Turning a Liability into an Asset: Re-purposing Inactive Petroleum Wells for Geothermal Energy Production

by

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Abstract

There are over 600,000 registered oil and gas wells in the province of Alberta, many of these are inactive wells that do not produce resource yet do present a significant environmental risk and financial liability in cleanup costs. There are no regulations stipulating the maximum length of time a well can be left suspended and, in recent years, an increasing number of wells have been put into the suspended state by owners. Paper 1 of this thesis uses a large data set obtained from the Alberta Energy Regulator to calculate the average volume of methane emissions from a leaking well and results indicating that leak duration and rate may be increasing over the years. Further, we provide simple social-cost-of methane computations which show that, under the right conditions, responsible policies can incentivise well owners towards remediation and reclamation and support efforts to flight climate change. In paper 2 we present an opportunity to mitigate the financial and environmental risk posed by these wells through retrofitting a selection of them for direct-use geothermal heat energy production. The goal of this paper is to assess the techno-economic feasibility of using the legacy oil and gas infrastructure to produce geothermal energy and improve the productivity of a cattle ranch by increasing the temperature of the drinking water available to cattle during the cold winter months. We estimate the average cost to retrofit one of the five suspended wells on ranch property at $212,999 and that it would require three retrofit wells to provide sufficient energy to raise the cattle drinking water temperature from 2.5°C to 10°C. Based on all estimated costs and revenues expected over the life of the project, we calculate that the project's expected net present value is negative $845,775. A key result of this paper is the creation of a model of well retrofit costs that can be expanded to further research and other geothermal re-

purposing projects. In paper 3, I use publicly available data from the GeoScout online database of petroleum wells, and the well retrofit cost model presented in paper 2 of this thesis to identify promising retrofit candidate wells. This paper first sorts and quantifies Alberta's wells by vertical depth, age, and regulatory status. Then I apply the cost retrofit model and bottom hole temperature data to rank each well by their likelihood of techno-economic retrofit success. The analysis finds 179,446 unique wellbores within Alberta that possess a vertical depth equal to or greater than 1000 metres; these can be retrofit at an average cost of $225,000. I also create a list of the top 100 retrofit candidate wells, demonstrating that suitable candidates may exist throughout all regions of the province.

Preface

This thesis consists of two collaboratively written and published papers and a third, unpublished, paper. I am the lead author on both published papers and the sole contributor to the unpublished work.

Paper 1 of the thesis is titled "An Updated Look at Petroleum Well Leaks, Ineffective Policies and the Social Cost of Methane in Canada's Largest Oil-Producing Province" and is coauthored by Maik Kecinski (University of Delaware, Department of Applied Economics and Statistics) and Sandeep Mohapatra (University of Alberta, Department of Resource Economics and Environmental Sociology). Maik Kecinski contributed to the overall writing and analysis of the paper; Sandeep Mohapatra was primarily responsible for the content of section 1.3. A revised manuscript, as presented here, was submitted on December 21, 2020 for publication consideration in journal Climatic Change.

Paper 2 of the thesis is titled "Assessing the Techno-economic Feasibility of Retrofitting a Petroleum Well for Direct Use Geothermal Energy Production: A Case Study" and is coauthored by Jonathan Banks and Arif Rabbani, both from the University of Alberta, Department of Earth and Atmospheric Science. Jonathan Banks contributed to the overall writing and analysis of the paper; Arif Rabbanni was primarily responsible for the content of sections 2.1 and 3.2.

Paper 3 of the thesis it titled "Identifying Target Petroleum Wells for Geothermal Energy Production Retrofit." I was the sole author of this paper; all writing and analysis is my own.

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The research and contents of this thesis were made possible with the guidance, help, and support of numerous individuals. First and foremost, I would like to acknowledge my two co-supervisors, Lianne Lefsrud and Vic Adamowicz, along with the principal investigator of the geothermal energy research team (and honorary third supervisor) Jonathan Banks. Lianne pushed me out of my comfort zone, encouraging new approaches and guidance on when tackling challenges. Vic was a sympathetic ear that provided support and valuable insights into my work. At times, when my motivation or direction wavered, Jonathan's passion and enthusiasm provided the inspiration I sorely needed.

Many other professors and staff at the University of Edmonton also helped to make this thesis what it is. In particular, the encouragement and insights of professors Maik Kecinski and Mohammad Torshizi helped to develop many of the ideas you see here.

Friends in the department of Resource Economics and Environmental Sociology provided laughter and welcome distractions. Lunchtime chats and commiseration (along with delicious baking) helped me keep my sanity throughout.

Finally, I owe a huge debt of gratitude to my family. Especially my wife Abigail, without whose encouragement I likely would not have applied to enter the Masters program and without her love and support I am not sure I would have finished. My daughter Astrid, who joined us half-way through my degree, probably slowed my progress but reminded me of what matters most in life and inspires me to always try to be my best self.

Table of Contents

List of Tables

List of Figures

Introduction

There are over 600,000 registered oil and gas wells in Alberta and nearly one-third of these wells are no longer producing and waiting to either be reactivated or fully remediated and the land reclaimed (Alberta Energy Regulator, 2018). Drilling and producing these wells has brought jobs and prosperity to the province, but the current era of low energy prices has highlighted the large number of inactive wells and the potential reclamation liability they present. One study has estimated the potential cost of plugging and reclaiming Alberta's wells at $8 billion (Dachis, Shaffer & Thivierge, 2017). Extensive hydrocarbon-based energy development has also led to high levels of Greenhouse Gas (GHG) emissions; Alberta contributed 38% of Canada's national total in 2017 (Environment and Climate Change Canada, 2019). As we have become increasingly aware of the impact that climate change can have on our environment, health, and economy many governments, including Alberta's, have acknowledged the need to reduce GHG's. Re-purposing oil and gas wells for geothermal energy production can potentially mitigate the well cleanup liability by extending a well's useful life and reduce GHG emissions by providing a source of renewable energy.

Geothermal energy is a renewable energy source which harnesses the naturally occurring heat found in the rocks and fluids beneath the Earth's surface. The deeper you travel below the surface, the warmer the temperature and greater the potential energy. At high enough temperatures electricity can be generated by using steam from the hot fluids to power a turbine. Lower temperatures resources (<80°C) can be used in "direct-use" applications to provide heat for buildings or industrial and commercial processes (Grasby et al, 2012). Although underground heat can be found anywhere on earth, it is not evenly distributed. The geothermal gradient, or rate at which the temperature increases with depth, changes with location. Traditionally, geothermal energy has been exploited near regions of tectonic activity where the gradient is high and hot water can be found relatively close to the surface. In Canada, the geothermal energy resource tends to be of lower quality (lower temperature) and more expensive to access (located deeper underground) which, combined with low fuel prices and a lack of policy support, has hindered development despite the Geological Survey of Canada identifying a substantial resource (Thompson, 2015).

Geothermal energy has several inherent advantages as an energy source. As with other renewables, it produces zero GHG emissions. Unlike other renewables, which depend upon constantly shifting environmental conditions, geothermal can be a baseload energy source that provides a near constant supply of power by drawing upon the persistent heat of the earth (Grasby et al, 2012). Geothermal energy projects also leave a small land footprint when compared to other renewables (Kagel, Bates, and Gawell, 2007). These advantages make geothermal energy an attractive option for a government that is keen on reducing carbon emissions and reducing the overall environmental impact of its energy supply. The primary disadvantage of geothermal energy production is that it requires significant up-front investment that can be prohibitive to development. A review of electricity generation options found geothermal power to possess the highest initial capital costs (Clauser & Ewert, 2018). The bulk of these capital costs are related to drilling and exploration, accounting for 30-95% of the initial expenditure (Caulk & Tomac 2017, Leitch et al 2017, Peachey 2019). Re-purposing an existing oil and gas well removes the need to drill a new geothermal well and minimizes the exploration risk. Although there will always be some uncertainty about what conditions exist deep beneath the earth's surface, there exists an extensive set of subsurface data from the hundreds of thousands of wells drilled in Alberta. These records often provide information regarding the temperature and geological conditions at the bottom of the wellbore and facilitate a reasonable estimate of the heat energy that can be produced.

Re-purposing inactive oil and gas wells for geothermal energy production provides new life for aging, inactive infrastructure while simultaneously providing Alberta with an additional source of renewable, non-GHG emitting energy. Producing deep geothermal heat energy also requires much of the same equipment and knowledge as conventional petroleum production (Leitch et al, 2017), which can spur renewed demand for some of Alberta's physical and intellectual energy capital. Despite these benefits and the presence of a significant heat resource, geothermal energy remains a nascent industry in Alberta. Marginal economic returns and lack of government support have stymied development.

This thesis consists of three papers that improve our understanding of the costs and benefits of a well re-purposing project and help promote geothermal energy development in Alberta and beyond.

Among the inactive wells in Alberta, over 116,000 (Alberta Energy Regulator, June 2018) of them are currently assigned the suspended status. The suspended status is considered a temporary state of inactivity while its owners decide to either reactivate or permanently plug (abandon) the well, but there is no stipulated maximum length of time a well can remain suspended. Alberta Energy Regulator (AER) allows indefinite suspension in hope that improving petroleum prices or technology will incentivize an owner to resume production activity and maximize resource extraction from the well. In turn, the past decade has seen a steady increase in the number of wells being suspended, an increase that has not been matched by the number of wells being abandoned[1]. A suspended well presents a higher risk than other wells because 1) a suspended well is more likely to leak methane due to a Surface Casing Vent Flow (SCVF) or Gas Migration (GM) event than either an active or a properly plugged/abandoned well (Ho et al, 2016, AER, Mar 2019) and 2) an abandoned well has already undergone a part of the cleanup process and so presents a smaller cost liability. Compounding these issues is that the longer a well is left as suspended the greater the chance its owner will go out of business and leave the well "orphaned". Although the industry-funded Orphan Well Association (OWA) was established to manage and cleanup inactive orphaned wells, a series of government loans and grants to the OWA[2] has cast doubt on the funding model and demonstrated that the cleanup liability is ultimately a public burden.

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[1] Analysis of the Alberta Energy Regulator (Mar, 2019). ST37: List of Wells in Alberta Monthly Update – Surface Hole Shapefile [Internet]. Finds that between 2011-2014, an average of 446 new suspensions and 363 abandonments were performed per month; by 2018 suspensions had increased to an average of 622 per month while the number of abandonments had remained relatively constant at 380. https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st37

[2] In 2017 the OWA received a $235 million repayable loan from the province of Alberta, the interest on which was covered by a $30 million grant from the federal government (OWA 2017 Annual Report – available from http://www.orphanwell.ca/OWA%201017-18%20Ann%20Rpt%20Final.pdf). In April of 2020, the Canadian federal government announced funding of $1 billion for the cleanup of inactive oil and gas wells in Alberta - https://www.canada.ca/en/department-finance/news/2020/04/canadas-covid-19-economic-response-plan-new-support-to-protect-canadian-jobs.html#Orphan_and_inactive_oil

The purpose of the first paper is to improve our knowledge of the environmental and financial risk presented by suspended wells in Alberta and to discuss policy options for mitigating that risk. It utilizes a data set acquired from the AER, detailing all reported incidents of SCVF or GM dating back to 1971, to quantify the volume of methane emissions from leaking wells. We begin with an econometric analysis that identifies trends in both the rate and duration of fugitive gas leaks over time. Then we assess the cost of those leaks by applying a social cost of methane (SCM) established in the literature.[3] Finally, we incorporate this SCM into a series of simple net present value analyses that compare the typical costs of leaving a well suspended against the average costs of abandonment and reclamation. Our work was motivated in part by the research of Muehlenbachs (2015, 2017), who conducted economic modelling on inactive wells in Alberta and suggested that corporate decision-making is governed by cost avoidance rather than resource maximization. We expand upon that idea by incorporating the SCM into a firm's financial analysis to assess whether paying this cost is likely to encourage more wells to be formally abandoned rather than remain suspended.

In the second paper, the focus turns to assessing the economic feasibility of re-purposing an oil and gas well for geothermal energy production. We undertake a case study of retrofitting inactive petroleum wells for geothermal heat production at a real operating cattle ranch in Alberta. The ranch owner believes that the temperature of his cattle's drinking water, which is just above freezing during the winter months, is leading to health concerns and increased feeding costs that affect the rancher's bottom line. Retrofitting one or more of the existing 33 oil and gas wells on ranch property to provide heat to that drinking water is one potential solution.

Paper two has three main goals. First, to provide a model for estimating the costs of retrofitting a petroleum well using oil and gas industry pricing data[4]. Second, to

[3] Marten, A. L., & Newbold, S. C. (2012) present an SCM of US$810, while Shindell, D. T., Fuglestvedt, J. S., & Collins, W. J. (2017) suggest a significantly higher SCM of US$3600 by incorporating human health costs and decreases in agricultural yields.

[4] To date, and to the best of my knowledge, there have been no well re-purposing projects completed anywhere. Banks (2017) and Lukawski (2014) both use oil and gas pricing data to estimate geothermal well costs

demonstrate a method of predicting the usable heat energy available from the retrofit well. Third, we project all revenues and expenses over a 25-year project lifecycle to improve our understanding of which variables have the greatest impact on the project's financial feasibility. Using the ranch case study provides a tractable, illustrative example of a well re-purposing project. The results are intended to be a starting point from which to assess other geothermal energy well re-purposing projects and to facilitate discussion of policy and programs that can enhance the number of economically viable opportunities.

The third paper is a quantitative analysis of all existing petroleum industry wells in Alberta that possess a vertical depth greater than 1000 metres. Comprehensive well information is made publicly available in Canada, but these are typically provided on a line-item basis and I am not aware of any publication that aggregates the data into useful totals and averages. The purpose of the analysis provided here is to understand the potential for geothermal well re-purposing projects in the province and identify the most promising target wells. This analysis compiles and categorizes Alberta wells by their vertical depth, licence status, and age. These are the most critical variables when estimating the geothermal energy potential and retrofit costs. Combining this information with the well retrofit cost model presented in paper two estimates the retrofit cost of each well in the province. Adding bottom hole temperature data highlights those wells with high energy potential to cost ratios that are most likely to be economically feasible for a well re-purposing project.

Following the three papers is a brief concluding chapter. I will summarize the key findings and discuss the implications from both a public policy perspective and a private firm perspective. I then use the findings to provide recommendations for government policy and programs moving forward.

Paper1: An Updated Look at Petroleum Well Leaks, Ineffective Policies, and the Social Cost of Methane in Canada's Largest Oil-Producing Province

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Abstract

Temporarily plugged or "suspended" wells pose environmental and economic risks due to the large volume of methane gas leaked. In the Canadian Province of Alberta, which, by far, has the largest number of petroleum wells in Canada, there are no regulations stipulating the maximum length of time a well can be left suspended. In recent years, an increasing number of wells have been put into the suspended state by owners. We show, using a large data set obtained from the Alberta Energy Regulator, that leak spells have increased between 1971-2019. For the same time-period, the probability of an unresolved leak has also increased, and the amount of methane emitted per leak has substantially gone up. Lastly, we provide a simple social-cost-of methane computations indicating that responsible policies can incentivise well owners towards remediation and reclamation and support efforts to flight climate change and improve upon economic expedience.

Keywords: Petroleum Wells, Methane Gas Emissions, Climate Change, Social Cost of Methane

JEL Codes: Q35, Q48, Q54, I18

1.1 Introduction

Methane (CH_4) is a powerful greenhouse gas possessing a 100-year global warming potential roughly 36 times greater than carbon dioxide (IPCC 2014). Although methane emissions come from a variety of sectors, the energy industry is the most significant contributor. In Canada, 44% of all methane emissions come from oil and gas facilities, predominantly from upstream operations such as exploration, drilling, production, and field processing (Environment and Climate Change Canada, 2014). In the Canadian Province of Alberta, where the economy is strongly linked to the energy sector, 70% of methane emissions come from upstream oil and gas activities (Government of Alberta, nd). Alberta has over 450,000 registered petroleum wells, and 155,000 of them are no longer producing and waiting to either be reactivated for production or permanently plugged and the land reclaimed (Dachis et al, 2017). Currently, there are roughly 81,000 petroleum wells in Alberta classified as suspended (Petrinex Alberta Public Data database). Figure 1.1 provides a geographical overview.

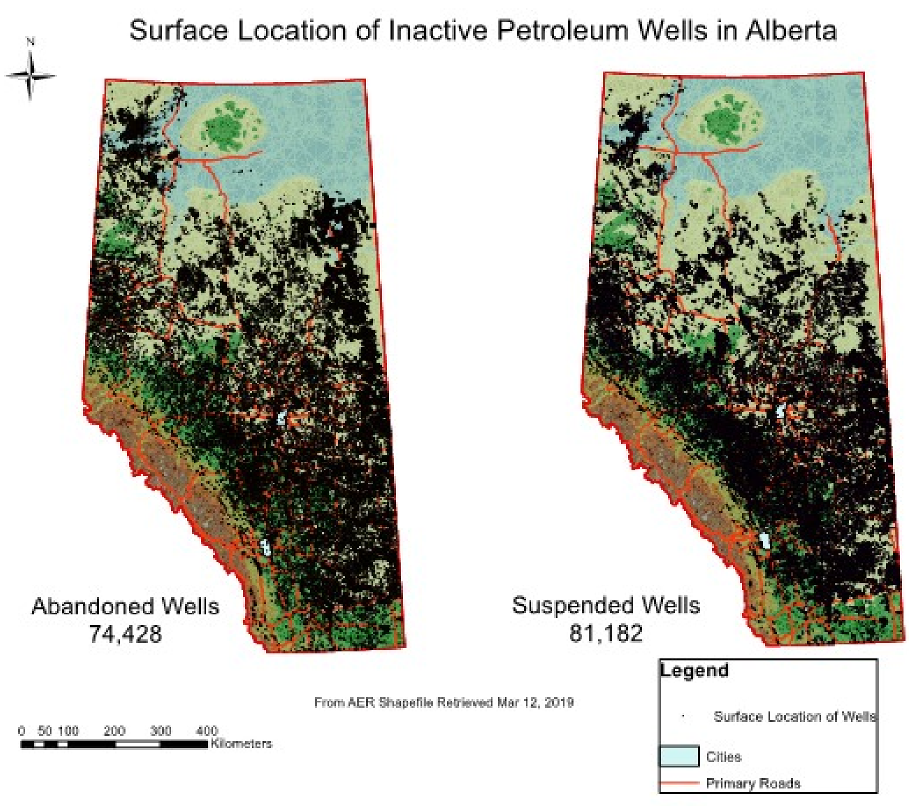

Figure 1.1: Surface Location of Inactive Petroleum Wells in Alberta, Canada

Although a suspended well is considered a temporary state of inactivity while owners decide to either reactivate or permanently plug (abandon) the well and reclaim the land, there exists no stipulated limit to the length of time a well is permitted to remain suspended (AER, Directive 013). The Alberta Energy Regulator (AER), which is the provincial body responsible for oversight of the oil and gas industry, allows indefinite suspension in hope that improving economic conditions or extraction technologies will once again make it profitable to produce from the well. Research has previously indicated that even a doubling of petroleum prices may result in reactivation of only 7 to 12% of wells, suggesting that corporate decision-making is governed more by avoidance of costs than gaining of benefit (Muehlenbachs 2015 and 2017). Due to a decline in petroleum prices in 2014, Alberta has experienced a rapidly growing number of suspended wells – between 2011-2014, an average of 446 new suspensions and 363 abandonments were performed per month; by 2018 there was an average of 622 new suspensions and 380 abandonments performed each month (AER 2019).

A pressing issue and substantial concern for policy makers is the length of time a well remains in suspended status, because the longer a well stays suspended, the more likely the owner will go out of business and leave the well "orphaned". Alberta is currently experiencing a rising number of orphan wells, leaving taxpayers and other industry participants to pay for monitoring and cleanup (Orphan Well Association, nd). The number of orphan wells in the province has increased from fewer than 100 wells in 2012 to over 3,200 in 2017. To combat this issue, the AER established the Orphan Well Association (OWA), who assume responsibility for these wells. However, their resources are limited and, should they fail, the liability ultimately becomes a public one.

While all petroleum wells have the potential to leak methane gas, according to the AER ST60B report (2018), inactive wells are more than twice as likely to have a reported "surface casing vent flow" or "gas migration event" (see Table 1.1 for definitions). Studies have also pointed out that permanently plugged (abandoned) wells are less likely to leak than temporarily plugged (suspended) wells, see for example Ho et al. (2016). These gas leaks pose human health risks, such as explosion or asphyxiation within confined spaces (Jackson et al 2013), pulmonary damage (Wilkinson et al 2009), or possible increased risk of some forms of cancer due to the presence of other volatile organic compounds that frequently accompany methane (McKenzie et al 2012). There are also environmental risks, particularly through contribution to climate change inducing greenhouse gas emissions (IPCC 2019), which would be of particular interest to policy makers tasked with enhancing public programs and welfare.

Table 1.1: Common Terminology and Descriptions related to Petroleum Wells

Terminology	**Description**
Active Well	Well has experienced volumetric activity (production, injection, or disposal) within the past 12 months.
Inactive Well	No fluid production or injection for a period of 12 months. Once inactive, the licensee (or owner) has an additional 12 months to suspend the well. Both suspended and abandoned wells are considered to be Inactive.
Suspended Well	Requires cleaning spills or debris around the wellhead, ensuring flow valves are turned off and either locked and chained or removed. Plugging of all outlet pipes, along with additional downhole plugging for riskier wells. Once suspended, a well must be inspected for spills or gas venting every one, three, or five years depending on risk category.
Abandoned Well (Plugged Well)	Placing cement and non-corrosive fluids (non-saline water is common) or mechanical plugs down the wellbore to seal off zones of oil or gas production from the surface. Cutting and capping the wellbore at one meter (minimum) below surface and covering with a vented plate.
Reclamation	Land is restored to a condition equivalent to what it was prior to development.
Remediation	Typically, part of the reclamation process. Refers to any decontamination of soil and groundwater that takes place during the reclamation process. Remediation typically accounts for one-third to three-fourth of the total cost of reclamation. Well owners or operators must continue to make surface lease payments until reclamation has been completed, which may take several years.
Surface Casing Vent Flow (SCVF)	Occurs because of plugging failure wherein pressure causes fluids to escape through open venting at the surface. A serious leak is one that is greater than 300 m^3 of flow per day, threatens water supply, or presents an otherwise immediate hazard – serious leaks and must be repaired within 90 days of discovery. Non-serious leaks require only annual monitoring for five years and do not need to be reported.

Gas Migration (GM)	Similar to SCVF, but more difficult to quantify because the gas leaks outside of the casing and migrates into the surrounding rock and soil. Testing is often done by digging a calibrated meter 50 cm down into the soil.

The point of this paper is twofold, first we uncover trends in well leakages from abandoned and suspended wells over time and in terms of volume emitted. We use a detailed data set acquired from the AER on Surface Casing Vent Flow (SCVF) and Gas Migration (GM) reports, dating back to 1971 for all Alberta petroleum wells. Through statistical analyses we then identify current well issues related to the time a leak remains unresolved and the volume emitted, that may provide policy makers and the public with additional information as to how to address these problems. Identifying these issues will also inform the literature about potential future research areas that have received not enough attention to date. Second, we apply a social cost of methane (SCM) value to the volume of emissions associated with suspended well leaks in Alberta. Although Canada's federal government has mandated a carbon price, it is based upon a CO_2 equivalent measure and may not accurately represent the cost of methane emissions. Incorporating a SCM, accounts for some of the externalities produced and allows for a more precise estimation of the total cost of emissions. A simple simulation exercise assesses whether paying for the cost of emissions could encourage increased well plugging and reclamation by firm and, in turn, help policy makers design more effective climate policies moving forward.

The remainder of this paper is organized as follows: in Section 2 we provide a brief background of the preceding literature, policy and practices employed by government and industry related to suspended wells. In Section 3 we present and discuss leak spells and volume between 1971-2019. In Section 4 we present results from the SCM simulation. Lastly, in Section 5, we briefly discuss policy options for how the government may address these inefficiencies using these results.

1.2 Background

The gas that is leaked from oil or natural gas wells is typically comprised of 95-99% methane (AER ST60B-2018). Methane is a particularly potent greenhouse gas, with a 100-year warming potential approximately 36 times that of carbon dioxide (CO_2), the primary contributor to global warming[5] (IPCC 2014). In the Canadian Province of Alberta, the largest producer of greenhouse gases among all Canadian Provinces and Territories, previous estimates have indicated that about 48% of oil and gas methane emissions are from intentional venting, while 46% are from unintentional releases that occur during the production, processing, transmission, storage, and delivery of fossil fuels. The unintentional releases are also termed fugitive emissions and accounted for 7.8% of all greenhouse gas emissions in Canada in 2017, fourth after energy (46%), transportation (28%), and agriculture (8.4%) (Environment Canada 2019). Though the volume of fugitive emissions is relatively small compared to the energy or transportation sectors as a whole, which has resulted in their receiving little public attention, they can play an important role in Alberta's and Canada's climate change policies.

Reliable estimates of fugitive emissions are hard to come by as leaks are reported to Environment Canada by the emitters themselves (Bachu 2017, Environment and Climate Change Canada 2018). The Canadian Association of Petroleum Producers (CAPP), an organization of upstream Canadian oil and gas firms, states that producers in Canada are self-guided by a set of methane management principles to support research and public policy, while collaborating with government and finding economic opportunities to reduce methane emissions (CAPP, nd). Furthermore, a CAPP report from 2017 states that the industry is committed to reducing methane emissions by 45% by 2025, which is in line with the federal government to meet Canada's emission reduction target – in 2016 the Canadian government released the "Pan-Canadian Framework on Clean Growth and Climate Change," which is the official plan for mitigating emissions. One of the core pillars of this framework is to utilize market-based instruments applied to a broad set of emissions sources, such as carbon pricing. The framework specifically identified methane

[5] Other important greenhouse gases include carbon dioxide (CO_2), nitrous oxide (NO_2), perfluorocarbons (PFCs), hydrofluorocarbons (HFCs), sulphur hexafluoride (SF_6) and nitrogen trifluoride (NF_3).

as a problem and aims to reduce methane emissions 40-45% by 2025 (Government of Canada, 2016).

In addition to the framework outlined by the federal government, Alberta's provincial government had issued a "Climate Leadership Plan," which echoed the federal goal to reduce methane emissions by 45% by 2025. The plan emphasized applying new standards and regulations for design, leak detection, and repair. As with the federal plan, the focus appeared to be on large facilities – leaving smaller releases, such as those from individual wells, untargeted. In May 2019, the newly elected government of Alberta repealed the Climate Leadership Plan, which also means that the Province of Alberta no longer collects a carbon tax (or any other greenhouse gas taxes) from its people, although regulations and penalties are in place for large, specified emitters (Alberta 2019). These changes occurred during the preparation of this manuscript and allowed the authors to specifically address the associated challenges in the Discussion section of this paper; the analysis conducted below is justified and, in part, based on the remaining federal Climate Leadership Plan. A general challenge Alberta must contend with, if it wants to reach its stated (set under the Climate Leadership Plan) or any potential future emissions targets, is that actual methane emissions levels are likely larger than the reported numbers. Research has previously demonstrated that reported values often grossly understate the actual level of methane emissions – for a comprehensive review see Brandt et al. (2014).

To prevent the cost of orphan well reclamation being borne by the public of Alberta, the AER has established methods of industry funding for the OWA that are outlined in AER Directive 006. First, there is an annual levy applied to all oil and gas producers; each firm pays a share of that levy equal to the estimated portion of the total province wide liability contributed by their petroleum wells. Second, the AER collects a $10,000 fee from new first-time licensees (new owners) of wells and this is transferred to the OWA. Third, the AER created the Liability Management Rating (LMR) program. Every producer firm receives an LMR rating equal to their deemed assets divided by deemed liabilities; if a firm has a rating of less than 1.0, they are at higher risk of becoming insolvent and must pay a security deposit to the AER for each well they drill. This deposit is used to offset the cost of well cleanup in the event the firm is unable to pay for the cleanup itself. Nonetheless, there is growing evidence that pure industry funding of the OWA is unsustainable. The 2017-2018 OWA Annual Report showed that the industry levy has increased from $15 million in 2014 to $45 million in 2018 and projected to reach $60 million in 2019 or 2020. Also, in 2017 the OWA took a $235 million repayable loan from the province of Alberta, the interest on this loan will be covered by a $30 million grant from the federal government. In April of 2020, the Canadian federal government announced funding of $1 billion for the cleanup of inactive oil and gas wells in Alberta.[6] These amounts demonstrate the increasing challenge of maintaining the current industry funded OWA model, calling for the need of improved policy approaches to deal with orphan wells and mitigate their potential burden to the public.

Common policy approaches to curb greenhouse gas emissions lie in the pricing of those emissions. For example, the social cost of carbon (SCC) is a well-established tool used by governments around the world to provide a dollar value to the environmental damages caused by CO_2; Environment and Climate Change Canada began using a SCC in 2010 (Wright, 2017). Unlike with carbon, and partly due to the absence of a market, a methane price currently does not exist. Therefore, a common approach to price methane emissions is to use its global warming potential (GWP) and convert it to the CO_2 equivalent (36 times CO_2), and then value its economic impact by multiplying GWP by SCC (Shindell et al. 2017, Marten and Newbold 2012). However, because the GWP only incorporates radiative forcing and ignores other impacts of gas release, this method tends to underestimate the social costs of methane. Methane has a shorter lifespan than carbon dioxide, which effects its sensitivity to discount rates relative to CO_2 and further complicates establishment of a proper SCM. For example, Marten and Newbold (2012) calculate a SCM by measuring the expected loss of future global economic output due to expected rise in temperature attributed to greenhouse gases and establish a social cost of methane (SCM) that is CDN$1050/t (converted from $US) at a 3% discount rate, but this value becomes just $479/t at 5% discount rate and increases to $1425/t at 2.5% discount. Another difference

[6] This amount was part of a total $1.7 billion funding announcement that also included a $200 million loan for the OWA and $500 million in funding for orphan well cleanup in the provinces of Saskatchewan and British Columbia (https://www.canada.ca/en/department-finance/news/2020/04/canadas-covid-19-economic-response-plan-new-support-to-protect-canadian-jobs.html#Orphan_and_inactive_oil).

is that methane lacks the fertilization capacity of carbon, leading to greater negative impact on agricultural yields (Shindell et al 2017, EPA 2016). Shindell et al. (2017) attempt to incorporate the decrease in forestry and agricultural yields, as well as damages to public health, to ascertain a SCM of CDN$4665/t at 3% discount rate.[7] This wide range of SCM values reflects the lack of consensus as to whether calculations of climate change costs should include only the direct impacts on climate or be expanded to include broader environmental impacts on human health and productivity.

