regina.

In 2016, the PV NPV values range from $-19,862.67 (with no additional incentive) to $14,481.90 (with a 30% additional incentive). In 2018, the NPV increases, ranging between $-12,889.57 and $25,153.55, and in 2020, these values were the highest, ranging from $-9,223.00 to $31,489.53. Unlike the NPV values for a PV system in Alberta, these values increase over time, indicating that starting a PV project in 2020 is the most economically viable since the NPV values are highest.

Dauphin, Manitoba offers an incentive of $1/W, up to 200 kW, through the provincial Solar Energy program (Manitoba Hydro, 2016). This incentive is offered at the residential level and was incorporated into the model by reducing the initial system costs prior to applying the additional 10%, 20%, and 30% incentives. Manitoba also has an electricity tariff of $0.07930/kWh and has lower levels of solar irradiance compared to Saskatchewan (Ecosmart, 2016). Figure 35 shows the NPV results for CPV in Dauphin using a 9% discount rate, where the average NPV (across all project start dates) is $-22,139.17.

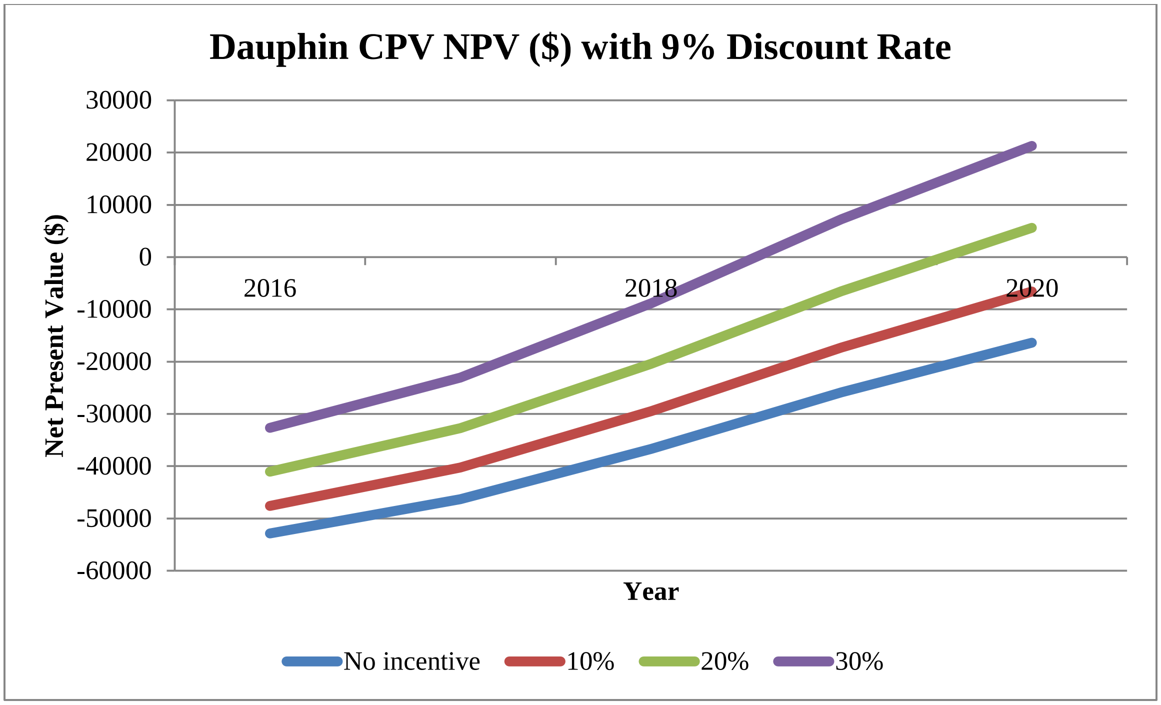


Figure 35: NPV for a CPV system in Dauphin using a 9% discount rate.

In 2016, the NPV values range from $-52,844.41 (with no additional incentive) to $-32,634.88. In 2018 the values range from $-36,680.79 to $-8,833.91, and in 2020 the NPV values range from $-16,372.15 to $21,276.45. These results indicate that deferring a CPV project until the year 2020, under a 9% discount rate and across all incentive scenarios, would be the most economically viable option since the NPV values are the highest in that year. These results can be compared to the NPV values for CPV using a 7% discount rate, where the average NPV across all incentives over time is $-5,062.25. This is a higher average compared to the 9% discount rate average, which was $-22,139.17. Figure 36 shows the results for a CPV system in Dauphin using a 7% discount rate.

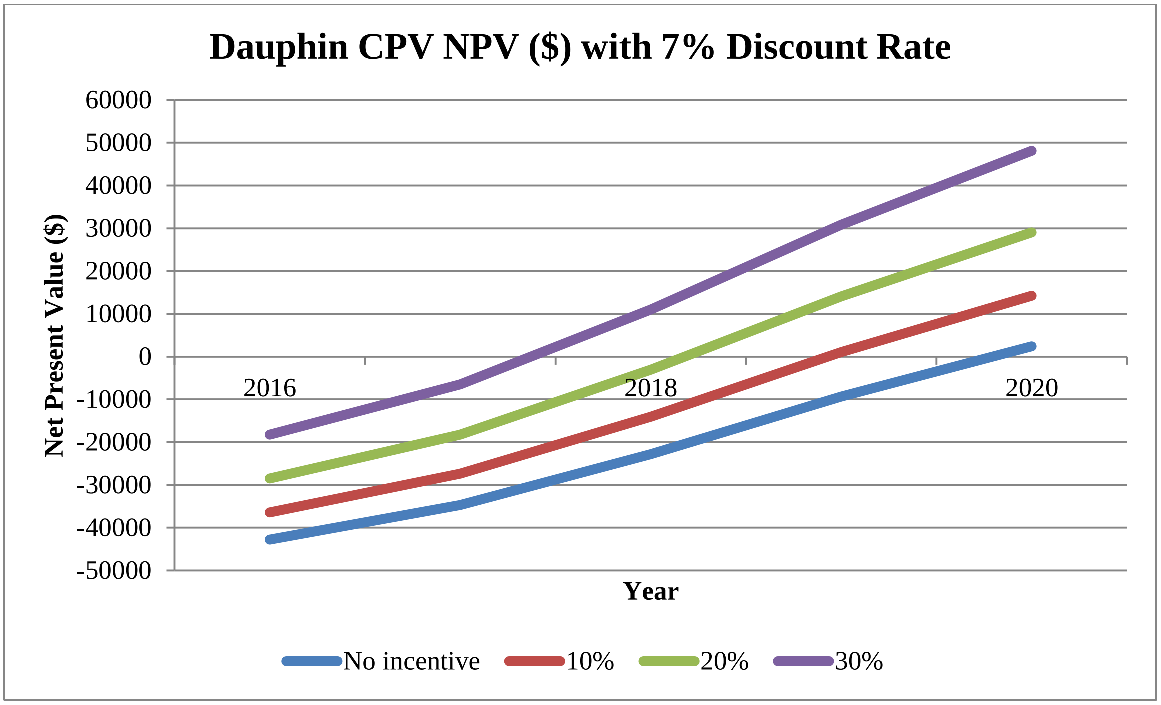


Figure 36: Net present values for a CPV system using a 7% discount rate in Dauphin.

The NPV values range from $-42,755.74 (with no additional incentive) to $-18,222.49 (with a 30% additional incentive) in 2016. In 2018, the values range from $-22,779.53 to $11,025.04, and in 2020, the NPV values are all positive, ranging from $2,422.17 to $48,125.49. As was the case with the NPV with a 9% discount rate, deferring the CPV project until 2020 results in the highest NPV values over time. However, under the additional 30% incentive scenario, deferring the project until 2018 would also yield positive NPV results. The NPV results for a PV system in Dauphin are not extremely favourable, as presented in Figure 37 below. The average NPV for a PV system is $-34,375.12, much lower than the both of the CPV NPV averages. As shown below, the NPV increases over time, although the values remain negative.

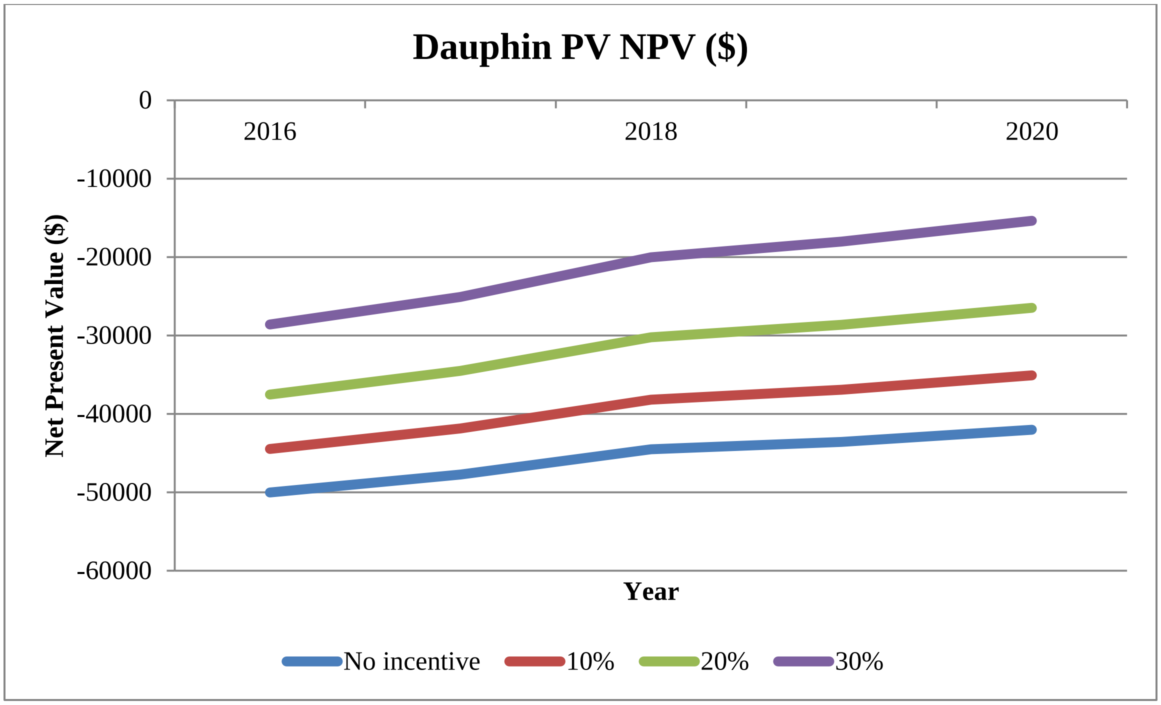


Figure 37: Net present values for a PV system in Dauphin.

In 2016, the NPV ranges from $-50,019.04 (no additional incentive) to $-28,598.63 (with a 30% additional incentive). In 2018, these values range from $-44,521.37 to $-20,034.73, and in 2020 range from $-42,012.73 to $-15,352.93.

The average NPV values for all 18 cities and project start dates are presented in Figure 38. This graph shows averages for three types of technology (CPV with a 9% discount rate, CPV with a 7% discount rate, and PV optimized). Across all 18 cities, the NPV is highest for CPV technology with a 7% discount rate.

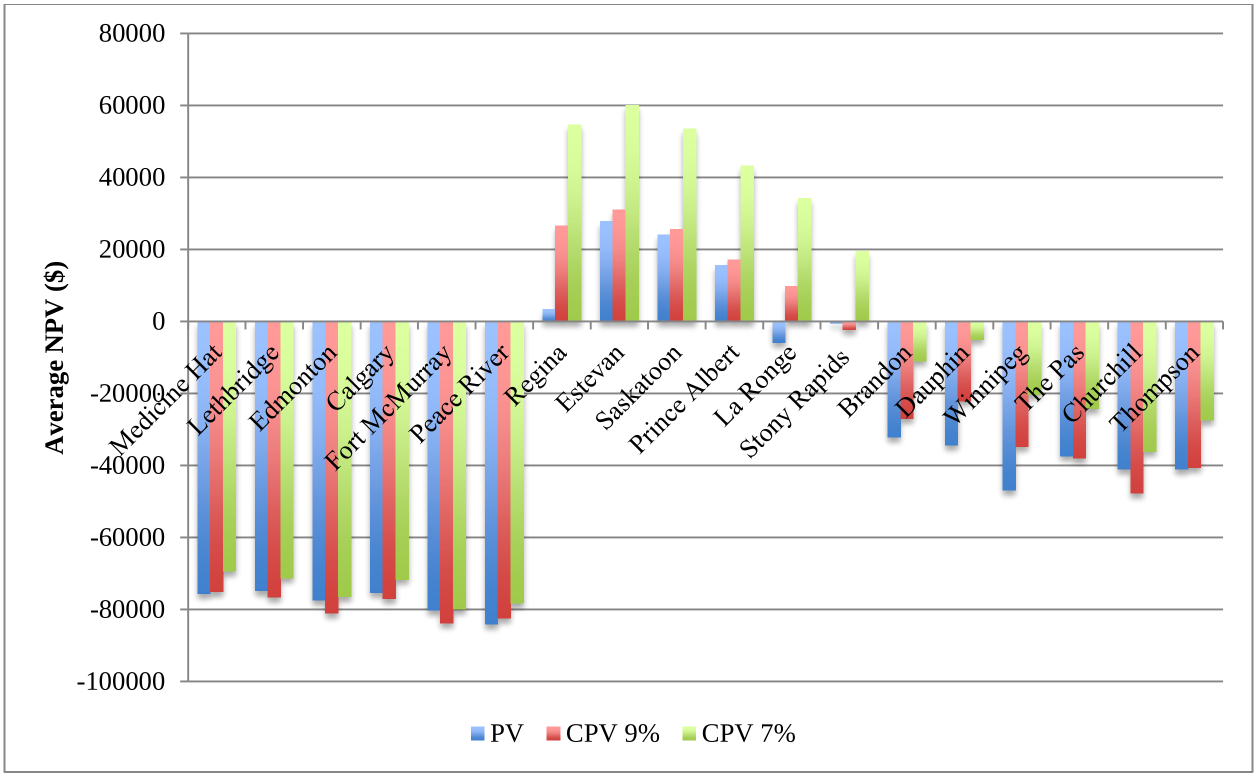


Figure 38: Average NPV across all 18 cities for PV, CPV with a discount rate of 9%, and CPV with a discount rate of 7%. This includes average NPV values across all four incentive scenarios for projects starting in 2016, 2018, and 2020.

Looking at Figure 38, if a household was interested in installing any type of solar technology and wanted to base their decision on NPV data, CPV technology using a 7% discount rate would be the most economically viable option since it results in the largest NPV values (for the 18 cities included in this study).

5.4 Sensitivity Analysis Results

This research analyzed the impact of optimizing PV tilt and azimuth for maximum revenue. The climate model for each city contained an optimization table that could be adjusted to any degree; for this study we focused on optimizing the tilt and azimuth values within ± 10° to get a coarse orientation, and within ± 2° for a fine, more accurate, orientation of the PV system. South facing PV refers to a solar installation where the azimuth is set to 0°, and the tilt is equal to the latitude of that city. As mentioned, the IRR and NPV analyses used PV fine as the "PV optimized" technology. Table 9 shows the results of running this optimization table for each city as well as the optimized revenue ($/kW/yr).

Table 9: Values for optimal azimuth and tilt (PV) are presented for each city based on the level of optimization. The table also presents the optimized revenue that is generated based on the degree of optimization.

Province	**City**	**Level of Optimization**	**Optimal Azimuth**	**Optimal Tilt**	**Optimized revenue ($/kW/yr)**
Alberta	Medicine Hat	Coarse	5	40	77.54
		Fine	6	44	77.45
		South facing	0	50.02	76.68
	Lethbridge	Coarse	5	40	79.23
		Fine	6	40	79.24
		South facing	0	49.63	78.42
	Edmonton	Coarse	0	40	63.76
		Fine	-2	44	63.80
		South facing	0	53.57	63.06
	Calgary	Coarse	5	40	78.02
		Fine	6	42	78.08
		South facing	0	51.10	77.51
	Fort McMurray	Coarse	5	50	67.67
		Fine	6	46	67.85
		South facing	0	56.65	66.73
	Peace River	Coarse	0	50	54.47
		Fine	2	46	54.61
		South facing	0	56.23	53.87
Saskatchewan	Regina	Coarse	0	40	215.51
		Fine	2	42	215.54
		South facing	0	50.43	213.41
	Estevan	Coarse	0	40	219.12
		Fine	0	40	219.12
		South facing	0	49.07	217.30
	Saskatoon	Coarse	5	40	213.27
		Fine	2	42	213.51
		South facing	0	52.17	211.38
	Prince Albert	Coarse	0	40	200.17
		Fine	2	42	200.38
		South facing	0	53.22	197.98
	La Ronge	Coarse	0	40	173.34
		Fine	2	44	173.77
		South facing	0	55.15	171.47
	Stony Rapids	Coarse	0	50	181.45
		Fine	2	46	181.78
		South facing	0	59.25	178.29
Manitoba	Brandon	Coarse	0	40	125.10

		Fine	0	40	125.10
		South facing	0	49.92	123.96
	Dauphin	Coarse	0	40	121.54
		Fine	-2	42	121.65
		South facing	0	51.10	120.69
	Winnipeg	Coarse	5	40	123.37
		Fine	6	40	123.37
		South facing	0	49.90	122.04
	The Pas	Coarse	0	40	116.86
		Fine	0	44	116.98
		South facing	0	53.97	115.46
	Churchill	Coarse	0	50	111.42
		Fine	2	46	111.61
		South facing	0	58.75	109.69
	Thompson	Coarse	5	50	112.13
		Fine	6	46	112.41
		South facing	0	55.80	111.00

The optimized revenue value is based on the optimized value ($) found in the optimization table (within the climate model), the number of years worth of data available from CWEEDS, and the kW output of the system. A sample calculation for the optimized revenue for PV fine in Edmonton is below, where 507.63 is the optimal value (in dollars) that was found in the climate model optimization table:

$$\frac{507.63}{51(\text{yrs})} \times \frac{1000}{156\text{W}}$$
$$= \$63.80/\text{kW/yr}$$

Based on the results in Table 9, it can be concluded that the greatest potential revenue earnings are PV projects in the province of Saskatchewan, followed by Manitoba, and then Alberta. Additionally, optimizing a PV system (either coarse or fine) results in higher revenue compared to south facing (non-optimized) PV system. This would be important for households, especially if a new house is being constructed with plans of installing a rooftop solar PV installation. If the homeowner's roof is not at the right angle to get the actual optimal IRR, Table 10 shows that there are wide ranges of roof angles that are possible to obtain an IRR that is close to optimal.

Table 10: This table shows the range of tilt and azimuth degrees that a PV system can be optimized to in order to obtain 95% or 99% revenue. Additionally, the table displays the change in azimuth between a PV south facing system and a PV optimized system, and the reduction in tilt angle from south facing to optimized PV. The ranges of tilt angles are displayed graphically in Figure 39.

City	**Latitude**	**95% Tilt Range**	**95% Azimuth Range**	**99% Tilt Range**	**99% Azimuth Range**	**Change in Azimuth from South facing to Optimized (+ values imply a shift towards the east of south)**	**Reduction in Tilt (from south facing to optimized)**
Medicine Hat	50.02	(18.93, 61.94)	(-37.63, 45.30)	(30.63, 50.54)	(-15.45, 22.52)	6°	6.02°
Lethbridge	49.63	(18.35, 61.42)	(-38.94, 44.22)	(30.09, 49.08)	(-16.01, 21.19)	6°	9.63°
Edmonton	53.57	(21.18, 64.41)	(-31.27, 41.56)	(33.25, 52.32)	(-15.86, 19.14)	-2°	9.57°
Calgary	51.10	(21.42, 63.99)	(-36.50, 41.72)	(33.26, 52.29)	(-13.97, 19.98)	6°	9.1°
Fort McMurray	56.65	(23.81, 66.0)	(-31.31, 41.79)	(35.54, 54.43)	(-11.67, 21.88)	6°	10.65°
Peace River	56.23	(24.59, 65.86)	(-31.02, 39.71)	(36.01, 54.63)	(-11.71, 21.31)	2°	10.23°
Regina	50.43	(19.55, 62.05)	(-37.80, 43.37)	(31.84, 50.45)	(-14.27, 21.03)	2°	8.43°
Estevan	49.07	(19.19, 61.58)	(-37.71, 43.39)	(31.26, 49.87)	(-14.10, 21.22)	0°	9.07°
Saskatoon	52.17	(21.87, 63.77)	(-36.62, 41.27)	(33.72, 52.07)	(-13.91, 19.30)	2°	10.17°
Prince Albert	53.22	(21.64, 66.49)	(-37.24, 41.43)	(33.67, 52.10)	(-14.20, 19.47)	2°	11.22°
La Ronge	55.15	(23.70, 64.98)	(-33.88, 40.69)	(35.13, 53.70)	(-11.78, 20.70)	2°	11.15°
Stony Rapids	59.25	(25.02, 66.98)	(-34.88, 39.26)	(37.04, 55.56)	(-13.94, 19.20)	2°	13.25°
Brandon	49.92	(19.04, 62.22)	(-37.90, 44.47)	(31.06, 50.31)	(-15.05, 22.05)	0°	9.92°
Dauphin	51.10	(21.36, 63.83)	(-37.16, 39.75)	(33.43, 51.85)	(-14.40, 18.13)	-2°	9.1°
Winnipeg	49.90	(18.52, 61.56)	(-36.54, 42.53)	(30.39, 49.60)	(-14.62, 20.47)	6°	9.9°
The Pas	53.97	(21.71, 64.15)	(-36.43, 40.07)	(33.64, 52.31)	(-13.77, 18.87)	0°	9.97°
Churchill	58.75	(24.73, 67.54)	(-35.97, 33.22)	(36.63, 55.60)	(-17.26, 14.39)	2°	12.75°
Thompson	55.80	(24.05, 66.53)	(-32.73, 40.09)	(35.67, 54.79)	(-13.28, 20.26)	6°	9.8°

The latitude and tilt ranges are presented graphically in Figure 39. The 95% tilt range represents what tilt the solar installation should be set at in order to earn 95% of the maximum revenue from the system. If the household wants to receive 99% of the maximum revenue, the tilt of the system should be set within the 99% tilt range in the above figure. Appendix A shows a sample calculation of how these values were obtained from the optimization table within the climate model.

As shown in Table 9, the optimal azimuth was only slightly different than the south-facing azimuth, whereas the optimal tilt was quite different from the latitude (the tilt for south facing PV). Since there was a large difference in tilt angles, which therefore impacts revenue earned, the following graph (Figure 39) shows the range of tilt angles that could be applied to get 95% or 99% revenue. The results in this figure can be used to assist households in determining the tilt angle of their solar PV installation, or it can be used to ensure that even if the rooftop is not angled exactly at the optimum angle, there are still wide ranges of angles that will result in earned revenue of the solar project.

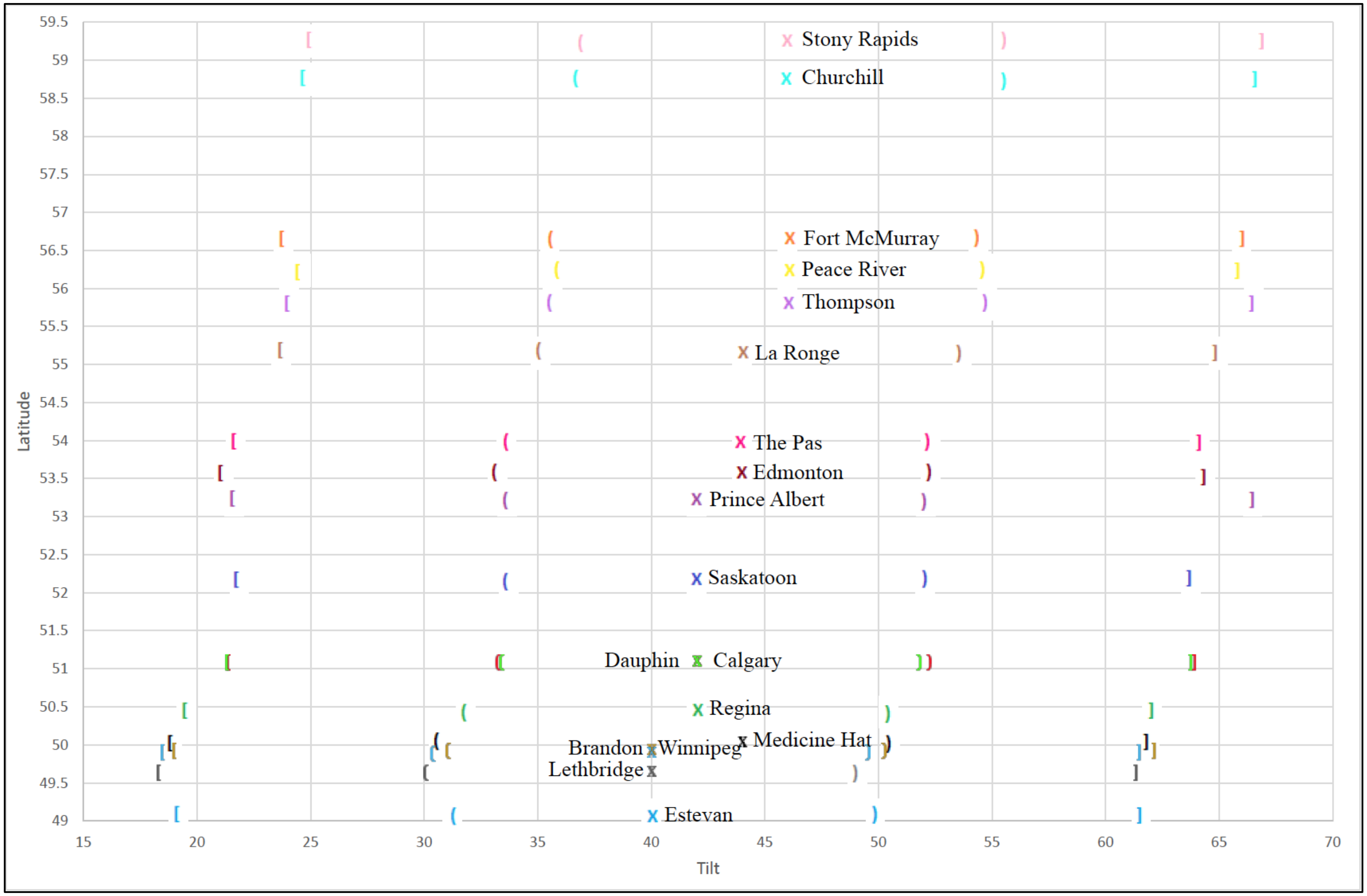


Figure 39: This figure shows the range of tilts based on whether the household wants to optimize for 99% revenue, or 95% revenue. Each city's optimal tilt, as represented by the symbol "X" is the PV optimized (fine) tilt value from Table 9. Square brackets [ ] represent the range of tilt angle that the household can set the PV system at to obtain 95% of revenue; curved brackets ( ) represent the range of tilt angle to obtain 99% of revenue. This is a graphical representation of the tilt ranges in Table 10.

6. Discussion

This study presented results for 18 cities within three Canadian provinces and looked at the impact of implementing various additional systems cost incentives on the economics of PV and CPV projects. The internal rate of return results were displayed and followed by maps that provided a visual picture of the IRR results over various incentive scenarios and project start dates for each city. The net present value results were then presented where it was shown that the discount rate impacts the NPV for CPV projects, and that PV technology produces a lower NPV compared to CPV technology. The final section of results presented data that spoke to the impact of PV optimization on the economic viability of a solar project.

Internal Rate of Return

As shown in section 5.1 and 5.2, across PV and CPV technologies, the IRR was lowest in the absence of an additional incentive to what current incentive, if any, is in place within the province. Since the province of Alberta does not have a residential cost incentive program for solar projects, the IRR values in Alberta were the lowest among the three provinces. This is also due to lower irradiance levels (Ecosmart, 2016) and low electricity costs ($0.048665/kWh), since it is cheaper for residents in Alberta to use traditional sources of electricity rather than invest in the installation of a solar project. Additionally, across all incentive scenarios and across all cities, the IRR increased over time, signifying that deferring a project until 2020 would prove the most economically favourable. This is due to increasing electricity prices over time, and declining systems costs. This explanation of increase in IRR over time is also true in Saskatchewan and Manitoba, although IRR values were higher compared to Alberta. A key finding of this study was that the impact of percent increases of IRR for CPV systems are less marked than those for

PV systems. This is due to the fact that CPV IRR is higher to begin with, and has lower systems costs. Additionally, the IRR increases by more than the sum of the electricity price increase and system price decrease for CPV, but for PV, the IRR increase is less than the percentages of the two factors. Again, this is due to CPV technology having greater IRR to begin with compared to PV.

Rodrigues et al. (2016) stated that if the interest rate is higher than the IRR of a project, it is not a viable investment. Since we are looking at residential solar projects, we can assume that the interest rate is similar or equal to the discount rate used. This essentially means that if the IRR is greater than the discount rate, the project should be pursued. In fact, from the literature review in an earlier section of this paper, the IRR is a discount rate that makes the NPV value equal zero. For PV technology, the discount rate is 7%, and for CPV technology, this study used a 7% and a 9% discount rate (Bazilian et al., 2013; Barbrose et al., 2013; Poullikkas et al., 2013; REN21, 2013; Swift 2013). As mentioned previously, the IRR results were the same for CPV with a 9% discount rate and a 7% discount rate. By looking at the graphs in section 5.1 and the IRR graphs in Appendix B, it can be seen where the IRR is greater than the discount rate and what incentive scenario provides that value. For instance, Edmonton and all other cities in Alberta, have negative IRR values, indicating that a solar project would not prove to be economically viable. For these cities, all IRR values are below the discount rate. In Saskatchewan, Regina has positive IRR values for both PV and CPV technologies, however, in 2016 under the “no additional incentive” scenario, the IRR value is 6.7%, just below the 7% discount rate. Therefore, implementing a project in 2016 when there is no additional incentive would yield poor economic results. For all other incentive scenarios in all years, the IRR is above the discount rate of 7%, with the highest IRR value being the 30% additional incentive scenario in 2020, 12.2%. Even the average IRR for projects starting in 2016, 2018 and 2020 across all scenarios is higher than the discount rate, with a value of 9.3%. In Dauphin, Manitoba, the PV IRR value in 2016 is as low as 0.91%. This is when there is no additional cost incentive applied, and this is well below the 7% discount rate (Figure 18). On the other hand, even under a 30% additional incentive scenario with a project start date of 2020, the IRR is largest with a value of 5.4%. This is less than the discount rate; investing in a PV project would therefore not be economically attractive. This method can be applied to all cities for both PV and CPV projects to determine the economic feasibility of a solar project.

Mapping the Internal Rate of Return

This paper produced 14 IRR contour maps across the three provinces that were analyzed under different incentive scenarios and different project start dates. At the time of writing, this has not been done in the literature before so this research may provide useful information to other studies that want to include more cities across additional provinces in order to create a full map of Canada. As described above, the IRR contour lines are based off of solar irradiance satellite measurements (Ecosmart, 2016). Each province has a unique irradiance pattern and different values of IRR so there is a wide range of information that can be taken from the maps. Out of the 14, the IRR values were highest for CPV technology with a 20% additional cost incentive with the project start dates of 2018 and 2020, and in 2018 with a 30% additional cost incentive. For PV technology, the IRR values were highest when the project started in 2018 under a 20% and 30% incentive scenario. As discussed in section 5.2, these maps are estimates of the actual patterns, since 18 cities is not a large enough sample size to create a full IRR map of Canada. This points to an area of future research that would prove beneficial to homeowners, industry, and government by speaking to the positive impact a systems cost incentive has on the IRR and NPV of solar projects.

Net Present Value

In terms of the net present value results, the discount rate did have an impact on the NPV, specifically for CPV technology. When the discount rate was high (9%; accounting for more risk), the NPV values were lower, since there is an inverse relationship between NPV and discount rate. Therefore, across all cities, NPV with a discount rate of 7% provided higher NPV values than CPV with a 9% discount rate, and is therefore a better investment. It was demonstrated that across both CPV and PV technologies, the NPV was lowest in the absence of an incentive compared to when an incentive was implemented. The average NPV was lowest (and negative) in all six cities in Alberta, for CPV and PV, and was the highest (and positive) in Saskatchewan. Manitoba had negative average NPV values that were across all incentive scenarios and project start dates, but less negative compared to the NPV in Alberta. CPV technology provided higher NPV values in all scenarios in each city; this can be attributed to the higher efficiency of the technology, by tracking the sun, as well as lower systems costs compared to PV. These factors, combined with rising electricity prices, all contribute to higher NPV values for CPV technology.

Sensitivity Analysis Results

Finally, this research looked at the effects of optimizing PV systems for IRR. It was found that optimizing the tilt had more of an effect on IRR compared to optimizing the azimuth, since the optimal tilt values were very different from the latitude (tilt for a south facing PV system), whereas the azimuth values were not dramatically different from the optimal azimuth values. This study also reported the range of tilt and azimuth degrees that would provide 95% or 99% of the maximum revenue. This information could be extremely useful for homeowners who are interested in installing PV systems on their rooftop; the optimization results show that even if the roof is not exactly at the optimal angle, there is a wide range of tilt angles that would provide 95% or 99% of maximum revenue. Furthermore, the greatest potential revenue earnings for PV projects are in the province of Saskatchewan, followed by Manitoba, and then Alberta.

7. Conclusion

This paper presented an analysis of the economic impact of various systems cost incentives for residential CPV and PV projects in three Western Canadian provinces. A total of 18 cities were analyzed at various levels of solar irradiance. If applicable, the provincial incentive for residential solar projects was taken into account before an additional incentive of 10%, 20%, and 30% was applied in order to analyze the internal rate of return and net present value under a range of possible cost rebates. The rising electricity prices coupled with declining capital costs of solar panels resulted in increasing IRR and NPV over time, where project start dates in 2020 proved to be the most economically viable.

The results show that the IRR values were higher for CPV systems compared to PV systems, with the highest values found in cities in Saskatchewan. The IRR results were also plotted on solar irradiance maps of Canada, which created estimated IRR contours based on irradiance patterns. This provided a visual depiction of where the most favourable locations are to install a solar project under various incentive scenarios. Lower latitude cities in Saskatchewan provided the largest IRR values, especially for CPV technology. CPV technology in Estevan, Saskatchewan had the largest IRR value of 17% under a 30% incentive in the year 2020, where the largest PV IRR value was 12.4% under a 30% incentive in 2020.

The net present value results indicated that CPV technology with a 7% discount rate is most favourable in all 18 cities since it produces the highest NPV values across all incentive scenarios. The highest NPV values were also found in Saskatchewan, specifically Estevan where the CPV NPV value with a 7% discount rate was $131,327.76 under a 30% incentive scenario for a project starting in 2020. The PV NPV was highest in 2020 in Estevan ($62,920.35) when an additional 30% incentive was applied.

Optimizing a PV system also increased the amount of revenue earned from the investment, particularly the optimized tilt angle. Various tilt ranges were presented to obtain 95% or 99% of the maximum revenue. These values would be useful for households when determining the tilt angle of their solar PV installation.

In conclusion, the economic viability of a project largely depends on the electricity tariff, but also on the implementation of a systems cost incentive. The more capital cost incentives that are provided, the more cost competitive solar power becomes with other traditional sources of electricity (i.e. natural gas, hydro, oil/coal etc.). If countries want to meet their climate change goals and emission reduction commitments, more efforts should be made to ensure that solar power is an economically feasible option, especially for homeowners. A key finding of this research is that the government needs to subsidize systems costs by 30% in order to make solar power profitable to a homeowner. Solar power is profitable when the IRR is greater than the discount rate (7% for PV, 7% or 9% for CPV). Overall, incentives that reduce systems prices have a major impact on the IRR and NPV of residential solar projects, and having an additional incentive offered would greatly improve the financial viability of residential solar projects.

8. Appendix A

Sample calculation for PV and CPV systems costs

Initially, projections of residential PV capital costs, presented by Feldman et al. (2015), were averaged for the years 2016, 2018, and 2020. The average capital cost in 2016 equalled $3.14/W, $2.88/W in 2018, and $2.76/W in 2020. NREL (2016b) then published an updated February 2016 value for residential PV capital costs, equal to $3.89/W. The following calculation was performed to find the percent increase:

$$\frac{(3.89 - 3.14)}{3.14} \times 100$$

= 0.2389 x 100
= 23.9% increase

The percent increase was then applied to the Feldman et al. (2015) 2018 and 2020 values:

2018: 2.88 x 1.239 = 3.57

2020: 2.76 x 1.239 = 3.42

This is how the PV capital costs ($/W) were calculated.

To find the new CPV capital costs, values from Haysom et al. (2014) were updated by applying the percent increase used for PV systems, as well as a percent increase from values presented by Feldman et al. (2015). The original CPV capital costs were $1.80/W in 2016, $1.45/W in 2018, and $1.21/W in 2020 (Haysom et al., 2014).

Feldman et al. (2015) projected capital costs for both residential and utility scale projects. Since there is less literature on CPV technology, averages were calculated for utility scale projects: $1.82/W in 2016, $1.66/W in 2018, and $1.52/W in 2020. In 2016, residential PV capital costs equalled $3.14/W, and utility scale PV capital costs equalled $1.82/W. The same calculation as above was performed to find the percent increase for residential, which is 73.5%. The calculation for CPV capital costs ($/W) is below.

CPV 2016: 1.80 (1.239) (1.735) = 3.86

CPV 2018: 1.45 (1.239) (1.735) = 3.11

CPV 2020: 1.21 (1.239) (1.735) = 2.60

Sample calculation for finding optimal azimuth and tilt ranges

In order to find the range of tilt and azimuth, for both 95% and 99% revenue, the following calculations were performed for each city. Edmonton will be used as an example. For all cities, the PV fine optimal value ($) was used to determine the 95% and 99% value to look for in the optimization table within the model.

