C-FER Technologies

200 Karl Clark Road
Edmonton, Alberta
Canada T6N 1H2
Tel 780.450.3300
Fax 780.450.3700

www.cfertech.com

Final Report

Feasibility Assessment for Canadian Strategic Petroleum Reserve

Prepared for
Alberta Innovates

Prepared by
Mahmoud Mahfouz, EIT
Brian Wagg, MSc, PEng
Gang Tao, PhD, PEng
Dinara Millington, MA
Neil Cameron, MBA, PEng

Reviewed by
Kirk Hamilton, PEng

March 2019
C517

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B. T. WAGG

Mar 18 2019

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C517

Approved By

Date MARCH 18, 2019

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PROJECT TEAM

Feasibility Assessment for Canadian Strategic Petroleum Reserve	C-FER Project: C517	
Task/Deliverable	**Contributors**	**Responsible Professional**
Project management and execution	Mahmoud Mahfouz, EIT	Brian Wagg, MSc, PEng
Project Champion and Reviewer	Brian Wagg, MSc, PEng	Brian Wagg, MSc, PEng
Project Reviewer	Kirk Hamilton, PEng	Kirk Hamilton, PEng
Cavern Stability Model	Gang Tao, PhD, PEng	Gang Tao, PhD, PEng
Market assessment/macro-economic Model	Dinara Millington, MA	
Salt Cavern Assessment	Neil Cameron, MBA, PEng	

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5.

TABLE OF CONTENTS

APPENDICES

LIST OF FIGURES AND TABLES

Figures

List of Figures and Tables

Tables

EXECUTIVE SUMMARY

C-FER Technologies (1999) Inc. ("C-FER") was granted funding by Alberta Innovates ("AI") to conduct a high-level feasibility study to assess the potential for a Strategic Petroleum Reserve ("SPR") to be used to manage provincial oil output. The SPR would be operated by diverting Alberta liquid petroleum products (crude or diluted bitumen) to storage during times of oversupply, which would reduce upstream supply gluts and help maintain competitive market prices for Alberta producers. Once the supply glut has passed, stored petroleum would be slowly re-introduced into the market over time in preparation for the next fill event. In this way, the facility will not strictly be used as a reserve and releases will not generally be timed to take advantage of swings in market prices. In addition, Alberta is rich with underground salt formations suitable for developing petroleum storage caverns.

A SPR in Alberta could potentially operate on a net zero investment basis, mainly through increased royalties and secondarily through selling the stored oil at favourable prices. It could also supply local refineries in times of supply disruptions.

Potential positive impacts of an SPR at the macro-economic scale include: steady drilling and oilfield development operations in a stable oil price environment, stable and predictable production levels and associated royalties, development of new refineries and petrochemical plants close to the SPR where supply is guaranteed, arbitrage from supply and demand and optimization of the commodity price, investor confidence and creation of more jobs in various areas of Alberta.

This assessment examined the use of underground storage caverns, which are created by drilling into underground salt formations and circulating water through the well to wash or dissolve the salt. Using conventional cavern washing methods, a cavern with a total volume of approximately 400,000 m^3 (2.5 million bbls of oil storage capacity) could be created in approximately 12 to 24 months.

The macro-economic model determined the total cost using an optimal operating strategy for a SPR with a 10 million barrel capacity. The total net present cost of constructing the facility and filling it with oil was estimated to be CAD$630 million, including CAD$132 million in construction costs, with the rest of the cost required for oil acquisition and holding. In this scenario, the model predicted an increase in oil price from CAD$47/bbl to CAD$56/bbl during the period when oil was being purchased to fill the caverns. This means SPR oil acquisition drives the price upwards by an additional 2 to 6% in the months of crude acquisition.

The price increase will have a direct impact on the government royalties and corporate taxes collected from oil sands producers. A regression model based on historical data of oil sands royalties and Western Canadian Select (WCS) prices revealed a positive and statistically significant relationship with every 1% increase in WCS price resulting in a 2.1% increase in oil sands royalties. This implies that the optimized SPR stockpiling policy could result in increased royalty revenues of approximately 4 to 12 percent during the period that oil is acquired to fill the SPR.

Note that this initial economic modelling work only considered a government-owned SPR within Alberta; however, further research should be conducted to determine if other approaches could increase the value of these facilities.

Also, this initial salt cavern assessment only considered developing new salt caverns using conventional washing methods in Alberta; however, further research could include exploring and developing novel methods for washing caverns in shorter periods, evaluating integrity and suitability of specific existing salt caverns, developing storage well management criteria and optimizing cavern size, location and configurations.

Effective implementation and management of the SPR is crucial to gain the net cost benefits. Therefore, it is recommended that various options be considered for creating an agile organization and policy framework to enable the efficient management of the SPR. This could include creating new organizations that are government-led, public-private partnerships or independent commissions. Finally, it is suggested to further examine development of an integrated Canada wide storage network where dilbit can be stored in Alberta, slowly fed to Alberta refineries for upgrading and finally stored in caverns located further downstream in the national pipeline network.

ACKNOWLEDGEMENTS

C-FER would like to acknowledge the contribution of Dinara Millington and Neil Cameron. Dinara has 15 years of experience in economic market analysis through her role as Vice President, Research at the Canadian Energy Research Institute ("CERI"). Neil Cameron is the President of Petronim Projects and a subject matter expert for salt caverns in the Western Canadian Sedimentary Basin. Neil has the expertise needed for cavern design and construction along with cavern operation and integrity assessment

C-FER would also like to acknowledge the funding provided by Alberta Innovates.

1. INTRODUCTION

C-FER Technologies (1999) Inc. (“C-FER”) was granted funding by Alberta Innovates (“AI”) to conduct a high-level feasibility study to assess the potential for a Strategic Petroleum Reserve (“SPR”) to be used to manage provincial oil output. The SPR would be operated by diverting Alberta liquid petroleum products (crude or diluted bitumen) to storage during times of oversupply, which would reduce upstream supply gluts and help maintain competitive market prices for Alberta producers. Once the supply glut is passed, stored petroleum would be slowly re-introduced into the market over time in preparation for the next fill event. Alberta is rich with underground salt formations suitable for developing petroleum storage caverns. Salt caverns are currently used for various purposes in Alberta by private companies, including both liquid and gas hydrocarbon storage.

This report presents a technical study of the feasibility of constructing salt caverns in the salt formations that form part of the Western Canadian Sedimentary Basin in Alberta.

This report also presents a macro-economic assessment of how a SPR could impact the price of Alberta liquid petroleum exports during supply surplus events, such as in December of 2018 when pipeline export capacity lagged oil production rates and in 2016 when a supply shortage event occurred during the forest fires in Fort McMurray, shutting down oil sands production for several weeks.

This study serves as an initial feasibility study and does not present details for developing a SPR in Alberta.

2. GENERAL OVERVIEW OF STRATEGIC PETROLEUM RESERVES

ASPR is a hydrocarbon storage facility held by a country's government to safeguard against potential energy crises. SPRs have typically been used by countries to make up for inventory shortfalls caused by interruptions in oil supply. A review of the literature addressing SPR operation and impact is provided in Appendix A. The following section summarizes some of the key findings of the literature review.

The International Energy Agency (IEA) mandates that each member country have oil stockpiles that equate to no less than 90 days of net imports (IEA 2019). Under the International Energy Program Agreement, net oil exporting countries are not required to meet this obligation. Canada, a founding member, is one of three net exporting countries that are part of the IEA and as such, is exempt from requiring a SPR.

Canada is a producer and a net exporter of crude oil. However, this global status masks the fact that Central and Eastern Canada are net importers of oil and poorly connected to most crude-producing regions of Western Canada. Consequently, Eastern Canada imports oil from foreign suppliers, like the USA, Algeria and Saudi Arabia. A 2007 news story (CBC 2007) revealed how vulnerable the Eastern Canadian market is to supply disruptions or spot shortages by reporting a shortage of furnace oil, brought on by an early winter and late-arriving fuel supplies on Cape Breton Island, which left consumers in a vulnerable position.

Generally, solution mined salt caverns are used for SPRs to store hydrocarbon products in liquid or gaseous states. Mined caverns in hard rock are also used for underground storage but can only store liquefied products. Underground storage facilities have relatively high construction costs but particularly low operating costs and asset longevity that can exceed 60 years. Underground storage causes smaller environmental impact than above-ground storage: smaller footprint of the surface facilities, better control over the risk of polluting the biosphere, lower visual impact (Londe 2017). Unforeseen accidents are also up to ten times more frequent in above-ground storage facilities compared to underground storage (Londe 2017).

A previous study considered whether Canada should build a SPR (Laxer 2008). The focus of this study was for the SPR to be used as insurance against undersupply and focused on developing facilities in Eastern Canada. Several other studies have focused on SPR operational challenges for the USA's SPR (the largest in the world at about 700 million barrels) by examining the optimal size and rate of withdrawal to manage supply interruptions.

While the USA's SPR is operated by the government, in Europe, a combination of coordinated public stocks and mandated requirements for minimum private sector holdings of refined products is used (Scheitrum et al. 2017). In the 2017 report published by the US Government Accountability Office (US GAO 2017), it was found that most IEA members hold at least a third of their reserves in refined petroleum products. In addition, some IEA members' reserves are geographically dispersed in their countries to respond to regional disruptions.

Various studies have been conducted to evaluate how a SPR can be operated to manage oil price in times of supply disruption. The impact on the oil price predicted in these studies varies widely, changing the price by less than 1% to over 30%. None of the studies reviewed addressed the impact of a SPR on oil price in times of oversupply.

3. THE CASE FOR A STRATEGIC PETROLEUM RESERVE IN ALBERTA

A SPR for Alberta has not been considered previously as they are typically used to manage (and secure against) supply interruptions, which traditionally has not been a problem in Alberta. However, creating additional storage capacity introduces the possibility of managing oversupply, especially in the case of Alberta, where the market price is mostly set by the USA since they are essentially the only export market for the oil. Therefore, a SPR in Alberta:

- Would be seen as a mechanism available to regulators, government and industry to react to disruptions in the market by taking oil off the market at strategic times;
- Could potentially operate on a net zero investment basis, mainly through increased royalties and secondarily through selling the stored oil at favourable prices; and
- Could supply local refineries in times of supply disruptions (such as when wildfires stopped oil sands production in the Fort McMurray region for several weeks in 2016).

Potential positive impacts of a SPR at the macro-economic scale include:

- Steady drilling and oilfield development operations in a stable oil price environment in Canada;
- Stable and predictable production levels and associated royalties;
- Development of new refineries and petrochemical plants close to the SPR where supply is guaranteed;
- Arbitrage from supply and demand and optimization of the commodity price; and
- Investor confidence and creation of more jobs in various areas.

This assessment examines utilizing a SPR for an oversupply scenario and focuses on storage facilities and the macroeconomic impact in Alberta only. The assessment considers that, once the SPR is filled in response to an oversupply event, the stock will be slowly released to the market over time. In this way, the facility will not strictly be used as a reserve and releases will not generally be timed to take advantage of swings in market prices.

Only underground storage facilities using salt caverns were considered in the assessment.

3.1 Alberta Salt Resources

Alberta contains vast salt layer formations that range from the south-east provincial border, through central Alberta and up to the northern provincial border. Figure 1 shows the distribution of the salt formations. Up to four different salt formations have the potential to be used for underground storage in Alberta; for this study, only the Prairie Evaporite and the Lotsberg salt formations were considered.