Other approaches to evaluating the potential social costs associated with petroleum wells in Alberta include work by Dachis et al and by Muehlenbachs. Dachis et al. (2017), estimated an CDN$8 billion expense for well cleanup by applying average plugging and reclamation costs to both active and inactive wells that are either orphaned or belong to a firm with an LMR less than 2.0. While they referred to this value as a social cost under the preposition that taxpayers are ultimately liable for the cleanup if industry goes bankrupt, they do not include externalities such as the cost of health and environmental damage, thus undervaluing the true cost. Muehlenbachs (2015 and 2017) uses a real options model and data on the operating decisions of 84,000 wells in Alberta to create a model which predicts the decision of well owners to either reactivate or decommission a well. Their model finds that the high costs of decommissioning (plugging and abandonment) to be the main reason wells are left inactive. Further to this, she offers that the externalities that result from these inactive wells may lead to a socially suboptimal outcome. Inspired, in part, by Dachis et al. (2017) and the economic modelling work conducted by Muehlenbachs (2015 and 2017), this paper seeks to improve upon the state of the knowledge of the true risk and cost to the public of having these wells remain in the suspended state.

[7] Both the Marten and Newbold (US$810) and Shindell (US$3600) papers report their respective SCM values in $US. To minimize any confusion, we have converted these figures to Canadian dollars using the 2018 annual US/CDN exchange rate reported by the Bank of Canada of 1.2957 at https://www.bankofcanada.ca/rates/exchange/annual-average-exchange-rates/.

1.3 Abandoned and Suspended Wells by the Numbers

The well leakage data was obtained from a Surface Case Venting Flow/Gas Migration Report for all companies in Alberta which was requested from the AER via their online portal on March 8, 2019 and received via email on March 12, 2019. The report includes the daily flow rate and duration of all reported SCVF and GM leaks in Alberta, along with information on well location and ownership, beginning in 1971.

In what follows we provide insights into SCVF and GM leaks from abandoned and suspended wells in Alberta between 1971 and 2019. Specifically, we focused on the length of time a leak persisted, the amount of time passed between "Report Date" and "Resolution Date" – we call this variable "leak spell;" and the emitted volume measured by the daily flow rate – we refer to this variable as "leak volume." We present these results below, which provide new information to policy makers and the public.

Figure 1.2 uses a nonparametric polynomial regression to depict the time trend of positive leak spells, that is the duration in days between the date that a leak was reported to the AER and the date it was closed. According to the AER Interim Directive 2003-01 leaks are resolved according to the following process. Leaks can be serious or non-serious. A serious leak is greater than 300m^3 of flow per day, in contact with usable water or presents an urgent hazard and must be resolved within 90 days. For a non-serious leak, the well licensee must perform tests on the well annually for five years, measuring the flow and stabilized pressure buildup to detect possible change. If there is no change in in the flow and pressure after five years of testing, or if the flow dies out completely, the leak is considered resolved. Figure 1.2 considers both types of leaks, from abandoned and suspended wells.

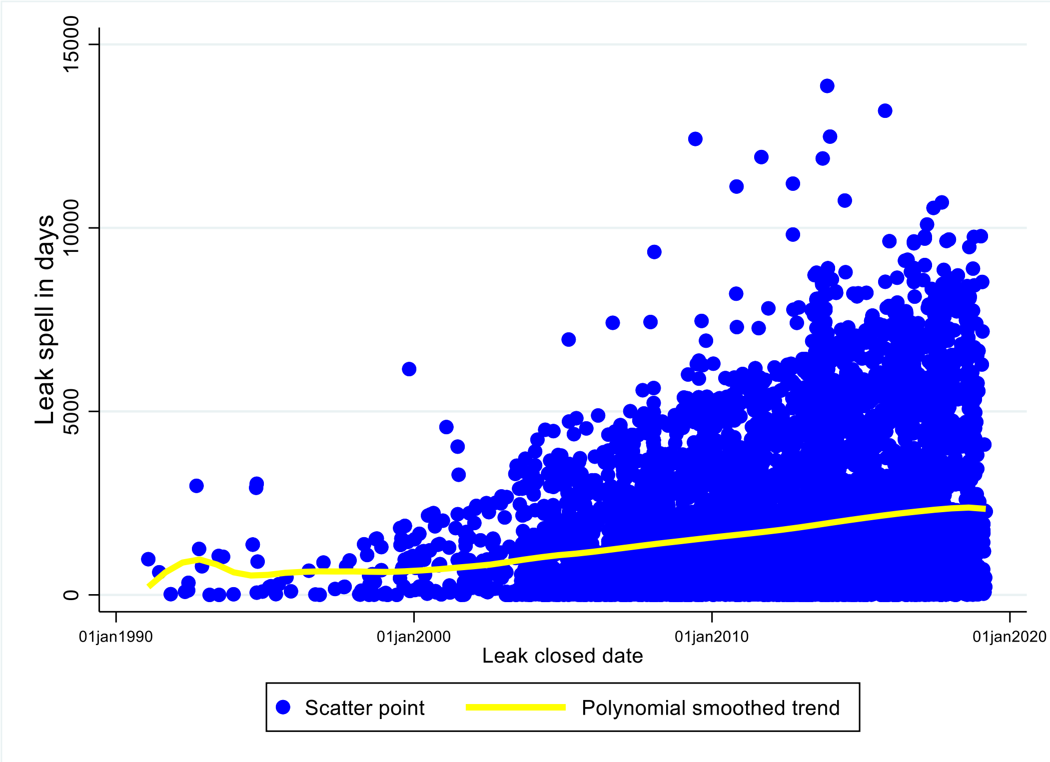

Figure 1.2: Leak Spells: Abandoned and Suspended wells 1971 to 2019.

The horizontal axis displays the date a leak was closed. The vertical axis shows the number of days the leak lasted before it was closed. Observations are drawn from daily data during the 1971-2019 time-period. For example, a single scatter point identifies the number of days a leak spell persisted at any given leak closure date. As we move along the horizontal axis from left to right, the trend line picks up ever longer periods of leak spells, resulting in an upwards sloping trend over time. The average spell in our data is 1,753 days (approx. 5 years). The maximum spell is 13,869 days (approx. 37 years). To control for the fact that later time periods allow for longer possible spells, we also use a constant backward-looking time-period of 20 years and only show leak spells during that 20-year period (Appendix 1B), which confirms the findings presented in Figure 1.2 of increasing leaks spells over time.

Moreover, Figure 1.3 shows for any reported leak (x-axis), whether the leak was attended to and closed or was still unresolved at the end of our sample time-period (2019). To this end, we ran a nonparametric regression of a dummy variable indicating that the reported leak was never resolved (open=1) against the reported date. The trend line in Figure 1.3

has the simple interpretation of the probability of a leak remaining open over the 1971-2019 period. The Figure suggests that the probability of leaks being unresolved and open has increased sharply over time, particularly in the late 2000s. However, since leaks early in the sample period have more time to be resolved than later leaks, we have also reported on the probability for a leak being resolved using a constant time window of 5 years and 10 years after being reported. These results can be found in Appendix 1C and 1D and confirm the finding of Figure 1.3 that incidence of unresolved leaks has increased sharply over time.

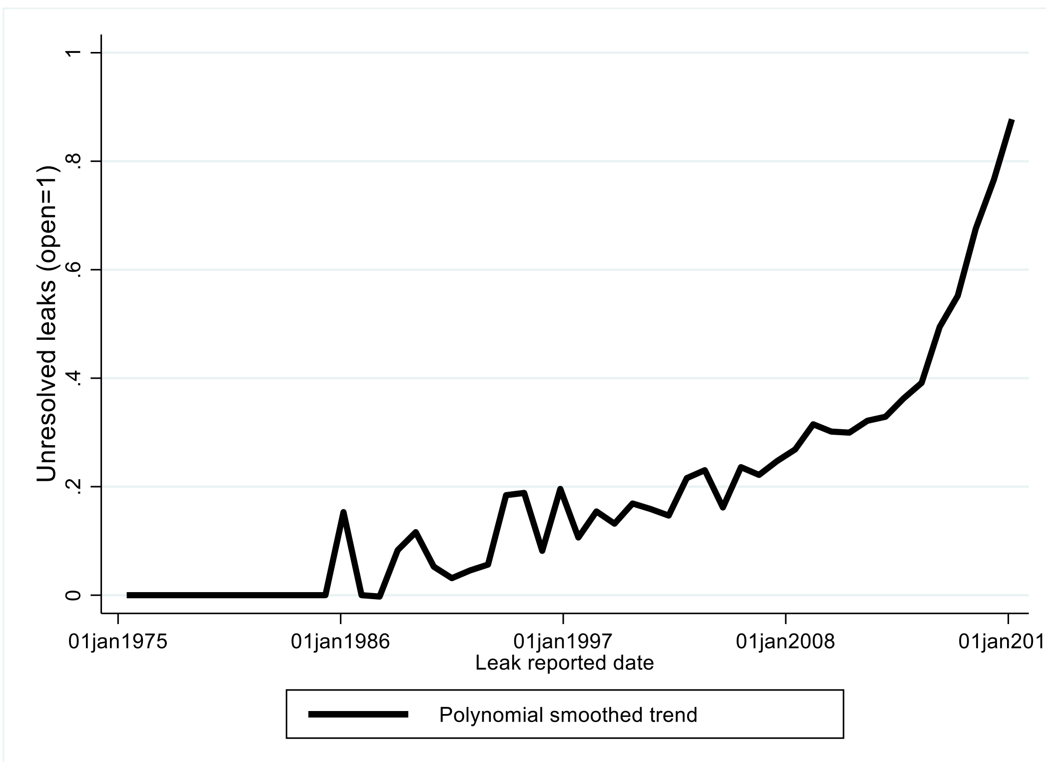

Figure 1.3: Probability of Open Spells: Abandoned and Suspended wells 1971 to 2019.

Finally, Figure 1.4 shows a trend in volume of methane emissions measured as a Flow Rate (m^3/day). There is an increasing trend in volume of methane emitted after the late 1980s. Specifically, there is a clear upward trend after 2010. This finding is concerning and should spawn new research exploring why we have experienced an increase in leak volume.

Combined, Figures 1.2-1.4 show that not only are leak spells increasing over time, but also that the probability of a reported leak remaining unresolved has increased. The importance of these findings is further amplified given that the amount of methane emitted per leak as also increased over time. As society faces increasing negative uncertainties related to climate change, regulators need to be aware of these issues and solutions need to be brought forward as soon as possible. Our cost approach in the next section might provide some guidance.

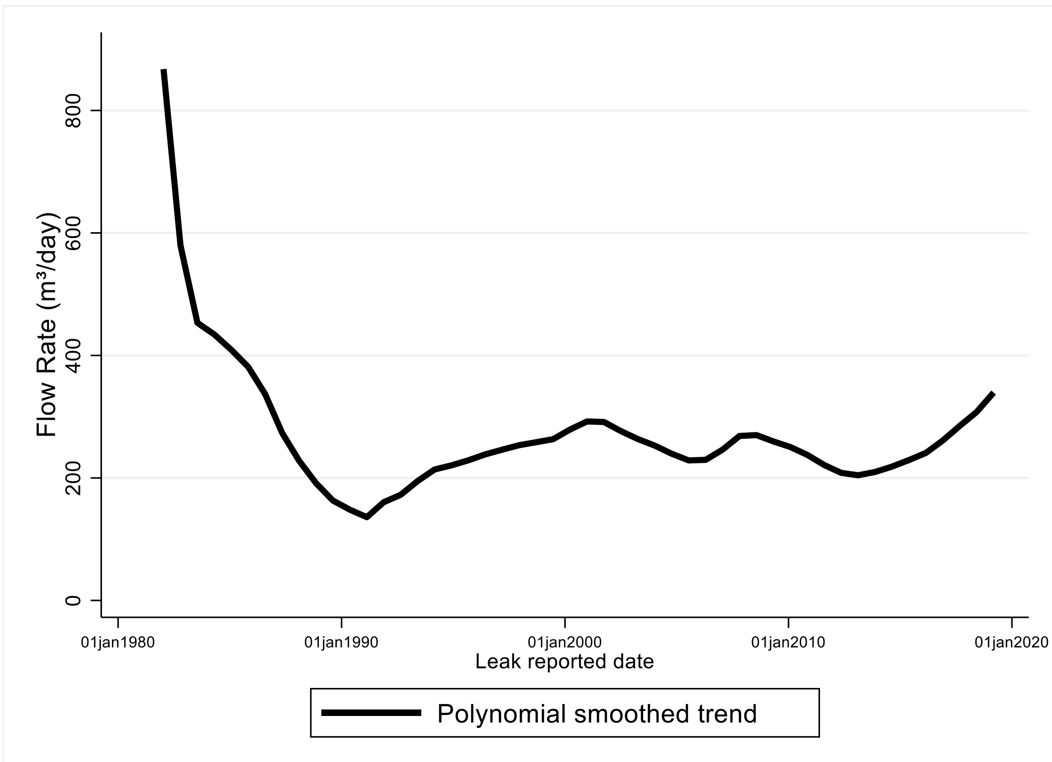

Figure 1.4: Flow Rate in m^3/Day: Abandoned and Suspended wells 1971 to 2019[8]

[8] Positive reported flow rates in the data started on January 13, 1982, reflected in the horizontal axis of Figure 4.

1.4 Cost Assessment Preparation with and without the Social Cost of Methane

1.4.1 Data Preparation Steps

To understand the financial motivations of owners of inactive wells, we must evaluate the costs associated with the choice to either leave a well in the suspended state or to undergo the process of abandonment and reclamation. To do so, we estimated the average costs associated with suspension and abandonment using publicly available data.

The choice to leave a well suspended will require annual surface lease payments to be paid by well owners until full reclamation has occurred and a certificate received. The annual surface lease rate was obtained by multiplying average surface lease costs per acre of $3,100 (taken from Alberta Agricultural and Rural Development, 2010 and supported by average land values reported by Government of Alberta, 2019) by the typical lease size of 1 ha (or 2.5 acres) as reported in Pasher et al. (2013). A suspended well must also be inspected at regular intervals; we assume these will occur in year one and every third year thereafter (a middle range of AER requirements) and have estimated the inspection cost using figures reported by the OWA. In 2017, the OWA completed 859 inspections at a total cost of $568 Million for an average cost of $661 per inspection (OWA 2018).

Alternatively, the owner may choose to pay to have the well abandoned and reclaimed. Although this process often takes several years to complete, we assume that all necessary equipment is available and no complications are experienced, so abandonment occurs in year one, reclamation occurs in year 2, and the reclamation certificate is received at the end of year 5 to account for the additional 2-4 years that typically elapse before a reclamation certificate is received from the AER (OWA, 2017). As such, our model features annual surface lease payments ($7,750) in years 1 through 5 and well inspections to test for leaks, as required by AER Directive 020, in years 1 and 4. We have based our estimated abandonment cost on actual costs from the OWA. Between 2015 and 2017, the OWA completed 676 well abandonments at an average cost of $70,500 (see Appendix 1A for more information). Reclamation values are difficult to ascertain from OWA reports because the process can take place in several steps over multiple years, so we use a reclamation cost that reflects a simple average of the 7 regional values provided by the AER (Table

1.2b). This combined abandonment ($70,500) and reclamation ($28,321) expense (total $98,821) is in line with both total AER liability values and the $100,000 liability per well used by Dachis et al. (2017).

Table 1.2a: Regional Abandonment Costs Overview

Alberta Energy Regulator	**Liability Value in Canadian Dollars ($/well)**
Area 1: Medicine Hat	75,506
Area 2: Calgary/Edmonton	78,105
Area 3: Drayton Valley/Grand Prairie	79,343
Area 4: Lloydminster	75,506
Area 5: Athabasca/Peace River	79,043
Area 6: High Level	89,069

Notes: Data taken from AER Directive 011 released March 31, 2015. Values shown are the Tubing and Rod Abandonment value at a depth of 2000-2499m for each region.

Table 1.2b: Regional Reclamation Costs Overview

Alberta Energy Regulator	**Liability Value in Canadian Dollars ($/well)**
Grassland Area East	16,500
Grassland Area West	25,250
Parklands Area	27,250
Foothills Area	29,250
Alpine Area	42,125
West Boreal Area	34,000
Boreal Area	23,875

Notes: Data taken from AER Directive 011 released March 31, 2015

The choice of discount rate has a significant effect on long-term economic outcomes. We have chosen to compare outcomes using four different discount rates; 10% was chosen based on a survey of corporate hurdle rates in the oil and gas industry (The Oxford Institute for Energy Studies); 7% demonstrates a more conservative private discount rate; 3% is the median value used by the US EPA and by Environment and Climate Change Canada for the SCC (ECCC, 2016); finally, we included a discount rate of zero, which may be appropriate considering that these analyses address climate change and other important inter-generational and inter-temporal issues (Goulder and Stavins 2002, Arrow et al. 1996).

To assess the SCM, we need to first determine the amount of methane leaked by suspended wells. Watson and Bachu (2009) utilized a dataset from the AER (then called the Energy

Resources Conservation Board) outlining SVCF/GM leak volumes and dates. We build on this approach by using our updated version of that dataset (SVCF/GM Report for all Companies in Alberta, March 2019) from the AER with a full history of recorded SCVF and GM migration data to calculate the expected methane emissions from a typical suspended well. This dataset contains a total of 34,186 reported cases of either form of gas leakage; 10,640 of which are "open" or active cases and 23,546 which are considered "closed". For most closed cases, the well is no longer leaking, either because it has been repaired or it was classified as non-serious and allowed to die out. However, there are nearly 3,200 closed cases labelled "monitor as required", suggesting that these leakages may be ongoing. 11,779 of all cases belong to currently suspended wells, including 6,631 closed and 5,148 open. Currently abandoned wells account for 7,276 of all cases, including 7,142 closed and just 134 open. One of the weaknesses of the dataset is that it only provides the current status of each well, so we do not know the status of the well at the time of leak onset. As such, the open cases are more likely to present an accurate representation of leak instances by status type and reaffirms that abandoned wells are much less likely to leak than a suspended well. The relatively low ratio of open abandoned cases to closed abandoned cases also suggests that many of the closed cases may have been active or suspended when the leak began but have since been plugged and abandoned.

Many reported cases of SVCF or GM found in the dataset list either no value or zero for release volume; although these may reflect leaks that have ceased but are not yet officially reclassified as closed, no explanation is provided so we removed these records from our calculations. This leaves 3,042 open cases of suspended wells with leaks. Based on a simple average, these leaks have been active for 3,065 days (8.4 years) and have a daily release is 24.7m^3/day. This volume is significantly higher than the data reported from 2015 of 13m^3/day (Ho et al, 2016). A weighted average of release volumes [($\sum$ daily release x days leaking)/total days leaking], further increases the average daily release to 42.6m^3 per day and demonstrates that wells leaking at higher volume rates tend to leak for a longer duration. Based on this weighted average, a typical leaking suspended well will emit 130,459 m^3 of total gas volume (3,065 days x 42.6m^3/day). For comparison, we also performed the same calculation for the abandoned open cases; 53 wells with non-zero release rates have been releasing a simple average of $3.3m^3$/day for 2265 days (6.2 years). The weighted average release for open abandoned cases is $2.6m^3$/day for a total weighted release volume of 5,834 m^3 (2265 days x $2.6m^3$/day).

Although our analysis is focused on open cases, the leak data from closed cases does provide some potentially useful insights. Amongst all 23,546 closed cases of SCVF or GM, 10,572 (45%) of these were allowed to die out, 7,495 (32%) were repaired – including categories "Problem Repaired" and "Repaired – SVCF/GM", 3,196 (14%) are "monitor as required" or "non-serious", 1,051 (4%) were found to have been reported as leaking in error, while the remainder fell under a variety of other small categories. As with the open cases, there were many release rates reported as zero or with no values which we eliminated from the calculation. A second challenge was establishing the duration of a leak for closed cases; the dataset reported numerous cases with a resolution date which precedes the onset date and no explanation for why. These negative or zero-day cases were also excluded from our calculation. This left 1,902 closed suspended cases for evaluation. The proportion of suspended wells that were resolved by repair is significantly smaller when compared to the broader population of closed cases; this may suggest that leak repairs are often completed as part of the abandonment process. For the suspended closed cases allowed to die out the weighted average release is $18.4m^3$/day for 1,723 days ($31,717m^3$ over 4.7 years). The repaired cases released a weighted average of $189.8m^3$/day for 1,092 days ($207,212m^3$ over 3.0 years). As expected, a leak that requires repair tends to be resolved more quickly, but still releases significantly more gas. In aggregate, suspended well closed cases release an average of $37.6m^3$/day for 1,550 days ($58,323m^3$ over 4.2 years). Compared to suspended open cases, the daily release from suspended closed cases is comparable, but the duration is less than half.

Due to the increased uncertainty around the possible change in well status from when the leak was active to its being closed and the ambiguity in the duration of many closed cases, we only use the data from open cases ($130,459m^3$ total gas release) for the SCM evaluation. No information exists or is publicly available regarding leaked gas composition (Bachu, 2017), but regional emissions analysis showed that gas releases are comprised of 97% methane (Johnson et al, 2017), so this paper will factor estimated gas emissions by 0.97

translating to 126,545m^3 of methane per leaking well. The SCM is priced in $/tonne, so we convert the volume release to tonnes based on the molecular weight of methane at Normal temperature and pressure which is a ratio of 0.668kg/m^3 (Engineering Toolbox 2003).

The final factor in determining expected methane emission from a suspended well is to estimate the percentage likelihood that any given suspended well will develop a leak. Although all wells, both active and inactive, have the potential to develop a leak, AER ST60B reports that while 7.2% of all drilled wells in the province report a SVCF or GM event, that figure increases to 10.9% when considering suspended wells only. Other work suggests a lower 4.6% chance of any well having a leak in 2005 (Watson & Bachu, 2009) with the odds rising to 6.6% in 2013 (Bachu, 2017). The work of Bachu and Watson also indicates that older wells are generally more likely to develop leaking due to outdated technology and regulations, but when comparing only newer wells those with suspended status are not more likely to leak than active wells; no direct comparison of suspended vs abandoned wells was provided. Given that these studies found a lower overall percentage of leaks, we applied a SVCF/GM percentage of 10.0% to the suspended well scenario, which is slightly lower than the value presented by the AER. However, empirical studies using regional airborne or ground-based measurement have indicated that wellsite methane emissions are significantly under reported (Johnson et al, 2017 & Zavala-Araiza et al, 2018). An investigation of 178 well-sites in the Montney play of British Columbia, Canada, where researchers physically visited and measured methane leakage at each well, found that 29% of abandoned and suspended wells currently have a SCVF or GM leak (Werring, 2018), so we have also included a SCM estimate based on this 29% leak rate.

1.4.2 Cost Estimates without the Social Cost of Methane

Owners who do not intend to reactivate their suspended wells have two options; they may leave the well suspended indefinitely or they may undergo the abandonment and reclamation process. As alluded to earlier, abandonment and reclamation are the socially preferred option, permanently plugging the well and returning the land to its (more-or-less) original status once production ceases at the well-head. Nonetheless, there are costs involved that largely determine owners' decisions. What is more, just because a well has been abandoned and plugged, does not mean that it will not leak; corrosion, improper abandonment, or damage from other activities can cause an abandoned well to leak. However, we see from the relatively low number of leak occurrences and small emission volumes that well abandonment does lead to reduced environmental, human, and animal health risks. Future research might determine the true percentage of leaks from abandoned wells and whether ambiguous monitoring requirements, such as "conduct regular testing", are responsible for some of the reduction.

The annual costs associated with suspension are small compared to abandonment and reclamation, at least in the short and medium run, which is precisely the time frame considered by most profit seeking firms. In contrast, we know that the decision to abandon and reclaim will eventually eliminate the monitoring and lease costs but will require a significantly greater capital investment now. Given the different cash flow timing for each option, we compare the total costs of each option and evaluate when the net present value of suspension is equal to the net present value of abandonment and reclamation. This is an important issue as suspension costs not only impact owners but, through the emitted methane gas, impact society and the environment. Hence, we specifically focus on the time frame that incentivise owners to abandon and reclaim as opposed to leave a well suspended and leaking.

Our calculated estimate of the present value of abandonment and reclamation includes the abandonment expense ($70,500)[9] in year one, reclamation ($28,321) in year two, a well inspection ($661) in years 1 and 4, plus annual surface lease payments ($7,750) in years 1 though 5. Suspension costs include annual surface lease payments, along with a wellsite inspection every three years, beginning in year 1, in perpetuity. Table 1.3 shows the results of this calculation, which demonstrate that there is little short-run financial incentive for a firm to undergo the abandonment and reclamation process with a well. Even using undiscounted cash flows, it would take nearly 18 years of suspension maintenance costs to equal the abandonment and reclamation costs.

[9] Abandonment and well inspection costs are based on OWA data, reclamation costs on AER liability tables, and lease costs on Government of Alberta land value data. A more detailed explanation on the calculation of these estimates can be found in the "Data Preparation Steps" section.

Table 1.3: Comparison of present value cost between abandonment/reclamation and suspension

Discount Rate	PV of Abandonment Costs	PV of Suspended Costs	Yr when Suspended = Abandonment
10%	$ 129,720	$ 87,887	Never
7%	$ 132,170	$ 121,948	Never
3%	$ 135,820	$ 272,150	24
Undiscounted	$ 138,893	Infinite	18

The AER found that costs can be reduced by up to 40% if a program is undertaken to abandon multiple wells in one region (AER, Area Based Closure). If a firm can reduce its abandonment cost by 40% (the year 1 abandonment expense is now $70,500 x 60% = $42,300), could this result in well owners favoring abandonment over suspension? We see from the calculated results (Table 1.4) that this reduction in abandonment costs fails to substantially impact the cost comparison. With zero discount rate, it still takes 14 years of suspended well payments to equal the up-front abandonment and reclamation expense. This indicates that programs designed at lowering abandonment costs may influence socially conscious firms to plug and reclaim their wells but are unlikely to affect the financial decision-making process of short-run focused organizations unless new policy directives that place emphasis on future cost and time frames intervene. Together, what these calculations demonstrate is that, even when a firm is optimistic about abandonment costs, the myopic profit-seeking firm is likely to choose to leave an inactive well suspended.

Table 1.4: Comparison of present value cost between abandonment/reclamation and suspension, where abandonment costs have been reduced by 40%

Discount Rate	PV of Abandonment Costs	PV of Suspended Costs	Yr when Suspended = Abandonment
10%	$ 101,520	$ 87,888	Never
7%	$ 103,970	$ 121,949	29
3%	$ 107,620	$ 272,150	17
Undiscounted	$ 110,693	Infinite	14

1.4.3 Cost Estimates with the Social Cost of Methane

From our analyzed dataset obtained from the AER, the average active SVCF/GM leak from a suspended well has been releasing 42.6m^3 of methane per day for 3,065 days (8.4 years) resulting in an estimated total lifetime methane emission of 130,459m^3 per well. At 97% methane content and converted to tonnes using the molecular weight of methane:

$130,459m^3$ x 0.97 x $0.668kg/m^3 \div 1,000kg/t$ = 84.5 tonnes of lifetime methane emission per well.

Dividing this total emission by 8.4 years, the expected methane emission from a leaking suspended well is approximately 10.0t in years 1-8 and 4.5t in year nine. We find the cost of these emissions by applying a SCM.

Using the CDN$1,050 (US$810) SCM suggested by Marten & Newbold (2013):

$1,050 x 10.0t = $10,500/year/well during years 1-8,

$1,050 x 4.5t = $4,725/year/well in year 9.

Using the CDN$4,665 (US$3,600) SCM suggested by Shindell (2017):

$4,665 x 10.0t = $46,650/year/well during years 1-8,

$4,665 x 4.5t = $20,992.50/year/well in year 9.

In the original scenario above (Table 1.3), we compared the cost to leave a well in the suspended state against the present value of abandonment and reclamation, using 10%, 7%, 3%, and 0% discount rates. We find that, even with abandonment expense reduced and non-discounted cash flows (Table 1.4), suspension costs do not surpass abandonment and reclamation costs for 14 years.

If we apply an additional suspension cost equal to the SCM, based on an average SCVF/GM leak of 10.0t for the first 8 years and 4.5t in year 9, how will it impact the cost comparison? Table 1.5 shows in which year the suspension costs become equal to the non-reduced abandonment and reclamation cost based on discount rate and SCM. We see that, if a firm is forced to pay for the methane emitted from a leaking well, especially at the higher SCM, it becomes much less financially advantageous to leave that well suspended.

Table 1.5: Year when suspension and abandonment/reclamation cost intersect, accounting for the social cost of methane (SCM)

	10% Discount Rate	7% Discount Rate	3% Discount Rate	0% Discount Rate
Base Case (No SCM)	Never	Never	24	18
SCM of CDN$1050/t	15	11	9	8
SCM of CDN$4665/t	2	2	2	2

However, this assumes a leaking well and not all suspended wells will develop a leak. Most suspended wells are on private land, which makes assessment difficult, and there is no consistent data on the percentage of wells that leak – values from 10% to 29% have been suggested. To account for the 10% chance of suspended wells experiencing a methane leak, we also reduce the expected yearly cost attributed to methane to 10% of full value. The results, shown in Table 1.6, indicate that when using undiscounted cash flows, the costs of an abandoned or suspended well become equivalent in year 13.