95% revenue calculation:

507.6306 x 0.95 = 482.249

Lower Limit Tilt

20 (479.9865); 30 (499.158)

$$\frac{479.9865 - 482.249}{479.9865 - 499.158} = \frac{x}{10}$$

x = 1.180
Tilt = 20 + x
Tilt = 21.180

Upper Limit Tilt

60 (492.494); 70 (469.2346)

$$\frac{492.494 - 482.249}{492.494 - 469.2346} = \frac{x}{10}$$

x = 4.4047
Tilt = 60 + x
Tilt = 64.405

Lower Limit Azimuth

-35 (473.8242); -25 (496.4165)

$$\frac{473.8242 - 482.249}{473.8242 - 496.4165} = \frac{x}{10}$$

x = 3.7291
Azimuth = -35 + x
Azimuth = -31.271

Upper Limit Azimuth

35 (490.2025); 45 (478.0859)

$$\frac{490.2025 - 482.249}{490.2025 - 478.0859} = \frac{x}{10}$$

x = 6.5641
Azimuth = 35 + x
Azimuth = 41.5641

99% revenue calculation:

507.6306 x 0.99 = 502.55

Lower Limit Tilt

30 (499.0076); 35 (504.4625)

$$\frac{499.0076 - 502.55}{499.0076 - 504.4625} = \frac{x}{5}$$

x = 3.24699
Tilt = 30 + x
Tilt = 33.24699

Upper Limit Tilt

50 (504.9305); 55 (499.7929)

$$\frac{504.9305 - 502.55}{504.9305 - 499.7929} = \frac{x}{5}$$

x = 2.3167
Tilt = 50 + x
Tilt = 52.3167

Lower Limit Azimuth

-20 (499.6976); -15 (503.1446)

$$\frac{499.6976 - 502.55}{499.6976 - 503.1446} = \frac{x}{5}$$

x = 4.1375
Azimuth = -20 + x
Azimuth = -15.863

Upper Limit Azimuth

15 (505.156); 20 (502.0022)

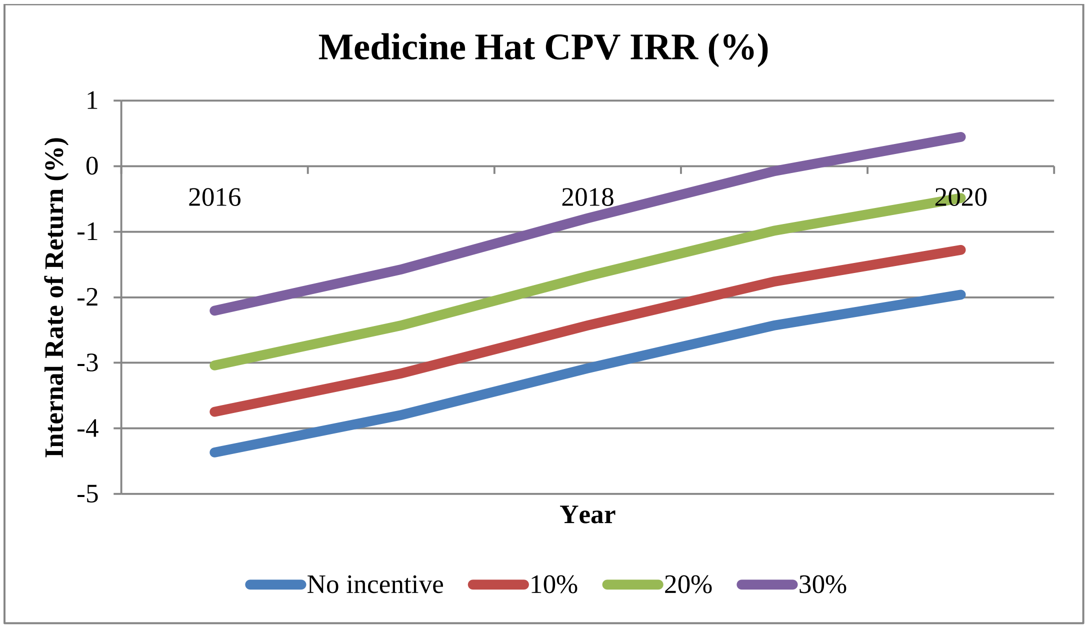
$$\frac{505.156 - 502.55}{505.156 - 502.0022} = \frac{x}{5}$$

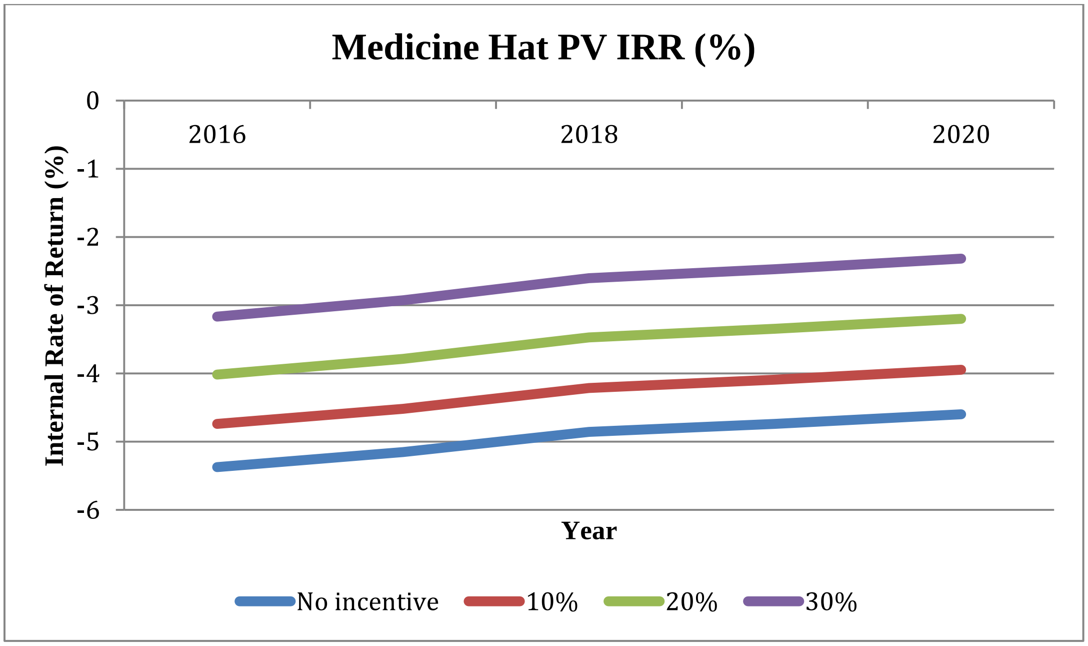
x = 4.1352
Azimuth = 15 + x
Azimuth = 19.1352

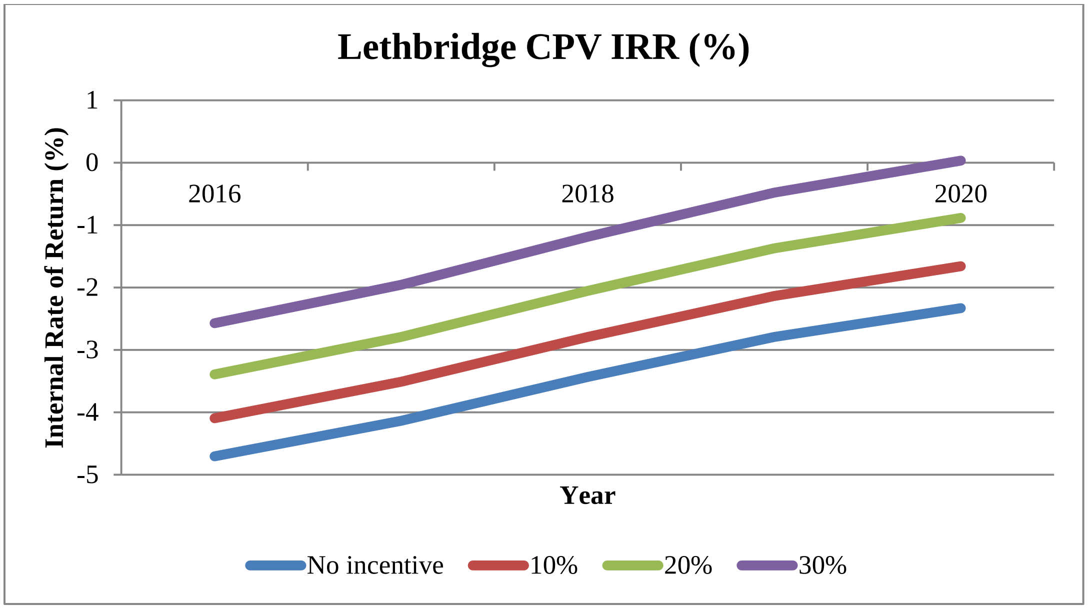
9. Appendix B

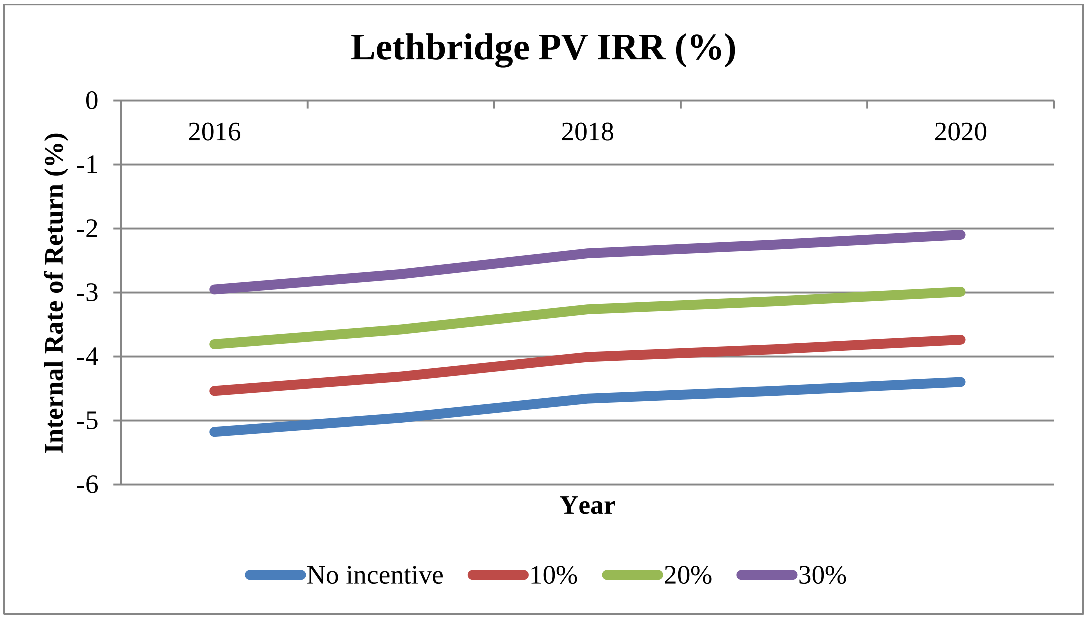
IRR maps: CPV and PV Optimized

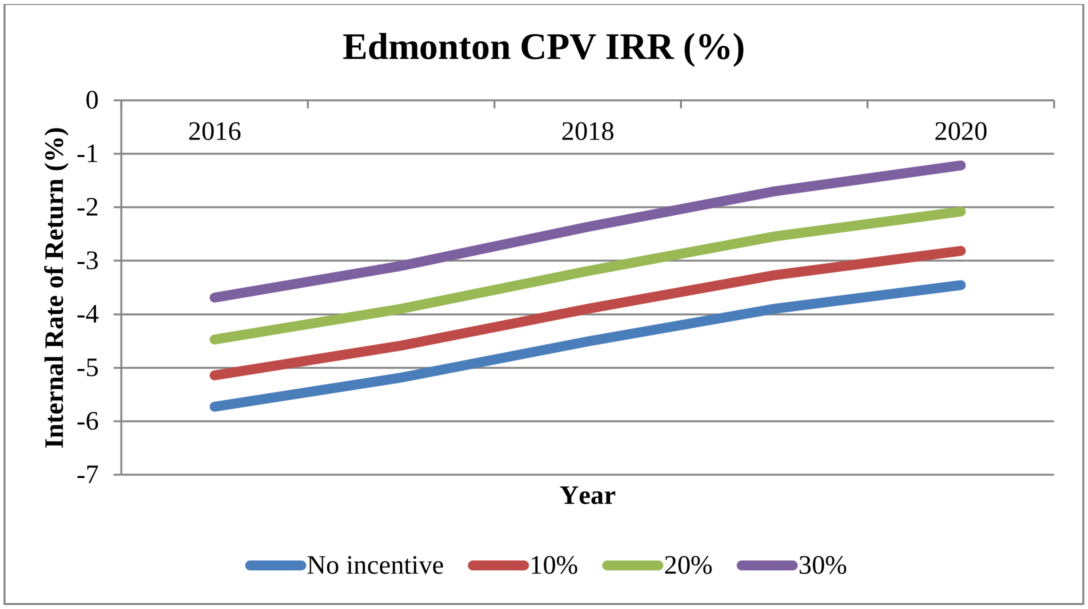
Alberta

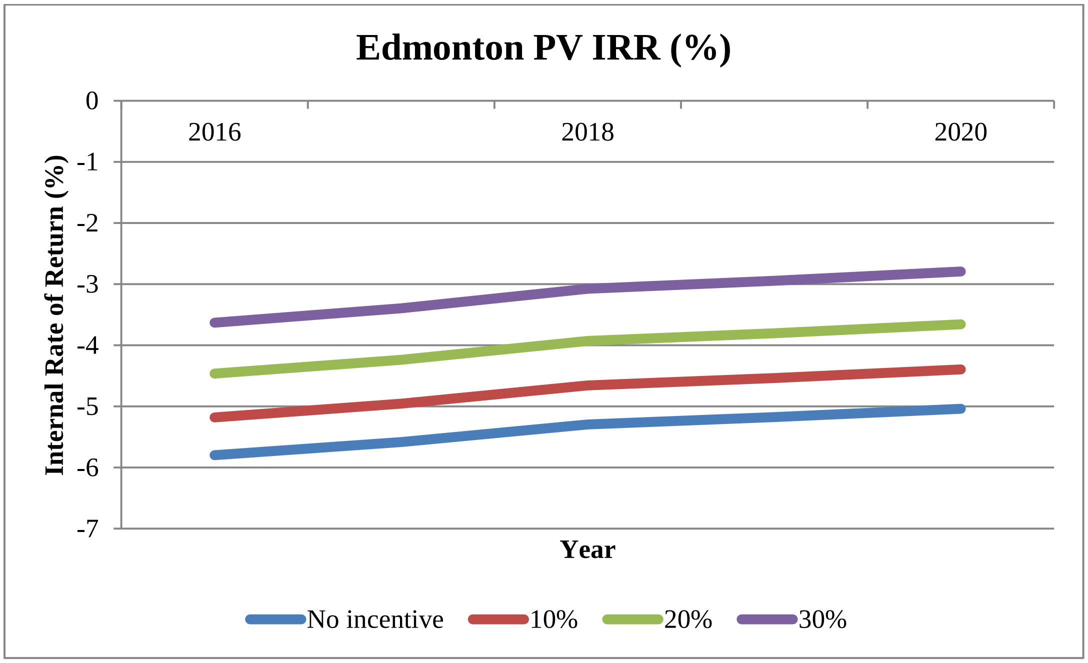


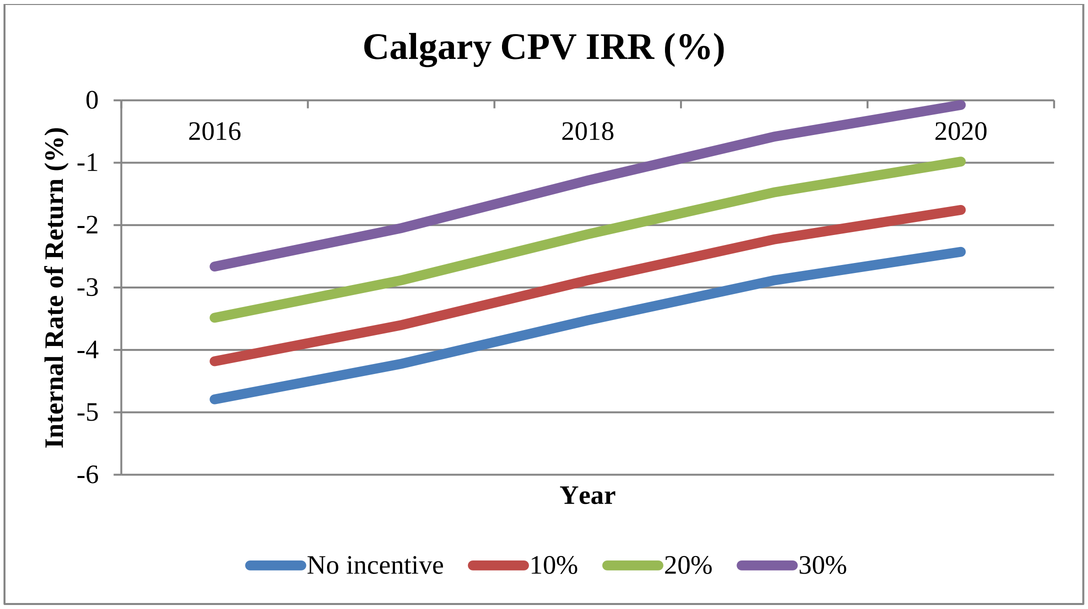


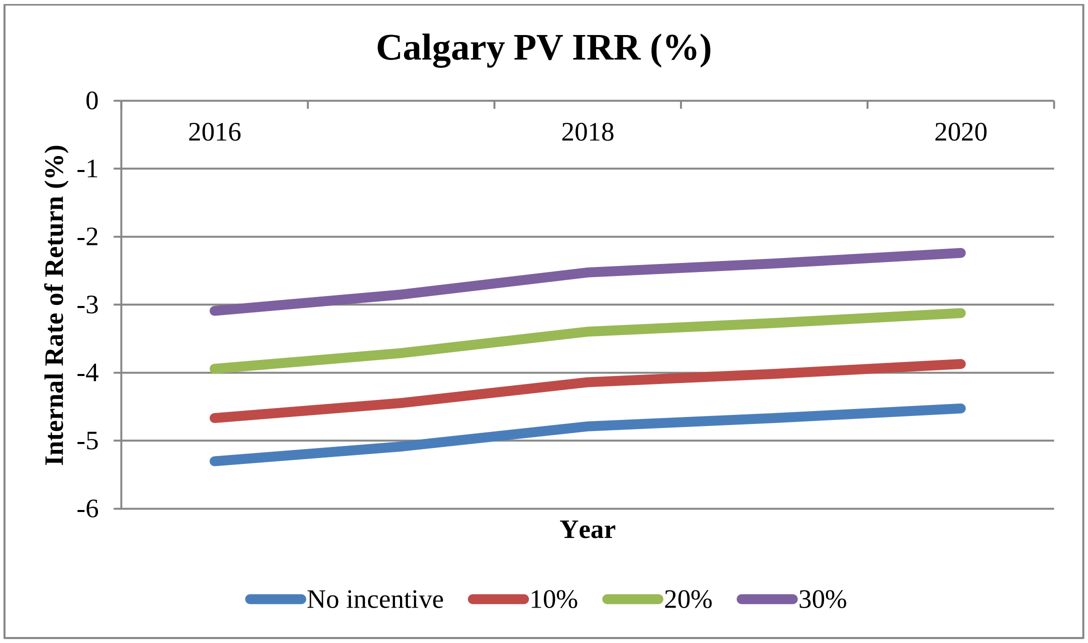

Lethbridge CPV IRR (%)
Internal Rate of Return (%)
1
0
-1
-2
-3
-4
-5
2016
2018
2020
Year
No incentive
10%
20%
30%

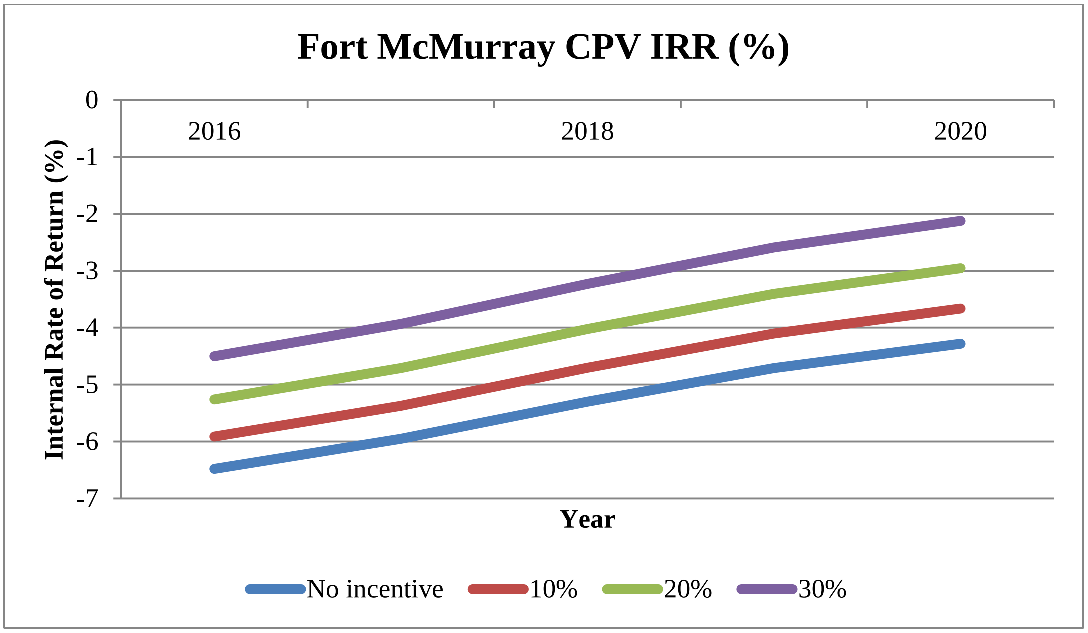

Lethbridge PV IRR (%)
Internal Rate of Return (%)
0
-1
-2
-3
-4
-5
-6
2016
2018
2020
Year
No incentive
10%
20%
30%

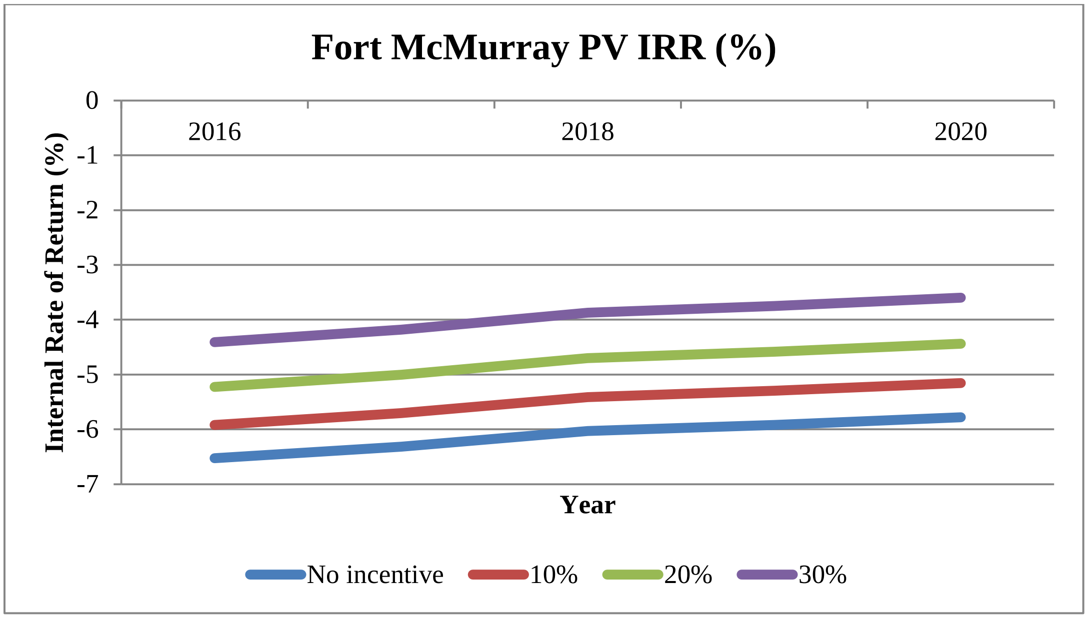

Edmonton CPV IRR (%)
Internal Rate of Return (%)
0
-1
-2
-3
-4
-5
-6
-7
2016
2018
2020
Year
No incentive
10%
20%
30%

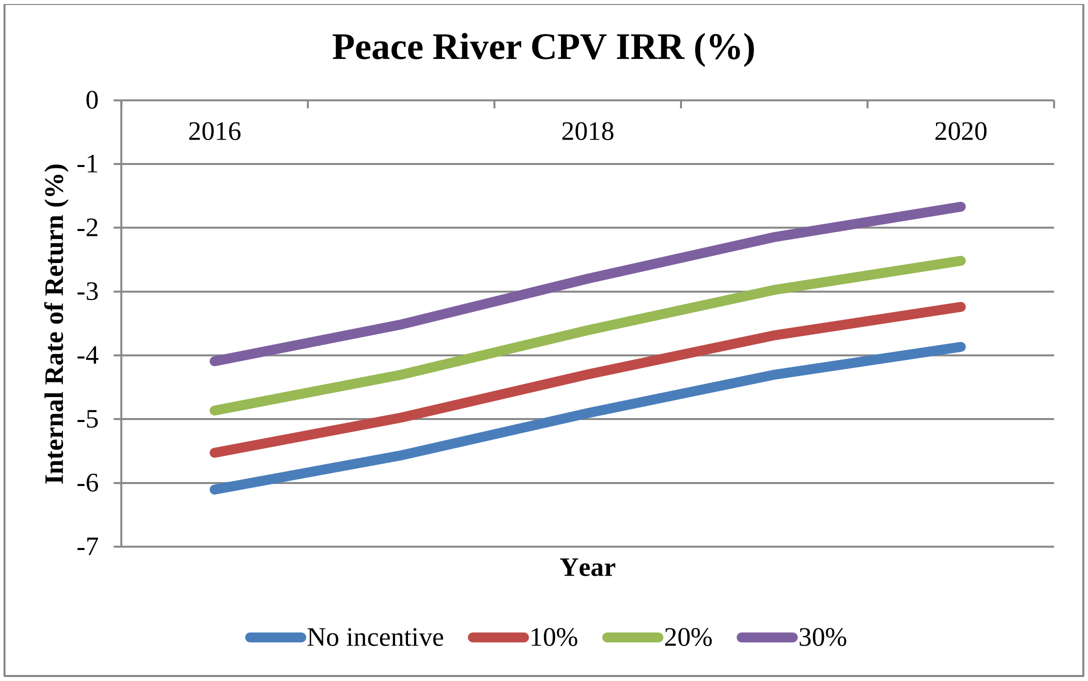

Edmonton PV IRR (%)
Internal Rate of Return (%)
0
-1
-2
-3
-4
-5
-6
-7
2016
2018
2020
Year
No incentive
10%
20%
30%

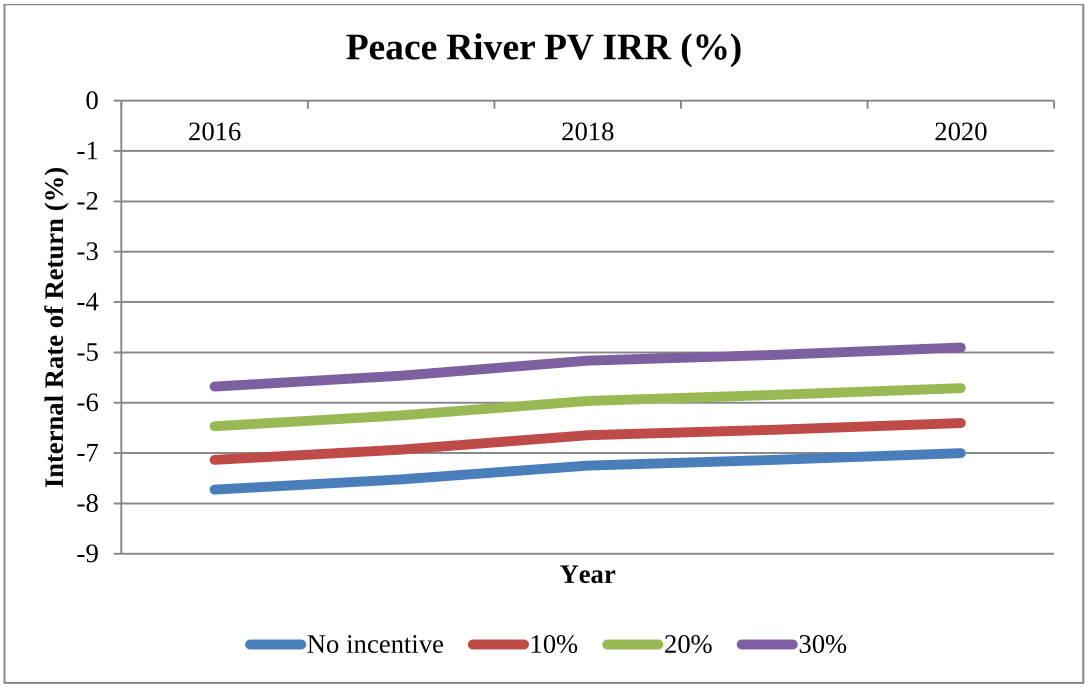

Calgary CPV IRR (%)
Internal Rate of Return (%)
0
-1
-2
-3
-4
-5
-6
2016
2018
2020
Year
No incentive
10%
20%
30%


Calgary PV IRR (%)
Internal Rate of Return (%)
0
-1
-2
-3
-4
-5
-6
2016
2018
2020
Year
No incentive
10%
20%
30%

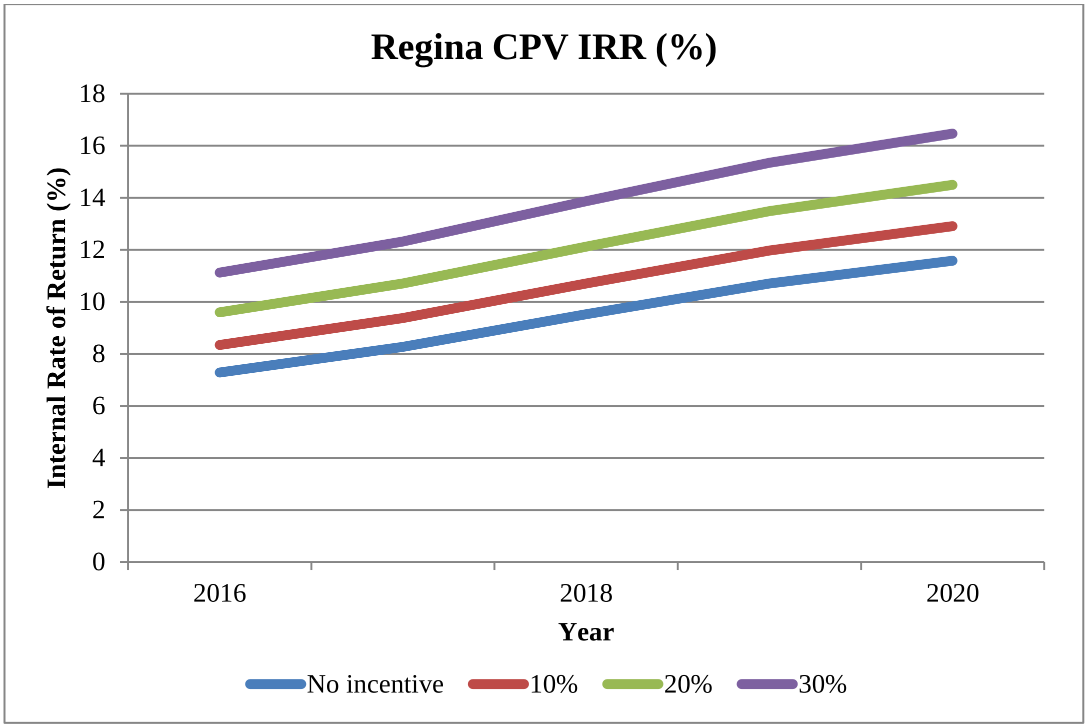

Fort McMurray CPV IRR (%)
Internal Rate of Return (%)
0
-1
-2
-3
-4
-5
-6
-7
2016
2018
2020
Year
No incentive
10%
20%
30%

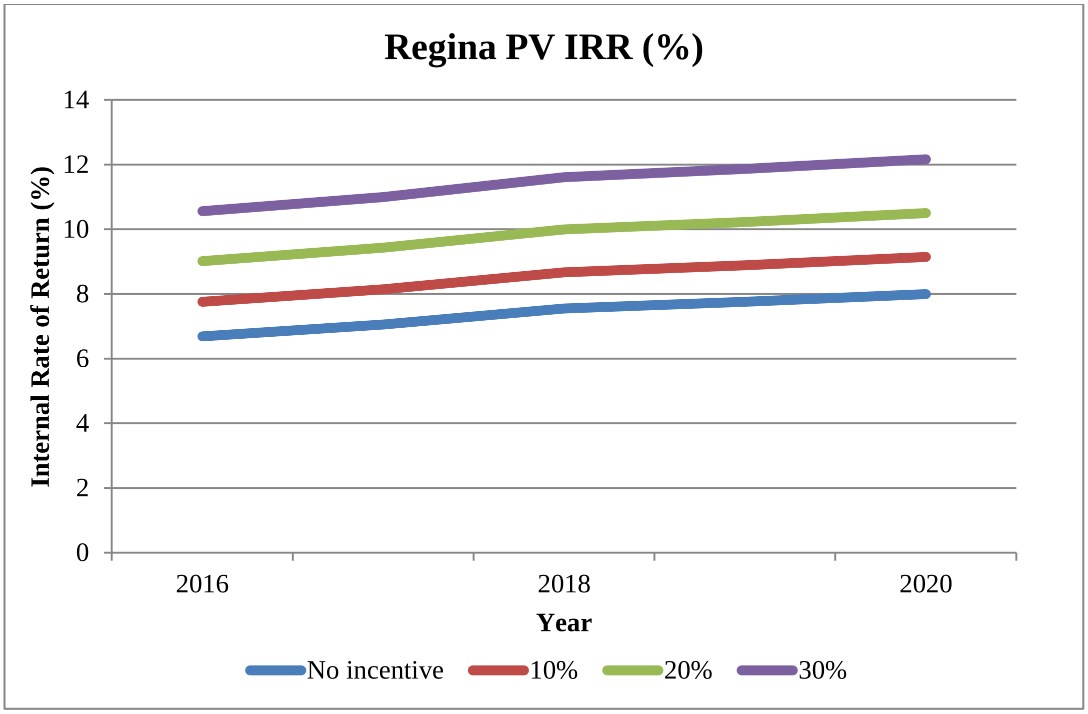

Fort McMurray PV IRR (%)
Internal Rate of Return (%)
0
-1
-2
-3
-4
-5
-6
-7
2016
2018
2020
Year
No incentive
10%
20%
30%

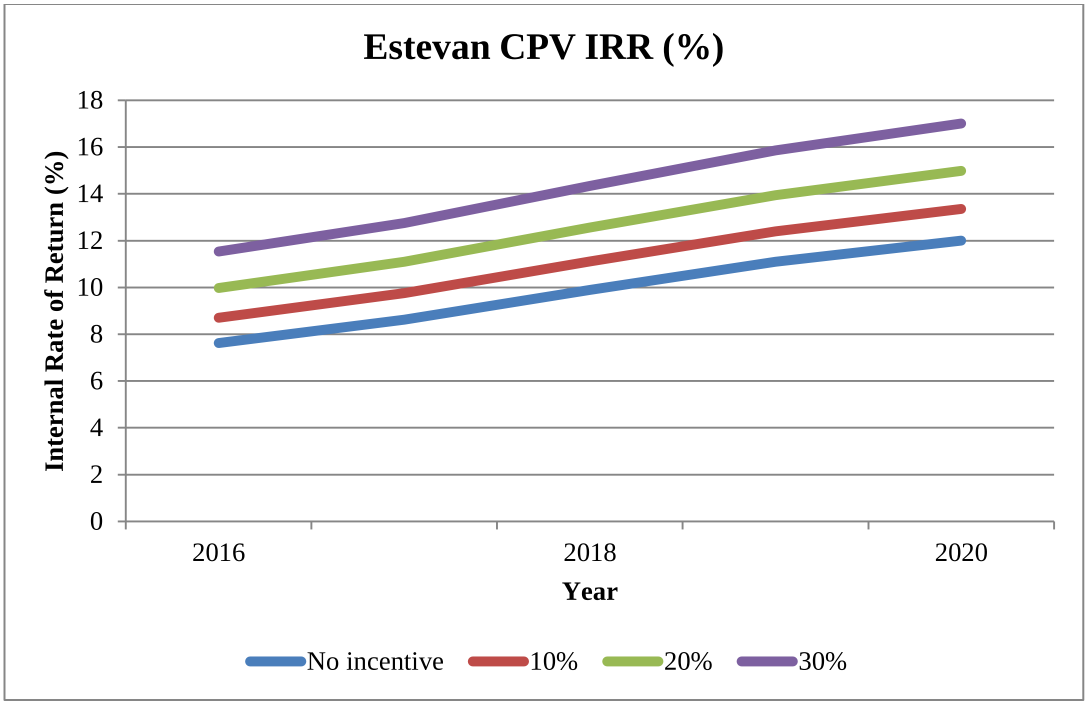

Peace River CPV IRR (%)
0
-1
-2
-3
-4
-5
-6
-7
2016
2018
2020
Internal Rate of Return (%)
Year
No incentive
10%
20%
30%

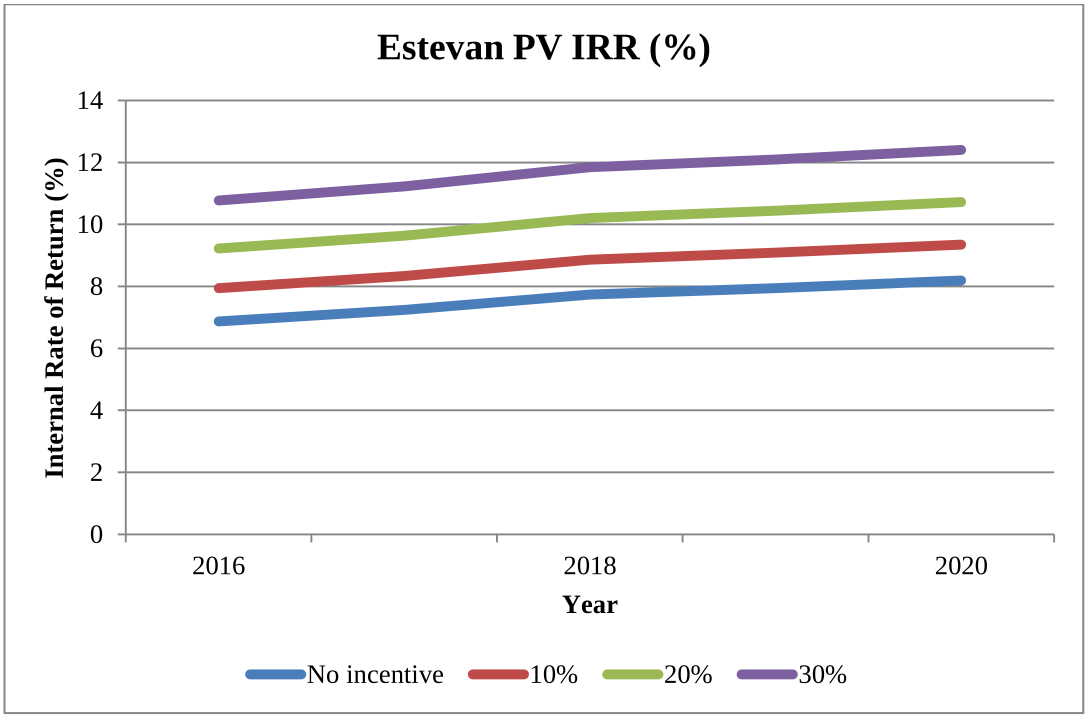

Peace River PV IRR (%)
0
-1
-2
-3
-4
-5
-6
-7
-8
-9
2016
2018
2020
Internal Rate of Return (%)
Year
No incentive
10%
20%
30%

