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THE SHELL QUEST CARBON CAPTURE AND STORAGE PROJECT

A ***GLOBAL FIRST*** IN
LARGE-SCALE COMMERCIAL
CARBON CAPTURE AND STORAGE
ASSOCIATED WITH
OIL SANDS UPSTREAM PRODUCTION

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Louis Helbig, beautiful destruction.ca

EXECUTIVE **SUMMARY**

In late August 2015, Shell Canada began sustained, commercial-scale operation of the first-ever CO_2 capture facility at an oil sands bitumen or heavy oil upgrader in the world, as well as transportation and storage of the carbon dioxide to a nearby geological storage site. This remarkable facility is situated near Edmonton, Alberta, Canada. This report explores the journey of the Shell Quest Carbon Capture and Storage Project team and its partners, and will provide valuable insights to other heavy oil upgraders and oil refineries globally that seek to reduce their lifecycle greenhouse gas emissions through deployment of CCS technologies and infrastructure.

The Shell Quest project was conceived in 2008 and began early operation seven years later. During this period, Shell Canada and its project team achieved many firsts:

- design, construction, and operation of an efficient, operating amine capture facility at an oil sands upgrader,
- transportation of the produced CO_2 to a suitable site for long-term storage at a nearby deep saline aquifer geological formation within 64 km of the Scotford Upgrader,
- development, deployment and management of a world-class geological storage site, and
- attainment of local, regional, national and international key stakeholder support and engagement for the undertaking.

This project was a ground-breaking achievement. Until it was operational, no other heavy oil upgrader or refinery in the world had deployed carbon capture and storage (CCS) to reduce its carbon footprint. Consequently, as of 2015, Shell Quest has provided a sustainability benchmark to the oil industry.

Shell Canada and its Athabasca Oil Sands Project joint-venture partners seized an opportunity presented by the Government of Alberta in 2008 with the newly announced Carbon Capture and Storage Fund. They successfully secured funds for the $1.35 billion+ Shell Quest project in 2009 and were equally successful finding financial support from the federal government through Natural Resources Canada's Clean Energy Fund. Together, governments have made a deep investment in the Project and its associated CCS technology development and commercialization by funding approximately 64% of research, design, engineering, construction and operating costs, including the first ten years of operation.

At the Shell Quest CCS Project, carbon capture and compression were integrated into three steam methane reformers at the Scotford Upgrader, with minimal impact on the operation and performance of the facility prior to carbon capture installation. The selected Shell Global Solutions' ADIP®-X amine carbon capture technology was re-designed and engineered to assure continued reliability of hydrogen production and seamless integration with upgrader processes and services, while minimizing energy losses associated with capture. The overall parasitic energy losses

+ All dollars in this report are Canadian unless otherwise stated.

The key factors that led to the success of this project included:

1/ A dedicated, technically-proven and experienced team of engineers and scientists at Shell Canada and its global corporate and research partners, contractors who took a carefully-crafted concept and built that into a first-of-a-kind commercial operation.

2/ Supportive JV partners that changed during the reporting period with a sale of most of the ownership in the Athabasca Oil Sands Project and the Shell Upgrader in early 2017.

3/ A deep financial commitment by governments through significant funding from the Alberta Carbon Capture and Storage Fund and the Government of Canada's Clean Energy Fund.

4/ An effective key stakeholder engagement strategy and project-wide team that succeeded in securing positive support for Shell Quest from the local community and businesses, regulators, governments and international organizations.

associated with capture and storage have been reported as 12-15% of total CO_2e emissions associated with the upgrader and the newly-incorporated CCS project. Pipeline design and construction were readily undertaken given they were within Shell Canada's long-established areas of expertise.

Geological storage of the captured CO_2 takes place at a world-class storage site that includes monitoring activities based on an MMV (monitoring, measurement and verification) plan that was a global first by being based on a thorough risk assessment process undertaken at project inception that utilized Bow Tie Analysis. MMV activities have been focused on effectively managing the risks to containment and conformance of the injected CO_2 within the Basal Cambrian Sands Storage Complex to ***as low as reasonably possible (ALARP)***. Passive and active safeguards comprising geological and engineered barriers are used to minimize risks to storage integrity. MMV activities provide assurance of the location, size and extent of the subsurface CO_2 plume and any potential leakages or seepages outside the storage reservoir.

Initially, a wide variety of new and proven MMV technologies were deployed at the Shell Quest storage site. Through their utilization for baseline and ongoing monitoring surveys, nearly 40% of those MMV technologies didn't add value to minimize storage risks, and have either been reduced in frequency of use or entirely ceased.

Furthermore, CO_2 injectivity in the first 16 months of operation has proven to be exceptional compared with pre-injection estimates, resulting in a forecast by Shell Canada that no further project well development will be required to support injection and storage capacity over the 25-year life of the project. Two of three instrumented injection wells built specifically for the project have been utilized as of December 2016. As of the date of this report, it is believed that the unused injection well might be safely abandoned as it would likely not be required before 2040 to sustain operation of the storage site.