Table 1.6: Year when suspension and abandonment/reclamation cost intersect, accounting for the social cost of methane (SCM) and 10% expectation of a SCVF/GM leak occurring

	10% Discount Rate	7% Discount Rate	3% Discount Rate	0% Discount Rate
Base Case (No SCM)	Never	Never	24	18
SCM of CDN$1050/t	Never	Never	22	17
SCM of CDN$4665/t	Never	27	16	13

On the other hand, if 29% of all suspended wells leak (Table 1.7), we get expected costs that would encourage profit-seeking firms to begin favouring abandonment and reclamation over suspension, especially at the higher SCM as the cot associated with abandoned or suspended well become equivalent in year 7.

Table 1.7: Year when suspension and abandonment/reclamation cost intersect, accounting for the social cost of methane (SCM) and 29% expectation of a SCVF/GM leak occurring

	10% Discount Rate	7% Discount Rate	3% Discount Rate	0% Discount Rate
Base Case (No SCM)	Never	Never	24	18
SCM of CDN$1050/t	Never	37	18	15
SCM of CDN$4665/t	9	8	7	7

1.5 Conclusion and Public Policy Discussion

Suspended petroleum wells are prone to gas leaks that release methane emissions into the atmosphere. These emissions contribute to climate change, impact human health, and reduce agriculture yields, all of which poses an additional cost on the public that has been termed the Social Cost of Methane. Currently, none of these costs are paid for by the owners of these wells. This is inefficient from an economic perspective and irresponsible from a policy perspective, particularly during a time when there is increasing urgency to reduce greenhouse gas emissions to combat climate change.

Using data obtained from the Alberta Energy Regulator, we show that between 1971-2019 leak spells (the amount of time between a leak is first reported to the time a leak is reported as closed) have increased. We also show that the probability of a reported leak being unresolved has increased. Moreover, during the same time-period, we find that the amount of methane emitted per leak has increased substantially. Lastly, the results from a social cost of methane (SCM) simulation revealed that when owners are forced to include the SCM in their decision to either leave a well in a suspended status or to undergo abandonment and reclamation, suspension becomes less desirable, especially in the medium-run. Likely our estimates still understate the true SCM, as these costs do not account for all human health related costs, the impacts on Indigenous culture, and many poorly understood environmental and ecosystem impacts from air pollution.

Given the increase in wells drilled in Alberta over the years, and the recent uptick in orphan wells, there exists increased urgency in understanding the environmental and economic implications to the public. These findings are particularly relevant when emphasis has been placed on reaching vital climate goals, such as those outlined by the federal Government of Canada. The Alberta government states that "Cutting methane emissions is a cost-effective way to reduce greenhouse gas emissions" (Alberta, nd); however, fugitive emissions are currently not subjected to any levy and recently updated AER Directives (such as 060 and 017) continue to exclude reporting requirements for methane release from SCVF or GM events (AER Bulletin 2018-37). Our analysis suggests that current policies disincentivize the remediation of abandoned wells, as it is significantly cheaper to leave wells in a suspended status. Without including the SCM, it makes far more monetary sense for a firm to pay the ongoing surface lease costs, which are far less than the immediate capital costs of abandonment and reclamation. A similar conclusion is also drawn by Muehlenbachs (2015 and 2017) and evident by the rising number of suspended wells relative to abandoned wells occurring in Alberta since 2014. Given the higher likelihood of leakage from suspended wells compared to reclaimed ones, policy makers should rethink existing policies that address these issues from a public health and climate policy perspective. Changing the status quo of owners who currently have little incentive to pay for abandonment and reclamation would likely reduce methane emissions and improve air and environmental quality. Albeit, appropriate policy instruments will be sensitive to the assumed percentage of suspended well leaks and selection of the discount rate.

Both a conservative SCM, adopted by the US EPA, and a higher SCM that attempts to incorporate the indirect effects of methane, have been suggested in the literature. The dataset obtained from the AER shows that open cases of suspended wells having gas leakage emit an average of 42.6m^3/day for 8.4 years, which yields 84.5 tonnes of methane for a typical leaking well. There are currently about 81,000 suspended wells in the Province of Alberta, which may or may not leak methane gas into the atmosphere. So far, these emissions have received little attention. If the government of Alberta is serious about addressing climate change, then the emissions from suspended wells deserve more attention and should be included in public decision making. For example, reported leakage equaled 83 million m^3 of natural gas in 2017, translating to 53,781 tonnes of methane emitted to the atmosphere (roughly 3% of the oil and gas contributions to methane emissions in Canada), producing about $56-250 million in unaccounted social cost.

To reduce methane emissions, tighter regulations, and increased monitoring, along with enforcement of repair timelines, would help to reduce gas leak volumes. However, the most effective solution may be to implement policy aimed at reducing the number of suspended wells, thus helping the province achieve its 45% methane reduction goal by reducing the instances of gas leakage and mitigating the future burden of clean up.

Policy makers interested in the welfare of their constituents (ostensibly their job), should hold well owners accountable for the externalities they produce. Moreover, given the associated variability of the social cost of methane and the urgency to address climate change, policy makers should err on the side of caution and use a higher SCM, for example as suggested by Shindell (2017) – this will also offset several decades of unaccounted externality, which were (and still are) paid by the public. Lastly, despite the analysis conducted in this article, policy makers may want to increase the cost associated with suspended wells just beyond the cost of abandonment and reclamation, thus, providing additional incentives for short-sighted well owners to paid for reclamation of the land. The urgency surrounding the negative implications of climate change leave little time to significantly reduce greenhouse gas emissions, including those produced by suspended petroleum well.

1.6 References

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Paper 2: Assessing the Techno-economic Feasibility of Retrofitting a Petroleum Well for Direct Use Geothermal Energy Production: A Case Study

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Abstract

There are over 450,000 registered oil and gas wells in the province of Alberta, Canada. Low energy prices have contributed to a recent increase of the number of wells that are inactive. These inactive wells present a significant environmental risk and financial liability in cleanup costs. However, these wells also present an opportunity to increase the production of clean, renewable energy by retrofitting a selection of wells for direct-use geothermal heat energy production. The goal of this paper is to assess the techno-economic feasibility of using the legacy oil and gas infrastructure to produce geothermal energy and improve the productivity of a cattle ranch by increasing the temperature of the drinking water available to cattle during the cold winter months. We estimate the average cost to retrofit one of the five suspended wells on ranch property at $212,999 and create a model of well retrofit costs that can be expanded to further research and other geothermal re-purposing projects throughout Alberta and hydrocarbon producing regions around the globe. We also estimate the geothermal power potential of the wells on the property and find that it would require three retrofit wells to provide the energy required to raise the cattle drinking water temperature from 2.5°C to 10°C. Finally, based on all estimated costs and revenues expected over the life of the project, we calculate that the project's expected net present value is negative $845,775. These results lead us to examine the financial and policy fundamentals of geothermal energy production that would allow these types of projects to be successful.

2.1 Introduction

2.1.1 Study Background

Western Canada's economy is strongly tied to its oil and gas industry. Through the years, over 450,000 oil and gas wells have been drilled in Alberta alone (Dachis, Shaffer & Thivierge, 2017). The Alberta Energy Regulator (AER) estimates current provincial hydrocarbon reserves at 164 billion barrels of crude bitumen (often referred to as oilsands), 1.7 billion barrels of conventional crude oil, 816 billion cubic metres of natural gas, and 33.1 billion tonnes of coal (AER, May 2019).

In recent years, an increasing number of wells have been shut-in and made inactive because production is no longer economical. Additionally, low hydrocarbon prices have caused several petroleum companies to go bankrupt, leaving a rapidly growing number of "orphaned" wells with no legal entity responsible for their cleanup. The Orphan Well Association, which was established by the AER to manage these orphaned wells, has recently been forced to accept government grants and loans to meet expenses (Orphan Well Association, 2018), casting doubt on the financial sustainability of the Orphan Well Association. Thus, the liability for orphaned wells ultimately lies with the province and its taxpayers.

Due to its economic dependence on hydrocarbon production, Alberta is among Canada's leading emitters of greenhouse gases. In 2017, Alberta was responsible for ~38% of total national greenhouse gas emissions, despite having just over 10% of Canada's population (Environment and Climate Change Canada, 2018). While oil and gas production is responsible for 48% of those emissions, Alberta's electricity sector also produces more gross greenhouse gas emissions than any other province in Canada due to its reliance on coal-fired generation (Canada Energy Regulator, 2019). Both the provincial and federal governments have acknowledged the importance of climate change and indicated that reducing GHG emissions is a priority. Indeed, Alberta was the first jurisdiction in North America to put a price on carbon emissions, in 2007, through the euphemistically named *Specified Emitter Regulations* (ERA Ecosystem Services, 2014). Although this price has been retained and even increased under a newly elected conservative government in 2019, carbon emissions have continued to increase while other province's emissions have remained relatively static or decreased (Environment and Climate Change Canada, 2020). New tactics are needed and increasing Alberta's energy generation from renewable sources is one way to achieve reduced greenhouse gas emissions.

Re-purposing existing oil and gas wells for geothermal energy exploitation would address both issues of inactive well liability and rampant greenhouse gas emissions. Geothermal energy harnesses the naturally occurring heat found beneath the Earth's surface. At high enough temperatures, electricity can be generated by producing steam to power a turbine, while lower temperature resources can provide "direct use" heating for large buildings, greenhouses, and other industrial and commercial applications (Leitch, Hastings & Haley, 2017). Re-purposing, or retrofitting, a petroleum well would extend the life of the existing asset while also providing a source of non-greenhouse gas emitting renewable energy.

Geothermal energy has the advantage over other renewables of being a baseload power source (Clauser & Ewert, 2018). Drawing upon the persistent natural heat of the earth, geothermal energy projects are typically capable of producing energy at 95% of approved capacity, while solar and wind projects that depend upon prevailing environmental conditions are typically closer to 40% of capacity (Grasby et al., 2012). Geothermal energy, however, is disadvantaged by significant up-front capital costs that can be prohibitive to many firms and often make a geothermal project uneconomical (Peachey, 2019). Exploration and drilling expenses are the most significant component of capital cost, comprising anywhere from 40-95% of the total (Leitch et al., 2017; Caulk & Tomac, 2017). Using an existing oil or gas well would remove most of the exploration and drilling expense and is estimated to be an order of magnitude cheaper than drilling and completing a new geothermal well (Banks et al, 2017). Lower temperature direct use heating projects, which do not require the additional infrastructure required to convert the heat to electricity, are especially promising from an economics perspective (Lavigne, 2018).

Geothermal resources lower than 80°C are too cool to generate electricity using current technologies but may be used for direct use heat applications (Grasby et al., 2012; Caulk & Tomac, 2017). In a survey of worldwide direct use geothermal heating applications, Lund and Toth (2020) find that direct use heating is being used for tasks such as space heating and timber drying in 88 reported countries. This demonstrates the global potential for direct-use geothermal energy. Presently, in Canada, direct use geothermal energy is limited to just two applications; commercial swimming and bathing, and the heating and cooling of buildings (Raymond et al., 2015). Despite the presence of significant geothermal resources, its utilization has been hindered in Canada by low fossil fuel prices and lack of policy support from government (Raymond et al., 2015; Leitch et al., 2017).

This paper is a techno-economic case study of retrofitting inactive petroleum wells for geothermal heat production on a cattle ranch in Alberta. After petroleum, agricultural products (crops, livestock, processed food, and beverages) are the highest export of Alberta (Government of Alberta, Dec 2017). This case is, therefore, also an illustrative example of the synergies between these industries.

The subject of this study is Tomahawk Ranch, a 14,500-acre grazing ranch home to several thousand cattle. The ranch's owner has stated that one of his greatest challenges is providing drinking water for his cattle during the winter months when ambient temperatures are well below freezing. The water that he is currently able to provide is as cold as 1˚C during winter months, possibly leading to premature cattle death, weight loss, and other health concerns that affect the ranch owner's bottom line. A potential solution to this problem is to retrofit one or more of the 33 existing oil and gas wells on the ranch to provide geothermal energy to the existing water system, thereby increasing the average drinking water temperature.

The goal of this paper is to demonstrate the techno-economic feasibility of using the legacy oil and gas infrastructure to improve the productivity of the cattle ranch. The water warming project at Tomahawk Ranch provides a tractable, real world example that can be used to assess the potential for well retrofits. This research will create a model of well retrofit costs that can be expanded to further research and other geothermal re-purposing projects throughout Alberta and hydrocarbon producing regions around the globe. It will also allow us to examine the financial and policy fundamentals of geothermal energy production that would allow these types of projects to be successful.

2.1.2 Geothermal Energy in the Western Canadian Sedimentary Basin

Although geothermal energy is largely unexploited as a resource in Alberta, there has been a significant amount of research into its potential. An ancillary benefit to the extensive petroleum drilling and production in the Western Canadian Sedimentary Basin is a robust set of subsurface temperature and hydrogeologic data. This data has facilitated much of Alberta's geothermal energy research. In the 1980s, the Atlas of the Western Canada Sedimentary Basin used bottom hole temperature data and regression techniques to create a map of the geothermal gradient in Alberta. Weides and Majorowicz (2014) improved upon this earlier work using newer and expanded datasets to create an updated geothermal gradient, as shown in Figure 2.1.

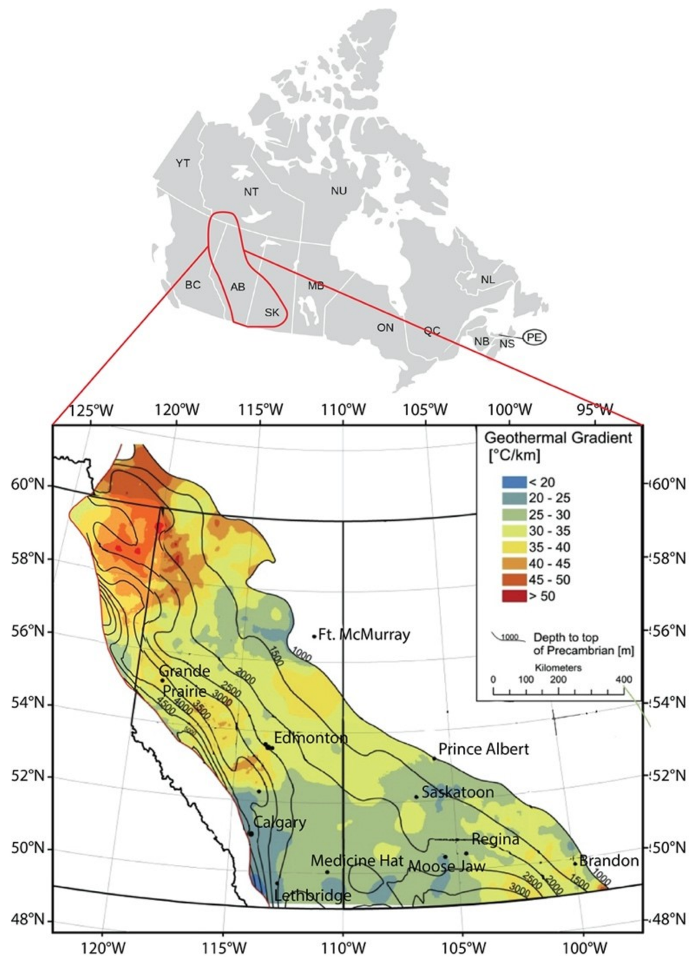

Figure 2.1: Geothermal gradient of the Western Canadian Sedimentary Basin (from Weides and Majorowicz, 2014)

More recent studies have used temperature and rock characteristic data from petroleum wells to further refine estimates of Alberta's geothermal energy potential. Banks and Harris (2018) quantified the total heat and electrical geothermal potential across western Alberta. Other papers have completed more focused studies and estimated the potential of a specific region or geological formation. Weides et al. (2013 & 2014), for example, investigated the geothermal power potential of a series of Devonian-aged reservoirs in central and western Alberta

Several cursory studies have also looked the economic factors controlling geothermal energy development in the Western Canadian Sedimentary Basin. Majorowicz and Moore (2014) take a closer look at the costs of developing an entire geological reservoir with new geothermal wells in Alberta. Palmer-Wilson et al (2018) used a two-step process based on geological and economic criteria, including the existence of population centres and existing infrastructure, to create a geothermal favourability map for Northeastern British Columbia. In a test of earlier research stating Canada's vast geothermal energy potential, Majorowicz and Grasby (2019) attempt to quantify what amount of that energy can be produced and conclude that geothermal power is only marginally economic when used for electricity generation and is likely feasible in only a few specific regions. One common trait of these economic studies is that they all include, via estimations, the cost incurred by drilling new geothermal wells.

A second trait shared by many of the studies evaluating the economics of geothermal power production is that they take a top-down approach to their analysis. They use regional totals and averages to estimate costs and production quantities. Geothermal energy production, however, is site specific (Clauser & Ewert, 2018) and requires a project level evaluation to determine its economic feasibility (Daniilidis et al., 2017). To date, Banks et al (2017) have conducted the most thorough study of the economics of geothermal energy development by estimating up-front expenses using local oil and gas drilling cost data from the annual PSAC drilling report and predicting revenues based upon regional electricity and natural gas prices.

The analysis of Tomahawk Ranch presented in this paper builds upon the earlier, rudimentary costing methods and energy potential calculations of Banks et al (2017), Banks and Harris (2018), and others by conducting a full lifecycle economic feasibility study of retrofitting real wells for a specific project. Focusing on a tangible, real world project will help to identify the variables that will most impact the economic outcome of a geothermal retrofit energy project, as well as demonstrate financial and policy viability.

2.1.4 Tomahawk Ranch Study Area

Tomahawk Ranch consists of 14,500 acres of land located in Parkland County, Alberta, approximately 100 km west of the provincial capital Edmonton, as shown in Figure 2.2. The ranch sits directly above the heart of the Western Canadian Sedimentary Basin, whose geothermal potential has been well studied, as described above. It is home to approximately 2,000 head of cattle, along with 33 petroleum wells of varying age and status.

One of the major challenges for the ranch is providing drinking water for the cattle during the cold winter months. Ambient temperatures from November until March have averaged a daily high of -1.7 °C and daily low of -11.6 °C over the past 10 years, including a low of -39.27 °C during January 2020 (Alberta Agriculture and Forestry, nd). Such temperatures are cold enough to freeze standing water. The water wells on Tomahawk's land were originally able to service only 5-10% of the property's total area. A recent 9.6 km installation of 75mm high density polyethylene pipe in a circuit has connected four water wells, allowing them to charge the water system from multiple locations and use a 1.12 kW pump that keeps the water flowing and prevents freezing. At various points, the water flows into an insulated tank where the cattle can drink from small holes. Although these holes often develop an icecap during the winter when water temperature can drop to 1 ˚C, they are tapered in a manner that allows the cows to easily dislodge the cap and access drinking water. With this system in place the ranch is now able to provide 5-6 l/s (~90 gal/min) of liquid water to about one third of the total acreage.

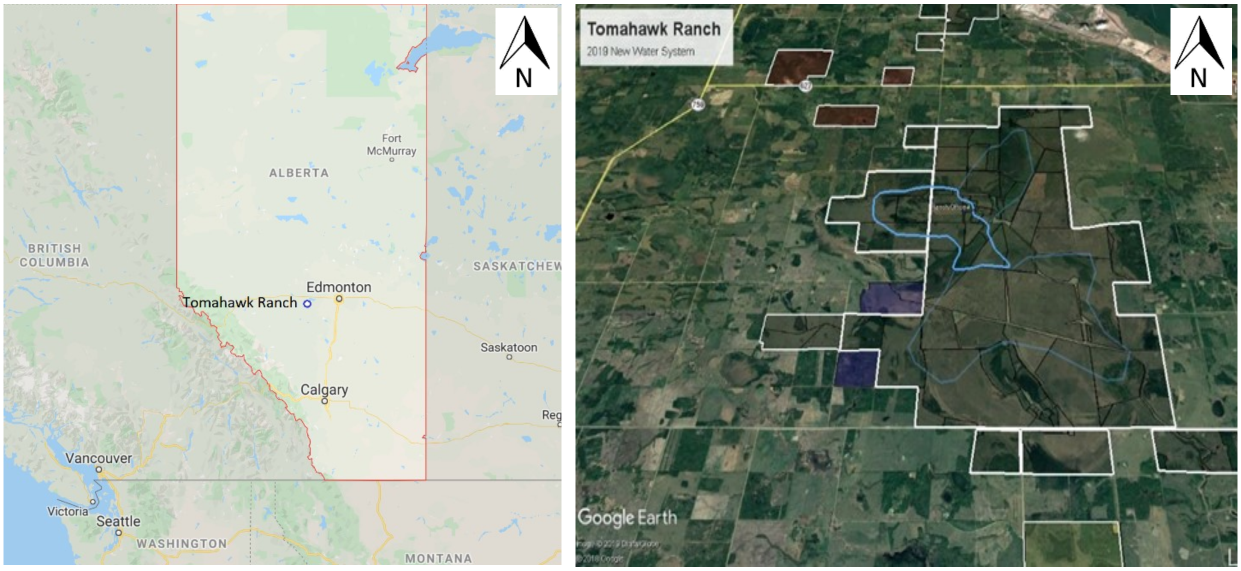

Figure 2.2: Left - The location of Tomahawk Ranch approximately 100km West and South of Alberta's provincial capital city of Edmonton. Right - A detailed view with the Tomahawk Ranch property outlined in white and the existing flowing water supply in blue

Although the cattle now have access to drinking water, the temperature of that water is often near freezing, and the Ranch owner believes that this may be causing weight loss or increased feed costs during the winter months. A literature review was unable to confirm this hypothesis but does suggest a link between ambient temperature and cattle health. Peterson et al (2016) found that water intake decreases as ambient temperature drops, but that animals offered warmer water will drink larger volumes. Other studies have also found that cattle dry matter intake tends to increase with cooler ambient temperature (Fox and Tylutki, 1998) and that the ratio of water intake to dry intake increases with warmer drinking water (Osborne, 2002). Collectively, these studies infer that cold water leads to decreased liquid intake along with increased dry feed intake. Intuitively, we understand that any ingested water must be warmed to the cow's internal body temperature. Every joule of energy used to warm their drinking water is a unit lost to maintenance or growth. Thus, cattle must consume greater quantities of feed to make up this deficit. Furthermore, the rancher has also noticed an increased mortality rate among birthed calves during the winter months and believes access to warmer water may lower that rate. If increasing the cattle's drinking water temperature decreases the amount of feed required or the mortality rate of calves, it would be a direct economic benefit of using a well retrofit for geothermal heat production at Tomahawk Ranch.

2.1.5 Well Status

In Alberta, petroleum well status definitions are defined as follows:

A well is considered “active” if it is producing fluid from the subsurface or being used to inject fluid, most commonly water, from the surface down into the reservoir. According to the AER’s Directive 013, a petroleum well is deemed “inactive” if there has been no fluid produced or injected for a period of 12 months. Once deemed inactive, the licensee (or owner) has an additional 6-12 months in which to “suspend” the well. Suspension, often labelled “temporary abandonment” in other jurisdictions, requires cleaning any spills or debris around the wellhead, ensuring flow valves are turned off and either locked and chained or removed so that they cannot be reopened, and placing plugs in all outlet pipes. Higher-risk wells also require additional downhole plugging. Once suspended, there is no limit to the length of time the well is permitted to remain in this condition, with the only stipulation being that it must be inspected for spills or gas venting every 1-5 years, depending on risk category. Well abandonment, which is often referred to as plugging a well, is the next step and is governed by AER Directive 020. Abandonment involves placing cement and non-corrosive fluids, such as non-saline water, or mechanical plugs down the wellbore to seal off zones of oil or gas production from the surface. It also requires digging a minimum of 1 metre below land surface to “cut and cap” the wellbore by covering it with a vented plate (Figure 2.3). Eventually, as there is also no time limit placed on abandonment, the land overlying the well must undergo reclamation. During the reclamation process the land is restored to a condition equivalent to what it was prior to petroleum development (AER- Reclamation). The term remediation is used to refer to any decontamination of soil and groundwater that takes place during the reclamation process and typically accounts for 65-75% of the total cost of reclamation (OWA, 2017). Until reclamation has been completed and a certificate issued by the AER, which often takes several years, the well owner must continue to make surface lease payments to landowners.

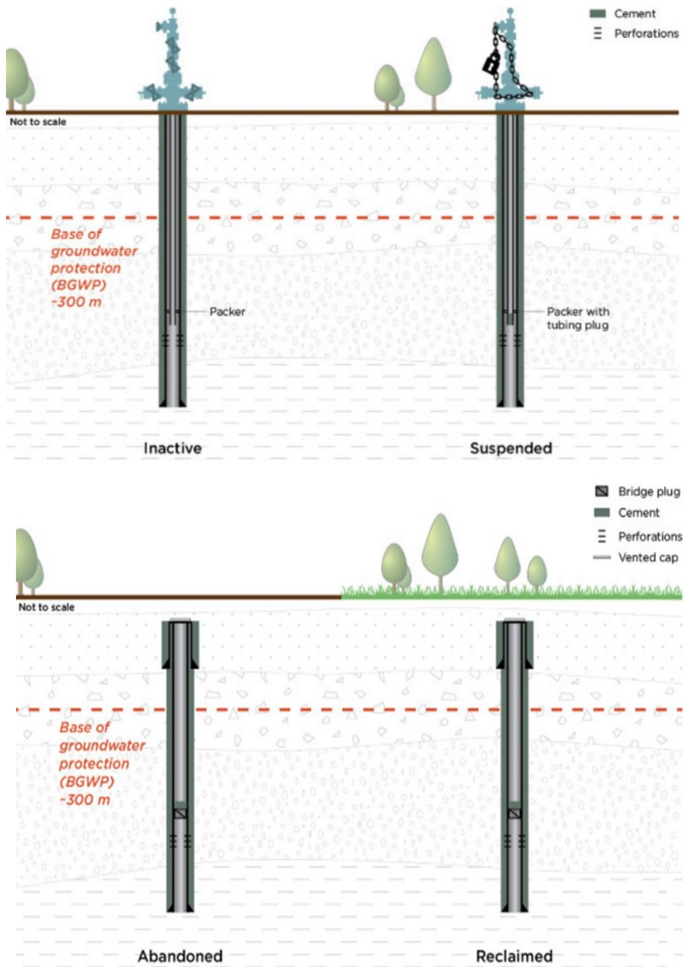

Figure 2.3: Top - Inactive vs Suspended Wellheads. Source: AER website: "How are Wells Suspended" [*https://www.aer.ca/regulating-development/project-closure/suspension-and-abandonment/how-are-wells-suspended.html*](https://www.aer.ca/regulating-development/project-closure/suspension-and-abandonment/how-are-wells-suspended.html)

Bottom - Abandoned vs Reclaimed Well. Source: AER website: "How are Wells Abandoned" [*https://www.aer.ca/regulating-development/project-closure/suspension-and-abandonment/how-are-wells-abandoned.html*](https://www.aer.ca/regulating-development/project-closure/suspension-and-abandonment/how-are-wells-abandoned.html)

2.2. Material and Methods

2.2.1 Study Overview

Our techno-economic assessment of retrofitting an oil or gas well for geothermal energy production at Tomahawk Ranch property contains two parts. First, we will first estimate the geothermal power potential of the wells on the properties. Then, we will estimate of all costs and revenues expected over the entire life of the project. Emphasis will be placed upon estimating the well retrofit expense, as we hope this can be used to inform further research on well retrofits in other regions. Revenues will depend upon the heat energy available from each wellbore and the projected benefit to cattle well-being.

We assume a 25-year project lifetime. The geothermal power potential of each well is estimated using a coaxial borehole heat exchanger configuration and a Matlab code adapted from Egbhali et. al. (2020, in revision). The full lifecycle economic evaluation will be completed using a custom-built Excel spreadsheet that includes a comprehensive list of inputs, as described in section 2.3, below.

Our analysis will begin with a base case, using the best estimate of each input variable to calculate the expected net present value. We will also calculate best-case and worst-case scenarios, which will provide a range between minimum and maximum net present value outcomes and provide an indication of project risk. Finally, a sensitivity analysis will demonstrate how a 20% increase or decrease to each key input variable changes the overall project net present value. This will identify which variables have the greatest impact on the project's economic feasibility.

2.2.2 Well Retrofit Process

Any oil and gas well that reaches, or could be made to reach, a suitable geothermal reservoir can potentially be re-purposed (Leitch et al., 2017). We model our retrofit on the Coaxial Borehole Heat Exchanger system outlined in the paper by Hu et. al. (2020). This is a closed-loop system, which circulates a fluid through the wellbore without any fluid entering or escaping the surrounding reservoir. Some advantages of using a closed-loop system include no corrosion or scaling risk as no foreign minerals can enter the fluid, no need for water processing, and no induced seismic activity from hydraulic fracturing. Also, it is possible to use different working fluids that can maximize heat recovery. A simple example schematic of such a wellbore is shown in Figure 2.4.

