TECHNICAL REPORT

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Cost-Benefit Analysis of Heavy Oil Casing Gas Conservation and Conversion Technologies

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EXECUTIVE SUMMARY

Natural gas conservation and conversion options are evaluated at oil batteries where gas production exceeds site energy demands but is not sufficient to motivate gas gathering infrastructure. These stranded gas flows are often released directly to the atmosphere as a reliable and low cost means of disposal. When observed at isolated batteries, venting excess sweet natural gas is a safe practice that doesn't cause offsite odours, exceed ground level ambient air quality objectives, increase lease sizes or incur landowner objections to aesthetically displeasing flare stacks. However, when aggregated together oil and bitumen battery venting is a noteworthy greenhouse gas (GHG) emission source with 8.95 megatonnes carbon dioxide (CO_2) equivalent (E) released in 2011 (approximately 9 percent of direct GHG from the Canadian upstream oil and gas industry as published in Environment Canada, 2014).

Regulatory Context

Both provincial and federal regulators have endeavored to mitigate flaring and venting from the upstream oil and gas industry with limited success. In 2008, Environment Canada and provincial regulators formally endorsed the World Bank voluntary standard for global gas flaring and venting reduction (Environment Canada, 2008) with the objective to "*minimize continuous and non-continuous production flaring and venting of associated gas*" (World Bank, 2004). The standard provides a decision-tree process for evaluating associated gas utilization through stakeholder engagement and broadening of the project boundary to include other gas sources and consumers (e.g., clustering). It also recommends financial incentives (e.g., royalty exemptions) to enhance the viability of alternatives to flaring and venting. Implementation of the voluntary standard is completed by provincial regulators. In fact, the World Bank modeled its standard on Directive 060 developed by the Alberta Energy Regulator (AER) based on recommendations from the multi-stakeholder Clean Air Strategic Alliance (CASA).

Recognizing public concerns regarding potential health, safety, and environmental impacts of flaring, the AER released the first version of Directive 060 in 1999. It included flaring and venting baselines; a flaring management framework and reduction targets; common economic assessment process for gas conservation; volume reporting requirements; and limitations on natural gas venting by the UOG industry. Subsequent versions expanded applicability of the gas conservation decision-tree to all flaring or venting sources greater than 900 m^3 per day per facility and reduced the NPV threshold to negative $55,000 (AER, 2016a).

Directive 060 proved successful for reducing flaring and venting emissions in Alberta until the mid-2000s. However, the decision to conserve versus vent natural gas depends on the market value of natural gas as evidenced in Figure A. Venting volumes reported in ST60B for UOG sources (AER, 2016a) steadily decline from 2000 until 2005 when natural gas prices peak (GLJ, 2015). From 2006 to 2013, venting volumes generally increase and trend with prices, suggesting price signals have a stronger influence on conservation practices than current regulatory intent. Although Directive 060 states "Venting is not an acceptable alternative to conservation or flaring", sweet gas venting is occurring because operators argue it is the only feasible alternative to flaring and it complies with stated limitations.

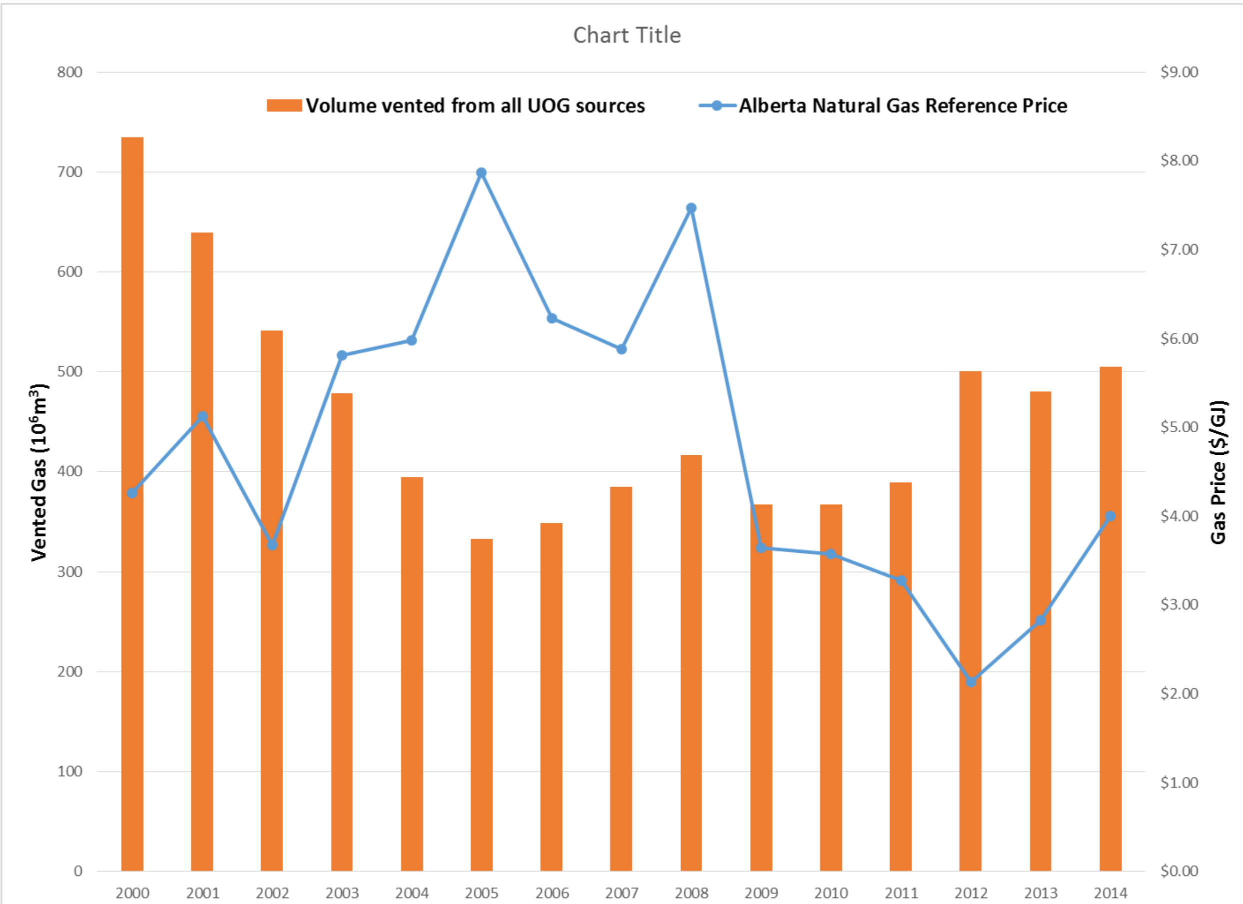

Figure A: Comparison of natural gas venting[1] by the UOG industry versus gas price.

British Columbia published Flaring, Incinerating and Venting Reduction Guidelines in 2008 while Saskatchewan published Directive S-10 in 2011. Both of these documents are similar to AERs Directive 060. Little regulatory effort is focused on flaring and venting mitigation outside of Western Canada because approximately 96 percent of Canadian UOG emissions occur in BC, AB and SK (Environment Canada, 2014).

Recent climate change policy developments are motivating further regulatory action to mitigate methane emissions and natural gas venting. In December 2015, Canada endorsed the United Nations Framework Convention on Climate Change (UNFCCC) Paris Agreement to limit global

[1] Includes vented volumes from in situ bitumen facilities, gas batteries, well testing, gas plants, gas gathering systems, natural gas transmission lines, and coalbed methane and shale gas activities. The report does not include vented volumes from bitumen upgraders and oil sands mine operations.

warming to less than 2^{o} C relative to pre-industrial levels with zero net anthropogenic GHG emissions by the second half of the 21st century. Details on how federal and provincial governments plan to reduce Canada's GHG emissions by 30 percent below 2005 levels by 2030 and implications for the oil and gas industry are expected in 2016. In anticipation of the Paris Agreement, Alberta released its climate leadership plan emphasizes methane reductions for the oil and gas sector as well as policy provisions to mitigate competitiveness impacts for trade exposed sectors. Carbon pricing will apply to "on-site combustion in conventional oil and gas" (i.e., natural gas fuel consumption and flaring) starting January 1, 2023 but not to fugitive and venting emissions. Instead, a new regulatory standard for controlling fugitive emissions (i.e., leak detection and repair) and voluntary standards for controlling venting will be developed through a multi-stakeholder process beginning early 2016.

Gas venting and flaring in the United States (US) has rapidly increased from 2.58 $10^{9}m^{3}$ in 2000 to 8.18 $10^{9}m^{3}$ in 2014 (EIA, 2015). This is due, in part, because of the quick and intense development of tight oil formations in Texas and North Dakota, which have significant volumes of associated gas. Regulating oil and gas production in the US is primarily the responsibility of the states, however, the Environmental Protection Agency (EPA) sets national environmental standards that states and tribes enforce through their own statutes. In 2012, the EPA finalized New Source Performance Standard (NSPS) for volatile organic compounds (VOCs) for the oil and natural gas industry (US EPA, 2012). Combined with amendments proposed in 2015, NSPS require producers to conserve natural gas flow-back that occurs during oil and gas well completions. Moreover, NSPS will also require reductions from new or modified pneumatic controllers, compressors, and storage tanks at natural gas and oil well sites; gathering stations; compressor stations and processing plants. NSPS measures are proposed with the objective of reducing methane emissions from the oil and gas sector by 40 to 45 percent from 2012 levels by 2025 (US White House. 2014). A regulatory impact analysis concluded that climate benefits outweigh implementation costs of the proposed NSPS rule (EPA, 2015a). Climate benefits were monetized by incorporating the social cost of methane that accounts for a number of anticipated climate impacts, including: human health, property damages from flood risk, agricultural productivity, and the value of ecosystem services.

Business Case Development

To assist industry and decision-makers determine appropriate flaring and venting thresholds for Western Canadian upstream oil and gas facilities; this study completes GHG reduction and economic assessments for the following gas conservation and conversion technology options. Equipment is sized for excess casing gas flows of 1,500 m^{3} per day or less because it is estimated 50 percent of Alberta casing gas is vented from such sites (Johnson and Coderre, 2012).

- **Onsite Power Generation**: Conserves up to 1,380 m^{3} casing gas per day by installing two 60 kW power generators and distribution lines for electricity sales.

- **Auxiliary Burner and Heat Trace**: Conserves up to 1,296 m^3 casing gas per day by utilizing heat from auxiliary burners installed in existing storage tank heater stacks.
- **Catalytic Line Heaters**: Conserves up to 315 m^3 casing gas per day by installing catalytic line heaters.
- **Catalytic Conversion**: Converts up to 110 m^3 of casing gas to carbon dioxide with excess vented.
- **Flaring**: Converts all excess casing gas to carbon dioxide via a small flare.
- **Vapour Combustor**: Converts up to 1,500 m^3 casing gas to carbon dioxide via a dedicated vapour combustor.

A representative, 2-well, Cold Heavy Oil Production with Sand (CHOPS) battery with the same casing gas flow rates, compositions and economic conditions was selected to provide a common basis for comparison. Net GHG emission reductions are assessed as the difference between baseline and project emissions achieved by each technology scenario. NPVs are calculated in compliance with AER Directive 060 instructions with sensitivity tests for upper and lower bound estimates of key parameters.

Results

A business case exists for the technology option when NPV is greater than zero and an investor can expect to recover their invested capital and earn a nominal rate of return. As shown in Table A, all options except catalytic line heaters, have a negative NPV under base-case conditions and would not normally be implemented because there is no economic benefit to facility owners. Average abatement costs (in present value terms) are also presented to show the total lifecycle cost incurred by an operator (net of any revenue) to avoid the release of one tonne of CO_2E.

Table A: Summary of conservation and conversion technology capital cost, NPV, GHG reduction and average abatement costs when initial excess gas flows equal 1,500 m^3 per day.

Technology Option	Type	Capital and Installation Cost[1]	NPV	GHG reduction relative to baseline	Average Abatement Cost ($/t CO_2E
Onsite Power Generation	Conservation	$419,120	-$271,969	79%	$6
Auxiliary Burner and Heat Trace		$282,080	-$231,135	81%	$5
Catalytic Line Heaters		$39,070	$92,425	26%	- $6
Catalytic Conversion	Conversion	$49,540	-$75,310	6%	$20
Flaring		$95,580	-$149,261	80%	$3
Vapour Combustor		$100,550	-$144,912	81%	$3

[1] *Installation and engineering costs are conservative and based a single unit. Installation of multiple units as part of a corporate retrofit program would likely improve work flow efficiency and reduce overall costs.*

Of particular note, is that all options are highly sensitive to pricing the GHG emission savings. Figure B shows the average abatement cost varies with the volume of excess casing gas initially available. For example, if a policy was implemented whereby a levy of \$30 per t CO_2E was charged on venting emissions, the vapour combustor would be economic at sites with initial excess casing gas flow rates greater than 252 m^3 per day while all technologies would be economic for initial flows greater than 561 m^3 per day. Alternatively, if a performance standard was set on the basis of the social cost of carbon in 2025[2] (\$81/t CO_2E), the vapour combustor would be economic at sites with an initial excess casing gas flow rate greater than 132 m^3 per day while all technologies would be economic for initial flows greater than 321 m^3 per day.

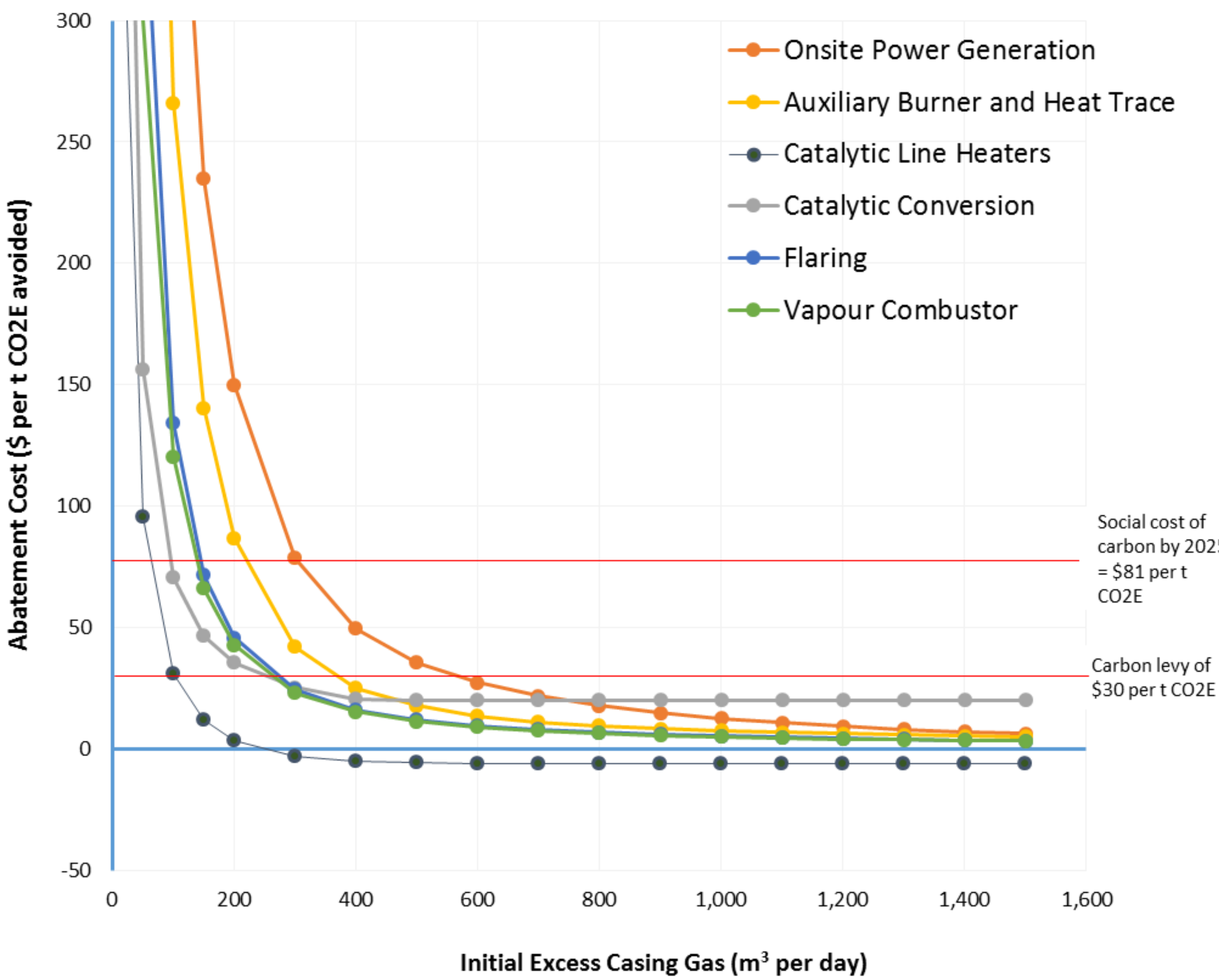

Figure B: Average abatement costs as a function of initial excess casing gas flow.

[2] 2025 is selected because this is the year Alberta intends to regulate methane controls if a 45 percent reduction is not voluntarily achieved by the oil and gas sector.

Conclusions

For many bitumen batteries with low gas flow, clustering to maximize the volume of casing gas available can produce positive conservation economics. However, if clustering isn't possible, the following observations for low-flow wells should be considered.

Catalytic line heaters have a positive base-case NPV and could be installed at sites where year-round casing gas use is indeed achieved by heat-tracing gas lines. Moreover, many sites have enough waste heat from existing pump engines that coolant loops could be used for heat tracing instead of additional line heaters. In these cases, battery operating costs and GHG emissions can be reduced for very little capital investment.

Conserving excess casing gas for small-scale, decentralized, electricity generation may be an important contribution to base-load power in Alberta as coal-fired power plants are phased out over the next 15 years. In cases where distribution lines are within 480 meters of the site and have sufficient capacity for the incremental power supply, base-case NPV is greater than the Directive 060 threshold requiring conservation projects to proceed. Moreover, monetization of carbon (in the range of $10 per t CO_2E) can swing the decision for sites to produce power if initial excess gas flows are above 1,300 m^3 per day. However, the decision also depends on whether site-specific casing gas flows are predictable over the eight year project life.

Installing auxiliary burners in tank heater stacks is an innovative approach to managing excess casing gas that minimizes impact to site lease sizes, traffic patterns and visual aesthetics. The burners respond well to variable gas flows from 0 up to 21 m^3 per hour per unit and produce heat for freeze protecting gas lines during cold months. Monetization of carbon (in the range of $10 per t CO_2E) can swing the decision for sites to install auxiliary burners if initial excess gas flows are above 900 m^3 per day. However, installation of a glycol exchanger and pump for heat-tracing may prove difficult and better accomplished with catalytic line heaters or excess heat from engine coolant loops.

When choosing a conversion technology because no conservation opportunities are available, consider that a flare will dispose much larger flows than a vapour combustor (i.e., max for a single combustor is 1,500 m^3 per day). Moreover, the average abatement cost for a flare decreases as flow rates increase while abatement costs remains relatively static for the vapour combustor. For example, the average abatement cost for a flare would be $0.49 per t CO_2E avoided and $2.26 per t CO_2E for the vapour combustor if initial flow increased to 10,000 m^3 per day. However, it's difficult for flares to maintain stable combustion at exit velocities less than 1 m/s (e.g., 680 m^3 per day or less for a 4" diameter flare tip).

Vapour combustors are recommended for converting gas flows less than 1,500 m^3 per day because they result in the greatest GHG reduction for the lowest average abatement cost. Moreover, they are specifically designed for intermittent flows typical of many CHOPS batteries.

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AEP	Alberta Environment and Parks
AER	Alberta Energy Regulator
AR4	IPCC Fourth Assessment Report
AR5	IPCC Fifth Assessment Report
BC OGC	British Columbia Oil and Gas Commission
BMS	Burner Management System
CAPP	Canadian Association of Petroleum Producers
CHOPS	Cold Heavy Oil Production with Sand
CASA	Clean Air Strategic Alliance
CO_2E	Carbon Dioxide Equivalent
CSA	Canadian Standards Association
EPA	Environmental Protection Agency
GHG	Greenhouse Gas
GJ	Gigajoule
GOR	Gas to Oil Ratio
IPCC	Intergovernmental Panel on Climate Change
NEB	National Energy Board
NPV	Net Present Value
NSPS	New Source Performance Standard
PFD	Process Flow Diagram
P&ID	Piping & Instrumentation Diagram
PTAC	Petroleum Technology Alliance of Canada
QA	Quality Assurance
QC	Quality Control
SCC	Social Cost of Carbon
$SC\text{-}CH_4$	Social Cost of Methane
SK ER	Saskatchewan Energy and Resources
UNFCCC	United Nations Framework Convention on Climate Change
UOG	Upstream Oil and Gas
VOC	Volatile Organic Compound
VRU	Vapour recovery Unit

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1 INTRODUCTION

Natural gas conservation and conversion options are evaluated at oil batteries where gas production exceeds site energy demands but is not sufficient to motivate gas gathering infrastructure. These stranded gas flows are often released directly to the atmosphere as a reliable and low cost means of disposal. When observed at isolated batteries, venting excess sweet natural gas is a safe practice that doesn’t cause offsite odours, exceed ground level ambient air quality objectives, increase lease sizes or incur landowner objections to aesthetically displeasing flare stacks. However, when aggregated together oil and bitumen battery venting is a noteworthy greenhouse gas (GHG) emission source with 8.95 megatonnes carbon dioxide (CO_2) equivalent (E) released in 2011 (approximately 9 percent of direct GHG from the Canadian upstream oil and gas industry as published in Environment Canada, 2014). Moreover, approximately 50 percent of this venting is released at batteries with less than 1,500 m^3 per day excess gas (Johnson and Coderre, 2012) and is the focus of the assessments completed below.

Given the growing emphasis on mitigating methane emissions in both the US and Canada, PTAC initiated a cost-benefit analysis of alternatives to venting. This study intends to identify and develop evidence that will assist industry and decision-makers determine appropriate flaring and venting thresholds for Western Canadian upstream oil and gas facilities.

It begins with a critical literature review of existing regulatory thresholds for key jurisdictions in North America summarized in Section 2. Followed by Section 3 that provides a detailed description of representative site and economic conditions assumed for base-case net present value (NPV) assessments. Section 4 presents a description of three gas conservation and three gas conversion technologies considered as well as GHG reduction results from an energy-balance model developed for this study. The business case for each technology option is evaluated based on NPV results and their sensitivity to key input parameter upper and lower bounds. The conclusions and recommendations are stated in Section 5. Detailed capital and installation cost estimates and the other input parameters used in modelling are provided in the Appendices.

2 LITURATURE REVIEW

2.1 CANADA

As part of the World Bank Global Gas Flaring Reduction (GGFR) initiative, Environment Canada established a private-public partnership implementation plan with Canadian regulatory authorities (Environment Canada, 2008). By 2008, the following authorities formally endorsed the voluntary standard for global gas flaring and venting reduction.

- National Energy Board (NEB)
- British Columbia Oil and Gas Commission (BC OGC)
- Alberta Energy Regulator (AER)
- Saskatchewan Energy and Resources (SK ER)
- Manitoba Science, Technology, Energy and Mines
- Canada-Newfoundland and Labrador Offshore Petroleum Board
- Newfoundland and Labrador Department of Natural Resources.

The Standard's initial goal for flaring and venting is "*no continuous flaring and venting of associated gas, unless there are no feasible alternatives.*" The ultimate goal of the Standard is to "*minimize continuous and non-continuous production flaring and venting of associated gas*" (World Bank, 2004). The standard provides a decision-tree process for evaluating associated gas utilization through stakeholder engagement and broadening of the project boundary to include other gas sources and consumers (e.g., clustering). It also recommends financial incentives (e.g., royalty exemptions) to enhance the viability of alternatives to flaring and venting.

Because Environment Canada does not directly regulate the oil and gas industry, implementation of the voluntary standard is completed by provincial regulators or the NEB for non-accord Canada lands. Applicable provincial regulations are summarized below.

Other initiatives to reduce venting emissions include Base-level Industrial Emission Requirements (BLIERs) for VOCs as well as planned measures to reduce GHG emissions. BLIERs are a cross-sectoral approach to ensure significant industrial sources meet a good base-level of performance and are intended to be equivalent with industrial requirements for "attainment areas" inside or outside Canada. However, non-consensus on base-level environmental regulations and other key issues remain. Stakeholders are reluctant to support proposed requirements without having a better understanding of cost implications.

In May 2015, Environment Canada announced plans to develop new regulatory measures for the oil and gas sector that would align with proposed actions in the United States. Namely, proposed updates to New Source Performance Standards (NSPS) that set methane and VOC emission reduction requirements for equipment leaks; pneumatic devices; well completions; storage tanks; centrifugal compressor wet seals; and reciprocating compressor rod packing sources.

In December 2015, Canada successfully negotiated the Paris Agreement with almost 200 other countries at the 21st session of the United Nations Framework Convention on Climate Change (UNFCCC) Conference of the Parties (COP). Key results of the agreement are to limit global warming to less than 2^{o} C relative to pre-industrial levels with zero net anthropogenic GHG emissions by the second half of the 21st century. Canada's formal target at COP 21 is to reduce GHGs by 30 percent below 2005 levels by 2030. Details on how the federal government plans to work with provinces to achieve this target and implications for the oil and gas industry are expected in March 2016.

2.1.1 ALBERTA

In 1998, flaring and venting management recommendations for the Province of Alberta were published by the consensus-based, multi-stakeholder Flaring and Venting Project Team (FVPT) of the Clean Air Strategic Alliance (CASA, 1998). These recommendations were developed recognizing public concerns regarding potential health, safety, and environmental impacts of flaring. The team focused on routine solution gas flaring because it represented approximately 70 per cent of the total gas flared in Alberta at the time. A consensus agreement on recommended provincial reduction targets and maximum facility flaring limits were based on a technology and economic assessment completed by the University of Calgary (Holford and Hettiaratchi, 1998). This study concluded it was economical to conserve 30 percent of total solution gas flared and that limiting facility flaring to a maximum of 2500 10^3m^3/yr would reduce the provincial total by 15 percent while a limit of 1,500 10^3m^3/facility/yr would reduce the provincial total by 25 percent. This motivated the firm provincial solution gas flare volume reduction schedule of 15 percent by end for 2000 and 25 present by end of 2001, relative to a 1996 baseline (AER, 1999). Given the management framework goal to eventually eliminate routine solution gas flaring, longer term reduction targets of 40 to 50 percent by 2003 and 60 to 70 percent by 2007 were also recommended with corresponding facility flaring limits (CASA, 1998).