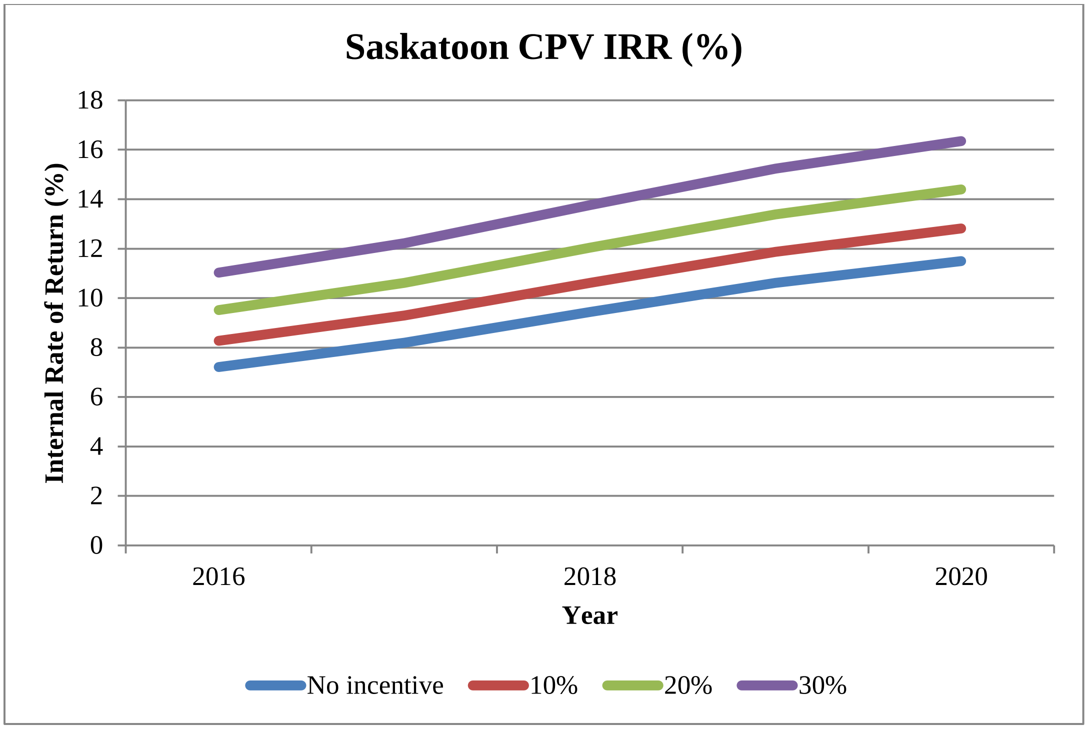
Saskatchewan

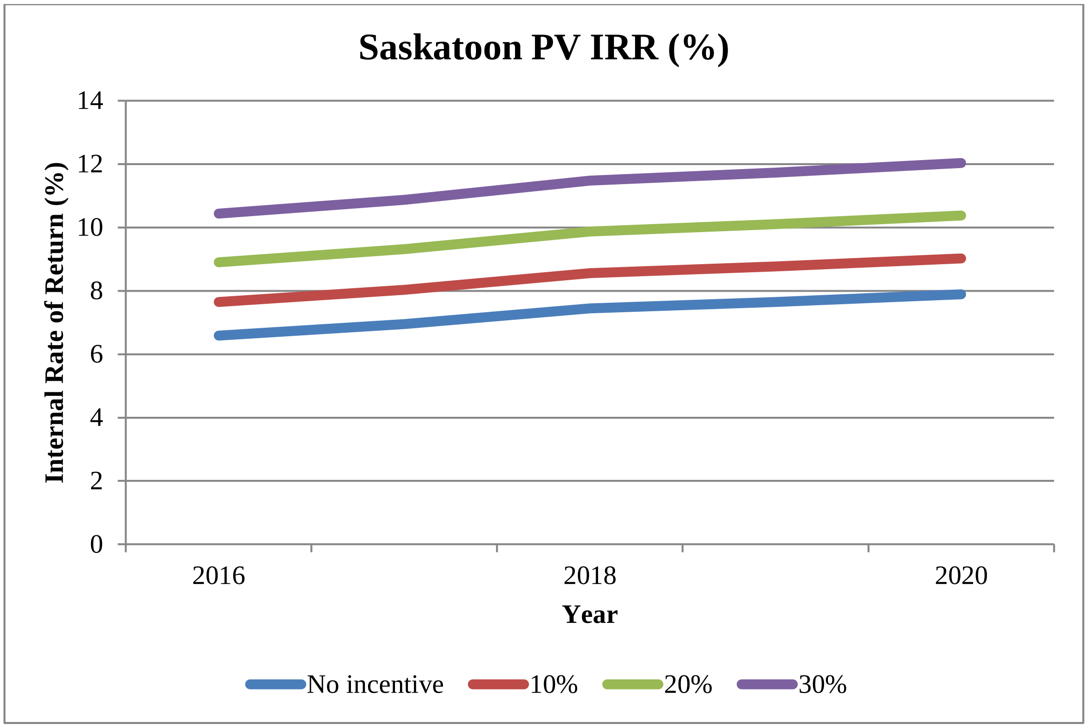


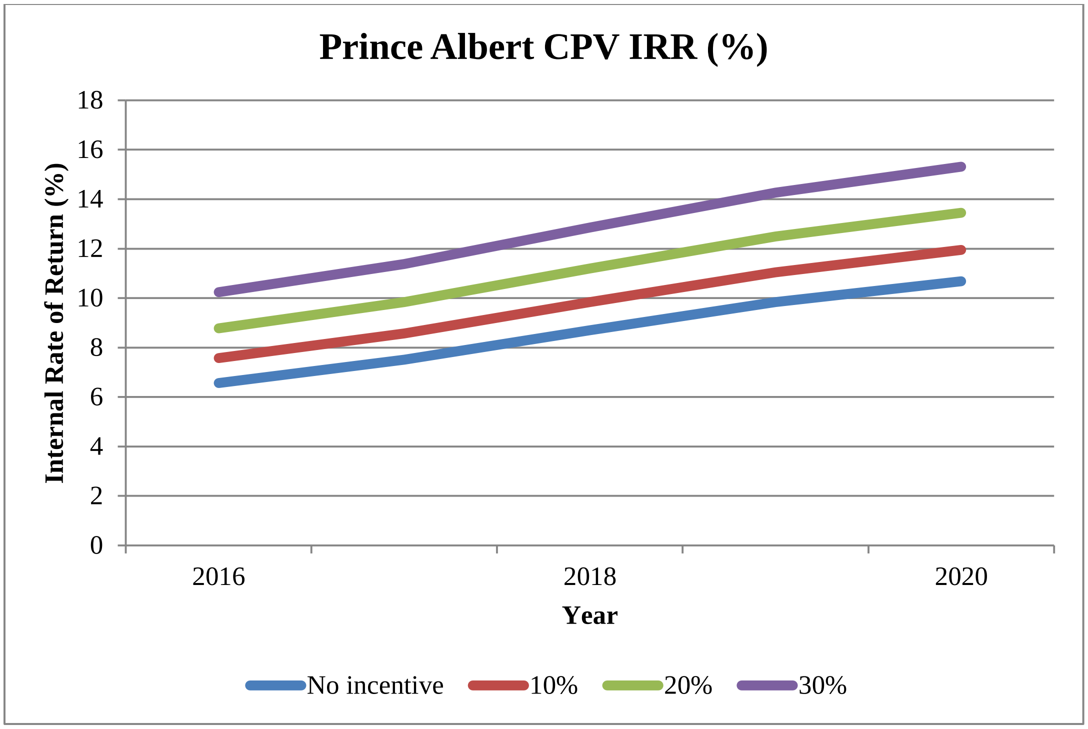


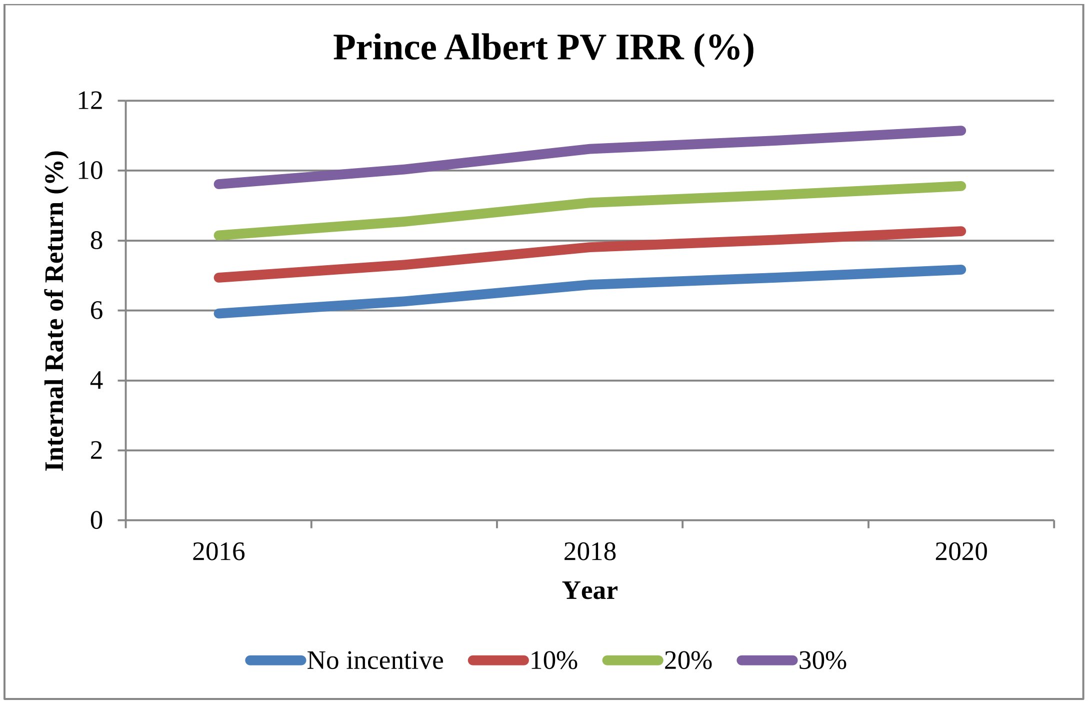

Estevan CPV IRR (%)
Internal Rate of Return (%)
0
2
4
6
8
10
12
14
16
18
2016
2018
2020
Year
No incentive
10%
20%
30%

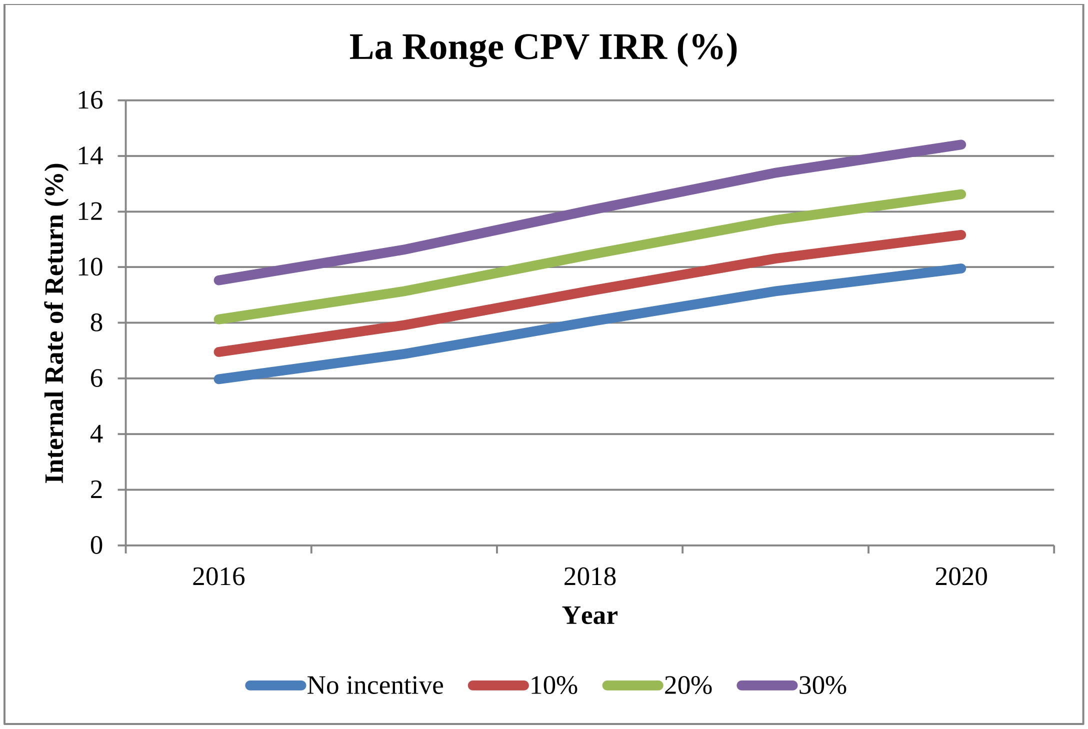

Estevan PV IRR (%)
Internal Rate of Return (%)
0
2
4
6
8
10
12
14
2016
2018
2020
Year
No incentive
10%
20%
30%

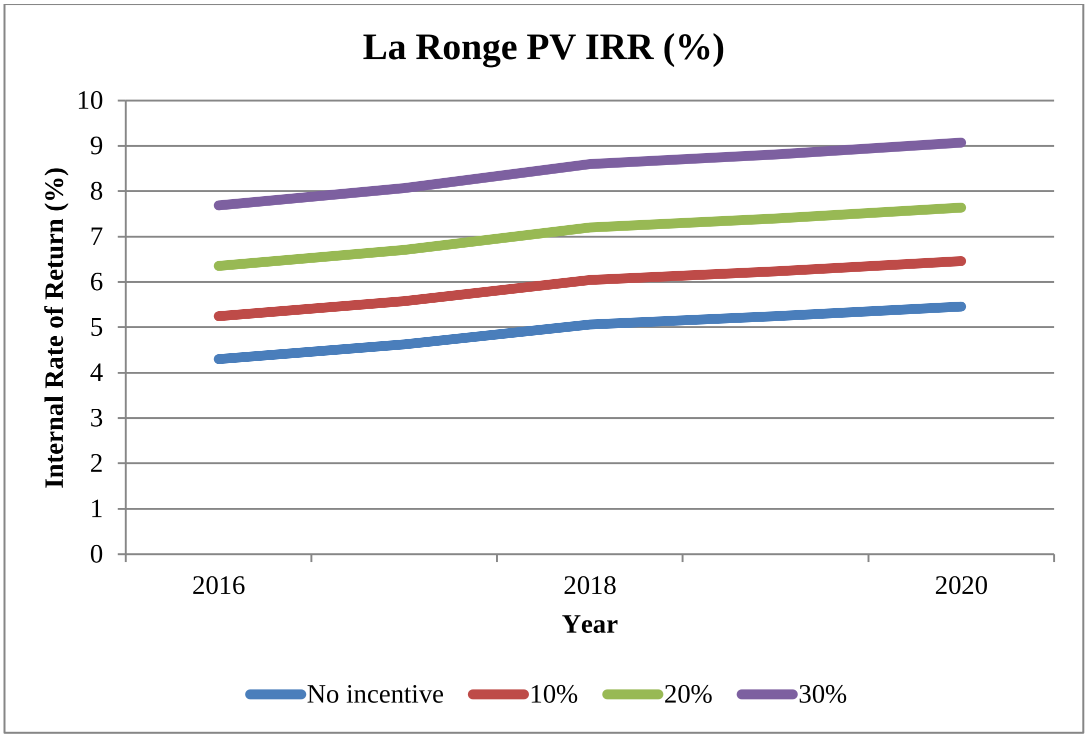

Saskatoon CPV IRR (%)
Internal Rate of Return (%)
0
2
4
6
8
10
12
14
16
18
2016
2018
2020
Year
No incentive
10%
20%
30%

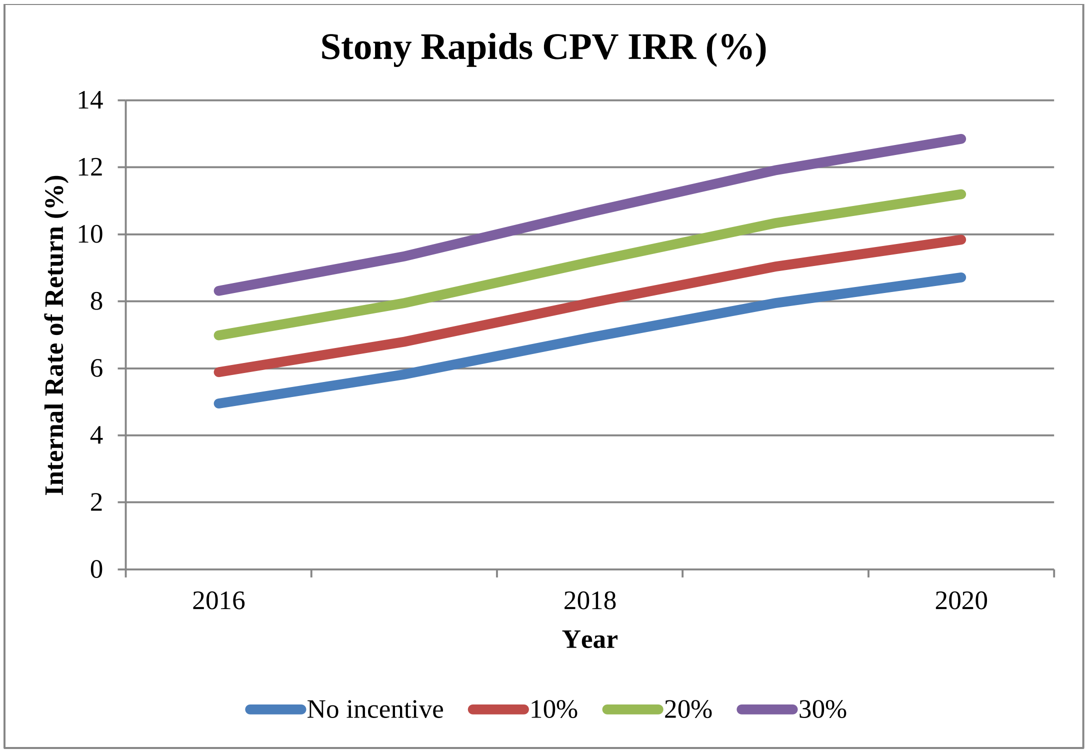

Saskatoon PV IRR (%)
Internal Rate of Return (%)
0
2
4
6
8
10
12
14
2016
2018
2020
Year
No incentive
10%
20%
30%

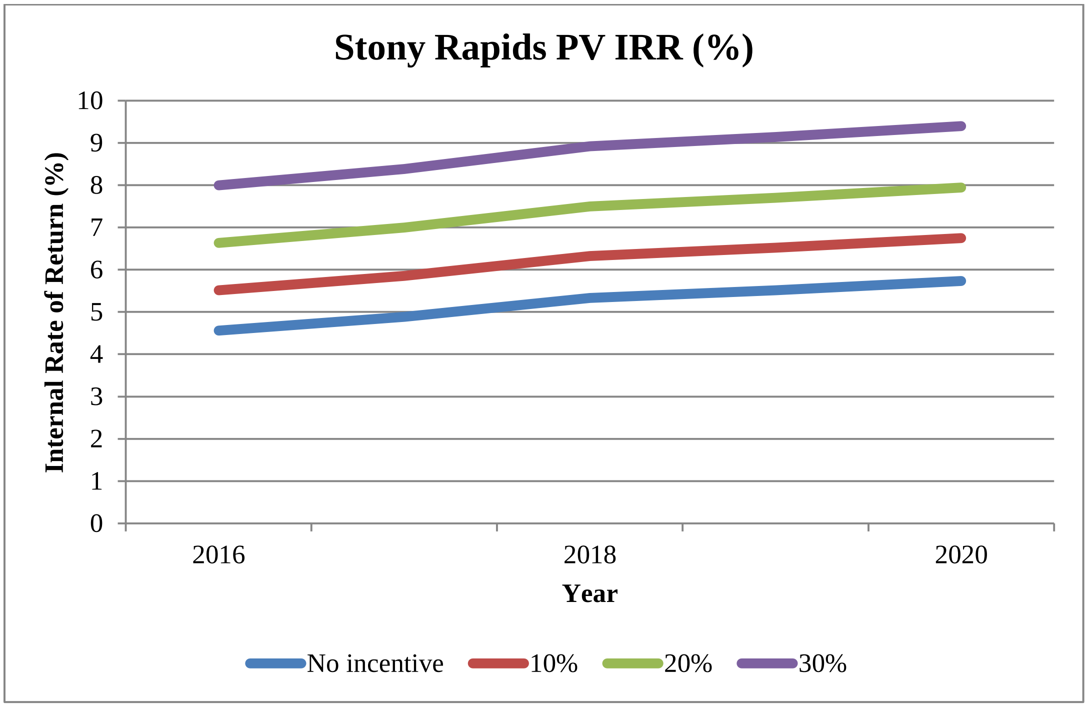

Prince Albert CPV IRR (%)
Internal Rate of Return (%)
18
16
14
12
10
8
6
4
2
0
2016
2018
2020
Year
No incentive
10%
20%
30%


Prince Albert PV IRR (%)
Internal Rate of Return (%)
12
10
8
6
4
2
0
2016
2018
2020
Year
No incentive
10%
20%
30%

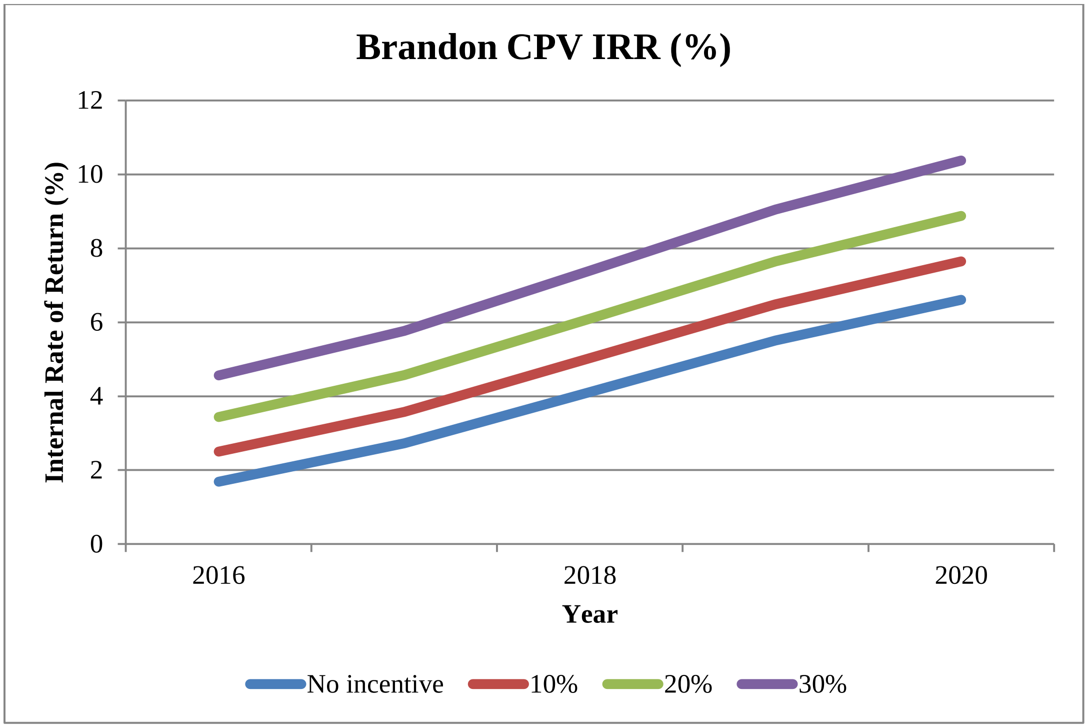

La Ronge CPV IRR (%)
Internal Rate of Return (%)
16
14
12
10
8
6
4
2
0
2016
2018
2020
Year
No incentive
10%
20%
30%

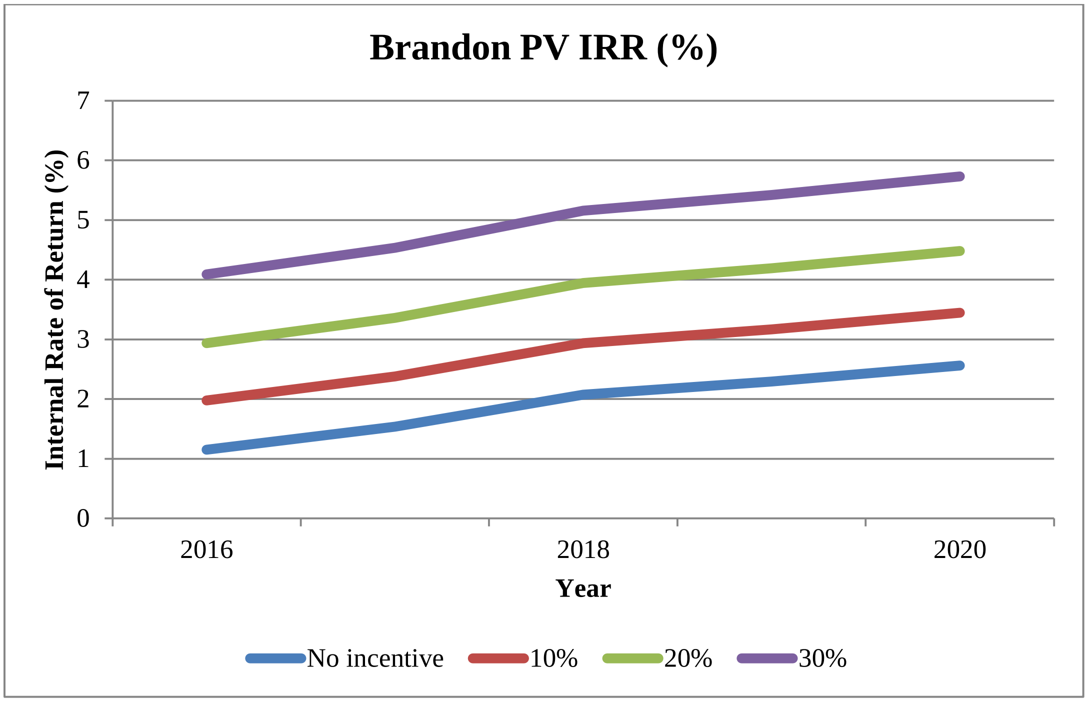

La Ronge PV IRR (%)
Internal Rate of Return (%)
10
9
8
7
6
5
4
3
2
1
0
2016
2018
2020
Year
No incentive
10%
20%
30%

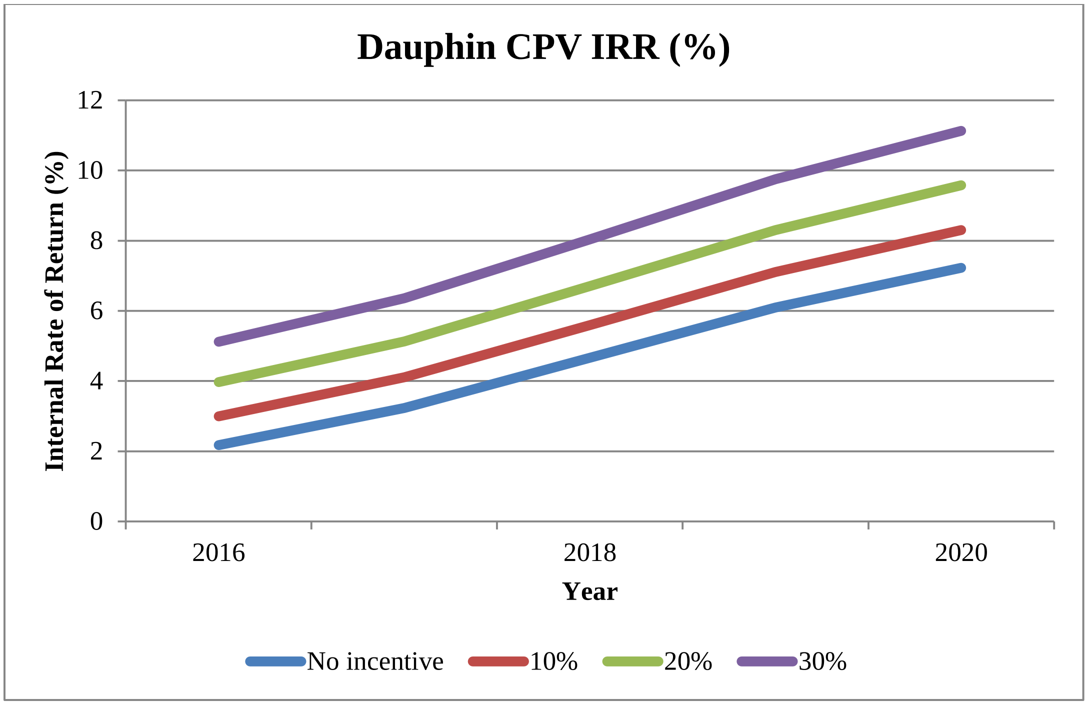

Stony Rapids CPV IRR (%)
Internal Rate of Return (%)
14
12
10
8
6
4
2
0
2016
2018
2020
Year
No incentive
10%
20%
30%

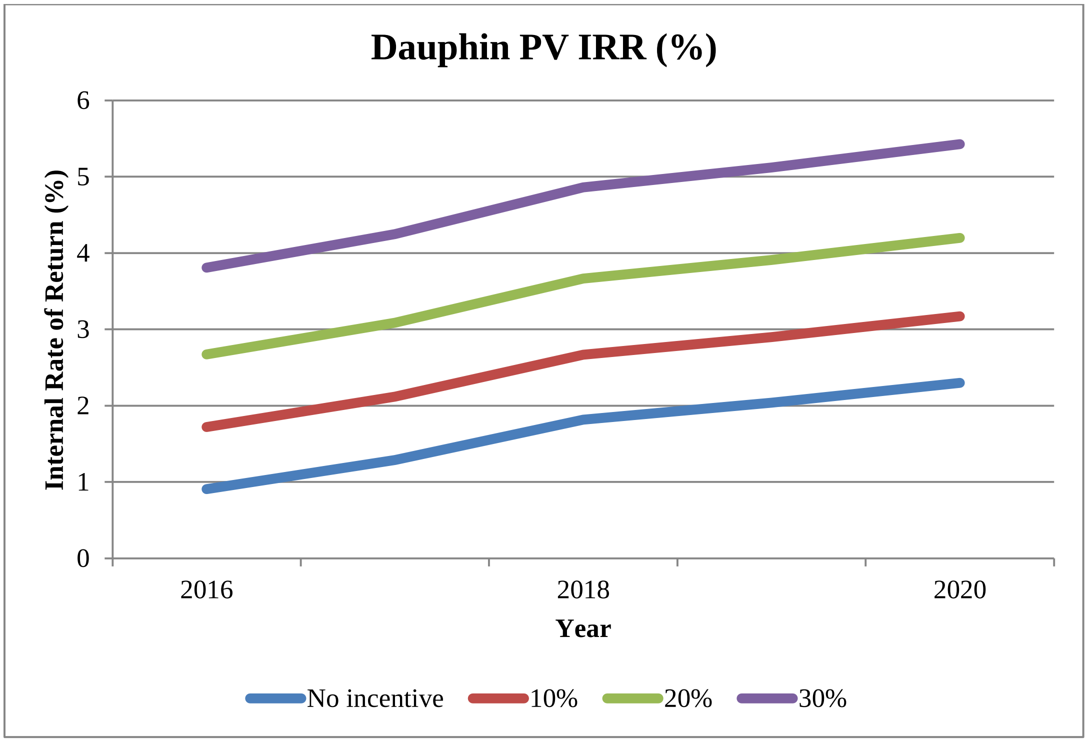

Stony Rapids PV IRR (%)
Internal Rate of Return (%)
10
9
8
7
6
5
4
3
2
1
0
2016
2018
2020
Year
No incentive
10%
20%
30%

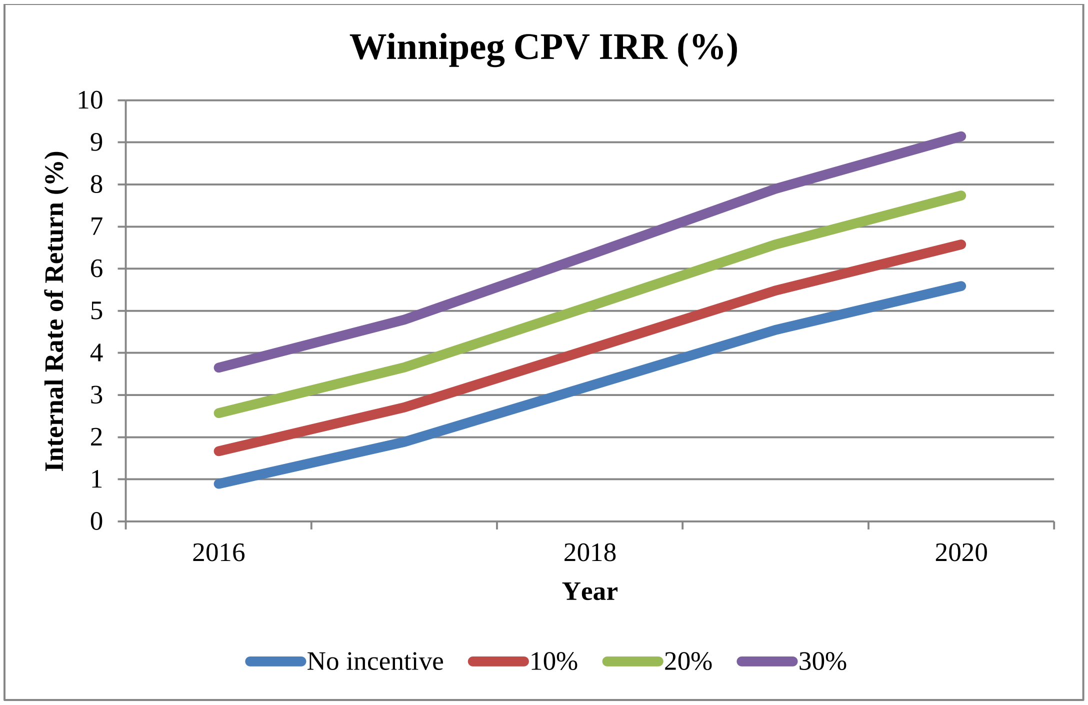
Manitoba

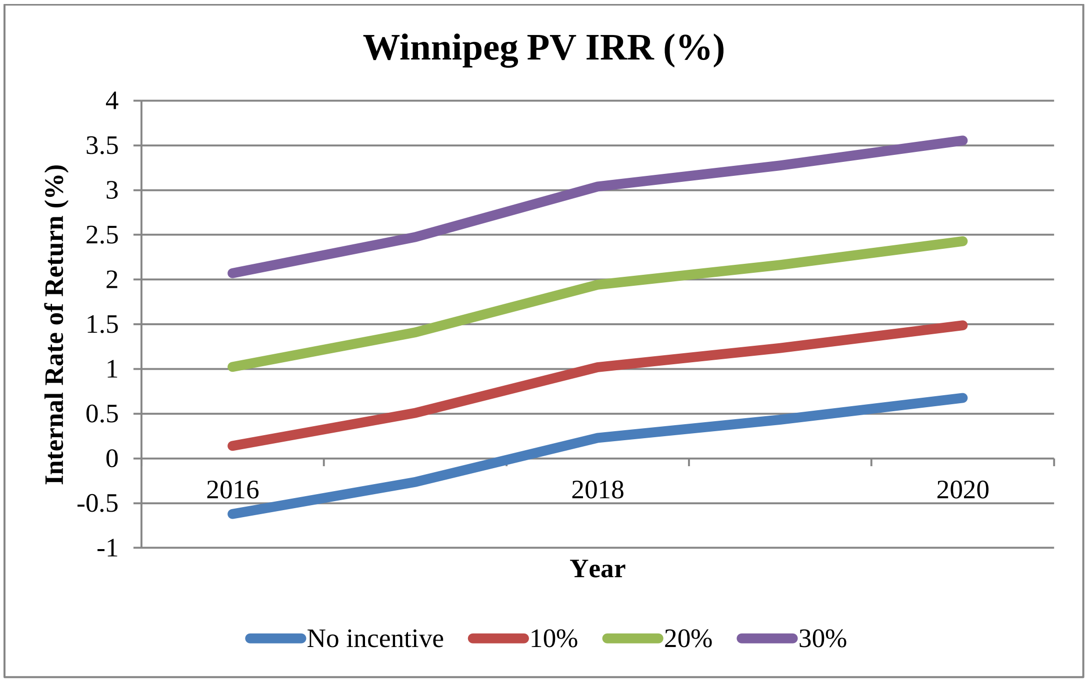

Brandon CPV IRR (%)
Internal Rate of Return (%)
12
10
8
6
4
2
0
2016
2018
2020
Year
No incentive
10%
20%
30%