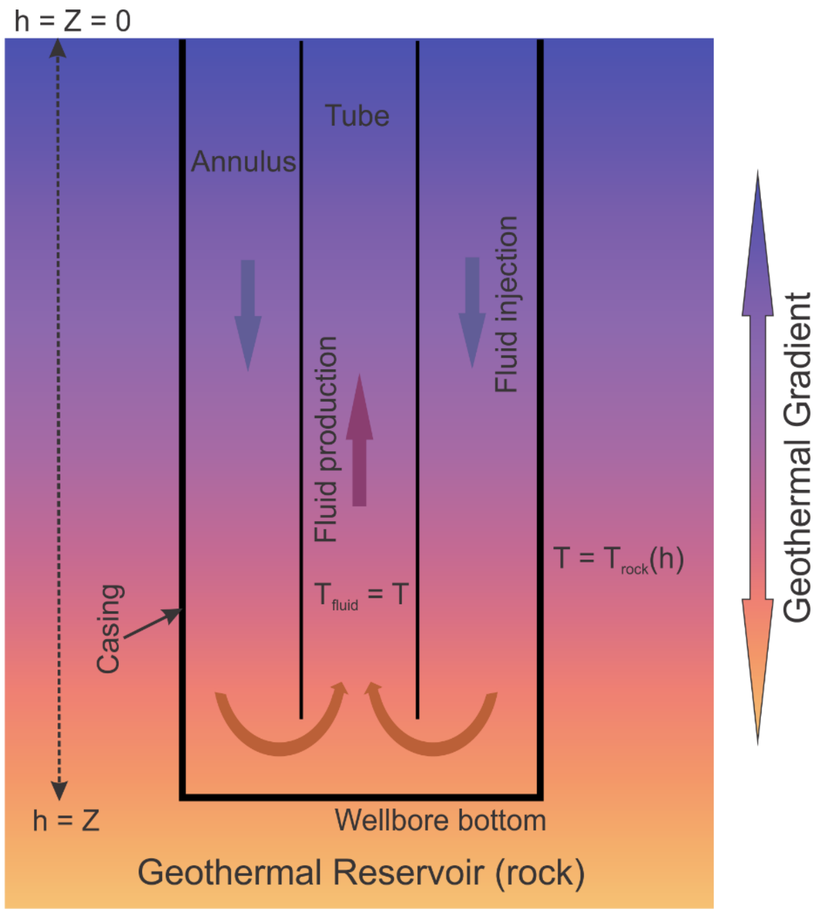

Figure 2.4: Simple schematic of a Coaxial Borehole Heat Exchanger for geothermal energy production from a retrofit petroleum well

Data on the individual wells at Tomahawk Ranch, including depth, bottom hole temperature, age, installed tubing and casing, and well status were obtained using the licensed GeoScout database of well data in Western Canada. Of the 33 independent wellbores located on Tomahawk Ranch land, 13 are currently classified as active. Twelve of the active wells currently hold Producing status, while the remaining active well is a Water Injector. Producing wells likely have value to their current owner, so would present an added acquisition cost; estimating the price of an actively producing well is beyond the scope of this paper, so the retrofit cost will be estimated for these wells, but they will not be considered for use in the retrofit project. The other 20 wells are inactive, 15 of which are abandoned and 5 are suspended. We expect abandoned wells to be more costly to retrofit than suspended wells due to the extra time and materials required to unplug the wellbore and reattach surface casing. Therefore, while we will calculate the retrofit costs of all the petroleum wells located on Tomahawk's land, we focus on the wells classified as suspended.

To be used as a deep coaxial borehole heat exchanger an oil and gas wellbore must extend to a subsurface depth of sufficient temperature. Wellbore tubing will be added or replaced and any producing zones within the wellbore must be sealed off to ensure that fossil fuels are not escaping to the surface. This will require an oil and gas service rig, so the surface lease must be in good repair and accessible to heavy equipment. Once the downhole changes are complete, the well will be fit at the surface with a new wellhead suitable for geothermal energy production. Broadly, all the costs of a well retrofit can be broken down into one of four categories: planning/lease preparation costs, well equipment costs, service tig costs, and tubing and casing costs.

2.2.3 Determining the Geothermal Power Potential of Each Well

Eghbali et al. (2020, in press) developed a MATLAB based numerical model for geothermal energy extraction using a coaxial borehole heat exchanger concept. Figure 2.4 above shows a diagram schematic for this concept. Here, we adapt the model to investigate the total thermal power available from a single-phase fluid (water) flow from the above mentioned five suspended wells at the operational conditions. Using a 1D numerical approach, Eghbali et al. (2020, in revision) studied the effects of single- and two-phase flow, as well as transient heat conduction to the surroundings' pressure profiles.

Out analyses couple thermodynamics, fluid flow, and geothermal heat transfer, with equations of states (EOS) for multiphase equilibrium calculations. The vertical wellbore in the geothermal formation consists of a thermally conductive casing surrounded by reservoir rock. The annulus and tube of the well are insulated thin layers of pipe. The fluid is produced through the tube and injected through the annulus. In a transient heat transfer scenario, the spatial extent and magnitude of thermal drawdown in the reservoir and the heat transfer between the well fluid and the formation rock are calculated at each depth and time increment.

The modeling procedure proceeds as follows: First, the initial fluid temperature is set as equal to the rock temperature at a depth of h (Z). Inviscid and isotropic fluid are then produced from the bottom of a vertical and insulated well, flowing upwards in a tube with a constant cross-sectional area. We assumed a one-dimensional (1D) variation of velocity, pressure, fluid temperature, and thermo-physical properties along the vertical direction (h). These variables are accompanied by lateral (perpendicular to the plane of the wellbore) heat transfer between the circulating fluid and the reservoir rock, through the wellbore casing. The total thermal resistivity among the fluid in the well and the reservoir rock is the sum of the fluid, pipe, insulation, and rock resistivities. The rate of heat transfer from the fluid to the rock is calculated as:

$$\dot{Q}_{fluid/rock} = \frac{T_{fluid} - T_{rock}}{R_{Total}} \qquad \text{(X1)}$$

where T_{rock} is estimated by summing the surface temperature and the geothermal gradient.

The produced fluid at temperature (T_{prod}) is cooled down at constant pressure to the surface (air) temperature (T_{o}). Given a constant mass flow rate ($\dot{m}$) over time and the specific heat capacity (c_p) of the circulating fluid (Table 1), the thermal power is finally calculated as:

$$Thermal\ Power = \dot{m}c_p\left(T_{prod} - T_o\right) \qquad \text{(X2)}$$

Table 2.1 describes the properties of the rocks and fluids used as the input parameters for the model. The first four wells have a similar depth (~1,670 m) and share the same properties of rocks. Well # 5 (00/06-22-051-05W5/0) is shallower (1,214 m) and has different rock properties. The model calculates the production temperatures and pressures every 5 days for 25 years. For every well, equation (X2) is then used to calculate the thermal power for a range of mass flow rates from 1 kg/s to 10 kg/s.

Table 2.1: Parameters for the 1D numerical model to calculate thermal power available for single phase fluid (water) from the five suspended wells at the operational conditions

Model Parameters	Values
Well length (m)	See Table X
Injection pressure (psia)	9000
Mass flow rate (kg/s)	1 to 10
Temperature (geothermal) gradient (°C/m)	See Table X
Injection temperature (°C)	5
Length increment for model (m)	5
Inner well radius (m)	0.03896
Pipe thickness (m)	0.0054864
Insulation thickness (m)	0.01
Diffusivity thickness of rock (m)	0.05
Pipe conductivity (W/m.K)-stainless steel	54
Cement conductivity (W/m.K)	0.55
Insulation conductivity (W/m.K)	0.04
Thermal conductivity of rocks (W/m.K)	2.5 (3.3 for well #5)
Surface air temperature T_o (ºC)	-10
Simulation time (days)	9132 (25 years)
Time increment for model (days)	5
Rock density (kg/m^3)	2630 (2500 for well # 5)
Rock specific heat capacity (J/kg.K)	910 (920 for well # 5)
Water specific heat capacity (J/kg.K)	4198

2.2.4 Well Retrofit Costs

The PSAC study is a bi-annually published guide that predicts the prices of oilfield services, equipment, and materials in Western Canada. This paper uses pricing based on the updated Winter 2019 PSAC Well Cost Study of wells in Alberta's Foothills region to estimate the cost of retrofitting a well for geothermal energy production.

2.2.4.1 Planning / Lease Preparation Costs

The Planning and Lease Preparation costs include licencing and permits, engineering design and planning, preparing the lease for heavy equipment, as well as miscellaneous and overhead cost components. Table 2.2 contains an itemized list of these costs as found in the Winter 2019 PSAC Well Cost Study. The Miscellaneous costs are calculated as an 8% surcharge on the other expenses to provide protection against cost overruns and unanticipated expenses, while overhead is an additional 2% surcharge applied to cover administrative staffing and materials. Although the expenses in this category may vary based on well location and ease of access to the well site, they are independent of existing wellbore characteristics, so we consider them to be fixed costs.

2.2.4.2 Well Equipment Costs

Well Equipment costs include the cost of a new wellhead at the surface and a packer installed downhole to seal off the old producing zone. These costs are also included in Table 2.2.

Table 2.2: Itemized list of fixed costs for retrofit of an oil and gas well for geothermal energy production.

Planning and Lease Preparation	Item Cost ($)	Description
Well License / Applications	500	Regulatory permit
Preparation & Roads	8,700	1 day of lease cleanup + supervision
In-house Engineering (Drilling)	16,000	100 hrs of engineering work
Equipment Inspection	3,500	Casing inspection log
Misc. Costs	2,296	8% Cost overrun buffer
Overhead	574	2% Administrative addition
Subtotal	31,570	
Well Equipment		
Packer	12,750	To seal wellbore from oil or gas producing zone
Wellhead	18,000	To replace old wellhead
Misc. Costs	2,460	8% Cost overrun buffer
Overhead	615	2% Administrative addition
Subtotal	33,825	

2.2.4.3 Service Rig Costs

Service Rig costs include the use of a rig and crew for three days, along with the materials needed to replace the tubing and test that the retrofitted well is in safe operating condition. Within their service rig costs the PSAC Well Cost Study includes items, such as hauling of equipment, that are not directly part of the service rig but are necessary for the service rig to complete its work; we have categorized costs in the same manner. We have chosen three days of rig time based upon discussion with oil and gas industry professionals. This includes two days to set up the rig, install tubing up to 2,500m depth, and dismantle the rig, plus a third day to replace the wellhead, install a packer, and conduct cementing and pressure tests. Although the wells included in this study are significantly shallower than

2,500m, suggesting that less time may be needed, we will maintain a conservative three-day estimate due to the novel nature of this well retrofit process. Service rig costs include both one-time expenditures (fixed costs) and items charged on a per-day basis (variable costs). As seen in the breakdown of costs in Table 2.3, the variable expenses add up to $24,088 of additional cost for each additional day of service rig time. This marginal day cost will be considered in our scenarios and sensitivity analysis.

2.2.4.4 Tubing and Casing Costs

Tubing and casing are a per metre variable cost that depends upon the depth of the wellbore. We assume that 73.0 mm 9.67 kg/m J-55 tubing and 114.3 mm 17.26 kg/m P-110 production casing will be used. According to the PSAC 2019 Well Cost Study, these classifications of pipe are commonly used in this geographic region. Several wells already have casing in place to their bottom depth and so only require tubing installation.

*Table 2.3: Itemized list of service rig cost components and tubing/casing costs. Note: an * denotes a cost item that is charged at a day-rate and is dependent upon the number of days the service rig is employed.*

Service Rig Costs	Item Cost/Day or Unit ($CDN)	Total Three-Day Cost ($CDN)	Description
Service Rig*	7,750	23,250	Rig and crew
Transportation*	2,500	7,500	Hauling of equipment
Other Services*	4,500	13,500	Vacuum truck
Completion Fluids*	4,500	13,500	Water and trucking
Logging (Cement Bond Log)	4,250	8,500	Run two CBL (check quality of cement job)
Slickline/Wireline (Other)	4,250	4,250	Gauge ring, run and pull recorders (confirm diameter/uniformity of internal wellbore)
Remedial Cementing	13,500	13,500	A run of remedial cementing (to repair existing cement plug deficiencies)
Wellsite Supervision*	1,400	8,400	Service rig days+3
Inspection / Safety	1,500	3,000	2 site inspections
Environmental*	1,000	3,000	Environmental technician cost per day
Lease & Road Maintenance*	500	3,000	Service rig days+3
Misc. Costs*	1550	8,112	8% Cost overrun buffer
Overhead*	388	2,028	2% Administrative addition
Subtotal		111,540	
Per Addl Day (Total Variable)		24,088	
Tubing and Casing Costs	**Price of Pipe ($/m)**	**Attachments & Accessories ($/m)**	**Description**
73.0 mm 9.67 kg/m J-55	20.75	-	Tubing Pipe
114.3 mm 17.26 kg/m P-110	35.75	2.00	Production Casing Pipe, Tongs, and Accessories
Misc. Costs			8% Cost overrun buffer
Overhead			2% Administrative addition

2.2.4.5 Calculating the Suspended Well Retrofit Expense

As described above (2.2.2), the cost of retrofitting an oil and gas well for geothermal energy production can be broadly broken into four components:

$C_{RS} = PLP + WE + SR_T + CT_T$

Where C_{RS} is the total cost of a suspended well retrofit, PLP is planning and lease preparation cost, WE is well equipment cost, SR_T is total service rig cost, and CT_T is the total casing and tubing cost.

PLP = sum of the item costs seen in Table 1

WE = sum of the item costs seen in Table 1

$SR_T = SR_F + SRV*D$

Where SR_F is the fixed cost or amount attributed to one day of service rig time, SR_V is the cost for each additional day, and D is the number of additional days the rig is required.

$CT_T = (T*TVD + C_P*TVD) * (1.1)$

Where T is tubing cost in $/m, C_P is the cost for production casing and accessories in $/m, and TVD is the total vertical depth or meters of pipe required and 10% is added for miscellaneous and administration costs.

2.2.4.6 Retrofitting an Abandoned Well

Abandoned wells would incur the same costs as above, plus additional time and expense to remove plugging fluid and/or mill out a cement plug and to reattach surface casing. These additional steps are considered by adding two days of Service Rig time, plus the cost to purchase one standard 10m length of surface casing pipe and weld it to the existing surface casing. Table 2.4 provides an itemized list of additional costs incurred for retrofitting an abandoned well.

*Table 2.4: Itemized breakdown of additional costs incurred to retrofit an abandoned well. Note: an * denotes a cost item that is charged at a day-rate and is dependent upon the number of days the service rig is employed.*

Additional Costs for an Abandoned Well	Cost Per Day/Unit	Total Two-Day Cost	Description
Cut & cap replace	870	870	10m of 244.5 mm 53.57 kg/m J-55
Welding	1,500	1,500	Day rate
Service Rig*	7,750	15,500	Rig and Crew
Transportation*	2,500	5,000	Hauling of equipment
Other Services*	4,500	9,000	Vacuum truck
Completion Fluids*	4,500	9,000	Water + trucking
Logging (cement bond log)	4,250	4,250	Additional CBL (check old cementing)
Wellsite Supervision*	1,400	2,800	Extra days of site supervision
Environmental*	1,000	2,000	Environmental technician per day
Lease & Road Maintenance*	500	1,000	Service days
Misc. Costs*		6,254	8% Cost overrun buffer
Overhead*		1,564	2% Administrative addition
Subtotal		$58,738	

2.2.4.7 Calculating the Abandoned Well Retrofit Expense

The additional cost to retrofit an abandoned well is as follows:

$AWC = SRA*2 + \text{welding day rate} + C_S*10\text{metres}$

Where AWC is abandoned well cost and C_S is the $/m cost for 244.5 mm 53.57 kg/m J-55 surface casing. The welding day rate is a fixed value for one day of welding obtained from the PSAC Well Study Report.

Total cost to retrofit an abandoned well will be calculated using the formula:

$C_{RA} = PLP + WE + SR_T + CT_T + AWC$ or $C_{RA} = C_{RS} + AWC$

2.2.5 Other Capital Costs

2.2.5.1 Surface Infrastructure & Connection

Water flow from the existing drinking water supply must be diverted to reach the retrofit well so that it can be heated. Upon reaching the well, the water will be injected down the wellbore and heated using the coaxial borehole heat exchanger model. We have assumed that the water supply will be diverted and connected to the wellbore using the same 75mm high density polyethylene pipe used in the existing water circuit. The owner of Tomahawk Ranch reported a price of $16.40-$32.80/metre, which includes pipe, all fittings and valves, and excavation for in-ground installation. Changes in topography and vegetation, which affected the excavation and installation, were primarily responsible for the range in reported cost. Our base estimate uses the mid-range value of $24.60/metre, while the low and high-end values will feature in the best and worst-case scenarios.

By using a map of the water system (from Figure 2.2) and plotting the relative location of each well based on its Unique Well Identifier (UWI), we can create a reasonable approximation of the geographic distance between each well and the nearest point of the existing water flow system. This distance will inform the length of pipe required for connecting water flow to the retrofit well (Figure 2.5).

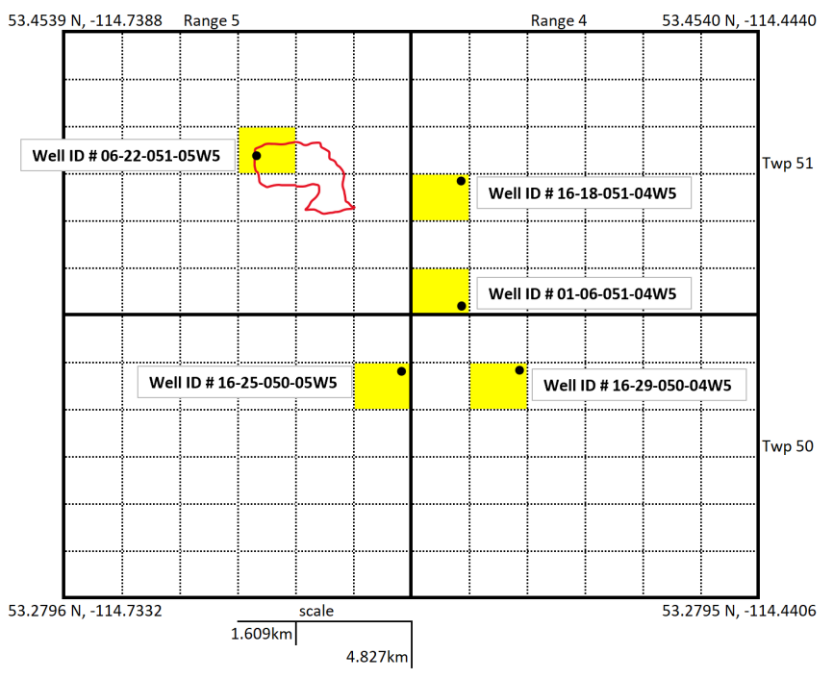

Figure 2.5: A plot of the Tomahawk water supply system(red line in upper left quadrant) and Suspended wells (black dots) on Tomahawk property on a grid representing the Dominion Land Survey for the area. Each square in the grid represents 1 square mile (2.6 square kilometres).

2.2.5.2 Calculating the Surface Infrastructure & Connection Cost

The surface infrastructure cost is calculated using the following equation.

SI = P * d

Where SI is the surface infrastructure cost, P is the $/m cost for high density polyethylene pipe and installation, and d is the distance between the well and water flow system.

2.2.5.3 Abandonment and Reclamation Costs

AER Directive 011 provides guidance for oil and gas operators regarding both abandonment costs and reclamation costs. Abandonment costs are broken down into one of six regions in Alberta and further delineated by vertical depth and downhole completion characteristics. Reclamation costs are separated into seven provincial regions. Well age also has a significant impact on these costs. Correspondence a with a remediation firm based in Calgary, AB suggests that wells drilled prior to 1996 incur the highest cleanup costs, while those wells drilled more recently than 2003 incur the lowest cleanup costs. The abandonment and reclamation costs used in this paper reflect the values suggested by AER guidance while accounting for the age factor by adding 25% to the expense for wells drilled prior to 1996 subtracting 25% for wells drilled after 2003. To reflect the uncertainty in clean-up costs, our abandonment and reclamation expense will be increased or decreased by a further 50% in the worst and best-case scenarios.

The Tomahawk Ranch property is located within Regional Abandonment Area 2 and the Regional Reclamation Parklands Area as outlined in AER Directive 006. A well in this location with depth between 1200-1999 metres has a listed abandonment cost of $56,505 and a reclamation cost of $27,350 (AER Directive 011) for a combined $83,755 base case expense which we will adjust based on well age. Additionally, these numbers reflect the cost today; in our calculation the expense will be incurred at the conclusion of the project. As such, the costs seen in Table 2.5 will be adjusted for inflation and applied at the end of year 25.

Table 2.5: AER Abandonment and Reclamation present-day costs adjusted by 25% for well age in the base scenario and adjusted again by 50% for best and worst-case scenarios

Well Age	Base Case	Best Case (-50%)	Worst Case (+50%)
1996-2003 Well	$ 83,755	$ 41,878	$ 125,633
Newer Well (-25%)	$ 62,816	$ 31,408	$ 94,224
Older Well (+25%)	$ 104,694	$ 52,357	$ 157,041

2.2.6 Operational Costs

Once the initial retrofit has been completed and the infrastructure is in place, ongoing operational costs are expected to be minimal. The installed infrastructure has a life expectancy exceeding that of the geothermal energy project, so no repair or replacement is anticipated.

Yearly operational costs will be subject to inflation and discount rates based on when they occur.

2.2.7 Calculating the Benefit

There are two anticipated benefits from heating the cattle drinking water. First, the cattle will need to expend fewer joules of energy to warm the consumed water internally, thereby requiring less feed to maintain their body weight. The ranch owner has provided the following data:

- Average daily water consumption per animal during the winter months is 20-40 litres.
- The cattle are predominantly fed Hay, which is purchased at a cost of $0.11/kg.
- A system which records the current water temperature was installed in February 2020; from mid-February to mid-April 2020 the average drinking water temperature was approximately 2.5°C.

Given that it takes 4.184kJ of energy to increase the temperature of 1L of water by 1°C and that the digestible energy present in 1g of hay is 11,087.6j (Merck Veterinary Manual, 2020), it requires 7.55g of hay to increase 20L of ingested water by 1°C. Using a hay price of $0.11/kg and 2,000 head of cattle, the cost of feed that goes towards internally warming drinking water is $1.66/day/1°C. The region around Tomahawk Ranch typically experiences 5 months of average air temperature at or below freezing (Alberta Agriculture and Forestry, 2020) and 103 days with snow cover of at least 5cm (Environment Canada, Dec 2019). As such, we assume 4 months (122 days) where the cattle are subject to winter temperatures and unable to forage. This provides a yearly benefit of $202.52 ($1.66/day * 122 days) in reduced feed costs for every 1°C the drinking water temperature is warmed by the retrofit well. Scaled-up calculations for the total water consumption per cow are found in the results.

The second benefit of warmer drinking water is a possible increase in birthed calves. It is difficult to attribute any loss directly to cold drinking water, but the ranch owner estimates that he loses 3-5% of his calves due to the cold and typical calf value is $700. If we assume that 5 additional calves will be birthed because of access to warmer drinking water, this presents a $3,500 annual benefit.

Our base economic analysis will include the estimated decrease in feed costs and no change to calf mortality rate; the best-case scenario will use a higher Hay price and include increased calving success of 5 additional calves.

2.3 Results

2.3.1 Well data

Figure 2.6 displays the distributions of the wells on Tomahawk property by bottom hole temperature, depth below surface, smallest casing size, and year drilled all sorted by regulatory status. Of the 33 (13 active, 15 abandoned, and 5 suspended) petroleum wellbores on Tomahawk Ranch, 26 (including 4 of the suspended wells) terminate in the Banff formation. These wells possess vertical depths between 1,500-1,750 m from the surface. Six other wells, including the one remaining suspended well, were drilled to the Cardium formation, with depths between 1,000-1,250m. A single well reaches the Nisku formation at a depth of 2,065m.

Twenty-four of the wellbore records (including all the suspended wells) contained the data needed to calculate a corrected bottom hole temperature. The corrected temperature values range from 58.91°C to 80.68°C.

The oldest well was drilled in 1981, while the most recent was drilled in 2013. There is a barbell distribution of well ages as the majority were either drilled in the 1980s or after 2005, with minimal activity during the intervening years. Most, including all of the suspended wells, possess a smallest casing diameter of 139.7mm, although a handful of currently producing wells have 177.8mm intermediate casing as their smallest casing size. Some of the abandoned wells have no casing at all.

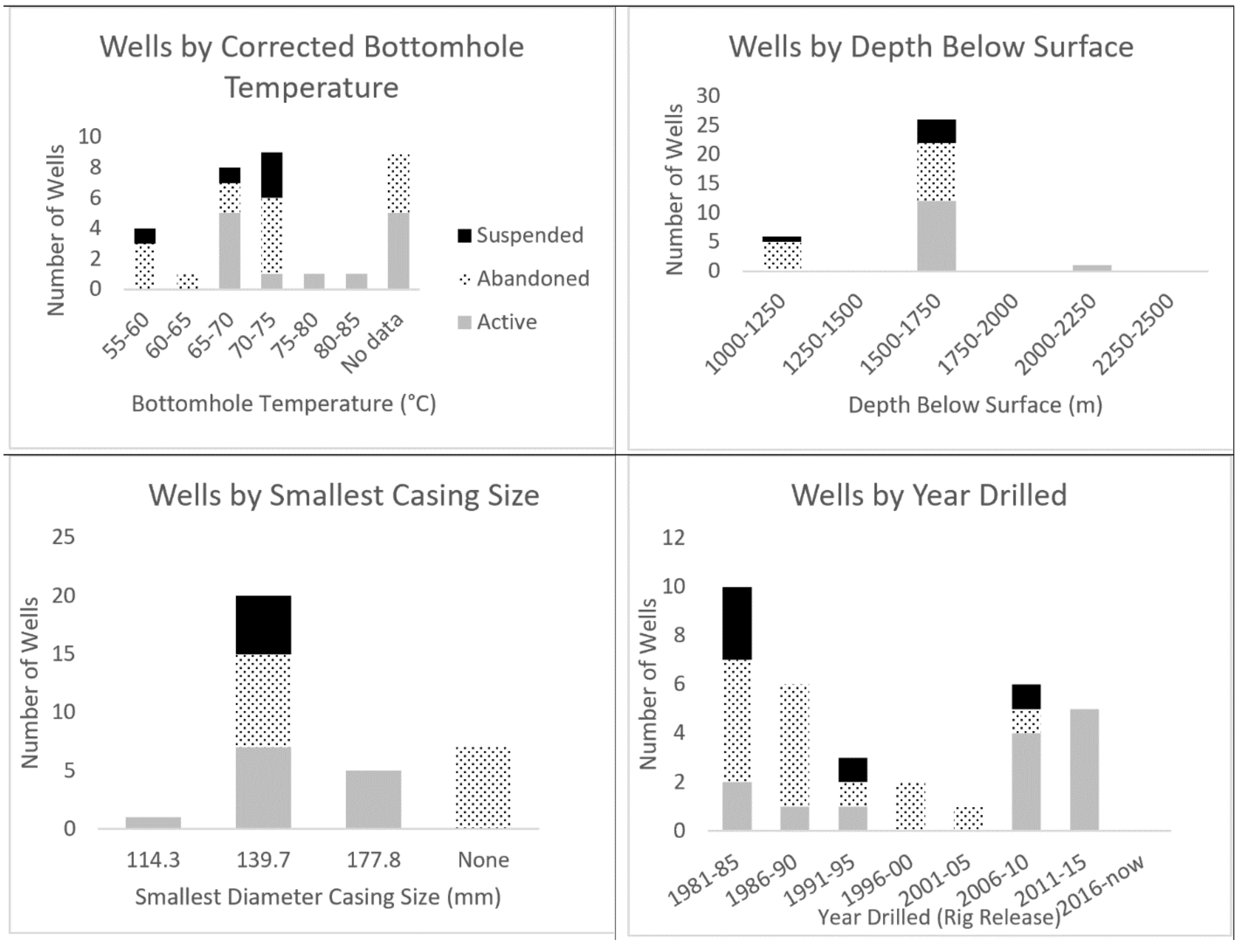

Figure 2.6: Distribution of the number of wells on Tomahawk property, sorted by regulatory status, for bottomhole temperature, vertical depth below earth surface, smallest diameter installed casing size, and year of drilling.

2.3.2 Geothermal Power Potential

Figure 2.7 shows the calculated thermal power for mass flow rates from 1 kg/s to 10 kg/s over 25 years for each of the five suspended wells. These graphs show that the thermal power outputs increase linearly with the rise of mass flow rate, as expected, and become steady within the first few weeks of the production period. The 25-year thermal power projections are more than 150 kW with >1 kg/s mass flow rate for the first three wells (Figure 2.7 a-c). For well # 4, the projection is around 100 kW with a 1-10 kg/s flow rate (Figure 2.7d). Due to the shallower depth, well # 5 is projected to produce 46 to 62 kW of thermal power over 25 years (Figure 2.7e). Figure 2.6f shows the produced temperature for well #5. The values of the fluid's produced temperature at 1 kg/s and 10 kg/s are 16 ºC and 6.5 ºC, respectively, revealing the influence of the flow rate on the temperature and, ultimately, on the thermal power. A lower flow rate produces fluid with higher temperatures but decreases the thermal power output.

The costs described below in Section 2.3.3 highlights that well # 5 (00/06-22-051-05W5/0) is the least expensive to be retrofitted for the geothermal energy.

The thermal power required to raise the water temperature from 2 ºC to 10 ºC, flowing at a rate of 5-6 l/s (~90 gallons/min), is ~190 kW. To achieve this power with a sustainably low flow rate (~ 1 to 3 kg/s), Figure 2.7 suggests that at least three wells, including #5, need to be retrofitted to supply geothermal power to the entire volume of cattle feed water.