- 700 10^3m^3/facility/year (1,918 m^3/day) to achieve a 40 percent provincial reduction.
- 500 10^3m^3/facility/year (1,370 m^3/day) to achieve a 50 percent provincial reduction.
- 350 10^3m^3/facility/year (959 m^3/day) to achieve a 60 percent provincial reduction.
- 250 10^3m^3/facility/year (685 m^3/day) to achieve a 70 percent provincial reduction.

The 1998 CASA recommendations reference an Alberta Research Council (ARC) experimental investigation of solution gas flaring. This study indicated pyrolytic reactions produce a complex variety of hydrocarbon byproducts within the flare flame and that the presence of liquid hydrocarbons impaired destruction of byproducts as well as hydrocarbons in the original gas stream (ARC, 1996). Crosswinds are also noted to reduce combustion efficiency resulting in a variety of compounds of concern being emitted to the atmosphere. An Alberta Health assessment of respiratory disorders in relation to solution gas flaring activities was completed but no positive correlation between these metrics could be established (Alberta Health, 1998).

CASA recommendations were adopted in the 1999 edition of AER Guide 60 and included flaring and venting baselines; flaring management framework and reduction targets; common economic assessment process; volume reporting requirements; and limitations on natural gas venting by the upstream oil and gas (UOG) industry. The key trigger for gas conservation is whether the project NPV is greater than zero. Moreover, documentation of the conservation economic assessment is required and "…*if continuous vent volumes are sufficient to support combustion, the gas should generally be burned in a flare*" (AER, 1999). Otherwise venting is permitted subject to the following limitations:

- H_2S releases not cause AAAQO or OEL exceedances or off-site odours.
- Gas releases containing more than 10 moles of H_2S per kilomole of gas must be burned.
- The true vapour pressure of hydrocarbon liquids stored in atmospheric storage tanks must not exceed 83 kPa where such tanks are vented to atmosphere.
- Benzene releases shall not 5 tonnes per year for facilities commissioned before January 1, 2001 and 3 tonnes per year after this date.

A draft Guide 60 was issued in late 2002 which reduced the Alberta total solution gas flaring limit to 670 10^6 m^3 per year (i.e., a 50 percent reduction relative to the 1996 baseline as recommended in CASA, 1998) and extended the decision tree process to include gas venting. All new solution gas flares and vents must be assessed for conservation opportunities. The draft received significant feedback, especially from CAPP. The CASA FVPT continues consensus discussions and issues three new reports and recommendations. Additional consultations with industry to resolve remaining issues and improve clarity of the draft directive (AER, 2007).

In 2004, CASA recommended conservation at all sites that flare or vent a combined volume of over 900 m^3/day/site of solution gas by January 1, 2006 if decision tree economic model results in a NPV of greater than negative $50,000 (CASA, 2004). This simple volume threshold was based on industry success exceeding the 2002 reduction target of 50 percent (actual reductions were 62 percent) and an economic assessment of 2002 conservation data collected by the AER (Rahim, 2004). The negative NPV was adopted because industry, public and regulators recognized value in gas conservation at marginally uneconomic sites. Moreover, no decision tree economic analysis was required for volumes less than 900 m^3/day/site which was intended to reduce the administrative work for both government and industry.

The 2006 release of Directive 060 adopted the 900 m^3/day/site threshold for conducting decision team economic evaluations as well as a NPV threshold of negative $50,000 for implementation.

The decision tree process was extended to account for both solution and non-associated gas venting and flaring (AER, 2006).

In 2010, Golder prepared a report for CASA evaluating the cost, and possible exemptions, for eliminating routine solution gas flaring and venting (i.e., 100 percent conservation). Interviews were completed with fiver produces, one supplier, the AER, AEP and two NGOs. However, the reports economic impact analysis was not definitive due to limited data from industry and because it was outside of Golders scope to develop. Therefore, a clear conclusion on the feasibility of eliminating of routine solution gas flaring and venting was not available. The CASA FVPT completed its final report in 2010 and acknowledged elimination of routine flaring and venting of solution gas had not yet been achieved. Moreover, the FVPT could not agree on how to achieve further reductions or whether 900 m^3/day was the economic and technical limit for conservation. Team members did agree that research to determine technical and economic limits for new and existing technologies designed for small volumes of solution gas was important (CASA, 2010).

Updates to Directive 060 in 2014 focused on odours and emissions in the Peace River Area. Section 8.7 was added and requires operators that produce heavy oil and bitumen in the Peace River area to capture and flare, incinerate or conserve all casing and tank-top gas; or shut in subject wells (AER, 2016a). Other updates included decreasing the NPV threshold for gas conservation to negative $55,000 and provision for the AER to direct licensee to conserve solution gas regardless of economics.

The flaring management framework regulated by Directive 060 proved to be a successful approach for mitigating flaring and venting emissions until the mid-2000s. Solution gas conservation reached a peak in 2005 where 96.3 percent of the gas produced was not flared or vented. Since then, conservation performance declined, hitting a low of 94.2 percent in 2012 (AER, 2016a). The decision to conserve versus vent natural gas is strongly dependent on natural gas market value as evidenced in Figure 1. Venting volumes reported in ST60B for UOG sources[3] steadily decline from 2000 until 2005 when natural gas prices peak (GLJ, 2015). From 2006 to 2013, venting volumes generally increase and trend with prices, suggesting price signals have a stronger influence on conservation practices than current regulatory measures. Although Directive 060 states “Venting is not an acceptable alternative to conservation or flaring”, sweet gas venting is occurring because operators argue it is the only feasible alternative to flaring and it complies with stated limitations. Thus overall gas venting is increasing because the volume of gas required for a conservation project NPV to be greater than -$55,000 increases as commodity prices decrease.

[3] Includes vented volumes from in situ bitumen facilities, gas batteries, well testing, gas plants, gas gathering systems, natural gas transmission lines, and coalbed methane and shale gas activities. The report does not include vented volumes from bitumen upgraders and oil sands mine operations (AER, 2016a).

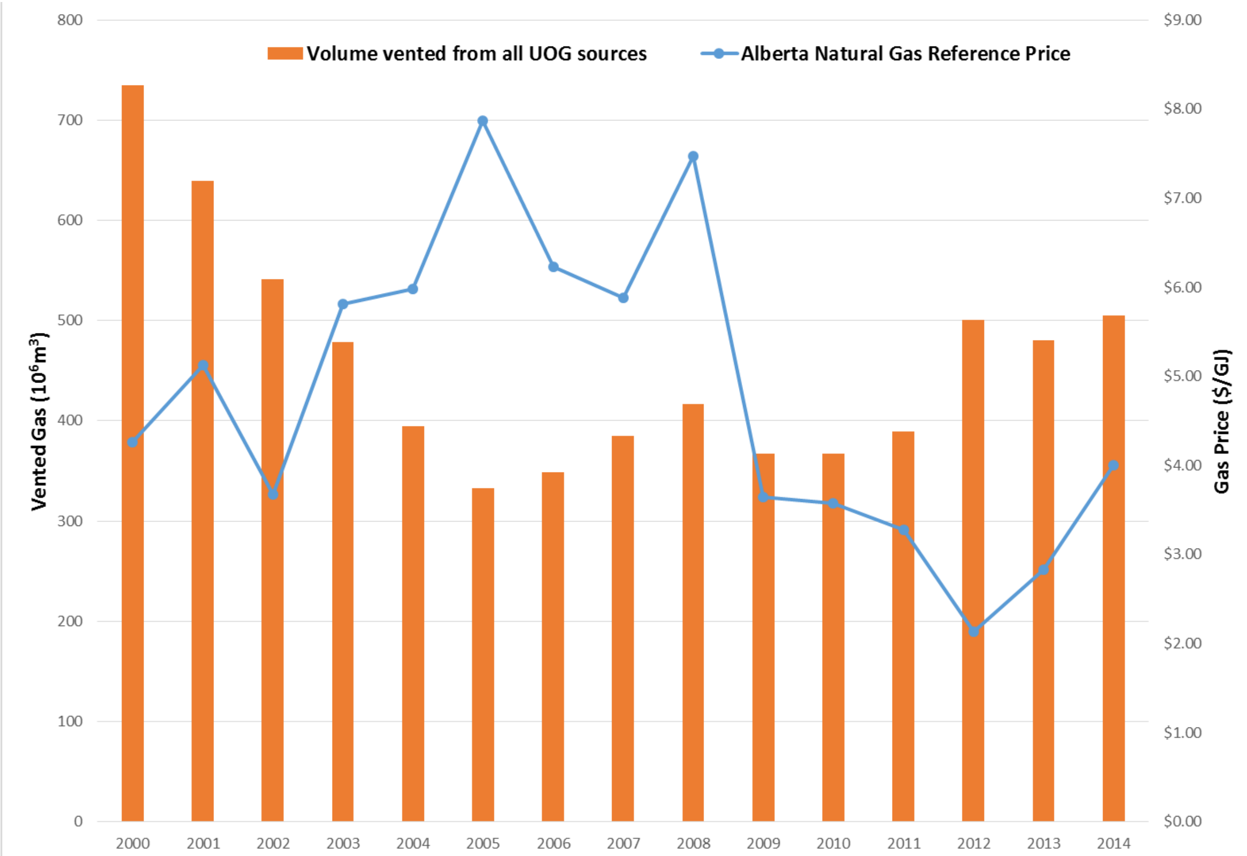

Figure 1: Comparison of natural gas venting by the UOG industry versus gas price.

The success and challenges of gas conservation in Alberta is the subject of many studies. For example, Johnson and Coderre (2012) present an Alberta (mature oil and gas producing region) case study for the conservation of associated gas normally flared or vented. They observed a relatively small number of batteries (approximately 445) exceeded the AER D060 threshold of 900 m^3/day were responsible for 62 percent (approximately 445 10^{6}m^3) of total solution flaring and venting in 2008. Thus mitigation at a relatively small number of sites could result in noteworthy progress toward AER D060 reduction targets. Following AER D060 guidelines for economic assessments, they determined the NPV of compressing gas into the existing pipeline network for 5945 batteries that report flaring or venting volumes during 2008. Other alternatives for conserving gas were considered (e.g., gas-to-liquid, micro-condensers, power generation as well as gas compression and re-injection for reservoir pressure maintenance), however, they were deemed uneconomical for the small gas volumes under consideration. Infrastructure location and gas volume data was applied to compression and pipeline cost models and benchmarked against anonymous industry project cost estimates with results indicating 90 percent of sites and 54 percent of the total gas volume could be recovered at a capital cost of approximately $384,000 per site (interestingly 2.1 percent of sites would cost more than $2 million to conserve). Other NPV calculation inputs applied by Johnson and Coderre (2012) are a natural gas price of \$3.97/GJ; 1% long-term inflation rate; 6% discount rate; gas production forecast of negative 0.2%; and a standard project lifetime of 10 years. Under these conditions, 190 sites and 32.6 percent (approximately 224 $10^6 m^3$) of total solution flaring and venting have a positive NPV while the volume of gas economical to conserve increases to approximately 46 percent (316 $10^6 m^3$) if a carbon value of \$15/t CO_2E is accounted. Because distance from pipeline was a controlling factor for tie-in costs, a direct correlation between positive NPV and the AER threshold for evaluation could not be provided. However, results suggest approximately 43 percent of sites above 900 m^3/day had a positive NPV in 2008.

In November 2015, Alberta released its climate leadership plan with four key policy objectives (AEP, 2015):

- Phasing out coal-generated electricity and developing more renewable energy.
- Implementing a new carbon price on greenhouse gas pollution (\$20/t CO2e in 2017 and \$30/t CO2e in 2018).
- A legislated oilsands emission limit.
- Employing a new methane emission reduction plan to achieve a 45% decrease by 2025.

The plan includes policy provisions to mitigate competitiveness impacts for trade exposed sectors (including the UOG sector). The carbon price will only apply to "on-site combustion in conventional oil and gas" (i.e., natural gas fuel consumption and flaring) starting January 1, 2023. Fugitive and venting emissions are exempt from the carbon price. Instead, new regulatory standards for controlling fugitive emissions (i.e., leak detection and repair) and voluntary standard for controlling venting will be developed through a multi-stakeholder process beginning in early 2016.

2.1.2 BRITISH COLUMBIA

In 2008, the BC OGC published Flaring, Incinerating and Venting Reduction Guidelines as part of BCs endorsement of the World Bank voluntary standard for global gas flaring and venting reduction (Environment Canada, 2008) as well as BCs Energy Plan to reduce GHG emissions (BC MEMPR, 2007). The 2008 guide incorporated requirements from AER D060 that are applicable and appropriate for BC. Sites that flare or vent more than 900 m^3/day must complete an economic assessment of gas conservation options. If the NPV of gas conservation is greater than negative \$50,000 or the GOR is greater than 3000 m^3/m^3; the well must be shut-in until the gas is conserved.

Moreover, the BC Energy Plan commits the province to "…*eliminate all routine flaring at oil and gas producing wells and production facilities by 2016, with an interim goal to reduce routine flaring by 50 per cent by 2011*." Updates to the guide in 2015 are intended to continue progress on Energy Plan goals and include the following provisions (OGC, 2015):

- Mandatory inline testing of wells near pipelines and populated areas;
- Approval is required for all well test and cleanup flaring;
- Implementation of a new flaring reporting system for wells;
- Facility design guidance to eliminate or reduce flaring;
- Requirements for flare meters at new gas plants and large compressor stations;
- Elimination of non-routine flaring approvals for pipelines and facilities

2.1.3 SASKATCHEWAN

In 2011, the SK ER Directive S-10 was published and provides regulatory requirements for reducing flaring, incinerating, and venting of associated gas in Saskatchewan (SK ER, 2011). This initiative intended to realize both environmental (e.g., reduced GHG, VOC, PM and PAH emissions) and economic (e.g., investment in gas gathering and processing infrastructure) benefits. A steering committee of UOG industry and Government representatives recommended adopting a simplified version of AER Directive 060. Directive S-10 is applicable to all oil wells or facilities licensed under The Saskatchewan Oil and Gas Conservation Act and is fully enforceable after July 1, 2015 (SK ER, 2011).

Sites that flare or vent more than 900 m^3/day must complete an economic assessment of gas conservation options. If the NPV of gas conservation is greater than negative $50,000 or the GOR is greater than 3500 m^3/m^3; the gas must be conserved or the well is shut-in.

2.2 UNITED STATES OF AMERICA

Gas venting and flaring in the United States (US) has rapidly increased in since 2000, partly because of the quick and intense development of the Eagle Ford formation in Texas and the Bakken and Three Forks formations in North Dakota, which have significant volumes of associated gas. In 2000, *reported* volumes of vented and flared natural gas in the US amounted to 2.58×10^9 m^3 (91.2 Bcf), rising to 8.18×10^9 m^3 (288.7 Bcf) by 2014 (EIA, 2015). The volume of vented and flared natural gas in 2014 represents just about 0.9 per cent of gross withdrawals.

Rates of venting and flaring vary from state to state, and volumes can be high even in states with low overall rates. In 2014, the top five sources of *reported* onshore vented and flared gas are (in decreasing order): North Dakota (3.66×10^9 m^3 (129.4 Bcf) or 28.0 per cent of gross withdrawals); Texas (2.32×10^9 m^3 (81.8 Bcf) or 0.9 per cent of gross withdrawals); Wyoming (8.38×10^8 m^3 (29.6 Bcf) or 1.5 per cent of gross withdrawals); New Mexico (6.26×10^8 m^3 (22.1 Bcf) or 1.8 per cent of gross withdrawals); and Alaska (1.64×10^8 m^3 (5.8 Bcf) or 0.2 per cent of gross withdrawals) (EIA, 2015). Several large producing states reported no vented or flared natural gas in 2014, including Arkansas, Colorado, West Virginia, Pennsylvania and Louisiana.

2.2.1 FEDERAL REGULATION

Regulating oil and gas production in the US is primarily the responsibility of the states. The federal government, nonetheless, regulates many activities on Federal and Indian lands that affect oil and gas development. About 15 per cent of US oil and gas production is from lands managed by the federal government (Humphries, 2014).

The Department of the Interior's Bureau of Land Management (BLM) is the federal agency responsible for overseeing oil and natural leasing and production on Federal and Indian lands; though some states require producers on Federal lands within state boundaries to comply with the state's oil and gas rules (Ratner and Tiemann, 2015). The BLM is charged with ensuring that oil and gas producers "use all reasonable precautions to prevent waste of oil and gas" (Mineral Leasing Act of 1920, §16). In 2014, the BLM gave warning that it plans to revise its oil and gas rules to set standards to limit venting and flaring of natural gas at oil and gas production facilities on lands it manages, and to define the appropriate use of oil and gas for beneficial use. Specifically, the proposed rule would delineate which activities qualify for beneficial use, minimize the amount of venting and flaring that takes place on oil and gas production facilities on Federal and Indian lands, and establish standards for determining avoidable versus unavoidable losses (OMB, 2014). A draft rule for publication in the Federal Register is expected in winter 2015, with Final Action anticipated in April 2016.

The US Environmental Protection Agency (EPA) drafts regulations that implement environmental laws (e.g., the Clean Air Act) written by Congress. Often, the EPA will set national standards that states and tribes enforce through their own statutes.

In 2012, the US Environmental Protection Agency (EPA) finalized New Source Performance Standard (NSPS) for volatile organic compounds (VOCs) and National Emissions Standards for Hazardous Air Pollutants (NESHAPs) for the oil and natural gas industry (US EPA, 2012). From 1 January 2015, the 2012 NSPS for VOCs requires producers of new or modified hydraulically fractured natural gas wells to use a procedure known as a "reduced emission completion" (or "green completion") to capture the natural gas that would otherwise escape to the atmosphere upon well completion.[4] Up to 31 December 2014, producers were allowed to direct emissions to a combustion device (such as a flare). Because VOCs and methane are normally emitted together, methane reductions are a co-benefit of the 2012 NSPS. However, the rule applies only to completions of hydraulically fractured natural gas wells; not to oil wells. There are also some exceptions to implementing green completions, including exploratory wells (where gas gathering pipelines are not established) and certain low-pressure wells.

4 A "reduced emission completion" means a well completion following fracturing or re-fracturing, where gas flowback that is otherwise vented is captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere (NSPS Subpart OOOO).

Moreover, the NSPS rule requires VOC reductions from new or modified: (1) pneumatic controllers and storage tanks at natural gas and oil well sites; (2) compressors, pneumatic controllers and storage tanks at gathering stations; (3) compressors, equipment leaks, pneumatic controllers and storage tanks at gas processing plants; and (4) storage tanks gas compressor stations. The rule does not apply to existing equipment, nor cover all sources of VOC emissions (US EPA, 2012).

In 2014, the EPA released, for external peer review, five technical white papers on major sources of VOCs and methane emissions in the oil and gas sector—namely, hydraulically fractured oil wells, equipment leaks, pneumatic controllers and pumps, compressors and liquids unloading. The papers focused on techniques to mitigate emissions of both pollutants. As noted in the President's Climate Action Plan - A Strategy to Reduce Methane Emissions, the EPA will use the papers, along with input received from the peer reviewers and the public, to fully evaluate a range of options to cost-effectively pursue additional reductions from these sources.

And in September 2015, the EPA proposed a rule to achieve additional reductions of VOCs and methane from the oil and gas industry. The rule proposes to amend the NSPS for the oil and natural gas source category, by setting standards for VOCs from sources not currently covered by the 2012 NSPS (such as completions of hydraulically fractured oil wells, pneumatic pumps and equipment leaks at gas and oil well sites and compressor stations) and for methane from sources that are currently regulated for VOC. The proposed amendments to the 2012 NSPS also extend the current VOC standards to the remaining unregulated equipment across the source category, and establish methane standards for the same equipment. In addition to the proposed standards for new and modified emissions sources, the proposed rule provides guidelines for states to reduce VOC emissions from existing sources in the oil and gas sector in areas with smog problems (ozone nonattainment areas) (Federal Register Number 2015-21023, RIN 2060-AP76). The EPA has indicated that it will complete the Final Rule by the summer of 2016 (US White House, 2014).

A regulatory impact analysis concluded that the proposed NSPS rule will have climate benefits of $200 million to $210 million in 2020 (2012$), which outweigh implementation costs of $150 to $170 million (EPA, 2015a). Climate benefits are monetized by incorporating the social cost of methane (SC-CH_4), a metric that estimates the monetary value of impacts associated with marginal changes in methane emissions. SC-CH_4 accounts for a number of anticipated climate impacts, including: human health, property damages from flood risk, agricultural productivity, and the value of ecosystem services. The NSPS regulatory impact analysis applied SC-CH_4 values that ranged from $430 to $7,200 (USD) per tonne of methane depending on the year considered and discount rate assumed (Marten et al, 2014). The EPA expects that avoided VOC emissions will also result in improvements to air quality and reduce health and welfare costs;

however, it concluded that these benefits cannot be monetized in a defensible manner which limits conclusions to qualitative statements.

2.2.2 STATE REGULATION

States have adopted different approaches to managing vented and flared gas within their respective jurisdictions. While no states currently ban flaring outright, some states do prohibit venting—for example, North Dakota and South Dakota (Richardson et al., 2014). Other states restrict venting and flaring in some fashion, while others have discretionary or aspirational standards. The latter are best characterized as a situation in which producers are required to minimize gas waste but the standards do not carry any enforceable requirement (Richardson et al., 2014). West Virginia and Pennsylvania, for example, employ discretionary or aspirational standards re both venting and flaring practices.

Below is a summary of the approaches to venting and flaring used in five key producing states. These states represent a sample of regulatory approaches *restricting* venting and flaring, ranging from more lenient (e.g., North Dakota and Texas) to more stringent (Colorado, Wyoming and Alaska).

Of note, a number of states are current reevaluating their approach in response to a recent upturn in the amount of gas being flared (WORC, 2014).

2.2.3 TEXAS

In addition to high gas production, a major reason for the low venting and flaring rate is the state's 'resource geography'. Texas—a long time major oil producer—has a highly-developed transportation and processing infrastructure that gives producers ready access to markets, much more so than in states experiencing recent oil and gas development, like North Dakota. The importance of legacy infrastructure is evident from the following quote in the San Antonio Express: "*There's a case to be made that it's cheaper for me to flare it at the wellhead than it is for me to build the infrastructure to move the gas. I'm throwing away money, but I'm throwing away less money.*" (Tedesco and Hiller, 2014)

The Texas Natural Resources Code states that "*in recognition of past, present, and imminent evils occurring in the production and use of gas as a result of waste in this production* […] *for the protection of the public and private interests against these evils* [the production of waste is prohibited] (§ 86.001). Waste includes, among other things, allowing any natural gas well to burn wastefully and allowing the escape of gas into the open air in excess of the amount necessary for the efficient drilling or operation of a well (§ 85.046). The Texas Railroad Commission (RRC) administers and enforces rules regulating venting and flaring within the oil and gas industry. Under state regulations, producers are not required to submit gas capture plans prior to obtaining drilling permits and are allowed to flare gas for up to 10 producing days after a well is initially completed (Tex. Admin. Code § 3.32 (f) (1) (A)). After 10 days, a producer can apply to the RCC to grant an exemption (permit) to allow flaring to continue. Producers need only apply for exemptions for wells flaring in excess of 1,416 cubic meter of gas per day; wells flaring less than or equal to this volume do not require a permit (Tedesco and Hiller, 2014). In the application the producer must explain why flaring is necessary at the well and demonstrate that they are making an effort to address the problem. A number of circumstances can be used to justify "necessity" under the regulations, including: workover operations; the release of low-pressure gas that would not otherwise be used or sold due to mechanical, physical, or economic impracticability; or the lack of a pipeline or market (Tex. Admin. Code § 3.32 (f) (2)). An exemption allows the producer to continue to flare for a period not to exceed 180 days. If a producer wants to flare gas for longer than 180 days they must request a hearing with the RCC (Tedesco and Hiller, 2014).

2.2.4 NORTH DAKOTA

Like many states, North Dakota law prohibits the waste of oil and gas—defined as "*The production of gas in excess of transportation or marketing facilities or in excess of reasonable market demand*." (N.D. Cent. Code Ann. § 38-08-02 16 (e) and § 38-08-03) However, the statutes also currently allow gas produced with crude oil from an oil well to be flared for one year from the date of first production at a well. (Note that venting is prohibited in North Dakota.) After this one-year period, the flaring must cease and the well must be either (N.D. Cent. Code Ann. § 38-08-06.4(2)): (a) capped; (b) connected to a gas gathering pipeline; (c) equipped with an electrical generator that consumers at least 75 per cent of the gas from the well; (d) equipped with a system to that compresses at least 75 per cent of the gas to liquid for various beneficial uses; or (e) equipped with other approved value-added processes that reduce the volume or intensity of the flare by more than 60 per cent.