The Shell Quest CCS Project began operating in August 2015

A series of issues and challenges faced by the Shell Quest team and its partners during the course of the Project are considered in this report. These involved regulations, financial, business and market factors, technical design and engineering, project site specifics, modular construction, risk assessment, and stakeholder engagement. The details in this report should assist future CCS deployment initiatives in considering the depth and breadth of complex issues involved in undertaking a commercial project of this nature.

The Project plan includes operation from mid-2015 to 2040, when the process of decommissioning the capture facility and pipeline and closing the storage site will begin. Beyond the period reported herein, the key to assuring continued exceptional performance of Shell Quest will lie in:

- maintaining a rigorous control of expenses to continue to reduce operating costs,
- continuing to operate infrastructure with technical skill and attention to details,
- seizing opportunities for improved efficiency through utilization of new practices and technologies,
- staying abreast of any changes in regulatory regimes and adjusting monitoring and closure plans, as well as operations, accordingly, and
- maintaining a high level of engagement with key stakeholders.

The Shell Quest Integrated CCS Project may be considered a tremendous success and a model of scientific, engineering and operational excellence. The Project has proven to the world that commercial-scale carbon dioxide capture at a bitumen and heavy oil upgrader, and more widely at oil refineries, is possible without compromising the quality or quantity of heavy oil conversion for the production of synthetic crude oil, transportation fuels, and other petroleum products.

Global demand for oil and its products is continuing to grow at a remarkable pace despite decades of dire warnings about peak oil. In 2017, world demand rose by 1.6% (1.5 million barrels per day), whereas the rate in the previous decade had averaged 1% [IEA, 2018]. Over time, world oil resources and production will continue to become increasingly heavy and consequently require relatively more processing than lighter oils. The carbon footprint of heavy crude oil upgraders and, indeed, all refineries must be significantly reduced if natural gas and other fossil energy resources will continue to be the sources for production of hydrogen and steam.

The Shell Quest Integrated CCS Project has set a carbon sustainability benchmark within the oil sands and heavy oil industry. It is now lies with the rest of the oil industry to follow the example of this world-leading project team, its corporate investors, and project partners to assure a continued trajectory toward meaningful reductions in GHG emissions associated with the utilization of heavy fossil energy resources.

The Shell Quest Integrated CCS Project may be considered a tremendous success and a model of scientific, engineering and operational excellence.

PREFACE

AUTHOR

This report is based on interviews and presentations by Royal Dutch Shell plc staff, as well as publicly-available reports and published literature, and conclusions drawn therefrom by the author.

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INTRODUCTION

This report considers the details of the Shell Quest Carbon Capture and Storage Project ("Shell Quest") that was undertaken by Shell Canada Energy Ltd. on behalf of its joint-venture partners, covering the period mid-2008 to the end of 2016, which includes:

- early and detailed planning,
- designing processes and facilities,
- planning and implementation of MMV activities,
- risk assessment,
- conceptual and detailed engineering,
- construction,
- commissioning, and
- early operating experience.

This is the first commercial CCS project undertaken by a Canadian oil sands operation, thereby setting a carbon-mitigation benchmark for the industry. The $1.35 billion+ project was co-funded by Shell Canada, Chevron Canada, Marathon Oil and Canadian Natural Resources Limited (CNRL), and the Governments of Alberta and Canada.

After several years of planning, design, engineering and construction, on October 1, 2015 the Shell Quest Project began commercial-scale capture of carbon dioxide from three on-site, steam-methane reformers at rate of 1.08 million tonnes per year at the Shell Scotford Upgrader northeast of Edmonton, Alberta, Canada. Following capture, the carbon dioxide is compressed, dried and sent by a dedicated 64-kilometre pipeline to an injection site utilizing two of three new injection wells located northeast of the Scotford Complex near Thorhild and Radway, Alberta.

The CO_2 is permanently stored in the Basal Cambrian Sands geological formation, a regionally confined deep saline aquifer lying just above the Pre-Cambrian basement. The Shell Quest Project will be operated over a minimum of 25 years, thereby reducing the greenhouse gas footprint of hydrogen production at the Scotford Upgrader by a minimum of 80%.

About Royal Dutch Shell plc ("Shell")

Shell was formed in 1907 by a merger between the Royal Dutch Petroleum Company of the Netherlands, which was incorporated in 1890, and the Shell Transport and Trading Company of the UK, which was incorporated in 1897 **[Wikipedia, 2017]**. For nearly a century, Shell Group was a dual-listed company that maintained separate British and Dutch companies but operated as a single business. The merger resulted in a 60% ownership of the business by the Dutch arm of the new company, which was responsible for production and manufacture, and a 40% ownership by the British company, which was responsible for transportation and storage of products. In 2005, the business was restructured into Royal Dutch Shell plc (RDS), moving to a single company structure with a primary listing on the London Stock Exchange and a secondary listing on the Amsterdam Stock Exchange. Shell is now headquartered in The Hague, Netherlands with its registered office located in London, UK. For tax purposes, Shell is a Netherlands company **[Shell, 2017b]**. Shell is one of the largest oil and gas companies in the world, currently ranked as number two behind ExxonMobil **[FT, 2017]**.