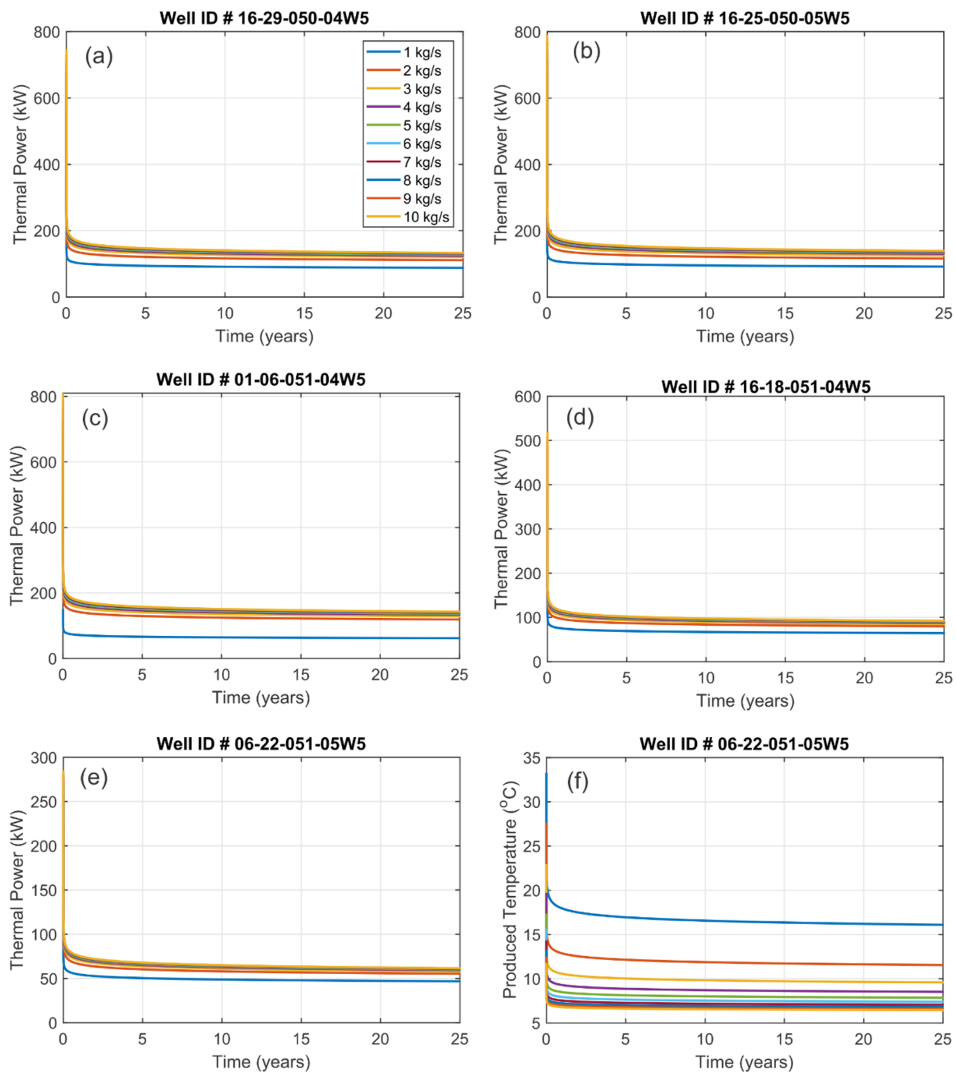

Figure 2.7: (a-e) 25 years projections of the thermal power, at 1 kg/s to 10 kg/s mass flow rate, for the five suspended wells at the Tomahawk Ranch Area, and (f) The produced temperature for the well # 5 at the same scenario.

2.3.3 Well Retrofit Costs

2.3.3.1 Suspended Wells

Using updated PSAC Winter 2019 Well Cost Study data, the average estimated cost to retrofit one of the five suspended Tomahawk wells for geothermal heat production is $212,999 (note: all dollar figure values are presented as Canadian dollars), ranging from a low of $204,645 to a high of $215,281. This narrow cost range reflects the similarity of wellbore depth and geographic location. Table 2.6 outlines the breakdown of retrofit costs for each suspended UWI. Casing is currently installed in these wellbores, so the tubing and casing expense consists of tubing only.

Table 2.6: Breakdown of retrofit costs for suspended wells on Tomahawk Ranch property

UWI	TVD (m)	Planning & Lease Prep	Well Equipment	Service Rig	Tubing and Casing	Total Cost ($CDN)
100/16-29-050-04W5/0	1665	$ 31,570	$ 33,825	$ 111,540	$ 38,004	$ 214,939
100/16-25-050-05W5/0	1670	$ 31,570	$ 33,825	$ 111,540	$ 38,118	$ 215,053
100/01-06-051-04W5/0	1680	$ 31,570	$ 33,825	$ 111,540	$ 38,346	$ 215,281
100/16-18-051-04W5/0	1671	$ 31,570	$ 33,825	$ 111,540	$ 38,141	$ 215,076
100/06-22-051-05W5/0	1214	$ 31,570	$ 33,825	$ 111,540	$ 27,710	$ 204,645

Approximately half of the expected retrofit cost, $104,671, is fixed. The relative homogeneity of the wellbores on the Tomahawk Ranch has resulted in the variable portion of service rig costs remaining constant. Thus, tubing and casing accounts for 100% of the retrofit cost variance

2.3.3.2 Abandoned Wells

The average estimated cost to retrofit one of the 15 abandoned wells on the Tomahawk Ranch is $301,421, or approximately $86,000 greater than a suspended well. There is also greater variation in retrofit cost, ranging from a low of $262,150 to a high of $346,018. This expanded range is largely due to six of these wellbores requiring casing installation in addition to tubing. Table 2.7 displays the estimated retrofit cost for each abandoned well.

Table 2.7: Breakdown of retrofit costs for abandoned wells on Tomahawk Ranch property. Highlighted Tubing and Casing costs indicate those wells that required production casing installation in addition to tubing.

UWI	TVD (m)	Planning & Lease Prep	Fixed Well Equipment	Service Rig	Tubing and Casing	Addl Cost for Aban Well	Total Cost ($CDN)
100/10-31-050-04W5/0	1634	$ 31,570	$ 33,825	$ 111,540	$ 37,296	$ 58,738	$ 272,969
100/16-31-050-04W5/0	1665	$ 31,570	$ 33,825	$ 111,540	$ 38,004	$ 58,738	$ 273,676
100/08-18-051-04W5/0	1655	$ 31,570	$ 33,825	$ 111,540	$ 37,775	$ 58,738	$ 273,448
100/14-18-051-04W5/0	1626	$ 31,570	$ 33,825	$ 111,540	$ 104,999	$ 58,738	$ 340,671
102/16-18-051-04W5/0	1160	$ 31,570	$ 33,825	$ 111,540	$ 26,477	$ 58,738	$ 262,150
100/06-12-051-05W5/0	1670	$ 31,570	$ 33,825	$ 111,540	$ 107,840	$ 58,738	$ 343,513
102/06-12-051-05W5/0	1693	$ 31,570	$ 33,825	$ 111,540	$ 109,325	$ 58,738	$ 344,998
100/03-13-051-05W5/0	1673.9	$ 31,570	$ 33,825	$ 111,540	$ 38,207	$ 58,738	$ 273,879
100/08-14-051-05W5/0	1680	$ 31,570	$ 33,825	$ 111,540	$ 108,486	$ 58,738	$ 344,159
100/02-22-051-05W5/0	1208.6	$ 31,570	$ 33,825	$ 111,540	$ 27,586	$ 58,738	$ 263,259
100/13-22-051-05W5/0	1708.8	$ 31,570	$ 33,825	$ 111,540	$ 110,346	$ 58,738	$ 346,018
100/08-23-051-05W5/0	1185	$ 31,570	$ 33,825	$ 111,540	$ 76,521	$ 58,738	$ 312,194
100/14-23-051-05W5/0	1708	$ 31,570	$ 33,825	$ 111,540	$ 110,294	$ 58,738	$ 345,967
100/08-24-051-05W5/0	1161	$ 31,570	$ 33,825	$ 111,540	$ 26,500	$ 58,738	$ 262,172
100/14-24-051-05W5/0	1164.3	$ 31,570	$ 33,825	$ 111,540	$ 26,575	$ 58,738	$ 262,248

Most of the additional expenses required for retrofitting an abandoned well are due to the extra two days of service rig time and the installation of production casing, as needed. There is also an additional $2,370 to replace and reattach the top portion of surface casing. As with the suspended wells, all retrofit cost variance for abandoned wells is attributed to the tubing and casing cost component.

2.3.4 Total Capital Expenses

Any well that undergoes the retrofit process will also need to be connected to the cattle's water supply and properly plugged and reclaimed at the end of the project's 25-year life. These expenses must also be considered when calculating which wellbores present the least capital expenditure.

Table 2.8 outlines the total capital investment expected for each suspended wellbore including the retrofit expense, the present value of the abandonment and reclamation cost, and the installation of high-density polyethylene pipe. Based on these values, the 100/06-22-051-05W5/00 UWI (well #5) requires the least capital investment.

Table 2.8: Summary of capital cost inputs for each suspended well on Tomahawk property.

UWI	Retrofit Cost	Year Drilled	Aban/ Rec Cost	Distance (m)	Pipe & Install Cost	Total Cost
100/16-29-050-04W5/00	$ 214,939	1983	$ 25,080	5000	$ 123,000	$ 363,019
100/16-25-050-05W5/00	$ 215,053	1985	$ 25,080	4800	$ 118,080	$ 358,213
100/01-06-051-04W5/00	$ 215,281	2007	$ 15,048	3400	$ 83,640	$ 313,969
100/16-18-051-04W5/00	$ 215,076	1981	$ 25,080	3200	$ 78,720	$ 318,876
100/06-22-051-05W5/00	$ 204,645	1995	$ 25,080	100	$ 2,460	$ 232,185

Tables 2.9 and 2.10 show the change to each capital expense component and the total expected capital investment required for each suspended well in a best or worst-case scenario. UWI 100/06-22-051-05W5/00 (well #5) remains the lowest cost option in all scenarios and provides the smallest differential between best and worst-case scenarios. UWIs 100/01-06-051-04W5/00 (well #3) and 100/16-18-051-04W5/00 (well #4) are the next best choices in terms of total cost and variance despite having the two highest costs for the retrofit itself.

Table 2.9: Capital cost component values for each Suspended well under the Best and Worst-Case scenarios

	Best Case			Worst Case		
UWI	Retrofit Cost	Aban/ Rec Cost	Pipe & Install Cost	Retrofit Cost	Aban/ Rec Cost	Pipe & Install Cost
Variable Adjustment	20% less	50% less	$ 16.40/m	20% increase	50% increase	$ 32.80/m
100/16-29-050-04W5/0	$ 171,951	$ 12,540	$ 82,000	$ 257,927	$ 37,620	$ 164,000
100/16-25-050-05W5/0	$ 172,042	$ 12,540	$ 78,720	$ 258,064	$ 37,620	$ 157,440
100/01-06-051-04W5/0	$ 172,225	$ 7,524	$ 55,760	$ 258,337	$ 22,572	$ 111,520
100/16-18-051-04W5/0	$ 172,061	$ 12,540	$ 52,480	$ 258,091	$ 37,620	$ 104,960
100/06-22-051-05W5/0	$ 163,716	$ 12,540	$ 1,640	$ 245,574	$ 37,620	$ 3,280

Table 2.10: Total capital investment expected for each wellbore for each scenario

UWI	Base Case	Best Case	Worst Case	Variance
100/16-29-050-04W5/0	$ 363,019	$ 266,491	$ 637,303	$ 370,752
100/16-25-050-05W5/0	$ 358,213	$ 263,302	$ 624,973	$ 361,613
100/01-06-051-04W5/0	$ 313,969	$ 235,509	$ 510,896	$ 275,346
100/16-18-051-04W5/0	$ 318,876	$ 237,081	$ 525,270	$ 288,150
100/06-22-051-05W5/0	$ 232,185	$ 177,896	$ 319,523	$ 141,626

2.3.5 Full Lifecycle Project Economics

Our geothermal power potential model indicates that three wells will need to be retrofit to provide sufficient power to increase the drinking water to 10°C. UWI's 100/06-22-051-05W5/00, 100/16-18-051-04W5/00, and 100/01-06-051-04W5/00 (wells #3,4 and 5) have the lowest expected capital investment and present the least financial risk of the five suspended wells evaluated for the Tomahawk Ranch geothermal energy retrofit project. As such, selection of these three wellbores provide the greatest chance for economic feasibility over a 25-year project lifecycle. Table 2.11 shows the input values used for calculating each of the scenarios.

Table 2.11: Input variables used in each project scenario

Revenue	Base Case		Worst Case		Best Case	
Hay Price ($/kg)	$	0.11	$	0.09	$	0.13
Yearly savings per 1°C Water Temp Increase	$	202.57	$	129.64	$	291.70
Increase in drinking water temp (°C)		7.5		7.5		7.5
Calf deaths		0		0		5
Value per Calf	$	700	$	700	$	700
Total Yr 1 Benefit	$	1,519	$	972	$	5,688
Initial Capital Investment						
Well retrofit cost	Base		Plus 1 rig day and 20% increase		Minus 1 rig day and 20% decrease	
Total Retrofit (3 wells)	$	635,002	$	848,719	$	450,190
HDPE Install ($/m)	$	24.60	$	32.80	$	16.40
HDPE Total	$	164,820	$	219,760	$	109,880
Total Initial Capital Investment	$	799,822	$	1,068,479	$	560,070
Abandonment and Reclamation	Base		50% increase		50% decrease	
Present A&R cost (1 newer well, 2 older wells)	$	272,204	$	408,306	$	136,102
Future A&R cost (in year 25: 2% inflation)	$	446,580	$	669,869	$	223,290

Using the base case assumptions, including an 8% discount rate on all future cash flows, the expected net present value of the project is negative $845,775. Expenses include the up-front capital investment of $635,002 for the three well retrofits and high-density polyethylene pipe installation and the future $446,580 cost for abandonment and reclamation of the wells in year 25 ($272,204 subject to 2% inflation for 25 years). Warming the cattle's drinking water temperature to 10°C (a 7.5°C increase) creates a present value lifetime benefit of just $19,255. The calculated overall net present value drops to -$1,153,969 in the "worst-case" scenario, while improving to -$520,588 in the "best-case" scenario. Figure 2.8 shows the present value of lifetime benefits and overall net present value for each scenario. In both the base and worst cases, despite a decrease in benefits as the chosen discount rate rises, the project's overall value increases. This counter-intuitive result is due to the accumulated benefits being less than the expected abandonment and reclamation expense at the conclusion of the project.

In all scenarios at all assessed discount rates, the projected net present value of this retrofit project is negative. The expected benefit from reduced feed costs is insufficient to justify the investment. In our base case, feed costs create $1,519 of benefit in year one, while $68,252 (rising with inflation each year) would be required to break even. In the best-case estimate, the addition of improved calf-birth rates decreases that gap, but still fails to make this a profitable project.

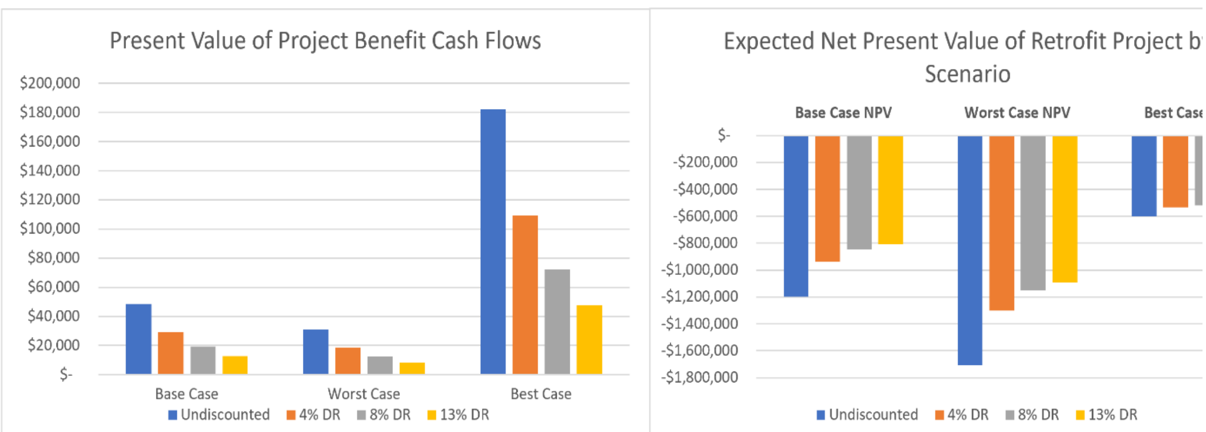

Figure 2.8: Left - Present value of all benefit cash flows. Right - Net present value of all project cash flows

2.3.5.1 Sensitivity Analysis

For the final step of our economic evaluation, we conducted a sensitivity analysis to better understand which variables have the greatest impact on projected net present value. Beginning with our base case scenario inputs, each variable is adjusted by 20% and the change in expected net present value is calculated. Recognizing that the benefits to cattle are unlikely to make a geothermal energy retrofit project feasible, we swapped out that value for the break-even annual revenue value of $68,252 in year one. Figure 2.9 shows the results of the analysis. Choosing a break-even revenue means that this variable must equals all expenses, so a 20% change on revenue has the largest impact on net present value. A 20% change to initial capital expenditure, the largest project expense, alters the project's financial outcome by nearly $160,000. Lowering the retrofit cost or finding an alternative revenue source will be the most effective means of making this project economically feasible. The discount rate is the next most influential factor on the project's net present value and highlights that private firms may value this type of project differently than public/government entity. Inflation rate has a relatively minor impact on project economics. Abandonment and reclamation costs have the least economic impact due to the discounting of this expense that occurs over 25 years time.

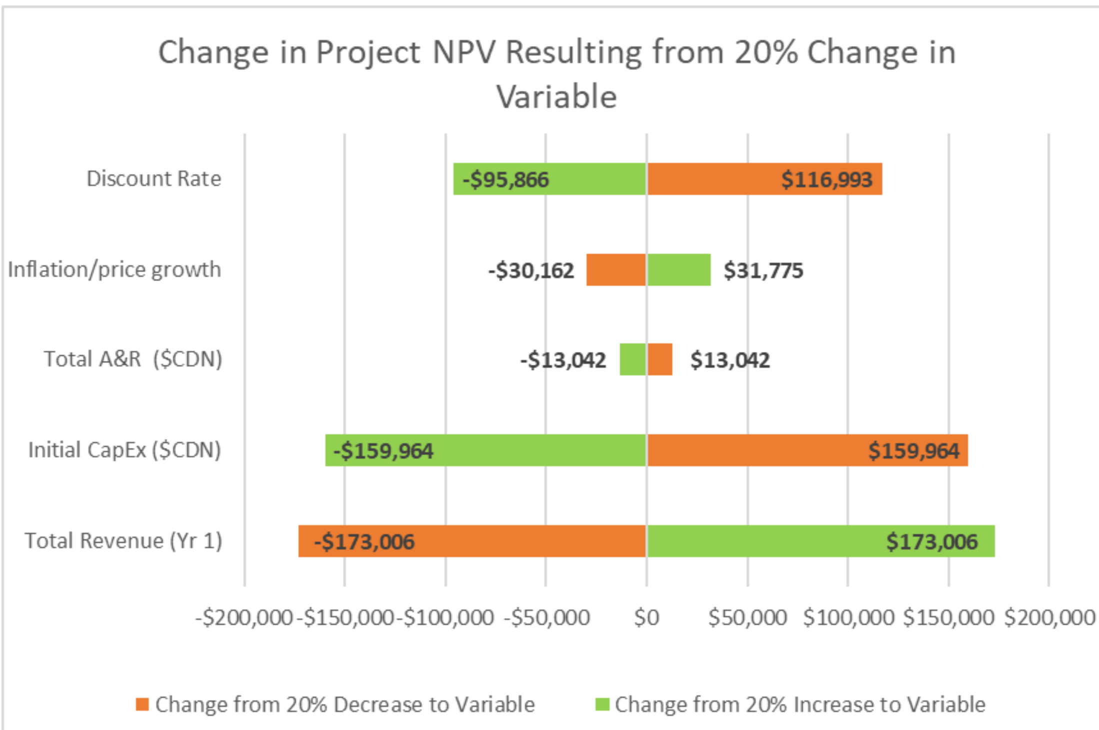

Figure 2.9: Sensitivity analysis showing change to project net present value resulting from 20% change to inputs

2.4 Discussion

2.4.1 Choosing a Well for Geothermal Energy Retrofit

Any project considering geothermal energy production from a retrofitted petroleum well should begin with a focus on suspended status wellbores. Based on the additional time and equipment required, we predict that the cost to retrofit an abandoned well will be at least

$50,000 greater than an identical suspended well. Making use of a suspended well may also result in fewer access and regulatory hurdles in a jurisdiction that is trying to encourage the reclamation of inactive well sites.

Wellbore depth is the most important factor in estimating the well retrofit cost. Although many of the prices suggested by the PSAC Well Cost Case study vary by geographic region, once constrained to a single region, the projected cost differences can be attributed solely to differing wellbore depth. Well depth is also the primary determinant of thermal power potential, as the geothermal gradient tends to remain relatively constant within a small geographic area. Thus, a reasonable estimate of well retrofit costs and thermal power potential can be made for any petroleum well in Alberta based on its depth, location, and regulatory status.

Because of the small differences in projected retrofit costs, other expenses play a key role when choosing the optimal well and determining economic feasibility. Amongst the five suspended wells evaluated in this study, retrofit costs varied by less than $11,000 and the present value of abandonment and reclamation costs varied by approximately $10,000. In contrast, the cost for HDPE pipe and installation varied by over $120,000. Of the three wells selected for retrofit in this study, two of them had the highest and second highest retrofit price-tag but presented significantly lower surface infrastructure costs that made them the lowest cost options overall. Surface infrastructure costs are also responsible for most of the variance in project costs when we calculated the best-case and worst-case scenarios. Reduced price variance also means that, from an economics perspective, these are also the lowest risk wellbores to choose for the geothermal energy retrofit. For these reasons, surface infrastructure costs proved to be the more influential variable and demonstrate the importance of well proximity in a potential well retrofit project.

The above findings can be used to simplify and expedite the evaluation of future geothermal energy well retrofit projects. Any given project at a pre-determined location will require a minimum amount of thermal power. A geothermal gradient map of Alberta can then be used to determine the approximate well depth required to attain that minimum thermal power. The well retrofit cost can be estimated based on this location and depth.

Then, a map, or list of well surface locations can be used to identify a suitable search radius, based on expected surface infrastructure costs, to find any wellbores that meet the required status, depth, and location requirements. If one or more wellbores meet these requirements, a more in-depth evaluation may be conducted to determine the best retrofit option.

2.4.2 Geothermal potential of the wells.

The model described here is numerical prediction of the thermal conduction between the well and the surrounding rock, as it is affected by operational conditions in both steady-state and transient environments. The thermal power output depends on the produced temperature and the fluid's total heat capacity (see Eqn. X1). The temperature decreases as the fluid reach the surface regardless of the mass flow rate. The amount of fluid temperature reduction varies with mass flow rate, because the fluid's total heat capacity decreases or increases as the mass flow rate gets smaller or larger. For example, for a 1500 m well, the fluid temperature as they flow to the surface drops by ~72% for a 0.1 kg/s flow rate but only ~7% if the mass flow rate is 5 kg/s. Eghbali et al. (2020, in press) also showed a threshold mass flow rate (~7 kg/s), after which the changes in production temperature are not significant. Nonetheless, the production pressure drops due to the friction associated with the larger mass of fluids and higher velocity.

The thermal power potential of each well is, therefore, controlled by the mass flow rate. High mass flow rates, however, might not feasible due to wells' dimensions, availability of fluids, and costs related to the pumping of a larger mass of fluid. A sustainable mass flow rate for retrofitting old oil and gas oils for direct use could be ~1 to 3 kg/s. In general, the thermal power required to raise the water temperature from 2 ºC to 10 ºC, flowing at a rate of 5-6 l/s (~90 gallons/min), is ~190 kW. For the Tomahawk Ranch area, to achieve this power with a sustainably low flow rate (~ 1 to 3 kg/s), Figure 6 suggests that at least three wells, including #5, need to be retrofitted to supply geothermal power to the entire volume of cattle feed water.

The hot and pressurized fluids flow upwards in a geothermal well. As the fluids flow towards the surface, the net energy changes due to the heat's loss to the surroundings and changes in the potential and kinetic energies. Fluid enthalpy changes adjust with the net energy change. The fluid flow mechanisms, thermodynamic and heat transfer must be investigated carefully to retrofit any oil and gas well for geothermal energy.

2.4.3 Discussion of Lifecycle Economics

The negative net present value of the geothermal energy retrofit project presented in this paper is primarily due to the lack of benefit that is expected from warming the cattle's drinking water. Reduction in feed costs provides approximately 2% of the $68,252 in year one revenue required for the project to break even. Adding the benefit of 5 additional calf births per year reduces the shortfall, but still results in net present value of -$520,588. As yet unknown health benefits to cattle from drinking warmer water may make this project economically feasible. Alternatively, different direct use heating projects such as greenhouses or aquaculture ponds might make more economically effective use of the generated heat energy and can be investigated by future researchers.

If sufficient benefit does exist, the sensitivity analysis demonstrates that incremental decrease to the expected up-front capital costs will have the greatest impact on financial outcome. Inflation rates have little impact on the final value of the project because it affects both revenues and costs. Abandonment and reclamation costs also have minimal impact on financial value; despite the large future dollar figure for cleanup costs, this becomes relatively small when discounted to present value. If policy were to shift so that abandonment and reclamation must occur within a specified time window, this could increase the benefit to a firm that is considering a well retrofit and could then push the abandonment and reclamation expense several years into the future.

The discount rate is one of the most influential variables on the expected outcome of this project and likely one of the most contentious. This juxtaposition is because there is no one true discount rate. Rather it is a number that differs based on context and intertemporal preferences. In this case, the chosen rate will impact the present value of both the annual benefits and the future abandonment and reclamation costs. Projected revenues are low enough from the Tomahawk Ranch project that the discount rate did not impact economic feasibility. We found that if a project is breaking even at an 8% discount rate, which approximates the rate used by profit-seeking firms, the net present value of that same project rises to positive $345,084 when the discount rate is lowered to 4%, which is representative of a social or public discount rate (Treasury Board of Canada Secretariat, 2007). These results reveal the influence of discount rate on long-term economic calculations and when social welfare is the primary concern, rather than profit-seeking, there is added benefit to this type of long-term project.

A potential benefit of a geothermal energy project that was not factored into this economic evaluation, is the potential offset of carbon emissions. In this case, there is no existing or alternate heat source to consider. However, conventional heating often makes use of a hydrocarbon fuel source, such as natural gas, propane, or possibly coal-fired electricity. If the geothermal energy being produced replaces production from conventional sources, there would be a significant reduction in carbon emissions. In the presence of a carbon tax or other emission penalty, this reduction could add material value for a profiting firm. For provincial and federal governments with a stated interested in reducing greenhouse gas emissions, there is a real opportunity to do so by incentivizing the type of project presented here.

2.5 Conclusion

Based upon the ranch owner's experience of increased cattle feed costs during the winter months and the intuition that an animal will need to expend some joules of energy to warm ingested drinking water to body temperature, we hypothesized that being able to warm that drinking water by a matter of degrees may reduce the animal's caloric intake and reduce overall feed costs. The ranch owner has also noticed fewer successful calf births during cold weather periods and that warmer drinking water may improve the birth rate.

The calculated net present value of retrofitting inactive oil and gas wells to geothermal wells for warming the drinking water for 2,000 head of cattle, however, is negative $845,775. This figure includes $865,030 of expenses and $19,255 of benefits. The expected reduction in feed costs of just over $1,500 per year are too small to justify significant capital spending.

The well retrofit project at Tomahawk Ranch is likely not economically feasible unless an alternative use for the heat is found. Our analysis, however, does provide valuable insight for future well retrofit evaluations. First, suspended status wells are the optimal retrofit target because they are likely easier to acquire the lease rights for and will have a lower retrofit price than an abandoned well with the otherwise same characteristics. Second, a reliable estimate of both the thermal power potential and well retrofit costs can be estimated based on knowledge of two factors, well location and vertical depth. Third, surface infrastructure expenses are the greatest source of variance in an overall project cost. These costs increase with increasing distance between the well (heat source) and water (heat recipient) and these distances can vary by kilometres. Thus, it can be inferred that proximity between retrofit well and the project is the most important consideration. Fourth, abandonment and reclamation costs are relatively unimportant to the overall project economics because of discounting and the long lifespan of a geothermal energy source. However, policy that requires a prompt abandonment and reclamation process would bring added financial benefit to a well retrofit project. Finally, the choice of discount rate for future cash flows plays a significant role in a project's economics. The long lifespan of a geothermal energy project, coupled with offset carbon emissions and the potential for reducing abandonment and reclamation liability from retrofit oil and gas wells, may make this type of project particularly appealing entities concerned with social welfare.

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Paper 3: Identifying Target Petroleum Wells for Geothermal Energy Production Retrofit

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Abstract

There are over 600,000 registered oil and gas wells in the province of Alberta. Many of these wells are inactive and present a significant liability for cleanup. Additionally, they present a potential environmental liability due to leaking greenhouse gases into the surrounding land and air. One possible solution to both liabilities is to re-purpose some of these wells for direct-use geothermal heat energy production. Using publicly available data from the GeoScout online database of petroleum wells and a well retrofit cost model presented by Schiffner et al, this paper first quantifies and sorts Alberta's wells by vertical depth, age, and regulatory status, then applies the retrofit model and bottom hole temperature data to rank each well by their likelihood of techno-economic retrofit success. The analysis finds 179,446 unique wellbores with a vertical depth greater than 1,000 metres that can be retrofit at an average cost of $225,000. Bottom hole temperature data is available for 45,687 of these wells. A list of the top 100 candidates for retrofit is created, showing that suitable candidates exist in many locations throughout the province.

3.1 Introduction

The Alberta Energy Regulator (AER) ST37 report lists over 600,000 registered oil and gas wells in Alberta. Earlier studies have estimated the cost to cleanup these wells and reclaim the surrounding land to be in the billions of dollars (Dachis et al, 2017). As well, many of these wells are at risk of leaking methane or other hydrocarbon substances and contaminating the surround air and soil (Ho et al, 2016). In a previous paper, I have suggested that a portion of these wells could be re-purposed to produce geothermal energy (Schiffner, Banks and Rabbani, 2020, in revision). The retrofit process gives new life to existing oil and gas infrastructure and can reduce the chance of leakage, thereby mitigating the financial and environmental risks of old petroleum wells while also providing a source of clean, renewable energy.