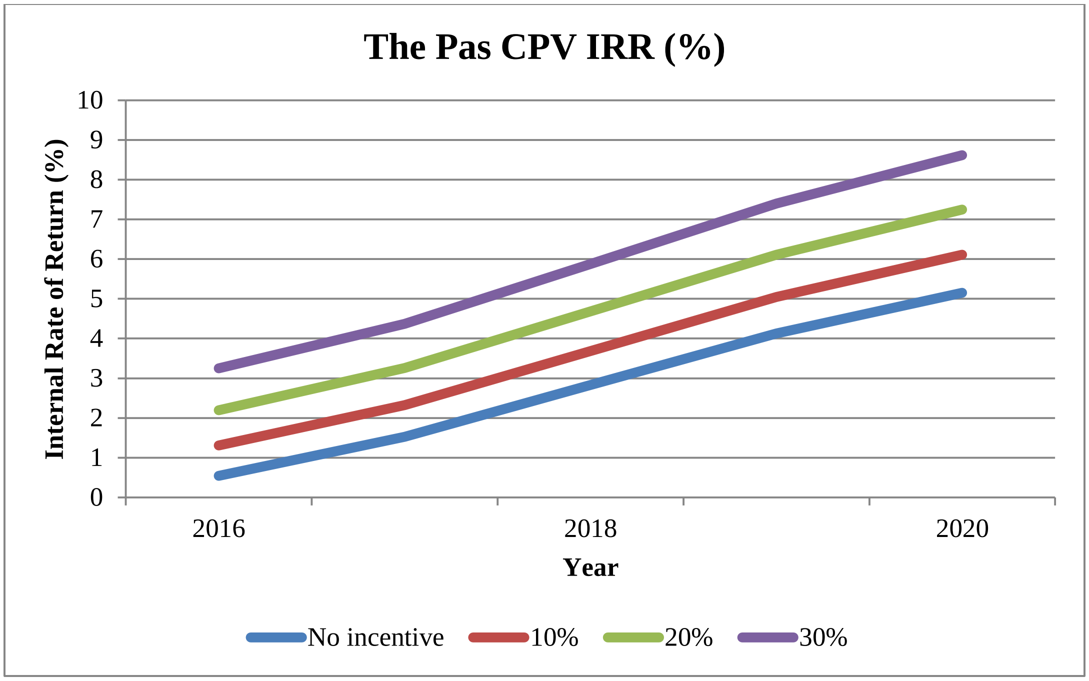

Brandon PV IRR (%)
Internal Rate of Return (%)
7
6
5
4
3
2
1
0
2016
2018
2020
Year
No incentive
10%
20%
30%

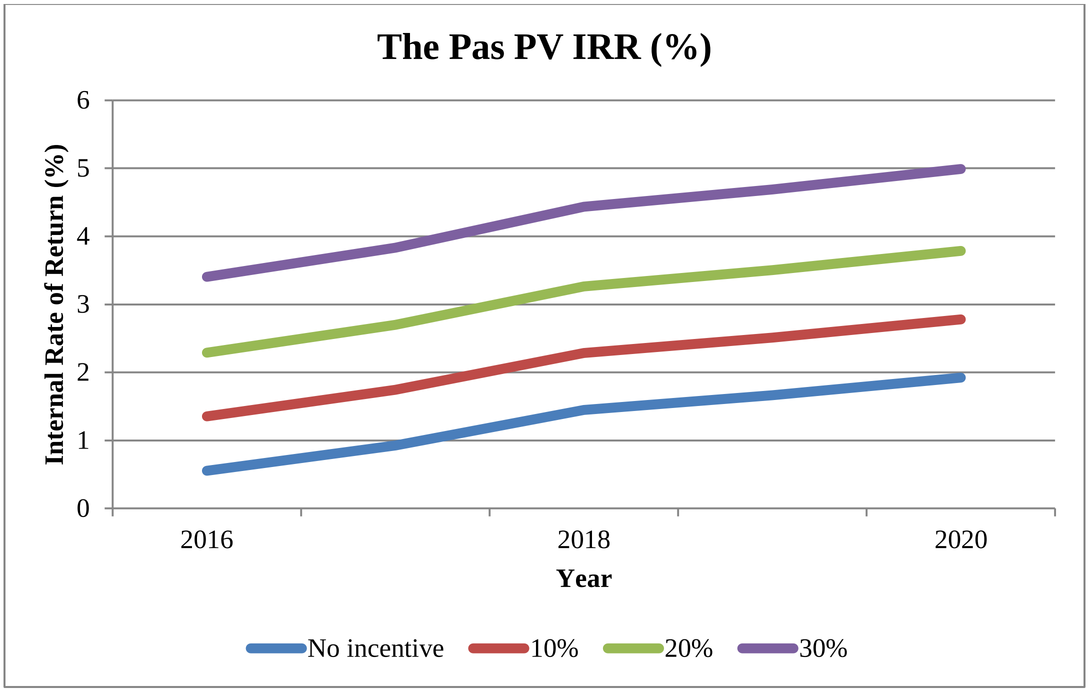

Dauphin CPV IRR (%)
Internal Rate of Return (%)
0
2
4
6
8
10
12
2016
2018
2020
Year
No incentive
10%
20%
30%

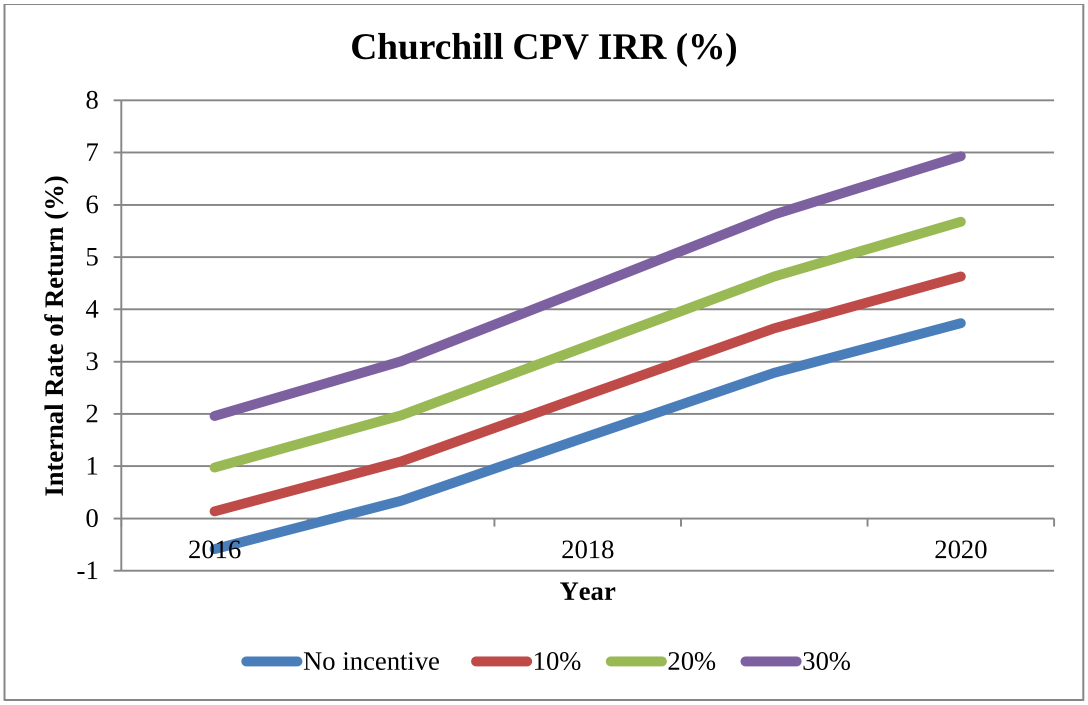

Dauphin PV IRR (%)
Internal Rate of Return (%)
0
1
2
3
4
5
6
2016
2018
2020
Year
No incentive
10%
20%
30%

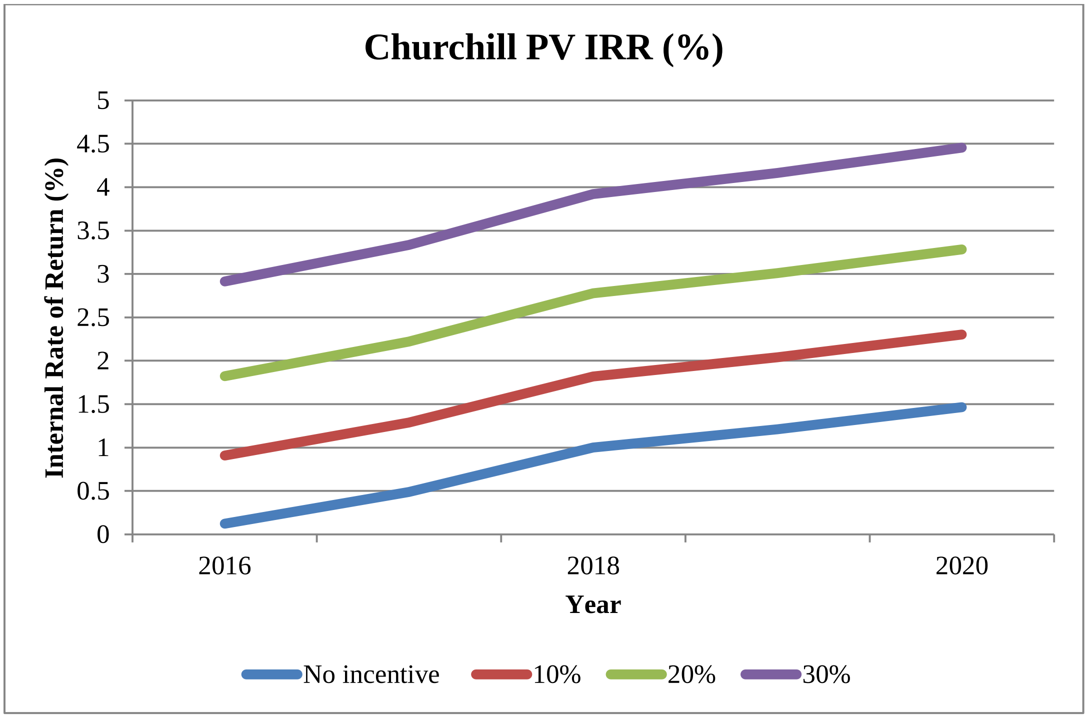

Winnipeg CPV IRR (%)
Internal Rate of Return (%)
10
9
8
7
6
5
4
3
2
1
0
2016
2018
2020
Year
No incentive
10%
20%
30%

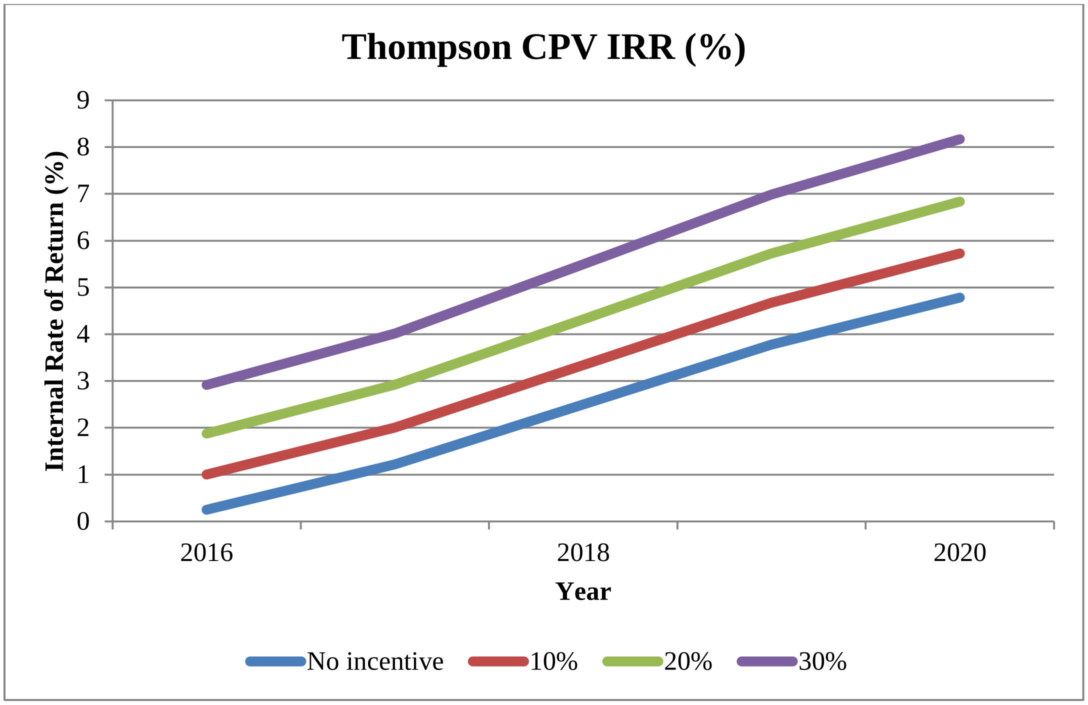

Winnipeg PV IRR (%)
Internal Rate of Return (%)
4
3.5
3
2.5
2
1.5
1
0.5
0
-0.5
-1
2016
2018
2020
Year
No incentive
10%
20%
30%

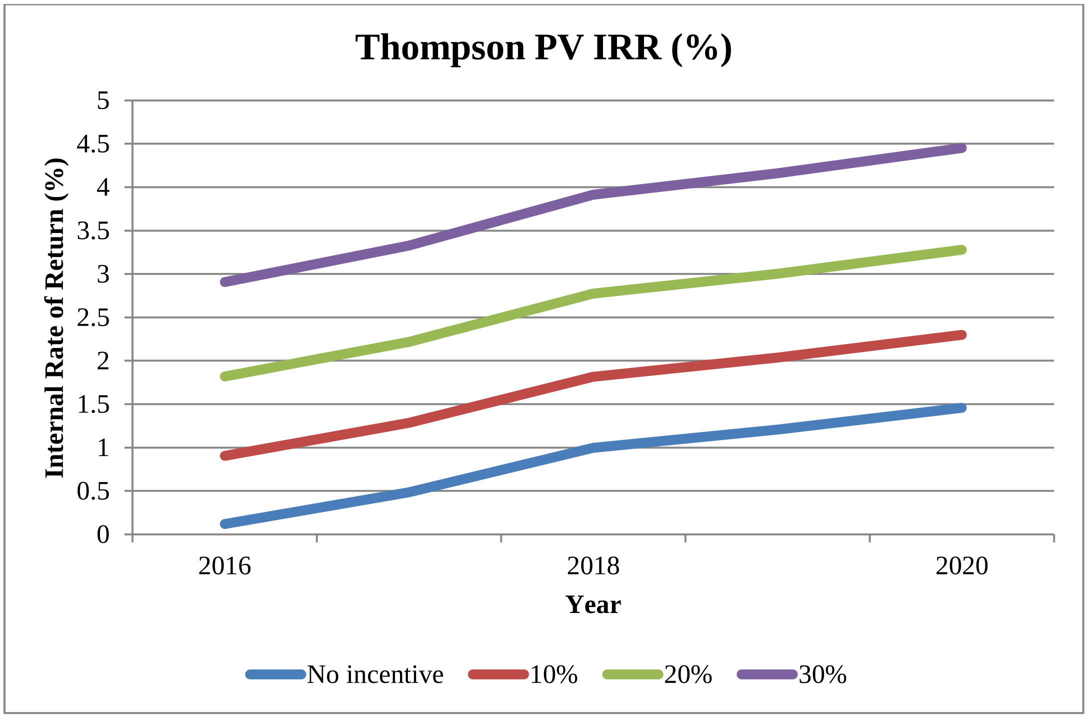

The Pas CPV IRR (%)
Internal Rate of Return (%)
10
9
8
7
6
5
4
3
2
1
0
2016
2018
2020
Year
No incentive
10%
20%
30%


The Pas PV IRR (%)
Internal Rate of Return (%)
6
5
4
3
2
1
0
2016
2018
2020
Year
No incentive
10%
20%
30%


Churchill CPV IRR (%)
Internal Rate of Return (%)
8
7
6
5
4
3
2
1
0
-1
2016
2018
2020
Year
No incentive
10%
20%
30%

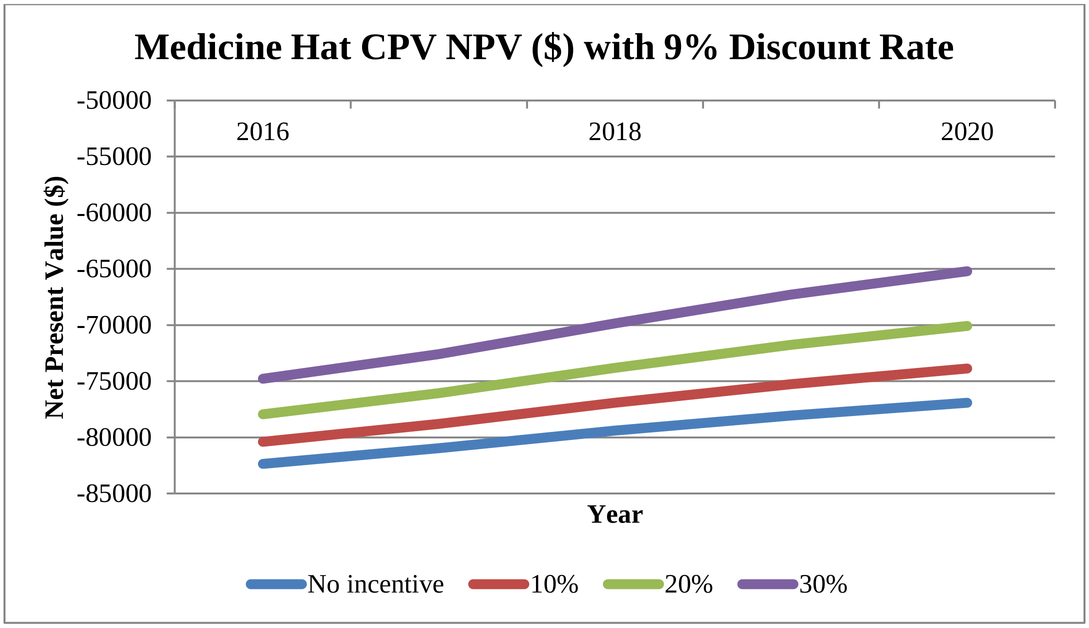

Churchill PV IRR (%)
Internal Rate of Return (%)
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
2016
2018
2020
Year
No incentive
10%
20%
30%

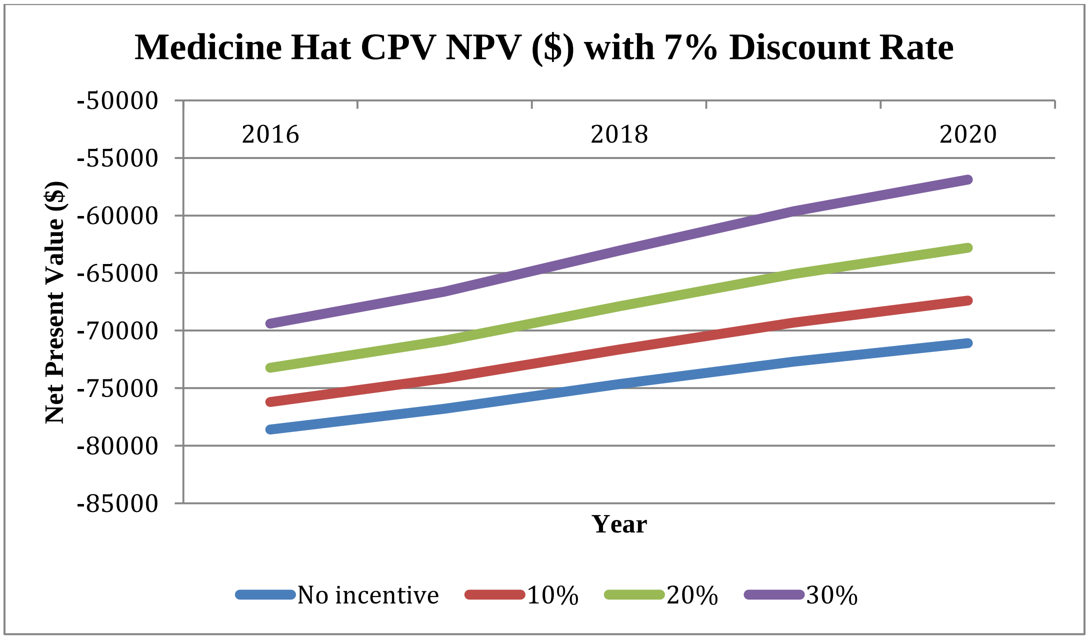

Thompson CPV IRR (%)
Internal Rate of Return (%)
0
1
2
3
4
5
6
7
8
9
2016
2018
2020
Year
No incentive
10%
20%
30%

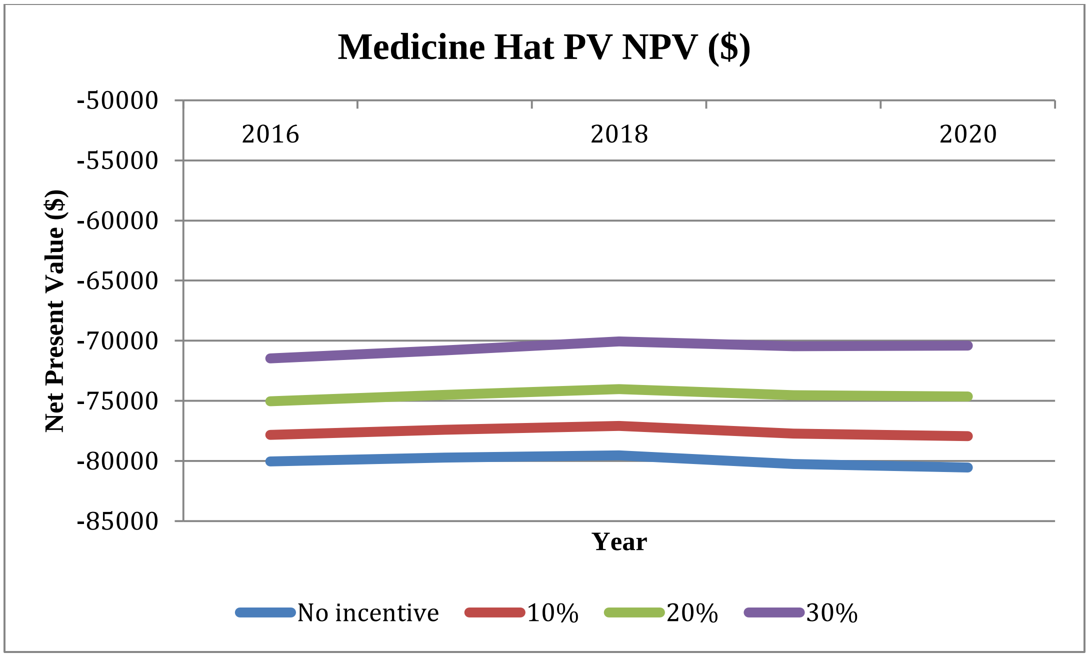

Thompson PV IRR (%)
Internal Rate of Return (%)
0
0.5
1
1.5
2
2.5
3
3.5
4
4.5
5
2016
2018
2020
Year
No incentive
10%
20%
30%

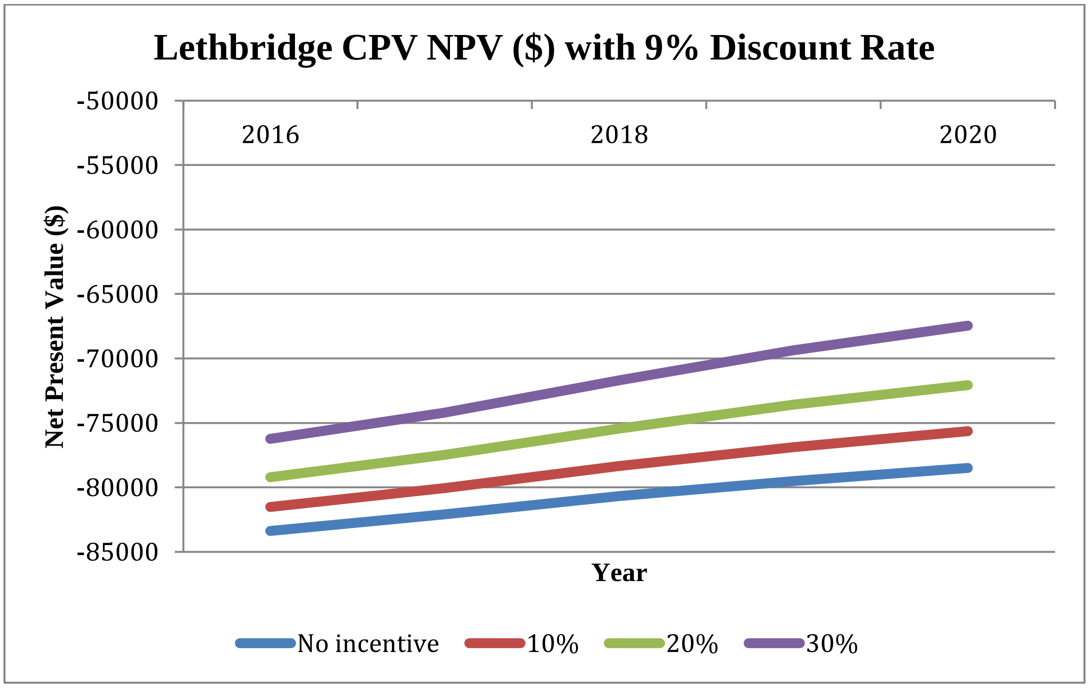
NPV maps: CPV using a 9% discount rate, CPV using a 7% discount rate, and PV

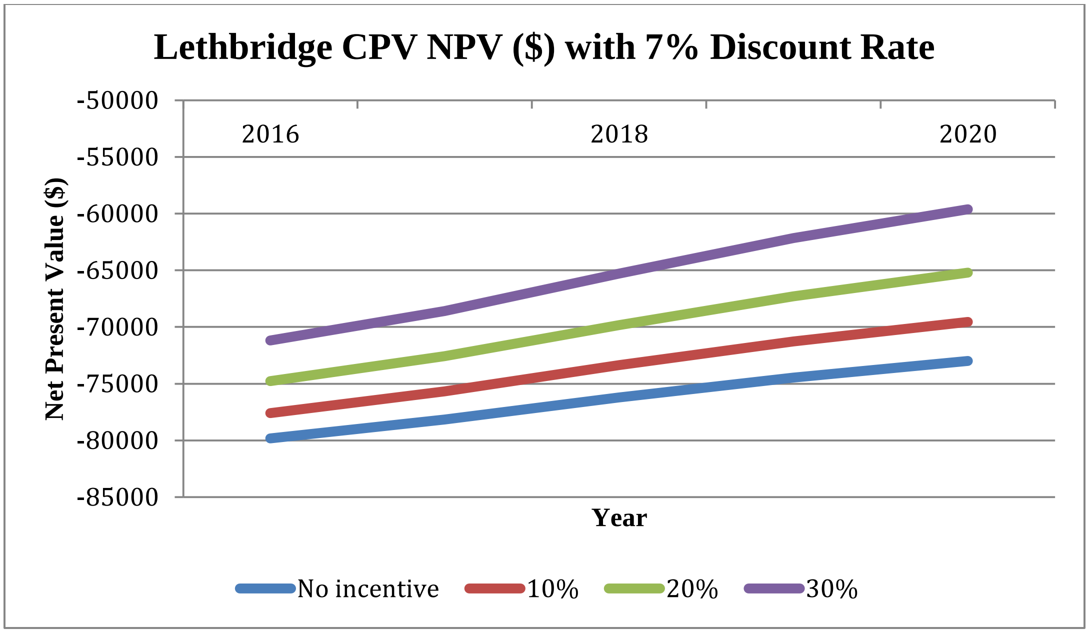
Alberta

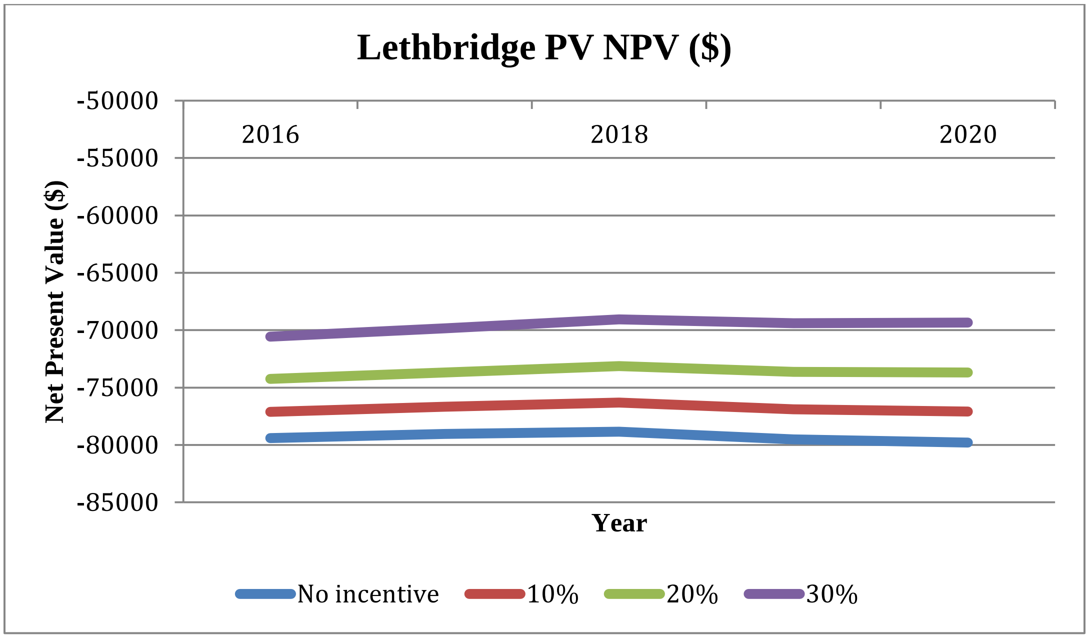


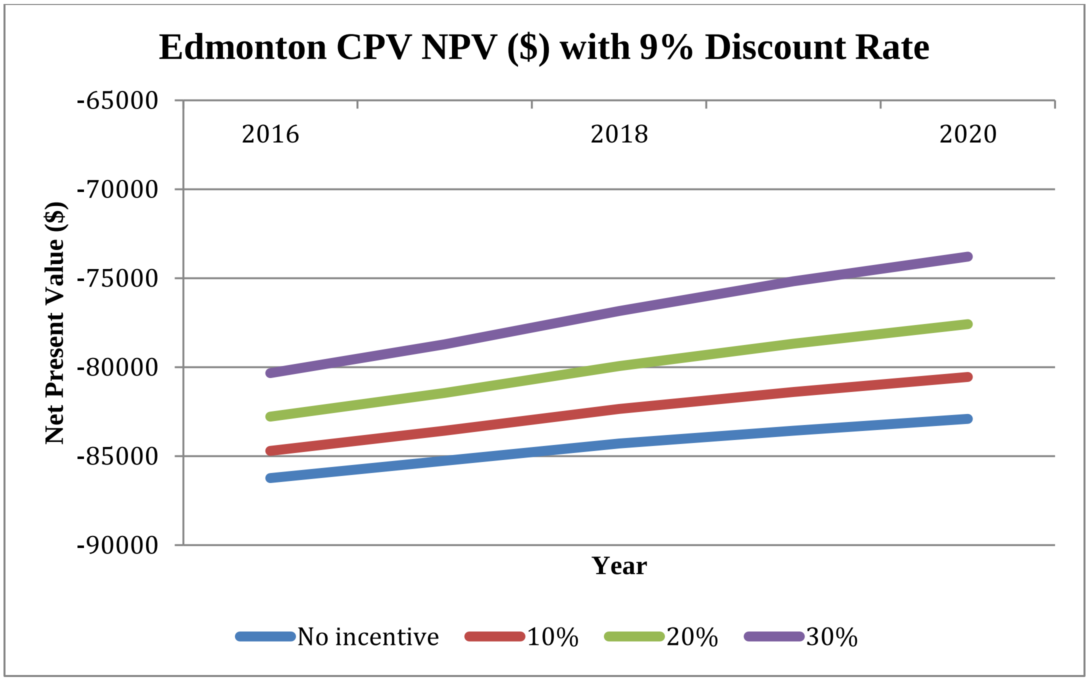


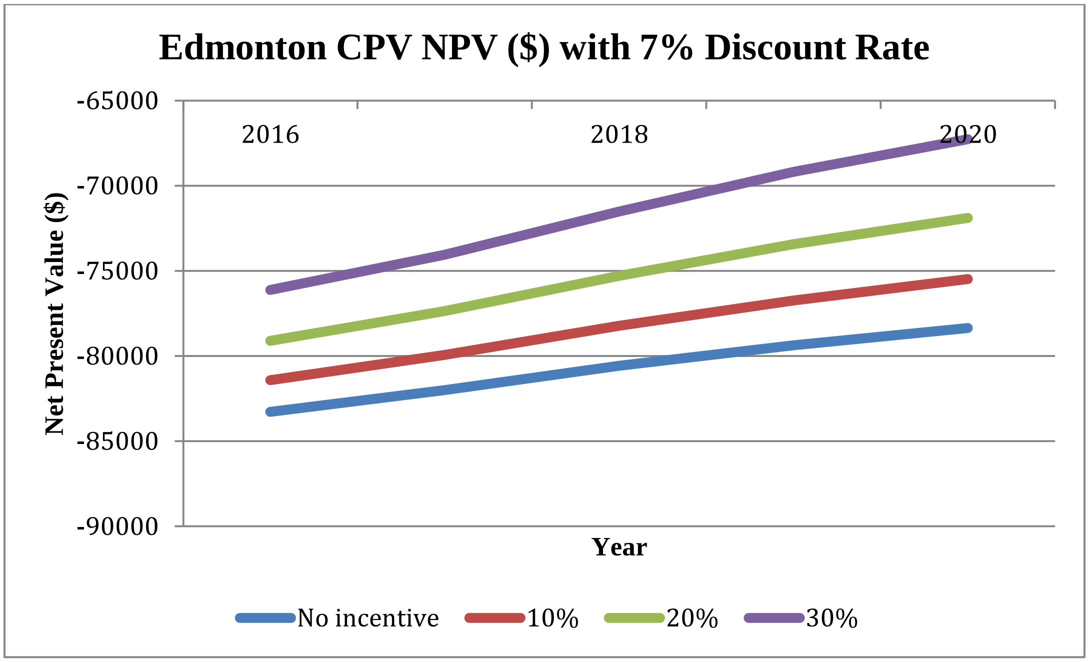

Medicine Hat PV NPV ($)
Net Present Value ($)
-50000
-55000
-60000
-65000
-70000
-75000
-80000
-85000
2016
2018
2020
Year
No incentive
10%
20%
30%

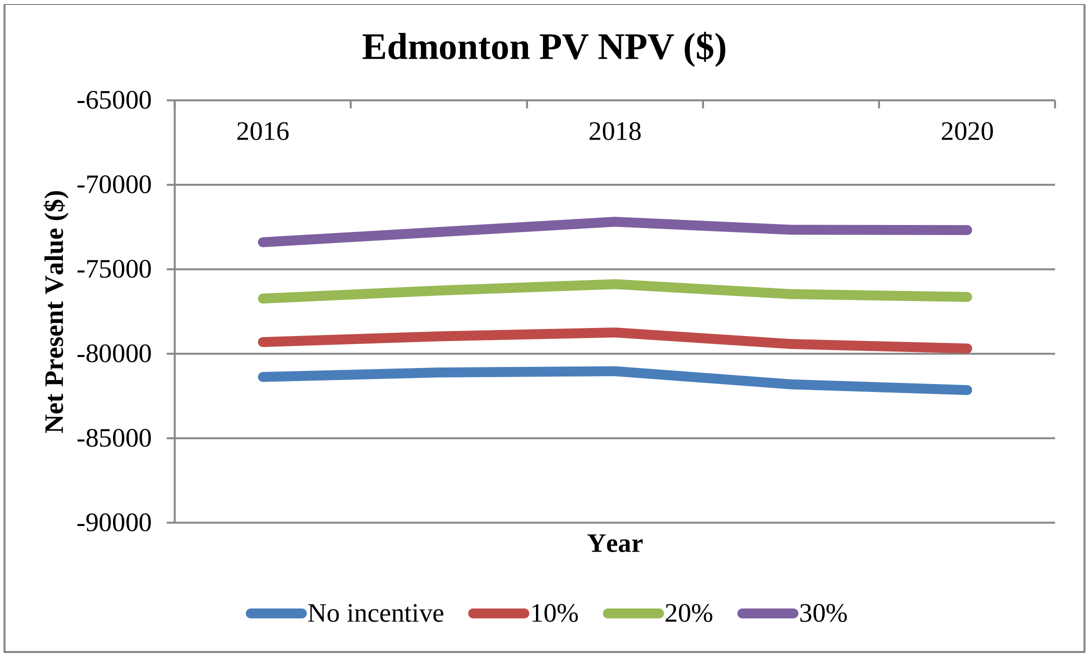

Lethbridge CPV NPV ($) with 9% Discount Rate
Net Present Value ($)
-50000
-55000
-60000
-65000
-70000
-75000
-80000
-85000
2016
2018
2020
Year
No incentive
10%
20%
30%

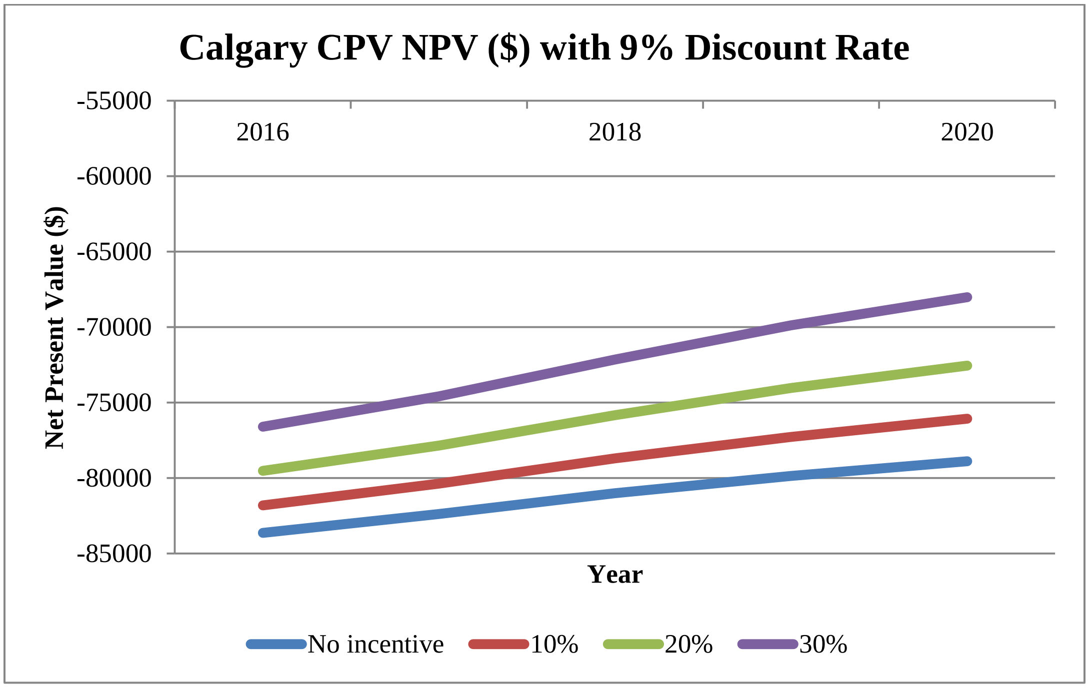

Lethbridge CPV NPV ($) with 7% Discount Rate
Net Present Value ($)
-50000
-55000
-60000
-65000
-70000
-75000
-80000
-85000
2016
2018
2020
Year
No incentive
10%
20%
30%