+ All dollars in this report are Canadian unless otherwise stated.

Shell is a vertically-integrated, United Kingdom-Dutch multinational energy company whose primary business focuses on every aspect of the oil and gas industry from exploration and production to petrochemicals. Shell also has business lines in carbon trading, technical services and technology licensing, and renewable power generation with an increasingly diverse energy portfolio. Shell operates in over 70 countries, producing approximately half a million tonnes of oil equivalent per day (TOE/d) (or 3.66 million barrels of oil equivalent per day (BOE/d)) and proven reserves of 1.81 billion TOE (13.248 billion BOE) **[Shell, 2017a]**.

Recently, Shell has increasingly focused on its conventional and unconventional gas exploration and production activities. In 2016, Shell acquired the BG Group for US$70 billion **[LA Times, 2015]**, thereby expanding its LNG business to become the world's largest producer **[Forbes, 2015]**. This renewed focus on natural gas was a key strategy to ensure sustained profitability during a major downturn in the oil business which has seen Shell's US$15 billion divestment of various assets, including US oil shale plays in 2014 **[OGJ, 2014]** and Canadian oil sands in 2017 **[Shell, 2017c]**. Accordingly, as of late 2017 its share price had nearly regained its value from 2012 **[NYSE, 2017]**.

In 2017, Shell's CEO Ben van Beurden, announced Shell's plan to cut its GHG emissions by 20% by 2035 and by 50% by 2050 as its commitment to the Paris Accord agreement **[The Times, 2017]**. Shell will also begin disclosing the net carbon footprint from use of its energy products. Shell has been reporting annually on carbon footprint from its own operations and energy use for several years. This commitment included a US$2 billion per annum expenditure on renewable energy sources, including wind power, solar power and hydrogen between 2018 and 2020. Shell began making significant investments in alternative and renewable energy beginning in the early 2000s. In 2010, Shell acquired a 50% ownership in Raizen, a joint venture with Brazilian, sugar-cane-based ethanol producer, Cosan **[EcoSeed, 2010]**.

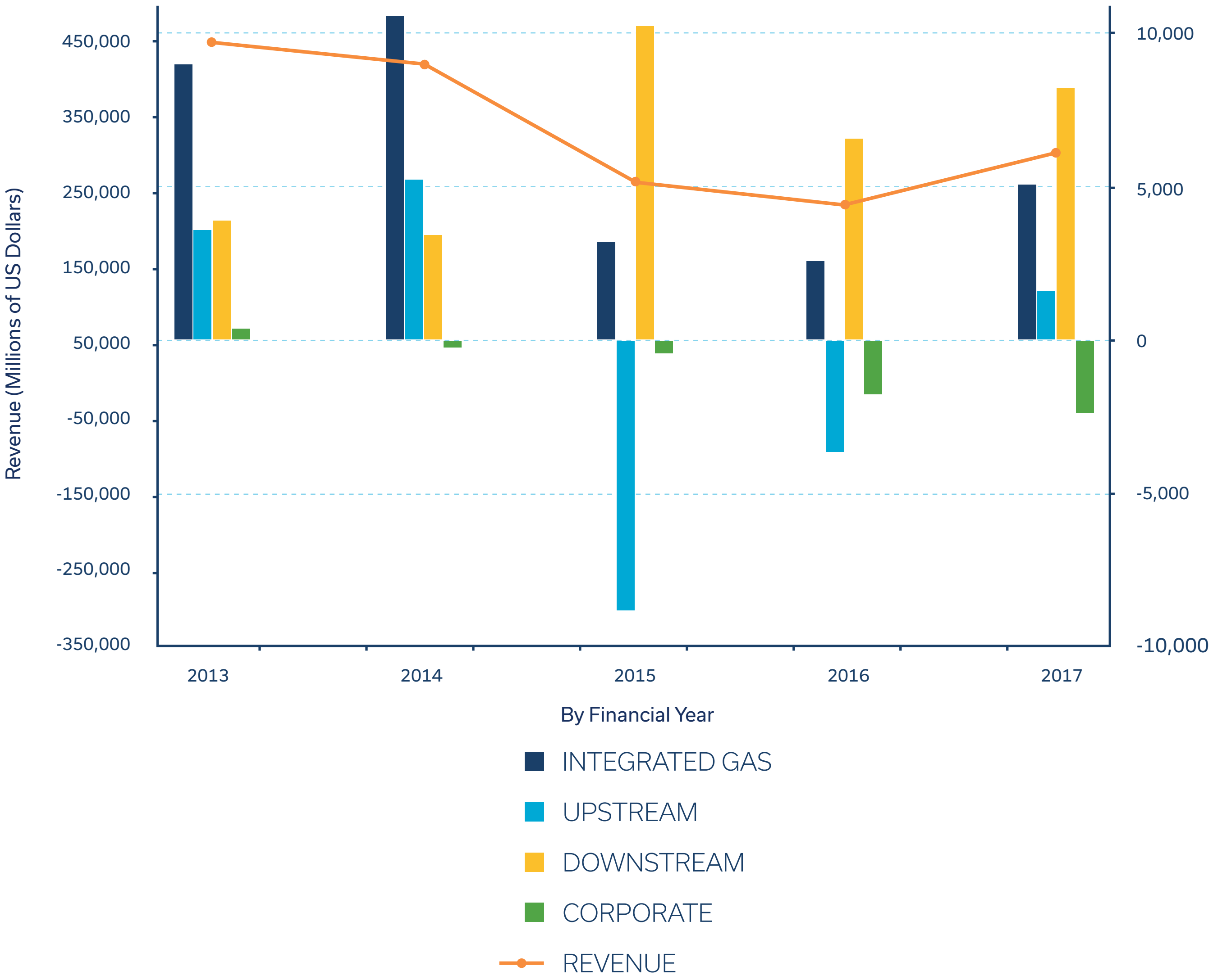
Shell's global revenue in 2017 was US$233.6 billion, which was notably down 35% compared to 5 years previously, as a result of a lengthy oil industry downturn that began in late 2014 (see Table 1 and Figure 1), although significantly improved compared with 2016. Since the 1960s, Shell has been an industry leader in technology development and licensing, investing nearly US$1 billion in research and development in 2017. Shell began adopting sustainable development corporate strategies, including carbon management, almost a quarter of a century ago. As of the end of 2017, Shell had 86,000 employees globally in major operating regions in North America, Europe, Africa, Australia, and Asia **[Shell, 2017d]**.