Schiffner et al (in revision) undertook a case study to estimate the geothermal energy potential from oil and gas wells and create a model of their retrofit costs. Although the project identified in the case study is not expected to be economically feasible, a key finding of the paper is that total well retrofit costs can be reliably estimated based on the well's regulatory status, geographic location, and total vertical depth (the length it extends beneath the earth's surface).

There are two main purposes to this paper. First, to sort Alberta's inventory of petroleum wells by vertical depth, age, and regulatory status to provide insight into the overall risk and potential they present. Second, to apply the Schiffner et al model of well retrofit costs and identify those wells that are most promising, from a techno-economical feasibility standpoint, for use in a geothermal direct use energy retrofit project utilizing the coaxial borehole exchange model as outlined by Hu et al (2020).

3.2 Methodology

3.2.1 Data Gathering

Well data for this research was obtained using the GeoScout online database of Canadian well data. GeoScout contains detailed information on a variety of well characteristics, including its geology, production history, ownership, and physical structure. To focus on those wells with potential to be retrofit for geothermal energy production, the GeoScout search was limited to wells located within the province of Alberta possessing a minimum vertical depth of 1,000 metres below surface. Well temperature increases with well depth, so shallower wells are less likely to be capable of producing economically viable geothermal energy.

In Western Canada, each well is identified by its own 16-digit Unique Well Identifier (UWI) code. This code identifies the bottom hole location of the well, based on the Dominion Land Survey system, and provides sequencing information about the well. Following its initial completion, a wellbore may undergo subsequent drilling or completions operations, such as deepening or re-entry, to access additional production. The final digit of the UWI is known as the event sequence code and reflects these operations. Initial drilling and completion have an event sequence code of '0', each subsequent event is assigned a value from 2-9. As such, up to nine unique UWI's, each with its own separate well record, could represent the same singular geothermal energy opportunity. To avoid overstating the geothermal energy retrofit potential, these duplicates must be accounted for. The simplest method to do this is to use only the UWI's with an event sequence code of '0'. However, it is common for the initial event to be officially abandoned while newer completions of the same wellbore are currently Active. Evaluating only the '0' events would result in inaccurate representation of well status. The most recent event sequence is most likely to represent current wellbore status, so the records from GeoScout were filtered so that only the most recent (highest number) event sequence code for each wellbore remained. This method will fail to remove all duplicate wellbores because a directional or horizontal well, once re-completed and extended, may reach a bottom-hole location that changes the location portion of the UWI. For example, wellbore 100/**01**-19-063-06W5/05 was later extended and, as a result, now reaches a neighbouring legal subdivision and this event has assigned the UWI 100/**05**-19-063-06W5/06. Although both records belong to the same wellbore, the difference in the location portion of the UWI makes automatic filtering challenging and a manual search would take a tremendous amount of time. There is likely to be some overstatement in the values presented here.

Any wells with a listed status of either “Licenced” or “Drilling” are also excluded from the analysis because they represent incomplete wellbores with unknown depths and other characteristics.

3.2.2 Well Sorting

The well information will be sorted and analyzed using the free, open-source software platform ‘R’ and Excel. Each UWI will be sorted according to its associated depth, regulatory status, and age. Depth plays a crucial role in determining both the geothermal energy potential and the cost of a retrofit, so it will be the primary sorting variable and wells will be grouped in 100m intervals.

Sorting by regulatory status is complicated by the existence of 113 status types in GeoScout, excluding licenced and drilling. To make the analysis tractable, I will condense these into 4 classifications labelled abandoned, active, cased, and suspended. A table of all status types and where they fall within the classification can be seen in Appendix 3A. In most cases, the classification is straightforward; for example, “Abandoned Oil”, “Abandoned Gas”, and “Abandoned Water Injector” are 3 of the 48 variations of abandoned wells that comprise the abandoned group. The Active group contains all wells listed as “Active”, “Producing”, or “Test” wells because they all indicate some form of active use by their owner. Suspended includes all “Suspended” or “Closed” status wells. Cased wells maintain their own classification due to the uncertainty of whether they will go into production or be abandoned.

Each well record will also be sorted according to its age because, as well age increases, the expected costs of reclamation and remediation increase. Discussion with well reclamation professionals has suggested that wells drilled prior to 1996 have the highest costs, while those drilled after 2003 have lesser costs (M. Newton, personal communication, July 2019). As such, I will group those wells drilled prior to 1996, those drilled between 1996 and 2003, and those drilled post 2003. Additionally, I will group the wells into 10-year intervals to search for patterns in their distribution. Well age will be determined as the year found in the well completion date contained in its GeoScout record.

3.2.3 Geothermal Energy Retrofit Potential

The final part of the analysis presented here outlines a methodology for identifying those wellbores that are the most promising candidates for re-purposing as direct use geothermal energy production wells. A paper by Schiffner, Banks, and Rabbani (2020, in revision) found that the cost to retrofit a petroleum well for geothermal energy production can be reasonably estimated using the well's vertical depth and that the energy capability of a well is dependent upon its bottom hole temperature. Using the formula presented in that paper, I calculate the expected retrofit cost for each wellbore that remains after the well sorting process described in section 3.2.1.

The formula to calculate the retrofit cost of an active, cased, or suspended well is based on fixed costs (FC), total vertical depth of the well in metres (TVD), tubing cost in dollars per metre (T), and variable costs (VC); the formula is presented below:

FC + TVD*T + (TVD-2500)*VC = Total retrofit cost

Or $176,935 + TVD*$20.75 + (TVD-2500)*$24,088 = Total retrofit cost

Abandoned wells require an extra $58,738 of fixed costs for additional time and materials. The formula presented by Schiffner et al also requires additional variable costs (directly dependent upon the wellbore's vertical depth) if casing installation is required on an abandoned well. The dataset used here does not include information on casing, so that factor is excluded from estimated retrofit costs. Thus, the retrofit costs calculated for many abandoned wells will understate the actual expected cost.

The second step was to apply the bottom hole temperature value, where available, for each well using a separate Drill Stem Test (DST) data file also downloaded from the GeoScout database. A DST measures, among other characteristics, wellbore temperature and pressure data. These tests are used to predict a well's productive capability but are not a regulated requirement, so bottom hole temperature information is unavailable for many wells. Of the wellbores that do have DST information available, many have multiple recordings from different depths or geological formations. For wellbores with multiple records, I apply a filter to remove all but the highest temperature record of any individual

UWI. This process risks overstating the actual energy potential of some wells by using an abnormal reading but does serve the goal of identifying promising targets.

As a final step, I divide the bottom hole temperature (in °C and multiplied by 1,000) by the estimated well retrofit expense. This provides a number value that can be used to rank the wells in manner that indicates those possessing the highest heat potential relative to the retrofit cost. The intent is to create a list of the 100 most promising retrofit candidate wells. Also, because suspended wells were identified as the most suitable retrofit candidates in the paper by Schiffner et al (2020, in revision), I will also create a list of 100 most promising candidate wells with the suspended status.

3.3 Results

3.3.1 Well Sorting

The initial search and download of records from GeoScout returned 244,420 UWI's of greater than 1000m vertical depth in the province of Alberta. 179,446 records remain after deleting the "Licenced" and "Drilling" status wells and filtering out the duplicates of any wellbores with multiple sequence events. Only 173,935 of these UWI's end with an event sequence code of '0', indicating that the filtering process failed to identify 5,511 of the duplicates. This suggests that values presented below may be overstated by 3%.

3.3.2 Depth

In this analysis, 1,000m is the minimum vertical depth cut-off, while the maximum vertical depth found for any UWI in the data is 6027m below the earth surface. The shallowest 100m depth interval, between 1,000m and 1,100m, contains the largest number of wells and accounts for nearly 15% of all wellbores. Figure 3.1 clearly shows that as the vertical depth increases, the number of corresponding wells decreases. Table 3.1 demonstrates that nearly 2/3 of the 179,446 UWI's possess a vertical depth of between 1,000m and 2,000m depth, while just 6.4% have a depth of 3,000m or greater and fewer than 1% are more than 4,000m depth.

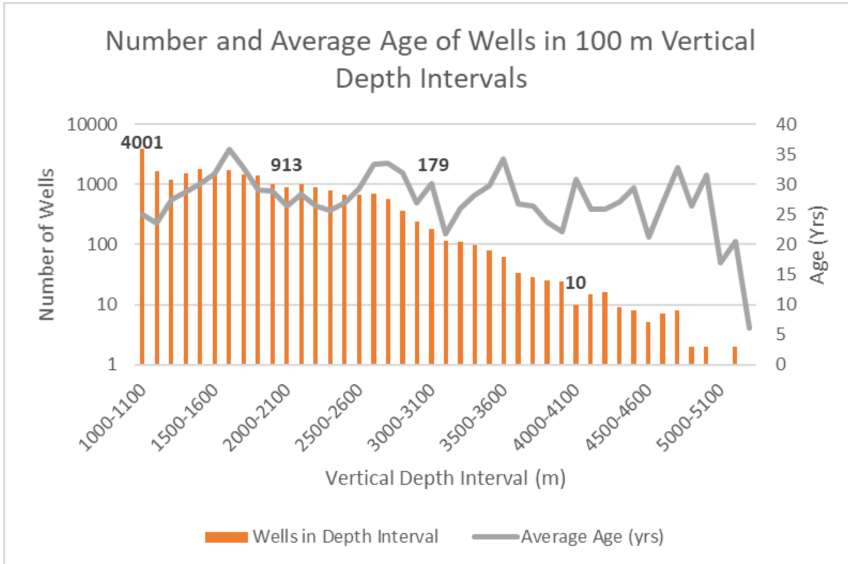

Figure 3.1: Histogram displaying the number of wellbores by vertical depth using 100m depth intervals and a line graph depicting the average well age (in years) for each depth interval. The wellbore numbers are on a logarithmic scale and the numbers in bold highlight the total wellbores in the 1000-1100, 2000-2100,300-3100, and 4000-4100 intervals.

TVD (m)	# of Wells	% of Wells
1000-2000	118966	66.3%
2000-3000	48958	27.3%
3000-4000	10458	5.8%
4000-5000	967	0.5%
5000+	97	0.1%

Table 3.1: Distribution of Alberta wells by 1000m vertical depth intervals

3.3.3 Well Status

Among the 179,446 wellbores analyzed were over 100 explicit status types which I have condensed into 4 broad status types; “abandoned”, “active”, “cased”, and “suspended”.

Given the regulatory requirement that all wellbores must eventually be abandoned, it is unsurprising that abandoned wells are the most common and comprise nearly half (Figure 2) of all wellbores. Active wells are the second most common, approximately one-third of the total, while suspended and cased wells make up 14% and 4% of the population, respectively.

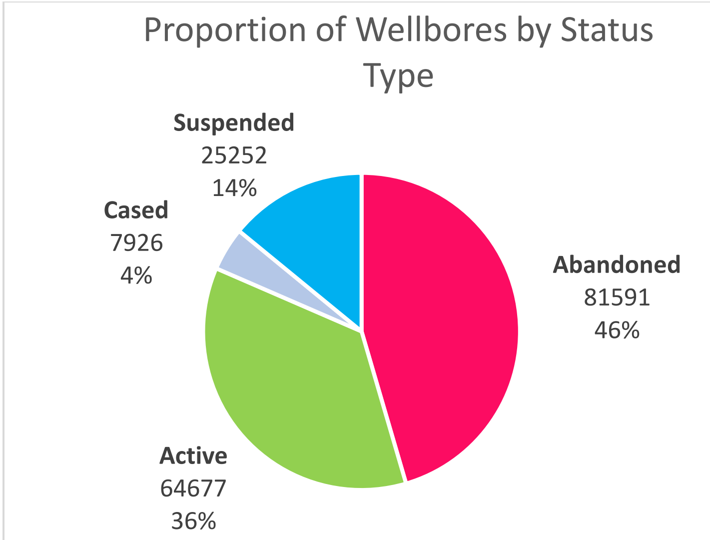

Figure 3.2: The proportion of wells, by status type, greater than 1000m vertical depth.

This pattern of abandoned being the most common well status, active a close second, and suspended and cased a distant third and fourth, is generally true at all 100m depth intervals. An exception to this is that between 2,000m and 3,500m vertical depth active wellbores are the most common. Also, beyond 3,000m vertical depth there are nearly equivalent numbers of cased and suspended status wells. At depths greater than 4,000m any patterns begin to smear due to the relatively small sample sizes.

3.3.4 Well Age

A well's age is correlated to its condition and associated reclamation and remediation costs. The oldest UWI, as found in GeoScout, was completed in 1908 (112 years old), while the oldest Active status well was completed in 1927 (93 years old). Figure 3.3 shows a distribution of wellbores in 10-year age groupings and demonstrates a steadily increasing number of new wells being drilled over time until dropping off significantly in the past 10 years. Due to the relatively small number of older wells, the final age group contains all wellbores 60 years of age or greater.

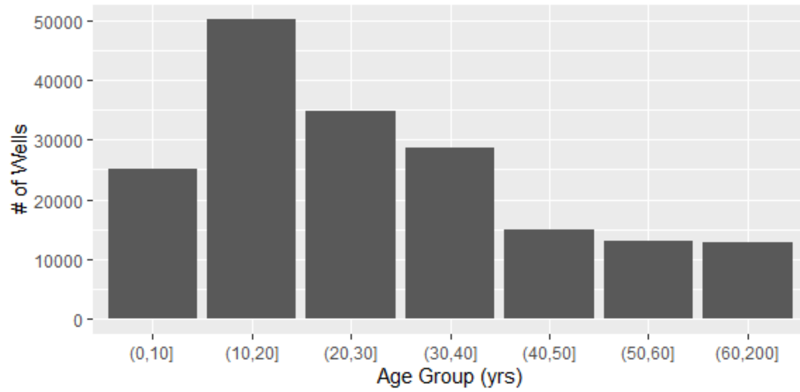

Figure 3.3: Bar graph displaying the total number of wellbores for each 10-year age interval based upon completion date.

Discussion with professionals in the industry has suggested that wellbores drilled prior to 1996 ("old" wells) tend to have the greatest costs, wells drilled between 1996 and 2003 present a neutral or mid-range cost expectation, while those drilled since 2003 ("recent" wells) have the lowest costs. Figure 3.4 presents the number of wellbores in each age classification and according to their status type. As expected, most "old" wells are abandoned, while most "recent" wells are active. The suspended status is relatively evenly distributed among all three age classifications.

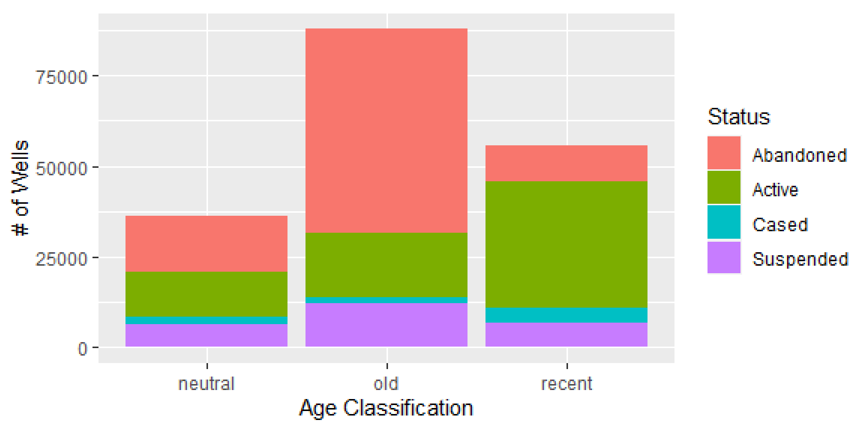

Figure 3.4: Distribution of Alberta wells by age classification and regulatory status

3.3.5 Well Retrofit Costs

Using the formula presented in the paper by Schiffner at al, I calculated the average retrofit cost for all 179,446 unique wellbores in the dataset to be $224,899. The average cost to retrofit an Abandoned well is $252,298, while the average suspended well retrofit cost is $195,488. Both active and cased status wells typically cost approximately $205,000 to retrofit. That these well tend to cost more to retrofit than suspended wells reflects that their average depth is approximately 200m greater than that of suspended wells.

3.3.6 Geothermal Energy Retrofit Potential

The DST data provided the bottom hole temperature values for 45,687 unique wellbores. Wells with temperature information were then separated according to regulatory status. Average values for retrofit cost, total vertical depth, bottom hole temperature, and retrofit feasibility potential (where higher scores represent greater likelihood of feasibility) were calculated for each status; these results are presented below in Table 3.2.

Table 3.2: Average retrofit costs, depth, bottom hole temperature, and feasibility potential of Alberta wells by regulatory status

Regulatory Status	Number of Wellbores	% of Total Wells	Retrofit Cost	TVD (m)	BHT (°C)	Retrofit Feasibility Potential
Active	7,284	16%	$ 199,163	1838.8	53.3	0.262
Suspended	5,375	12%	$ 196,046	1769.3	52.8	0.265
Abandoned	31,685	69%	$ 252,079	1708.9	51.0	0.199
Cased	1,343	3%	$ 200,568	1870.1	55.6	0.273
Total	45,687	100%	$ 235,536	1741.5	51.7	0.219

Compared to the larger population of all wellbores with 1000m depth or greater, a significantly larger proportion of those with bottomhole temperature data are abandoned, while far fewer are Active. As expected, the bottom hole temperature is correlated to average vertical depth. The retrofit feasibility potential score is similar for all well status', except for abandoned wells which have decreased feasibility due to increased retrofit costs.

3.3.7 Wellbores with the Greatest Retrofit Potential

The final step in this analysis is ranking the wells according to their retrofit feasibility potential score, calculated as BHT*1,000/Retrofit Cost. I first scored and ranked all wellbores, regardless of status, then selected the top 100 scoring wells (The full list of 100 can be seen in Appendix 3B). Of these 100 wells, 36 are active, 26 are suspended, 31 are abandoned, and 7 are cased. While abandoned wells make up 46% of the overall well population, just 31% the most promising retrofit candidate wells are abandoned. The average retrofit feasibility potential score for these 100 top wells is 0.554, approximately

2.5 times greater than the average score of the full population. I then repeated this process considering only suspended status wells (Full list of top 100 in Appendix 3C). Table 3.3 lists the individual results for top 5 candidate suspended wells and the average of the top 100 suspended wells.

Table 3.3: Suspended wells with the greatest retrofit feasibility potential

UWI	BHT value (°C)	TVD (m)	Total Retrofit Cost	Retrofit Feasibility Potential
100/14-32-040-25W4/00	130.0	1707	$ 193,253	0.673
100/08-35-036-04W5/00	150.0	2383	$ 223,564	0.671
100/10-18-055-12W5/02	136.0	1978	$ 205,405	0.662
100/07-05-031-27W4/00	146.1	2460	$ 227,003	0.644
100/06-10-064-02W6/00	148.0	2575	$ 232,173	0.637
Avg for Top 100 Suspended	**104.4**	**2384.0**	**$ 223,610**	**0.468**

When compared to the average values of all 5,375 suspended wells, the top 100 wells are approximately 600 metres (35%) deeper and possess bottom hole temperatures that are twice as high.

3.4 Discussion

The initial data extraction from GeoScout resulted in 244,420 UWI's with a vertical depth greater than 1,000m in Alberta. AER's ST37 report lists over 600,000 registered wells in the province, so we can infer that over half of all petroleum wells in Alberta reach less than 1,000 metres beneath the surface. Of the 179,446 unique wellbores that remained after filtering out the multiple completions, nearly two-thirds of these possess a vertical depth between 1,000 and 2,000 metres. Despite advancement in drilling technologies, most of Alberta's oil and gas wells remain less than 2,000 metres in depth. This suggests that many wells likely lack the heat energy required to be suitable for geothermal energy production and firms interested in pursuing well retrofit projects need to be selective.

The number of oil and gas wells drilled in Alberta has consistently increased over time until recently. There have been fewer wells drilled in the past ten years than there were in the 1980's, 1990's, or 2000's; this is likely due to the decrease in energy prices that began in

2014. As expected, most newer wells remain active while most older wells have been abandoned. However, the number of suspended wells in each age classification (older, newer, neutral) remains proportionately similar. This suggests that a percentage of all wells tend to be suspended and then left in that state indefinitely, thus the lack of change among age classes.

Among the four broad regulatory statuses of active, suspended, abandoned, and cased wells, abandoned wells tend to be the shallowest, while active and cased wells reach greater depths on average. Combined with the evidence that abandoned wells are older and active wells are more recent, this suggest that average well depth has been increasing over time. As such, recently drilled wells and those wells drilled in the future may offer increased potential for geothermal energy retrofit.

Compared to the full population of wellbores reaching greater than 1,000 metres vertical depth, a significantly greater percentage of wells with DST data are abandoned and a much smaller percentage are active. This indicates that fewer wells are having DST's performed now than in the past. Additionally, only one-quarter of the wells have DST data available. Further efforts to identify promising geothermal energy retrofit targets will benefit from another source of bottom hole temperature data or from interpolating temperatures using the information from nearby wells.

When identifying wells from the full population that appear to be most promising for geothermal energy retrofit, relatively few are abandoned. The increased cost to retrofit an abandoned well makes techno-economic feasibility less likely. However, abandoned wellbores in regions with above-average heat gradients can make suitable retrofit candidates and should not be eliminated from consideration or evaluation. When identifying the 100 most suitable suspended wells for retrofit, I found that these wells were 35% deeper and nearly 100% warmer than the full population of suspended wells. This suggests that, even though retrofit costs increase with depth, the increased energy potential of deeper wells tends to make them better retrofit targets. A firm interested in a geothermal retrofit project can most effectively identify target wells by searching for the deepest available well in a geographic area with above-average heat gradient.

3.5 Conclusion

Ignoring any UWIs with a current regulatory status of "Licenced" and "Drilling" and filtering out multiple completions, there are 179,446 unique wellbore records for the province of Alberta in the GeoScout online database. 46% of these are abandoned wells and nearly two-thirds of them are relatively shallow with a vertical depth between 1,000 and 2,000 metres. There does not appear be a correlation between well depth and its status. However, the data does indicate newer wells tend to be drilled to a greater depth than older wells.

In this analysis, I estimated the cost to retrofit each well for geothermal direct-use heat energy production using a cost model presented by Schiffner et al (2020, in review). The average retrofit cost for all 179,446 unique wellbores is nearly $225,000. When the more costly abandoned wells are removed, the average retrofit cost drops to approximately $200,000. The final step was to apply bottom hole temperature data to the wells and calculate a retrofit feasibility score based on a simple ratio of temperature to retrofit cost. Results indicate that abandoned wells are less likely to be capable of techno-economically feasible energy production, but suitable candidates exist amongst all well status types. As well, the increased potential energy available from deeper wells likely justifies the extra retrofit expense in many cases.

One challenged faced in this process was the relative lack of bottom hole temperature information. Drill Stem Test data was available for just 45,687 (approximately ¼) of the above wellbores. The results presented here can be enhanced by finding another source of bottom hole temperature information or through interpolation of temperature data for those wells lacking data.

3.6 References

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Conclusion

The research contained in this thesis is presented with three objectives in mind. First, to improve our understanding of the costs and benefits, including externalities, associated with re-purposing an inactive oil and gas well for geothermal energy production. Second, to quantify the potential for economically feasible geothermal energy well re-purposing projects in the province of Alberta. Third, to provide guidance to policy makers interested in either mitigation of inactive well liabilities or encouraging development of geothermal energy. Hence, this concluding chapter is comprised of four parts. We begin with a summary of the results and key findings from each of the three papers presented within the thesis and finish with a discussion of the overall well retrofit opportunity in Alberta and policy implications.

Results from Paper 1: An Updated Look at Petroleum Well Leaks, Ineffective Policies, and the Social Cost of Methane in Canada's Largest Oil-Producing Province

The Environmental Enhancement and Protection Act (EPEA) stipulates that the land on which petroleum wells are located must be returned to a state equal to that prior its development (Alberta Energy Regulator, ndb); this means that all wells must eventually undergo plugging/abandonment and reclamation. Previous studies that have attempted to quantify the total cleanup liability in Alberta have estimated a cost as high as $8 billion (Dachis et al, 2017). This is a large sum, but still fails to include the additional cost borne by the public resulting from the leaking of methane emissions into the atmosphere. The cost of the negative impact on the environment and human well-being posited by methane emissions has been termed the Social Cost of Methane (SCM). Currently, no one is responsible for paying the SCM from a leaking well.

Suspended wells are especially prone to developing a leak. Plugging a suspended well would reduce both the financial clean-up liability and the chance of developing a leak but, under current regulations in Alberta there is no limit to the length of time that a well is permitted to remain suspended and there is little incentive for an owner to undertake the process of abandonment and reclamation. A simple comparison of the net present value of estimated costs demonstrates that it is financially advantageous for the owner to pay the ongoing surface lease and inspection expense for the suspended well and affirms the earlier work of Muehlenbachs (2015 and 2017) who suggested that the high costs of decommissioning (plugging and abandonment) to be the main reason wells are left inactive. This suggests that policy which taxes or requires payment for emissions, and therefore balances the financial equation, may result in more rapid reclamation.

In this paper we analyze a large data set obtained from the AER that reports on the duration and leakage rate of all Surface Casing Vent Flow (SCVF) and Gas Migration (GM) events from 1971-2019. We assess this data for any trends and calculate the typical methane emission volume from a leaking well. Then we investigate whether payment of the Social Cost of Methane for the expected methane emissions from a suspended well would alter the cost benefit analysis sufficiently to encourage an owner to promptly abandon and reclaim the well.

Key Finding 1.1 – Petroleum well gas leaks due to Surface Casing Vent Flow (SCVF) and Gas Migration (GM) are lasting longer and emitting higher volumes of methane.

We found that the duration of a leak, the amount of time between when the leak is first reported and resolution/repair, has steadily increased between 1971 and 2019. This can be at least partly attributed to the fact that the percentage of well leaks that are active/open (not resolved/repaired) has also grown over time. A greater proportion of leaking wells are simply being monitored until they resolve themselves without any mitigating action being taken. Further to this, the flow rate of a leak (m^3 of emissions per day) has also trended upward over the years. This indicates that once a suspended well develops a leak, it typically continues to leak for a significantly longer period and emit methane at higher rates now than would have even 20 years ago. Given concerns related to climate change, regulators need to be aware of these trends in methane emissions from leaking wells and seek out solutions as soon as possible.

Key Finding 1.2 –Aggregate methane leak emission volumes are significant and present a cost valued in the billions

From the AER dataset we calculate that the average active SCVF/GM leak from a suspended well has emitted $42.6m^3$ of gas per day for 8.4 years, resulting in 84.5 tonnes of methane added to the atmosphere. Based upon SCM pricing of either $1,050/t or $4,665/t, a 10-29% chance of a suspended well developing a leak, and the existence of 116,000 suspended wells in Alberta, the estimated cost of future methane emissions damages is between $1.03 billion (10% leak rate and conservative SCM) and $13.26 billion (29% leak rate and high SCM) (Table 4.1).

Table 4.1: Estimated value of methane emissions from suspended wells in Alberta

Chance of Leak	SCM	
	$1050	$4665
10%	$ 1.03 billion	$ 4.57 billion
29%	$ 2.98 billion	$ 13.26 billion

These emissions occur at different times and will be spread over many years, which can make them easier to disregard as a minor concern. However, the aggregate release of methane from SVCF/GM presents a very real risk and a significant cost to the public that additional to the abandonment and reclamation expense.

Key Finding 1.3 – Forcing well owners to pay a Social Cost of Methane for leaking well emissions is unlikely to incentivize them to participate in prompt well abandonment and reclamation

Under the status quo, where well owners are not responsible for the methane emissions from a leaking well, there is financial incentive to leave a well in the suspended state. Being forced to pay the SCM for a leaking well is unlikely to change the suspended well decision for a profit-seeking firm. Although the aggregate value of SCVF/GM methane emissions are significant, once this cost is distributed amongst all suspended wells it is unlikely to incent prompt abandonment and reclamation. It is only in an extreme scenario, using the highest probably of developing a leak along with the highest value of SCM, that suspension costs surpass abandonment and reclamation costs in less than 10 years. Increased regulations and monitoring would likely prove more effective in reducing provincial methane emissions from leaking wells.

Limitations and Future Research from Paper 1

One limitation of this analysis is the sparse data that is available for SCVF or GM leaks. According to AER Interim Directive 2003-01, a non-serious leak is only subject to annual testing for a period of five years; these results do not need to be reported and if the leak has not become serious then no further testing is required. This means that, for many wells, the rate of emission is reported just once and the reported values do not capture any fluctuations or changes over time. Further to this, GM testing is recommended for all wells but only required in specified regions, so some instances of leak may be going undetected.

A second limitation of this analysis is the uncertainty regarding what percentage of wells will develop a leak. While it is generally acknowledged that suspended wells are more prone to leakage (AER Sep 2018, Ho et al, 2016), there is little consensus in the literature regarding what that percentage is. Previous research has suggested that anywhere between 4.6% (Bachu and Watson, 2009) and 29% (Werring, 2018) of oil and gas wells will develop a leak. Even these studies fail to document the differences between active, suspended, and abandoned wells. Initially, as part of this paper, we had hoped to use the dataset to determine the likelihood of a leak, but the wells only contain information on their current regulatory status and so it is unknown what the well status was at leak onset.

Field investigation or further research of historical data may provide a more accurate rate of leak occurrence and would facilitate a more accurate depiction of the risk presented by all wells that may change some of the results found in this paper.