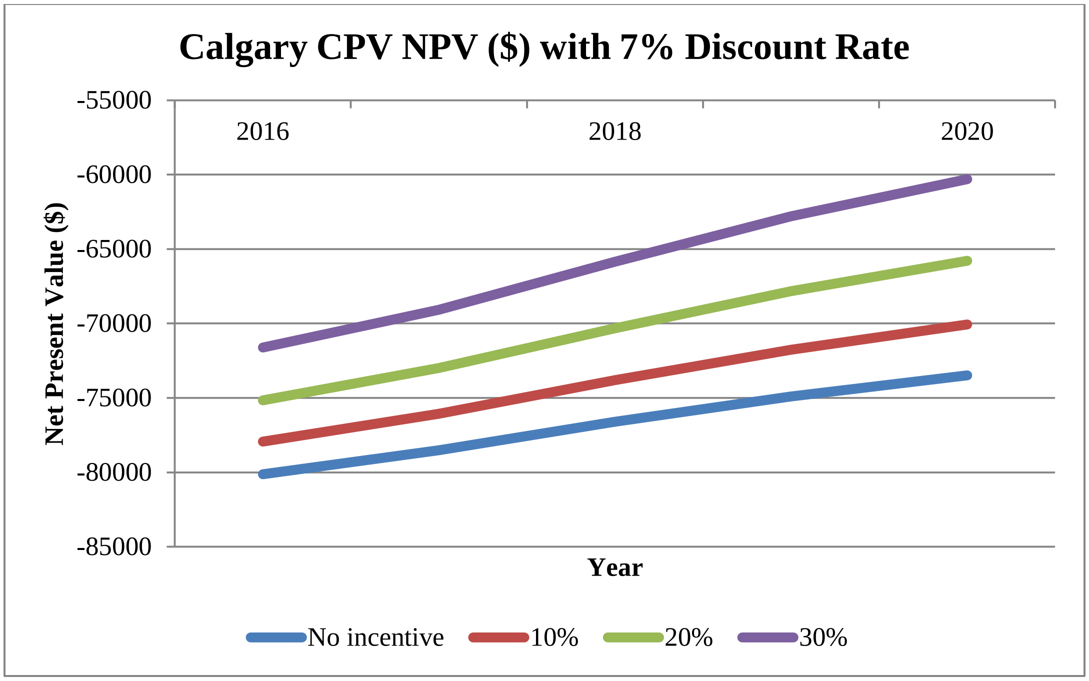

Lethbridge PV NPV ($)
Net Present Value ($)
-50000
-55000
-60000
-65000
-70000
-75000
-80000
-85000
2016
2018
2020
Year
No incentive
10%
20%
30%

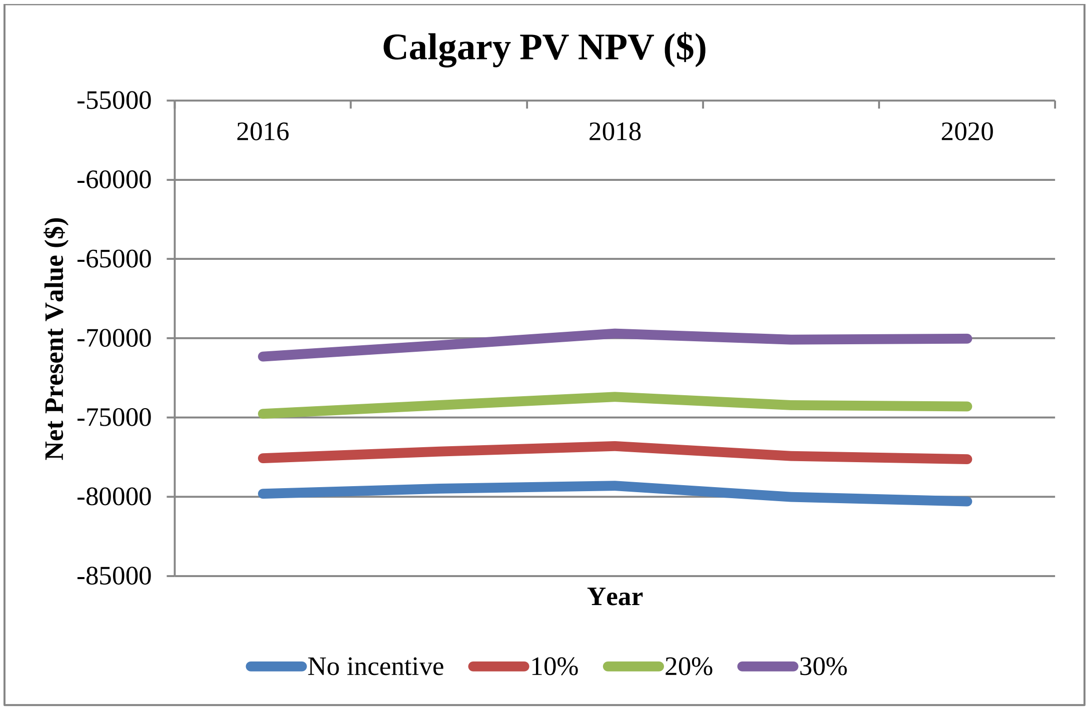

Edmonton CPV NPV ($) with 9% Discount Rate
-65000
-70000
-75000
-80000
-85000
-90000
2016
2018
2020
Net Present Value ($)
Year
No incentive
10%
20%
30%

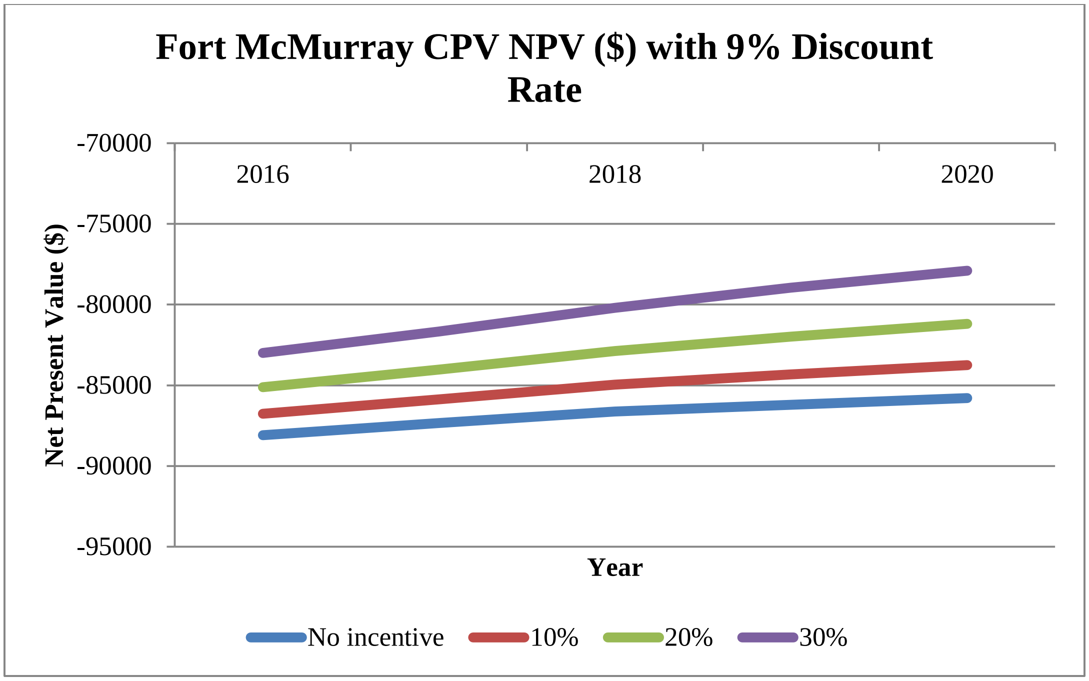

Edmonton CPV NPV ($) with 7% Discount Rate
-65000
-70000
-75000
-80000
-85000
-90000
2016
2018
2020
Net Present Value ($)
Year
No incentive
10%
20%
30%

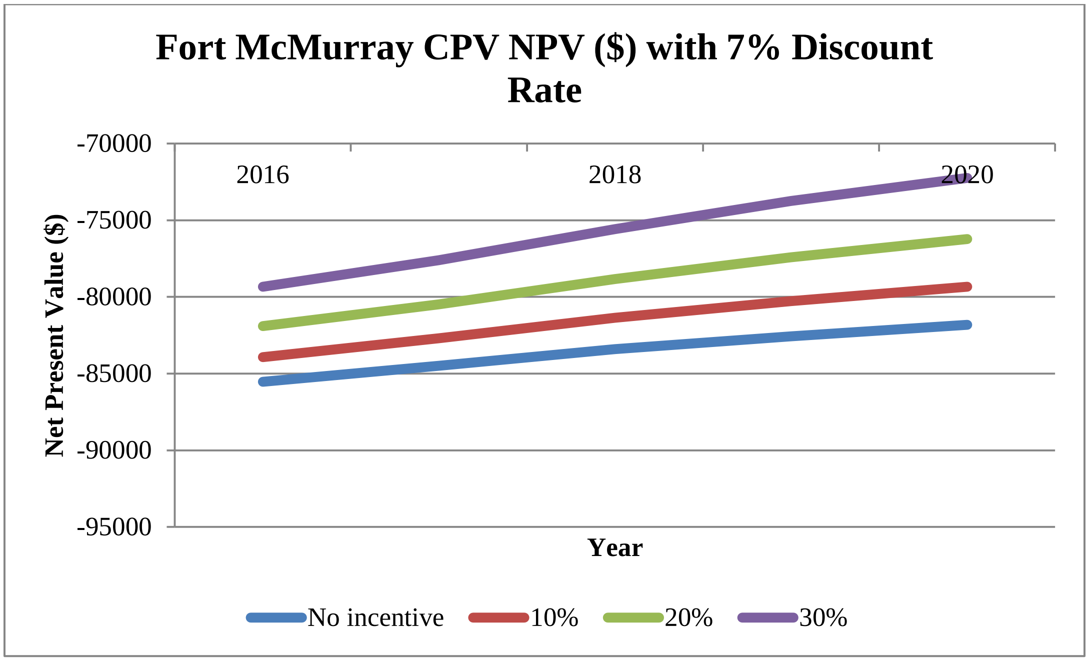

Edmonton PV NPV ($)
-65000
-70000
-75000
-80000
-85000
-90000
2016
2018
2020
Net Present Value ($)
Year
No incentive
10%
20%
30%

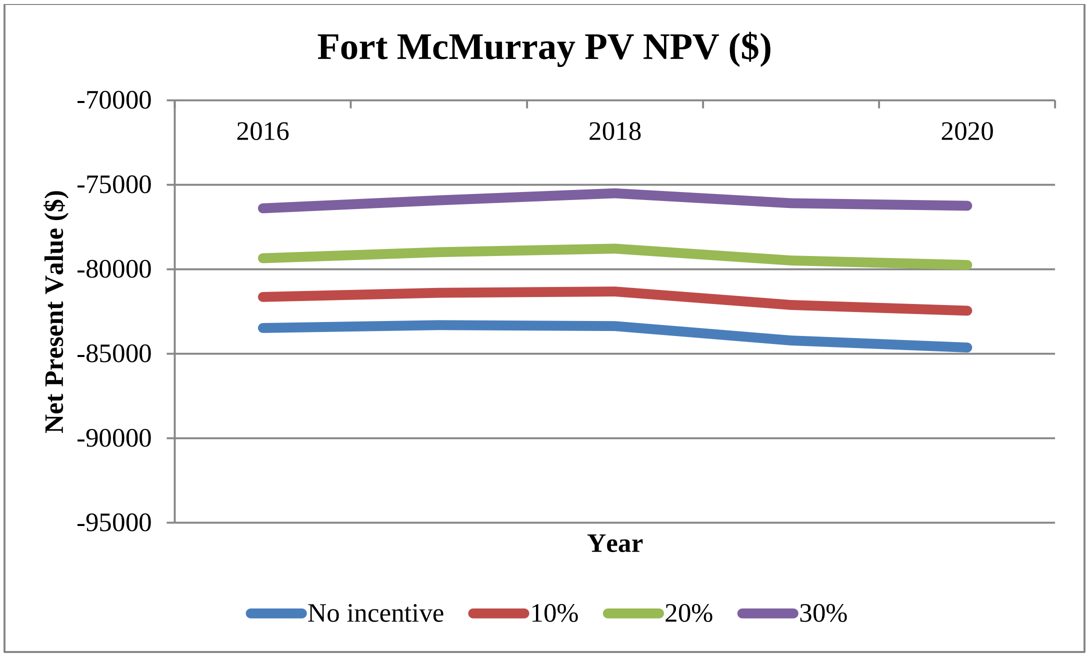

Calgary CPV NPV ($) with 9% Discount Rate
-55000
-60000
-65000
-70000
-75000
-80000
-85000
2016
2018
2020
Net Present Value ($)
Year
No incentive
10%
20%
30%

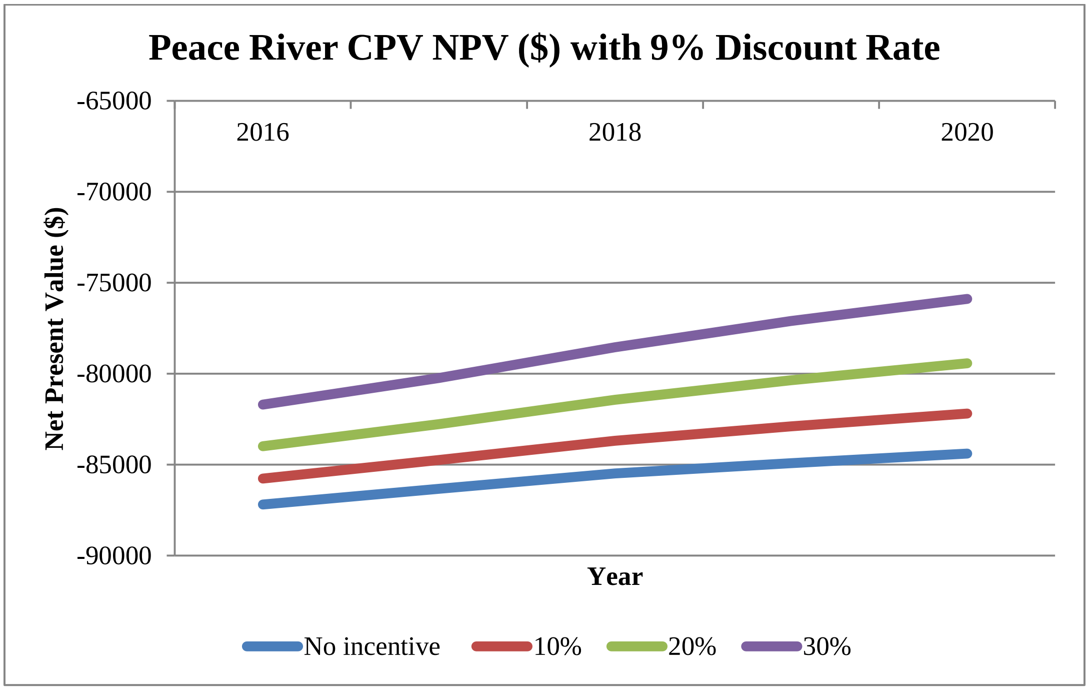

Calgary CPV NPV ($) with 7% Discount Rate
Net Present Value ($)
-55000
-60000
-65000
-70000
-75000
-80000
-85000
2016
2018
2020
Year
No incentive
10%
20%
30%

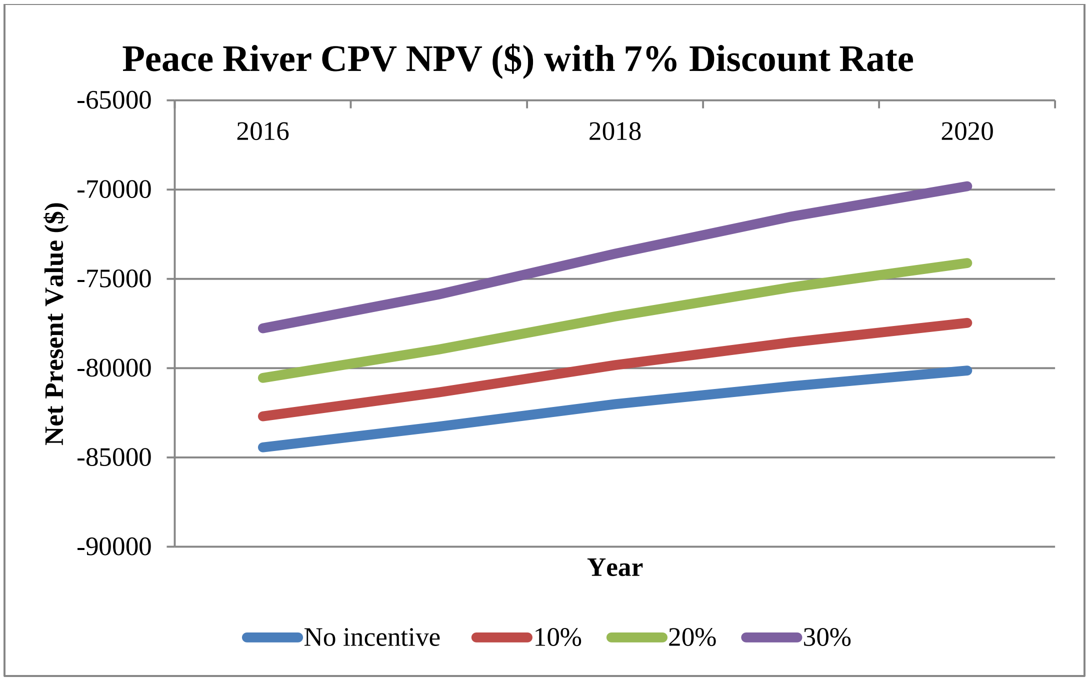

Calgary PV NPV ($)
Net Present Value ($)
-55000
-60000
-65000
-70000
-75000
-80000
-85000
2016
2018
2020
Year
No incentive
10%
20%
30%

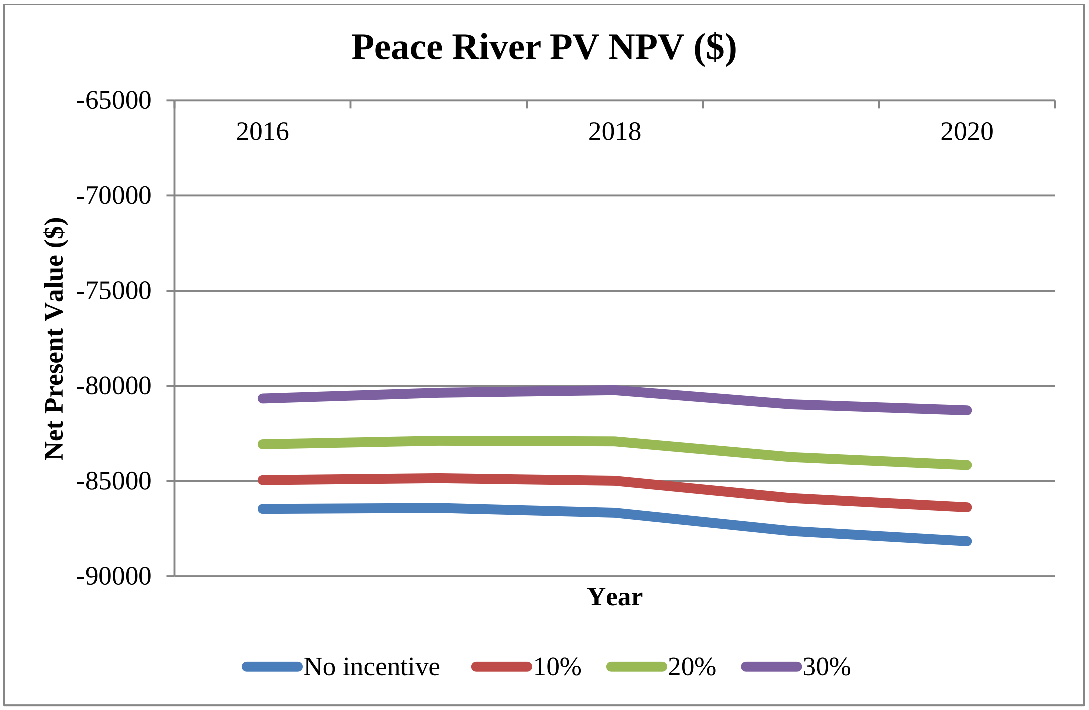

Fort McMurray CPV NPV ($) with 9% Discount Rate
-70000
-75000
-80000
-85000
-90000
-95000
2016
2018
2020
Net Present Value ($)
Year
No incentive
10%
20%
30%


Fort McMurray CPV NPV ($) with 7% Discount Rate
-70000
-75000
-80000
-85000
-90000
-95000
2016
2018
2020
Net Present Value ($)
Year
No incentive
10%
20%
30%

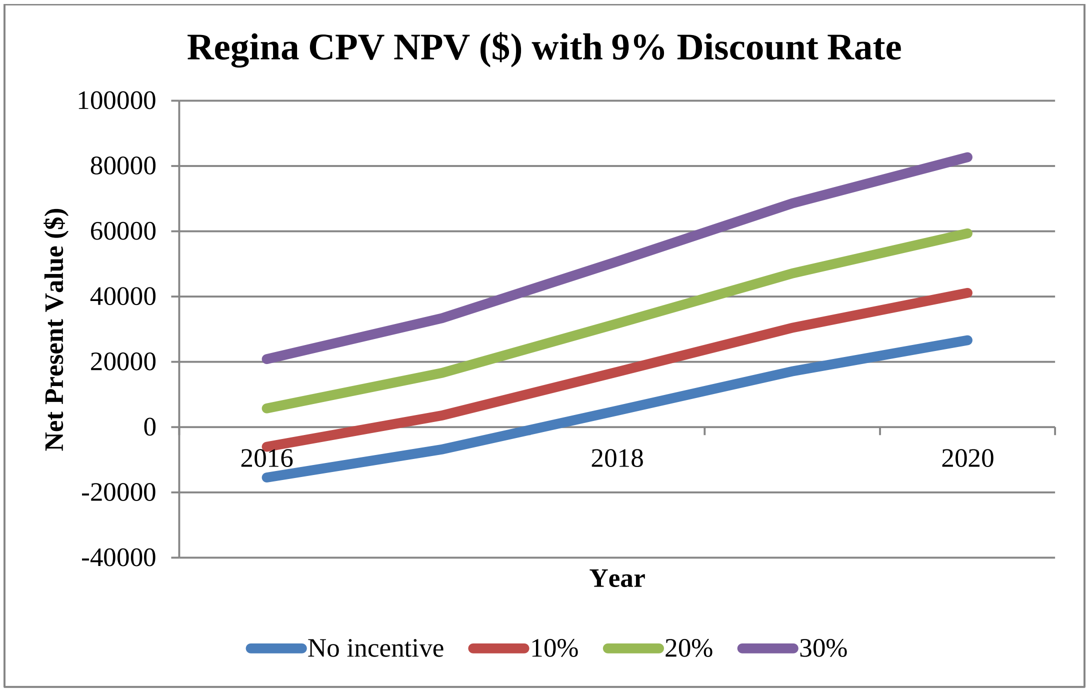

Fort McMurray PV NPV ($)
-70000
-75000
-80000
-85000
-90000
-95000
2016
2018
2020
Net Present Value ($)
Year
No incentive
10%
20%
30%

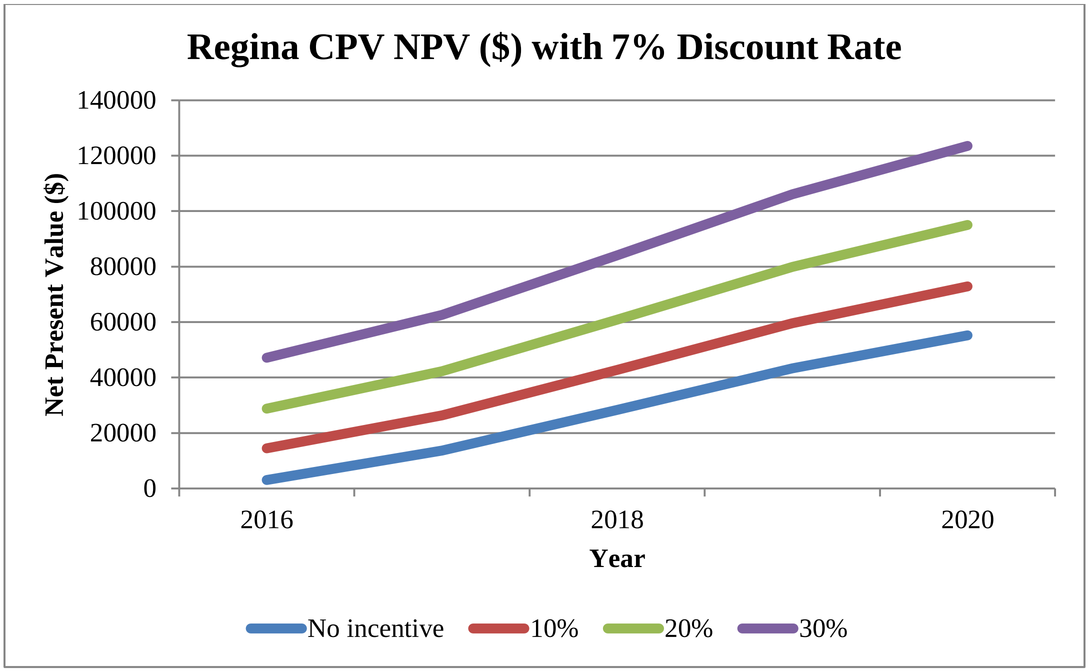

Peace River CPV NPV ($) with 9% Discount Rate
-65000
-70000
-75000
-80000
-85000
-90000
2016
2018
2020
Net Present Value ($)
Year
No incentive
10%
20%
30%

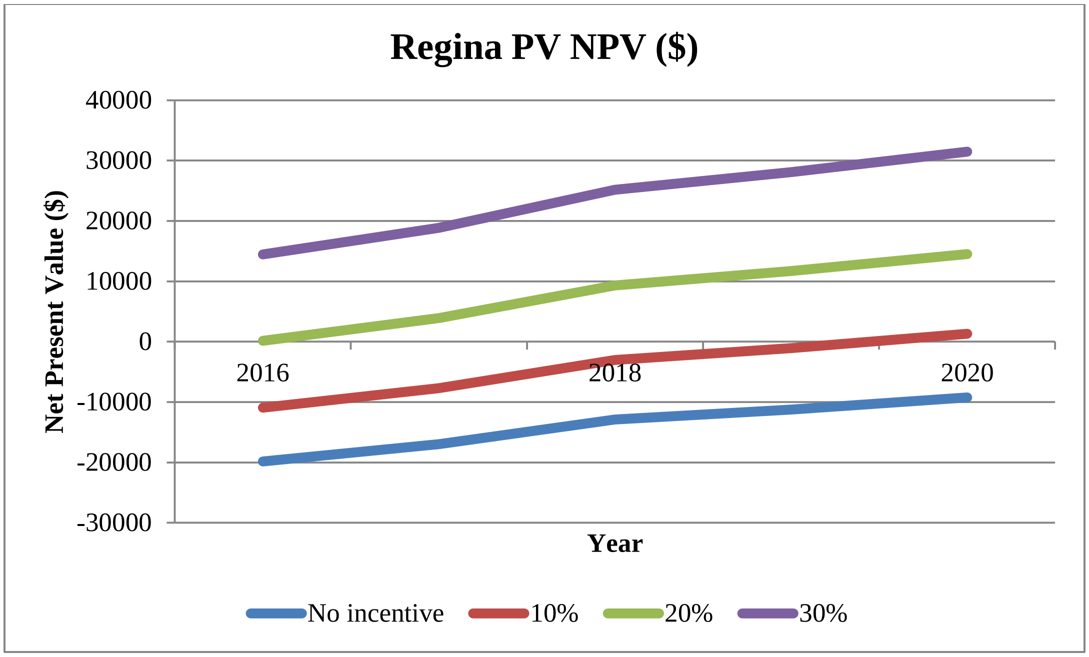

Peace River CPV NPV ($) with 7% Discount Rate
-65000
-70000
-75000
-80000
-85000
-90000
2016
2018
2020
Net Present Value ($)
Year
No incentive
10%
20%
30%

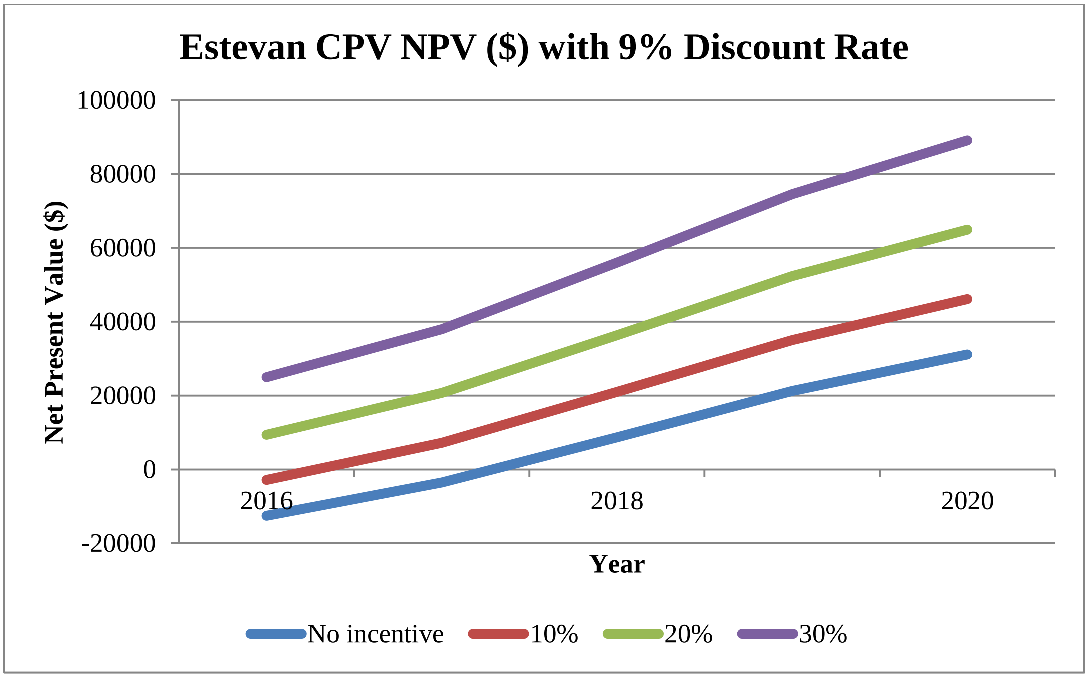

Peace River PV NPV ($)
-65000
-70000
-75000
-80000
-85000
-90000
2016
2018
2020
Net Present Value ($)
Year
No incentive
10%
20%
30%

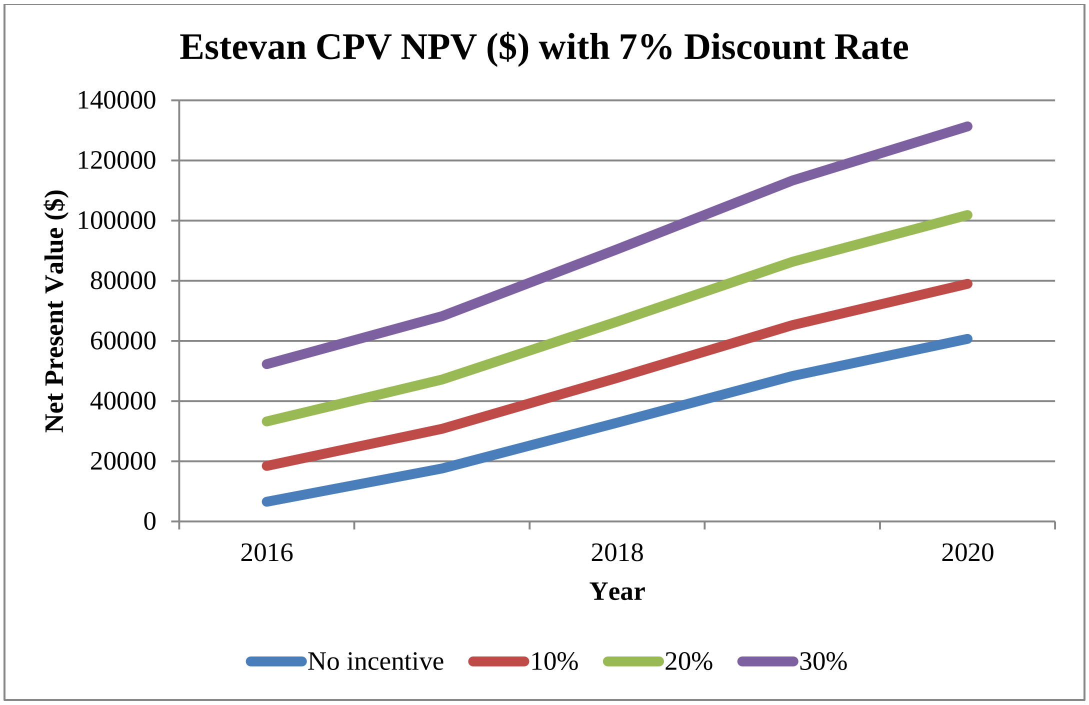
Saskatchewan

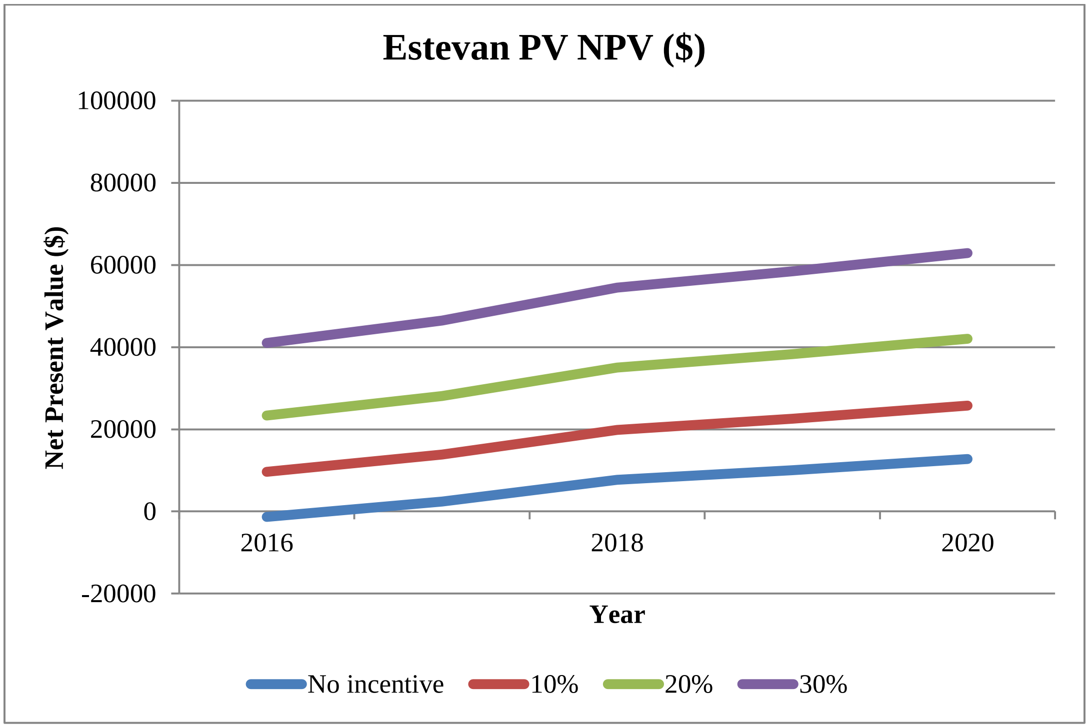


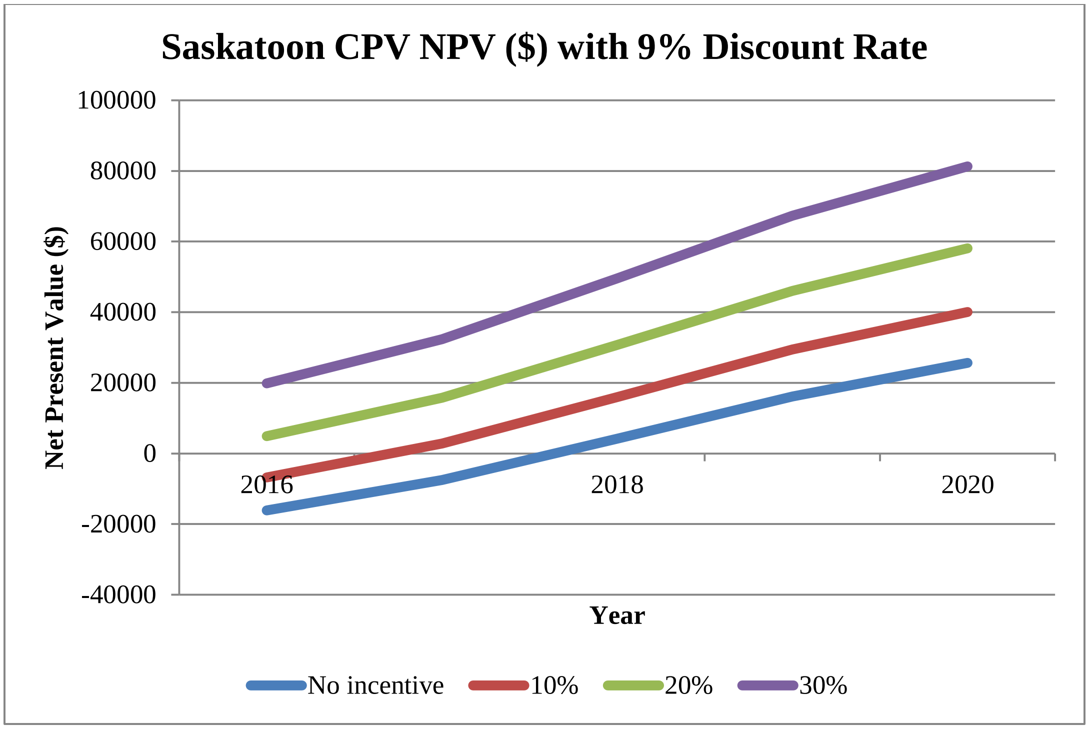


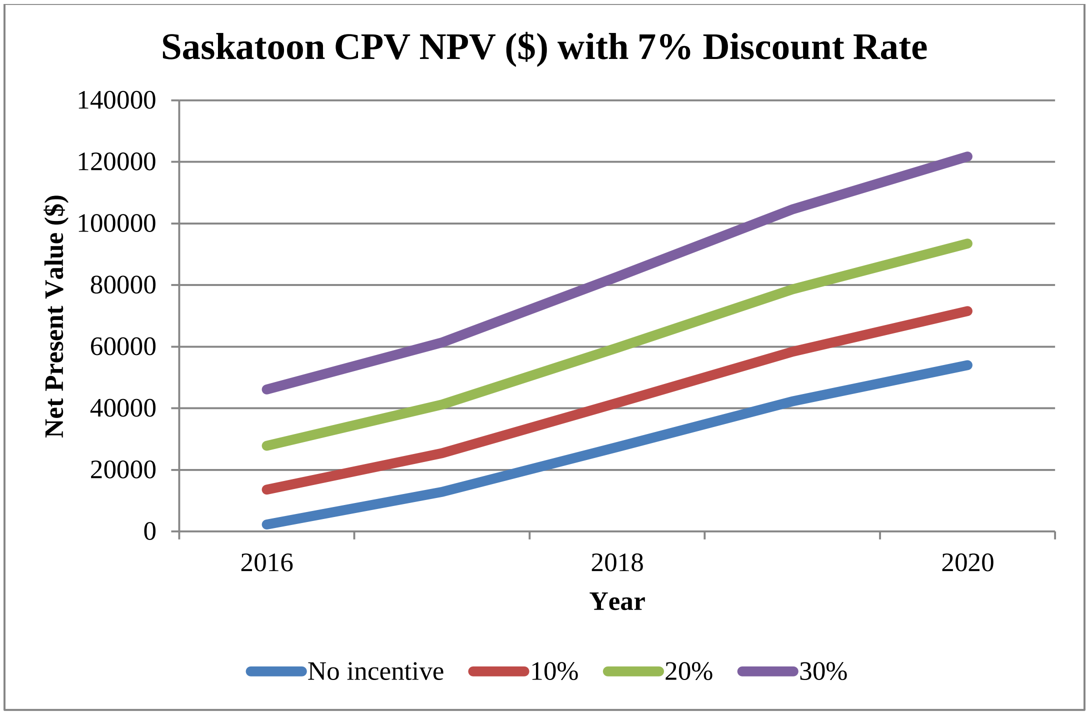

Regina PV NPV ($)
40000
30000
20000
10000
0
-10000
-20000
-30000
2016
2018
2020
Net Present Value ($)
Year
No incentive
10%
20%
30%