TABLE 1 | ROYAL DUTCH SHELL PLC FINANCIAL & OPERATING SUMMARY FOR 2017 **[Source: Shell, 2017a]**

US$305.2 Billion in Revenue	70 Countries (with Operations)
US$13.4 Billion in Income	588,255 m^3 oil equivalent (3.7 Million BOE/d) in Production Sales
US$1.48 Earnings per Share	73 Million Tonnes Direct GHG emissions (CO_2e)
US$24.0 Billion Capital Investment	1.945 m^3 oil equivalent (12.233 Billion BOE) Proved Reserves
US$922 Million in R&D Spending	3.7 Million BOE Daily Production
5.8% Return on Capital	91.5% Refinery and Chemical Plant Availability
24.8% Gearing (Net Debt:Capital)	86,000 Employees (Global)

FIGURE 1 | ROYAL DUTCH SHELL PLC ANNUAL REVENUE AND EARNINGS BY BUSINESS SEGMENT FOR 2013-2017

[Shell, 2017d]



SHELL'S HISTORY IN CANADA

Shell Canada was established in 1911. Its first marketing terminal was constructed that year in Montréal, Québec. The company grew significantly during the 1960s through a series of acquisitions, leading to strong regional positions across Canada. Consequently, Shell Canada was the "heir" to a number of Canada's earliest petroleum companies **[Tippett, 2008]**, which is typical of the growth of multinational companies throughout the 20th century.

Shell Canada is an integrated oil and gas company with diverse assets in both upstream and downstream businesses **[Shell, 2017e]**. Shell Canada's assets as of December 31, 2017 are shown in Table 2, with comparison to the end of 2016 to show the impact of business refocus away from oil sands and onto natural gas assets.

TABLE 2 | SUMMARY OF SHELL'S PROVED OIL AND GAS RESERVES IN CANADA AS OF DECEMBER 2017

[Source: Shell, 2016a and Shell, 2017a]

	VOLUME (METRIC) in millions		**VOLUME (IMPERIAL) in millions**		**UNITS**	
	2016	2017	2016	2017	Metric	Imperial
Developed Assets						
Crude oil and natural gas liquids	1.9	2.9	14	21	TOE	BOE
Natural gas	12,970	24,325	458,000	859,000	SCM	SCF
Synthetic crude oil	188.6	88.3	1,387	649	TOE	BOE
Bitumen	0.3	0	2	0	TOE	BOE
Undeveloped Assets						
Crude oil and natural gas liquids	0.5	0.1	4	1	TOE	BOE
Natural gas	10,930	11,695	386,000	413,000	SCM	SCF
Synthetic crude oil	85.3	0	627	0	TOE	BOE
Bitumen	-	0	-	0	TOE	BOE
Total Developed and Undeveloped Assets	**296.5**	**121.0**	**2,180**	**890**	**TOE**	**BOE**

The aforementioned sustained drop in the price of WTI that began in late 2014 from a high in the previous year of US$130/bbl to levels below US$80/bbl, and rapidly dropping, resulted in a marked decline in the oil industry, with the Canadian oil sands becoming marginally profitable to unprofitable in many cases. Company amalgamations and insolvency rates were high. The industry became increasingly national in character, with international investment from multinational oil companies dropping significantly. Shell Canada sought to reduce its losses from oil sands operations by making significant closures and sales of assets between 2015-2017. Consequently, Shell sold its 60% share of the Athabasca Oil Sands Project (AOSP) to Canadian Natural Resources (CNRL) and bought half of Marathon Oil's 20% stake, thereby reducing its ownership interest. CNRL acquired half of Marathon Oil's ownership. Chevron maintained its ownership level at 20%. Shell remains the operator of the Scotford upgrader and the Quest CCS project **[Shell, 2017c]**.