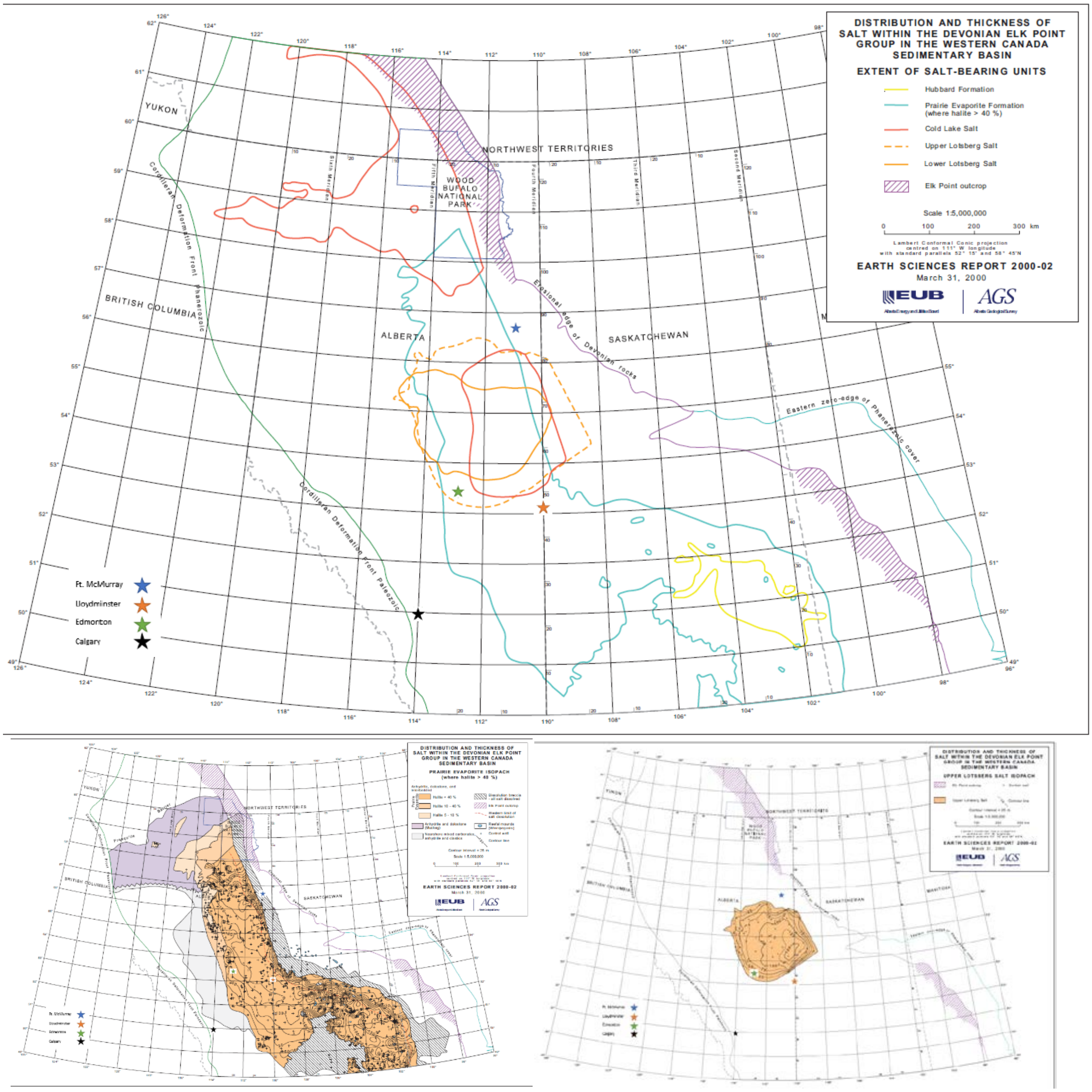


Figure 1 Distribution of Salt Formations across Alberta (Top), Distribution and Thickness of the Prairie Evaporite (Bottom Left), and Distribution and Thickness of Upper Lotsberg (Bottom Right) (Grobe 2000)

The Prairie Evaporite is the most consistent and prolific salt formation in the Province and is the largest salt body in Western Canada. In Saskatchewan, it is mostly developed for potash mining, while in Alberta it is frequently used for building industrial waste disposal caverns. Thick portions of the Prairie Evaporite, such as near Fort McMurray, would be suitable for hydrocarbon storage caverns.

The Upper Lotsberg is a world class salt formation for cavern construction with very few impurities. It is located perfectly under Alberta's Heartland and in-situ oil sands operations. The Upper Lotsberg typically has a 99% salt quality and high creep rate for salt. Thickness and high salt quality make the Upper Lotsberg a very attractive candidate for hydrocarbon storage caverns.

3.2 Current and Potential Salt Cavern Locations in Alberta

Many companies in Alberta already operate salt caverns for various purposes, such as salt mining, industrial waste disposal and hydrocarbon storage. Central Alberta is currently the hub for hydrocarbon storage. Plains, Pembina, ATCO, Keyera, and Dow all have caverns located near Fort Saskatchewan with pipeline infrastructure built. ATCO Pipelines recently developed the Heartland Energy Centre in Alberta's Industrial Heartland, which currently operates four caverns (~400,000 m^3) with the potential to develop upwards of 40 caverns for storing hydrocarbon products (ATCO 2018).

The Alberta Industrial Heartland is a prime location to develop salt caverns as it is strategically located near in-situ oil sands operations and has easy access to major distribution options, including pipeline and rail. Being situated near the Sturgeon Refinery, which refines dilbit to diesel or gasoline, provides a potential local market for the stored oil. Figure 2 shows a map of the location of four current caverns and major petrochemical facilities in the Alberta Industrial Heartland

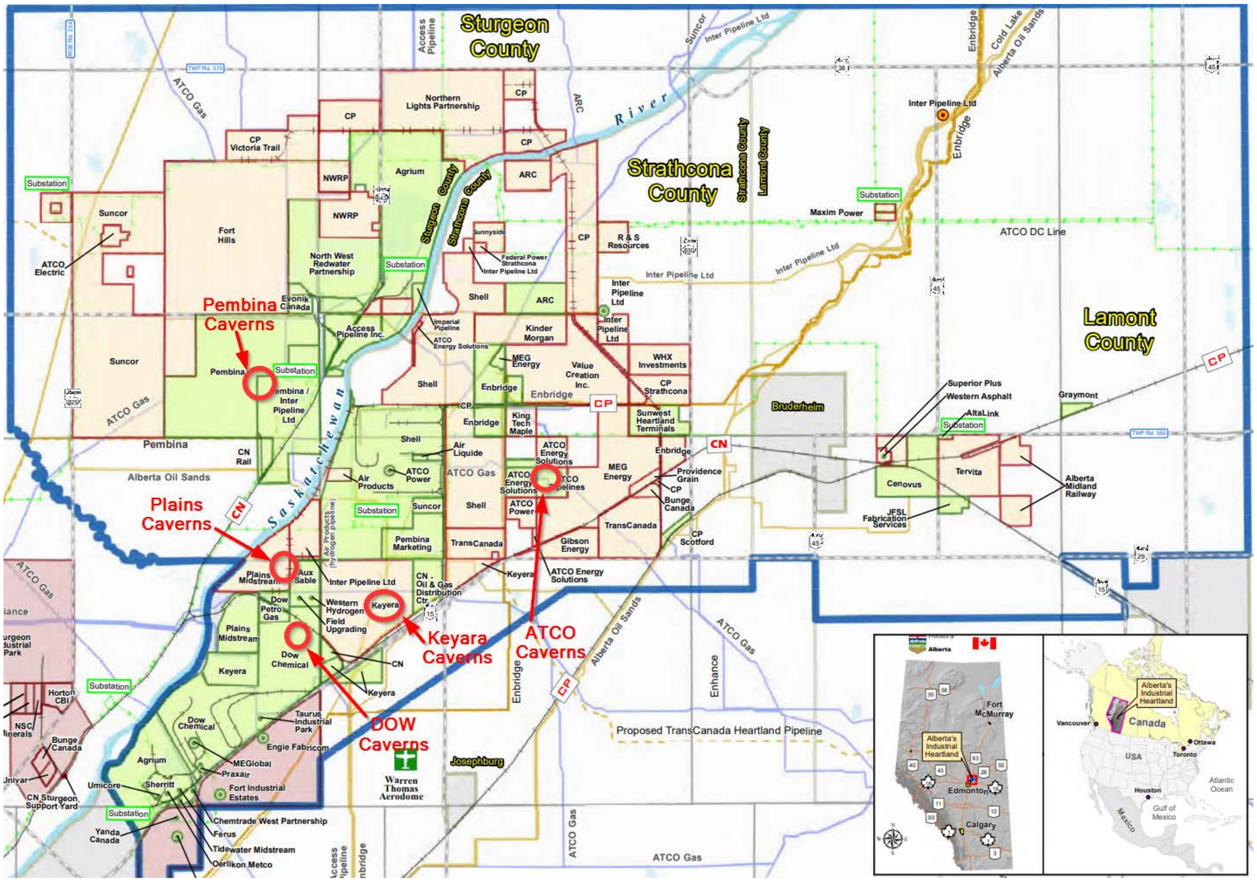


Figure 2 Major Petrochemical Facilities and Locations of Existing Salt Caverns in the Alberta Industrial Heartland (Strathcona 2018)

Hardisty, Alberta is another potential location for the development of salt caverns for a SPR. Currently, there are four caverns operated by Enbridge on the north side of Highway 13. Hardisty is a significant crude oil transportation hub with access to major pipelines and rail. Hardisty is located downstream of many Alberta refineries; therefore, there is less potential for refining the stored crude. Figure 3 shows some of the major pipelines and rail terminals near Hardisty.

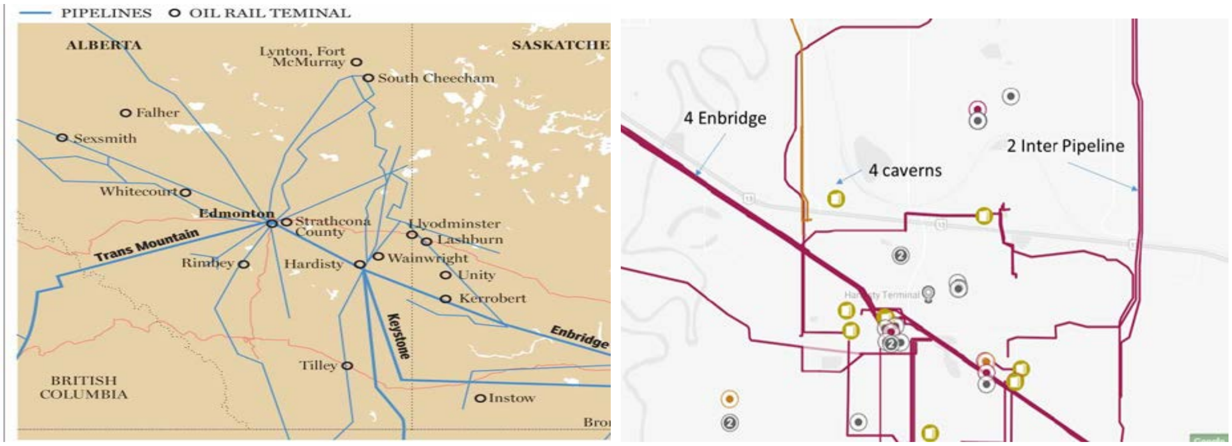


Figure 3 Major Pipelines and Rail Terminals in Alberta (Left), and Near Hardisty (Right) (NEB 2019)

Fort McMurray, Alberta is also a potential location to develop the SPR salt caverns as it is directly adjacent to the oil sands operations and transportation pipelines. Fort McMurray is located upstream of Alberta refineries, therefore allowing the option of transporting the stored crude to be refined in the Province if the local supply is disrupted.

Additional engineering, geological and economic assessments of these specific sites are needed to determine the optimal location of the salt caverns for the SPR.

3.3 Repurposing Potash Solution Mines

There are numerous salt caverns in Saskatchewan that have been developed to recover potash that might have the potential to be repurposed as part of a SPR. Many of these caverns are situated on major pipeline routes as they require significant natural gas supplies to dry the potash. However, these caverns were not designed for liquid hydrocarbon storage and many have uneven or asymmetric roof structures that could trap some of the stored oil, making it difficult to recover from the cavern and adds challenges to abandonment. These caverns are also downstream of Canadian oil refineries, so any sale of oil from the SPR would have to be to refineries in the USA, even in cases where Canadian refineries are in short supply. Due to these limitations, these caverns were not considered in this preliminary assessment but could be evaluated to form part of a nation-wide SPR network.

3.4 Salt Cavern Development, Operation and Deliverability

Salt caverns are created by drilling into underground salt formations and circulating water through the well to wash or dissolve the salt, creating a cavity. For large volume storage caverns, thicker salts are easier to manage and as such, the targeted salt formation should be 100 m thick. Thinner salt depositions require larger diameter caverns and more frequent interventions to control washing and roof shaping, making them less desirable. Water (or brine) is used in the washing process;

typically 10 m^3 of water must be circulated through the well to leach 1 m3 of cavern space. The salt-laden brine produced from the washing process is typically injected into brine bearing formations below the salt formation.

Using conventional cavern washing methods, and assuming that 500 m^3/hr of water can be utilized for continuous circulation through the well, two 80 m diameter by 80 m deep caverns with a total volume of approximately 400,000 m^3 each could be created in approximately 24 months. A cavern of this size equates to approximately 2.5 million bbls of oil storage capacity. Multiple caverns are usually developed at each site to take advantage of the cavern leaching, and oil supply and withdrawal infrastructure. The caverns would be developed following the Canadian Standards Association (CSA) Z341 standard "Storage of hydrocarbons in underground formations".

The caverns are kept continuously filled with oil and brine, with the pressure of the fluid helping to support the cavern walls and roof. When oil is pumped into the cavern, the brine in the cavern flows to surface, where it is stored in large brine ponds. When oil needs to be withdrawn from the cavern, the stored brine is pumped back into the cavern, forcing the oil into the pipeline transportation system. Lack of permeability of the salt and ability to heal fissures ensures that the stored product is not lost.

The salt caverns can be configured as either single, or dual entry. Single entry caverns, where one well is drilled into each cavern, are the standard configuration used in industry. The stored product is pumped through the annulus of the well and the brine is pumped through a central tubing string, as shown in Figure 4. Dual entry caverns, where two wells are drilled, have increased capital costs but allow higher flow rates in and out of the cavern through dedicated injection and withdrawal wells, as shown in Figure 4. Even though deliverability is higher, the fluid velocities through the wells are reduced, leading to less wear and erosion in the wellbore and longer equipment operating life. For this study, only single entry caverns were considered.