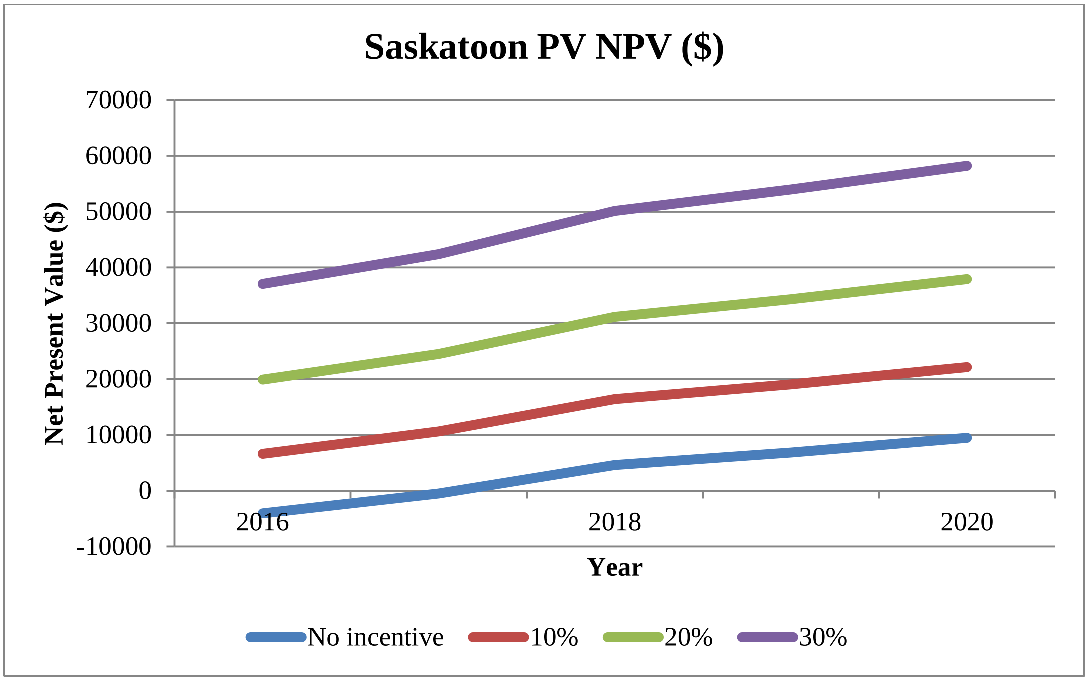

Estevan CPV NPV ($) with 9% Discount Rate
100000
80000
60000
40000
20000
0
-20000
2016
2018
2020
Net Present Value ($)
Year
No incentive
10%
20%
30%

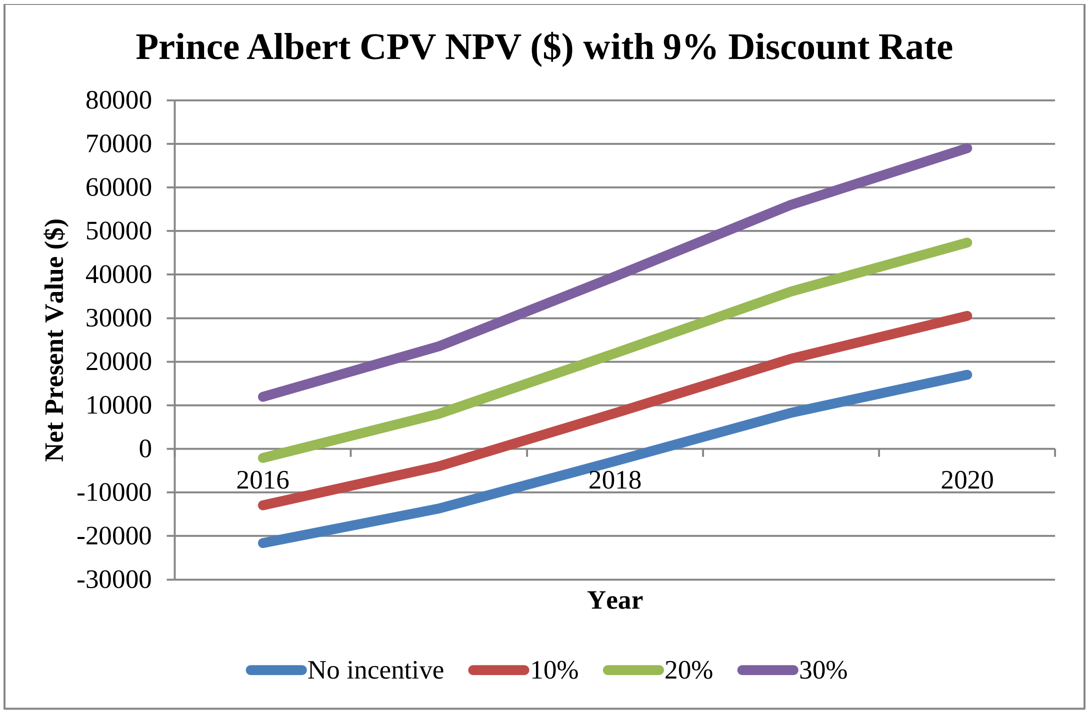

Estevan CPV NPV ($) with 7% Discount Rate
Net Present Value ($)
140000
120000
100000
80000
60000
40000
20000
0
2016
2018
2020
Year
No incentive
10%
20%
30%

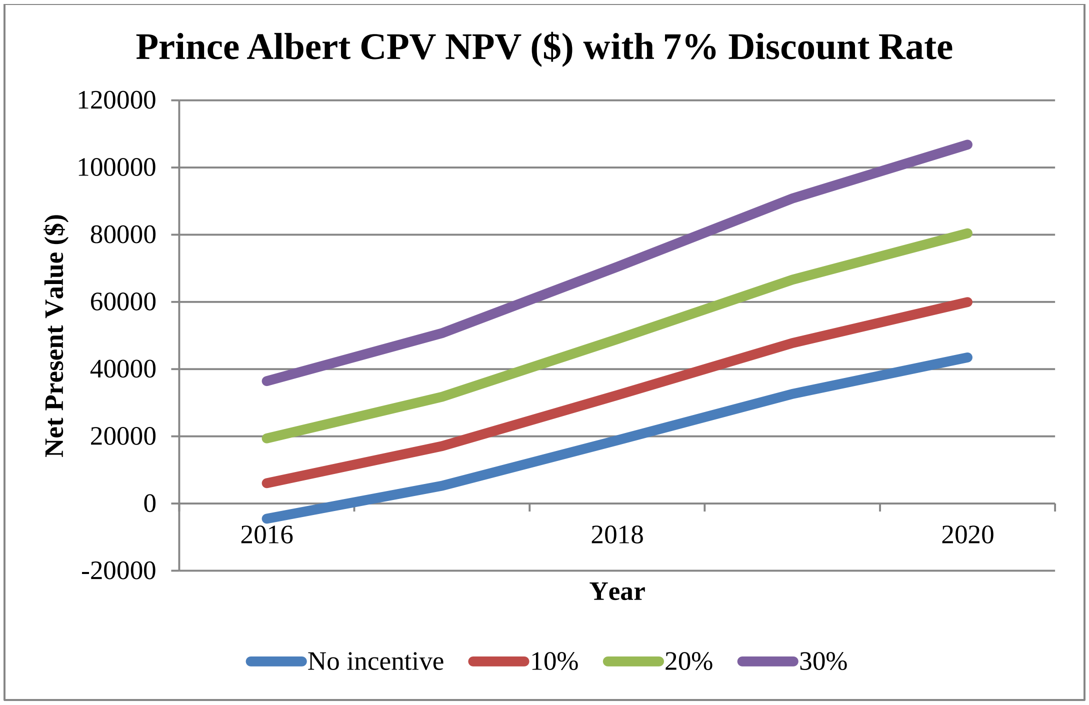

Estevan PV NPV ($)
Net Present Value ($)
100000
80000
60000
40000
20000
0
-20000
2016
2018
2020
Year
No incentive
10%
20%
30%


Saskatoon CPV NPV ($) with 9% Discount Rate
100000
80000
60000
40000
20000
0
-20000
-40000
Net Present Value ($)
2016
2018
2020
Year
No incentive
10%
20%
30%

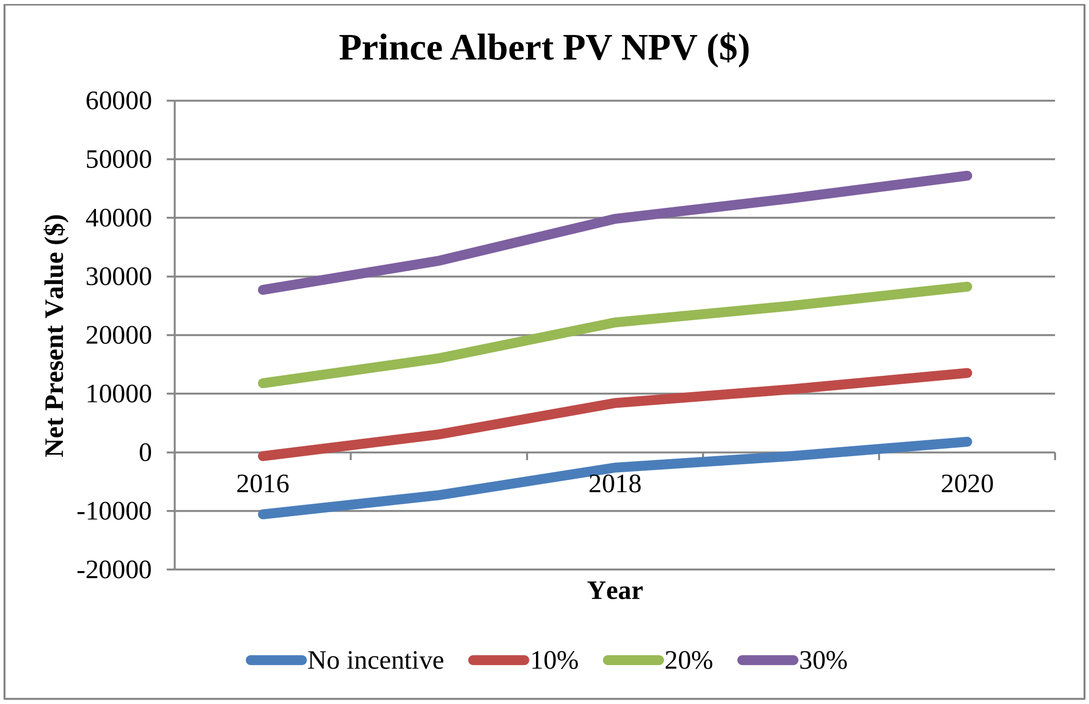

Saskatoon CPV NPV ($) with 7% Discount Rate
140000
120000
100000
80000
60000
40000
20000
0
Net Present Value ($)
2016
2018
2020
Year
No incentive
10%
20%
30%


Saskatoon PV NPV ($)
Net Present Value ($)
70000
60000
50000
40000
30000
20000
10000
0
-10000
2016
2018
2020
Year
No incentive
10%
20%
30%

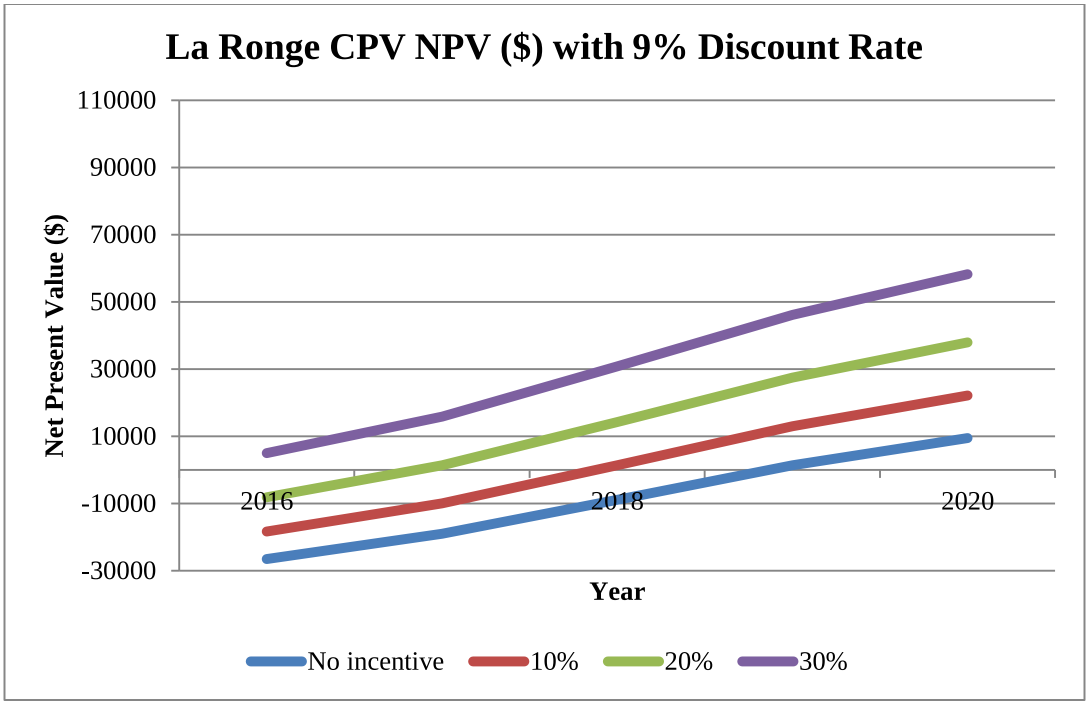

Prince Albert CPV NPV ($) with 9% Discount Rate
Net Present Value ($)
80000
70000
60000
50000
40000
30000
20000
10000
0
-10000
-20000
-30000
2016
2018
2020
Year
No incentive
10%
20%
30%

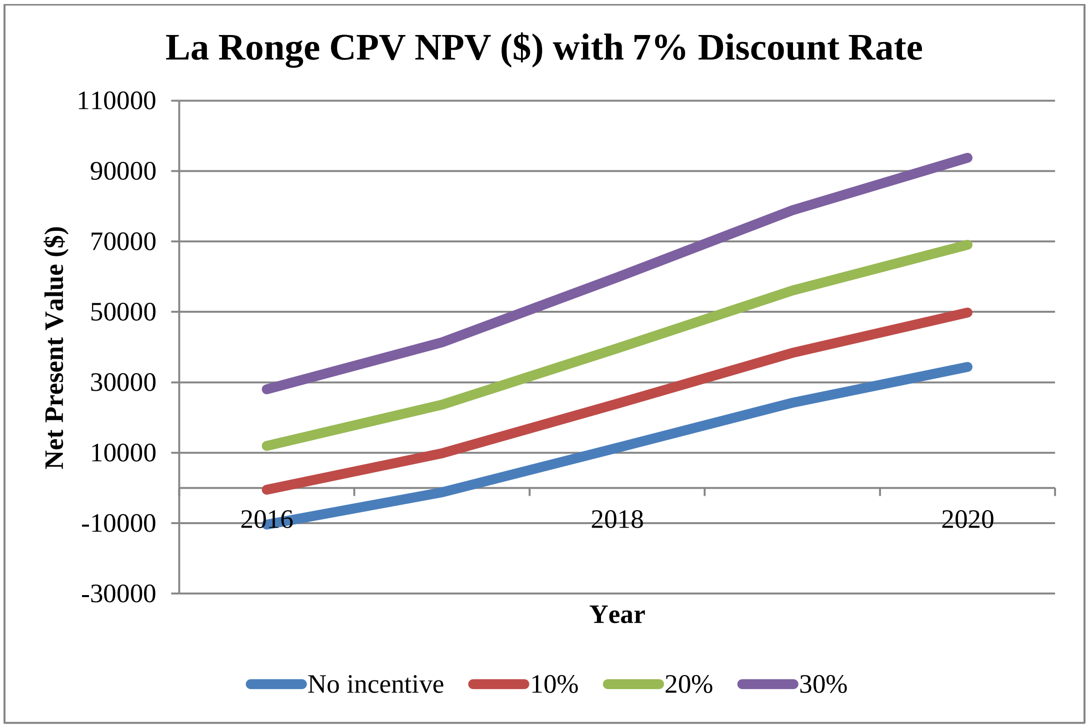


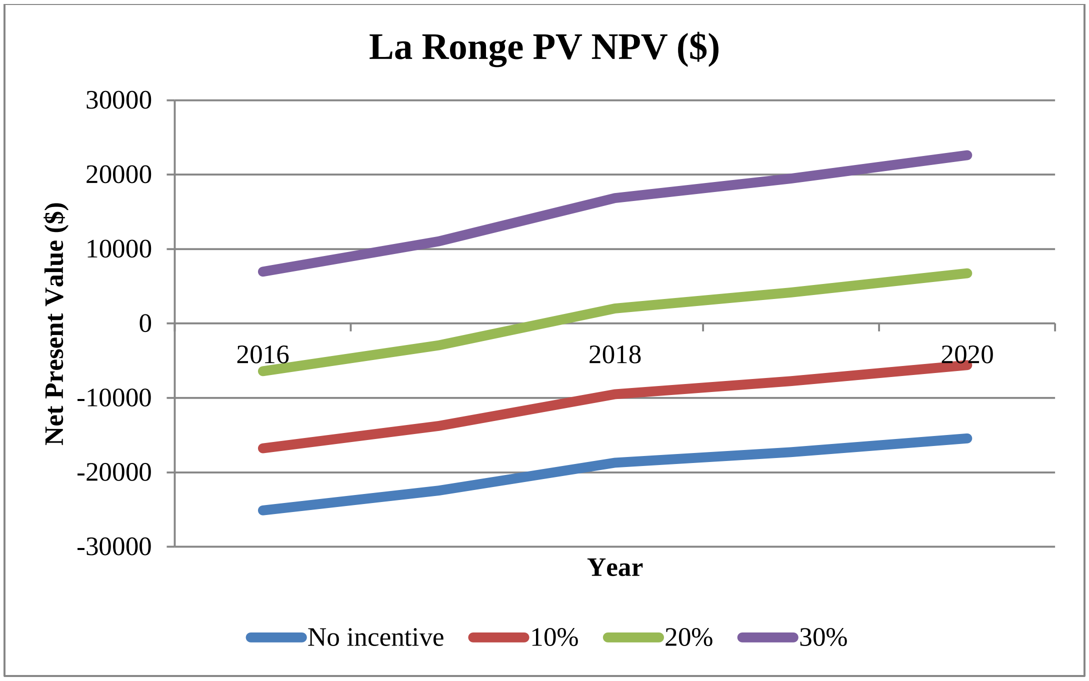
Prince Albert CPV NPV ($) with 7% Discount Rate
Net Present Value ($)
120000
100000
80000
60000
40000
20000
0
-20000
2016
2018
2020
Year
No incentive
10%
20%
30%

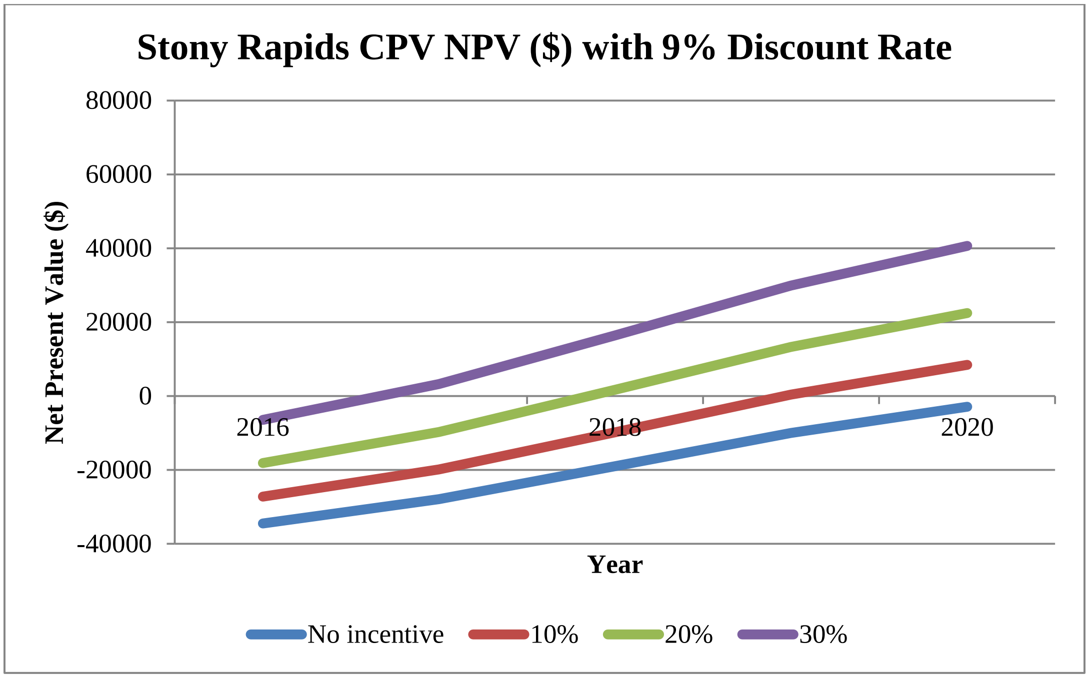


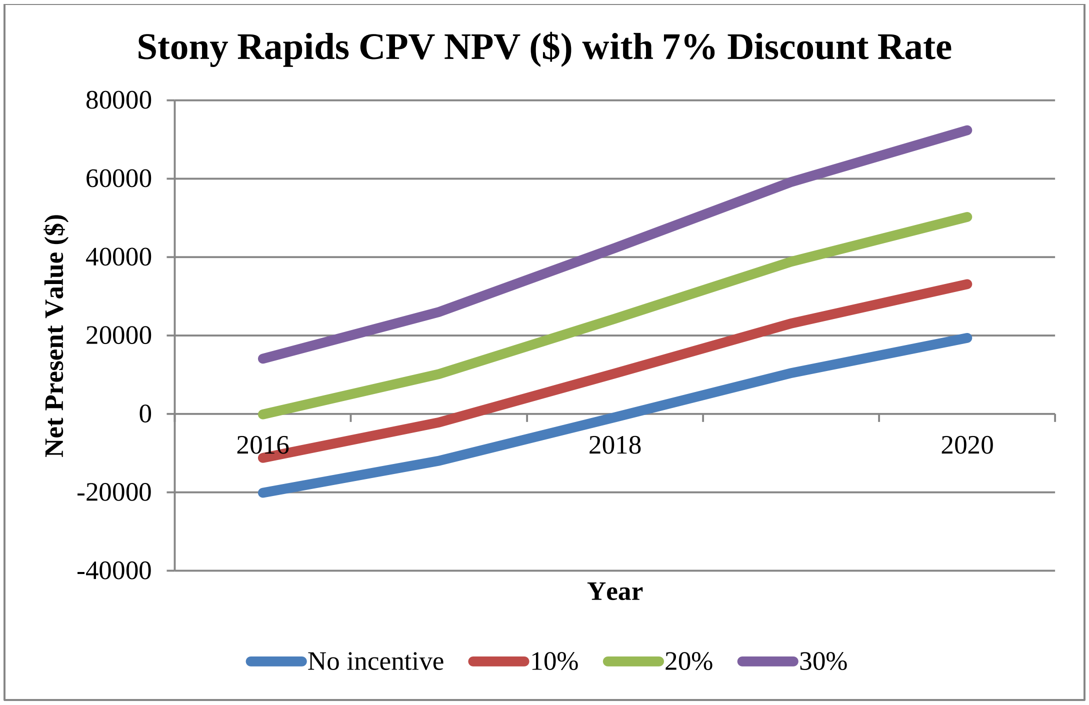
Prince Albert PV NPV ($)
Net Present Value ($)
60000
50000
40000
30000
20000
10000
0
-10000
-20000
2016
2018
2020
Year
No incentive
10%
20%
30%

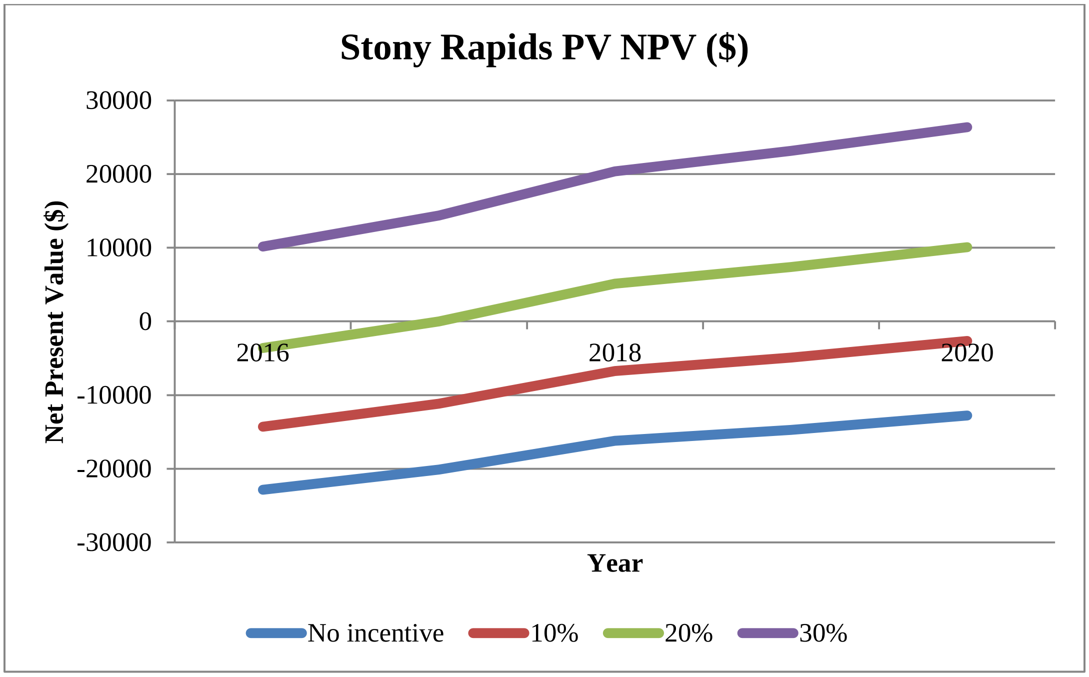

La Ronge CPV NPV ($) with 9% Discount Rate
110000
90000
70000
50000
30000
10000
-10000
-30000
Net Present Value ($)
2016
2018
2020
Year
No incentive
10%
20%
30%


La Ronge CPV NPV ($) with 7% Discount Rate
110000
90000
70000
50000
30000
10000
-10000
-30000
Net Present Value ($)
2016
2018
2020
Year
No incentive
10%
20%
30%

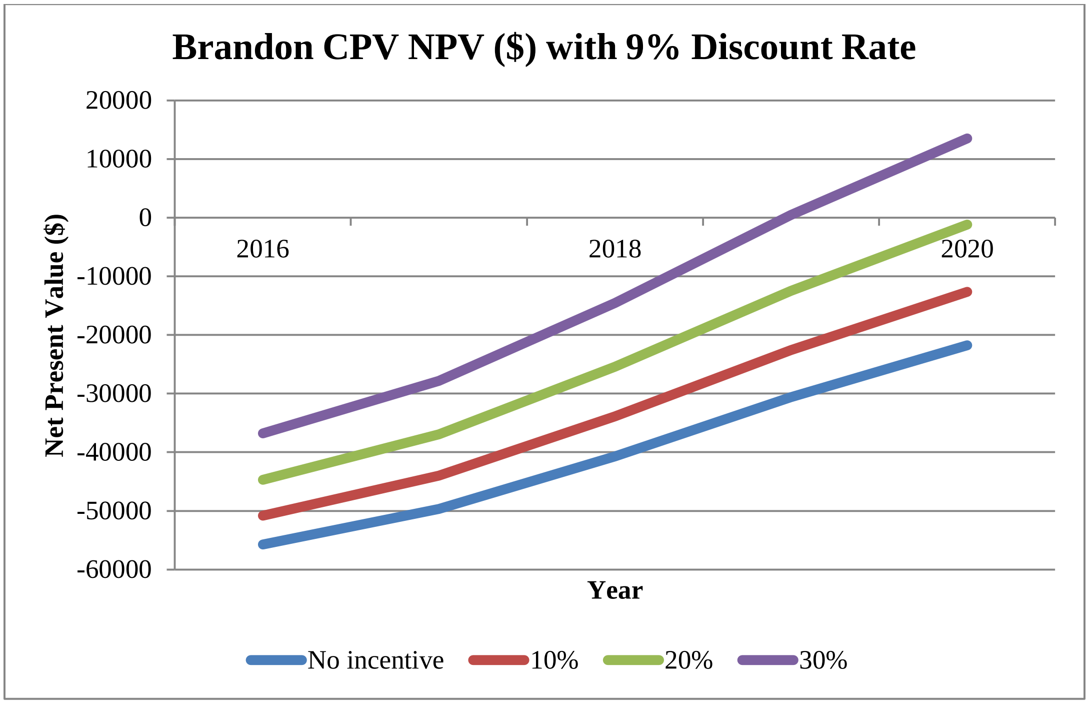

La Ronge PV NPV ($)
Net Present Value ($)
30000
20000
10000
0
-10000
-20000
-30000
2016
2018
2020
Year
No incentive
10%
20%
30%

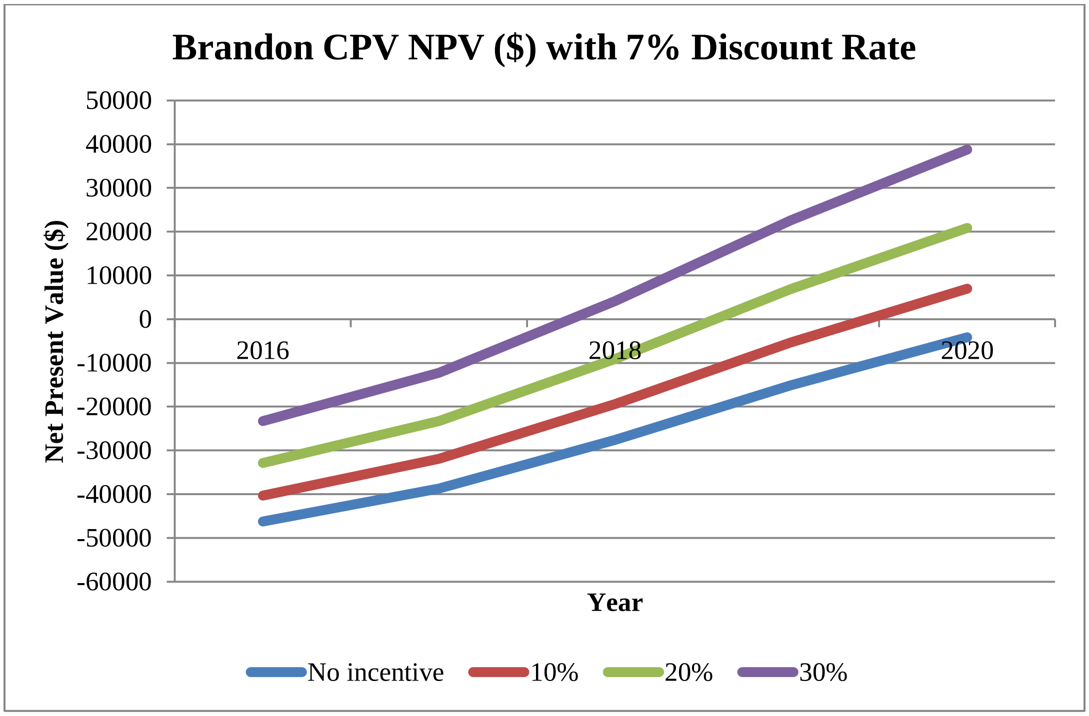

Stony Rapids CPV NPV ($) with 9% Discount Rate
Net Present Value ($)
80000
60000
40000
20000
0
-20000
-40000
2016
2018
2020
Year
No incentive
10%
20%
30%

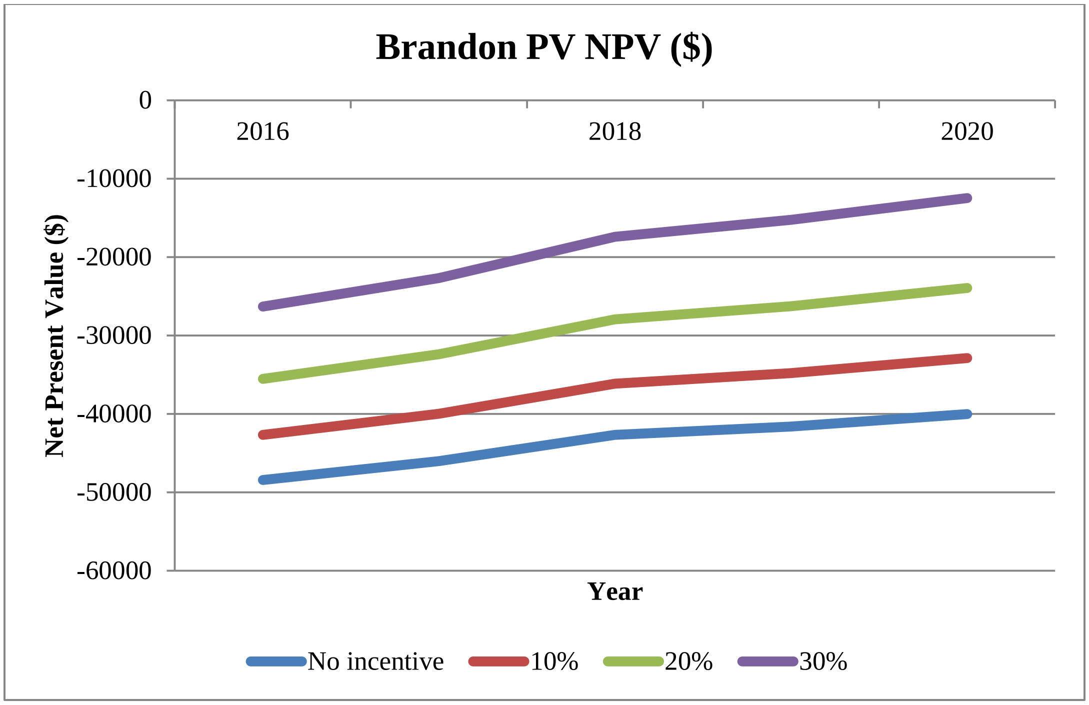

Stony Rapids CPV NPV ($) with 7% Discount Rate
Net Present Value ($)
80000
60000
40000
20000
0
-20000
-40000
2016
2018
2020
Year
No incentive
10%
20%
30%


Stony Rapids PV NPV ($)
Net Present Value ($)
30000
20000
10000
0
-10000
-20000
-30000
2016
2018
2020
Year
No incentive
10%
20%
30%

Manitoba


Brandon CPV NPV ($) with 9% Discount Rate
20000
10000
0
-10000
-20000
-30000
-40000
-50000
-60000
Net Present Value ($)
2016
2018
2020
Year
No incentive
10%
20%
30%


Brandon CPV NPV ($) with 7% Discount Rate
50000
40000
30000
20000
10000
0
-10000
-20000
-30000
-40000
-50000
-60000
Net Present Value ($)
2016
2018
2020
Year
No incentive
10%
20%
30%