Producers that flare for longer than the one year period are required to pay royalties to the mineral owner and gross production tax on the flared gas to the state (N.D. Cent. Code Ann. § 38-08-06.4(4)). However, producers may apply to the North Dakota Industrial Commission (NDIC) for a permit to flare longer than one year. If the producer can demonstrate to the satisfaction of the NDIC that connecting the well to a natural gas gathering pipeline or equipping the well with other equipment as required by the statute is economically infeasible at the time of the application or in the foreseeable future, then an exemption may be granted to continue flaring gas (N.D. Cent. Code Ann. § 38-08-06.4(6)). Under the statute, connecting a well to a gathering pipeline is economically infeasible if the direct costs of both connecting the well to the line and operating the connecting facilities over the life of the well "*are greater than the amount of money the operator is likely to receive for the gas, less production taxes and royalties, should the well be connected*." (N.D. Admin. Code § 43-02-03-60.2). To account for "*the cost of money and other overhead costs that are not figured in the direct costs of connecting the well and operating* *the connecting facilities*" the application may inflate estimated direct costs by 10 per cent (N.D. Admin. Code § 43-02-03-60.2). Each application for an exemption must contain evidence relating to (N.D. Admin. Code § 43-02-03-60.2):

- The basis for the gas price used in the calculations;
- The direct cost of connecting the well to the line and operating the connecting facilities;
- The current daily rate of gas flared;
- Estimated gas reserves and the volume of gas available for sale;
- The economically infeasibility of equipping the well with an electrical generator to produce electricity from the gas or a system to compress at least 75 per cent of the gas to liquid for beneficial uses as a fuel.

Gas capture plans are now required along with applications to drill for new wells.

2.2.5 COLORADO

Colorado has one of the most restrictive approaches to venting and flaring. Under regulations promulgated by the Colorado Oil and Gas Conservation Commission (COGCC), unnecessary or excessive flaring of natural gas produced from a well is prohibited (Colo. Code Regs. 404-1 912 (a)). However, the regulations do not define "excessive" or "unnecessary" flaring. A producer may only flare gas after advanced notice has been given to, and approval obtained from, the COGCC Director, except during an upset condition, well maintenance, well stimulation flowback, purging operation, or productivity test (Colo. Code Regs. 404-1 912 (b)). Furthermore, notice must be provided to the local emergency dispatch or the local governmental designee prior to flaring, or in no case, more than two hours after the flaring occurs (Colo. Code Regs. 404-1 912 (e)).

Beginning August 1, 2014, Colorado requires the use of green completions for newly constructed, hydraulically fractured, or recompleted oil and natural gas wells statewide. Green completions are required on wells "*capable of naturally flowing gas in flammable or greater concentrations at a stabilized rate in excess of five hundred (500) MCFD* [14,160 m^3/day] *to the surface against an induced surface backpressure of five hundred (500) psig* [3,450 kPa] *or sales line pressure, whichever is greater*." (Colo. Code Regs. 404-1 805 (b) (3) A.) Exploratory wells are exempt. Green completion are also not required where a well is not sufficiently proximate to a sales line or where they are not technically and economically feasible (Colo. Code Regs. 404-1 805 (b) (3) B.). What constitutes technically and economically infeasible is not defined.

Gas from wells covered by the rules must be routed to a gas gathering line or controlled by 95 per cent; if using combustion device, the device must be designed to achieve 98 per cent control. Where green completions are not technically feasible, producers shall employ "Best Management Practices" (BMPs) to reduce emissions.

2.2.6 WYOMING

The Wyoming Oil and Gas Conservation Commission (WOGCC) issues state-wide rules and regulations that govern the development of oil and gas. In Wyoming, the flaring of natural gas from the oil and gas industry is regulated by defining it as "waste". Under Wyoming law, the definition of waste includes, among other things, the flaring of gas from gas wells except when necessary for the drilling, completing or testing of the well (Wyo. Stat. Ann. § 30-5-101 (a) (G)). In addition, the burning or escape (venting) of natural gas into the atmosphere without the heat therein being utilized for other manufacturing or domestic purposes is deemed wasteful and it is prohibited (Wyo. Stat. Ann. § 30-5-121 and § 30-5-102).

The WOGCC rules, nonetheless, do allow some flaring by acknowledging that not all flaring constitutes waste. In a few circumstances venting or flaring does not constitute waste and is permissible under emergency or upset conditions, such as equipment failures, abnormal pressures and other conditions that create unavoidable short-term venting or flaring of gas; well purging and evaluation tests; and production tests not exceeding a period of 15 days (Wyo. Admin. Code OIL GEN Ch. 3, § 39 (a)). Also, producers currently may vent or flare up to 1,700 m^3 of gas per day from individual oil wells without any notice to the WOGCC, but must apply for a permit to flare more (Wyo. Admin. Code OIL GEN Ch. 3, § 39 (b)).

If venting or flaring occurs (or is anticipated to occur) under circumstances not addressed by § 39 (a) or (b), a producer may apply for retroactive (or prospective) authorization to flare (Wyo. Admin. Code OIL GEN Ch. 3, § 39 (c)). Authorization may be granted by the WOGCC upon receipt of an application that sufficiently establishes that the venting or flaring does not constitute waste. The application must contain, among other things, the following: a statement of the reasons for venting or flaring; the estimated duration of venting or flaring; the estimated daily volume of vented or flared gas; a compositional analysis of the gas if containing hydrogen sulfide or a low BTU content; and the distance to the nearest point of sale or pipeline (Wyo. Admin. Code OIL GEN Ch. 3, § 39 (c)). The rule contains no explicit requirement for the applicant to establish the economic infeasibility of venting or flaring.

Wyoming laws also require green completions for all new oil and gas wells to reduce emissions and capture gas for sale rather than venting or flaring. Emissions of volatile organic compounds (VOC) and hazardous air pollutants (HAP) associated with the flaring and venting of natural gas at well completions and re-completions shall be eliminated to the extent practicable by routing the recovered gas into a gas sales line or collection system.

The WOGCC has initiated a review of its rules on flaring and appears likely to tighten limits on flaring and venting (WORC, 2014).

2.2.7 ALASKA

In 1971 the Alaska Oil and Gas Conservation Commission (AOGCC) ordered an end to the flaring of gas produced along with oil from Cook Inlet platforms, except for what was needed for safety flares on the platforms. The policy now applies statewide. Any gas flared, except for up to one hour for emergencies, operational upset, system testing or other lease operation authorized for safety, constitutes "waste" of the natural gas resource and is prohibited (WORC, 2014). The waste of oil and gas in Alaska is prohibited under state statute AK Stat § 31.05.095 (2012). Waste is defined to include "*the release, burning, or escape into the open air of gas, from a well producing oil or gas, except to the extent authorized by the* [Alaska Oil and Gas Conservation Commission]." (AK Stat. § 31.05.170)

Producers must re-inject the gas into ground if they are not going to capture and sell it. Any gas "*release, burning, or escape into the air*" exceeding one hour requires the submission of a written report describing "*why the gas was flared or vented, the beginning and ending time of the flaring or venting, the volume of gas flared or vented*…" and any compliance actions taken to minimize the volume of gas released or burned (AK Admin. Code 20 AAC 25.235(b)).

3 REPRESENTITIVE SITE CONDITIONS

Technology evaluations are based on common site equipment and conditions to minimize the number of assumptions required and provide a common basis for comparison. The representative bitumen battery, Cold Heavy Oil Production with Sand (CHOPS), described below was selected because this facility type contributes the most to natural gas venting in Alberta (AER, 2016a).

3.1 COLD HEAVY OIL PRODUCTION WITH SAND (CHOPS)

CHOPS surface facilities include the wellhead, an electric motor or hydraulic system that drives a down-hole progressing cavity pump, and produced fluid piping connected to storage tank(s). Gas that comes out of solution in the reservoir (downhole) is produced through the well annulus (area between well production tubing and cement casing) to dedicated casing gas surface piping. The hydraulic system or electric generator is normally driven by a natural gas or propane-fueled engine.

The produced fluids, including oil, water, sand and remaining gas in solution; are flow-lined to production tanks often operating in series. Aided by heat, demulsifier chemical and gravity; water and oil separate into discrete layers with sand eventually settling to the bottom. The production tanks are typically maintained at 70 to 80 °C with casing gas or propane fueled, in-tank, tube heaters. Solution gas disengages from the oil in the production tank and released to the atmosphere. Produced oil is removed from the production tanks and loaded into trucks for disposition to central treatment or sales terminal facilities depending on the water in oil fraction. Water is also removed from production tanks, loaded into trucks and injected into producing formation or disposed. Sediment is periodically removed from production tanks with vacuum trucks and disposed.

A fundamental challenge to gas conservation at CHOPS wells is inconsistent casing gas flow rates. New Paradigm Engineering Ltd. describes CHOPS wells experiencing three production phases (New Paradigm, 2015). Initial production is a homogenous foamy oil which typically lasts for a few months to a year. Oil foaming occurs downhole when gas comes out of solution from high viscosity oil during the pump induced pressure drop. Gas is released from the surface production tank as heating and chemical aids break down the foam. Stabilized flow occurs when oil and gas phases are able to separate in the reservoir (in void spaces created by producing sand). Gas flows to surface through the well annulus (i.e., casing gas) while oil is pumped through the production tubing. It is important to note that if the reservoir fluid level drops to the same depth as the pump intake (i.e., the well is 'pumped-off'), gas is compressed by the progressing cavity pump resulting in alternating production of oil and gas up the tubing. When this occurs gas is released from the surface production tank instead of the casing vent. End of life flow occurs after 6 to 8 years and is characterized by inconsistent slugs of gas, oil and water. GOR may be higher during this period but oil production rates are much lower.

Decisions regarding gas conservation may be delayed by producers until consistent GOR measurement results are observed over a period of time. Given the finite period of stable flow, delaying installation of gas conservation equipment after the stabilized flow phase begins jeopardizes their economic feasibility. Thus it's important to account for 'tank-top' gas when determining GORs during the initial production phase. Economic assessments completed for this study are based on 8 years of stable flow and assume reservoir fluid levels are monitored to avoid gas production via the tubing (i.e., well 'pump-off').

3.2 REPRESENTITIVE BATTERY

The representative battery for base-case economic assessments features two wellheads, two reciprocating engines for pumping (45 kW each) and two heated production tanks (750,000 BTU/HR each). A combined on-site fuel demand of 27.6 GJ per day is supplied by casing gas during warm months (7) and propane during colder months (5). Conservation and conversion technologies described below are designed based on continuous availability of 1,500 m^3 per day of excess casing gas during the first year of production. Although assessments don't account for upset conditions or interruption to casing gas flow, lower bound flow rates are modelled in the sensitivity analysis to quantify possible impacts on NPV.

Use of propane as the primary fuel source at CHOPS batteries is declining because of industry efforts to reduce purchased fuel costs (by maximizing casing gas utilization) and to mitigate environmental impact. However, a review of 2016 AER ST60 records indicates up to 14 percent of bitumen batteries in 2011 and up to 9 percent of batteries in 2016 could reduce or eliminate propane fuel[5] (AER, 2016b). These sites could implement conservation opportunities and are featured in the economic assessments below.

A two-well pad was selected as the representative battery because low gas flows are more likely to occur at pads with low well counts. The two-well pad type accounts for approximately 6 percent of total wells, 9 percent of total gas production and 11 percent of total venting in 2016 as presented in Figure 2 (AER, 2016b)[6]. Gas flow conditions targeted by this study certainly can occur at pads with different well counts but a static pad configuration was adopted to simplify assessments.

[5] Sites identified by those reporting natural gas production greater than 18 $10^3 m^3$/month (i.e., enough gas to run 1 engine and 1 tank heater) but zero natural gas fuel use **plus** sites reporting natural gas fuel in summer but not winter.
[6] Based on statistics available for AER battery types 331, 341 and 342. Paper batteries (type 343) were not evaluated because of insufficient data granularity.

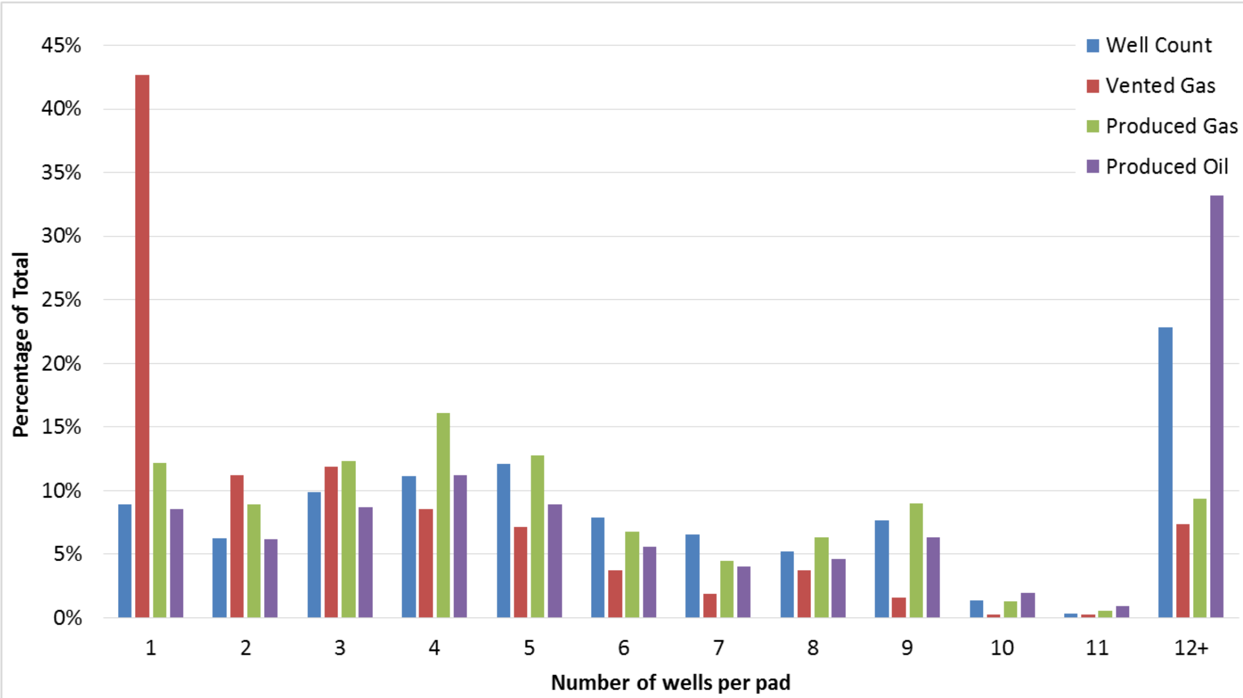

Figure 2: Distribution of total well counts, gas vented, gas produced and oil produced for bitumen batteries in Alberta by the number of wells per pad (AER, 2016b).

Development of heavy oil reservoirs is trending to larger 'super' pads that may feature up to 12 (or even 14) oil wells per pad. Increasing the number of wells per pad improves the economics for gas conservation because flows are typically much greater than 1,500 m^3 per day (and not included in the current study).

Typical wellhead casing gas temperatures range from 5 to 15^o C while pressures range from 35 to 200 kPa gauge. Casing gas is typically sweet and composed of mostly methane. The casing gas composition presented in Table 1 with a Higher Heating Value (HHV) of 39 MJ/m^3 is utilized for economic assessments (Environment Canada, 2014).

Tank-top gas is not considered in this study because flows are typically small and difficult to conserve (i.e., tank vapours are highly variable and water-saturated at tank-top temperatures ranging from 30 to 60^o C). Moreover, odourus gas flows are not considered in the current study because substantive regulatory barriers to releasing this gas already exist; including new regulations for Peace River area eliminating the direct release of casing and solution gas to the atmosphere (AER, 2015). Casing and solution gas produced within the Peace River area of Alberta contains odourous compounds, including H_2S observed to range from 1 to 700 ppm (Clearstone, 2014).

Table 1: Typical casing gas composition.	
Compound	**Mol fraction**
Nitrogen	0.0018
Hydrogen Sulphide	0.00003
Carbon Dioxide	0.0009
Methane	0.9801
Ethane	0.0091
Propane	0.0004
n-Butane	0.0006
i-Butane	0.0004
n-Pentane	0.0005
i-Pentane	0.0004
Hexane	0.0009
Heptane plus	0.0049

3.3 BASELINE GHG EMISSIONS

Baseline GHG emissions from fuel combustion and casing gas venting for the representative battery are presented in Table 2 equal 59,312 t CO_2E over the 8 year project life. Emissions are determined using an energy-balance model that assumes initial casing gas available onsite is 2,000 m^3 per day and site energy demand to operate pump engines and tank heaters is 27.6 GJ per day. During warm months (7) casing gas is used to meet site energy demands while propane fuel is used during cold months (5). Excess casing gas, not used as fuel, initially equals about 1,500 m^3 per day and is vented to the atmosphere. Fugitive and storage tank emissions are not included in the model and baseline value because the proposed technologies have negligible impact on these sources.

NPV calculations and sensitivity analysis are completed with casing gas declining over time according to the production forecast and the site energy demand remaining constant. The emissions upper bound is constrained by the volume of available casing gas plus any propane fuel used for site energy demands. The lower emission bound occurs when zero casing gas is available and propane fuel is used for the entire site energy demand.

Net GHG emission reductions are assessed as the difference between representative battery baseline emissions and project emissions achieved by each technology scenario.

Table 2: Baseline GHG emissions for the representative battery over the 8 year project life.					
Year	**Casing Gas Available**	**Propane Combusted (during cold months)**	**Casing Gas Combusted (during warm months)**	**Casing Gas Vented**	**GHG Emissions**
	(10^3m^3/yr)	**(GJ/yr)**	**(10^3m^3/yr)**	**(10^3m^3/yr)**	**(t CO_2E/yr)**
2016	730	4,138	149	581	10,225
2017	674	4,138	149	525	9,291
2018	622	4,138	149	474	8,429
2019	574	4,138	149	426	7,634
2020	530	4,138	149	382	6,899
2021	489	4,138	149	341	6,221
2022	452	4,138	149	303	5,595
2023	417	4,138	149	268	5,018
Total	4,488	33,104	1,188	3,300	59,312

GHG emissions are presented on a CO_2 Equivalent (e) basis using Global Warming Potentials (GWP) of 1 for Carbon Dioxide, 25 for Methane and 298 for Nitrous Oxide from the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (AR4) over a 100 year time horizon (IPCC, 2012)[7]. Casing gas combustion CO_2 emissions are determined by mass balance and conversion efficiency of 0.999 while emission factors for CH_4 (49.58 g/GJ) and N_2O (1.305 g/GJ) are adopted from WCI Table 20-4 (WCI, 2013). Venting CO_2 and CH_4 emissions are determined by mass balance while propane combustion factors are adopted from WCI Table 20-2 (60.96 kg CO_2E/GJ).

3.4 ECONOMIC CONSIDERATIONS

Key metrics and assumptions used to determine technology Net Present Values (NPV) are described in the following sections.

3.4.1 NET PRESENT VALUE

The NPV of a conservation or conversion project is the algebraic sum of the present value of projected incremental benefits less the present value of projected incremental costs over the project's useful life. It is calculated by multiplying the projected incremental benefits (i.e., where relevant, revenue from sales, avoided fuel purchases and the salvage value of project infrastructure) and incremental costs (i.e., investment expenditures and recurring operating costs, net of any baseline cost savings) incurred each year, by the appropriate discount factor, and

7 AR4 GWP values for a 100 year time horizon are applied to be consistent with those specified in current federal and western province GHG reporting regulations.

summing all the resulting discounted values over the useful life of the project.[8] Project NPVs are calculated on a *before-tax* basis and exclude contingency and overhead costs.

If the calculated NPV is greater than zero, then the investor can expect to accrue an addition to their net worth as well as recover the invested capital and earn a nominal rate of return on their investment equal to the discount rate. The *before-tax* addition to net worth is equal to the positive amount of the NPV.

A summary table is presented for each technology delineating the amount of casing gas used; product generated; revenue from sales or avoided costs; and net capital and operating costs. This overall approach is consistent with AER Directive 060. GHG emission reductions attributable to conservation projects are not monetized in the base-case. The sensitivity of base-case NPVs to key input parameters is tested, using upper and lower bounds estimates. In general, monetizing GHG reductions has the greatest influence on project NPVs with modest carbon valuation resulting in positive NPVs for each technology over a range of initial gas flows.

3.4.2 NPV SENSITIVITY (TORNADO CHARTS)

The sensitivity of the project NPV to key input parameters is presented in the form of a tornado chart. A tornado chart is a type of bar chart that reflects how much impact varying an input parameter has on project NPV, providing both a ranking and a measure of magnitude of the impact, shown as an absolute (present value dollar) deviation from base-case NPV. The base-case NPV is shown in the chart by the dashed vertical line rising from $0 on the horizontal axis, which corresponds to all inputs set at their base-case values—i.e., with no sensitivities incorporated. Input parameters are ranked so that the input that causes the greatest variation in the project NPV is shown first (at the top); the input that causes the second greatest variation is ranked second, and so on. The size of each bar shows the deviation (positive or negative) from the base-case NPV as the input parameter assumes lower and upper bound values. The ends of each bar shows the assumed lower and upper bound values.

Lower and upper bound values for each parameter are modelled one at a time, and the impact on the project NPV recorded. Note that a lower bound value is not necessarily a lower number, but rather an input assumption that yields a more pessimistic project NPV (e.g., capital and installation costs). Likewise, an upper bound value is an input assumption that generates a more optimistic project NPV.

[8] The discount factor constitutes the weight applied to dollars received in future years. It is used to convert future dollar flows into present day equivalents: discount factor = $(1 + r)^{-t}$. Where r is the nominal annual discount rate and t is the year in which a cost or benefit is incurred.

3.4.3 PRODUCTION FORECAST

Clearstone reviewed gas production rates for 2,800 Alberta bitumen wells between 2006 and 2015 and observed an annual mean decline (on an exponential basis) of 26 percent with a lower 99th percentile of 1.8 percent and upper 99th percentile of 130 percent. However, production forecasts are dominated by commodity price, drilling and completion program success, technology advancements and operational factors rather than physical reservoir pressure and production declines. Ultimately, wells are drilled, recompleted or used for enhanced oil recovery to maintain or increase production depending on commodity prices and corporate cash flow. Therefore a modest production decline of 8 percent is applied to Base-Case economic assessments with sensitivity analysis using upper and lower 99th percentiles. This is a more conservative forecast than the 0.2 percent annualized decrease applied by Johnson and Coderre (2012) that recognizes current depressed commodity prices.

3.4.4 PRICE FORECASTS

Natural gas and propane prices are based on the October 1, 2015 commodity price forecast from GLJ Petroleum Consultants Limited (GLJ). Assessments use the Alberta Natural Gas Reference Price (ARP) which is an average field price for all Alberta gas sales, as determined by the Alberta Department of Energy through a survey of actual sales transactions. Propane prices are based on Edmonton values. For both gas and propane, the full (current dollar) time series provided by GLJ over the period 2016-2025 is used for the base-case; these are shown in **Error! Reference source not found.**. Note that the projected values rise in real terms—i.e., the average annual compound growth rate (AACGR) (4.4% in the case of natural gas) exceeds the long-term annual rate of general price inflation (2.1%).

Prices for sensitivity analysis are constructed as follows:

1. Lower (upper) bound prices in 2016 are 10% less (more) than base-case values provided by GLJ; and
2. Lower (upper) bound prices in 2016 grow at the 25th (75th) percentile of the projected base-case AACGR (2016-2025) with the upper bound capped at highest historical price observed over the period 2005-2015.

Table 3: Projected (Current Dollars) Natural Gas and Propane Prices used in the NPV Calculations.				
Year	**Natural Gas**		**Propane**	
	Base-case	**Sensitivity**	**Base-case**	**Sensitivity**
	($ / GJ)	**($ / GJ)**	**($ / GJ)**	**($ / GJ)**
2016	3.03	2.73 - 3.34	3.76	3.38 – 4.13
2017	3.20	2.80 - 3.52	4.74	3.56 – 4.97
2018	3.30	2.88 - 3.72	5.90	3.75 – 5.97
2019	3.38	2.96 - 3.93	6.24	3.95 – 7.17
2020	3.47	3.03 - 4.15	6.56	4.16 – 8.62
2021	3.66	3.12 - 4.38	7.06	4.38 – 10.36
2022	3.85	3.20 - 4.62	7.57	4.61 – 12.45
2023	4.04	3.28 - 4.88	8.07	4.85 – 13.15
2024	4.29	3.37 - 5.15	8.44	5.11 – 13.15
2025	4.38	3.46 - 5.44	8.61	5.38 – 13.15

The electricity price in 2016 equals the most recent 12-month rolling average of the pool monthly summary price published by the Alberta Electric System Operator (AESO). This power price is then escalated at the long-term annual rate of general price inflation under the base-case (i.e., 2.1%). Projected electricity prices are provided in **Error! Reference source not found.**.

Electricity prices for sensitivity analysis are constructed as follows:

1. Lower (upper) bound prices in 2016 are equal to the 25th (75th) percentile of the most recent 12-month rolling average pool price; and
2. Lower (upper) bound prices in 2016 grow at the lower (upper) bound long-term annual rates of general price inflation over the period 2016-2025.

For the purpose of the NPV calculations, and to facilitate one-way sensitivity analysis, all prices (for natural gas, propane, electricity, and carbon savings) are modelled as levelized prices. A levelized price is the "annualized' dollar amount which, over a period of *N* years (the lifetime of a conservation project) discounted at the nominal annual discount rate, will be equivalent to the present value of a stream of annual prices over the same period. For example, the levelized gas and propane prices corresponding to the annual price series in **Error! Reference source not found.** under the base-case are, respectively, $3.45 per GJ and $6.07 per GJ.

Table 4: Projected (Current Dollars) Electricity Prices used in the NPV Calculations.		
Year	**Base-case ($ / MWh)**	**Sensitivity ($ / MWh)**
2016	35.45	21.85 – 36.80
2017	36.20	22.20 - 37.60
2018	36.95	22.60 - 38.35
2019	37.75	22.95 - 39.15
2020	38.50	23.35 – 40.00
2021	39.35	23.75 - 40.85
2022	40.15	24.15 - 41.70
2023	41.00	24.55 - 42.55
2024	41.85	25.00 - 43.45
2025	42.75	25.40 – 44.40

3.4.5 INFLATION RATE

The long-term annual rate of general price inflation under the base-case is 2.1%. This rate is the average year-on-year (all-item) Consumer Price Index (CPI) observed in Alberta over the period Oct 2002 to Oct 2015. The CPI for Alberta is generated by Statistics Canada and published monthly in "Economic Trends" by the Government of Alberta, Treasury Board and Finance, Economy and Statistics.