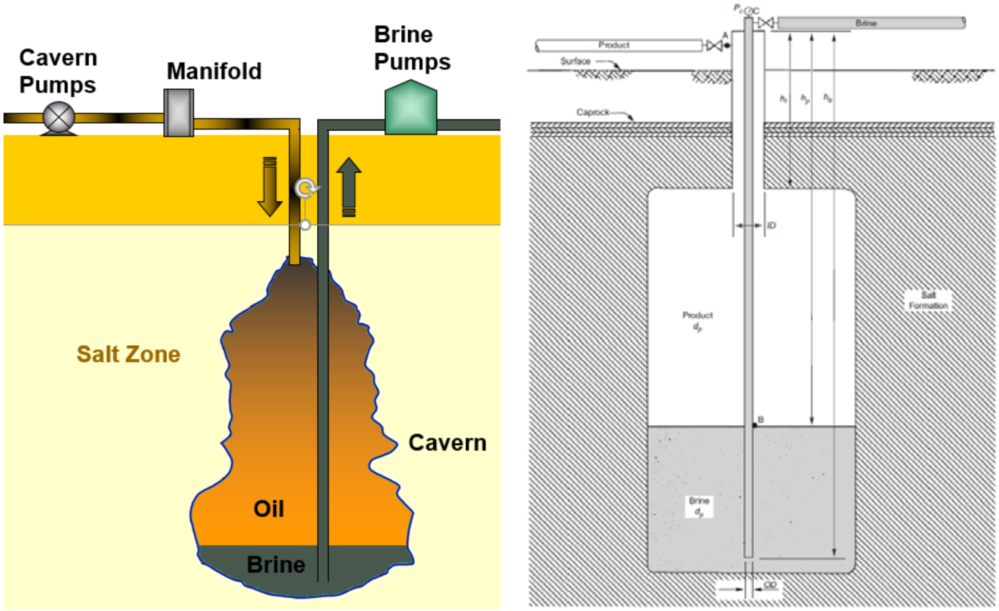


Figure 4 Dual Entry (Left) and Single Entry (Right) Salt Cavern Configuration (API 2013)

The maximum injection and production rates for a single entry cavern were determined assuming the wellbore consists of a casing size of 16 inches and tubing size of 10 $^{3}/_{4}$ inches. It was also assumed that the stored fluid will be unweathered dilbit with a viscosity between 350 and 1000 cSt, depending on the pipeline temperature. Based on these assumptions, the maximum injection and production rates were determined to be approximately 500 m^3/hr, which equates to approximately 80,000 bbl/day/cavern.

3.5 Salt Cavern Stability Assessment

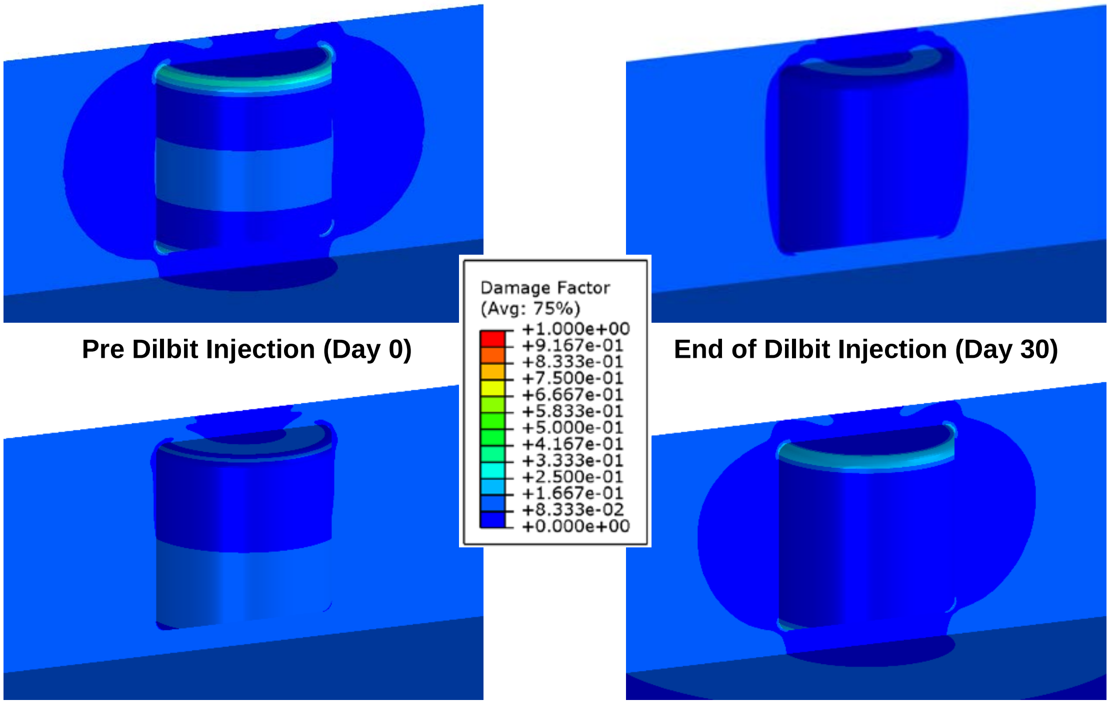
The structural stability of a generic salt cavern was evaluated based on advanced Finite Element Analysis (FEA) using the commercial program Abaqus® v2018. Appendix B provides a detailed description of the model, assumptions, analysis procedures and all results.

The analysis was performed to evaluate how a few key load conditions that are representative of the service life of the cavern could affect the cavern stability. To minimize the shear stress around the cavern, an assumed constant wellhead pressure of 8 MPa was applied in all analysis steps simulating the operating scenarios of the cavern. Table 1 lists the load conditions associated with the three operating scenarios considered in the analysis. Note that the cavern-wellbore interaction is not considered in this preliminary FEA study and would be further evaluated as part of a complete engineering assessment.

Operating Scenario	Duration (days)	Wellhead Pressure (MPa)	Cavern Fluid
Dilbit Injection	30	8	brine gradually replaced by dilbit
Dilbit Storage	90	8	dilbit
Dilbit Production	30	8	dilbit gradually replaced by brine

Table 1 Simulated Cavern Operating Scenarios

The cavern structural stability assessment determined the damage factor (van Sambeek et al.1993) in the salt formation surrounding the cavern. A damage factor greater than 1.0 indicates the onset of dilation damage of the salt surrounding the cavern and a damage factor less than 1.0 indicates a safe condition where the operating conditions do not cause damage to the cavern. Figure 5 shows the results of an analysis of an 80 m diameter by 80 m deep cavern where the maximum value of the damage factor of 0.25 was found at the corners of the cavern. This small damage factor indicates that these operating conditions do not cause any cavern stability concerns. Note that the wellhead pressure has an impact on the stress state around the cavern, and hence, the overall cavern stability. A further design assessment is warranted to define a range of wellhead pressures that are acceptable for each individual salt cavern.



Pre Dilbit Injection (Day 0)

End of Dilbit Injection (Day 30)

End of Dilbit Storage (Day 120)

End of Dilbit Production (Day 150)

Figure 5 Damage Factor around Salt Cavern (Design Case 1)

Note that a more detailed engineering design and evaluation is required for each salt cavern that is to be constructed and should include:

- Detailed characterization of the mechanical properties of the salt material through comprehensive lab testing;
- Assessment of the cap rock integrity to ensure the overall structural stability of the cavern within the bedded salt layer;
- A more detailed evaluation of the fluid pressure condition for all potential scenarios (construction, operation cycles, work over, etc.) over the entire service life of the cavern, and estimation of the resulting stress conditions and damage potential;
- Evaluation of the impact of pressure change induced cavern volume reduction and optimization of the pressure condition to minimize such impact; and
- Evaluation of the cavern roof displacement and the associated impact on well integrity (casing pipe body integrity, connection sealability, cement integrity, etc.).

3.6 Salt Cavern Facility Requirements

Facility and equipment requirements for salt cavern washing and storage are fairly minimal. The set up cost of a 10 million barrel dilbit storage facility would generally range from $100 to $140 million dollars. Once the initial facility has been built, additional storage caverns can be built at a minimal incremental cost to the project.

Some of the facilities required for the cavern washing operation include: water supply, fresh water storage tanks, water injection pumps, pad fluid injection pumps, flow and quality measurement systems, brine return tanks for water cleaning, disposal injection pumps, disposal filtration systems and a disposal well.

Some of the facilities required during the storage operation include: dilbit injection pumps, metering skid, flare, brine pond, brine pumps, dewatering system and a freshwater bypass.

4. MACRO-ECONOMIC ASSESSMENT

Crude oil has been a critical fuel for many decades of world economic growth. Since oil is not abundant everywhere, it must be transported long distances and is consequently affected by factors such as geopolitics, weather and logistics that can disrupt the supply and cause increases in local prices. A SPR could be used to make up for the shortfall in supply caused by these disruptions and help to moderate prices. Moderating a rise in oil prices thereby limits adverse macro-economic effects from a supply disruption.

Western Canada and Alberta face a different challenge compared to areas with little or no local petroleum production, such as Eastern Canada where supply disruptions are the greatest concern. Alberta, the largest crude producer in Western Canada, sometimes suffers from a lack of sufficient export pipeline capacity to move the oil produced to market. Simply put, total production rates can exceed export pipeline capacity out of Western Canada, thus creating an oversupply market situation. The National Energy Board (NEB 2018b) reported in September 2018 that the amount of crude oil available for export exceeded available pipeline capacity by an estimated 202,000 barrels per day. This estimate would be 365,000 barrels per day if pipeline throughput, rather than available capacity, was used to represent the amount of crude oil that can actually move out of the basin by pipeline, as shown in Figure 6.

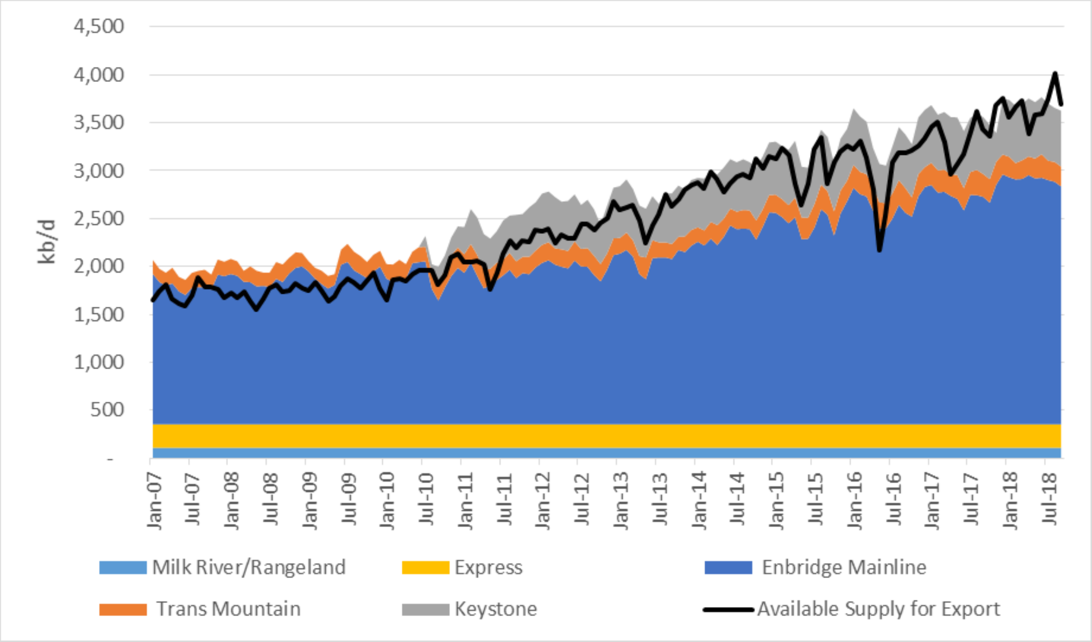


Figure 6 Western Canadian Pipeline Throughput and Crude Available for Export (NEB 2018b)

This excess oil supply is either held in surface storage tanks, where available, or exported by other modes of transportation, such as rail, all of which have high associated costs thus reducing revenues, royalties and taxes. The Western Canada (Saskatchewan, Alberta and British Columbia) current estimated storage capacity (above ground) is 88,000,000 barrels, of which approximately

88% is in Alberta. Most of this storage capacity is typically required to operate the current export pipeline system and would not be available to manage oversupply situations.

Because of market access issues, Canadian petroleum benchmarks have traded at larger than normal differentials to other North American crudes, like West Texas Intermediate (WTI). Western Canadian Select's (WCS) (the Canadian Heavy benchmark for Alberta bitumen and other heavy crudes) price started falling in May 2018 as pipelines were getting full and apportioned. The WTI-WCS differential grew to over US$40/bbl in October 2018, with a discount of US$50 per barrel on some trading days in October 2018, when it was clear that total available crude supply for export outstripped pipeline export capacity (Figure 7).