Shell Canada's upstream business is now focused on exploration and production of natural gas and natural gas liquids, and marketing and trading of natural gas, synthetic crude oil and bitumen, and power. Its downstream business in Canada is focused on refining, supplying, trading and shipping crude oil globally. Shell manufactures a range of products, including fuels, lubricants, bitumen, and liquefied petroleum gas for commercial and residential customers. Shell is the largest producer of sulphur in Canada from its natural gas and bitumen upgrading operations. The sulphur is converted into pellets and shipped internationally via Vancouver, British Columbia (BC). It is used to make a range of products including fertilizers and pharmaceutical drugs **[Shell, 2017f]**.

Shell holds approximately 1,600 oil and gas leases in Canada, mainly in Alberta and British Columbia (BC). It also holds a 31.3% interest in the Sable Offshore Energy project, which is located off the coast of eastern Canada. In addition, it holds leases in deep-water offshore resources in Nova Scotia and Newfoundland, with a 50% interest and operatorship in the Shelburne exploration project. Shell also holds a number of exploration licenses off the coast of BC and in the Mackenzie Delta of the Northwest Territories (NWT). There are, however, federal and provincial moratoria currently in place **[GOBC, 2017]** regarding drilling and tanker traffic off the west coast of Canada as of 1972 and 1959, respectively, due to increased tanker traffic from Alaska bound for California.

As part of LNG Canada, Shell Canada launched a large LNG project in Kitimat, BC in 2013. Joint venture partners include Shell (50%), PetroChina (20%), Korea Gas Corporation (15%) and Mitsubishi Corporation (15%). The project is one of 17 proposed LNG projects off the coast of BC **[LNGinBC, 2017]**. Shell plans to take a final investment decision (FID) in 2018. The company has delayed FIDs on other LNG projects in North America (e.g. Lake Charles, LA, USA) due to depressed global LNG market conditions.

THE ALBERTA ECONOMY

At the beginning of 2018, Alberta had a population of 4.3 million people, an increase of 1.4% from the year before and growing at a rate slightly higher than the national population **[GOA, 2018b]**. As of July 1, 2017, Alberta was home to 11.7% of Canadians, the fourth largest Canadian province by population, although notably Ontario is by far the largest province with 38.7% of Canada's total population **[StatCan, 2017]**. In recent years, the provincial population increase has been due principally to immigration from other countries, but also migration from other parts of Canada. The GDP of Alberta in 2017 was $304.7 Billion (2007 dollars), or 17.6% of Canada's national GDP and third-ranking behind Ontario (37.6%) and Quebec (19.0%) **[StatCan, 2018]**. Alberta's primary industries include energy (oil, natural gas, and electrical power), agricultural products, manufacturing and construction. Alberta's energy exports comprised 70.7% of all exports from the province in 2017 **[GOA, 2018b].**

Alberta's energy exports comprised over 70% of all exports in 2017.

A BRIEF HISTORY OF CANADA'S OIL SANDS

Oil sands were first discovered along the banks of the Athabasca River in northeastern Alberta where the bituminous deposits seep onto the river bank **[Hunt, 2011]**. Early use of the bitumen was made by First Nations peoples who blended the heavy tar-like oil with spruce fir tar to waterproof canoes. Europeans first noticed the oily material in the early 1700s, although its economic value was not realized until the late 1800s when the deposit was assessed by the Geological Survey of Canada and it was recognized as one of the largest oil resources in the world.

In 1929, Dr. Karl Clark at the University of Alberta patented a water and caustic soda process for extracting bitumen from oil sand **[CAPP, 2018a]**. However, it wasn't until 1967 that the first commercial-scale operation of oil sands mining, bitumen extraction and upgrading was established by the US-based Sun Oil Corporation at its Great Canadian Oil Sands facility near Fort McMurray, Alberta **[George, 2012]**. That facility is still operated by Canada's Suncor Energy and is known as Base Plant. Upgrading is required to convert the extra extra heavy oil or bitumen into a synthetic crude oil with an API gravity of approximately 30°. This synthetic oil mimicked the quality of conventional crude oil and enabled fungibility at existing North American refineries without the need to re-tool to accommodate high proportions of heavy oil.

Syncrude Canada, a consortium of oil companies and investors, began operating an integrated oil sands mining and upgrading facility at Mildred Lake in 1978. Shell Canada followed with its operation at Albian and Scotford in 2003. Canadian Natural Resources Limited (CNRL) established the latest integrated oil sands mining and upgrading operation at Horizon in 2009. By that time, Suncor and Syncrude had expanded their first operations to include additional surface mines. The final oil sands mine and bitumen extraction facility to be constructed began operation by Imperial Oil Resources (Canada) (IOR) in 2011 at Kearl. Diluted bitumen from Kearl is pipelined to the USA for conversion into petroleum products and transportation fuels. It wasn't until 2017, eight years following start-up of CNRL's Horizon upgrader that another one was operational at the Sturgeon Refinery. Two significantly smaller conventional heavy oil upgraders also exist in Saskatchewan at Lloydminster (Husky Energy) and Regina (CCRL) **[OSM, 2018a]**.