The long-term annual rate of general price inflation rate is used to escalate net annual costs and estimated salvage values (where relevant), in addition to electricity prices. This is necessary to ensure consistent treatment of all cost and benefit streams in the NPV calculations, which is performed in current (or nominal) dollars.

For sensitivity analysis, lower and upper bound estimates of CPI for 2016-17 from five major Canadian banks are used. The lowest estimate of CPI for Alberta in 2016-17 is 1.7% and the highest estimate is 2.1%. These rates are assumed to apply over the entire period 2016-2025.

3.4.6 DISCOUNT RATE

The nominal discount rate under the base-case is 5.70% per year. It is based on the Oct 2015 prime lending rate of ATB Financial on loans payable in Canadian dollars (2.7% per year) plus 3% per year (as per Directive 060). As noted in Section 3.4.1, the discount factor determines the weight assigned to future benefits in the NPV calculations. This factor declines exponentially with the discount rate. The higher the annual discount rate, the lower the weight assigned to future benefits in the determination of a project's NPV. All future cost and benefits flows are discounted at the nominal annual discount rate in the NPV calculations—i.e., converted to present day equivalents.

For sensitivity analysis, lower (upper) bound nominal annual discount rates reflect the lowest (highest) prime lending rate observed over the period 2010-2015. The lower bound discount rate is: 2.25% + 3.00% = 5.25% per year; the upper bound discount rate is: 3.00% + 3.00% = 6.00% per year.

3.4.7 ROYALTIES

Project NPVs are first calculated on a royalties-in basis (i.e., paying royalties at 5% under the base-case) for incremental casing gas and gas by-products that would otherwise be vented. Uneconomic projects (with NPVs less than negative $55,000) are subsequently assessed on a royalty-out basis (i.e., not paying royalties). If the re-calculated NPV is greater than negative $55,000, the operator may apply to the AER for an "otherwise flared solution gas" royalty waiver.

3.4.8 CAPITAL AND INSTALLATION COSTS

A detailed breakdown of equipment, material, installation, and engineering costs is presented in Section 6.2 for each technology option considered. Equipment costs are based on current technology vendor quotes. Installation and engineering costs are conservative and based on professional experience and judgement for installation of a single unit. Installation of multiple units as part of a corporate retrofit program would likely improve work flow efficiency and reduce overall costs. A base-case target estimate as well as lower (-25 percent) and upper (+50 percent) bound estimates are provided for each technology option.

Although Directive 060 indicates the capital cost of a new flare must be subtracted from gas conservation costs, this is not completed because it would preclude comparisons between conservation versus conversion projects.

3.4.9 SALVAGE VALUE

The net salvage value of equipment at the end of a conservation project's useful life (8 years under the base-case) is estimated by a qualified professional and included as project revenue in the last year of operating life. A base-case and lower and upper bound estimate are provided for each technology option.

3.4.10 OPERATING COSTS

Operating costs depend on the frequency and duration of site visits by field operators and maintenance staff, plus the cost of replacement parts and materials. A base-case and lower and upper bound estimate are provided for each technology option.

3.4.11 CARBON AND METHANE PRICING

Greenhouse gas emission savings attributable to each conservation project are monetized in one of two ways:

3.4.11.1 SOCIAL COST OF CARBON

The social cost of carbon—or SCC as it is known—is used in the U.S. to evaluate the climate change benefits of proposed new rules or changes to existing rules.

The US EPA defines the SCC as "an estimate of the economic damages associated with a small increase in CO_2 emissions, conventionally one metric ton, in a given year." It measures the full global damage costs of an incremental unit of carbon (or equivalent amount of other greenhouse gases) emitted at a particular point in time, summing the full global cost of the damage that unit imposes over its lifetime in the atmosphere. Damage costs include a wide range of anticipated climate-related impacts, including *inter alia* net changes in agricultural productivity, adverse human health outcomes, property and infrastructure damage from flooding, and changes in energy system costs associated with changes in cooling and heating demand. It is thus a measure of social costs.

Calculating the SCC requires quantification of the whole process linking anthropogenic emissions of GHGs with impacts on social welfare at a global scale; this task is performed by integrated assessment models (IAMs). Three IAMs from the peer-reviewed literature were used to generate values of the SCC for rulemaking in the U.S (EPA, 2015b); these are shown in current Canadian dollars in Table 5. Many climate-related impacts associated with an incremental unit of carbon emitted today are expected to occur for many decades and even centuries. The present value of those damages is thus highly sensitive to the chosen discount rate; this is evident from the values in Table 5, which are provided for three different discount rates typical of climate policy analysis. Moreover, since the amount of damage done by each incremental unit of carbon in the atmosphere depends on the concentration of atmospheric carbon today and in the future to which the increment is added, the SCC associated with emissions in 2020, 2025, 2030 rises as global emissions and concentrations of GHGs in the atmosphere increase. The SCC also increases over time as natural and socio-economic systems become increasingly stressed in response to greater levels of climatic change (reducing their coping capacity).

The SCC is important because it signals what society should, in theory, be willing to pay now to avoid the future damage caused by incremental carbon emissions. Policy-makers should be willing, in the interests of society, to make rules that result in emissions savings which cost up to and no more than the damage they expect the emissions to cause, because to do so would make society better off. This is how the SCC values are applied in the U.S., i.e., to value the benefits (and justify the implementation) of GHG emission reductions in rules like the proposed New Source Performance Standards (NSPS) for the oil and natural gas industry.

In the context of this project, the SCC values are used in two way:

1. In conjunction with estimates of the average abatement costs for each conservation project (see below), to determine the initial casing gas flow rates whereby the project would be economic if GHG emission reduction benefits are valued at the base-case SCC for 2025; and
2. As part of an upper bound sensitivity test, in which the GHG emission reductions over the life of a conservation project are valued at the base-case SCC values.

Table 5: Estimates of the Social Cost of Carbon (Average across all three IAMs, in current Canadian dollars).

Year	Base-case (3% discount rate)	Lower Bound (5% discount rate)	Upper Bound (2.5% discount rate)
	($ / t CO_2E)	($ / t CO_2E)	($ / t CO_2E)
2016	54	16	84
2017	57	17	88
2018	61	17	91
2019	64	18	95
2020	67	19	99
2021	70	20	103
2022	73	21	107
2023	75	22	112
2024	78	23	116
2025	81	24	120

3.4.11.2CARBON LEVY

The Government of Alberta recently released its Climate Leadership Plan (AEP, 2015). Among other policy initiatives, the Plan calls for a carbon price to be applied across all sectors, starting at $20 per t CO_2E on January 1, 2017 and rising to $30 per t CO_2E on January 1, 2018. Thereafter the price will increase in real terms annually (at 2% above general price inflation).

The carbon price, whatever form it takes (e.g., a levy or tax) will be extended to "on-site combustion in conventional oil and gas" starting January 1, 2023. Although the plan indicates non-regulatory performance standards will be applied to venting sources instead of a direct carbon price, the Alberta price signal is considered to better understand its potential influence on project economics. A special sensitivity test is performed whereby project NPVs are calculated with lifetime CO_2E emission reductions monetized using the carbon price schedule Table 6. The valuation of emission savings prior to 2023 usefully indicates the future economic potential for carbon abatement within this source sector.

Table 6: Carbon Levy (modeled after proposed economy-wide levy in Alberta).

Year	Base-case ($ / t CO_2E)
2016	Zero
2017	20.00
2018	30.00
2019	31.25
2020	32.50
2021	33.85
2022	35.25
2023	36.70
2024	38.20
2025	39.75

3.4.12 ABATEMENT COSTS

For each project the average (net) abatement cost (in current $ per t CO_2E avoided) is calculated under base-case assumptions. This metric defines the total cost, *net* of revenue from sales or avoided fuel purchases, incurred by the operator to avoid the release of one tonne of CO_2E to the atmosphere. It is given by:

$$Average\ Abatement\ Cost = \frac{PVC - PVB}{GHG}$$

Where:

PVC = Present Value Costs

= $\sum_{t=0}^{N} \frac{C_t}{(1+r)^t}$

PVB = Present Value Benefits

=

$$\sum_{t=0}^{N} \frac{B_t}{(1+r)^t}$$

GHG = Avoided GHG Emissions

$$= \sum_{t=0}^{N} E_t$$

t	=	year (with year t = 0 being the year in which the investment is made)
N	=	useful life of project (in years)
r	=	nominal annual discount rate
C_t	=	project's costs in year t
B_t	=	project's benefits in year t (excluding the monetization of CO_2E savings)
E_t	=	project's CO_2E savings in year t *determined with AR4 GWPs of 25 for* CH_4 *and 298 for* N_2O *for a 100 year time horizon.*

Although it's acknowledged reducing 1 tonne of CH_4 emissions now is of greater environmental benefit than reducing 1 tonne of CH_4 emissions in the future, CO_2E emissions used in the average abatement cost calculation are not discounted because of limitations in the GWP term as a measure of climate forcing effects. The GWP is an overly simplified means of comparing instantaneous emissions and evaluating their effects over a common time horizon (e.g., often 100 years) while assuming the ambient environment remains relatively constant (IPCC, 2013: Section 8.7). However, because GWPs are simple and practical to apply, they are almost universally adopted. More rigorous alternatives to model the actual climate forcing effect of specific GHG reduction projects are beyond the capability of most project proponents. Developing engineering estimates for a CO_2E discount rate (instead of those applied in AER D060 economic analysis) was considered but preliminary analysis suggested the discount would be close to zero. Moreover, the most recent IPCC Fifth Assessment Report (AR5) specifies methane has a GWP of 36 (i.e., 44 percent greater than the AR4 GWP of 25) plus it can be argued a 20 year horizon GWP of 72 is more appropriate for an 8 year project lifetime (i.e., 288 percent greater than the AR4 GWP of 25). Thus, this study adopts AR4 GWPs (100 year time horizon) because they produce conservative (i.e., lower) estimates of future CO_2E than alternatives and they align with current western Canadian GHG regulations.

If PVC >PVB, then the average abatement cost is positive. This implies the operator incurs a cost for each tonne of CO_2E saved. In contrast, if PVC < PVB, the average abatement cost is negative, and the operator accrues a resource saving for each tonne of CO_2E saved.

The average abatement cost has several useful interpretations. In the current context, it provides a yardstick for determining whether or not a conservation project (at different casing gas flow rates) is economic relative to different valuations of the CO_2E savings. In general:

- If the average abatement cost of a conservation project is negative, then that project is economic even without the monetization of CO_2E savings;

- If the average abatement cost of a conservation project is positive, but is *less than* the prevailing carbon price, then that project would be economic if CO_2E savings are monetized and included in the benefits stream; and
- If the average abatement cost of a conservation project is positive, but is *greater than* the prevailing carbon price, then that project would remain uneconomic even if CO_2E savings are monetized and included in the benefits stream.

4 ASSESSMENT OF TECHNOLOGY OPTIONS

A review of gas conservation and conversion technologies suitable for casing gas flows less than 1,500 m^3 per day was completed. It followed a decision tree process, developed with the support of PTAC (New Paradigm, 2002), to identify the following practicable options for gas conservation (3) and conversion (3). The decision tree prioritized conservation projects but also recognized the environmental benefits of methane conversion to carbon dioxide instead of venting.

- **Onsite Power Generation**: Conserve up to 1,380 m^3 casing gas per day by installing two 60 kW power generators and distribution lines for electricity sales.
- **Auxiliary Burner and Heat Trace**: Conserve up to 1,296 m^3 casing gas per day by utilizing heat from auxiliary burners installed in existing storage tank heater stacks.
- **Catalytic Line Heaters**: Conserve up to 315 m^3 casing gas per day by installing catalytic line heaters.
- **Catalytic Conversion**: Convert up to 110 m^3 of casing gas to carbon dioxide with excess vented.
- **Flaring**: Convert all excess casing gas to carbon dioxide via a small-scale flare.
- **Vapour Combustor**: Convert up to 1,500 m^3 casing gas to carbon dioxide via a dedicated vapour combustor.

The following sections provide technology descriptions; NPV results; a sensitivity analysis identifying parameters most import to achieving a positive NPV; and the influence of carbon valuation on NPV. Additional technologies were considered but not included in economic assessments because the casing gas flow rate and composition considered are not sufficient to make these options practicable. These include gas compression into gathering pipelines, gas compression into mobile trucks and hydrocarbon liquid recovery with a micro-condenser.

4.1 ONSITE POWER GENERATION

4.1.1 DESCRIPTION

Generating electricity for use onsite or delivery into nearby distribution lines is a productive means of conserving excess gas. Given the range of excess casing gas targeted by this study, two 60 kW power generators that consume up to 1380 m^3 per day when operating at full load are proposed. As casing gas flows decline, engine loading can be turned-down or a unit removed to match fuel supply. However, unexpected drops in gas flow are more difficult to manage and would likely cause unit shut-downs.

Industrial Engines Ltd. supplies the enclosed skid mounted package presented in Figure 3. This unit features an inlet fuel scrubber to remove any free liquids or dirt particles, a Ford V-10 (6.8 liter) engine and Stamford UCI274E generator that produces 3-phase, 60 hz power over a range of voltages. An engine thermal efficiency of 30 percent and generator power factor of 0.8 are applied when calculating output power. To prevent water condensing and wintertime ice blockages, the casing fuel lines are maintained above the wellhead temperature (15^o C) by heat tracing with excess heat from the hydraulic pump engine glycol coolant.

Figure 3: 60 kW enclosed natural gas generator package (Industrial Engines Ltd.)

Most 2-well oil batteries do not have power demands sufficient for the proposed generators so produced power is sold to the local distribution company. In most cases, this requires construction of power lines to the nearest distribution system which is assumed to be 2 km for the base-case. As discussed below, distance to a suitable distribution line has a tremendous impact of project economics. A simple process flow diagram identifying basic components of the system is presented in Figure 4. Note that propane fuel is used to fuel other site energy demands during cold months.

Connection to the power distribution system must comply with Canadian Electrical Code Section 84, CSA C22.2 No 107.1 and Canadian electrical product certification standards. Moreover, power plants must obtain approval through the Alberta Utilities Commission Rule 007 (AUC, 2008) and can complete a simplified application form when generating less than 1 MW. The simplified application requires provision of basic administrative and system details; agreement with the local distribution company for connection; completion of a noise impact assessment, an electric single-line diagram, site plot plan, evidence that a participant involvement program was completed and whether public objections were raised.

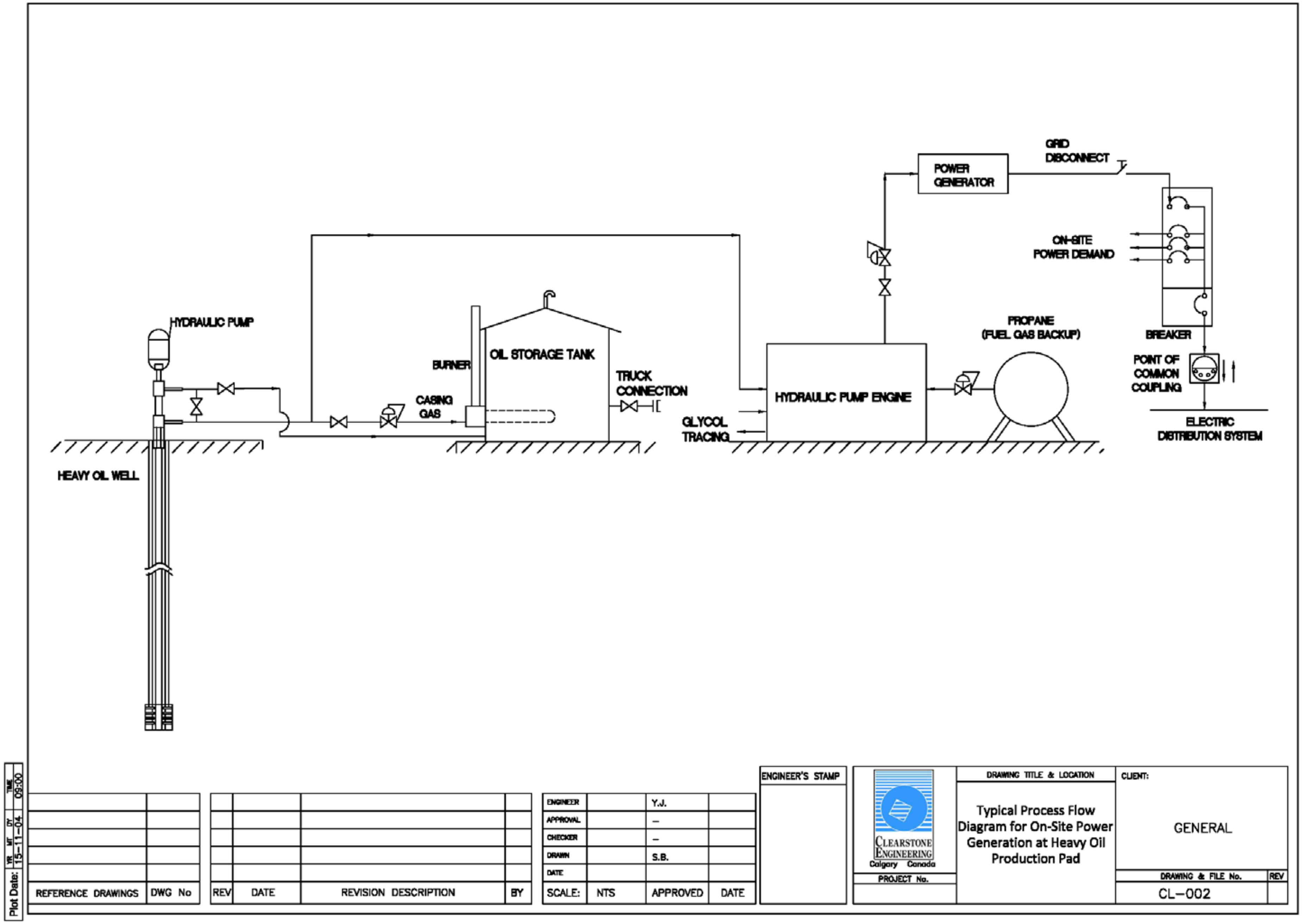

Figure 4: Process flow diagram for on-site power generation at a heavy oil well-pad.

4.1.1 GHG EMISSION REDUCTIONS

Utilizing excess casing gas to produce electricity instead of venting reduces GHG emissions by 79 percent (46,870 t CO_2E) relative to baseline GHG emissions as shown in Table 7. The remaining 21 percent are due to generator and site fuel combustion (gas and propane) plus casing gas vented during the first two years of operation (approximately 95 10^3m^3). Venting still occurs because the volume of excess gas exceeds the generators maximum fuel demand of 1,386 m^3 per day until production declines below this threshold in the second year. Also, the combustion efficiency of engines (99.5 percent) is better than flares (98 percent) and catalytic heaters (80 percent), thus, less methane is released to the atmosphere due to incomplete combustion.

Using casing gas in a productive manner also reduces indirect emission by about 4,900 t CO_2E[9] because 8,300 MWh of electricity generated from more carbon intensive sources (e.g., coal plants) is displaced over the 8 year project. The importance of distributed (or decentralized) projects to provide base-load power will increase as coal power plants are phased out as part of Alberta's climate leadership plan (AEP, 2015). Phasing-out coal power may also increase electricity prices faster than predicted in Table 4 (based on long-term annual rate of general price inflation). However, only direct emission reductions occurring onsite are included in Table 7 and NPV assessments.

Table 7: Avoided GHG emissions when producing power from excess casing gas.

Year	Baseline GHG Emissions	Project Case				Avoided GHG Emissions
		Casing Gas Combusted	Casing Gas Vented	Propane Combusted	GHG Emissions	
	(t CO_2E/yr)	(10^3m^3/yr)		(GJ/yr)	(t CO_2E/yr)	(t CO_2E/yr)
2016	10,225	655	75	4,138	2,826	7,399
2017	9,291	655	19	4,138	1,892	7,399
2018	8,429	622	0	4,138	1,505	6,924
2019	7,634	574	0	4,138	1,409	6,225
2020	6,899	530	0	4,138	1,320	5,580
2021	6,221	489	0	4,138	1,238	4,984
2022	5,595	452	0	4,138	1,162	4,434
2023	5,018	417	0	4,138	1,092	3,926
Total	59,312	4,393	95	33,104	12,442	46,870

[9] Estimated based on the Alberta Environment grid displacement factor of 0.59 t CO_2E/MWh applied to GHG offset projects.

4.1.2 ECONOMIC ASSESSMENT AND SENSITIVITY

The project earns revenue by selling power, however, power sales are small relative to the incremental lifecycle costs of the project. The base-case NPV equals negative $289,379 (on a royalties-in basis) and negative $271,969 (on a royalties-out basis) with complete results for the latter delineated in Table 8 for an eight year operating life. Input parameters are presented in appendix Figure 31 with details of capital and installation costs (base-case of $419,120) presented in appendix Table 26. These include the equipment, installation, studies and AUC Rule 007 application for connecting a new generator to a distribution line (approximately $50,000) plus up to $100,000 per km of installed power line (Genalta, 2015).

The sensitivity of NPV to upper and lower bounds for key input parameters is tested and results presented in the Figure 5 tornado chart. If distribution lines to the site already exist and have sufficient capacity for the incremental power supply, the project NPV increases by $254,495 (royalties-out basis) and is greater than the Directive 060 threshold requiring conservation projects to proceed. As evident from Figure 5, project NPV is also highly sensitive to the monetization of GHG emission reductions. Valuing GHG emission reductions at a levelized SCC of $64 per t CO_2E avoided (derived from column two in Table 5) increases the base-case project NPV by $2,704,205 to $2,432,235. The project NPV is also sensitive to assumptions relating to (in declining order of sensitivity): the production forecast; capital and installation costs of the generator; annual operating costs; and the price of electricity.

The average abatement cost for this project is $5.80 per t CO_2E avoided. That is, for every tonne of CO_2E not released to the atmosphere as a result of the project the operator incurs an average cost of $5.80 (to purchase and install the technology). As shown in Figure 6, the average abatement cost (and NPV) varies with the volume of excess casing gas initially available. If a policy was implemented whereby a levy of $30 per t CO_2E was charged on venting emissions, this conservation project would be economic at sites with initial excess casing gas flow rates of about 561 m^3 per day or greater. Alternatively, if a performance standard was set on the basis of the social cost of carbon in 2025, the use of this conservation technology would be economic at sites with an initial excess casing gas flow rates around 321 m^3 per day or greater.

Note that if more casing gas was produced or batteries were clustered together, building a larger power plant would reduce the cost of power lines per unit of electricity produced. Genalta Power has demonstrated larger power plant are feasible by successfully commissioning a number of solution gas to power projects in Alberta ranging from 4 to 20 MW.

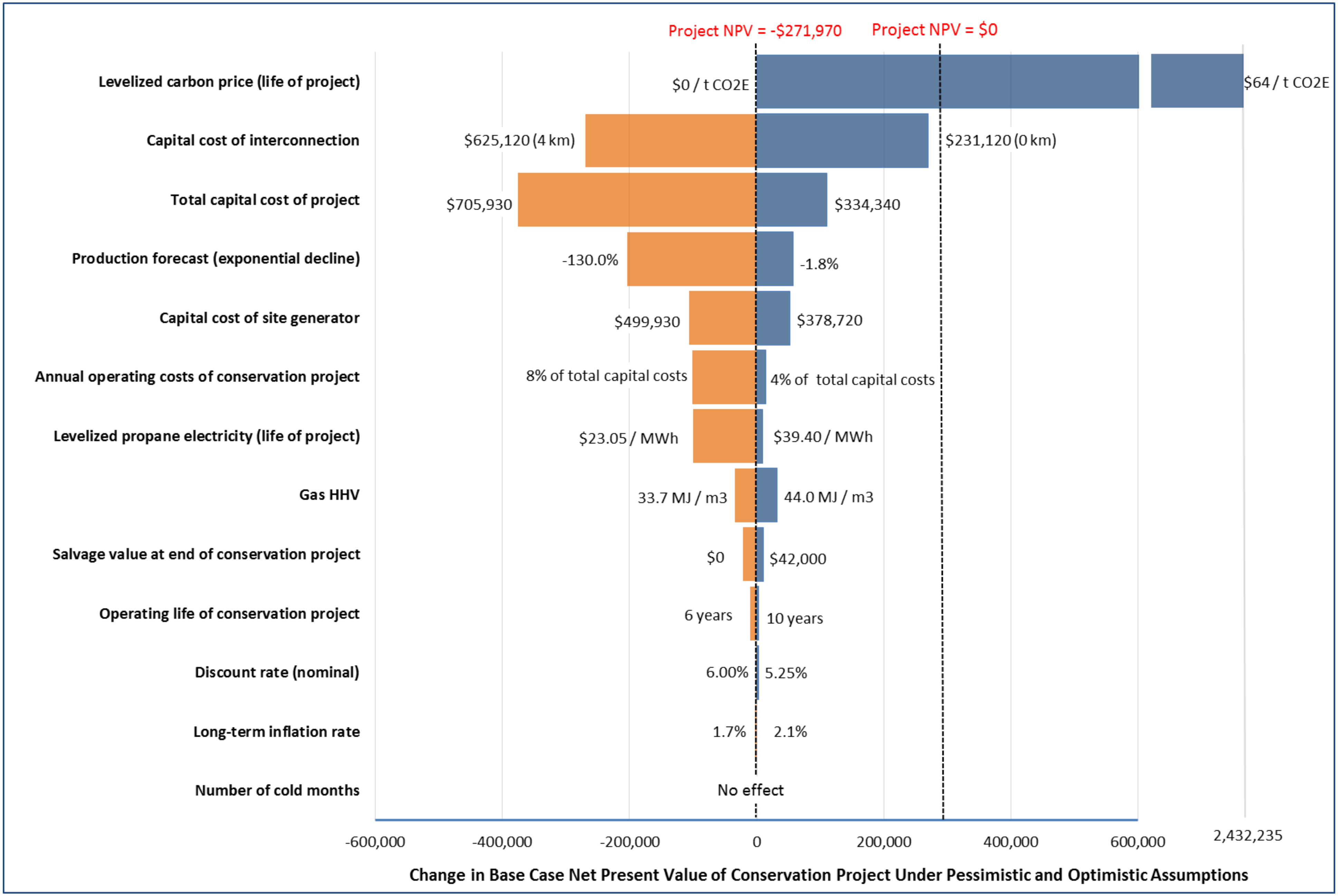

Figure 5: Tornado Chart Showing Impact of Upper and Lower Bound Input Values on NPV for generating power with excess casing gas.