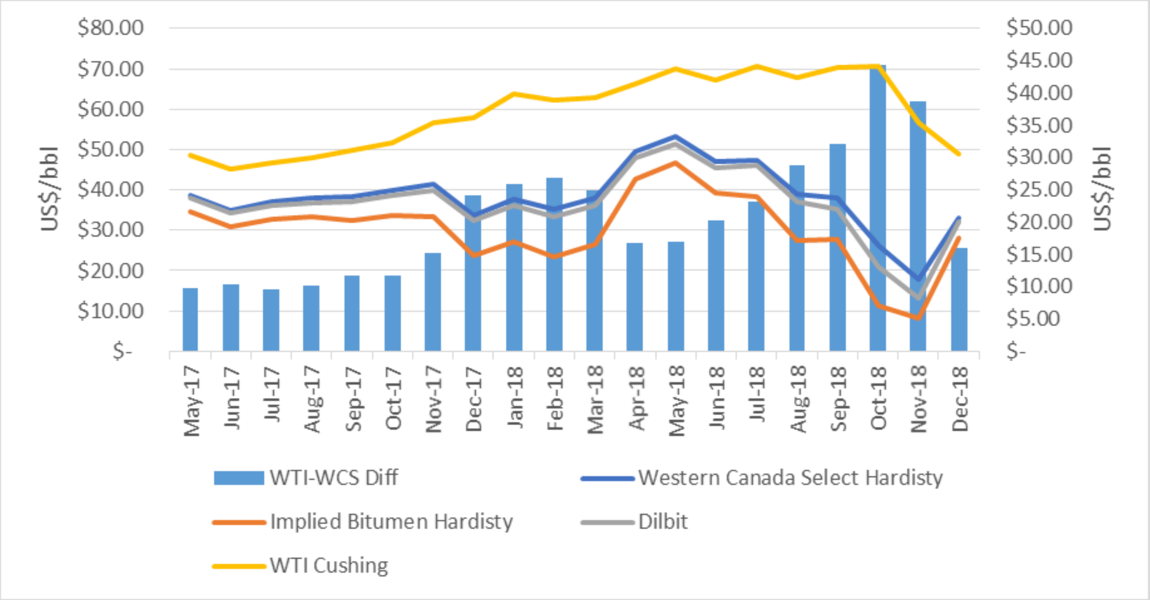


Figure 7 Canadian Crude Prices and Differentials (Source NRCAN, Baytex Energy)

In Alberta, a SPR could be used as an option to mitigate the crude oversupply situation. While recent government-imposed production cuts have managed to bring the WCS price to trade at historically low WTI-WCS differentials, they brought other unintended consequences, one of which impacts crude-by-rail economics. Low differentials do not support crude-by-rail exports and producers are cutting back on their railed volumes of crude. In addition, cutting bitumen production by shutting in in-situ oil sands wells could damage the reservoir and ultimately negatively affect the oil recovery factor, and thus, the future value of the asset. These producers may be more hesitant to reduce production, even when prices are very low.

This feasibility study assessed if a SPR in Alberta would be effective at managing the price of oil exports in times of supply surplus. Specifically, diluted bitumen or dilbit is assumed to be the stored commodity, priced at calculated dilbit prices. A macro-economic model was developed to analyze such a SPR and its impact on crude oil price, and the economic impact of a price change is then evaluated on oil sands royalties. A detailed description of the economic model used in this assessment is provided in Appendix C.

The analysis focussed on determining the following:

- Volume of oil required to be put in long-term storage to affect the market price;
- Market price effect, as a result of the government becoming an oil purchaser;
- Short-term and long-term effect on the price of oil; and
- Length of time needed to store purchased oil to have an economic impact.

4.1 Model Inputs

The assumed storage capacity of the SPR is calculated according to the IEA policy for net-importing member nations where a nation's reserves should equal to 90-days of net petroleum imports. Table 2 illustrates the determination of the minimum SPR capacity for Canada.

SPR	Unit	2018 Actual	Assumed
Total Imports	kb/d	784	414
90 days of Imports	kb	70,552	37,252
SPR Size	Mb	70.6	37
Central and Eastern Canada SPR	Mb		30
Western Canada SPR	Mb		7
Assumed SPR Capacity	Mb		10
Note: Assumed total imports are 2018 actual imports less Line 3 incremental capacity of 370 kb/d			

Table 2 Canadian SPR Capacity Determination

The parameters required for the economic model and the assumed starting values are shown in Table 3.

Variable	Value	Units
Assumed capacity	10	million bbls
Maximum acquisition rate	3	million bbls per month
Maximum drawdown rate	3	million bbls per month
Stockpile period	24	months
Supply amount in normal state	56	million bbls per month
Demand in normal state	14	million bbls per month
WTI price in normal state	$83.96	2018 average CAD$/bbl
Dilbit price in normal state	$46.93	2018 average CAD$/bbl
Holding cost per unit	$1.33	CAD$/bbl
Construction cost	0.25	factor
Price elasticity	-0.034	based on Canadian data
Demand growth rate	1.1%	historic value
Discount rate	0.50%	6% annual disc rate

Table 3 Basic Parameters and Assumptions

A multi-period optimization problem was considered where the government aims to fill the SPR in a given period. At the beginning of each time step in the model, the decision-makers choose to acquire (or release) a certain amount of oil in the SPR based on given market states defined by oil supply volume, SPR size and oil price.

The solution for the model is to find an optimal SPR policy which determines the series of acquire/release decisions into all possible market states while minimizing total SPR building cost.

4.2 Modelling Results and Conclusions

With the base case parameters shown in Table 3, Figure 8 shows the optimal path of acquisition and SPR stored volume over 24 months. Note that the storage cavern construction was estimated to take 20 months, after which oil acquisition occurred at a rate of up to 3 million bbl/month. This represents the optimal acquisition path found by the model, which minimizes the total costs of SPR construction and operation. The total discounted cost of building a SPR of 10 million barrel capacity is CAD$630 million, including CAD$132 million in construction costs, with the rest of the cost required for oil acquisition and holding.

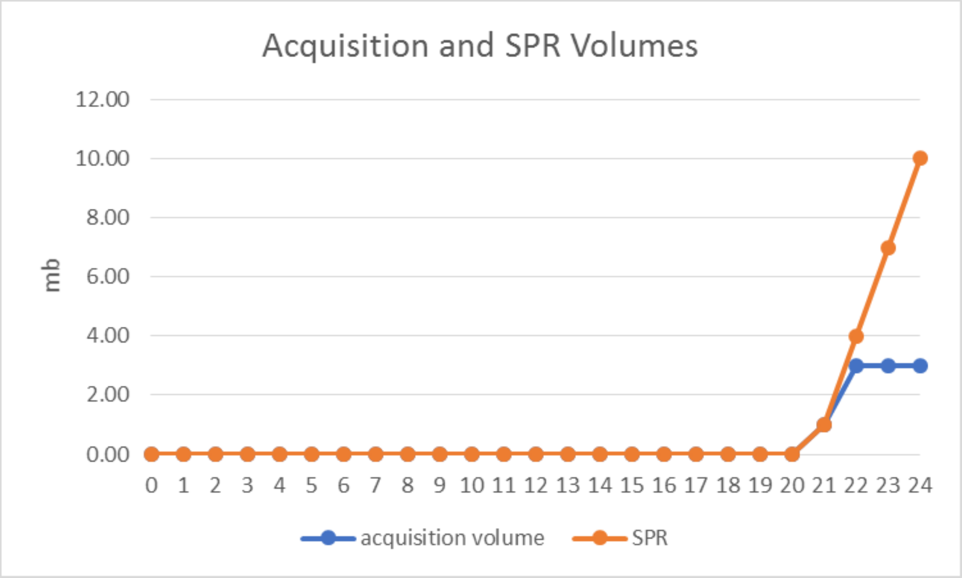
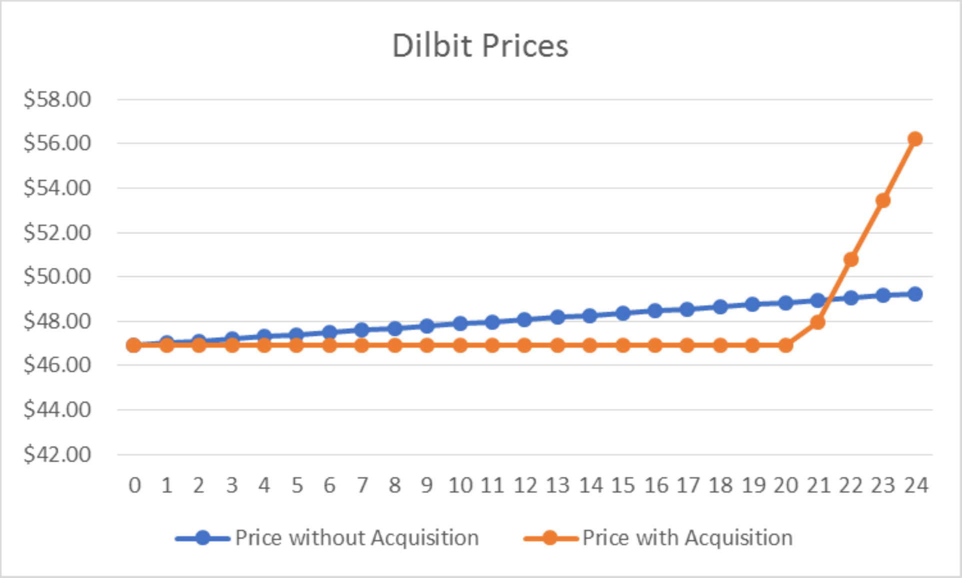


Figure 8 Optimal Acquisition and SPR Size Over Time

As shown in Figure 9, without the SPR stockpiling, the oil price was assumed to gradually increase from CAD$47/bbl to CAD$49.2/bbl at an average annual growth rate of 2.4%. With a SPR and acquisition of 10 million barrels of oil, the model predicts an increase in oil price from CAD$47/bbl to CAD$56/bbl. This means SPR oil acquisition drives the price upwards by an additional 2 to 6% in the months of crude acquisition.



Note: Price without acquisition is non-optimized and based off historical data, while the price with acquisition is modelled based on supply-demand and determined changes in demand due to oil acquisition in the optimized scenario

Figure 9 Price Change due to Crude Acquisition

The price increase will also have several other economic impacts, among which is the impact of government-collected oil sands royalties and corporate taxes. Here, a regression model based on historical data of oil sands royalties and WCS prices revealed a positive and statistically significant relationship with a 1% increase in WCS price, resulting in a 2.1% increase in oil sands royalties. This implies that the optimized SPR stockpiling policy will result in increased royalty revenues of approximately 4 to 12% during the period that oil is acquired to fill the SPR.

In summary, the volume of oil required to be put in long-term storage to affect the market price is determined by evaluating the optimal size of a SPR in Alberta; in this case it is 10 million barrels. The SPR size could vary depending on whether incremental pipeline capacity from projects such as Enbridge Line 3 will be filled with barrels directed towards Central and Eastern Canada, thus reducing that market's crude imports, which in turn will change the size of the assumed SPR.

The market price effect, because of the government becoming an oil purchaser, is demonstrated by the modelling results. It was shown that the price could increase by 2 to 6% during the period of oil acquisition to fill a SPR. Further research on the interaction between the private sector and government and how each behaves could unveil a more complex relationship and its impact on market prices.

The short-term price increase will be felt when the government makes crude purchases for SPR storage; however, it is not clear whether this price increase will be sustained in the long term. Many factors could impact the duration of the price lift.

5. GO-FORWARD RECOMMENDATIONS

5.1 Market Assessment

The initial work considered a government-owned SPR within Alberta; however, further research should be conducted to determine if other approaches could increase the value of these facilities. It is recommended to expand this research to consider:

- Private oil and gas sector's involvement. For instance, the upstream, midstream, and downstream companies have common motivation to revive the industry and make it more predictable and efficient;
- Interaction between private and public sectors on decisions to fill and drawdown crude inventories;
- Federally or provincially held SPR with different implications regarding taxes, royalties and drivers of operating policies in each situation;
- Evaluation of specific historic events to examine the effect of the SPR and assess the investment pay-out period;
- Other options for using the caverns for more than hydrocarbon storage, such as partial upgrading or other value-add activities; and
- How social welfare could be impacted by disruptions in supply.

The security value of strategic energy reserves is a very complex issue. Beyond the simplified analysis of the economic factors considered in this model, strategic energy reserves constitute a policy option open to the decision makers that is at least equivalent to those of planning the national economy for an emergency. It is recommended to examine such options not only in terms of their economic feasibility and/or necessity, but in terms of a wider class of considerations, such as: short-term and long-term economic benefits, security and foreign policy implications, and social benefits. To estimate the security provided by maintaining a certain level of reserves, all these factors must be quantified.

5.2 SPR Management

Effective implementation and management of the SPR is crucial to gain the net economic benefits. Therefore, it is recommended that various options be considered for creating an agile organization and policy framework to enable the efficient management of the SPR. This could include creating new organizations that are government-led, public-private partnerships or independent commissions.

Additionally, it is suggested to further examine development of an integrated Canada-wide storage network where dilbit can be stored in Alberta, slowly fed to Alberta refineries for upgrading and then finally stored in caverns located further downstream in the national pipeline network.