In 1964, IOR began piloting a thermal "in-situ" bitumen recovery facility near Cold Lake, Alberta based on the cyclic steam stimulation (CSS) process developed for heavy oil fields in Bakersfield, California. The process was deployed at commercial scale in 1975 and is the oldest in-situ thermal bitumen operation in Canada **[GOA, 2018a]**. In 1967, Dr. Roger Butler at IOR invented an "in-situ" bitumen recovery process named steam-assisted gravity drainage (SAGD) for deep mobilization of bitumen using steam. Piloting of the process was conducted under the auspices of the Government of Alberta's Alberta Oil Sands Technology and Research Authority (AOSTRA est. 1974) during the 1980s and 1990s **[CAPP, 2018a]**. It proved to be more economic and efficient than CSS and has since seen widespread application in Canada's oil sands and conventional heavy oil operations in Western Canada and globally.

The first SAGD in-situ bitumen production operation went into service in 2001 at Cenovus Energy's Foster Creek operation near Cold Lake, Alberta close to IOR's Cold Lake operation. Until this time, oil-sands mining had dominated bitumen production. As of early 2018, however, in-situ bitumen production comprised approximately 55% of total oil sands production. Nonetheless, since 2000, mining-based bitumen extraction has grown by 245%, while in-situ-based bitumen extraction has grown by 500% **[OSM, 2018a]**. In-situ bitumen production is predominantly sold at market as diluted bitumen that does not entail full or partial upgrading through addition of heat and hydrogen. In-situ bitumen production processes still rely heavily upon natural gas consumption in order to generate steam for bitumen mobilization and to treat and recycle water for steam generation. Consequently, both mining-based and in-situ bitumen production are greenhouse gas intensive processes.

THE HISTORY OF SHELL CANADA'S MINING-BASED OIL SANDS OPERATIONS

Shell Canada acquired its first oil sands leases from the Government of Alberta in 1953-54. The Athabasca Lease 13 was approximately 50 square kilometres and contained about 5 billion barrels of recoverable bitumen. In 1995-96, Lease 13 and Shell's other Athabasca leases were about to expire. Shell Canada built a business case for oil sands production that looked positive enough under various business scenarios in the late 1990s, when oil prices were very low at $10-$15/bbl, that Shell could make a considerable profit from synthetic crude oil production utilizing bitumen produced at an oil sands mine. New innovations were developed to improve the business case for oil sands mining, bitumen extraction and upgrading by reducing the capital and operating expenses historically experienced by Syncrude and Suncor, the only two operating integrated oil sands mines with on-site upgraders at the time **[Glenbow, 2012]**.

Piloting at Athabasca Lease 13 was undertaken in the late 1990s. Construction ensued quickly thereafter with full-scale operation of the Albian oil sands mine beginning in 2003 that included a remote upgrader located via pipeline near Edmonton at the pre-existing Scotford Complex. The original investment amounted to over $4 billion (2003 dollars) and precipitated an industry-wide oil sands boom that continued until late 2014. Collectively, the operation was known as the Athabasca Oil Sands Project (AOSP) and operated as a joint venture (JV) with 60% ownership by Shell. Ownership of the remainder of the partnership changed hands a few times, including BHP Billiton, Marathon Oil and Chevron. As of 2018, Shell holds a 10% ownership in AOSP assets and continues to operate the Scotford Upgrader. Chevron holds a 20% interest and CNRL now owns 70% of AOSP. CNRL operates the Albian mine as a result of asset sales by Shell Canada and Marathon Oil in March 2017 **[Shell, 2017c]**.