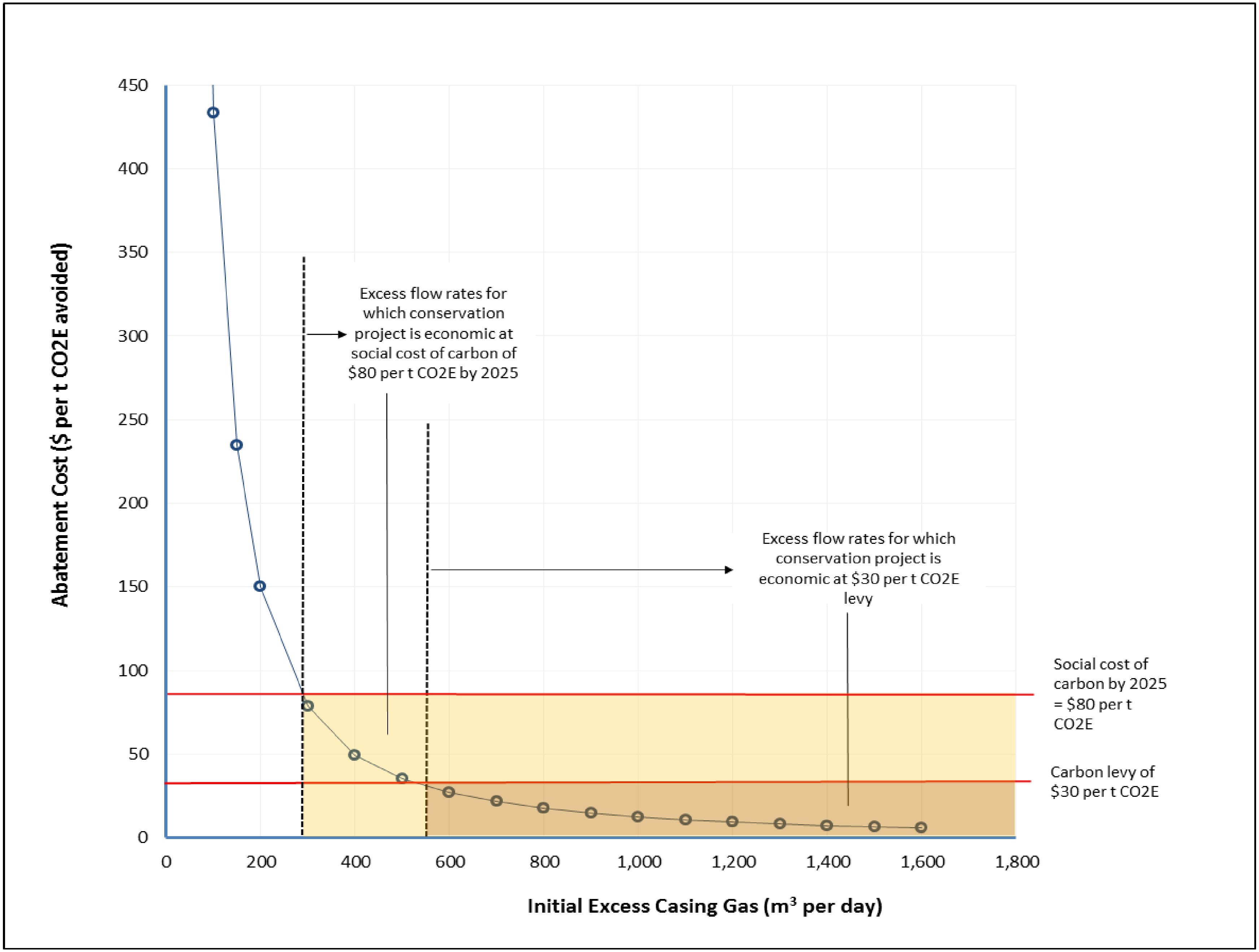

Figure 6: Average abatement cost as a function of initial excess casing gas when used for generating power.

Table 8: Evaluation of base-case Net Present Value (NPV) for generating power (royalty-out basis).									
Year	**Casing Gas Available at Site**	**Electricity Sales**	**Royalty Payments**	**Salvage Value**	**Total Net Project Benefits (discounted)**	**Net Capital Costs**	**Net Operating Costs**	**Total Net Project Costs (discounted)**	**Total Project Net Benefits (discounted)**
	($10^3 m^3$/ year)	**(MWh / year)**	**($ / year)**	**($)**	**($ / year)**	**($ / year)**	**($ / year)**	**($ / year)**	**($ / year)**
2015						419,120		419,120	-419,120
2016	730	1,316	0	0	47,235	0	19,256	18,218	29,017
2017	674	1,316	0	0	44,688	0	19,661	17,598	27,090
2018	622	1,232	0	0	39,565	0	20,074	16,998	22,567
2019	574	1,107	0	0	33,651	0	20,495	16,419	17,232
2020	530	992	0	0	28,535	0	20,926	15,860	12,675
2021	489	886	0	0	24,113	0	21,365	15,320	8,793
2022	452	789	0	0	20,294	0	21,814	14,798	5,496
2023	417	698	0	33,618	38,576	0	22,272	14,294	24,282
Total	4,488	8,337	0	33,616	276,656	419,120	165,863	548,625	-271,969

4.2 AUXILIARY BURNER AND HEAT TRACE

4.2.1 DESCRIPTION

Spartan Controls and REM Technology Inc. have developed the SlipStream® GTS vapour combustor emission control device. This technology combusts excess gas in an auxiliary burner installed in the tank heater exhaust stack as shown in Figure 7. The main burner combusts casing gas for normal tank heating duty but, as the name suggests, a pressure controlled slipstream is directed to the auxiliary burner. When casing line pressure drops below a set-point, the auxiliary burner is closed and all casing gas is flowed to the main burner. When no tank heating is needed, the GTS control system directs gas flow to the auxiliary burner. Thus, the system can modulate from zero excess gas up to a maximum of 21 m^3/hr flow to the auxiliary burner. A process flow rendering identifying basic components of the system is provided by Spartan Controls and presented in Figure 8. Key benefits include high combustion efficiency (99.9 percent) with no visible flame or additional stacks considered visually displeasing by landowners. Moreover, no changes to lease size or truck traffic patterns are required

An automated burner management system (BMS) with pilot gas to the main and auxiliary burners is installed to ensure safe and continuous combustion. The pressure control valve-train adds a small backpressure (~1.7 kPa) to the casing line and, in most cases, does not impact well production so no additional compression is required.

Gas conservation is achieved when excess heat is recovered from the auxiliary burner with a glycol heat exchanger and used to heat trace gas lines. During colder months, propane fuel is often used instead of casing gas to eliminate the risk of fuel supply freeze-off that would shut-in production. Freeze protecting gas lines allows for year round utilization of casing gas instead of propane fuel which is a direct economic benefit to the facility. Moreover, worst case GHG emissions occur when propane fuel is used instead of casing gas because the gas is vented instead of conserved. For example, a single 60 kW pump engine burns approximately 5,000 GJ of fuel per year. Using propane fuel instead of casing gas results in almost 2,200 t CO_2E of additional GHG emissions because of unnecessary venting (i.e., approximately 0.44 tonnes CO_2E are emitted per GJ of propane fuel burned).

GHG, capital cost and NPV results presented below are based on the installation of two SlipStream® units with one auxiliary burner outfitted with a heat exchanger and glycol loop for pipe heat tracing. The maximum volume of casing gas combusted by the auxiliary burners (2) is 1,008 m^3 per day.

Figure 7: Installation of a SlipStream® GTS control system and auxiliary burner (Spartan Controls).

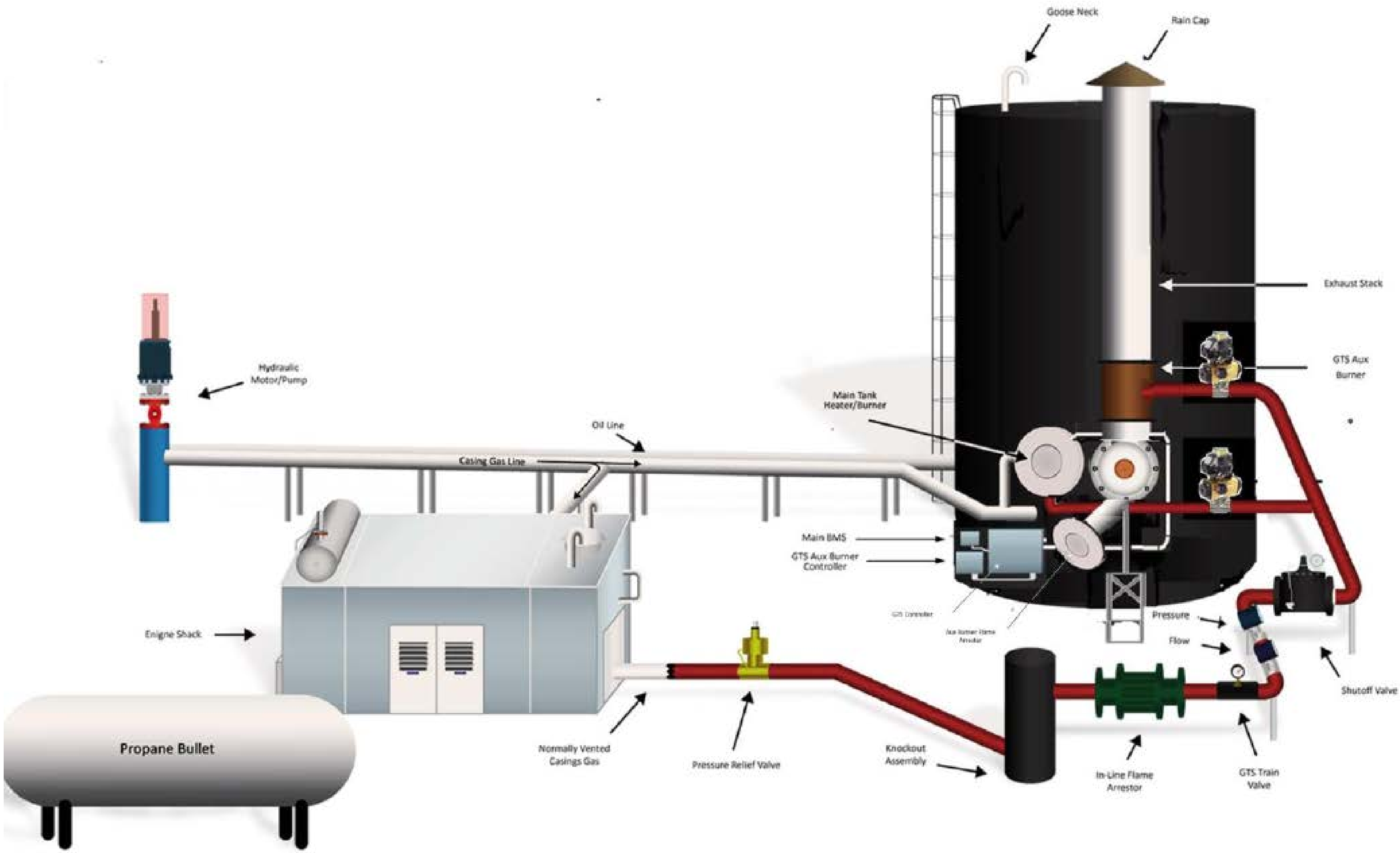

Figure 8: Process flow rendering for the SlipStream® GTS system installed at a heavy oil well-pad.

4.2.2 GHG EMISSION REDUCTIONS

Emission reductions occur when casing gas normally vented is combusted in the auxiliary burner or used, instead of propane, for site energy demands (provided waste heat from the auxiliary burners is successfully used to heat-trace lines during cold months). The SlipStream® GTS installation described above achieves an 81 percent reduction (47,951 t CO_2E) relative to baseline GHG emissions as shown in Table 9. When the battery begins production, the initial casing gas flow is 2,000 m^3 per day where 707 m^3 is used to fuel site energy demands; 1,008 m^3 is combusted in the auxiliary burners; and the remainder is vented (~295 m^3 per day). As production declines, venting goes to zero after two years and gas disposed in the burner decreases to approximately 440 m^3 per day after 8 years. Zero propane is used for site energy demands.

Table 9: Avoided GHG emissions for the SlipStream® GTS installation.

Year	Baseline GHG Emissions	Project Case				Avoided GHG Emissions
		Casing Gas Combusted	Casing Gas Vented	Propane Combusted	GHG Emissions	
	(t CO_2E/yr)	(10^3m^3/yr)		(GJ/yr)	(t CO_2E/yr)	(t CO_2E/yr)
2016	10,225	622	108	0	3,042	7,183
2017	9,291	622	51	0	2,108	7,183
2018	8,429	622	0	0	1,253	7,177
2019	7,634	574	0	0	1,156	6,477
2020	6,899	530	0	0	1,067	5,832
2021	6,221	489	0	0	985	5,236
2022	5,595	452	0	0	910	4,686
2023	5,018	417	0	0	840	4,178
Total	59,312	4,329	159	0	11,361	47,951

4.2.3 ECONOMIC ASSESSMENT AND SENSITIVITY

Although no products are sold, this technology generates cost savings by avoiding wintertime propane fuel consumption. However, this cost saving is small relative to the incremental lifecycle costs of the technology, resulting in a base-case NPV of negative $248,150 (on a royalties-in basis) and negative $231,135 (on a royalties-out basis). Complete results for the latter case are delineated in Table 10 for an eight year operating life (other input parameters are presented in appendix Figure 27). Estimated capital and installation costs under the base-case amount to $282,000 (details are presented in appendix Table 22). The sensitivity of NPV to upper and lower bounds for key input parameters is tested and results presented in the Figure 9 tornado chart.

As evident from Figure 9, project NPV is highly sensitive to the monetization of GHG emission reductions. Valuing GHG emission reductions at a levelized SCC of $64 per t CO_2E avoided increases the base-case project NPV by $2,478,725 to $2,247,600. If GHG emission reductions are monetized according the Alberta carbon levy schedule in column two of Table 6, the base-case project NPV increases by $1,009,520 to $778,385 (not shown in Figure 9).

The project NPV is also sensitive to assumptions relating to (in declining order of sensitivity): capital and installation costs; the number of cold months; the production forecast; annual operating costs; and the price of propane. However, the valuation of GHG emission reductions is the only input parameter that yields a positive project NPV when upper bound assumptions are adopted.

The average abatement cost for the conservation project is $4.82 per t CO_2E avoided. That is, for every tonne of CO_2E not released to the atmosphere as a result of the project the operator incurs an average cost of $4.82 (to purchase and install the technology). As shown in Figure 10, the average abatement cost (and project NPV) varies with the initial casing gas flow rate. For a site with an initial excess flow rate of 50 m^3 per day, average abatement costs are close to $700 per t CO_2E saved (NPV = negative $381,729), falling rapidly to just over $30 per t CO_2E saved (NPV = negative $274,460) for a site with an initial excess flow rate of 360 m^3 per day, and thereafter declining gradually to $5 per t CO_2E saved (NPV = negative $231,135) for a site with an initial excess flow rate of 1,500 m^3 per day. If a policy was implemented whereby a levy of $30 per t CO_2E was charged on venting emissions, this conservation project would be economic at sites with initial excess casing gas flow rates of about 360 m^3 per day or greater. Alternatively, if a performance standard was set on the basis of the social cost of carbon in 2025, the use of this conservation technology would be economic at sites with an initial casing gas flow rate around 208 m^3 per day or greater.

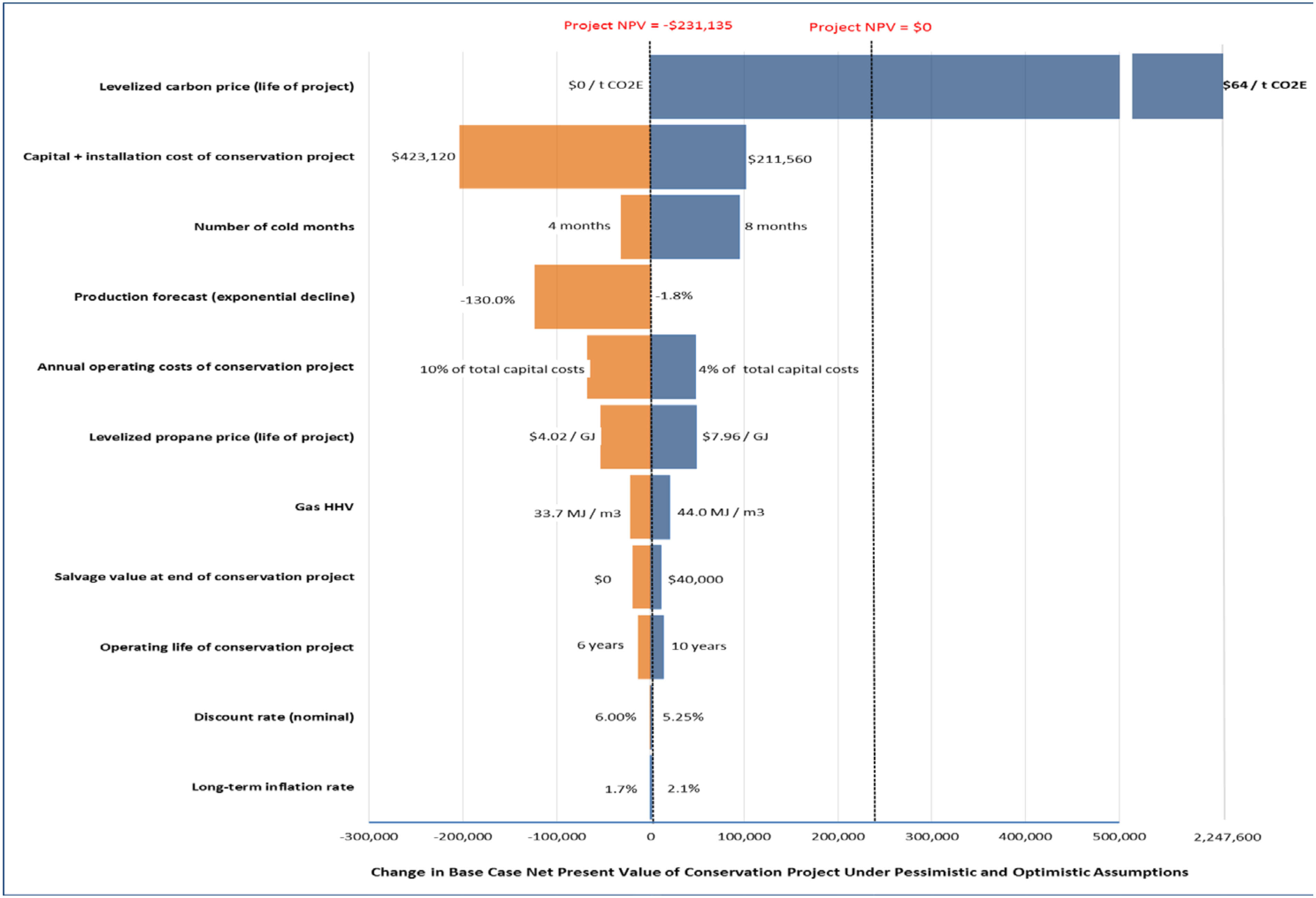

Figure 9: Tornado Chart Showing Impact of Upper and Lower Bound Input Values on NPV for the SlipStream® GTS.

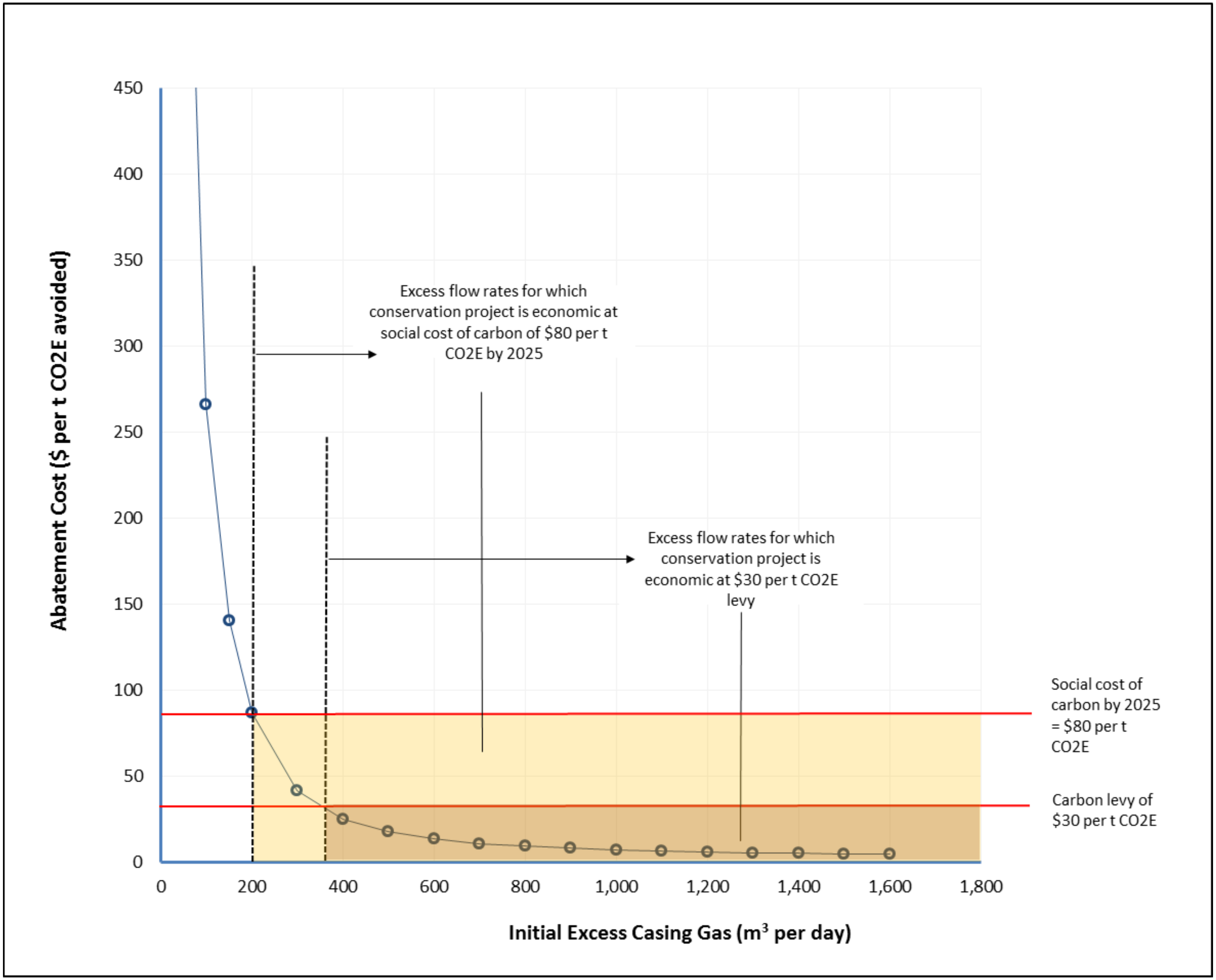

Figure 10: Average abatement cost as a function of initial excess casing gas for the SlipStream® GTS.

Table 10: Evaluation of base-case Net Present Value (NPV) for the SlipStream® GTS (royalties-out basis).											
Year	Casing Gas Available at Site	Propane Avoided	Levelized Propane Price	Avoided Fuel Purchases	Royalty Payments	Salvage Value	Total Net Project Benefits (discounted)	Net Capital Costs	Net Operating Costs	Total Net Project Costs (discounted)	Total Project Net Benefits (discounted)
	($10^3 m^3$/ year)	(GJ / year)	($ / GJ)	($ / year)	($ / year)	($)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)
2015								282,080		282,080	-282,080
2016	730	4,138	6.07	25,118	0	0	23,764		18,720	17,711	6,053
2017	674	4,138	6.07	25,118	0	0	22,482		19,113	17,108	5,375
2018	622	4,138	6.07	25,118	0	0	21,270		19,515	16,525	4,745
2019	574	4,138	6.07	25,118	0	0	20,123		19,925	15,962	4,161
2020	530	4,138	6.07	25,118	0	0	19,038		20,343	15,418	3,619
2021	489	4,138	6.07	25,118	0	0	18,011		20,770	14,893	3,118
2022	452	4,138	6.07	25,118	0	0	17,040		21,206	14,386	2,654
2023	417	4,138	6.07	25,118	0	29,599	35,117		21,652	13,896	21,221
Total	4,488	33,104		200,945	0	29,599	176,844	282,080	161,244	407,979	-231,135

4.3 CATALYTIC LINE HEATERS

4.3.1 DESCRIPTION

Scott Can Industries Ltd. developed and manufactures AURORA heat-tracing units that utilize casing gas fuel. The heat tracing loop is installed on casing gas lines, as presented in Figure 12, to minimize water condensation, ice blockages and wintertime reliance on propane fuel. A 12” x 24” catalytic heater is used to heat a methanol-based working fluid contained in the constant volume exchanger presented in Figure 11. When the fluid boils a pressure-set valve opens, forcing the working fluid into the heat trace loop. As the fluid travels through the loop, it cools, condenses and returns to the reservoir located above the exchanger. This cycle is repeated and maintains circulation in a 20 meter heat-trace loop without an electric or pneumatic pump. The unit startup and operating characteristics are similar to those described for catalytic converter discussed above. The units are designed for Class I Div I hazardous areas and can be located close to the wellhead or production tanks.

Figure 11: AURORA heat exchanger and methanol reservoir (Scott Can Industries Ltd.)