Results from Paper 2: Assessing the Techno-economic Feasibility of Retrofitting a Petroleum Well for Direct Use Geothermal Energy Production: A Case Study

Both the Alberta provincial government and the Canadian federal government have committed to reducing greenhouse gas emissions. One method of doing so is to increase the percentage of energy generation produced from renewable sources. This paper undertakes a case study evaluating the economic feasibility of retrofitting inactive petroleum wells to produce direct use geothermal energy to warm the drinking water for cattle on a Central Alberta ranch.

Step one of the evaluation was to estimate the cost of the well retrofit based on the Coaxial Borehole Heat Exchanger system outlined in the paper by Hu et al (2020) and pricing information obtained from the Winter 2019 Petroleum Services Association of Canada

(PSAC) Well Cost Study. Retrofit costs were estimated for each of the 15 plugged/abandoned and 5 currently suspended wells on ranch property. We estimate that the average cost to retrofit a suspended well for geothermal heat production is $212,999, with little variance in cost; abandoned wells present a significantly higher, $301,421, and more variable retrofit expense.

The next step was to estimate the heat energy that can be produced from each of the five suspended wellbores. The energy potential was modelled using MATLAB software with assumptions made for surface temperature, injection mass flowrate, inner and outer radius of the annulus, thermal conductivity, and heat capacity. We find relatively little variance between wells and estimate they can generate between 200.8kWT and 239.0kWT in year one, decreasing to 187.1kWT and 217.1kWT in year 25.[10]

The final step was to assess the economic feasibility of the project by estimating all expected revenues and expenses occurring over a 25-year lifecycle. Expenses include the well retrofit expense that was calculated earlier plus additional surface infrastructure to make use of the heat energy and the future abandonment and reclamation cost for the well. Expected revenues are based on predicted decreases in feed consumption and improved birth-rates of calves resulting from having access to warmer drinking water. Three scenarios were considered (see Appendix 2 for breakdown); a base case with the best estimates of input variables, a worst case with high costs and pessimistic revenues, and a best case with low costs and optimistic revenues. At an 8% discount rate on future cash flows the calculated net present value of the project is negative in all scenarios, suggesting the project is not economically feasible. A sensitivity analysis was also performed to determine which variables have the greatest impact on the financial outcome.

[10] We assume a project life of 25 years. This is based upon previous studies (Hu et al, 2020 & Palmer-Wilson et al, 2018) that have estimated a productive lifespan of between 25 and 30 years for geothermal energy projects.

Key Finding 2.1 – A Reasonable Estimate of the Cost to Retrofit a Petroleum Well for Geothermal Heat Energy Production Can Be Made Based on Geographic Location and the Vertical Depth of the Wellbore

Our analysis found that, to retrofit any of the suspended wells at Tomahawk Ranch for geothermal heat energy production using a coaxial borehole heat exchanger system, all the cost variability was due to different vertical depths and the installation of tubing and/or casing along those depths. When considering the province as a whole, there may be change to several of the fixed cost components of a retrofit based on regional differences around access to roads and equipment. However, within a given region, all retrofit cost variance can be attributed to differences in well depth.

Key Finding 2.2 – The Distance Between the Retrofit Well and the Location or Object Making Use of the Heat (Proximity to Destination) is Critical to Economic Feasibility

Retrofitting a well facilitates the production of heat energy; however, it must also be connected to a destination that will use the heat. To calculate the total capital investment required to make use of the five suspended wells on ranch property, in addition to the cost of the retrofit itself, it was also necessary to estimate the cost to purchase and install plastic pipe for connecting the well to the drinking water system, as well as the anticipated future abandonment and reclamation expenses. Although the retrofit is the largest cost component, over 90% of the variance in total capital expenditure was due to the per metre charge for plastic pipe and installation.

Different geothermal heat energy projects will require different types of surface infrastructure, so the costs presented in this study may not directly correlate. However, this example does demonstrate that it can be expensive to transport heat and that the distance between the retrofit well and end user of heat may be the most important variable when assessing project economic feasibility.

Key Finding 2.3 – The Financial Benefit of Providing Warm Drinking Water to Cattle During the Winter Months Does Not Justify the Capital Expenditure of a Well Retrofit Project

There are two projected benefits from heating the drinking water made available to cattle. First, the cattle will need to expend fewer joules of energy to warm the consumed water to body temperature and, thus, will require less feed to maintain their body weight. Second, the ranch owner reports a lower successful birthing rate of calves during the winter and hopes that access to warmer drinking water may improve that rate.

Based on 2,000 head of cattle each consuming an average of 20 litres of water day, the ranch spends $1.66 per day on feed for every 1°C below cattle body temperature the drinking water is. Using geothermal energy to heat that drinking water from 2.5°C to 10°C for 4 winter months provides an annual financial benefit of $1,519 ($1.66/day/°C*122 days*7.5°C) in year one. This amount falls far short of the projected $68,252 in revenue/benefit required to break even. An optimistic scenario that assumed 5 additional successful births would occur due to the increased water temperature brought an addition benefit of $3,500 per year, but still far short of a profitable project. It does not appear to be economically feasible for heat energy to be used for the sole purpose of warming drinking water for cattle. When considering similar well retrofit projects in the future, the revenue generated by that project likely needs to be in the ballpark of at least $60,000-$70,000. Ventures such as a greenhouse or aquaculture pond are possible economically feasible alternatives.

Key Finding 2.4 – Choosing a Discount Rate to Apply to Future Cash Flows Plays a Crucial Role in Determining the Economic Feasibility of a Geothermal Energy Project

Aside from the upfront capital expenditure and expected annual revenues, the chosen discount rate is the variable that has the greatest impact on the project's financial outcome. The discount rate has such a significant effect because of the project's long lifespan and the large abandonment and reclamation expense that occurs at the project's conclusion. The undiscounted expense to abandon and reclaim the three retrofit wells in 25 years time is projected to be $446,580 but, when discounted at 8%, the present value becomes just $65,029. In the hypothetical scenario where revenues are just high enough for the project to break even, lowering the discount rate to 6.4% (a 20% decrease from 8%) improves the project's net present value by approximately $117,000. Lowering the discount rate increases the value of future revenues more than it increases the liability of abandonment and reclamation. This demonstrates that organizations with lower discount rates may find more value in a long-term geothermal energy project.

Limitations and Future Research from Paper 2

A limitation of this analysis is that, to the best of our knowledge, there have been no actual projects that make use of a re-purposed and oil and gas well for geothermal energy production using the coaxial borehole heat exchanger concept. Although similarity in the materials, knowledge, and process needed to create either a petroleum well or geothermal energy well make oil and gas data a good proxy, the values used here are estimates. When a re-purposing project is first undertaken, it may reveal challenges or opportunities that have not been considered or reveal that some of the costs presented in this paper may under or overestimate the actual expenses. It will be prudent to revisit the models presented here once the data from completed projects becomes available.

A second limitation of the analysis presented here is that there was no comparison of the geothermal energy to an alternative energy source. It is likely that future projects considering the use of geothermal energy from a retrofit well will either be replacing an existing energy source or considering the use of a different source. For these situations, the capital costs associated with the geothermal energy will be at least partially offset by the costs required for that alternate source. Additionally, the use of non-GHG emitting geothermal energy may produce tax incentives or other benefits as result of not using conventional energy. Future projects should consider these elements.

Results from Paper 3: Alberta's Petroleum Well Quantitative Analysis

At the time of writing, there were 174,209 unique wellbores of 1,000 metres or greater vertical depth registered in the province of Alberta. Most of these wells have abandoned status (46%) and approximately two-thirds are relatively shallow wells with a vertical depth between 1,000-2,000 metres. These are positive indicators that generally indicate a decreased well cleanup liability in the province but tend not to be characteristics suggestive of techno-economically feasible geothermal energy production. After estimating the retrofit cost of each well and applying bottom hole temperature data where available, I was able to rank the wells based on their energy potential to retrofit cost ratio score. I found that the 100 highest ranked suspended wells were 35% deeper and nearly 100% higher in temperature than the full population of suspended wells. Despite the higher capital investment necessary to retrofit a deeper well, the increased depth increases the probability of geothermal energy retrofit feasibility.

Key Finding 3.1 – Suspended Status Wells are Equally Likely to be Found in Any Age Classification

Wells that have been more recently completed are more likely to have active status, while most older wells have abandoned status. However, the proportion of suspended wells in each age classification (older, newer, neutral) remains relatively constant. The similarity between age classes supports the notion that there is a percentage of suspended wells will likely be left in that state indefinitely.

Key Finding 3.2 – Abandoned status wellbores are less likely to be techno-economically feasible than other status wellbores but should not be removed from consideration.

Of the 45,687 unique wellbores with drill stem test bottom hole temperature data available, 69% of them have abandoned regulatory status. Meanwhile, just 31% of the top 100 wellbores ranked for retrofit feasibility potential have abandoned status. Generally, the increased cost to retrofit an abandoned well makes techno-economic feasibility less likely. However, 6 of the top 10 feasibility score wells are abandoned, which suggests that wells with this regulatory status should not be eliminated from consideration. Abandoned wellbores in regions with above-average heat gradients may make suitable retrofit candidates.

Key Finding 3.3 – The 10 Highest Ranked Suspended Wells are in Geographically Diverse Locations

Of the 10 highest scoring suspended wells, none are located within the same or even adjacent townships. The two geographically closest wellbores are separated by over three townships or more than 30 kilometres. This indicates that potential geothermal energy retrofit projects will not be constrained to only a few select region of the province and that suitable candidate wells may be found throughout Alberta.

Limitations and Future Research from Paper 3

Drill stem test data, downloaded from the GeoScout online database, was only available for approximately 25% of the unique wellbores with 1,000 metres or greater vertical depth. The ranking system demonstrated in this paper could become much more comprehensive with either a second source of bottom hole temperature data and/or through large-scale interpolation of the data to find values for the remaining wells that lack temperature information.

Further analysis could also refine the estimated retrofit cost values calculated here. As stated by Schiffner et al (2020, in revision), some of the cost inputs will vary by geographic region. This paper used a single cost model based upon the Alberta Foothills region. An evaluation that separates the wells according to region and applies a cost model specific to that region will enhance the accuracy of the retrofit cost and feasibility ranking results.

Discussion and Policy Implications

For many years, the Alberta economy has been tied to its oil and gas industry. Although the province has often benefitted from this tie, it is now faced with a potential multi-billion-dollar legacy liability to clean up and reclaim the land from the hundreds of thousands of drilled petroleum wells drilled. From a liability standpoint, suspended wells are especially concerning because they are neither producing resource nor undergone any of the cleanup and reclamation process. Thus, these wells present full liability risk while providing none of the benefit expected from a typical well. Under the status quo it is cheaper, on average, to leave an inactive well in the suspended state than it is to undergo the proper plugging/abandonment and reclamation process. This fact has likely contributed to the increased number of wells being left suspended in recent years.

An additional risk posed by these wells is their potential to leak methane into the atmosphere. Although any well could leak, suspended wells are much more prone to leakage than their plugged/abandoned counterparts. What is more, our analysis of nearly 50 years of data indicates that leaks are now lasting longer and emitting higher volumes of emissions than in the past. An average SCVF/GM leak from a suspended well will last result 8 ½ years and add 84.5 tonnes of methane to the atmosphere. There are currently over 116,000 suspended wells in Alberta; although there is a lack of consensus over the percentage of suspended wells expected to develop a leak, anywhere from 10%-29% has been reported which would result in between 11,600 to 33,640 leak events. This suggests that between 980,000 and 2.84 billion tonnes of methane could be emitted over the coming years and contribute billions of dollars in social climate change damages. Further research to improve our understanding of well leak probability would provide additional clarity regarding the extent of actual emissions and damages.

The Government of Alberta that has stated its goal to reduce methane emissions, but recent regulatory efforts have focused reduction by large emitters through the *Specified Emitters Regulations* (ERA Ecosystem Services, 2014). Individually, SCVF/GM occurrences represent small emission volumes that receive little attention and are governed by rules that were last updated 17 years ago in 2003. However, the aggregate emissions from these leaks present a significant risk and there is a clear opportunity to mitigate climate change by addressing SCVF/GM leaks from inactive wells. Tighter regulations, such as lowering the flow rate that requires immediate repair, or increased monitoring requirements, such as requiring annual well inspections or ongoing leak measurement that does not end after five years, could help to reduce emissions. However, reducing the number of suspended wells may be the most effective option.

Policy aimed at reducing the number of suspended wells can significantly reduce both the financial cleanup liability and methane emissions from legacy wells. Current regulation in Alberta places no limit on the time that a well is permitted to remain suspended and in recent years we have witnessed an increased number of wells being left in that state. Our investigation asked whether forcing well owners to pay the social cost of methane for their emissions would encourage well abandonment and reclamation. Despite the large volume of aggregate emissions, our analysis indicates that once that cost is spread over all suspended wells, it is unlikely to encourage profit-seeking firms to plug/abandon and reclaim their wells.

Alternatively, it may be possible to reduce the number of suspended wells by giving some of them new life through re-purposing them for direct use geothermal energy production. Although any existing well extending deep enough into the earth to access a sufficient heat resource can be re-purposed, suspended wells offer the most financial promise because they are currently unproductive and typically less expensive to retrofit than an abandoned well. The process of retrofitting, or re-purposing, a well involves sealing the wellbore to prevent further oil or gas production, which is similar to the process for repairing a leak (AER, 2003). Putting the well back in use also defers the cleanup cost and provides the opportunity for a licensing process that requires a bond to be paid up-front for future abandonment and reclamation liabilities. Thus, re-purposing an inactive well likely reduces methane emissions and potentially mitigates the cleanup liability. An additional benefit of this process is the potential goodwill that a firm can earn with the public by pursuing renewable energy projects. Large oil and gas projects such as pipelines often face stiff opposition with environmental impacts being a primary concern. A company could enhance its social license to operate (that is, they are perceived to be a responsible and reliable company) by simultaneously pursuing geothermal or other "green" energy projects.

High capital costs are the primary barrier to geothermal energy project and lack of economic feasibility often hinders development. The Tomahawk Ranch case study illustrates that projects based on livestock watering are likely not economically feasible, but this is more a reflection of the lack of benefit from providing warmer drinking water to cattle than of prohibitive costs. Growing unique crops in a geothermally heated greenhouse or fish in an aquaculture pond would likely generate higher revenue and may be worth investigation. Also, in most cases, the use of geothermal heat energy will replace the cost of electricity, natural gas, or other fuel otherwise needed and there will be financial benefit accrued by not needing to pay for that fuel source. Further study is needed to assess the potential revenue or energy cost savings that would result from supplying the required heat from a re-purposed well. These future studies will be aided by the findings provided here; both the retrofit cost and heat generating potential of a well can be estimated using a simple model based on the well's vertical depth and geographic location.

Governments may find more value than private firms in well re-purposing projects. From a social welfare perspective, these projects not only offer the prospect of a deferred and/or reduced well cleanup liability and mitigation of methane emissions through reduction in leaks from inactive wells, they also provide a source of renewable energy. Every unit of thermal energy provided by the geothermal well is one unit that does not need to be generated with greenhouse gas emitting natural gas, propane, or fossil-fuel fired electricity, which can help achieve the goal of GHG emission reduction. Additionally, long-term projects such as these typically provide greater financial benefit when a lower discount rate is applied and governments tend to adopt a lower discount rate compared to private firms, often using a 3% social discount rate for environmental projects (Treasury Board of Canada Secretariat, 2007).

The social welfare of Alberta and Canada stands to benefit from well re-purposing projects. The papers presented in this thesis have detailed that suspended oil and gas wells present the greatest environmental and financial liability and, currently, private firms are not financially incented to undergo abandonment and reclamation. Retrofitting some of these suspended wells can reduce and/or defer these liabilities while simultaneously increasing the percentage of Canadian power generation that comes from renewable sources. From a public perspective, it would be sensible to promote these projects. However, challenging economics and lack of policy support have hindered geothermal energy development to this point. Grants or tax incentives that offset a portion of the capital cost are one potential solution. Alternatively, incentives for GHG emission reduction or renewable energy generation may encourage well retrofit projects. Although paper one found that forcing firms to pay for methane leaks appears unlikely to change firm decision-making, combining the requirement to pay with more stringent well monitoring requirements or suspension time-limits may encourage retrofitting or at least prompt well abandonment.

There exists an opportunity to address the liability of inactive oil and gas wells and mitigate climate change inducing GHG emissions. This thesis highlights this opportunity and presents a pathway for further analysis and consideration.

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Appendices

Appendix 1A – Cost data obtained from Orphan Well Association Annual Reports

Well abandonment cost based on aggregate average from three years of published data.

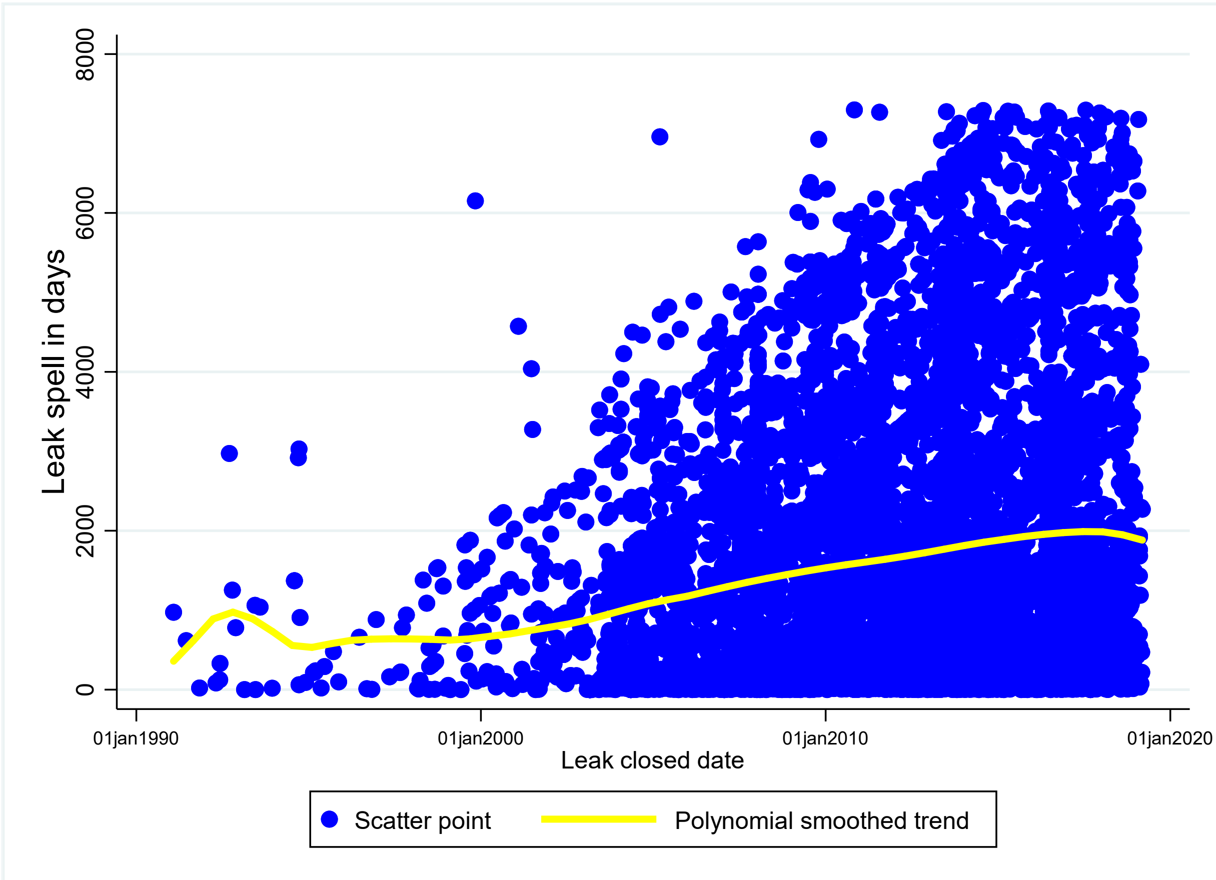
Year	Orphan Wells Abandoned	Total Abandonment Costs ($M)	Avg Cost to Abandon ($M)
2017	259	$ 18,460	$ 71.3
2016	232	$ 12,483	$ 53.8
2015	185	$ 16,742	$ 90.5
Total	**676**	**$ 47,685**	**$ 70.5**

Well inspection costs were only published in a single report (2017).

Year	Number of Inspections	Total Inspection Cost ($M)	Avg Cost per Inspection ($M)
2017	859	$ 568	$ 0.661

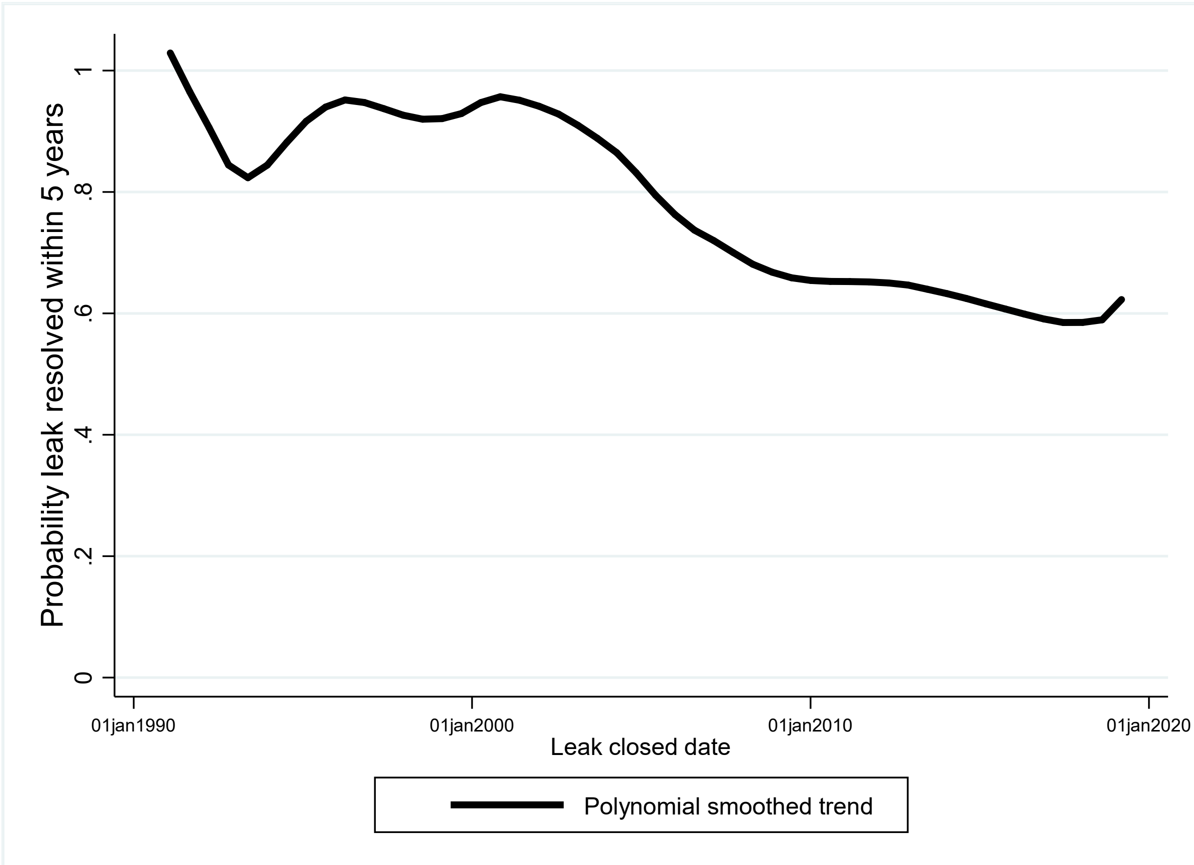
Source: Values gathered and summarized from Orphan Well Association: Annual Reports 2015/2016, 2016/2017, and 2017.

Appendix 1B -Leak Spells: Abandoned and Suspended wells 1971 to 2019 (in 20-year intervals)



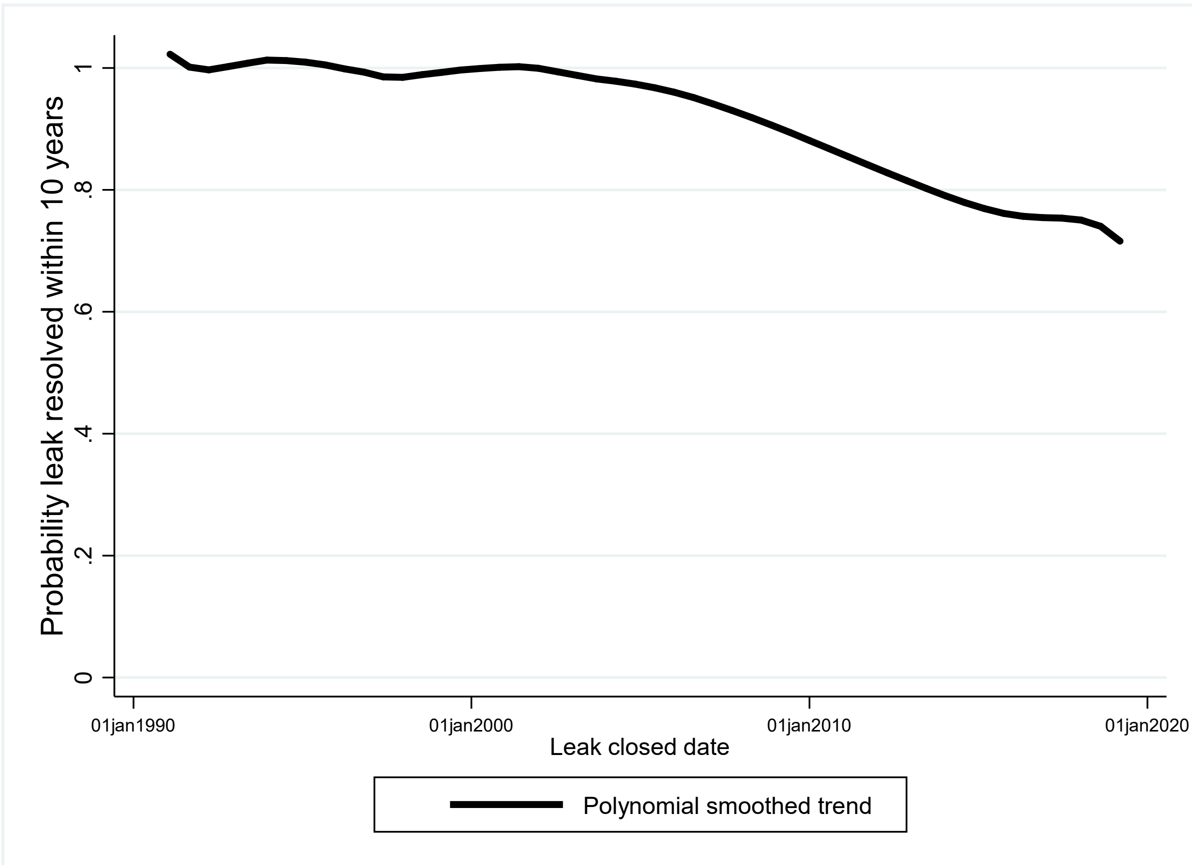
Note: Every closing date can potentially be associated with a 20-year (or lesser) spell, which reduces the rise in leak times purely due to sampling over larger time periods. Since our data begins in 1971, this approach allows analysis over the same 1990-2019 timeframe but only shows the leak spell during the previous 20 years so that all time points are treated similarly.

Appendix 1C - Probability of Resolved Spells: Abandoned and Suspended wells 1971 to 2019 (5-year interval)



Note: The results show a decline in the probability of resolving a leak within 5 years, over time.

Appendix 1D - Probability of Resolved Spells: Abandoned and Suspended wells 1971 to 2019 (10-year interval)



Note: The results show a decline in the probability of resolving a leak within 10 years, over time.