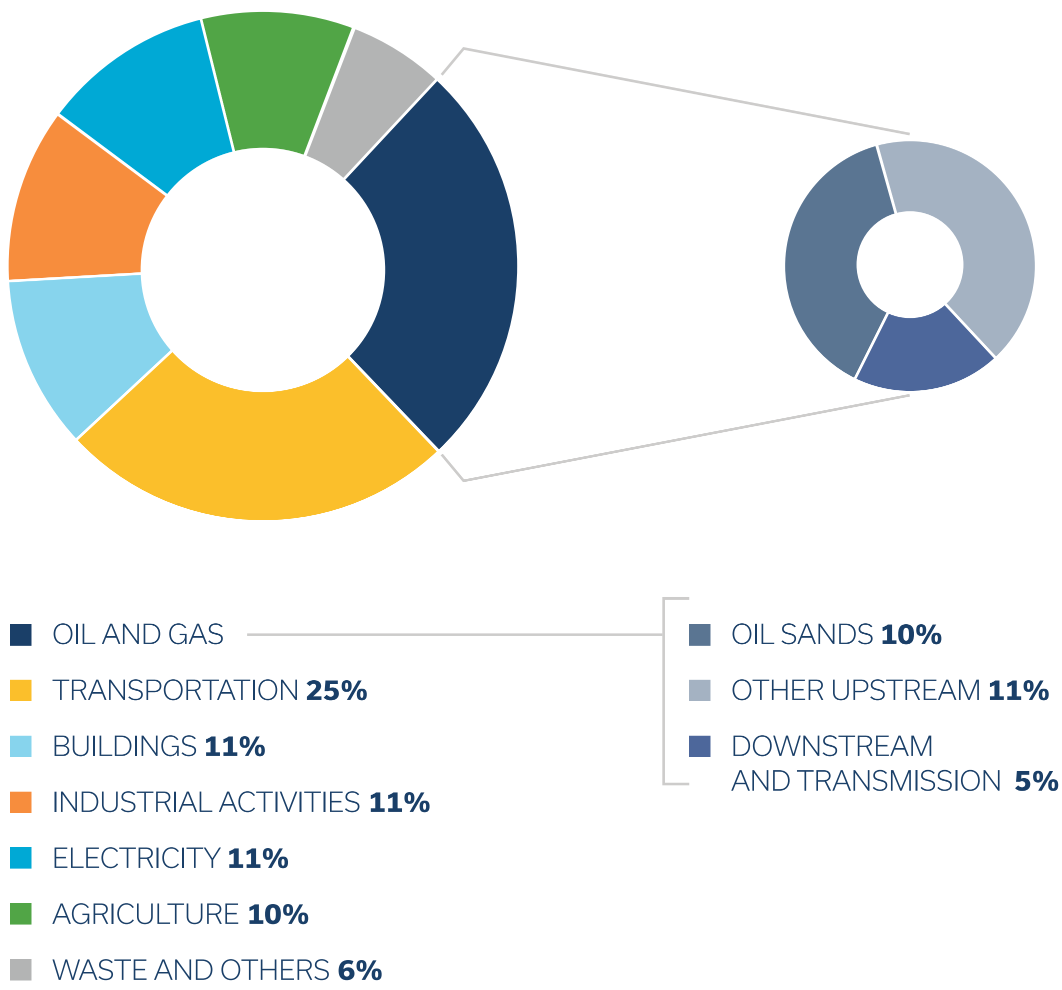
At the Albian surface mine (and subsequently-developed Shell oil sands mines), bitumen is extracted from the ore and then diluted with paraffinic solvent. The diluted bitumen is shipped via the 510-km InterPipeline Corridor Pipeline to the Scotford Complex for upgrading **[InterPipeline, 2009]**. The Scotford Upgrader was unique compared with upgraders in operation at the Syncrude and Suncor mines, as Shell Canada chose to utilize proprietary Shell hydrocracking technology during the bitumen conversion process, rather than delayed coking technology, thereby realizing a 17-22% product yield increase of synthetic crude oil (SCO) **[OSM, 2018a]**. However, it is typically more expensive from capital and operating perspectives to operate hydrocrackers compared with delayed cokers. Hence, the business case for hydrocracking relies heavily upon the differential between light oil and heavy oil pricing (SCO vs. diluted bitumen) as well as the price of natural gas.

Shell Canada significantly reduced its ownership interest in the Athabasca Oil Sands Project and the Scotford Upgrader in the first half of 2017.

GHG EMISSIONS PROFILES FOR ALBERTA AND CANADA

Canada's total GHG emissions in 2012, the last year of reported global data **[WRI, 2015]**, were 856 Mt CO_2e including land-use change and forestry, or 714 Mt CO_2e excluding land-use change and forestry, which was 0.85% or 0.74% of the global total GHG emissions in the same year, while its population was only 0.5% of the global total. This is due, in part, to its natural-resource-focused economy necessitating the use of significant amounts of energy to recover metals, minerals, oil and natural gas, as well as for agricultural purposes. As shown in Figure 2, all industrial activities, oil and gas production, and agriculture emit a total of nearly half of Canada's total GHG emissions **[ECCC, 2018]**. Oil sands represent a significant share of GHG emissions at 10% of the national total. Canada is a net exporter of oil and gas and is the supplier of the largest share of imported oil into the USA. The nation's production of oil in 2017 averaged 670,000 cubic metres per day (4.2 million barrels per day) of which 73% comprised oil-sands-derived synthetic crude oil and diluted bitumen, and conventional heavy oil.