5.3 Salt Cavern Assessment

The initial assessment considered developing new salt caverns using conventional washing methods; however, further research could:

- Explore and develop novel methods for washing caverns in less time and with less water;
- Evaluate the integrity and suitability of specific existing salt caverns that could be converted to SPR storage;
- Evaluate methods to reduce viscosity of dilbit within a cavern;
- Evaluate techniques for multiple cavern entries and methods to improve filling/emptying times;
- Develop storage well management criteria to guard against well bore failures, along with better methods for roof stability control; and
- Optimize cavern location, configurations and spacing for the massive and stacked bedded salt formations that are found throughout Western Canada.

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APPENDIX A – LITERATURE REVIEW

A literature review was completed to evaluate how Strategic Petroleum Reserves (SPR) have been implemented in various countries and what research has been undertaken to optimize their operations. The following summarizes the findings of this literature review.

A.1 FEASIBILITY AND APPLICATION

Laxer (2008) looked into Canada creating an SPR, with a focus on using the SPR as insurance against undersupply and mostly considered Eastern Canada. The study mentions that, although Canada as a whole is a net exporter of oil, Eastern Canada is considered to be a net importer. Similarly, McEvoy (2012) examined if Canada should have a SPR. The article cites that Quebec imports 90% of its crude oil from foreign sources and is particularly susceptible to an oil supply shock. It also attempts to quantify the cost of building and operating an SPR; however, the scenarios considered in these earlier studies are different from this assessment in that the current assessment examines utilizing an SPR for oversupply scenarios and considers Alberta only. The current assessment also considers that the SPR will be slowly emptied over time (i.e. not strictly used as a reserve) and only considers underground storage options, such as salt caverns.

Note that this assessment does not include the effect that the NAFTA Proportionality Clause (Laxer 2018) would have on oil acquisition for the SPR. The Proportionality Clause prevents Canada from reducing oil exports to the USA, even in times of short supply. However, the recent USCMA trade deal does not include such a proportionality clause (Government of Canada 2019), allowing supply management through curtailment of production, which took effect in January 2019, or operation of an SPR.

The majority of previous studies have focused on SPR decision challenges for the USA’s SPR by examining the optimal size and rate of withdrawal to manage supply interruptions. More recently for countries like China, Bai et al. (2014) points out that China's government has established an SPR that follows practices of other countries, and reportedly aims to comply with the IEA standard, which requires crude oil holdings equivalent to 90 days of net petroleum imports by the country. The construction of China’s SPR began in 2004 and is expected to be completed in three phases over 30 years.

While China is building its SPR, the USA is in flux when it comes to their vast SPR holdings. The increase in domestic crude production, coupled with falling imports, has resulted in significant changes in the USA market. Specifically, the changes have impacted pipeline flows, creating bottlenecks and blocking SPR’s shipments to key refining centres. Scheitrum et al. (2017) suggest that a European model of the SPR could be adopted for the USA. In Europe, governments use a combination of coordinated public stocks and mandated requirements for minimum private sector holdings of refined products in a system that is more interactive between private industry holdings and public policy.

Appendix A – Literature Review

In 2016, the US Department of Energy presented its Long-Term Strategic Review (LTSR) (US DOE 2016) where they provide an overview of the SPR and address key challenges that will impact the SPR's ability to carry out its energy security mission. Major topics examined in this report include the state of the SPR's surface and subsurface infrastructure, bottlenecks in the North American midstream pipeline infrastructure that impact the SPR's ability to move oil to the market, a discussion of some of the costs and benefits of SPR options, SPR modernization requirements for infrastructure life extension, the addition of dedicated marine terminals, and issues with the SPR's authorizing legislation, the Energy Policy and Conservation Act (EPCA).

In the 2017 report published by the US Government Accountability Office (US GAO 2017) "Strategic Petroleum Reserve: Preliminary Observations on the Emergency Oil Stockpile", US GAO's work and preliminary observations show that the USA's SPR is limited in its ability to respond to domestic supply disruptions, including severe weather events, for three main reasons:

- The SPR is almost entirely composed of oil and does not include refined products like gasoline, which may not be effective for responding to all disruptions. For example, following Hurricanes Katrina and Rita, nearly 30 percent of the USA's refining capacity was shut down for weeks, disrupting supplies of gasoline and other petroleum products. The SPR could not mitigate the effects of disrupted supplies of refined products.
- The SPR is nearly entirely located in the Gulf Coast, so it may not be responsive to disruptions in other regions, such as the west coast.
- Statutory authorities governing SPR releases may inhibit their use for regional disruptions.

US GAO's preliminary observations show that other IEA member countries generally have used one of five reserve structures configured in various ways. The structures are defined by whether countries hold either public reserves (e.g. the SPR), industry reserves (e.g. placing reserve holding requirements on industry), or a combination of both. Most IEA members hold refined petroleum products in reserve, with many members holding at least a third of their reserves in these products. For example, in Germany, 55 percent of reserves are in petroleum products.

In addition, some IEA members' reserves are geographically dispersed in their countries to respond to regional disruptions. For example, France has reserves in each of its seven regions and has used these to address fuel supply disruptions because of recent domestic strikes.

In 2006, the same US GAO issued a report that made several recommendations, including:

- Study how to best implement experts' suggestions to fill the SPR more cost-effectively, including acquiring a steady dollar value of oil for the SPR over the long term and providing industry with more flexibility in the royalty-in-kind program to delay oil delivery to the SPR;
- Conduct a new review to examine the maximum amount of heavy oil that should be held in the SPR and ensure that the US DOE implements its own recommendation to hold at least 10% volume of heavy oil in the SPR; and

- Periodically reassess the appropriate size of the SPR considering the changing oil supply and demand in the USA and around the world.

A.2 UNDERGROUND STORAGE

Underground hydrocarbon storage techniques have been used for SPRs since the early 1970s. The successful implementation of underground storage can be attributed to economic efficiency, safety and excellent environmental track record (Londe 2017). Salt caverns are an underground storage option that can be used to store products in liquid or gaseous states. Mined caverns in hard rock are another technique used for underground storage, but can only store liquefied products. Depleted gas zones are also utilized to store natural gas. The number of wells required and the age of the wells increases the risk of loss of control (Aliso Canyon gas leak, 2015, California, USA). The investment costs for underground liquid storage facilities can be 50% lower than those of above-ground storage facilities (Londe 2017). Underground storage also requires less maintenance compared to above-ground, which contributes to the lower operating cost.

Underground cavern storage has a smaller environmental impact than above-ground storage; the surface facilities create a smaller footprint, it has better control over the risk of polluting the biosphere, and creates low visual impact (Londe 2017). Unforeseen accidents are also up to ten times less frequent in underground cavern storage facilities compared to above-ground (Londe 2017). Most accidents in underground storage facilities can be attributed to well bore integrity management.

A.3 ECONOMIC MODELLING

In the academic literature there are several methods or approaches that focus on implementing SPR policy, optimal stockpile size, and fill-up and drawdown strategies. Samouilidis et al. (1982) used a decision tree model to quantify the optimal size of SPR, where a branch of the decision tree can be evaluated in terms of a cost function, which includes the inventory procurement and maintenance cost and the shortage cost inflicted by a petroleum shortfall. Nordhaus (1974) examined the optimal reserve size for the USA using a two-period optimization model. Oren et al. (1986) presented a non-linear programming model to perform a steady-state analysis on the optimal size and rates of fill-up and drawdown under a variety of supply and demand conditions.

A dynamic programming model was determined to be able to address the optimal SPR size and acquisition and release strategies contingent upon supply and demand conditions. Teisberg (1981) developed a long-term stochastic dynamic model that explored the SPR size, as well as the fill-up and drawdown policy for the US. Bai et al. (2014) and Bai et al. (2016) developed a dynamic programming model and Markov decision process approach to explore China’s optimal stockpile and drawdown strategies within different market scenarios, respectively.

Some literature has examined the performance of already established petroleum reserves, like those in the USA. Bai and Dahl (2018) explored historical performance of the USA’s SPR by comparing actual real costs with estimated real benefits. This initial experimentation found that better management could have significantly enhanced the value of the USA's SPR, especially for the 1990-91 disruption. Considine (2006) developed a monthly econometric model of the world crude oil market. This paper finds that drawdowns of SPR may be futile because the price impacts of stock sales can be partially or completely offset from output reductions by world oil producers. On the other hand, stock sales can substantially reduce market prices in the event of a major disruption, although SPR stockpiles would be considerably depleted in this scenario.

Other papers used game theory to analyze competitive and cooperative relationships among different market agents, such as importers, exporters, governments and speculators. Murphy et al. (2010) developed a Markov game of the buildup and drawdown of the reserve in which a public player aims to maximize consumer welfare at the same time as private holders of inventory maximize profit. The authors argue that the "US government has not proved to be adept in managing the reserve" and "if market signals can be harnessed to manage the reserve, the problem of suboptimal management of the reserve is ameliorated". The authors discuss the possibility of using financial tools to manage SPR better in a financial market in which both public and private benefits and their interactions are considered.

Further, Wright et al. (1982) illustrate that private storage is reduced by the presence of a public stockpile. They argue that attempts by the government to act as a von Stackelberg leader who takes account of the private storage reaction function lead to a feedback rule which is in their model inferior to a simple Nash rule, by which the "public accumulates stocks till the marginal cost of a unit publicly stored equals the consumption value expected in the next period."

The few empirical estimates of the SPR price effect vary widely: SPR releases are estimated to lower the price of crude oil by 3 to 32%, while SPR purchases are estimated to increase the price of crude oil by 0.4 to 32% (Verleger 2003, Considine 2006). Stevens (2014) illustrates, by using a structural vector autoregression (VAR) model of the USA oil market, that unanticipated oil releases from the SPR have no measurable effect on oil prices and unanticipated oil purchases for the SPR raise oil prices 1.5% over 20 weeks following purchase.

The lack of consistency among these estimates is evidence that identifying the effect of SPR policy on oil prices is difficult. Thus, isolating the effect of SPR policy is challenging because the policy depends, in part, on the state of the market.

APPENDIX B – SALT CAVERN STABILITY ASSESSMENT

The structural stability of a generic salt cavern was evaluated based on advanced Finite Element Analysis (FEA) using the commercial program Abaqus® v2018.

B.1 FEA MODEL DESCRIPTION

In this assessment, the cavern shape was assumed to be cylindrical and two cavern sizes were considered (Case 1: 80 m diameter with 80 m height; and Case 2: 100 m diameter with 80 m height). A large flat roof has the greatest stress and is therefore considered the most conservative case to ensure stability.

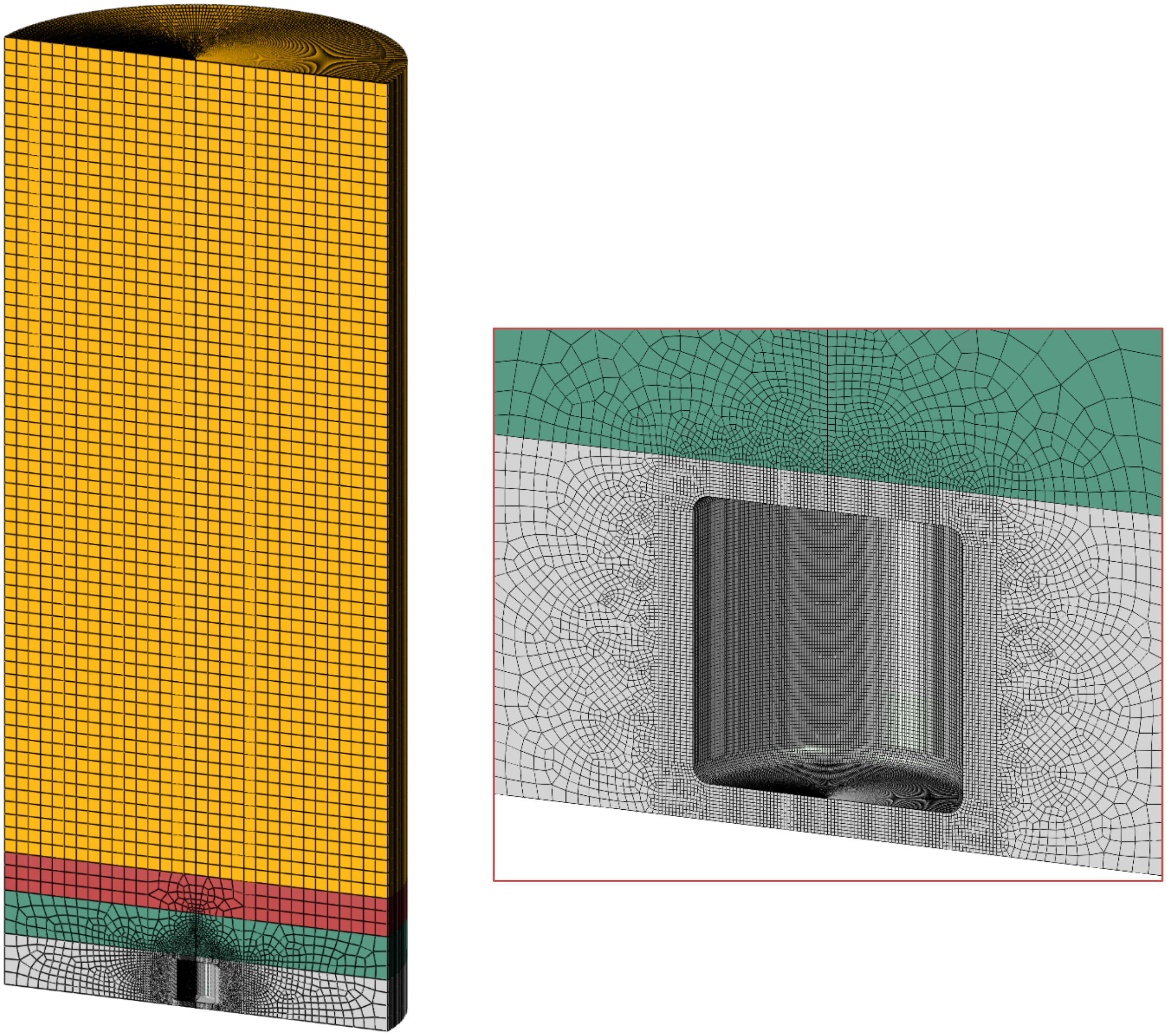
Figure B.1 shows the 3D rendering of the axisymmetric FEA model for the salt cavern. Fine mesh size of approximately 1 m was used for the regions surrounding the cavern. For the salt regions far from the cavern and the formation layers above the salt layer, mesh sizes varied from 1 m to 25 m.