Appendix 1E - Present Value of Costs Analysis (Base Case at 3% Discount Rate)

Year	Capital Costs	PV of Capital and Lease Payments	Sum PV Aband & Rec Costs	Lease Costs			Discount Rate	3%			
				Loss of Use	Nuisance	Well Inspection	Total Suspended Costs	Discount	PV Suspended Costs	Sum PV Well Suspended Costs	Aband & Rec less Suspension
Year 1	$ 70,500	$ 78,911	$ 78,911	$ 1,500	$ 6,250	$ 661	$ 8,411	1.00	$ 8,411	$ 8,411	$ 70,500
Year 2	$ 28,321	$ 35,020	$ 113,931	$ 1,500	$ 6,250		$ 7,750	1.03	$ 7,524	$ 15,935	$ 97,996
Year 3		$ 7,305	$ 121,237	$ 1,500	$ 6,250		$ 7,750	1.0609	$ 7,305	$ 23,240	$ 97,996
Year 4		$ 7,697	$ 128,934	$ 1,500	$ 6,250	$ 661	$ 8,411	1.092727	$ 7,697	$ 30,938	$ 97,996
Year 5		$ 6,886	$ 135,820	$ 1,500	$ 6,250		$ 7,750	1.125509	$ 6,886	$ 37,823	$ 97,996
Year 6			$ 135,820	$ 1,500	$ 6,250		$ 7,750	1.159274	$ 6,685	$ 44,509	$ 91,311
Year 7			$ 135,820	$ 1,500	$ 6,250	$ 661	$ 8,411	1.194052	$ 7,044	$ 51,553	$ 84,267
Year 8			$ 135,820	$ 1,500	$ 6,250		$ 7,750	1.229874	$ 6,301	$ 57,854	$ 77,965
Year 9			$ 135,820	$ 1,500	$ 6,250		$ 7,750	1.26677	$ 6,118	$ 63,972	$ 71,847
Year 10			$ 135,820	$ 1,500	$ 6,250	$ 661	$ 8,411	1.304773	$ 6,446	$ 70,418	$ 65,401
Year 11			$ 135,820	$ 1,500	$ 6,250		$ 7,750	1.343916	$ 5,767	$ 76,185	$ 59,634
Year 12			$ 135,820	$ 1,500	$ 6,250		$ 7,750	1.384234	$ 5,599	$ 81,784	$ 54,036
Year 13			$ 135,820	$ 1,500	$ 6,250	$ 661	$ 8,411	1.425761	$ 5,899	$ 87,683	$ 48,136
Year 14			$ 135,820	$ 1,500	$ 6,250		$ 7,750	1.468534	$ 5,277	$ 92,961	$ 42,859
Year 15			$ 135,820	$ 1,500	$ 6,250		$ 7,750	1.51259	$ 5,124	$ 98,084	$ 37,735
Year 16			$ 135,820	$ 1,500	$ 6,250	$ 661	$ 8,411	1.557967	$ 5,399	$ 103,483	$ 32,337
Year 17			$ 135,820	$ 1,500	$ 6,250		$ 7,750	1.604706	$ 4,830	$ 108,313	$ 27,507
Year 18			$ 135,820	$ 1,500	$ 6,250		$ 7,750	1.652848	$ 4,689	$ 113,001	$ 22,818
Year 19			$ 135,820	$ 1,500	$ 6,250	$ 661	$ 8,411	1.702433	$ 4,941	$ 117,942	$ 17,878
Year 20			$ 135,820	$ 1,500	$ 6,250		$ 7,750	1.753506	$ 4,420	$ 122,362	$ 13,458
Year 21			$ 135,820	$ 1,500	$ 6,250		$ 7,750	1.806111	$ 4,291	$ 126,653	$ 9,167
Year 22			$ 135,820	$ 1,500	$ 6,250	$ 661	$ 8,411	1.860295	$ 4,521	$ 131,174	$ 4,646
Year 23			$ 135,820	$ 1,500	$ 6,250		$ 7,750	1.916103	$ 4,045	$ 135,219	$ 601
Year 24			$ 135,820	$ 1,500	$ 6,250		$ 7,750	1.973587	$ 3,927	$ 139,146	-$ 3,326
Year 25			$ 135,820	$ 1,500	$ 6,250	$ 661	$ 8,411	2.032794	$ 4,138	$ 143,283	-$ 7,464

The values found in the above table are as follows:
Capital Costs – the expected capital expense, abandonment in year 1 and reclamation in year 2, applicable only to abandoned and reclaimed wells
PV of Capital and Lease Payments – The sum of Capital Costs, Lease costs, and Well Inspection divided by the Discount
Sum PV Aband & Rec Costs – Accumulated discounted total of abandonment and reclamation costs
Loss of Use and Nuisance – Components of annual lease payments; Well Inspection – well inspection cost
Total Suspended Costs – sum of lease payments and well inspection costs for the year
Discount – cumulative discount, based on the chosen discount rate (3% in this example), applied to the yearly expense
PV Suspended Costs – Total Suspended Costs/Discount
Sum PV Well Suspended Costs – Accumulated total of PV Suspended Costs
Aband & Rec less Suspension - Sum PV Aband & Rec Costs less Accumulated total of PV Suspended Costs. In the above example, this value becomes negative in year 24 indicating that during this year the total costs of suspension equal and surpass the total abandonment and reclamation costs

Appendix 1F - Present Value of Costs Analysis (Including CDN$1,050 Social Cost of Methane at 10% Discount Rate)

				Lease Costs				Discount Rate	10%			
	Capital Costs	PV of Capital and Lease Payments	Sum PV Aband & Rec Costs	Loss of Use	Nuisance	Well Inspection	SCM	Total Suspended Costs	Discount	PV Suspended Costs	Sum PV Well Suspended Costs	[illegible]
Year 1	$ 70,500	$ 78,911	$ 78,911	$ 1,500	$ 6,250	$ 661	$ 10,500	$ 18,911	1.00	$ 18,911	$ 18,911	$ [illegible]
Year 2	$ 28,321	$ 32,792	$ 111,703	$ 1,500	$ 6,250		$ 10,500	$ 18,250	1.1	$ 16,591	$ 35,502	$ [illegible]
Year 3		$ 6,405	$ 118,108	$ 1,500	$ 6,250		$ 10,500	$ 18,250	1.21	$ 15,083	$ 50,585	$ [illegible]
Year 4		$ 6,319	$ 124,427	$ 1,500	$ 6,250	$ 661	$ 10,500	$ 18,911	1.331	$ 14,208	$ 64,793	$ [illegible]
Year 5		$ 5,293	$ 129,720	$ 1,500	$ 6,250		$ 10,500	$ 18,250	1.4641	$ 12,465	$ 77,258	$ [illegible]
Year 6			$ 129,720	$ 1,500	$ 6,250		$ 10,500	$ 18,250	1.61051	$ 11,332	$ 88,589	$ [illegible]
Year 7			$ 129,720	$ 1,500	$ 6,250	$ 661	$ 10,500	$ 18,911	1.771561	$ 10,675	$ 99,264	$ [illegible]
Year 8			$ 129,720	$ 1,500	$ 6,250		$ 10,500	$ 18,250	1.948717	$ 9,365	$ 108,629	$ [illegible]
Year 9			$ 129,720	$ 1,500	$ 6,250		$ 4,725	$ 12,475	2.143589	$ 5,820	$ 114,449	$ [illegible]
Year 10			$ 129,720	$ 1,500	$ 6,250	$ 661		$ 8,411	2.357948	$ 3,567	$ 118,016	$ [illegible]
Year 11			$ 129,720	$ 1,500	$ 6,250			$ 7,750	2.593742	$ 2,988	$ 121,004	$ [illegible]
Year 12			$ 129,720	$ 1,500	$ 6,250			$ 7,750	2.853117	$ 2,716	$ 123,720	$ [illegible]
Year 13			$ 129,720	$ 1,500	$ 6,250	$ 661		$ 8,411	3.138428	$ 2,680	$ 126,400	$ [illegible]
Year 14			$ 129,720	$ 1,500	$ 6,250			$ 7,750	3.452271	$ 2,245	$ 128,645	$ [illegible]
Year 15			$ 129,720	$ 1,500	$ 6,250			$ 7,750	3.797498	$ 2,041	$ 130,686	-$ [illegible]

The values found in the above table are as follows:
Capital Costs – the expected capital expense, abandonment in year 1 and reclamation in year 2, applicable only to abandoned and reclaimed wells
PV of Capital and Lease Payments – The sum of Capital Costs, Cease costs, and Well Inspection divided by the Discount
Sum PV Aband & Rec Costs – Accumulated discounted total of abandonment and reclamation costs
Loss of Use and Nuisance – Components of annual lease payments
Well Inspection – well inspection cost
Total Suspended Costs – sum of lease payments, well inspection, and SCM costs for the year
Discount – cumulative discount, based on the chosen discount rate (10% in this example), applied to the yearly expense
PV Suspended Costs – Total Suspended Costs/Discount
Sum PV Well Suspended Costs – Accumulated total of PV Suspended Costs
Aband & Rec less Suspension - Sum PV Aband & Rec Costs less Accumulated total of PV Suspended Costs. In the above example, this value becomes negative in year 15 indicating that during this year the total costs of suspension equal and surpass the total abandonment and reclamation costs

Appendix 2 – Input variables used in base, best, and worst lifecycle economic evaluations of Tomahawk Ranch geothermal energy well retrofit project

	Base Case	**Worst Case**	**Best Case**
Revenue			
Hay Price ($/kg)	$ 0.11	$ 0.09	$ 0.13
Yearly savings per 1°C Water Temp Increase	$ 202.57	$ 129.64	$ 291.70
Increase in drinking water temp (°C)	7.5	7.5	7.5
Calf deaths	0	0	5
Value per Calf	$ 700	$ 700	$ 700
Total Yr 1 Benefit	$ 1,519	$ 972	$ 5,688
Initial Capital Investment			
Well retrofit cost	Base	Plus 1 rig day and 20% increase	Minus 1 rig day and 20% decrease
Total Retrofit	$ 635,002	$ 848,719	$ 450,190
HDPE Install ($/m)	$ 24.60	$ 32.80	$ 16.40
HDPE Total	$ 164,820	$ 219,760	$ 109,880
Total Initial Capital Investment	$ 799,822	$ 1,068,479	$ 560,070
Abandonment and Reclamation	Base	50% increase	50% decrease
Present A&R cost	$ 272,204	$ 408,306	$ 136,102
Future A&R cost (in year 25: 2% inflation)	$ 446,580	$ 669,869	$ 223,290

Appendix 3A – List of which regulatory status types comprise the 5 broad categories of Abandoned, Active, Cased, Suspended, or Licensed and Drilling

"Abandoned"

- Abd
- Abd A Gas Disp
- Abd Air Inj
- ABD BIT Oil
- Abd Brn Wat
- Abd CBM Gas
- ABD CO2 Inj
- ABD Cyc BIT Oil
- ABD Cyc Oil
- Abd Gas
- Abd Gas Inj
- Abd Gas Stor
- ABD LPG Stor
- ABD N2 Inj
- Abd Obsr
- Abd Oil
- Abd Re-ent
- Abd Re-ent Gas
- Abd Re-ent Gas Stor
- Abd Re-ent Oil
- ABD Re-ent Solv Inj
- Abd Re-ent Wtr Dsp
- Abd Re-ent Wtr Inj
- Abd Solv Inj
- ABD Trng
- Abd Waste Indst
- Abd Wtr Disp
- ABD Wtr Farm
- Abd Wtr Inj
- Abd Wtr Source
- Abd Zn
- Abd ZnA Gas Disp
- Abd Zn Bit Oil
- Abd Zn CBM Gas
- Abd Zn cmgl
- Abd Zn Drn
- Abd Zn Gas
- Abd Zn Gas Inj
- Abd Zn Gas Str
- Abd Zn Obsrv
- Abd Zn Oil
- Abd Zn Shale Gas
- Abd Zn Solv Inj
- Abd Zn Waste Disp
- Abd Zn Wtr Dsp
- Abd Zn Wtr Inj
- Abd Zn Wtr Src
- Drld & Abd
- Jnkd & Abd

"Active"

- Act A Gas Disp
- Act Brn Wat
- Act Cmgl
- Act CO2 Inj
- Act Cyc Oil
- Act Drn
- Act Gas Frm
- Act Gas Inj
- Act Gas Stor
- Act LPG Stor
- Act Obsrv
- Act Solv Inj
- Act Trng
- Act Waste
- Act Waste Dsp
- Act Waste Indst
- Act Wtr Dsp
- Act Wtr Farm
- Act Wtr Inj
- Act Wtr Src
- Flow Brn Wtr
- Flow CBM Gas
- Flow CBM ShaleGas
- Flow Gas
- Flow Oil
- Flow Shale Gas
- Gas Cyclical
- Lift Oil
- Oil
- Pmp BIT Oil
- Pmp Brn Wtr
- Pmp CBM Gas
- Pmp Gas
- Pmp Oil
- Pmp Shale Gas
- Pmp Shale Gas & Other
- Test CBM Gas
- Test Gas
- Test Shale Gas

"Cased"

- Cased

"Licensed" or "Drilling"

- Drlg
- Drlg Gas
- Drlg Oil
- Lcsd

"Suspended"

- Susp A Gas
- Susp A Gas Disp
- Susp BIT Oil
- Susp Brn WTR
- Susp CBM Gas
- Susp CBM Shale Gas
- Susp CO2 Inj
- Susp Cyc Oil
- Susp Gas
- Susp Gas Inj
- Susp Gas Str
- Susp N2 Inj
- Susp Oil
- Susp Shale Gas
- Susp Slv Inj
- Susp Wst Disp
- Susp Wtr Indst
- Susp Wtr Inj
- Susp Wtr Src
- Susp Obsrv
- Closed
- Clsd Gas
- Clsd Oil
- Clsd Wtr Disp
- Clsd Wtr Inj

Appendix 3B – List of top 100 overall wells ranked in order of highest retrofit feasibility potential

UWI	Status	BHT value (°C)	TVD (m)	Total Retrofit Cost	BHT/Cost Ratio
100/14-17-042-13W4/00	Abandoned	238.9	1029.3	$ 221,605	1.078
100/12-36-109-12W6/00	Abandoned	272.8	2246.4	$ 276,177	0.988
100/16-03-118-04W6/04	Active	148	1540.8	$ 185,801	0.797
100/06-29-059-01W6/00	Abandoned	260	3401	$ 327,947	0.793
100/11-04-071-13W6/02	Active	215	3520	$ 274,545	0.783
100/11-10-107-07W6/00	Abandoned	208	2176.3	$ 273,034	0.762
102/11-15-055-25W4/02	Active	124	1147.6	$ 168,171	0.737
100/02-04-039-03W5/02	Active	153.6	2249.8	$ 217,592	0.706
100/11-27-058-22W5/00	Abandoned	209	2782.8	$ 300,228	0.696
100/10-30-054-25W5/00	Abandoned	280	5075	$ 403,006	0.695
100/14-32-040-25W4/00	Suspended	130	1707	$ 193,253	0.673
100/08-35-036-04W5/00	Suspended	150	2383	$ 223,564	0.671
100/07-19-075-10W6/00	Active	143	2208	$ 215,717	0.663
100/10-18-055-12W5/02	Suspended	136	1978	$ 205,405	0.662
100/07-05-031-27W4/00	Suspended	146.1	2459.7	$ 227,003	0.644
100/16-16-062-12W5/00	Active	154	2743	$ 239,706	0.642
100/16-32-055-18W5/00	Abandoned	180	2366	$ 281,540	0.639
100/06-10-064-02W6/00	Suspended	148	2575	$ 232,173	0.637
100/10-08-075-10W6/02	Suspended	134	2169	$ 213,969	0.626
100/12-12-067-07W6/00	Abandoned	224	4157.5	$ 361,867	0.619
100/04-29-052-08W5/02	Suspended	140	2475	$ 227,689	0.615
100/06-07-067-08W6/00	Active	165	3480	$ 272,751	0.605
100/02-07-037-03W5/00	Abandoned	184	2922.7	$ 306,501	0.600
100/15-03-118-04W6/00	Abandoned	148	1653.7	$ 249,602	0.593
100/01-28-045-15W5/00	Abandoned	208	4135.6	$ 360,885	0.576
100/11-14-015-14W4/00	Abandoned	126.7	1015	$ 220,964	0.573
100/10-35-071-13W6/03	Abandoned	190.5	3560	$ 335,076	0.569
100/02-10-020-09W4/00	Active	92	1031.4	$ 162,961	0.565
100/11-14-035-04W5/00	Abandoned	178.3	3131.8	$ 315,877	0.564
100/13-36-105-07W6/02	Cased	120	2230.8	$ 216,740	0.554
100/04-10-064-18W5/00	Active	137.8	2983.1	$ 250,471	0.550
100/06-05-012-21W4/00	Active	90	1065	$ 164,467	0.547
100/11-28-073-13W6/00	Abandoned	150	2210	$ 274,545	0.546
100/16-23-014-19W4/02	Suspended	92	1175	$ 169,400	0.543
100/06-09-021-15W4/02	Active	90	1122	$ 167,023	0.539
100/11-04-011-19W4/02	Suspended	90	1152.4	$ 168,386	0.534

100/06-32-080-23W5/00	Active	93	1280	$ 174,108	0.534
100/05-17-048-20W5/00	Active	155.8	3912.4	$ 292,139	0.533
100/10-01-070-11W6/02	Active	130.4	2880	$ 245,848	0.530
100/16-16-052-21W5/00	Suspended	158.9	4107.5	$ 300,887	0.528
100/15-24-109-05W6/00	Suspended	102	1725	$ 194,061	0.526
102/02-36-031-14W4/03	Cased	88.5	1154	$ 168,458	0.525
100/16-09-071-08W5/00	Abandoned	142	2135	$ 271,182	0.524
100/14-06-121-11W6/02	Cased	102.4	1773	$ 196,213	0.522
100/12-09-109-05W6/02	Cased	101.7	1743.5	$ 194,890	0.522
100/06-02-079-22W5/02	Active	110	2125	$ 211,996	0.519
100/04-09-033-26W4/02	Active	84.8	1045	$ 163,571	0.518
100/06-06-062-19W5/00	Active	135.6	3247.6	$ 262,331	0.517
100/01-18-029-23W4/03	Active	92	1379	$ 178,547	0.515
100/07-12-055-12W5/00	Active	104	1915	$ 202,580	0.513
100/10-10-028-11W4/03	Abandoned	115	1085	$ 224,102	0.513
100/06-04-030-27W4/00	Abandoned	148	2519.8	$ 288,436	0.513
100/12-14-039-24W4/02	Suspended	104.4	1941.6	$ 203,772	0.512
102/08-14-051-11W5/00	Active	110.6	2215	$ 216,031	0.512
100/06-19-060-15W5/00	Suspended	120	2627.4	$ 234,522	0.512
100/06-36-022-19W4/00	Active	90	1322.8	$ 176,027	0.511
100/06-23-070-10W6/00	Abandoned	134	1950	$ 262,887	0.510
100/06-15-073-09W6/02	Suspended	112	2299	$ 219,798	0.510
100/07-19-081-09W5/00	Abandoned	130	1799.8	$ 256,152	0.508
102/07-08-083-11W5/00	Abandoned	128	1725	$ 252,799	0.506
100/06-12-100-12W6/00	Active	118.4	2625	$ 234,415	0.505
100/14-18-082-11W6/00	Active	93	1505	$ 184,196	0.505
100/10-23-031-27W4/00	Abandoned	140	2286	$ 277,953	0.504
100/06-36-032-14W4/00	Active	87.2	1261	$ 173,256	0.503
100/05-12-126-07W6/00	Abandoned	131.1	1923.3	$ 261,690	0.501
100/12-30-046-18W5/00	Active	142.2	3808.4	$ 287,476	0.495
100/14-08-049-04W5/00	Suspended	86.7	1315.2	$ 175,686	0.493
100/10-30-049-16W5/02	Active	126.7	3131.8	$ 257,139	0.493
102/05-10-054-11W5/00	Abandoned	130	1976.6	$ 264,080	0.492
100/10-18-039-02W5/03	Suspended	105.6	2185.4	$ 214,704	0.492
100/16-03-025-12W4/00	Suspended	80.6	1055	$ 164,019	0.491
102/08-26-055-22W5/03	Suspended	142.2	3869.9	$ 290,234	0.490
100/16-01-063-16W5/00	Abandoned	134	2190	$ 273,648	0.490
100/07-14-062-18W5/02	Cased	125	3107.7	$ 256,058	0.488
102/04-18-021-08W4/00	Active	79	1021	$ 162,495	0.486
100/06-32-073-13W6/02	Abandoned	145	2740.2	$ 298,318	0.486
100/04-29-110-05W6/02	Cased	93.3	1682.6	$ 192,159	0.486
100/06-20-044-17W5/00	Active	151.1	4341	$ 311,357	0.485

100/04-06-108-06W6/00	Suspended	98	1909.9	$ 202,351	0.484
100/07-35-029-01W5/00	Active	114.4	2682.2	$ 236,979	0.483
100/10-23-050-17W5/00	Active	121.1	2994.7	$ 250,991	0.482
100/08-05-075-08W6/00	Suspended	98.9	1973	$ 205,180	0.482
102/10-13-108-07W6/02	Active	96.7	1876	$ 200,831	0.481
100/02-25-066-11W5/00	Suspended	115.6	2761.5	$ 240,535	0.481
100/12-06-023-03W5/00	Suspended	121.1	3035	$ 252,798	0.479
100/07-28-061-12W5/00	Suspended	113.3	2672.2	$ 236,531	0.479
100/16-06-051-16W5/02	Active	103.1	2197.6	$ 215,251	0.479
100/07-28-052-17W5/00	Abandoned	164.4	3767.3	$ 344,371	0.477
100/15-09-116-06W6/00	Suspended	90	1615.7	$ 189,160	0.476
100/08-10-117-12W6/00	Abandoned	118.7	1656	$ 249,705	0.475
100/04-15-118-12W6/02	Suspended	92.1	1720	$ 193,836	0.475
100/02-05-109-05W6/00	Active	94	1810	$ 197,872	0.475
100/03-21-052-22W5/00	Abandoned	176.7	4383	$ 371,978	0.475
100/06-26-073-13W6/00	Abandoned	141	2712.7	$ 297,085	0.475
100/10-02-046-14W5/00	Active	124.4	3249.2	$ 262,403	0.474
100/14-30-096-10W6/00	Cased	110.1	2582	$ 232,487	0.474
100/06-31-047-17W5/00	Active	152.8	4593.3	$ 322,669	0.474
100/16-20-080-09W5/00	Suspended	92	1739	$ 194,688	0.473
100/06-15-032-21W4/00	Active	88	1558	$ 186,573	0.472
100/03-12-110-08W6/00	Abandoned	126.7	2079.3	$ 268,685	0.472

Appendix 3C- List of top 100 Suspended wells ranked in order of highest retrofit feasibility potential

UWI	Status	BHT value (°C)	TVD (m)	Total Retrofit Cost	BHT/Cost Ratio
100/14-32-040-25W4/00	Suspended	130	1707	$ 193,253	0.673
100/08-35-036-04W5/00	Suspended	150	2383	$ 223,564	0.671
100/10-18-055-12W5/02	Suspended	136	1978	$ 205,405	0.662
100/07-05-031-27W4/00	Suspended	146.1	2459.7	$ 227,003	0.644
100/06-10-064-02W6/00	Suspended	148	2575	$ 232,173	0.637
100/10-08-075-10W6/02	Suspended	134	2169	$ 213,969	0.626
100/04-29-052-08W5/02	Suspended	140	2475	$ 227,689	0.615
100/16-23-014-19W4/02	Suspended	92	1175	$ 169,400	0.543
100/11-04-011-19W4/02	Suspended	90	1152.4	$ 168,386	0.534
100/16-16-052-21W5/00	Suspended	158.9	4107.5	$ 300,887	0.528
100/15-24-109-05W6/00	Suspended	102	1725	$ 194,061	0.526
100/12-14-039-24W4/02	Suspended	104.4	1941.6	$ 203,772	0.512
100/06-19-060-15W5/00	Suspended	120	2627.4	$ 234,522	0.512
100/06-15-073-09W6/02	Suspended	112	2299	$ 219,798	0.510
100/14-08-049-04W5/00	Suspended	86.7	1315.2	$ 175,686	0.493
100/10-18-039-02W5/03	Suspended	105.6	2185.4	$ 214,704	0.492
100/16-03-025-12W4/00	Suspended	80.6	1055	$ 164,019	0.491
102/08-26-055-22W5/03	Suspended	142.2	3869.9	$ 290,234	0.490
100/04-06-108-06W6/00	Suspended	98	1909.9	$ 202,351	0.484
100/08-05-075-08W6/00	Suspended	98.9	1973	$ 205,180	0.482
100/02-25-066-11W5/00	Suspended	115.6	2761.5	$ 240,535	0.481
100/12-06-023-03W5/00	Suspended	121.1	3035	$ 252,798	0.479
100/07-28-061-12W5/00	Suspended	113.3	2672.2	$ 236,531	0.479
100/15-09-116-06W6/00	Suspended	90	1615.7	$ 189,160	0.476
100/04-15-118-12W6/02	Suspended	92.1	1720	$ 193,836	0.475
100/16-20-080-09W5/00	Suspended	92	1739	$ 194,688	0.473
100/10-09-067-18W5/00	Suspended	115.6	2872.7	$ 245,521	0.471
100/09-36-108-07W6/03	Suspended	93.3	1836	$ 199,038	0.469
100/02-17-068-10W5/00	Suspended	110	2640.8	$ 235,123	0.468
100/02-14-077-25W5/02	Suspended	103.3	2328.7	$ 221,129	0.467
100/10-05-058-19W5/00	Suspended	129.4	3581.4	$ 277,298	0.467
100/02-08-044-27W4/00	Suspended	104.4	2386.6	$ 223,725	0.467

100/07-05-060-15W5/02	Suspended	110	2664	$ 236,163	0.466
100/05-36-107-10W6/02	Suspended	98.9	2148.5	$ 213,049	0.464
100/13-08-100-06W6/00	Suspended	104.4	2459	$ 226,972	0.460
102/10-14-116-05W6/00	Suspended	85.6	1547.5	$ 186,102	0.460
100/01-02-108-10W6/02	Suspended	97.8	2139.3	$ 212,637	0.460
100/16-15-097-08W6/00	Suspended	102	2343	$ 221,770	0.460
100/08-27-099-11W6/00	Suspended	107.2	2610	$ 233,742	0.459
100/05-05-064-18W5/02	Suspended	115.6	3034.3	$ 252,767	0.457
102/16-06-024-14W4/02	Suspended	74	1008.8	$ 161,948	0.457
100/11-10-053-19W5/02	Suspended	113.3	2928.5	$ 248,023	0.457
100/07-34-096-08W6/00	Suspended	100.6	2315	$ 220,515	0.456
100/02-04-064-18W5/00	Suspended	113.9	2972.1	$ 249,978	0.456
100/05-02-098-09W6/00	Suspended	104.4	2521	$ 229,752	0.454
100/01-02-087-09W5/00	Suspended	82.2	1438.7	$ 181,223	0.454
100/06-28-109-06W6/00	Suspended	87.8	1726	$ 194,105	0.452
100/12-12-067-10W5/00	Suspended	104.4	2545.1	$ 230,832	0.452
100/12-33-109-08W6/00	Suspended	94.4	2060.4	$ 209,099	0.451
100/04-09-109-05W6/00	Suspended	91	1904.9	$ 202,127	0.450
100/15-11-110-09W6/00	Suspended	96.7	2191.1	$ 214,960	0.450
100/16-01-062-20W5/00	Suspended	118.3	3267.5	$ 263,223	0.449
100/04-18-107-10W6/00	Suspended	93	2013.9	$ 207,014	0.449
100/10-31-109-04W6/00	Suspended	87	1725	$ 194,061	0.448
100/02-18-062-18W5/02	Suspended	121.1	3430.8	$ 270,545	0.448
100/02-20-107-09W6/00	Suspended	91.6	1984.2	$ 205,683	0.445
100/07-07-051-11W5/00	Suspended	97.8	2296.7	$ 219,694	0.445
100/10-09-099-10W6/03	Suspended	103.9	2610	$ 233,742	0.445
100/08-15-073-18W5/00	Suspended	101	2470.4	$ 227,483	0.444
100/10-34-065-23W5/00	Suspended	111.1	2984	$ 250,512	0.443
100/08-18-045-04W5/00	Suspended	90	1941	$ 203,746	0.442
100/04-13-065-24W5/00	Suspended	121.1	3511.3	$ 274,155	0.442
100/11-20-107-09W6/02	Suspended	90	1942	$ 203,790	0.442
100/06-12-053-23W5/00	Suspended	140.6	4500	$ 318,486	0.441
102/07-15-107-09W6/02	Suspended	90	1947	$ 204,015	0.441
100/05-16-097-09W6/00	Suspended	101	2509.3	$ 229,227	0.441
100/10-01-065-18W5/00	Suspended	115	3235.5	$ 261,788	0.439
100/11-28-037-08W5/02	Suspended	132.2	4124.9	$ 301,667	0.438
100/02-11-065-19W5/00	Suspended	110	2999.8	$ 251,220	0.438
100/10-14-050-22W5/02	Suspended	145	4789.3	$ 331,458	0.437

100/11-08-047-17W5/00	Suspended	142.8	4679.4	$ 326,530	0.437
100/12-15-067-18W5/00	Suspended	106.2	2835	$ 243,831	0.436
100/05-18-110-07W6/00	Suspended	86.9	1861.7	$ 200,190	0.434
100/02-14-111-07W6/00	Suspended	84.6	1748.8	$ 195,128	0.434
100/06-27-097-09W6/00	Suspended	98.3	2455	$ 226,792	0.433
100/16-21-096-11W6/02	Suspended	100.3	2560	$ 231,500	0.433
100/11-09-096-10W6/02	Suspended	100.1	2553	$ 231,186	0.433
100/10-06-064-13W5/03	Suspended	105.6	2842.3	$ 244,158	0.433
102/16-26-107-09W6/00	Suspended	90	2045.2	$ 208,418	0.432
100/10-23-014-19W4/00	Suspended	74	1220.7	$ 171,449	0.432
100/10-36-028-01W5/00	Suspended	103.3	2741.7	$ 239,647	0.431
100/08-29-109-06W6/02	Suspended	83.3	1708.7	$ 193,330	0.431
100/08-14-108-07W6/00	Suspended	89.7	2042.8	$ 208,310	0.431
100/04-08-064-19W5/00	Suspended	109.4	3072.4	$ 254,475	0.430
100/14-15-087-10W6/04	Suspended	98.3	2502	$ 228,900	0.429
100/06-16-111-06W6/00	Suspended	82.1	1667.1	$ 191,464	0.429
100/02-19-061-19W5/02	Suspended	115	3380.8	$ 268,303	0.429
100/07-14-043-11W5/02	Suspended	106.5	2939	$ 248,494	0.429
100/15-29-109-06W6/03	Suspended	82.8	1713	$ 193,522	0.428
100/06-19-110-07W6/02	Suspended	86.7	1935.5	$ 203,499	0.426
100/13-30-115-06W6/02	Suspended	81.1	1642.6	$ 190,366	0.426
100/02-22-107-09W6/00	Suspended	87.8	1998.1	$ 206,306	0.426
102/16-03-044-10W5/00	Suspended	107	3012	$ 251,767	0.425
100/09-13-110-08W6/02	Suspended	90.6	2156.5	$ 213,408	0.425
100/02-27-074-19W5/02	Suspended	95	2394	$ 224,057	0.424
100/10-05-109-07W6/03	Suspended	87.8	2016.3	$ 207,122	0.424
100/16-03-116-07W6/00	Suspended	80	1610	$ 188,904	0.423
100/10-18-079-11W6/00	Suspended	95	2400	$ 224,326	0.423
102/15-21-115-06W6/03	Suspended	79.4	1584.4	$ 187,756	0.423
100/14-21-108-07W6/00	Suspended	86.7	1972	$ 205,136	0.423