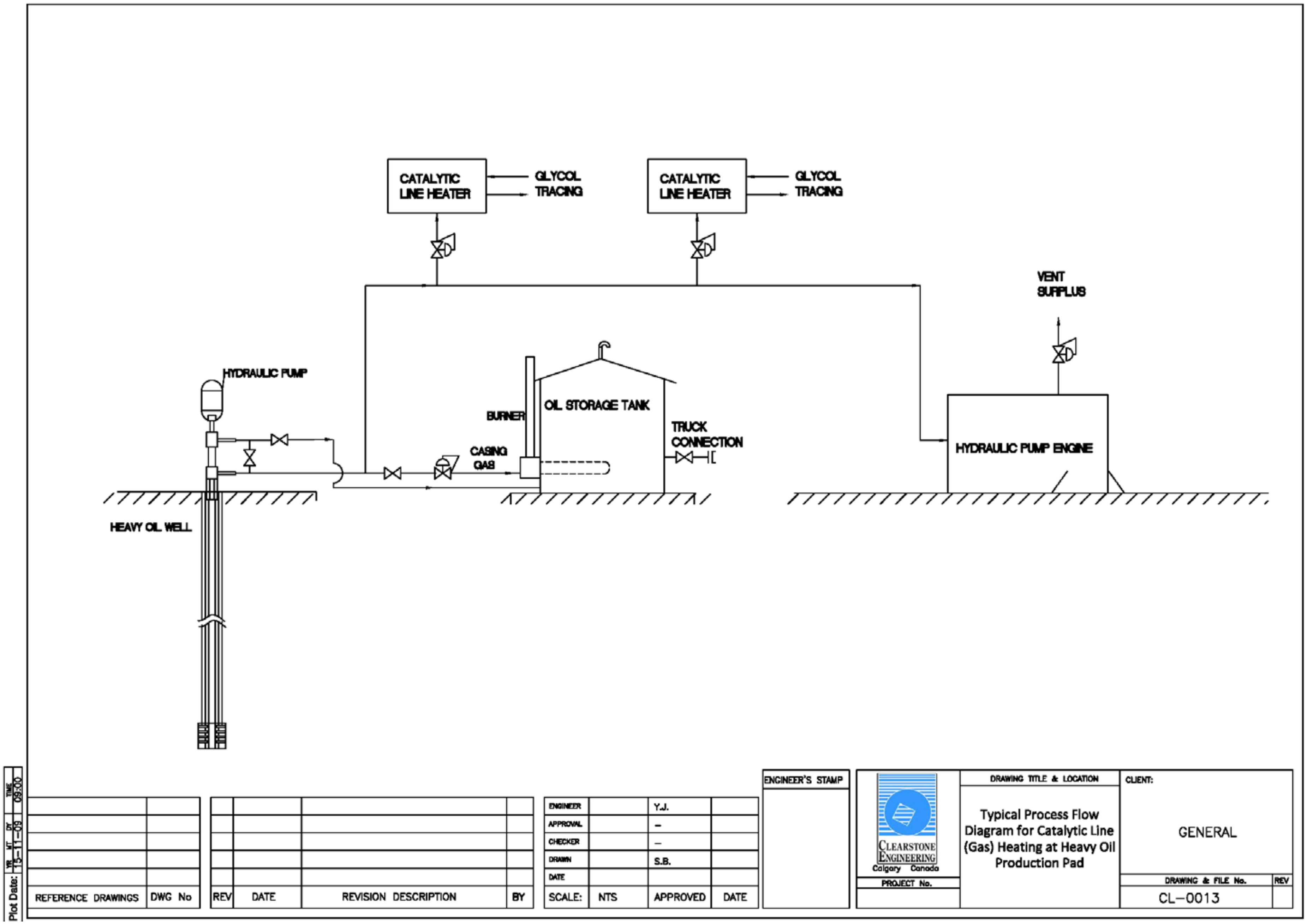

Figure 12: Process flow diagram for catalytic line heating at a heavy oil well-pad.

The units consume about 6.5 m^3 per day and enable about 700 m^3 of casing gas fuel use during cold months so the installation of four units at a battery reduces venting by about 115 10^3 m^3 per year. Ideally, these units would complement other gas conversion equipment as a low-cost means of freeze protection.

4.3.2 GHG EMISSION REDUCTIONS

Emission reductions occur because casing gas line heaters enable the use of this gas for site energy demands during cold months (instead of propane). Additional reductions occur because the line heaters consume a small amount of casing gas that would otherwise be vented. Combined emission reductions are about 15,317 t CO_2E (26 percent) relative to baseline GHG emissions as shown in Table 11. Zero propane is used for site energy demands.

Table 11: Avoided GHG emissions for the catalytic line heater installation.

Year	Baseline GHG Emissions	Project Case				Avoided GHG Emissions
		Casing Gas Combusted	Casing Gas Vented	Propane Combusted	GHG Emissions	
	(t CO_2E/yr)	($10^3 m^3$/yr)		(GJ/yr)	(t CO_2E/yr)	(t CO_2E/yr)
2016	10,225	264	466	0	8,310	1,919
2017	9,291	264	410	0	7,377	1,919
2018	8,429	264	358	0	6,515	1,919
2019	7,634	264	310	0	5,719	1,919
2020	6,899	264	266	0	4,985	1,919
2021	6,221	264	225	0	4,307	1,919
2022	5,595	264	188	0	3,681	1,919
2023	5,018	264	153	0	3,103	1,919
Total	59,312	2,113	2,376	0	43,996	15,317

4.3.3 ECONOMIC ASSESSMENT AND SENSITIVITY

This technology generates revenue by avoiding wintertime propane fuel consumption which is sufficient for a NPV of positive $92,425 (on a royalties-in basis) and $97,315 (on a royalties-out basis). Complete results (royalty-in basis) are delineated in Table 12 for an eight year operating life. Input parameters are presented in appendix Figure 29 with details of capital and installation costs (base-case of $39,070) presented in appendix Table 24.

As evident from the Figure 13 tornado chart, project NPV is highly sensitive to the monetization of GHG emission reductions. Valuing GHG emission reductions at a levelized SCC of $64 per t CO_2E avoided increases the base-case project NPV by $681,700 to $774,100.

The project NPV is also sensitive to assumptions relating to (in declining order of sensitivity): capital and installation costs; the number of cold months; the rate of decline; the price of propane, operating life of the project, gas HHV and annual operating costs.

There are no abatement costs for this project. Indeed, using casing gas instead of propane fuel earns the owner \$6 for every t CO_2E avoided when initial excess gas is greater than 700 m^3 per day. As shown in Figure 14, average abatement costs are still significant for sites with little initial excess casing gas (and propane is required to meet site energy demands). If a performance standard was based on the social cost of carbon in 2025 (\$81/t CO_2E), this conservation approach would be economic at sites with initial casing gas flows greater than 60 m^3 per day. If a carbon levy of \$30 per t CO_2E was applied, this technology would be economical for sites with initial excess casing gas of 102 m^3 per day or greater. Initial flows below these thresholds offset very little propane fuel.

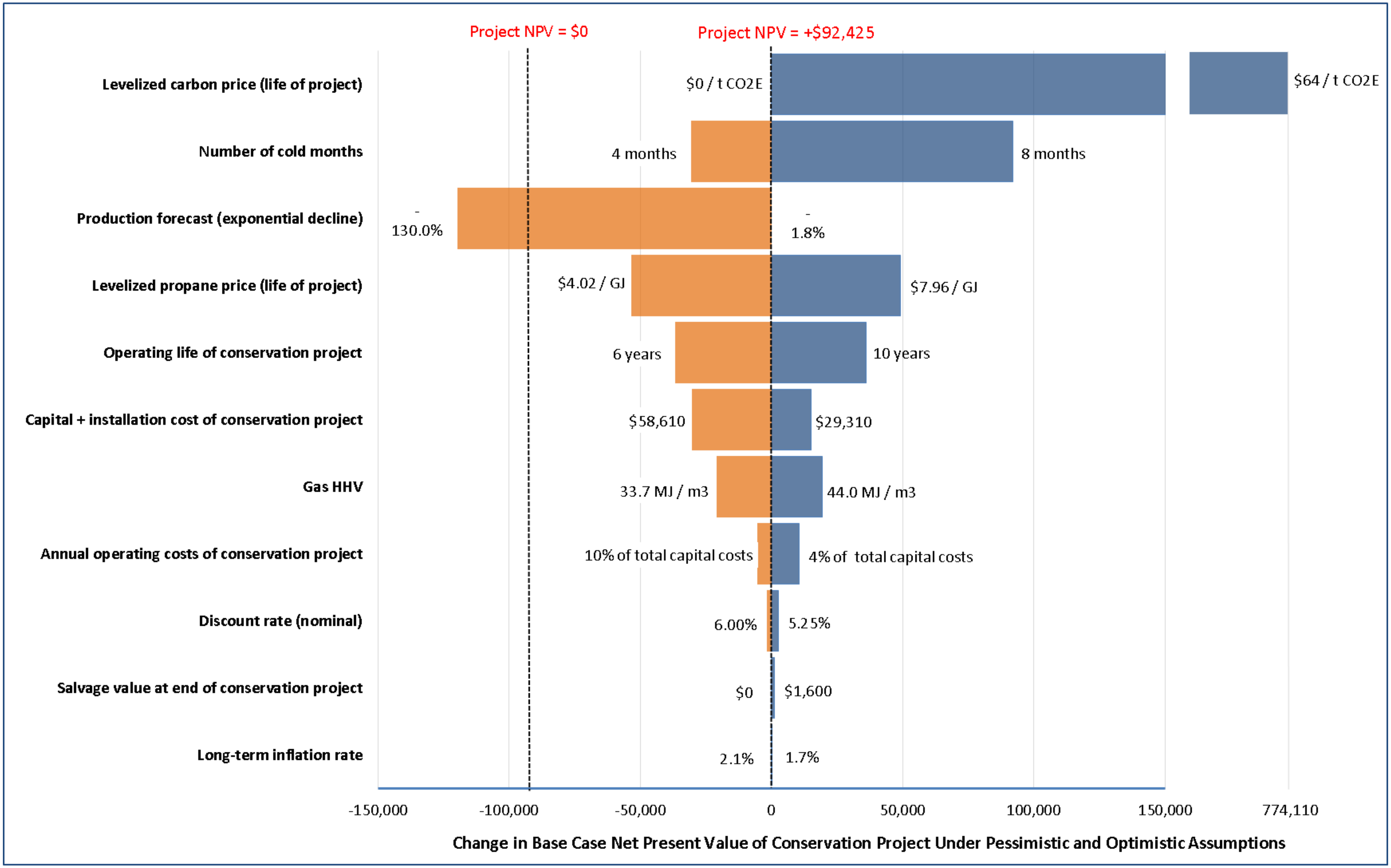

Figure 13: Tornado Chart Showing Impact of Upper and Lower Bound Input Values on NPV for catalytic line heaters.

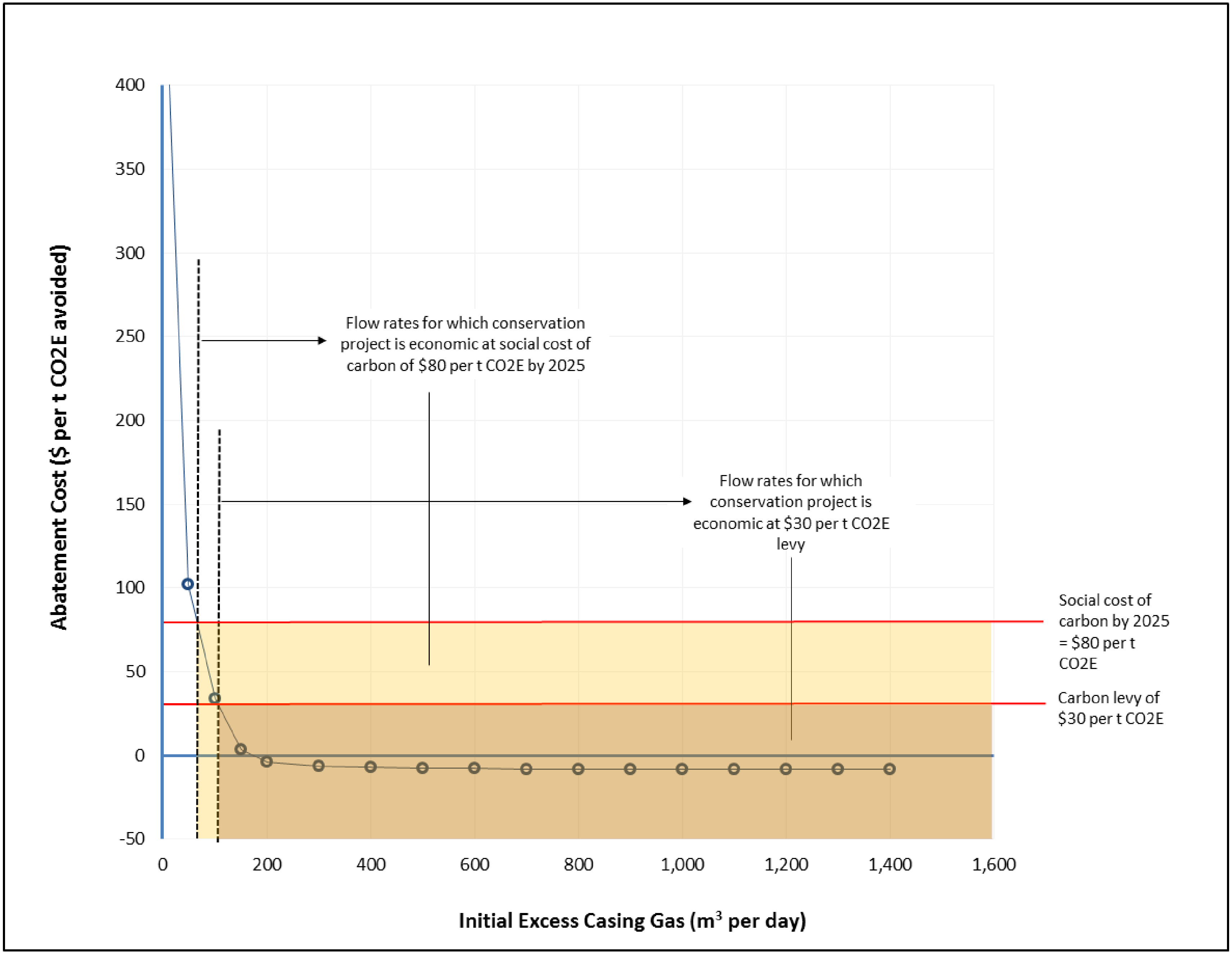

Figure 14: Average abatement cost as a function of initial excess casing gas for catalytic line heaters.

Table 12: Evaluation of base-case Net Present Value (NPV) for catalytic line heaters (royalties-in basis).											
Year	**Casing Gas Available at Site**	**Propane Avoided**	**Levelized Propane Price**	**Avoided Fuel Purchases**	**Royalty Payments**	**Salvage Value**	**Total Net Project Benefits (discounted)**	**Net Capital Costs**	**Net Operating Costs**	**Total Net Project Costs (discounted)**	**Total Project Net Benefits (discounted)**
	($10^3 m^3$/ year)	**(GJ / year)**	**($ / GJ)**	**($ / year)**	**($ / year)**	**($)**	**($ / year)**	**($ / year)**	**($ / year)**	**($ / year)**	**($ / year)**
2015								39,070		39,070	-39,070
2016	730	4,138	6.07	25,118	778	0	23,027		3,191	3,019	20,008
2017	674	4,138	6.07	25,118	778	0	21,786		3,258	2,916	18,869
2018	622	4,138	6.07	25,118	778	0	20,611		3,327	2,817	17,794
2019	574	4,138	6.07	25,118	778	0	19,499		3,397	2,721	16,778
2020	530	4,138	6.07	25,118	778	0	18,448		3,468	2,628	15,819
2021	489	4,138	6.07	25,118	778	0	17,453		3,541	2,539	14,914
2022	452	4,138	6.07	25,118	778	0	16,512		3,615	2,452	14,059
2023	417	4,138	6.07	25,118	778	0	15,621		3,691	2,369	13,253
Total	4,488	33,104		200,945	6,225	0	152,957	39,070	27,487	60,532	92,425

4.4 CATALYTIC CONVERSION

4.4.1 DESCRIPTION

For sites with little excess casing gas, catalytic conversion of methane to carbon dioxide is a plausible option for reducing GHG emissions. Units designed to convert 55 m^3/day were developed and field tested by New Paradigm Engineering Ltd. The unit shown in Figure 15 is simple and modular. Multiple units can be deployed at a single pad to match excess casing gas flows and moved to other pads as flows change. No lease area changes are required because the units are designed for Class I Div I hazardous areas and can be located close to the wellhead or production tanks.

The unit shown in Figure 15 is manufactured by Scott Can Industries Ltd. and features four catalytic pads plus a small pilot pad (with a direct current electric heating element for unit startup). Power for startup can be from a truck battery or small portable generator. Once the pad temperature is high enough to start the catalytic reaction, pilot gas is supplied. After the pilot catalytic heater is running (normally about 15 minutes), gas is supplied to the main unit and the catalytic reaction propagates from the pilot to the other pads. The unit will self-regulate with variable gas flows as long as the pilot gas flow doesn't stop. Thus, flow controls, shown in the Figure 16 PFD, preferentially supply pilot gas to ensure reliable operation of the pilot pad.

Figure 15: Field installation of a catalytic conversion unit (New Paradigm Engineering Ltd).

Research at the University of Alberta confirmed catalytic converter destruction is not impacted by the presence of water vapour in the fuel however it decreases if liquid water wets the catalyst pad or if oxygen supply is restricted (Hayes et al., 2010). Therefore, fuel gas supply lines are winterized to avoid water condensation and freeze-off by utilizing excess heat from pump engines. The short distance of pipe from the engine to the catalytic converter is heat traced with engine coolant, insulated and equipped with a water trap and drain. Heat from the catalytic reaction prevents piping freeze-off within the enclosure. Units are also equipped heat driven fans and are titled to promote oxygen distribution. A methane destruction efficiency of 80 percent (Hayes et al., 2010) is used for GHG and economic calculations.

4.4.2 GHG EMISSION REDUCTIONS

Emission reductions occur when casing gas normally vented is converted to CO_2 in the catalytic conversion units. The installation described above achieves a 6 percent reduction (3,769 t CO_2E) relative to baseline GHG emissions as shown in Table 13. Emission reductions are constrained by the maximum catalytic throughput of 110 m^3 per day which is well below initial casing gas flow of 1,500 m^3 per day. Ideally, catalytic converters would be installed at sites with very low flows (i.e., less than 220 m^3 per day) and moved from site to site according to declining gas production. It's possible to increase throughput by installing more units and achieve greater emissions reductions, however, capital costs would increase accordingly with little change to NPV outcomes.

Table 13: Avoided GHG emissions for a catalytic conversion unit.

Year	Baseline GHG Emissions	Project Case				Avoided GHG Emissions
		Casing Gas Converted	Casing Gas Vented	Propane Combusted	GHG Emissions	
	(t CO_2E/yr)	($10^3 m^3$/yr)		(GJ/yr)	(t CO_2E/yr)	(t CO_2E/yr)
2016	10,225	189	541	4,138	9,754	471
2017	9,291	189	485	4,138	8,820	471
2018	8,429	189	433	4,138	7,958	471
2019	7,634	189	386	4,138	7,163	471
2020	6,899	189	341	4,138	6,428	471
2021	6,221	189	301	4,138	5,750	471
2022	5,595	189	263	4,138	5,124	471
2023	5,018	189	228	4,138	4,547	471
Total	59,312	1,509	2,979	33,104	55,544	3,769

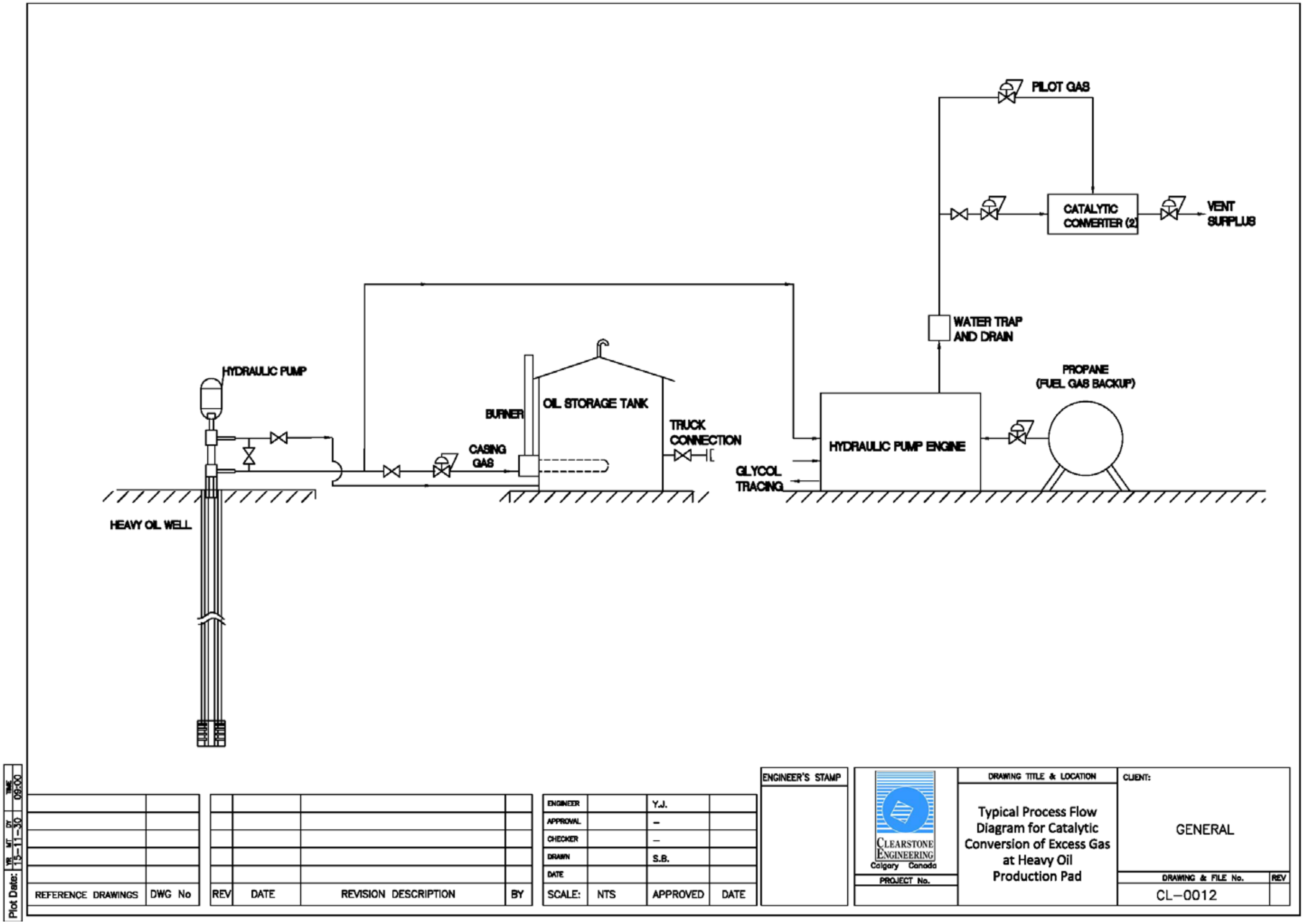

Figure 16: Process flow diagram for catalytic conversion at a heavy oil well-pad.

4.4.3 ECONOMIC ASSESSMENT AND SENSITIVITY

This technology does not generate revenue and will always have a negative NPV unless the benefit of GHG reductions is monetized. The base-case NPV equals negative $73,310 (on a royalties-out basis) with complete results delineated in Table 14 for an eight year operating life. Input parameters are presented in appendix Figure 28 with details of capital and installation costs (base-case of $49,540) presented in appendix Table 23.

As evident from the Figure 17 tornado chart, project NPV is highly sensitive to the monetization of GHG emission reductions. Valuing GHG emission reductions at a levelized SCC of $64 per t CO_2E avoided (derived from column two in Table 5) increases the base-case project NPV by $265,800 to $190,500. The project NPV is also sensitive to assumptions relating to (in declining order of sensitivity): capital and installation costs; annual operating costs; and operating life. However, the valuation of GHG emission reductions is the only input parameter that yields a positive project NPV when upper bound assumptions are adopted.

The average abatement cost for this project is $20 per t CO_2E avoided. Abatement costs vary with flow as shown in Figure 18. However, because catalytic throughput is small (110 m^3 per day) relative to excess casing gas initially available onsite (1,500 m^3 per day), the average abatement cost (and project NPV) does not vary until excess casing gas falls below 400 m^3 per day. If a performance standard was based on the social cost of carbon in 2025 ($81/t CO_2E), this conversion technology would be economic at sites with initial casing gas flows greater than 83 m^3 per day. In a carbon levy of $30 per t CO_2E was applied, this technology would be economical for sites with initial excess casing gas of 233 m^3 per day or greater.