Relatively large distances were considered between the cavern and the lateral boundaries of the models to ensure that the cavern responses were insensitive to boundary constraints. During the analysis, the far end boundaries were fixed laterally while still allowing vertical movements. The bottoms of the models (the bottom of the salt layer) were fixed vertically and the tops of the models (the ground surface) were unconstrained.

The FEA model considered four formation layers as listed in Table B.1, and the cavern was located within the Upper Lotsberg salt layer. The response of the three overburden formation materials was modeled using a linear elasticity model with the Young's modulus and Poisson's ratio listed in Table B.1. The Upper Lotsberg salt material was modelled using an elastic-viscoplastic constitutive behavior. The elastic response of the salt was modelled using linear elasticity, and the viscoplastic (creep) response was modelled using an Abaqus material user subroutine developed at C-FER based on the published Multimechanism Deformation (M-D) creep model (Munson and Dawson 1982), which is one of the widely used salt creep models. The M-D creep model parameters were calibrated based on a combination of published information (Li 2015, Osinga 2013) and C-FER's previous experience.

Formation Layer	Depth (m)	Young's Modulus (GPa)	Poisson's Ratio	Density (kg/m^3)
Overburden	0 to 1600	28	0.35	2390
Prairie Evaporate	1600 to 1675	27	0.32	2260
Contact Rapids	1675 to 1760	58	0.18	2720
Upper Lotsberg	1760 to 1860	30	0.19	2180

Table B.1 Formation Layer Properties



Global View

Local View

Figure B.1 FEA Model for Salt Cavern Stability Assessment (Axisymmetric Model)

B.2 ANALYSIS PROCEDURES AND RESULTS

The analysis was performed in two stages. The first stage included several analysis steps to implement the in-situ formation stress, the brine hydrostatic pressure (brine density of 1200 kg/m^3) and the salt layer temperature (45°C). In addition, the salt creep mechanism was also activated to achieve a stress state of the cavern after a long period of solution mining process (e.g. around 24 months). The results obtained at the end of the first stage analysis established a mostly stabilized stress state of the cavern.

The second stage also included several analysis steps to simulate a few key load conditions that are representative of the service life of the cavern. In order to minimize the deviatoric stress around the cavern, an assumed constant wellhead pressure of 8 MPa was applied in all analysis steps, simulating the operation scenarios of the cavern. Three operation scenarios were simulated and Table B.2 lists the associated load conditions for each scenario. Note that during the dilbit injection analysis, the brine hydrostatic pressure was gradually replaced by the dilbit hydrostatic pressure (dilbit density of 990 kg/m^3) over 30 days. While during the dilbit production analysis, the dilbit hydrostatic pressure was gradually replaced by the brine hydrostatic pressure over 30 days.

Operation Scenario	Duration (days)	Wellhead Pressure (MPa)	Cavern Fluid
Dilbit Injection	30	8	brine gradually replaced by dilbit
Dilbit Storage	90	8	dilbit
Dilbit Production	30	8	dilbit gradually replaced by brine

Table B.2 Simulated Cavern Operation Scenarios

Evaluation of the structural integrity of the salt cavern was based on the dilation criteria proposed by Ratigan et al. (1991), as shown in Equation [1]. This criteria is one of the most commonly used dilation criterion for rock salt material, and it provides a linear relationship between the square root of the second invariant of deviatoric stress tensor ($\sqrt{J_2}$) and the first invariant of the stress tensor (I_1).

$$\sqrt{J_2} = 0.27I_1 \qquad [1]$$

Therefore, the results of stress invariants obtained from FEA can be used to assess the salt dilation potential, based on the salt dilation criteria. van Sambeek et al. (1993) suggested using a damage factor based on Ratigan et al.'s dilatancy criteria to evaluate the dilation potential, and the damage factor is defined in Equation [2]. As such, a damage factor less than 1.0 would suggest a safe condition and a damage factor equal to 1.0 would indicate the onset of dilation damage. Furthermore, van Sambeek et al. (1993) also suggested that a damage factor between 0.8 and 1.0

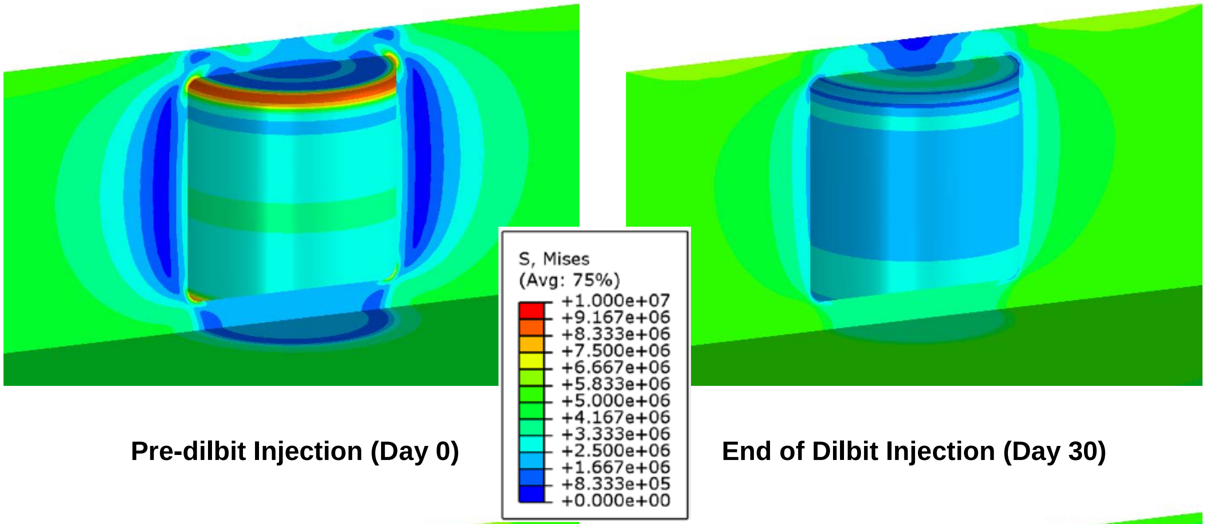
is an indication of a potentially disturbed zone. Therefore, from a conservative basis, a damage factor of 0.8 was considered as the criteria for cavern structural integrity assessment in this study.

$$D = \frac{\sqrt{J_2}}{0.27 I_1} \qquad [2]$$

Figures B.2 and B.4 present the contour plots of the effective stress ($\sigma_{eff} = \sqrt{3J_2}$) distribution around the cavern at various times through the simulation steps for Design Cases 1 and 2, respectively. The damage factor around the cavern was obtained through further post-processing of the stress results following Equation [2], and the results are shown in Figures B.3 and B.5. The results show some high effective stress regions at the corner regions of the cavern when the cavern is fully filled with brine. High effective stress regions also resulted in a higher damage factor than other regions, as shown in Figures B.3 and B.5. However, the maximum value of the damage factor at these locations (corners of the cavern) is around 0.25 to 0.26, which is small enough to not cause concern regarding the cavern stability. Note that the wellhead pressure has a great impact on the stress state around the cavern, and hence the overall cavern stability. A further design assessment is warranted to define an acceptable range of wellhead pressure for each individual salt cavern.

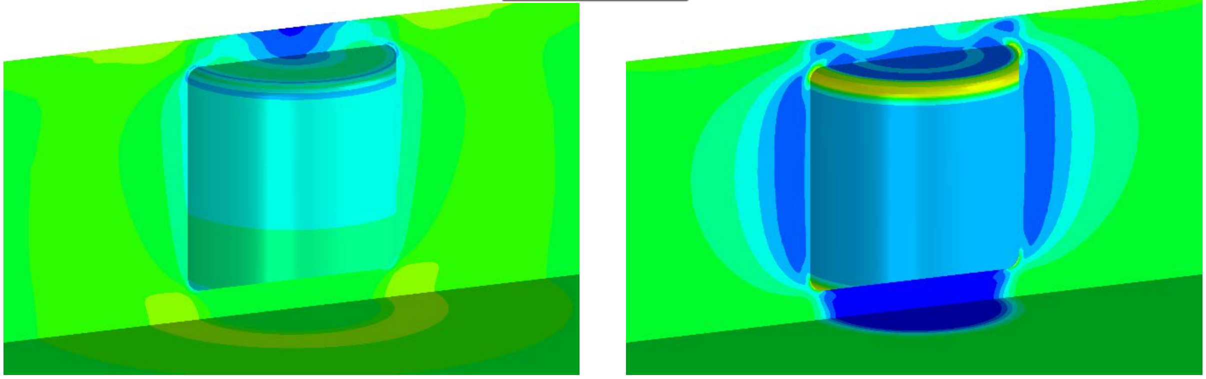
Note that this is a preliminary assessment of the salt cavern stability on its own, as the primary objective of this study is to demonstrate the feasibility of using the salt cavern for hydrocarbon liquid storage. A more detailed engineering design and evaluation is required for each actual salt cavern project. A few key issues that need to be addressed in the detailed engineering evaluation should include but not be limited to:

- Detailed characterization of the mechanical properties of the salt material through comprehensive lab testing on salt core;
- Assessment of the cap rock integrity to ensure the overall structural stability of the cavern within the bedded salt layer;
- A more detailed evaluation of the fluid pressure condition for all potential scenarios (construction, operation cycles, work over, etc.) over the entire service life of the cavern, and estimation of the resulting stress conditions and dilatancy potential (e.g. damage factor);
- Evaluate the impact of insoluble layers within the salt formation;
- Evaluation of the impact of pressure change induced cavern volume reduction and optimization of the pressure condition to minimize such impact; and
- Evaluation of the cavern roof displacement and the associated impact on well integrity over the project lifetime (casing pipe body integrity, connection sealability, cement integrity, etc.).