Brandon PV NPV ($)
Net Present Value ($)
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-10000
-20000
-30000
-40000
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2016
2018
2020
Year
No incentive
10%
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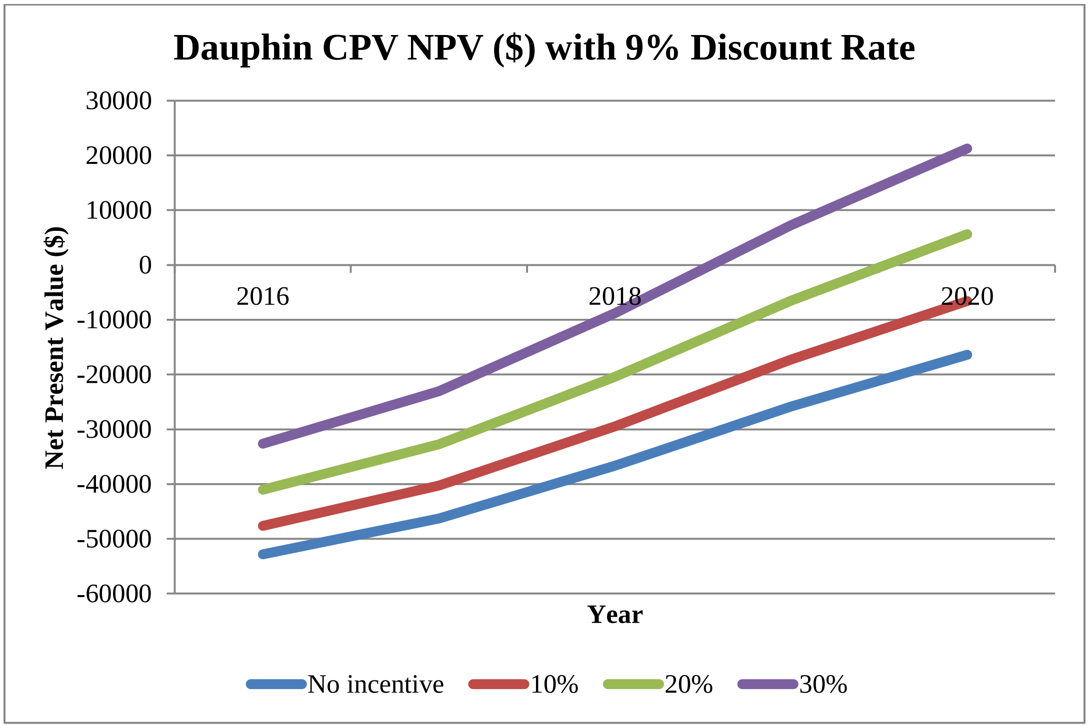
30%


Dauphin CPV NPV ($) with 9% Discount Rate
Net Present Value ($)
30000
20000
10000
0
-10000
-20000
-30000
-40000
-50000
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2016
2018
2020
Year
No incentive
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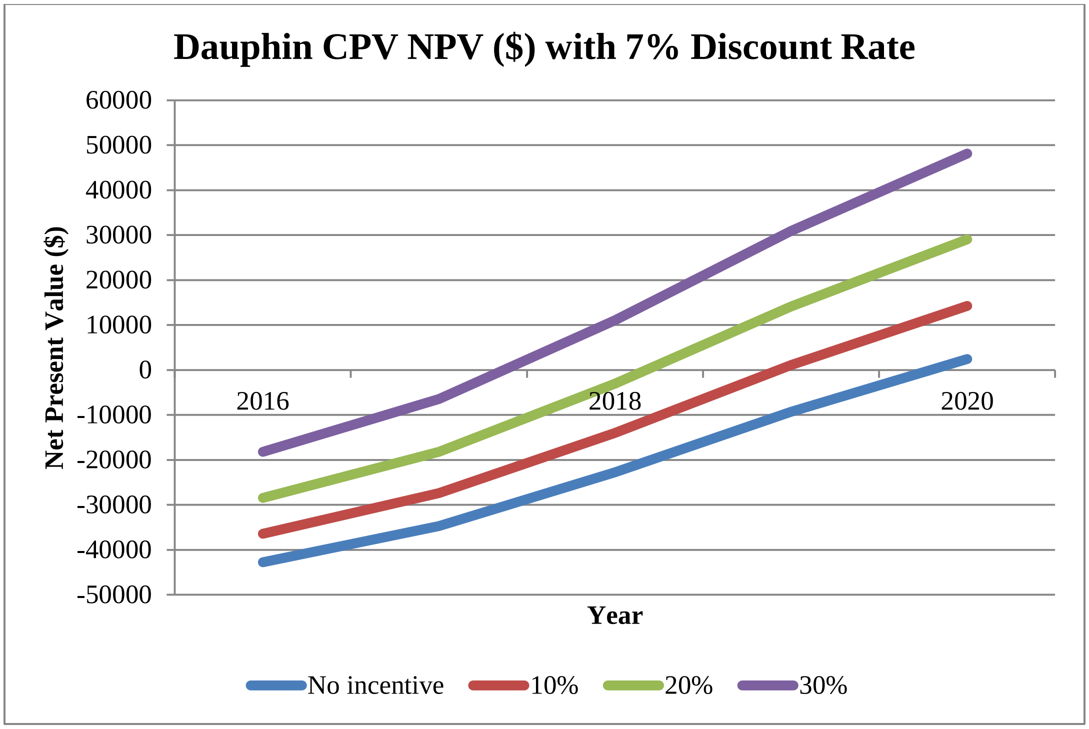
20%
30%


Dauphin CPV NPV ($) with 7% Discount Rate
Net Present Value ($)
60000
50000
40000
30000
20000
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2016
2018
2020
Year
No incentive
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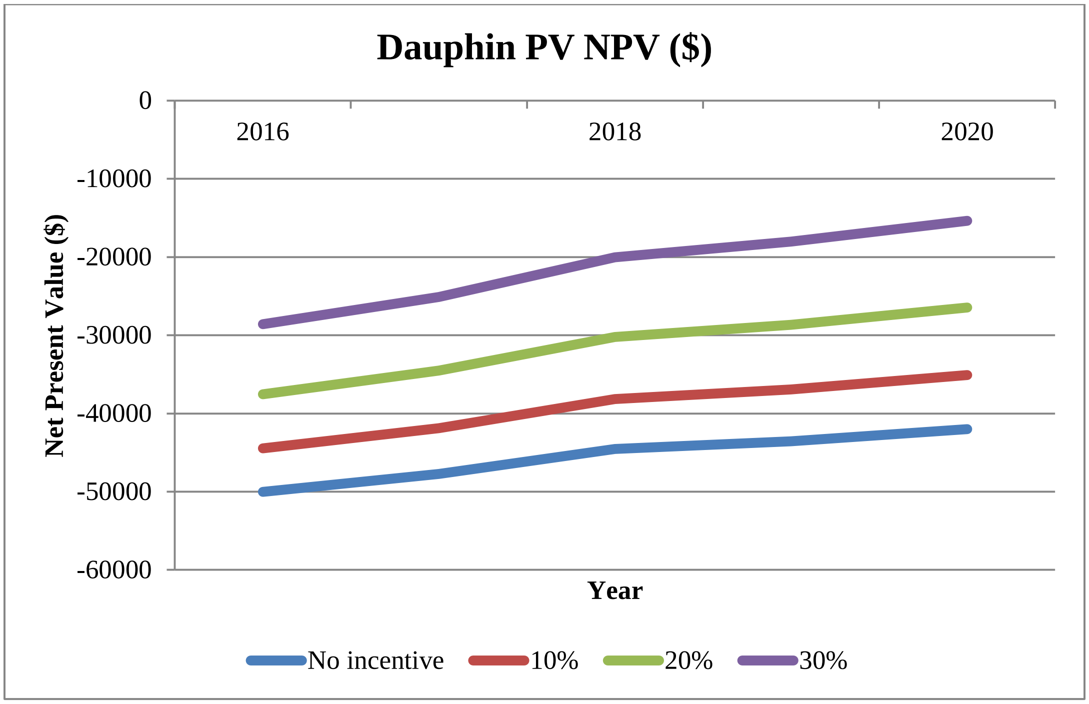
Dauphin PV NPV ($)
Net Present Value ($)
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2016
2018
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Year
No incentive
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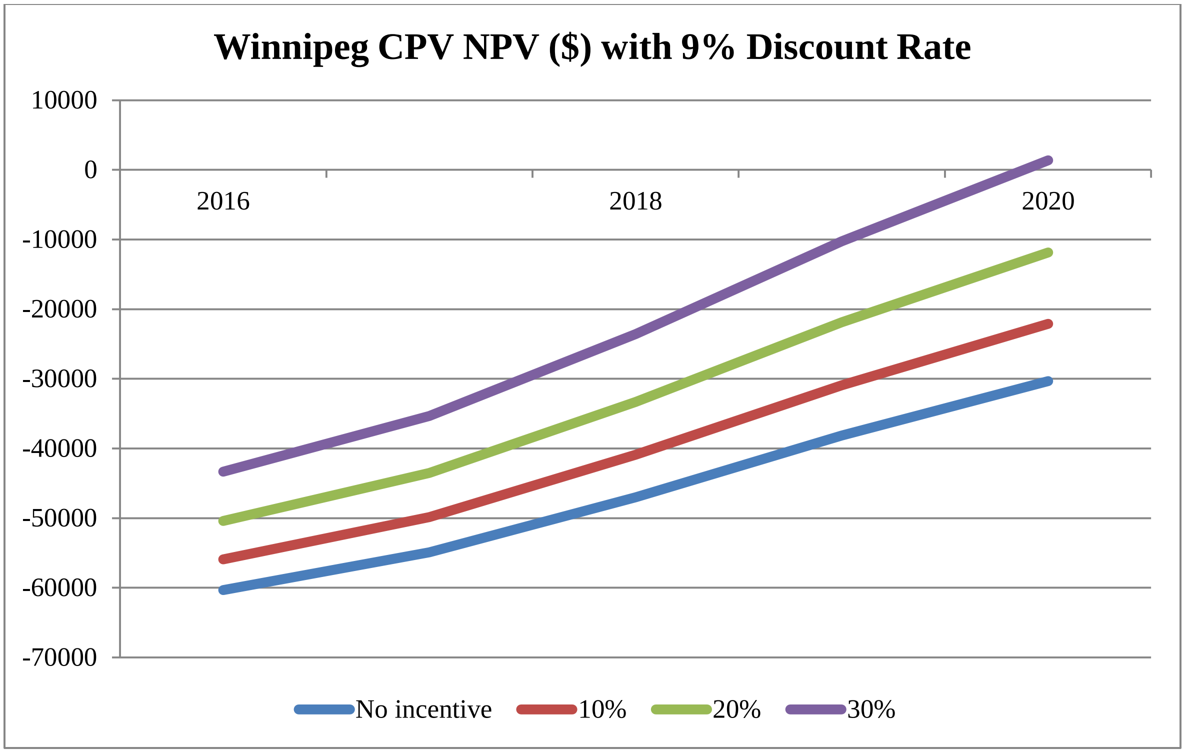
Winnipeg CPV NPV ($) with 9% Discount Rate
10000
0
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-30000
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-70000
2016
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2020
No incentive
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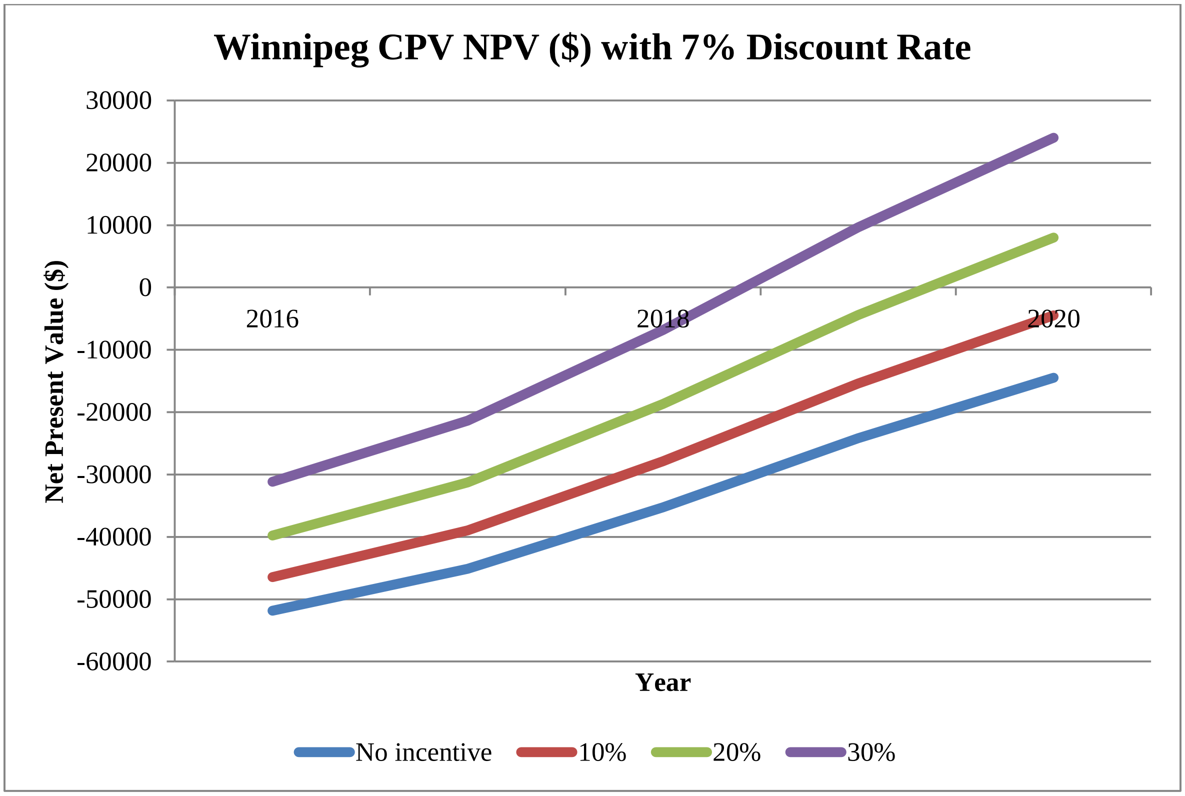
Winnipeg CPV NPV ($) with 7% Discount Rate
Net Present Value ($)
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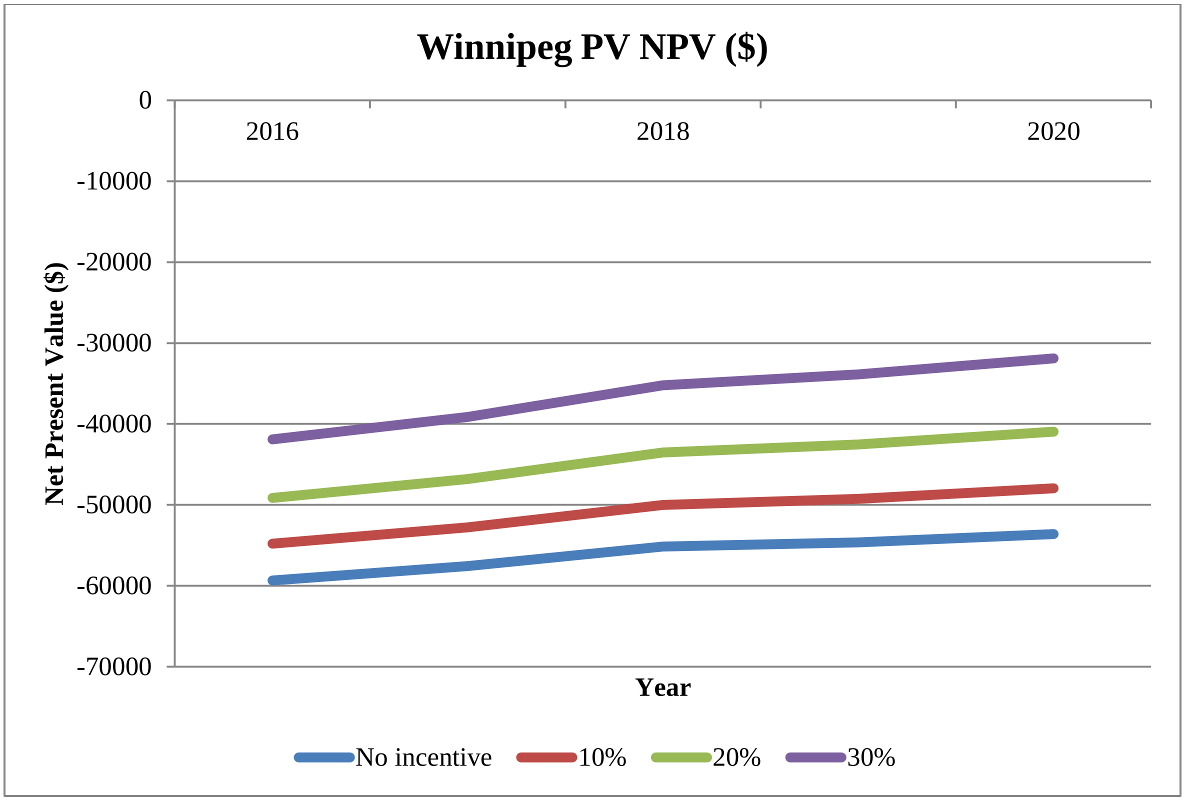
Winnipeg PV NPV ($)
Net Present Value ($)
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2016
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No incentive
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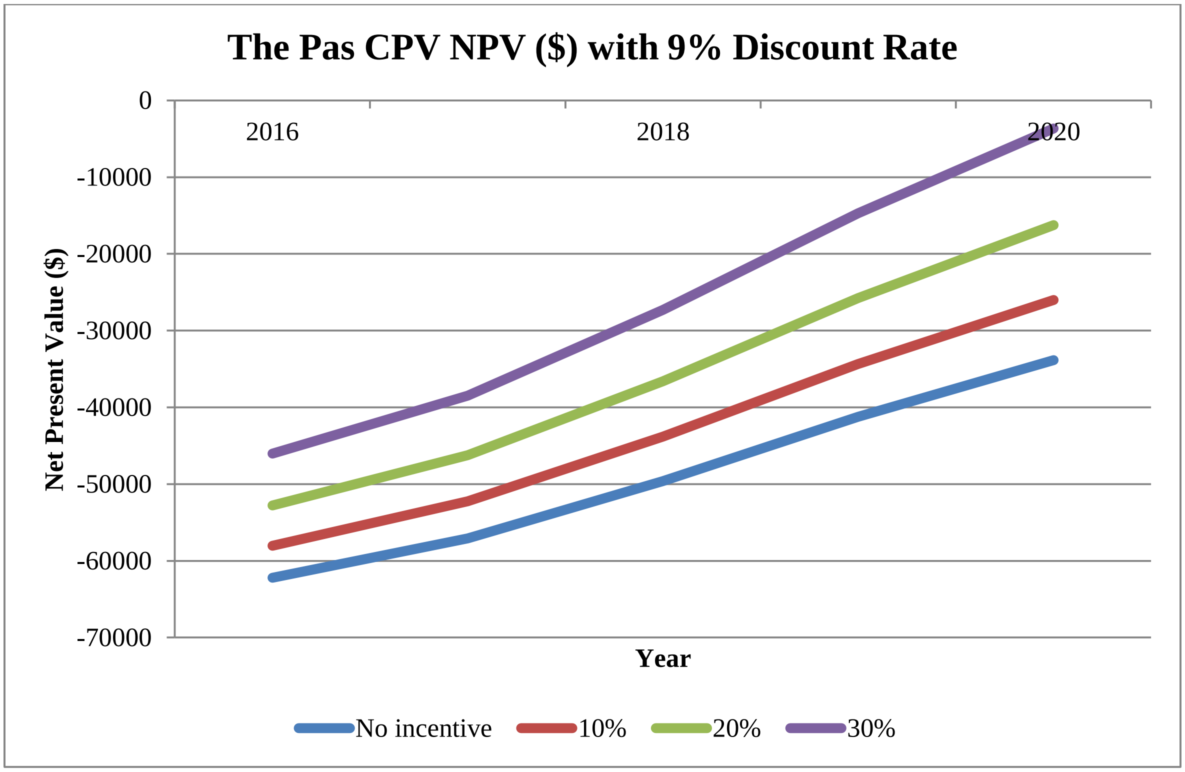
The Pas CPV NPV ($) with 9% Discount Rate
Net Present Value ($)
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2016
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Year
No incentive
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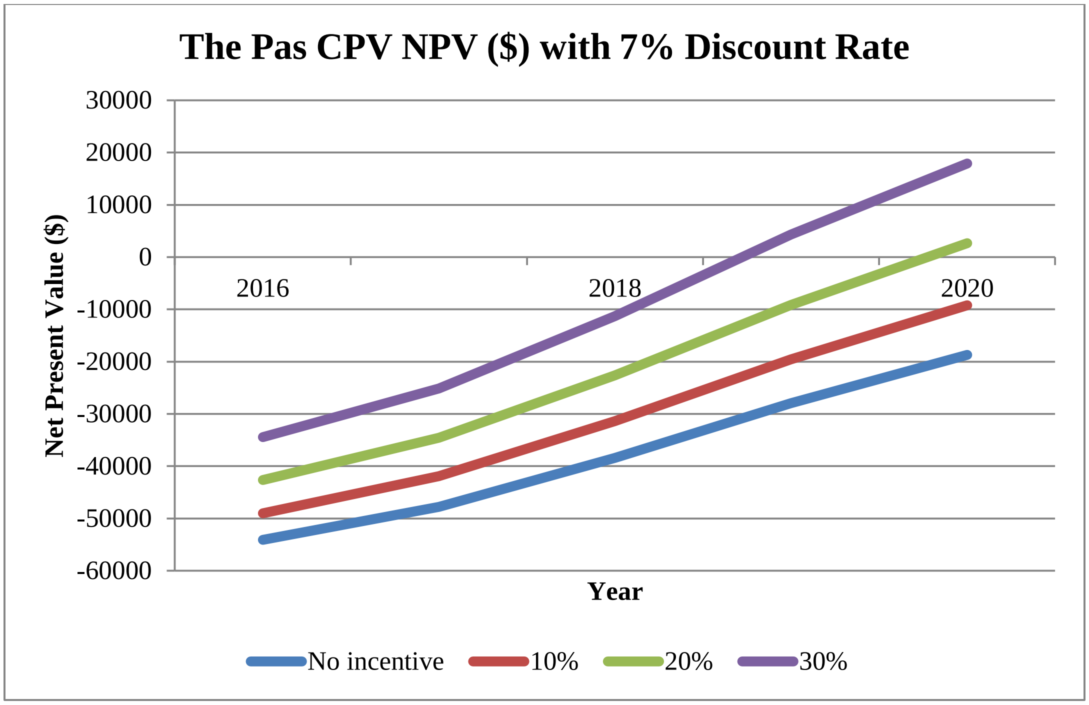
The Pas CPV NPV ($) with 7% Discount Rate
Net Present Value ($)
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No incentive
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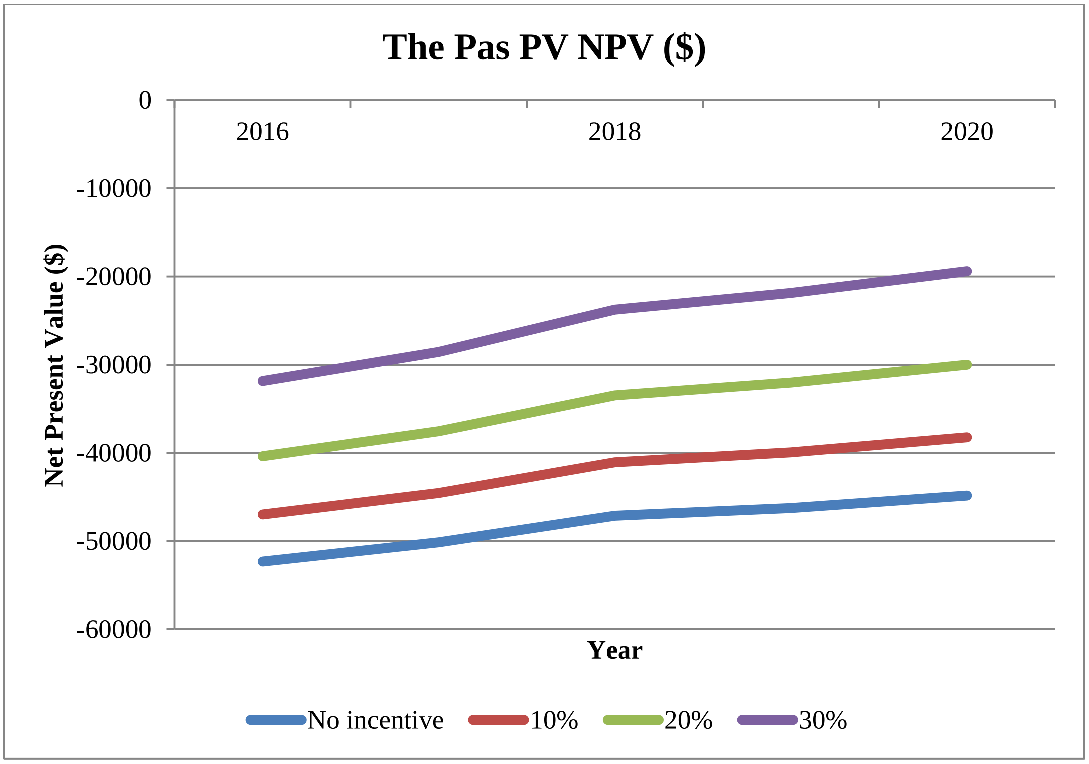
The Pas PV NPV ($)
Net Present Value ($)
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-10000
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2016
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No incentive
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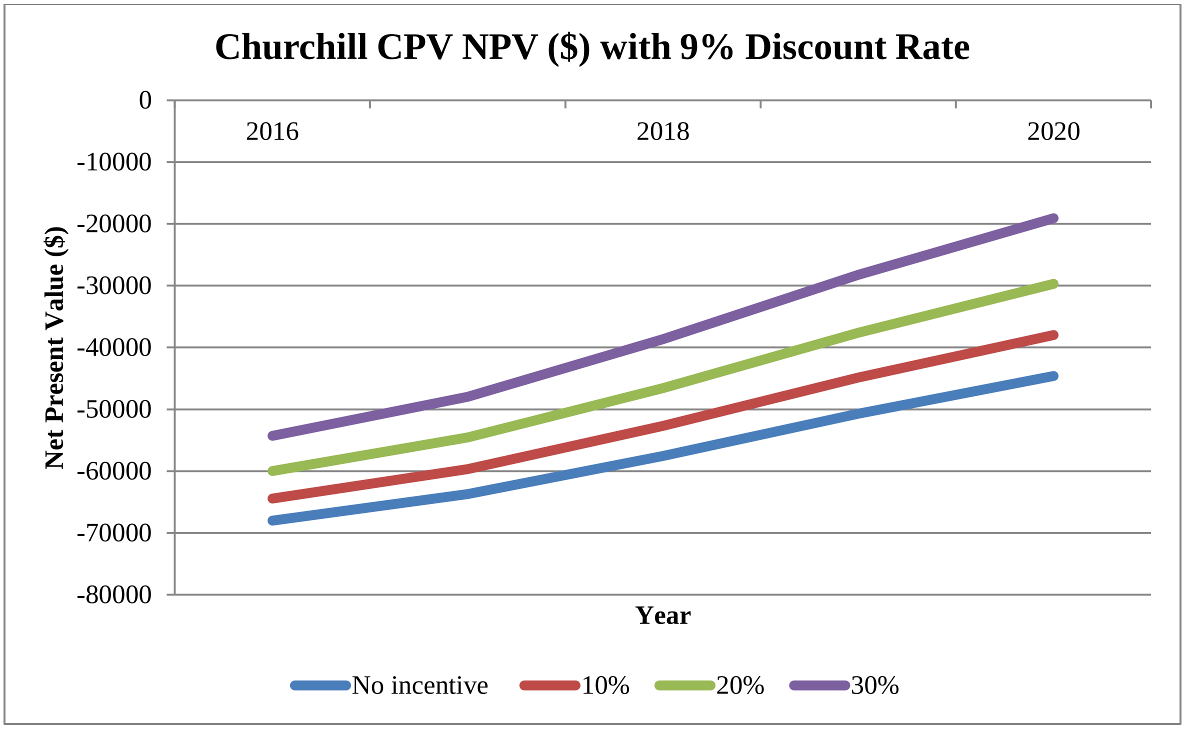
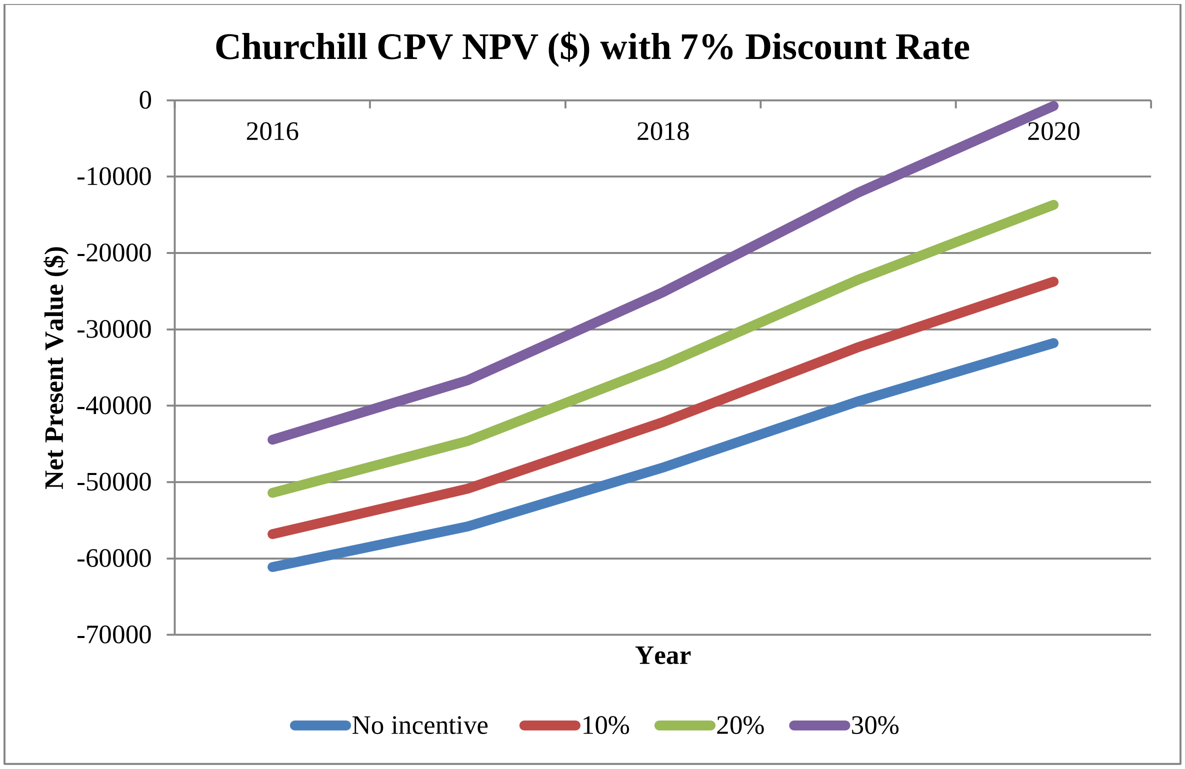
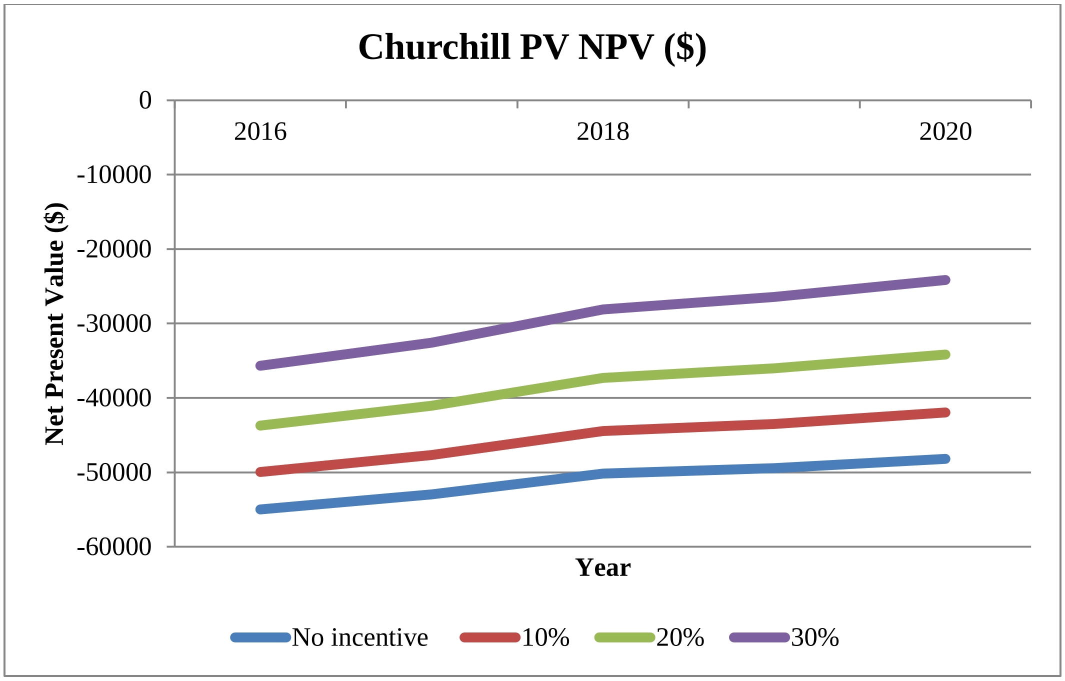
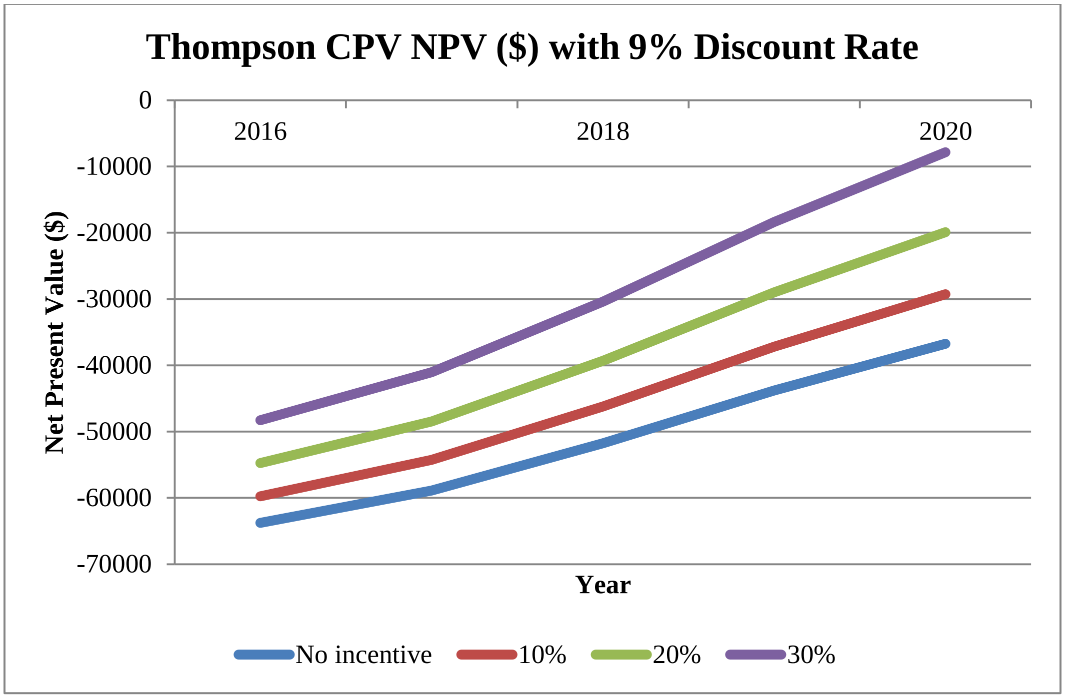


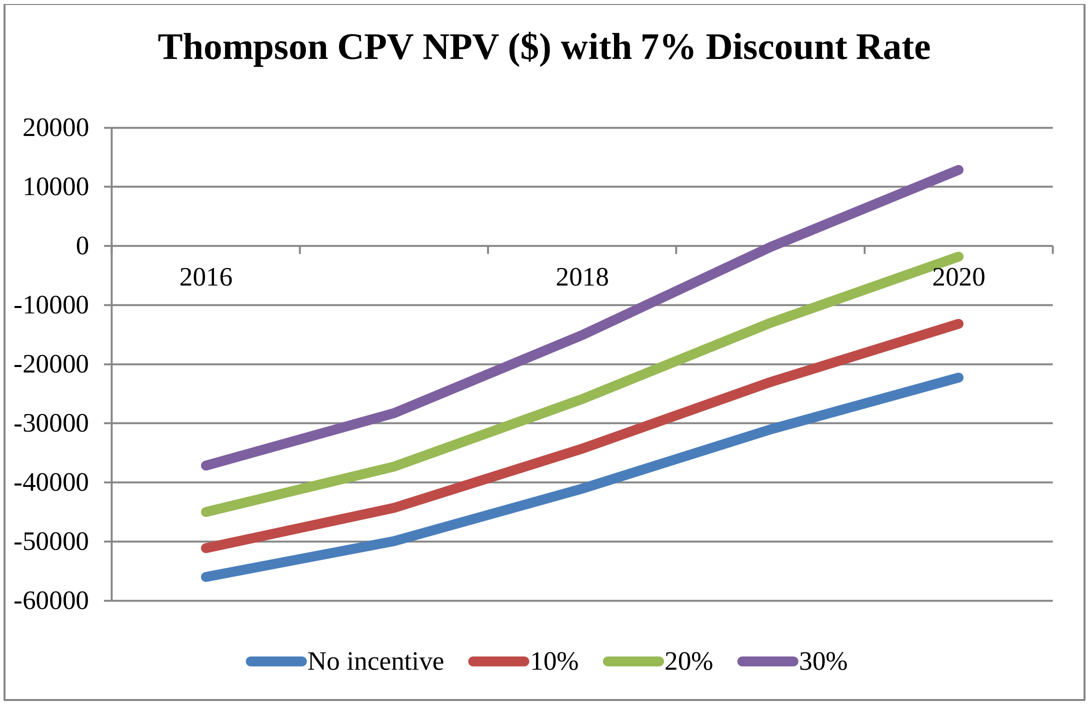
Churchill CPV NPV ($) with 9% Discount Rate