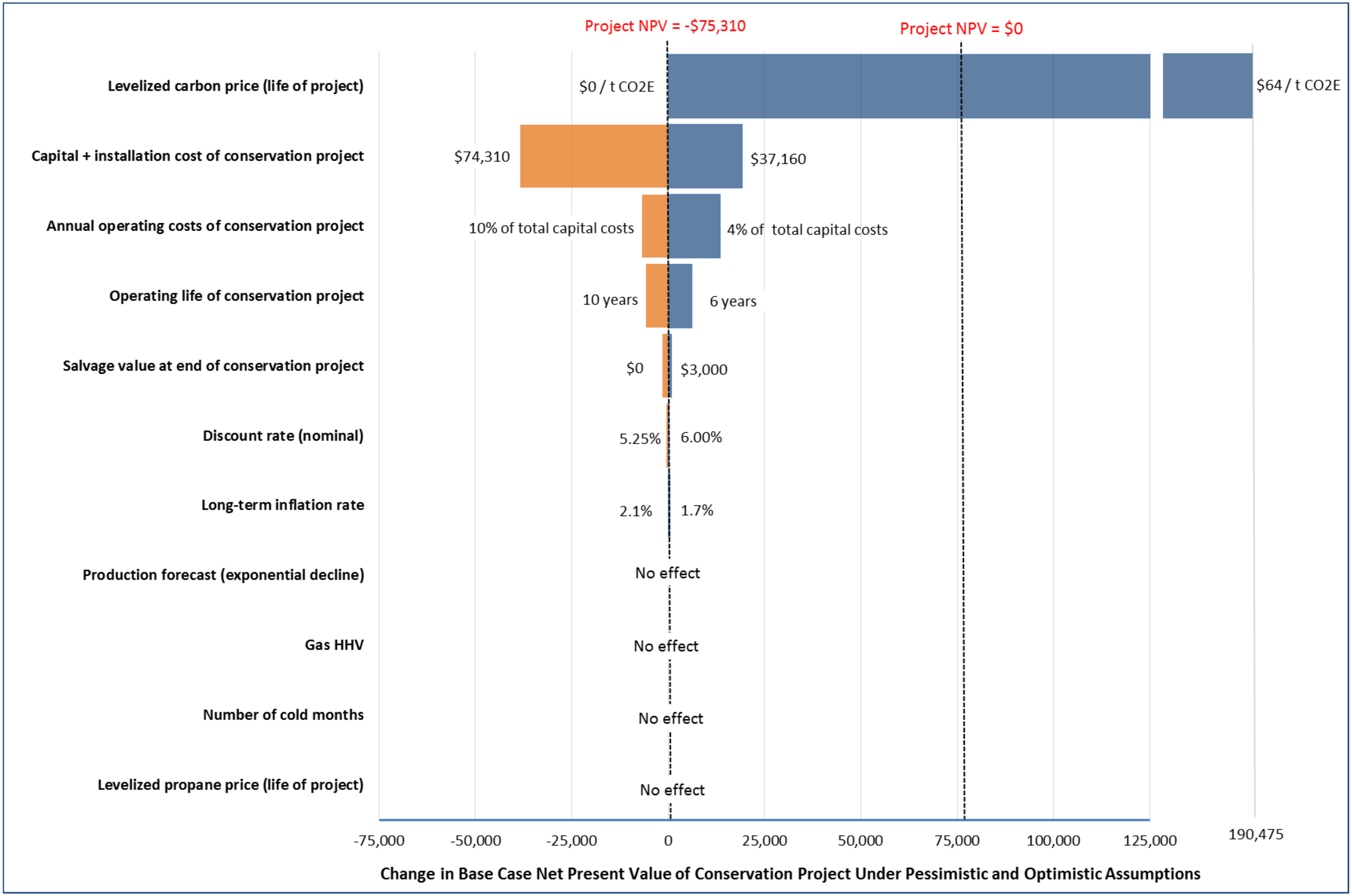

Figure 17: Tornado Chart Showing Impact of Upper and Lower Bound Input Values on NPV for a catalytic conversion unit.

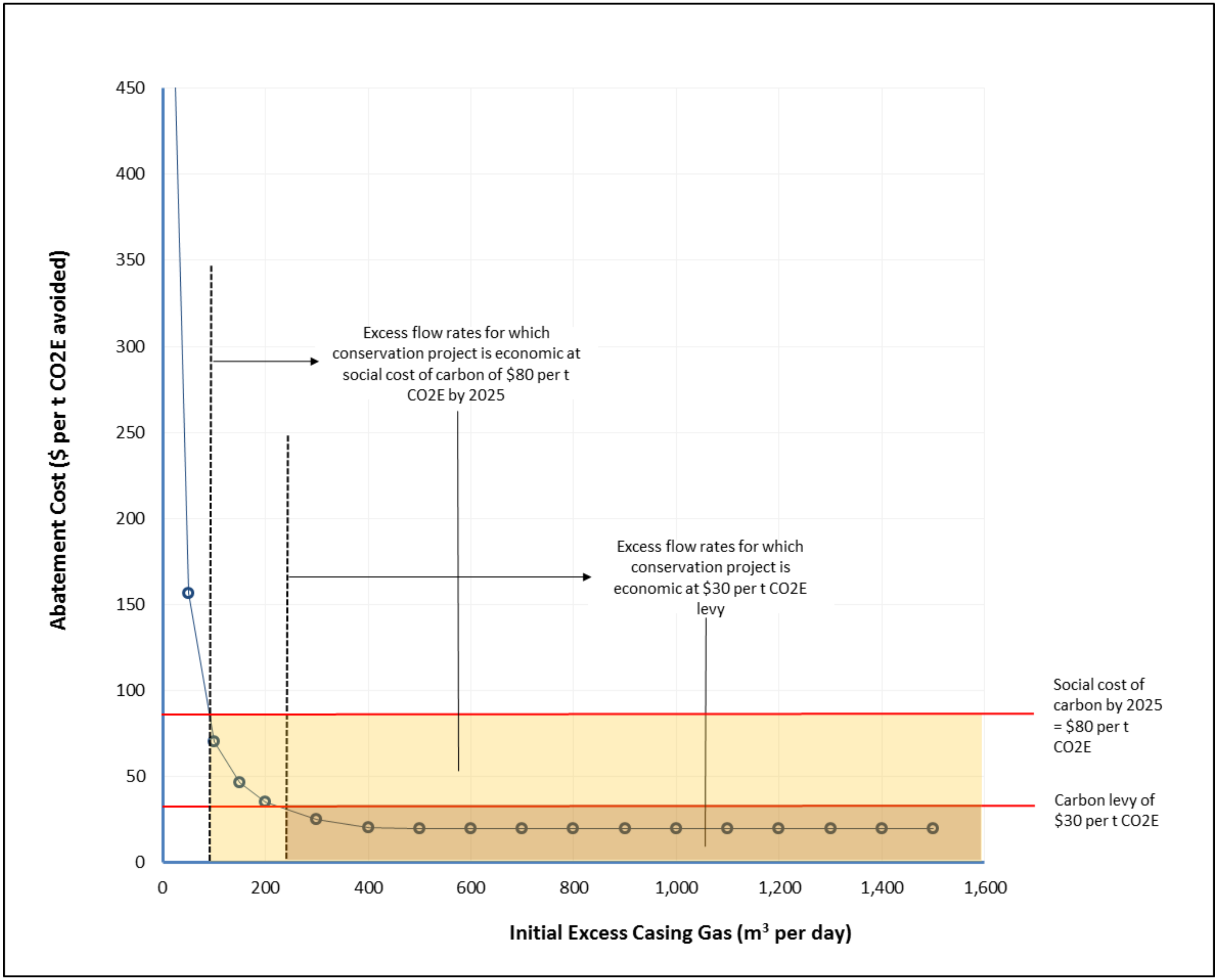

Figure 18: Average abatement cost as a function of initial excess casing gas for a catalytic conversion unit.

Table 14: Evaluation of base-case Net Present Value (NPV) for a catalytic conversion unit (royalty-out basis).									
Year	**Casing Gas Available at Site**	**Propane Avoided**	**Royalty Payments**	**Salvage Value**	**Total Net Project Benefits (discounted)**	**Net Capital Costs**	**Net Operating Costs**	**Total Net Project Costs (discounted)**	**Total Project Net Benefits (discounted)**
	($10^3 m^3$/ year)	**(GJ / year)**	**($ / year)**	**($)**	**($ / year)**	**($ / year)**	**($ / year)**	**($ / year)**	**($ / year)**
2015						49,540		49,540	-49,540
2016	730	0	0	0	0		4,046	3,828	-3,828
2017	674	0	0	0	0		4,131	3,698	-3,698
2018	622	0	0	0	0		4,218	3,572	-3,572
2019	574	0	0	0	0		4,307	3,450	-3,450
2020	530	0	0	0	0		4,397	3,333	-3,333
2021	489	0	0	0	0		4,490	3,219	-3,219
2022	452	0	0	0	0		4,584	3,110	-3,110
2023	417	0	0	2,250	2,250		4,680	3,004	-1,560
Total	4,488	0	0	2,250	2,250	49,540	34,853	76,753	-75,310

4.5 FLARING

4.5.1 DESCRIPTION

Open-flame and shielded flares are a common method of disposing continuous and intermittent waste gas streams. The stack selected for this study is 12.2 meters high with a 76 mm (3 inch) tip diameter and meets performance standards specified in AER Directive 060 Section 7. It's designed for continuous flow of 2,000 m^3 per day with provision for a maximum flow of 34,000 m^3 per day. Propane purge gas (0.17 m^3 per hour) is supplied to the flare header to prevent air ingress at the flare tip during low and no flow conditions while a solar powered spark ignitor provides a continuous ignition source. As shown in Figure 19, liquids entrained in the gas flow are separated at a knock-out drum integrated into the base of the flare stack and accumulated liquids are trucked-out. The flare lines and knock-out are heat traced and insulated to prevent freeze-off. An in-line detonation arrestor is installed immediately upstream of the stack to safe guard against explosions. The stack must be located at least 25 meters from crude bitumen wells and storage tanks which may require larger lease areas and changes to truck traffic patterns.

A simple process flow diagram identifying basic system components is presented in Figure 20.

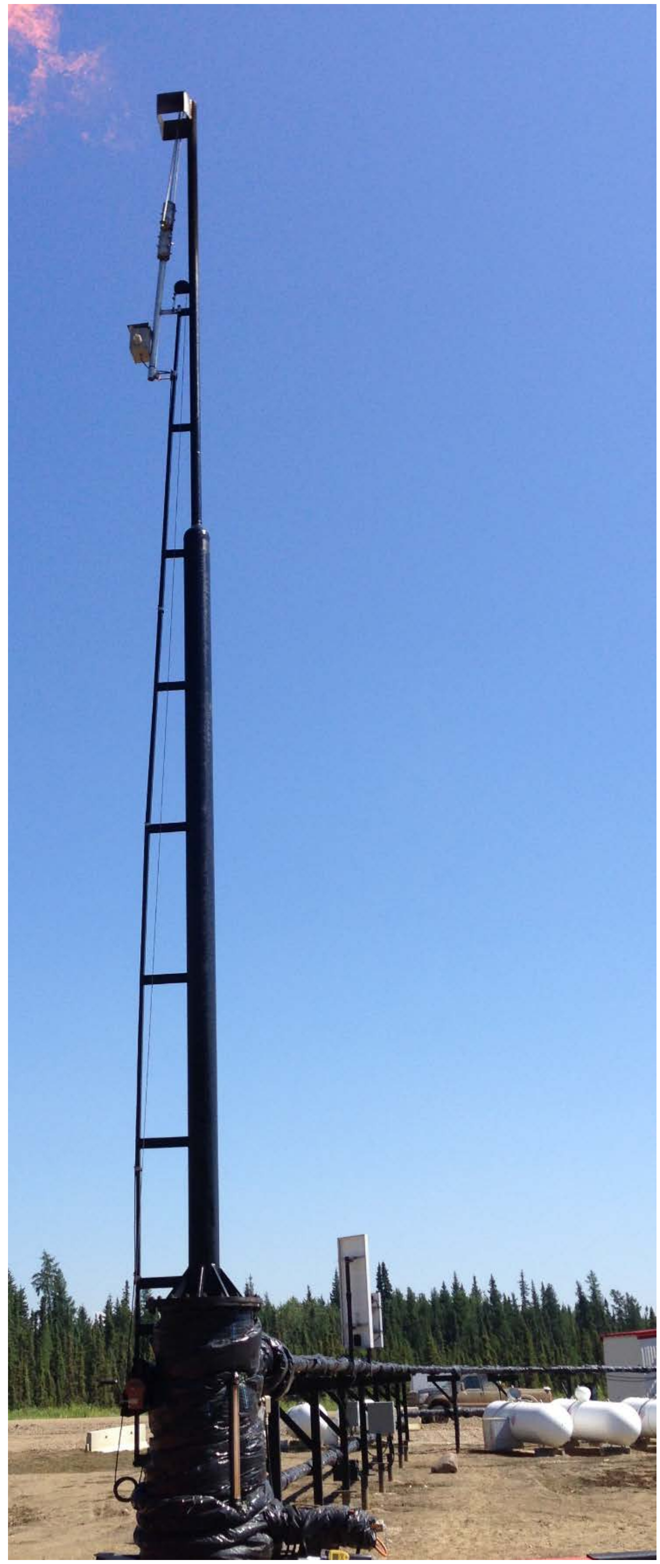

Figure 19: A shielded-flame flare stack with integral knock-out drum.

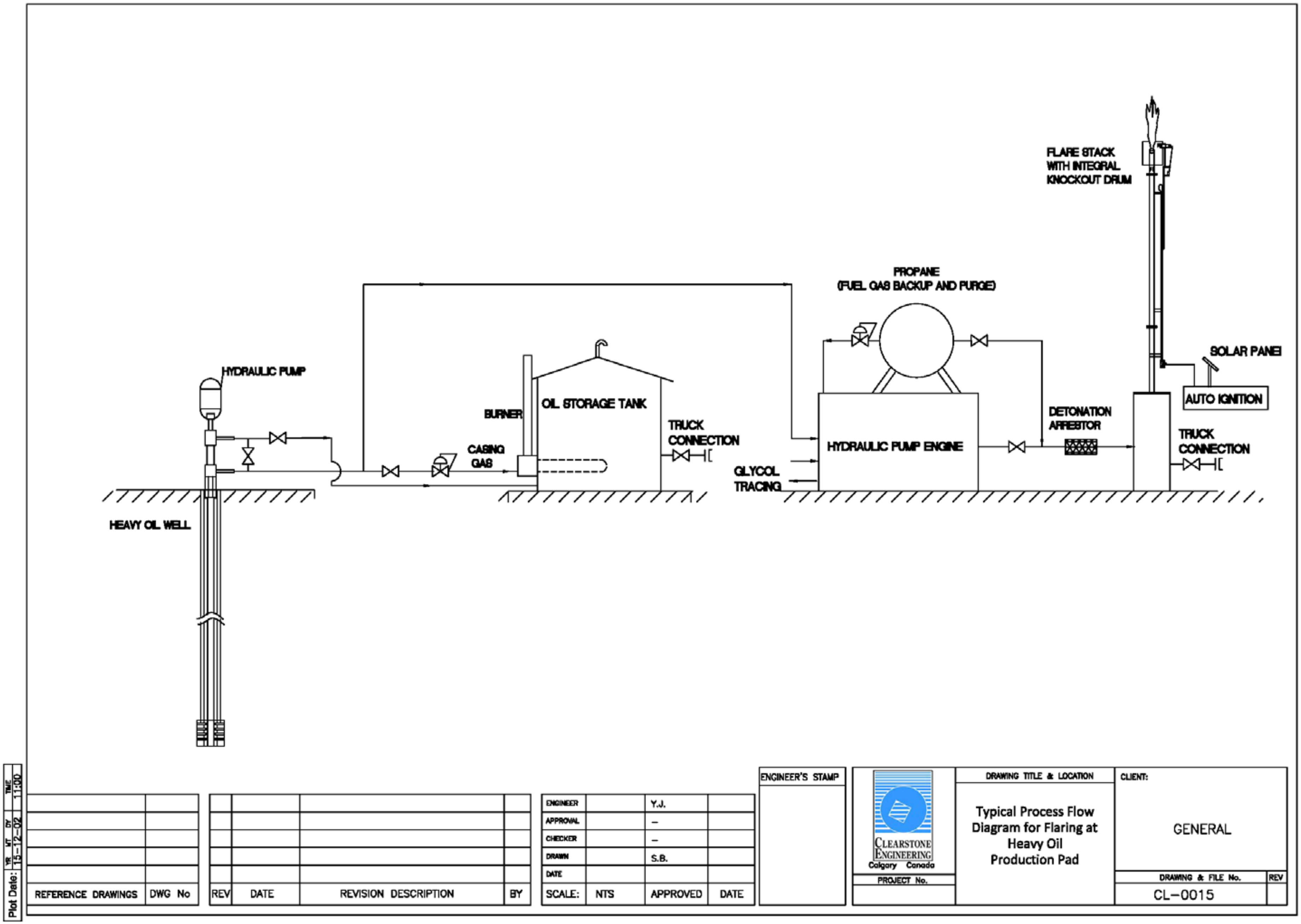

Figure 20: Process flow diagram for flaring at a heavy oil well-pad.

4.5.2 GHG EMISSION REDUCTIONS

Combusting excess casing gas in a flare stack instead of venting reduces GHG emissions by 80 percent (47,421 t CO_2E) relative to baseline GHG emissions as shown in Table 15. Project case emissions are otherwise the same as baseline emissions except propane purge gas is combusted with casing gas in the flare stack. This scenario doesn't investigate any other options to utilize casing gas.

Given the maximum flaring design capacity of 34,000 m^3 per day and supply of propane purge gas, the flare should be able to safely combust high and low flow fluctuations in daily casing gas availability. A combustion efficiency of 98 percent is used in the mass balance for determining CO_2 and CH_4 emissions (Environment Canada, 2014). Although efficiency can improve as the exit velocity and heating value of the gas increase, and then decrease when soot formation (black smoke), unstable combustion (exit velocity less than 1 m/s) and/or lift-off of the flame from the flare tip start to occur.

Table 15: Avoided GHG emissions when flaring excess casing gas.

Year	Baseline GHG Emissions	Project Case				Avoided GHG Emissions
		Casing Gas Combusted	Casing Gas Flared	Propane Combusted	GHG Emissions	
	(t CO_2E/yr)	(10^3m^3/yr)		(GJ/yr)	(t CO_2E/yr)	(t CO_2E/yr)
2016	10,225	149	581	4,278	1,866	8,359
2017	9,291	149	525	4,278	1,740	7,551
2018	8,429	149	474	4,278	1,623	6,806
2019	7,634	149	426	4,278	1,516	6,118
2020	6,899	149	382	4,278	1,417	5,482
2021	6,221	149	341	4,278	1,325	4,896
2022	5,595	149	303	4,278	1,241	4,355
2023	5,018	149	268	4,278	1,163	3,855
Total	59,312	1,188	3,330	34,223	11,891	47,421

4.5.3 ECONOMIC ASSESSMENT AND SENSITIVITY

Flaring does not generate revenue and will always have a negative NPV unless the benefit of GHG reductions is monetized. The base-case NPV equals negative $167,268 (on a royalties-in basis) and negative $149,261 (on a royalties-out basis) with complete results for the latter delineated in Table 16 for an eight year operating life. Input parameters are presented in appendix Figure 30 with details of capital and installation costs (base-case of $95,580) presented in appendix Table 25.

As evident from the Figure 21 tornado chart, project NPV is highly sensitive to the monetization of GHG emission reductions. Valuing GHG emission reductions at a levelized SCC of $64 per t CO_2E avoided increases the base-case project NPV by $2,621,000 to $2,472,000. The project NPV is also sensitive to assumptions relating to (in declining order of sensitivity): capital and installation costs; annual operating costs; and operating life. However, the valuation of GHG emission reductions is the only input parameter that yields a positive project NPV when upper bound assumptions are adopted.

The average abatement cost for this project is $3.15 per t CO_2E avoided. That is, for every tonne of CO_2E not released to the atmosphere as a result of the project the operator incurs an average cost of $3.15 (to purchase and install the technology). Because the flare can dispose flow rates much greater than the project case, the average abatement cost decreases as flow rates increase. For example, the average abatement cost would be $0.49 per t CO_2E avoided if flaring increased to 10,000 m^3 per day. If a performance standard was based on the social cost of carbon in 2025 ($81/t CO_2E), flaring would be economic at sites with initial casing gas flows greater than 139 m^3 per day. If a carbon levy of $30 per t CO_2E was applied, flaring would be economical for sites with initial excess casing gas of 263 m^3 per day or greater.

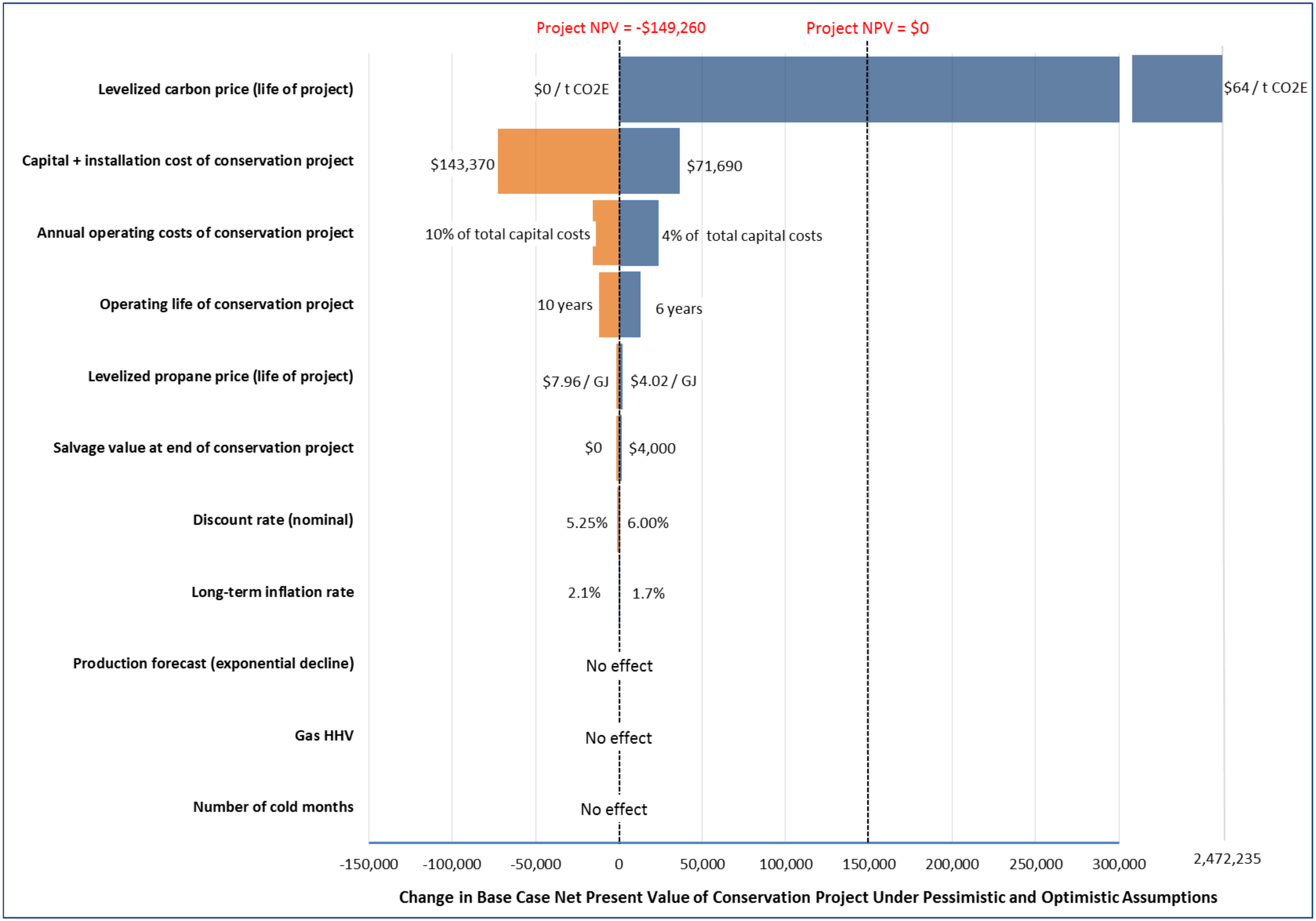

Figure 21: Tornado Chart Showing Impact of Upper and Lower Bound Input Values on NPV for flaring excess casing gas.

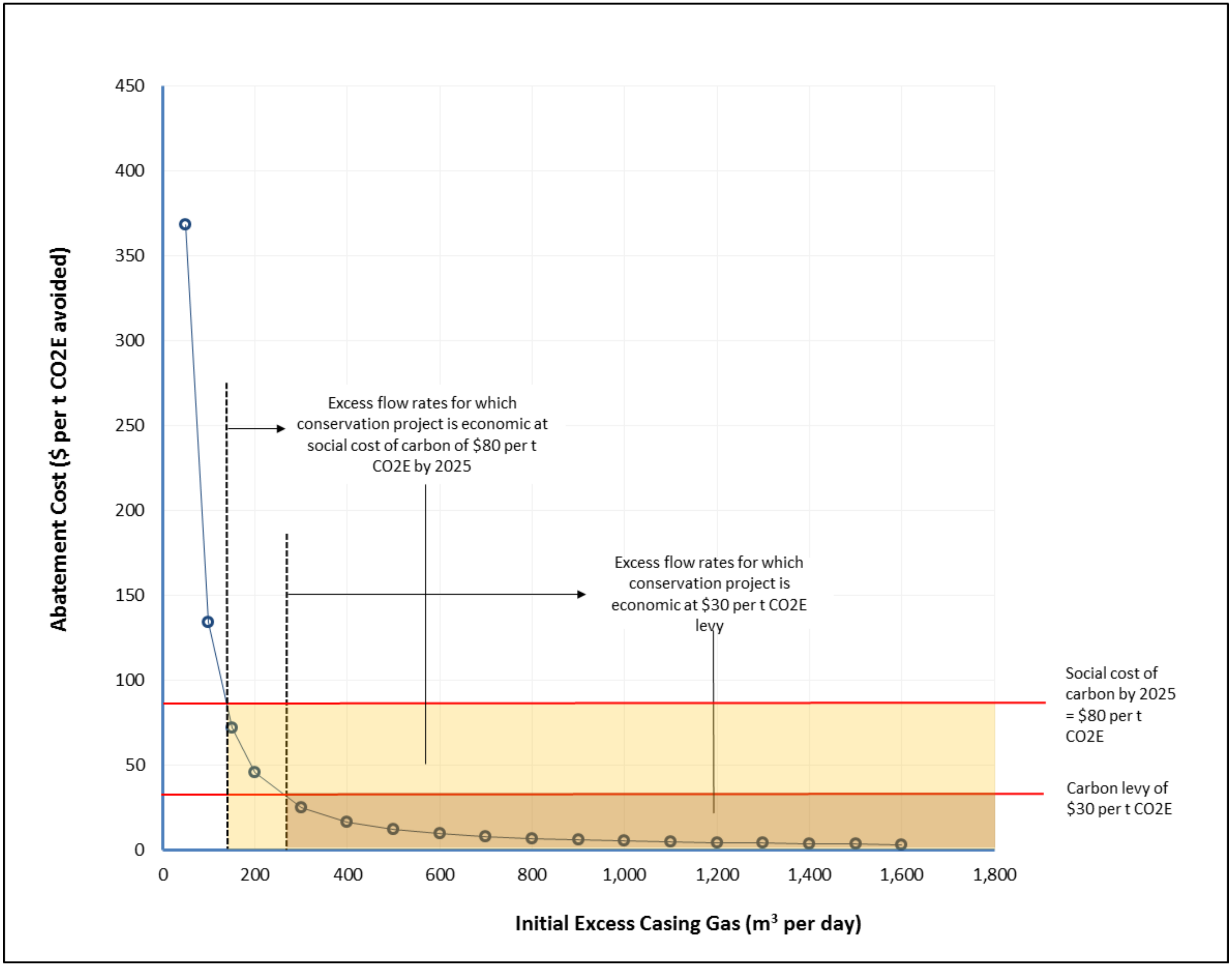

Figure 22: Average abatement cost as a function of initial excess casing gas for a flare.