Pre-dilbit Injection (Day 0)

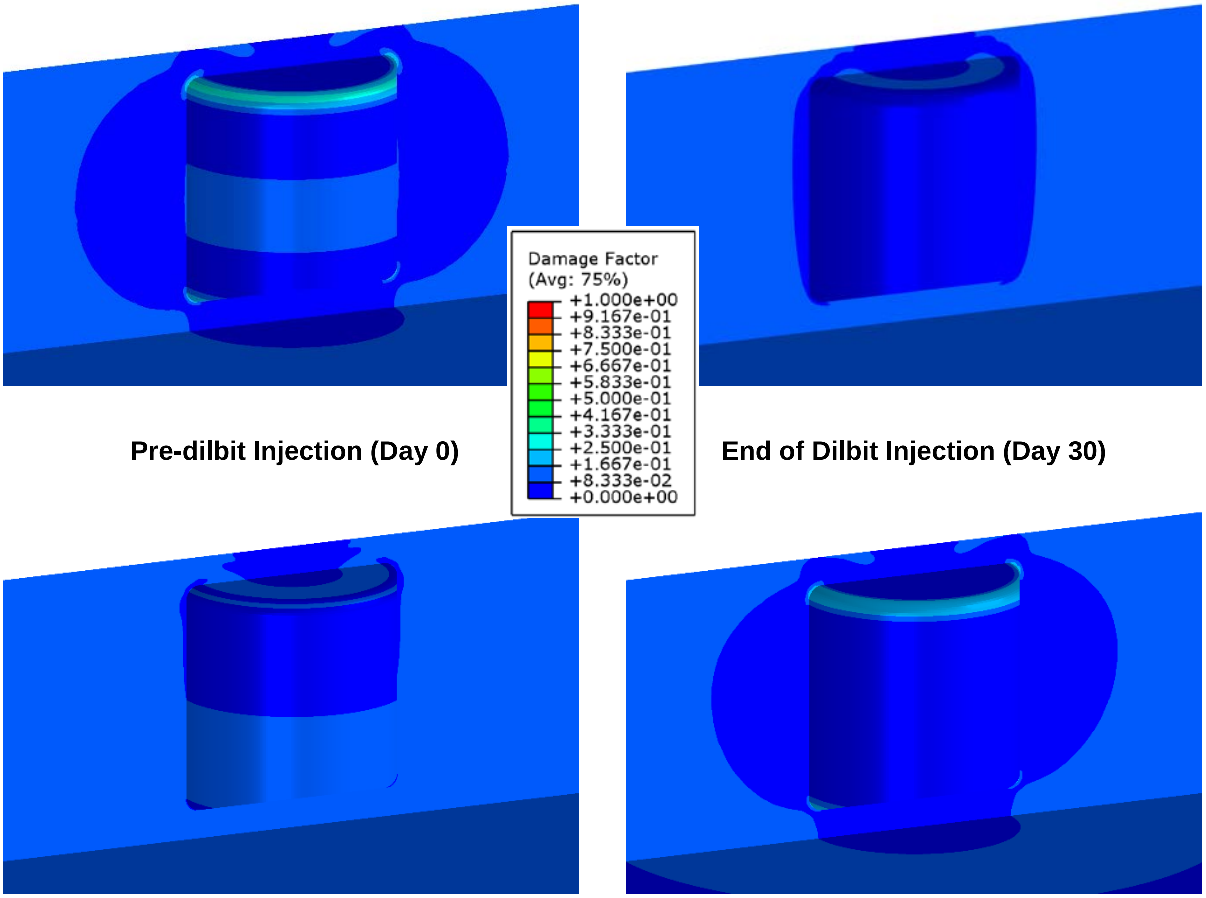
End of Dilbit Injection (Day 30)



End of Dilbit Storage (Day 120)

End of Dilbit Production (Day 150)

Figure B.2 Effective Stress (Pa) Distribution around Salt Cavern Design Case 1



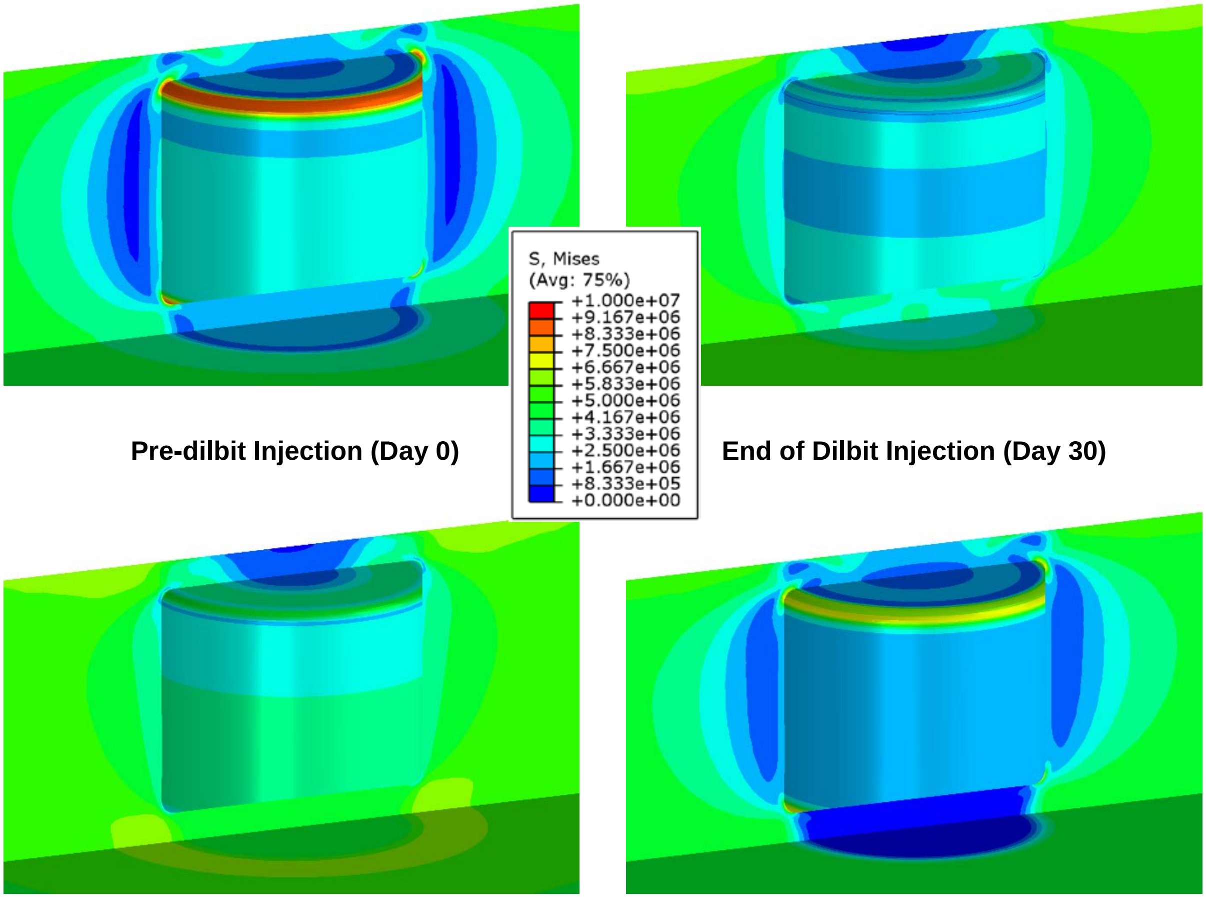
Pre-dilbit Injection (Day 0)

End of Dilbit Injection (Day 30)

End of Dilbit Storage (Day 120)

End of Dilbit Production (Day 150)

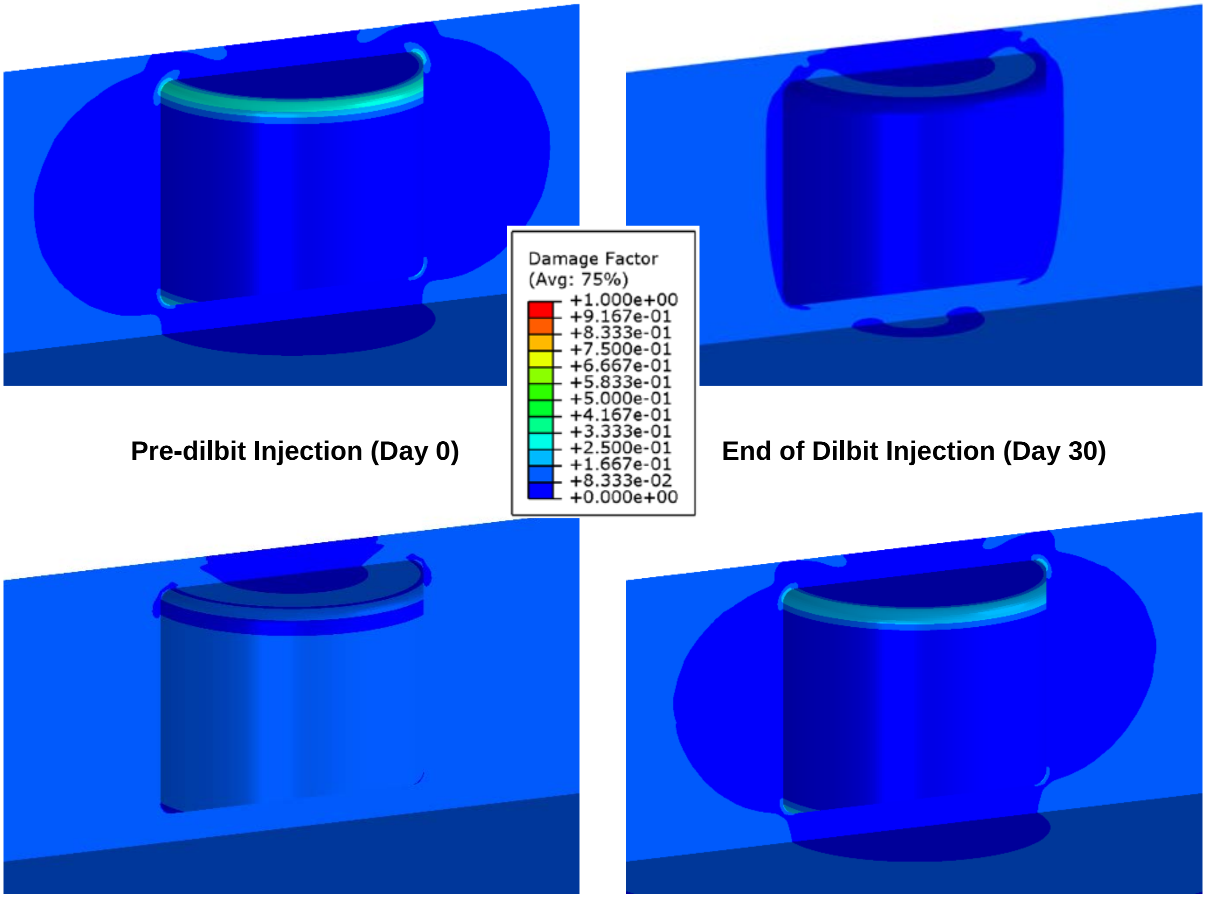
Figure B.3 Damage Factor around Salt Cavern Design Case 1



Pre-dilbit Injection (Day 0) **End of Dilbit Injection (Day 30)**

End of Dilbit Storage (Day 120) **End of Dilbit Production (Day 150)**

Figure B.4 Effective Stress (Pa) Distribution around Salt Cavern Design Case 2



Pre-dilbit Injection (Day 0)

End of Dilbit Injection (Day 30)

End of Dilbit Storage (Day 120)

End of Dilbit Production (Day 150)

Figure B.5 Damage Factor around Salt Cavern Design Case 2

APPENDIX C – ECONOMIC MODELLING

Crude oil has been a critical fuel for many decades of world economic growth. Due to imbalance of reserves distribution, oil must be transported long distances, which is concurrently affected by factors such as geopolitics, weather, logistics and disruptions. The most severe disruptions of the 1970s (an oil embargo) gave rise to the establishment of a government-held domestic stockpile of crude oil in the US. Economic evidence showed that these massive disruptions affect economic growth, especially for oil-importing countries. Such economic damage could be managed through being prepared with an advance response measure – a Strategic Petroleum Reserve (SPR). An SPR could be used to make up for the shortfall caused by interrupted oil supply. By moderating a rise in oil prices (if used effectively without delay), the SPR thereby limits adverse macro-economic effects from a supply disruption. Efficient use of SPR is important for it to be effective at combating a price spike. Although a large disruption, like the embargo in the 1970s, is highly unlikely, small to moderate disruptions like unexpected upgrader outages, natural disasters, infrastructure shut-ins or accidents are probable.

Western Canada, specifically Alberta, faces a different challenge compared to Eastern Canada. Alberta, the largest crude producer in Western Canada, is suffering from the lack of export pipelines. Simply put, total production rates exceed export pipeline capacity out of Western Canada, thus creating an oversupply market situation. The National Energy Board (NEB 2018b) reported in September 2018 that the amount of crude oil available for export exceeds available pipeline capacity by an estimated 202,000 barrels per day. This estimate would be 365,000 barrels per day if pipeline throughput, rather than available capacity, was used to represent the amount of crude oil that can actually move out of the basin by pipeline (Figure C.1).

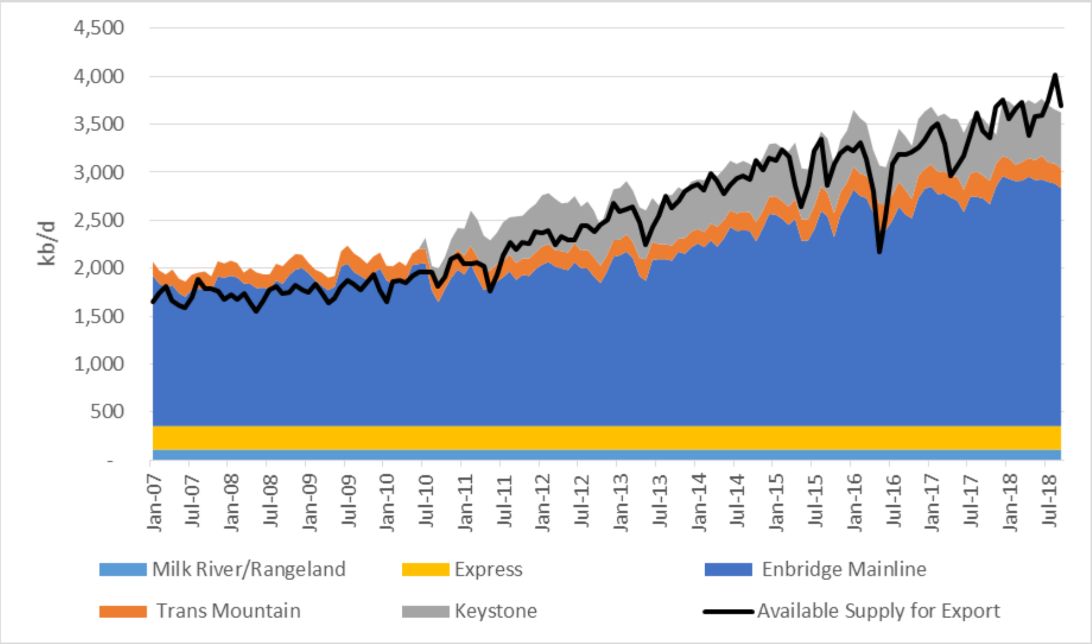


Figure C.1 Western Canadian Pipeline Throughput and Crude Available for Export (NEB 2018b)

This excess oil supply is either held in surface storage tanks, where available, or exported from the Western Canada Sedimentary Basin (WCSB) by other modes of transportation, such as rail. Western Canada's (Saskatchewan, Alberta and British Columbia) current estimated storage capacity (above ground) is 88,000,000 barrels, of which approximately 88% is contained within Alberta.