Churchill CPV NPV ($) with 7% Discount Rate


Churchill PV NPV ($)
0
-10000
-20000
-30000
-40000
-50000
-60000
2016
2018
2020
Net Present Value ($)
Year
No incentive
10%
20%
30%


Thompson CPV NPV ($) with 9% Discount Rate
0
-10000
-20000
-30000
-40000
-50000
-60000
-70000
2016
2018
2020
Net Present Value ($)
Year
No incentive
10%
20%
30%


Thompson CPV NPV ($) with 7% Discount Rate
20000
10000
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2016
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No incentive
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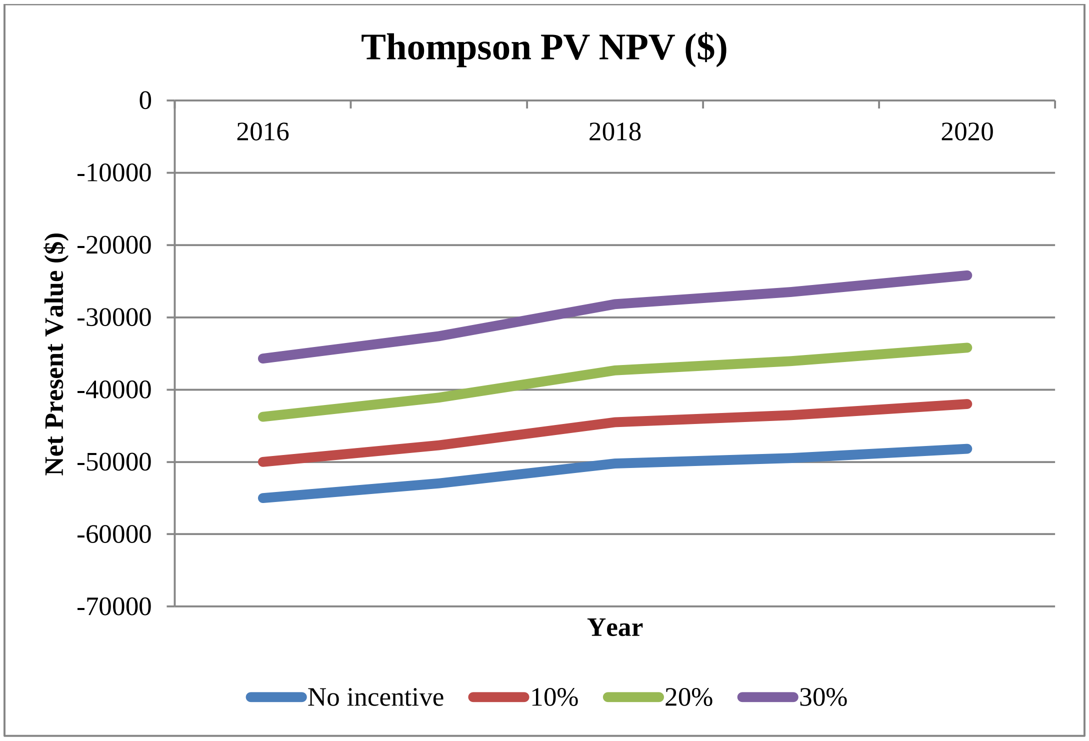
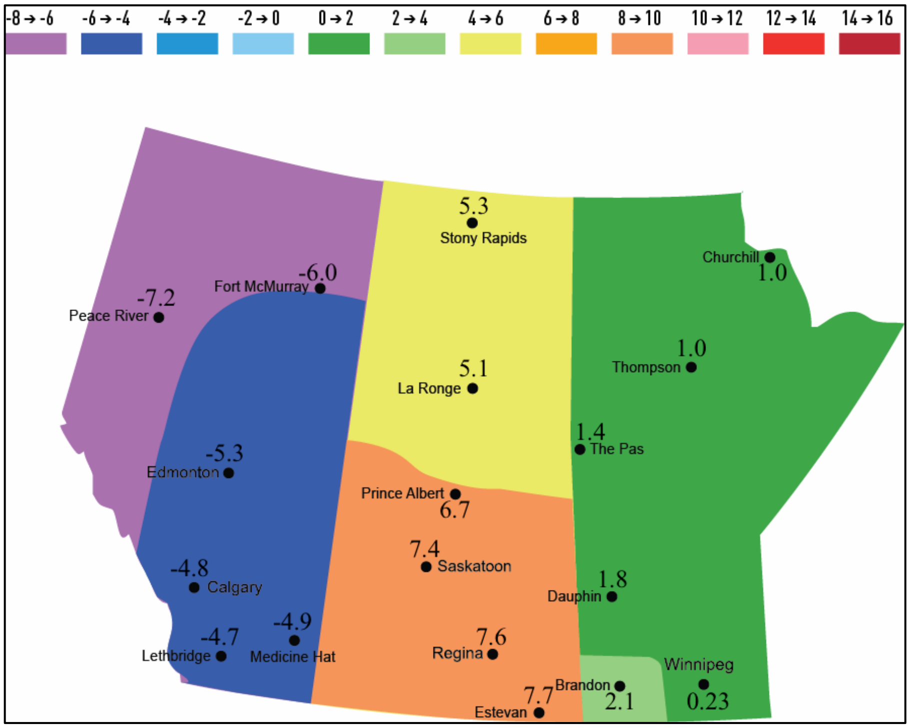

Thompson PV NPV ($)
0
-10000
-20000
-30000
-40000
-50000
-60000
-70000
Net Present Value ($)
2016
2018
2020
Year
No incentive
10%
20%
30%

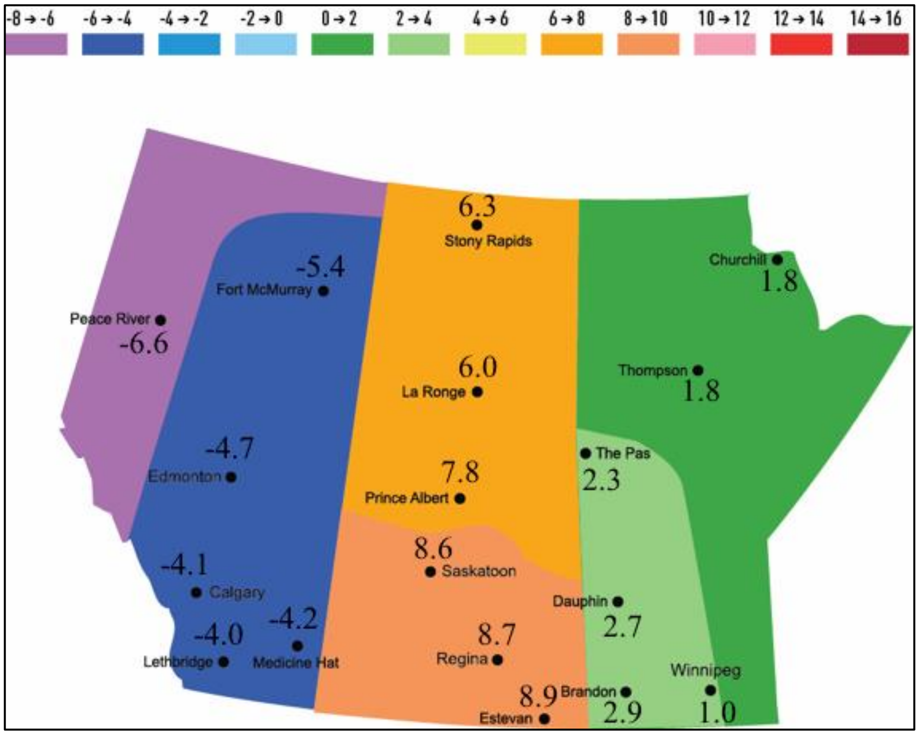
10. Appendix C

Mapping the IRR over various years and incentive scenarios (14 maps total)

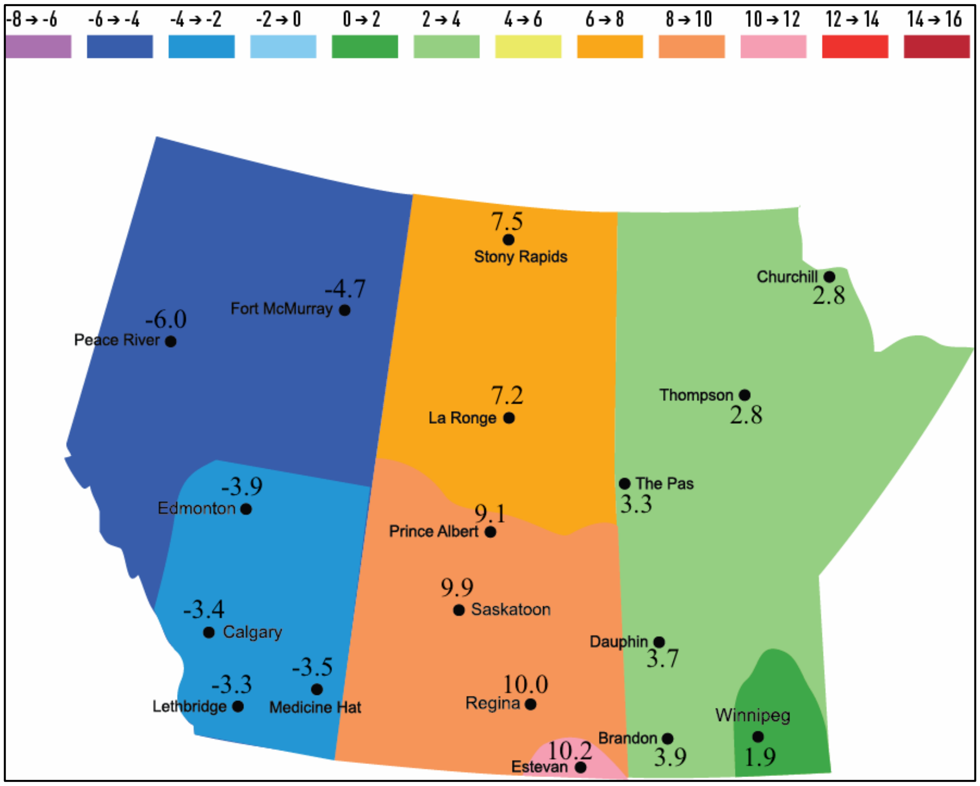
PV 2018 no additional incentive:



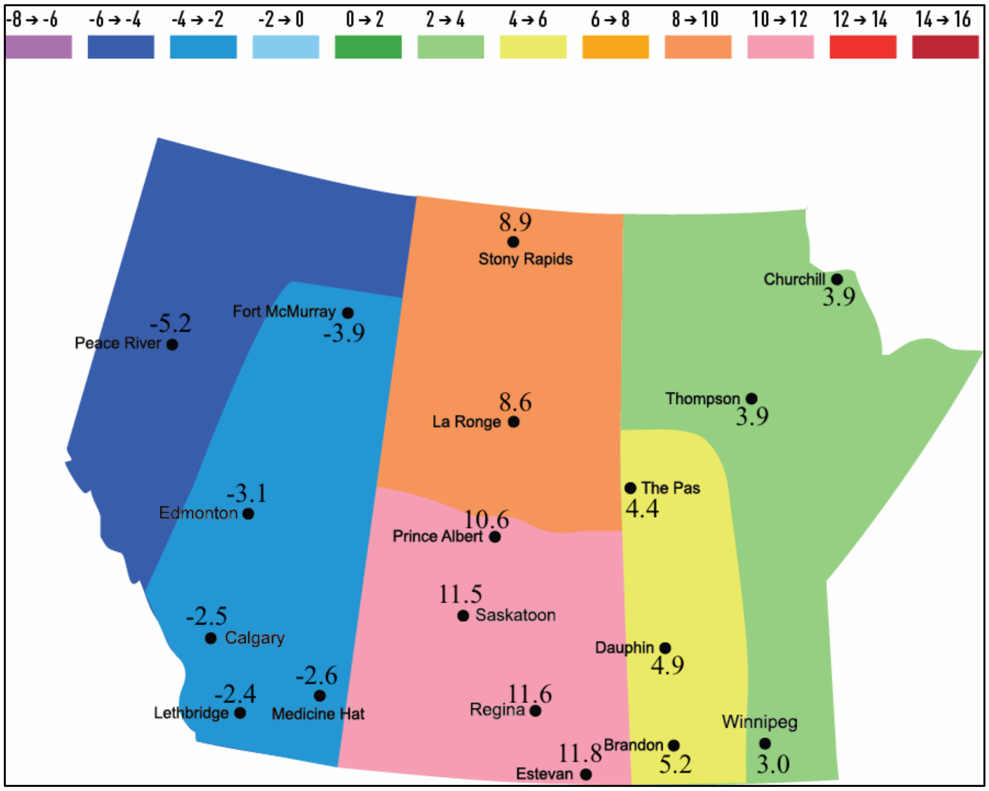
PV 2018 10% additional incentive:



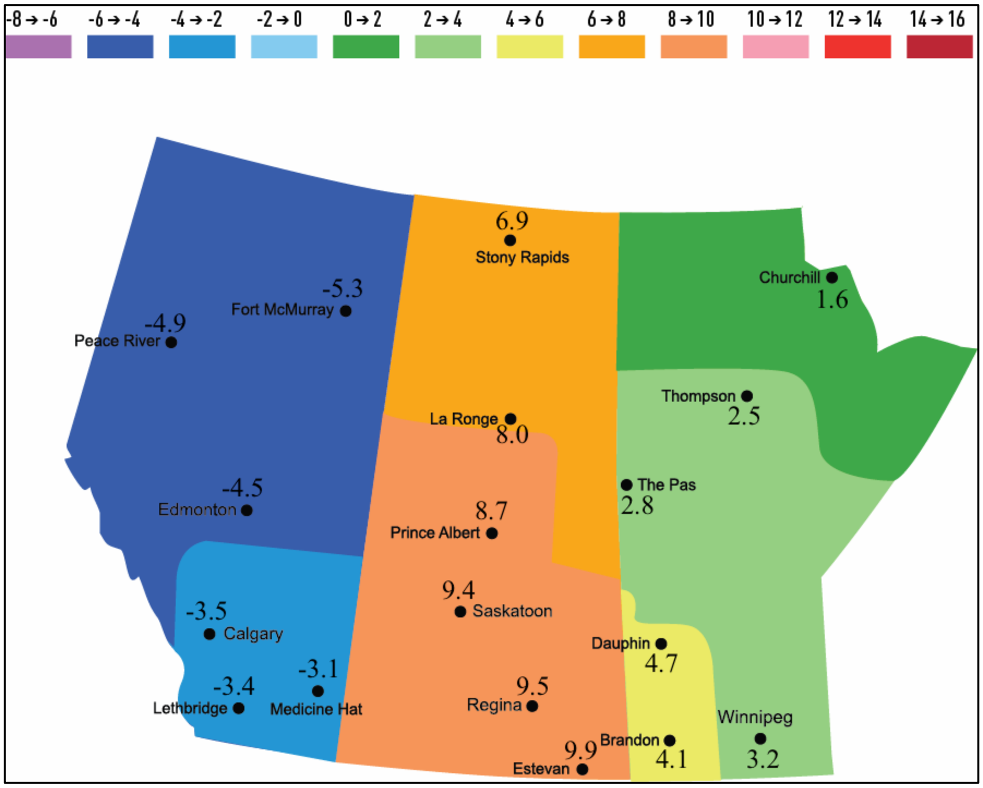
PV 2018 20% additional incentive:



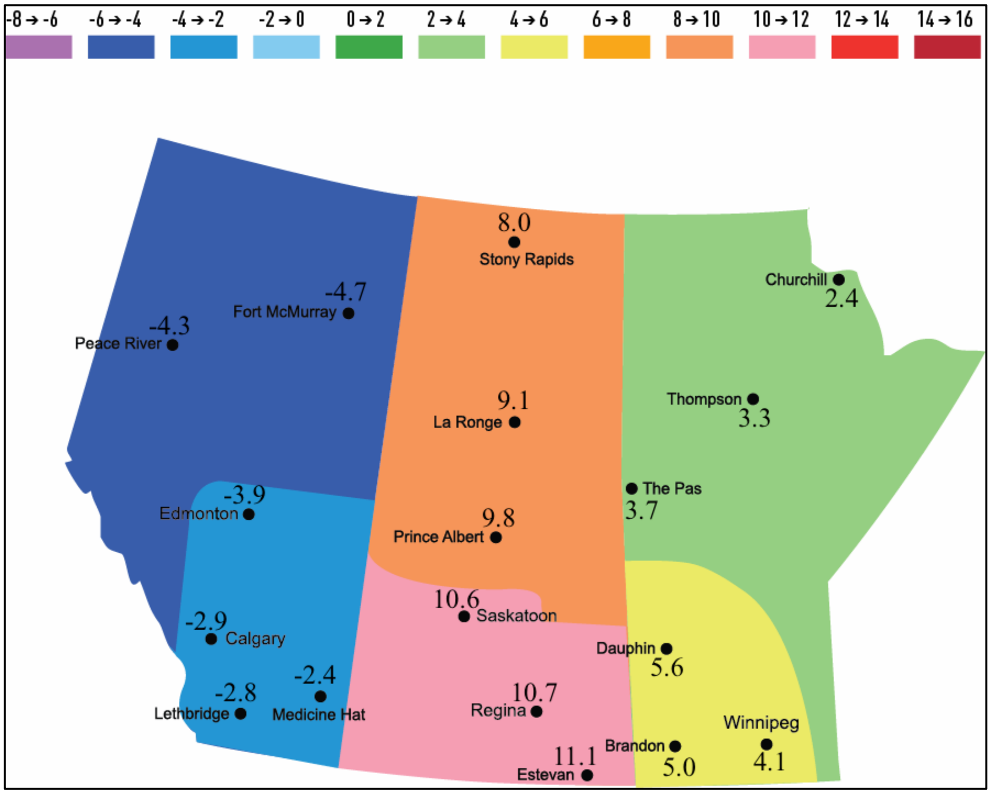
PV 2018 30% additional incentive:



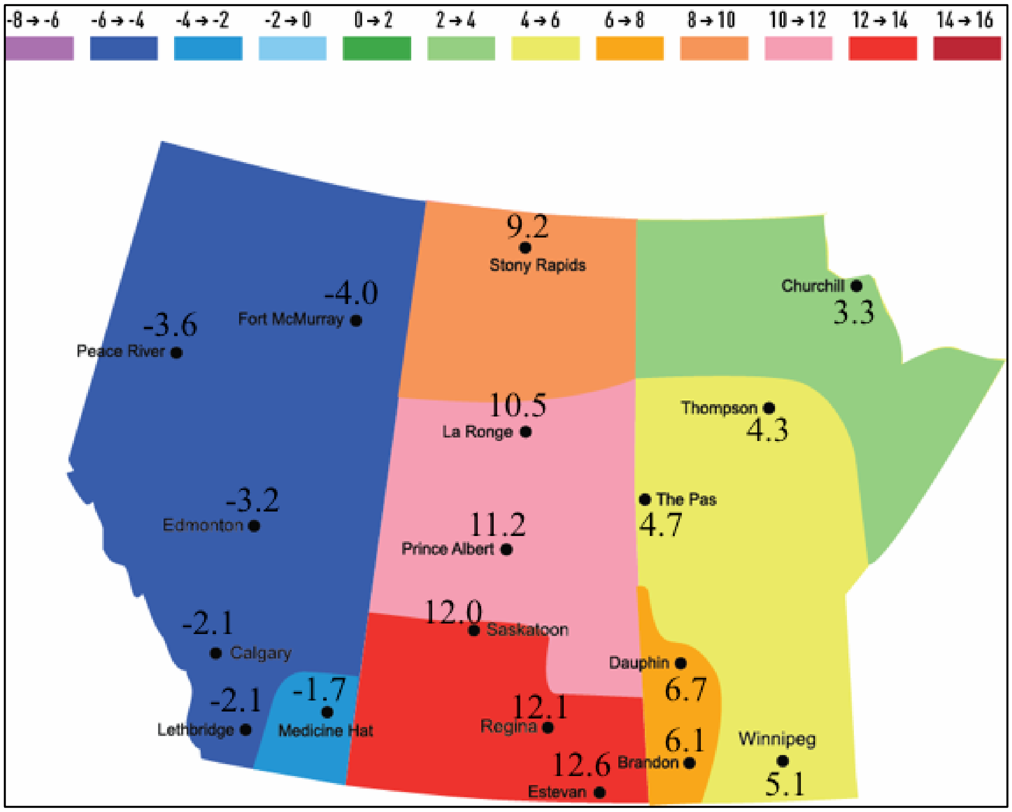
CPV 2018 no additional incentive:



CPV 2018 10% additional incentive:



CPV 2018 20% additional incentive:



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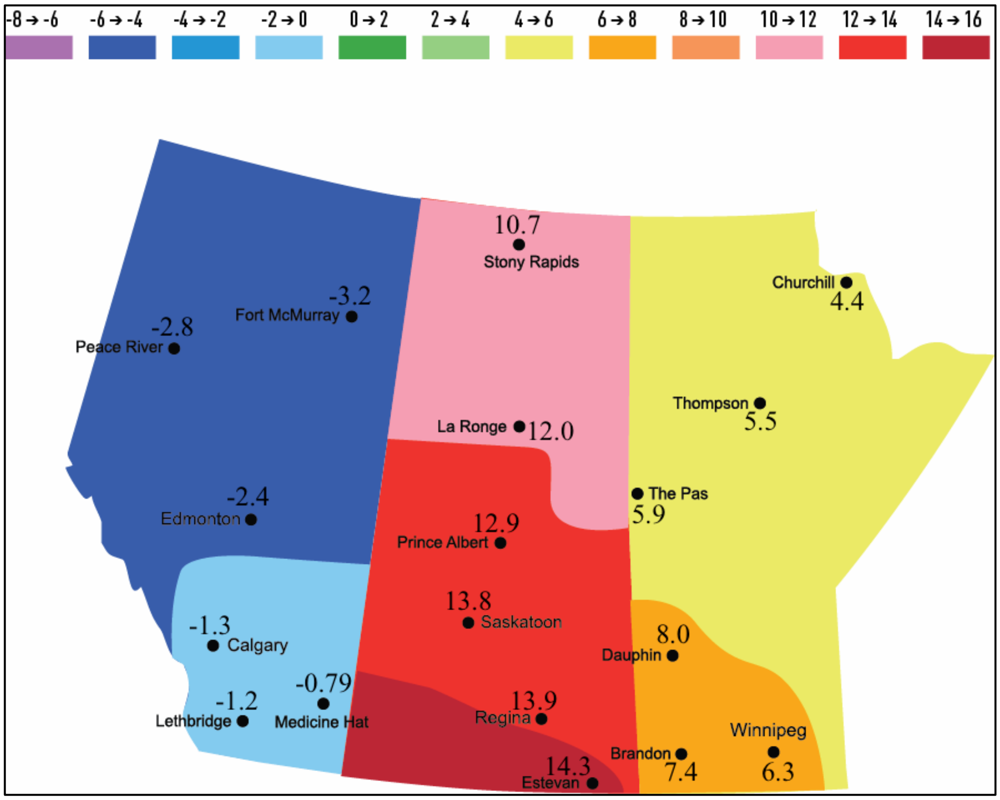
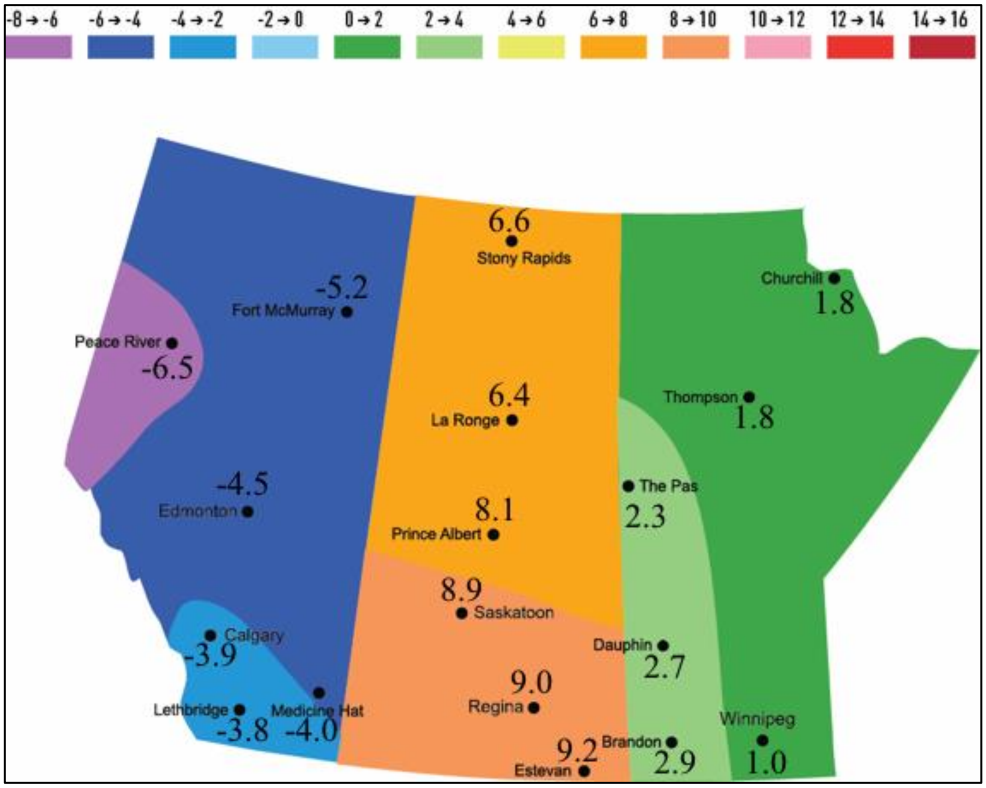
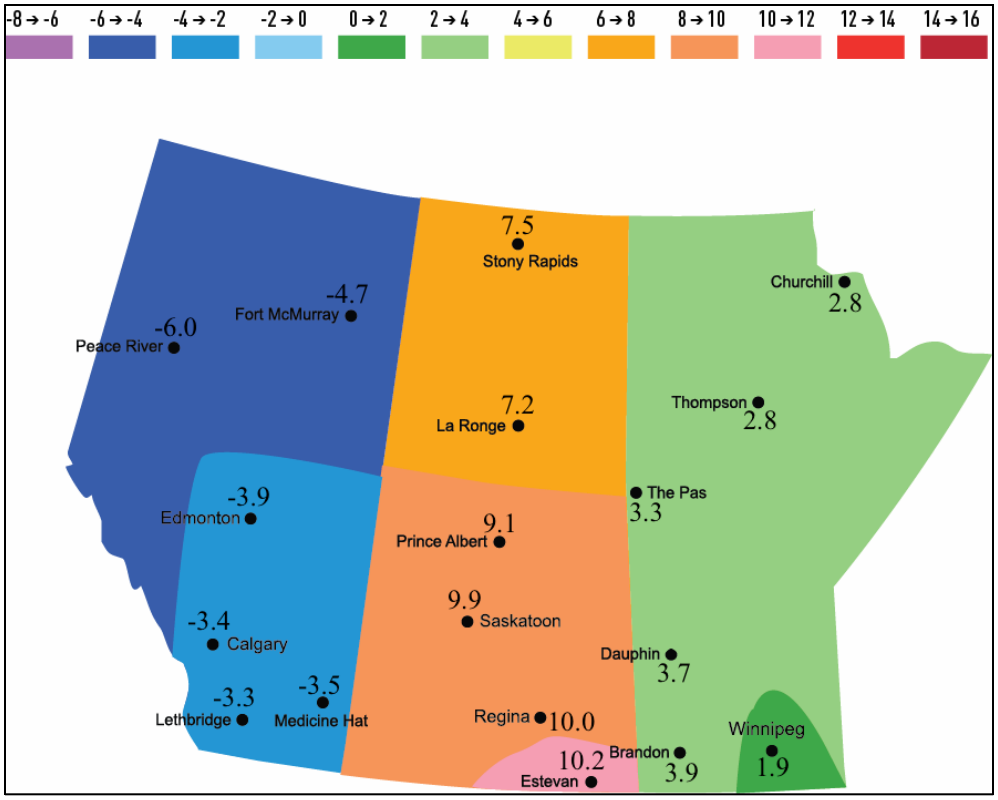


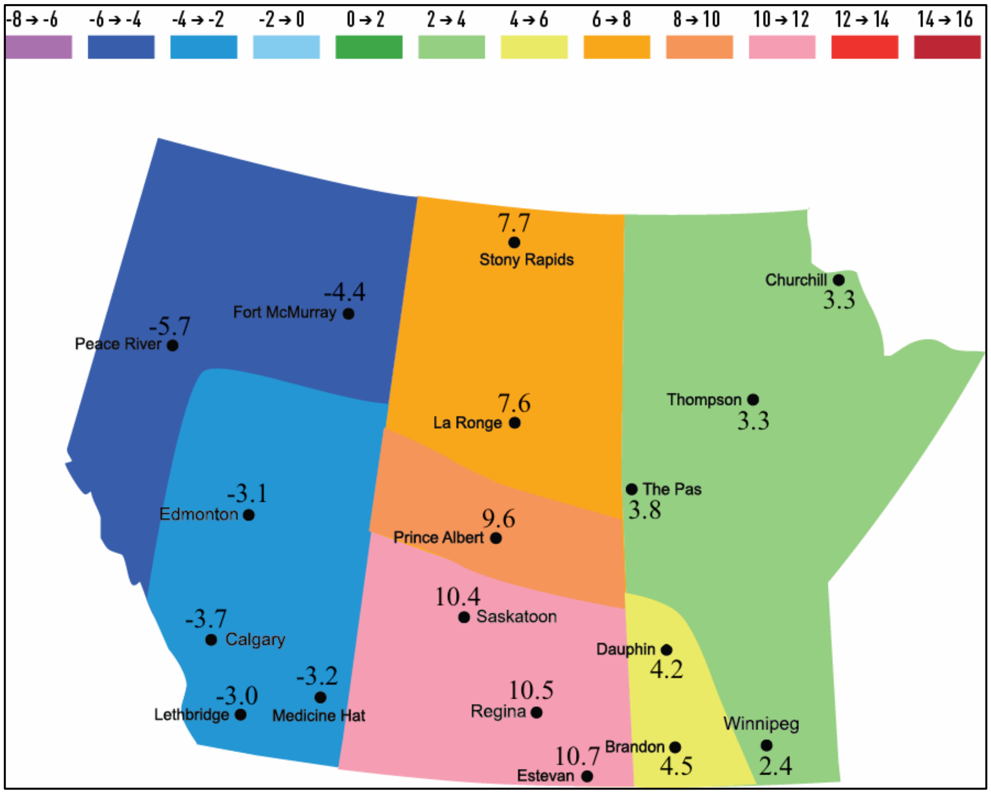
PV 20% additional incentive for 2016 project start date:



PV 20% additional incentive for 2018 project start date:



PV 20% additional incentive for 2020 project start date:



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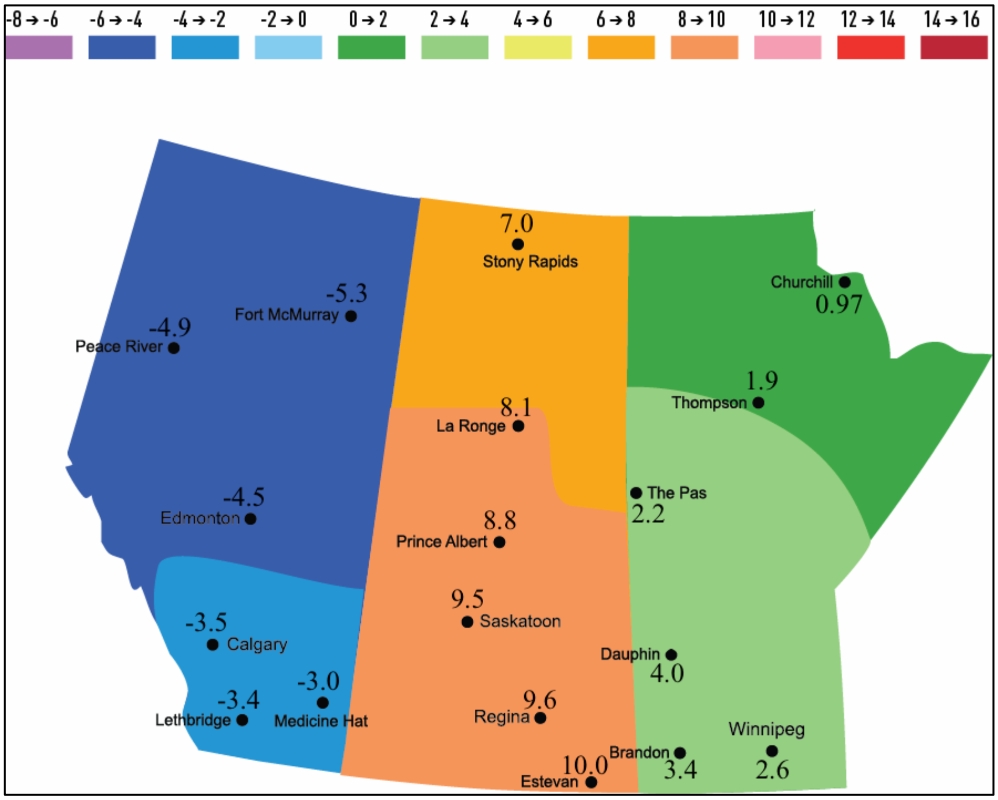

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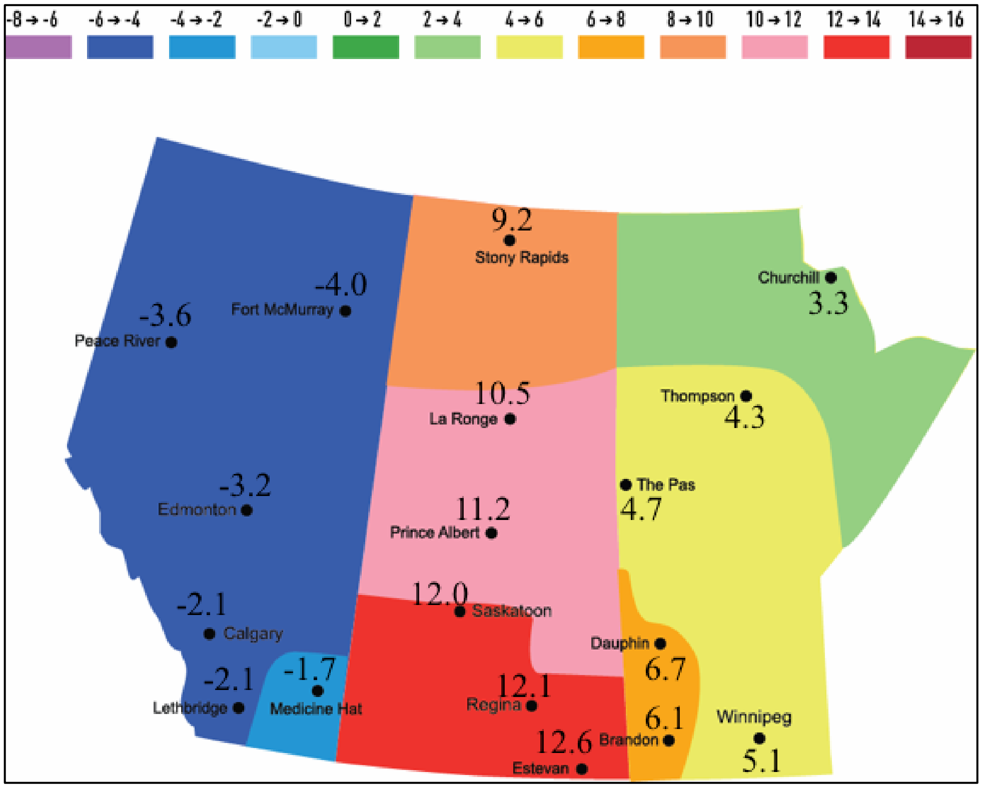

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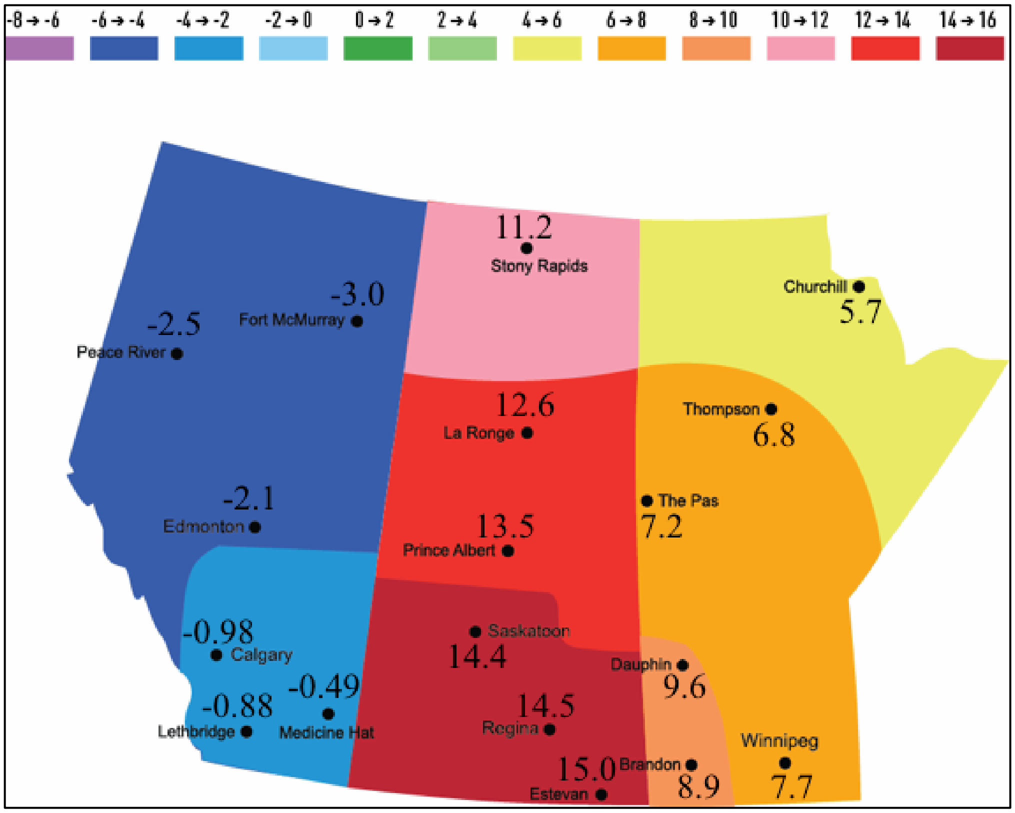

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