Table 16: Evaluation of base-case Net Present Value (NPV) for flaring excess casing gas (royalty-out basis).

Year	Casing Gas Available at Site	Propane Avoided	Royalty Payments	Salvage Value	Total Net Project Benefits (discounted)	Net Capital Costs	Net Operating Costs	Total Net Project Costs (discounted)	Total Project Net Benefits (discounted)
	(10^3m^3/ year)	(GJ / year)	($ / year)	($)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)
2015						95,580		95,580	-95,580
2016	730	-140	0	0	0		8,266	7,820	-7,820
2017	674	-140	0	0	0		8,422	7,538	-7,538
2018	622	-140	0	0	0		8,581	7,266	-7,266
2019	574	-140	0	0	0		8,743	7,004	-7,004
2020	530	-140	0	0	0		8,909	6,752	-6,752
2021	489	-140	0	0	0		9,078	6,510	-6,510
2022	452	-140	0	0	0		9,251	6,276	-6,276
2023	417	-140	0	2,394	1,536		9,427	6,051	-4,514
Total	4,488	-1,120	0	2,394	1,536	95,580	70,678	150,797	-149,291

4.6 VAPOUR COMBUSTOR

4.6.1 DESCRIPTION

Black Gold Rush Industries Ltd. has developed BGR 18, 24 and 36 Low Pressure Vapour Combustors to destruct natural gas from well casing, produced oil storage tanks and dehydrators. This study considers the BGR 24 combustor which is a 6.1 meters high, free-standing unit with no visible flame. Its patented high efficiency burner is designed for flows up to 1,500 m^3 per day and provides 99.9 percent combustion efficiency without additional fuel gas or air assist. Although this technology is very similar to an incinerator, it is not termed such because it's not designed to operate with a minimum exit temperature of 600^{o}C or residence time of 0.5 seconds. The unit is equipped with a solar powered ACL 3200 (I) continuous spark ignition system for destruction of intermittent flows. Entrained liquids are separated in an upstream knock-out drum and accumulated liquids are trucked-out. The gas lines and knock-out are heat traced and insulated to prevent freeze-off. Air intake flame arrestors plus an in-line flame arrestor on the waste-gas supply line are installed to safe guard against explosions.

Figure 23: Field installation of a BGR 24 vapour combustor (Black Gold Rush Industries Ltd.)

A BGR 24 unit is shown in Figure 23 and has the same process flow as the flaring system presented in Figure 20, except there is no propane purge gas and its proposed location is between the wellhead and production tank. Applications to the AER for reduced spacing are supported by unit testing that demonstrate sufficient mitigation of AER safety concerns (Gold Rush, 2016).

4.6.2 GHG EMISSION REDUCTIONS

Disposing excess casing gas in a vapour combustor instead of venting reduces GHG emissions by 81 percent (47,911 t CO_2E) relative to baseline GHG emissions as shown in Table 17. The combustion efficiency (99.9 percent) of this technology is better than the flare (98 percent) and catalytic heaters (80 percent). Thus, less methane is released to the atmosphere due to incomplete combustion in flares and catalytic heaters. However, 34 10^3m^3 of casing gas is vented during the first year of operation because the volume of excess gas exceeds the combustors maximum throughput capacity of 1,500 m^3 per day. Zero casing gas is vented during subsequent years because of production declines.

There is no change to baseline propane combustion emissions, to run site equipment during cold months, because waste heat isn't recovered from the vapour combustor.

Table 17: Avoided GHG emissions when disposing excess casing gas in a vapour combustor.

Year	Baseline GHG Emissions	Project Case				Avoided GHG Emissions
		Casing Gas Combusted	Casing Gas Vented	Propane Combusted	GHG Emissions	
	(t CO_2E/yr)	(10^3m^3/yr)		(GJ/yr)	(t CO_2E/yr)	(t CO_2E/yr)
2016	10,225	696	34	4,138	2,194	8,031
2017	9,291	674	0	4,138	1,585	7,706
2018	8,429	622	0	4,138	1,483	6,946
2019	7,634	574	0	4,138	1,389	6,245
2020	6,899	530	0	4,138	1,302	5,597
2021	6,221	489	0	4,138	1,222	4,999
2022	5,595	452	0	4,138	1,148	4,448
2023	5,018	417	0	4,138	1,079	3,938
Total	59,312	4,454	34	33,104	11,402	47,911

4.6.3 ECONOMIC ASSESSMENT AND SENSITIVITY

This technology does not generate revenue and will always have a negative NPV unless the benefit of GHG reductions is monetized. The base-case NPV equals negative $162,703 (on a royalties-in basis) and negative $144,912 (on a royalties-out basis) with complete results for the latter delineated in Table 18 for an eight year operating life. Input parameters are presented in appendix Figure 31 with details of capital and installation costs (base-case of $100,550) presented in appendix Table 26.

As evident from the Figure 25 tornado chart, project NPV is highly sensitive to the monetization of GHG emission reductions. Valuing GHG emission reductions at a levelized SCC of $64 per t

CO_2E avoided increases the base-case project NPV by $2,493,000 to $2,348,000. The project NPV is also sensitive to assumptions relating to (in declining order of sensitivity): capital and installation costs; annual operating costs; and operating life. However, the valuation of GHG emission reductions is the only input parameter that yields a positive project NPV when upper bound assumptions are adopted.

The average abatement cost for this project is $3.02 per t CO_2E avoided. That is, for every tonne of CO_2E not released to the atmosphere as a result of the project the operator incurs an average cost of $3.02 (to purchase and install the technology). As shown in Figure 24, the average abatement cost varies with the volume of excess casing gas initially available and stabilizes at 1,500 m^3 per day (i.e., maximum throughput of the combustor). Average abatement costs are below $10 per t CO_2E reduced for sites with excess casing gas greater than 560 m^3 per day during their first year of operation. If a policy was implemented whereby a levy of $30 per t CO_2E was charged on venting emissions, this conservation project would be economic at sites with initial excess casing gas flow rates of about 252 m^3 per day or greater. Alternatively, if a performance standard was set on the basis of the social cost of carbon in 2025, the use of this conservation technology would be economic at sites with an initial excess casing gas flow rates around 132 m^3 per day or greater.

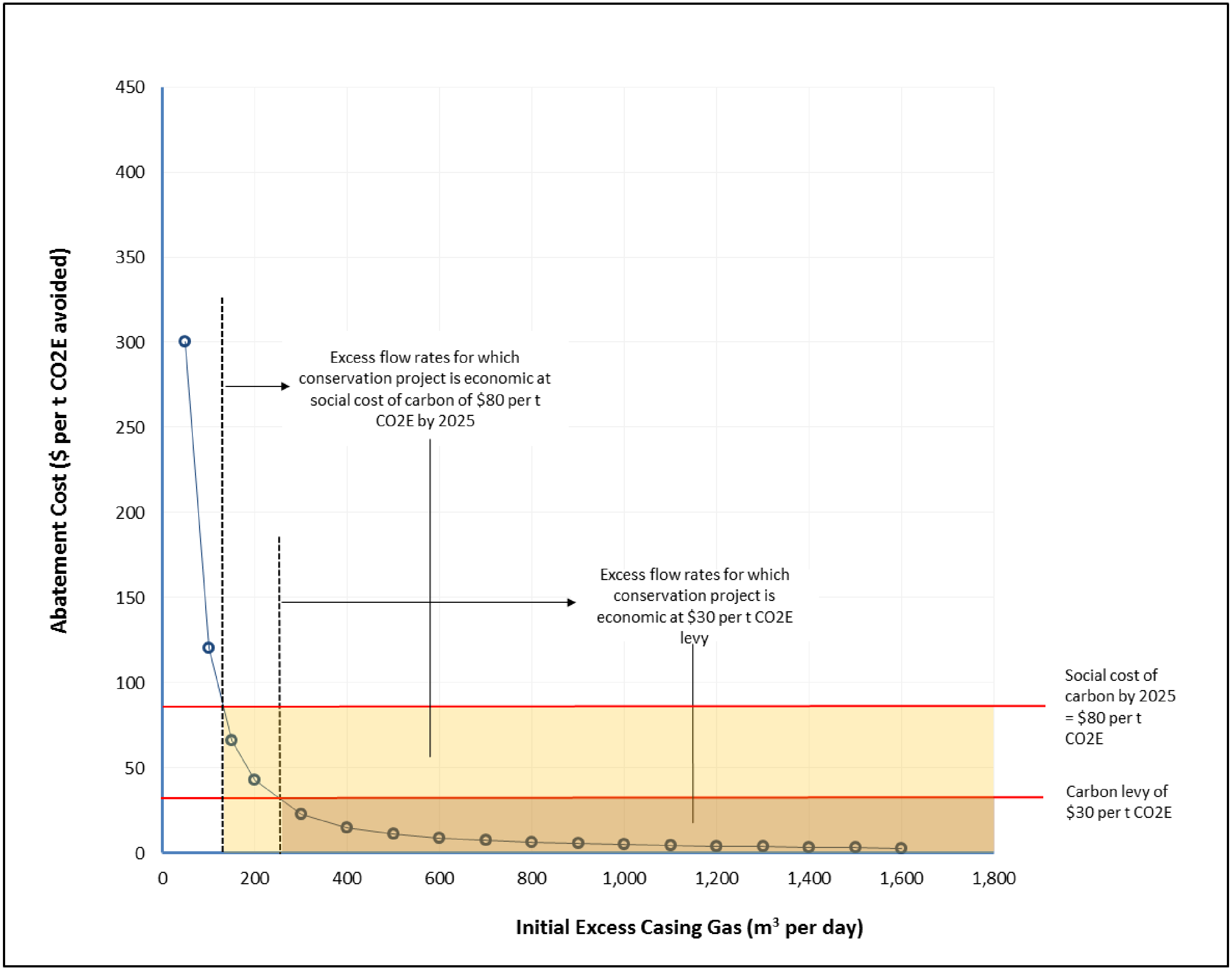

Figure 24: Average abatement cost as a function of initial excess casing gas for the vapour combustor.

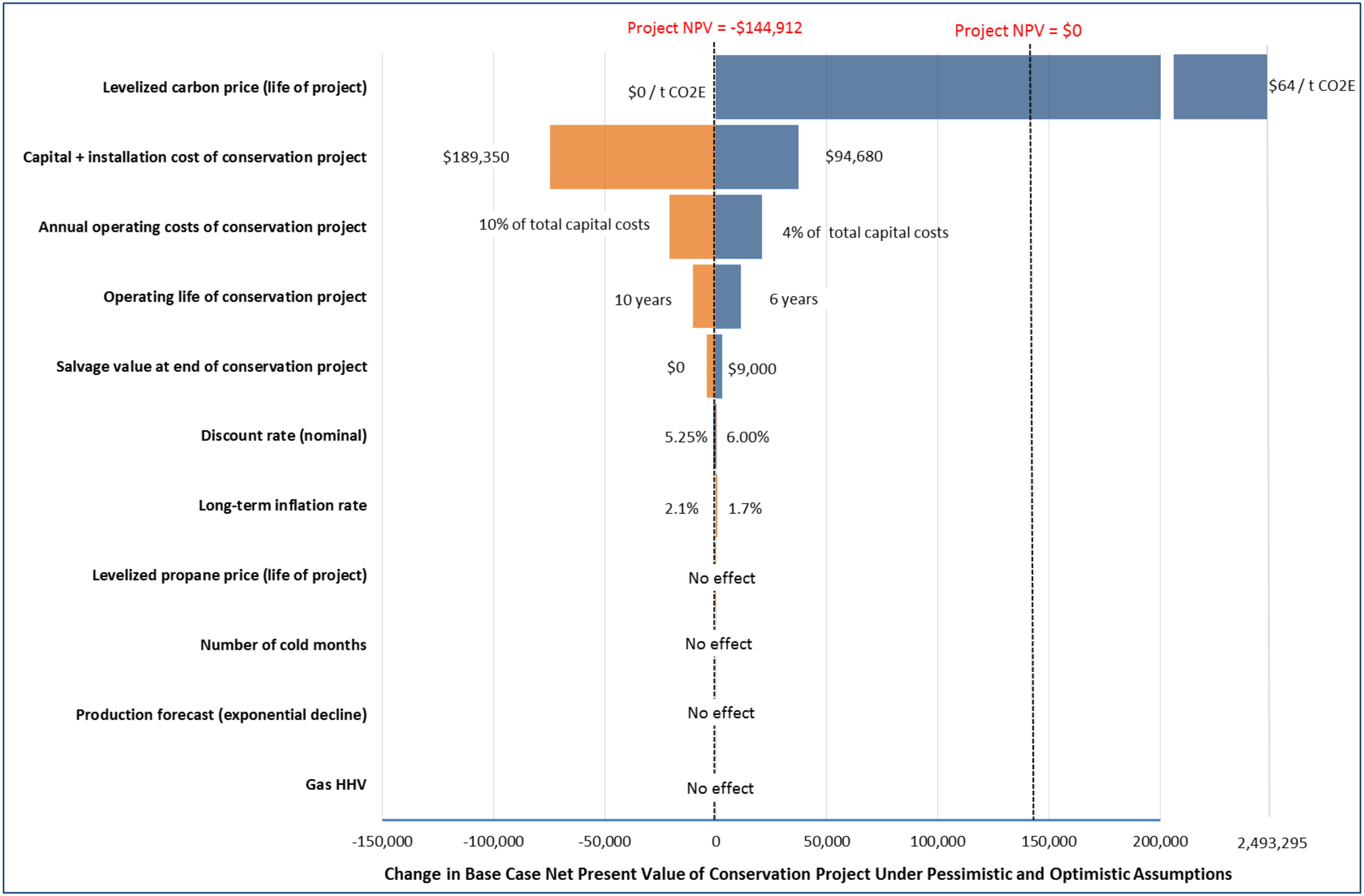

Figure 25: Tornado Chart Showing Impact of Upper and Lower Bound Input Values on NPV for the vapour combustor.

Table 18: Evaluation of base-case Net Present Value (NPV) for the vapour combustor (royalty-out basis).

Year	Casing Gas Available at Site	Propane Avoided	Royalty Payments	Salvage Value	Total Net Project Benefits (discounted)	Net Capital Costs	Net Operating Costs	Total Net Project Costs (discounted)	Total Project Net Benefits (discounted)
	($10^3 m^3$/ year)	(GJ / year)	($ / year)	($)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)
2015						100,550		100,550	-100,550
2016	730	0	0	0	0		7,186	6,799	-6,799
2017	674	0	0	0	0		7,337	6,567	-6,567
2018	622	0	0	0	0		7,491	6,344	-6,344
2019	574	0	0	0	0		7,649	6,127	-6,127
2020	530	0	0	0	0		7,809	5,919	-5,919
2021	489	0	0	0	0		7,973	5,717	-5,717
2022	452	0	0	0	0		8,141	5,522	-5,522
2023	417	0	0	6,182	3,968		8,312	5,334	-1,367
Total	4,488	0	0	6,182	3,968	100,550	61,898	148,880	-144,912

4.7 OTHERS

4.7.1 GAS COMPRESSION INTO GATHERING SYSTEMS

The most common and successful gas conservation strategy is to compress excess gas into gathering systems for processing at downstream gas plants. This 'tie-in' strategy is well understood by facility operators and implemented when sufficient excess gas is produced. Tie-in costs increase and become prohibitive as the distance from a pipeline, with suitable pressure and [H_2S] tolerances, increases. One operator indicated tie-in projects are not practicable for flows less than 1,500 m^3 per day unless a gathering pipeline is already connected to the subject battery.

No further assessment is completed because this option is already considered by facility operators and similar cost-benefit analysis already completed (Coderre and Johnson, 2012).

4.7.2 CANGAS MOBILE GAS COMPRESSION

CanGas Solutions Inc. will compress, dehydrate, sweeten and transport excess natural gas via compressed natural gas (CNG) trailers. This approach is ideal where gas can be used to offset diesel fuel consumption (e.g., at drilling rigs) in close proximity to the source wells. Diesel fuel savings are available to pay the cost of gas compression and transport. This approach is also successful at sites under regulatory order to conserve gas or shut-in oil production (e.g., where gathering pipeline commissioning is delayed or downstream gas facilities are shut-in). However, a gas volume greater than 4,000 m^3/day, oil price greater than $70 per barrel and truck hauling distances less than 50 km are required for this option to be feasible.

4.7.3 HYDROCARBON LIQUIDS RECOVERY

Condensable hydrocarbons can be recovered from solution gas streams at oil batteries by installing a micro-condenser system. Produced hydrocarbon liquids are stored in pressurized vessels or injected into sales oil pipelines. Residue gas from the condenser is cleaner burning than raw solution gas and may be used for onsite fuel demands or to generate electricity. Because this technology is only practicable for rich gas streams containing more than 10 percent propane (or heavier), whereas casing gas under consideration is lean (i.e., 98 percent methane), no further economic assessment is completed.

5 CONCLUSIONS AND RECOMMENDATIONS

To assist industry and decision-makers determine appropriate flaring and venting thresholds for Western Canadian upstream oil and gas facilities, GHG reduction and economic assessments are completed for three gas conservation and three conversion technology options installed at a CHOPS battery. NPV calculations for each option are consistent with Section 2.9.1 of AER Directive 060, with sensitivity tests performed for upper and lower bound estimates of key parameters. Base-case assessments consider a representative battery where approximately 500 m^3 per day of sweet casing gas is used to fuel site equipment while an excess of 1,500 m^3 per day is vented during the first year of operation. As shown in Table 19, all options except one, have a negative NPV under the base-case and would not normally be implemented because there is no economic benefit to facility owners. These unattractive NPVs result are simply due to no or low revenue potential relative to life cycle equipment and labour implementation costs.

In all cases, clustering wells to maximize the volume of casing gas available for conservation is critical for demonstrating positive economics. However, if clustering isn't possible, the following observations for low-flow wells should be considered.

Catalytic line heaters have a positive base-case NPV and could be installed at sites where year-round casing gas use is indeed achieved by heat-tracing gas lines. Replacing propane with casing gas fuel is one of the only ways to reduce battery operating costs and GHG emissions for relatively little capital investment. Moreover, many sites have enough waste heat from existing pump engines that coolant loops could be used for heat tracing instead of additional line heaters. In these cases, battery operating costs and GHG emissions can be reduced for very little capital investment.

Table 19: Summary of conservation and conversion technology capital cost, NPV, GHG reduction and average abatement costs when initial excess gas flows equal 1,500 m^3 per day.

Technology Option	Type	Capital and Installation Cost	NPV	GHG reduction relative to baseline	Average Abatement Cost ($/t CO_2E
Onsite Power Generation	Conservation	$419,120	-$271,969	79%	$6
Auxiliary Burner and Heat Trace		$282,080	-$231,135	81%	$5
Catalytic Line Heaters		$39,070	$92,425	26%	- $6
Catalytic Conversion	Conversion	$49,540	-$75,310	6%	$20
Flaring		$95,580	-$149,261	80%	$3
Vapour Combustor		$100,550	-$144,912	81%	$3

Without monetizing their environmental benefit, there is little economic motivation to implement other gas conservation and conversion projects when excess gas flows are less than 1,500 m^3 per day. However, and of particular note, is that all options are highly sensitive to pricing the GHG emission savings. Average abatement costs are presented in Table 19; they show the total lifecycle cost incurred by an operator (in present value terms and net of any revenue) to avoid the release of one tonne of CO_2E. If the monetary value attached to avoiding the release of one tonne of CO_2E is higher than these average abatement costs, then the project will have a positive NPV.

Benefits to society from avoiding the release of GHGs that are external to commodity prices are internalized into the decision calculus of this study by monetizing the GHG emission reductions. In the U.S., broad social costs of anticipated climate-related impacts attributable to GHG emissions are monetized using SCC values; these values are used to evaluate the net benefits of proposed performance standards and rules that avoid the release of GHG emissions. Project economics are favorable and rules justified when the SCC exceeds the marginal carbon abatement cost, other things being equal. Applying the U.S. rule-making framework to this project, we set the price of GHG reductions at a SCC of $81 per t CO_2E (i.e., the EPA SCC for emissions of GHG s in 2025[10], valued at a 3% discount in current Canadian dollars) for technologies capable of reducing GHG emissions by 80 percent and used this SCC price-point to determine minimum flow thresholds that result in positive NPVs for the technologies considered. These minimum flows represent the point where the SCC (marginal benefit) value assigned to each tonne avoided is just greater than the total lifecycle cost of avoiding the release of the same tonne. Results summarized in Table 20 indicate gas should be conserved for initial flows greater than 208 m^3 per day and converted when initial flows are greater than 132 m^3 per day. Venting should be permitted when initial flows are less than 132 m^3 per day where the marginal abatement cost of carbon for all technologies considered exceeds the marginal social cost.

The Alberta Climate Leadership Plan proposes to implement an economy-wide carbon price, but the exact form of the carbon pricing mechanism is yet to be determined. Nonetheless, even performance standards, like those under development in the U.S., implicitly price GHG emissions from venting and flaring.[11] To simulate the possibility of GHG emissions from venting and flaring eventually being priced in Alberta, whether explicitly or implicitly, minimum flow thresholds are evaluated based on an assumed price of $30 per t CO_2E being levied on GHG emissions from this sector; results are presented in Table 20. The carbon value assumed to be imposed in Alberta indicates gas should be conserved for initial flows greater than 360 m^3 per

10 2025 is selected because this is the year Alberta intends to regulate methane controls if a 45 percent reduction is not voluntarily achieved by the oil and gas sector.

11 Performance standards are a form of direct regulation, in which government typically commands a desired emission level and then controls and enforces compliance. By restricting sites to specific technology choices and practices, direct regulation places an implicit price on GHG emissions. This is in contrast to taxes/levies that explicitly price GHG emissions.

day and converted when initial flows are greater than 252 m^3 per day. Venting should be permitted when initial flows are less than 252 m^3 per day.

Table 20: Excess casing gas flow required during the first year of battery operation for positive NPVs when GHG reductions are monetized.

Technology Option	Type	$81/t CO_2E SCC	$30/t CO_2E Alberta Levy
		Excess Flow (m^3 per day)	
Onsite Power Generation	Conservation	321	561
Auxiliary Burner and Heat Trace		208	360
Flaring	Conversion	139	263
Vapour Combustor		132	252

Conserving excess casing gas for small-scale, decentralized, electricity generation may be an important contribution to base-load power in Alberta as coal-fired power plants are phased out over the next 15 years. In cases where distribution lines are within 480 meters of the site and have sufficient capacity for the incremental power supply, base-case NPV is greater than the Directive 060 threshold requiring conservation projects to proceed. Moreover, monetization of carbon (in the range of $10 per t CO_2E) can swing the decision for sites to produce power if initial excess gas flows are above 1,300 m^3 per day. However, the decision also depends on whether site-specific casing gas flows will be stable and predictable over the eight year project life.

Installing auxiliary burners in tank heater stacks is an innovative approach to managing excess casing gas that minimizes impact to site lease sizes, traffic patterns and visual aesthetics. The burners respond well to variable gas flows from 0 up to 21 m^3 per hour per unit and produce heat for freeze protecting gas lines during cold months. Monetization of carbon (in the range of $10 per t CO_2E) can swing the decision for sites to install auxiliary burners if initial excess gas flows are above 900 m^3 per day. However, installation of a glycol exchanger and pump for heat-tracing may prove difficult and better accomplished with catalytic line heaters or excess heat from engine coolant loops.

When choosing a conversion technology because no conservation opportunities are available, consider that a flare will dispose much larger flows than a vapour combustor (i.e., max for a single combustor is 1,500 m^3 per day). Moreover, the average abatement cost for a flare decreases as flow rates increase while abatement costs remains relatively static for the vapour combustor. For example, the average abatement cost for a flare would be $0.49 per t CO_2E avoided and $2.26 per t CO_2E for the vapour combustor if initial flow increased to 10,000 m^3 per day. However, vapour combustors are recommended for converting variable flows from 0 to 1,500 m^3 per day because it's difficult for flares to maintain stable combustion at exit velocities less than 1 m/s (e.g., 680 m^3 per day or less for a 4" diameter flare tip). Because catalytic conversion units have high abatement costs, mainly due to their small flow range, this conversion technology is not recommended.

Complementary to the possibility of performance standards or a carbon tax/levy being imposed on venting sources, carbon valuation could be introduced into Directive 060 economic assessments for conservation projects. The main advantage of this approach is leveraging an existing and familiar regulation to quickly achieve venting reductions. Updates to the directive would include setting a carbon price schedule and establishing methodology for consistent GHG quantification and integration with NPV calculations.

Finally, a natural extension of this study is to apply the economic model and sensitivity tests to other technologies and site conditions. Of particular interest are results from the PTAC sponsored, conceptual engineering study of new near-commercial technologies to reduce methane venting from cold heavy oil production (final report anticipated in 2016).