Crude-by-rail is a more expensive alternative to pipeline transportation. Rail historically has been used when pipeline infrastructure is not available, or when price differentials are wide enough for rail to be economic. There are, however, limitations to the use of rail. Unless facilities already exist, rail capacity cannot be brought on at short notice to accommodate sudden increases in demand caused by insufficient pipeline capacity or when extraordinary circumstances affect pipeline operations. It also takes time to acquire specialized tank cars, locomotives, and associated loading/unloading infrastructure, and to train crews. Oil companies wishing to transport their oil production by rail are also competing for rail space with many other commodities.

Potential positive impacts of a SPR at the macro-economic scale include: steady drilling operations, steady and predictable production, potential new refineries and petrochemical plants close to the SPR, creation of small networks of pipelines at lower cost and less public opposition, possible arbitrage from supply and demand and optimization for the commodity price, investor confidence, and creation of more jobs in various demographic areas.

C.1 ECONOMIC MODEL

C.1.1 Oil Price Determination

The oil price is determined exclusively by demand and supply fundamentals; supply–demand equilibrium model is used to determine oil price. Changes in crude acquisition will affect oil price by shifting the demand function. In the case of adding to the stockpile, the demand function shifts out and creates a new higher equilibrium price.

The global demand function is stated as Demand(u_t, p_t, t). We further assume that Alberta's demand is a fixed fraction of that demand, γDemand(u_t, p_t, t).

The supply condition, Supply(i, t), depends on the state of the oil market, i (normal or disruption), and time, t. Then the price of oil is determined by the market-clearing condition:

$$\mathrm{Supply}(i, t) = \mathrm{Demand}(u_t, p_t, t) \qquad [1]$$

The solution to Equation [1] is a function of the acquisition amount, u_t, the oil supply status, i, and time, t.

$$p_t = \mathrm{P}(u_t, i, t) \qquad [2]$$

It is worth noting that by making supply constant and only changing demand with stockpile changes, we have implicitly assumed there are no changes in other government stockpiling programs or commercial inventories.

Supply of oil normally arrives in a uniform stream sufficient to meet the nation's requirements. When there is a shortage in oil supplies, which often results in increases in crude oil prices, SPR drawdown can fill such shortages and stabilize oil prices in the short-term. Thus, the macroeconomic loss during a large-scale disruption is not considered here. For one reason, large scale disruption is highly unlikely. Secondly, when a large-scale disruption happens, the stockpiling should be shut down immediately and the drawdown strategy should be quite different from a small shortfall case.

C.1.2 Dynamic Programming Model

A multi-period optimization problem is considered. The government aims to fill up its SPR in a given period. At the beginning of each time, t, decision-makers choose to acquire (or release) a certain amount of u_t for SPR based on given market states, w_t, ϵ, and W. Market state w_t includes information of oil supply, $\mathrm{S}_{\mathrm{upply\text{-}t}}$, SPR size, s_t, and oil price, p_t.

The solution of the dynamic programming model is to find an optimal SPR policy, $\pi^* \in \Pi$, which maps decision series $\{u_1, u_2, \ldots, u_t\}$ into all possible market states, w_t, ϵ, and W while minimizing total SPR building cost.

Regarding the stockpiling costs, the following costs are included:

- Construction costs incurred from construction of storage facilities
- Acquisition costs (or revenues from sales)
- Holding costs generated by SPR maintenance, daily management and other costs

Further research is needed to evaluate broader economic costs, such as consumer welfare loss. Consumer welfare loss equals to the change in consumer surplus resulting from any induced price changes from crude oil acquisition and drawdown.

Establishing and maintaining public SPR costs taxpayers considerable capital investment. Here, the construction cost is determined by the ratio of capital cost to the crude acquisition cost. The construction cost is indicated as a ratio of SPR acquisition cost – Equation [4].

$$C_c = \phi C_a \qquad [3]$$

The acquisition cost depends on the size of acquisition and oil price. The cost for fill (+) or revenue from sales (-) is the price from Equation [1] or

$$C_a = u_t P(u_t, i, t) \qquad [4]$$

With u_t, the net flow of reserves bought (or sold) (i.e. when $u_t > 0$ is a net acquisition, $u_t < 0$ is a net sale). We do not include transportation costs, as we assume that the storage facilities located near infrastructure. Fill/drawdown capacity constraints for u_t are as follows.

We set $u_t \in [\bar{u}, \underline{u}]$, where $\bar{u}$ and $\underline{u}$ are maximum acquisition and drawdown rate, respectively.

The last element of cost is the stockpile holding cost, C_h, equal to a monthly unit cost, v, times existing reserve plus acquisition/drawdown (u_t):

$$C_h = v(s_t + u_t) \qquad [5]$$

Then, the stockpile cost for a single month, t, is:

$$V(w_t, u_t, t) = C_c + C_a + C_h \qquad [6]$$

We assume that the SPR's planned size is S_T, which is supposed to be fully filled in T months. The model finds the optimal stockpile amount, u_t^*, for each month, t, to minimize the discounted stream of stockpile cost for the whole period.

All the necessary elements for the model are defined. We can further specify the Bellman equation for our problem as follows:

$$f_t(w_t) = \min_{u_t \in [M^-, M^+],\ s_t \in [0, M]} \{V_{t,n}(s_t,u_t,t) + 1/(1+r) f_{t+1}(s_{t+1})\},\ t = 1,\ldots.T \qquad [7]$$

$$f_{T+1}(w_{t+1}) = 0$$

where w_t indicates the state at the beginning of period, t, and r represents the discount rate. Note $f_t(w_t)$ equals the total cost of stockpiling from period $t+1$ to the end period T. Stockpiling stops at year T, so the cost $f_{T+1}(w_{t+1})$ equals zero.

C.1.3 Solution Method

For the given discrete and finite dynamic system, we employed a backward induction algorithm to solve the model. Backward induction is one of the main methods used for solving the Bellman equation. Starting at the last time period, T, compute the value function for each possible state, wt, ϵ, and W, and then step back another time period. Since the objective SPR size is given by S_T, it proceeds by first considering the last time, T, a decision, u_T, might be made. Using this information, the decisionmakers then determine the action of u_T-1 at the second-to-last time, T-1. A backward dynamic programming algorithm for the given problem is as follows:

Step 0. Initialization:

> Initialize the terminal contribution, $f_t(w_t)$.
> Set $t = T$-1.

Step 1. Calculate:

> $f_t(w_t) = \min \{V_t,n(w_t,u_t,t) + 1/(1+r)f_t+1(w_t+1)\}$
> for each of w_t, ϵ, and W.

Step 2. If t > 0, decrement t and return to Step 1. Otherwise, stop.

The algorithm finds the optimal acquisition sizes, u*, for each period in a recursive way. Meanwhile, the model finds the optimal policy, π*, for each market state during the process of total cost minimization. The general recursive process from Step 1 backwards from step T is also given by Figure C.2.

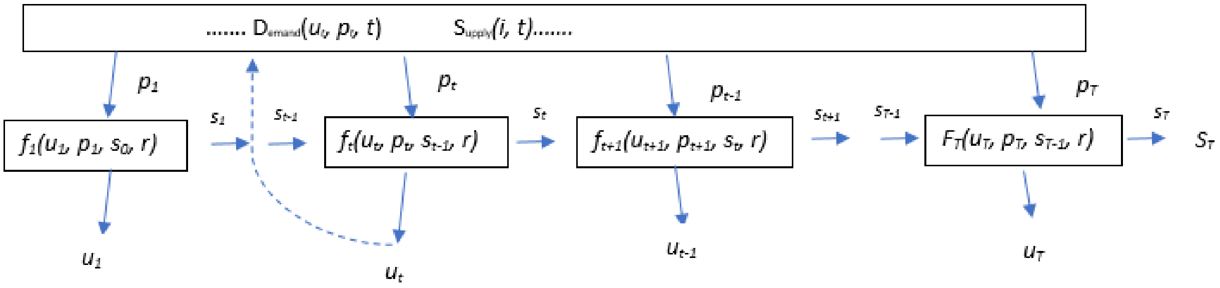


Figure C.2 Modelling Process

C.1.4 Model Inputs

The government aims to build a reserve of a certain size in a specified time interval. It makes the decision to absorb or drawdown the stockpile at the beginning of each month based on given information. The information includes oil supply, demand, price and SPR capacity. Price is determined by market supply and demand, as show in Figure C.1. The starting values of the solution variables are provided in Table C.2.

Assumed capacity is calculated as per the IEA policy for net-importing member nations. A nation’s reserves should equal 90 days of net petroleum imports. Here, we evaluate Canadian total imports, since Canada is a net-exporter. Table C.1 illustrates the determination of an SPR size for Canada.

SPR	Unit	2018 Actual	Assumed
Total Imports	kb/d	784	414
90 days of Imports	kb	70,552	37,252
SPR Size	Mb	70.6	37
Central and Eastern Canada SPR	Mb		30
Western Canada SPR	Mb		7
Assumed SPR Capacity	Mb		10

Table C.1 Canadian SPR Determination

To derive numerical solutions for our model (Equations [1] to [7]), starting values and parameters must be specified. These are provided in Table C.2.

Variable	Value	Units
Assumed capacity	10	million bbls
Maximum acquisition rate	3	million bbls per month
Maximum drawdown rate	3	million bbls per month
Stockpile period	24	months
Supply amount in normal state	56	million bbls per month
Demand in normal state	14	million bbls per month
WTI price in normal state	$83.96	2018 average CAD$/bbl
Dilbit price in normal state	$46.93	2018 average CAD$/bbl
Holding cost per unit	$1.33	CAD$/bbl
Construction cost	0.25	factor
Price elasticity	-0.034	based on Canadian data
Demand growth rate	1.1%	historic value
Discount rate	0.50%	6% annual disc rate

Table C.2 Basic Parameters and Assumptions

Total imports in 2018 were 784 thousand barrels per day (kb/d), with majority going to provinces in Central and Eastern Canada. A 90 day supply, i.e. an optimal SPR size, amounts to 70.6 million barrels (mb).

Assuming Enbridge Line 3's incremental volumes, once the project is complete, will be directed towards Central and Eastern Canada, forecasted total imports are then 2018 imports less Line 3 incremental capacity of 370 kb/d. This brings the total SPR size down to 37 million barrels. However, if the pipeline project is delayed or incremental volumes are not dedicated to Central and Eastern Canada, then the total SPR size requirement will be greater.

Majority of Canadian imports are directed towards Central and Eastern Canada, therefore a large proportion of SPR was assigned to that region. Based on Parkland Institute's report (Laxer 2008), there are "61 salt caverns … sufficient to hold about 31 million barrels of oil". Directing 30 million barrels to Central and Eastern Canada leaves 7 million barrels of oil allocated to Western Canada, rounding an assumed proposed capacity for an Alberta SPR to 10 million barrels of dilbit.

The analysis in this report is limited by only evaluating Alberta's case. Future research will be needed to look at Eastern Canada's case for SPR.

Maximum acquisition and drawdown rates are based on technical evaluation of possible sites in Alberta and Saskatchewan, which is discussed further in the report. The determined maximum drawdown rate is 80 to 100,000 barrels per day (b/d), taking the 100 kb/d and converting to a 30 day supply, which results in a 3 million barrels maximum drawdown rate. The maximum acquisition rate is assumed to be the same as the maximum drawdown rate. In theory, this is a satisfactory assumption; however, filling and drawdown rates can vary depending on type of cavern, technology, and crude.

The stockpile period is assumed to be 24 months. One period in the model is assumed to be a 30 day month. The supply amount is the historic 2018 monthly average production of Alberta non-upgraded bitumen – 1.88 mb/d, which translates to a 30 day supply of 56 million barrels. The demand amount is the historic 2018 monthly refinery demand in Alberta – 456 kb/d, which translates to a 30 day demand of 13.7 million barrels.

The holding cost is based on the US SPR holding cost of US$1.00/barrel or CAD$1.33/barrel. Also, the construction cost ratio to acquisition cost is referenced from US SPR data.