FIGURE 2 | CANADA'S GHG EMISSIONS PROFILE FOR 2016 [Sources: ECCC, 2018 and CAPP, 2018b]

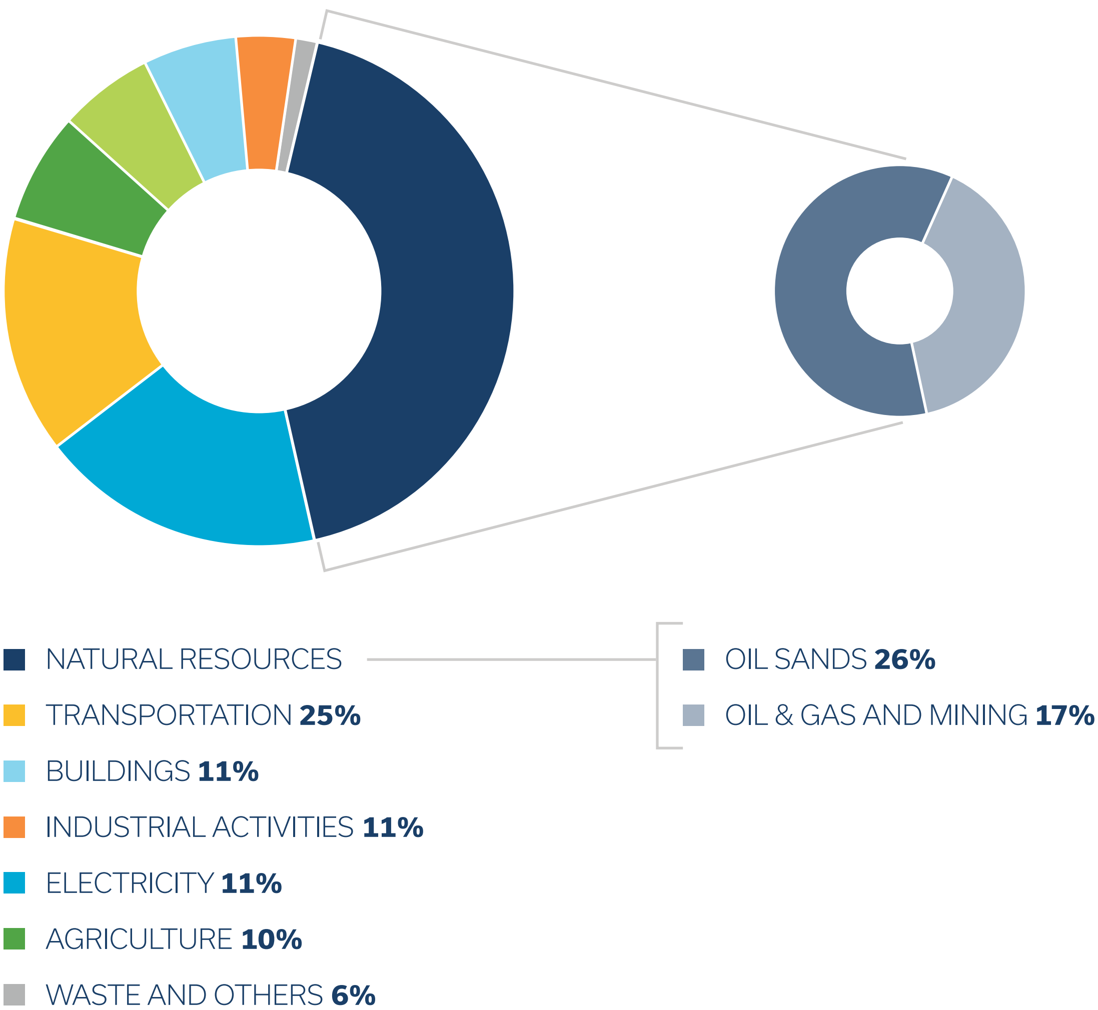


The Government of Canada has announced a targeted GHG emissions reduction of 30% below 2005 levels by 2030 **[GOC, 2018]**.

Alberta produces 90% of the total volume of heavy oils and upgraded heavy oils in Canada, amounting to 380,000 cubic metres per day (2.8 million barrels per day) on average. The remainder of the heavy oil production is produced by Saskatchewan as conventional heavy oil which is either upgraded to a synthetic light oil product or diluted and sold as a blended heavy oil. The percentage of oil sands production from mining-based operations is declining while overall oil sands production is increasing in Alberta. As of 2017, 37% of all oil sands and heavy oil production from Alberta was upgraded into a light synthetic crude oil in processes similar to those used at the Shell Scotford Upgrader, the location of carbon dioxide capture considered in this report.

As a consequence of the significant level of heavy oils production and bitumen upgrading in Alberta, coupled with a significant level of unmitigated GHG emissions from coal-fired power generating stations, the province emits the highest share of GHG emissions compared with Canada's other provinces and territories. In 2013, the last year reported by the Government of Alberta, provincial GHG emissions amounted to 267 Mt of CO_2e annually **[GOA, 2013]**. The breakdown of emissions by sector is shown in Figure 3.

FIGURE 3 | ALBERTA'S GHG EMISSIONS PROFILE BY SECTOR FOR 2013 **[Source: GOA, 2013]**



GHG REGULATIONS FOR CANADA'S OIL SANDS

While the Government of Canada has regulations in place that set an upper limit on emissions from coal-fired power generation, there are no specific federal GHG regulations that target the oil sands industry. Additionally, the Pan Canadian Framework on Climate Change **[GOC, 2016]** has set an ambitious target to reduce national GHG emissions by 30% from 2005 levels by 2030. Carbon pricing and significant reduction in methane emissions from the oil and gas sector are key components of the Framework. The manner in which each province chooses to reduce its GHG emissions inventory is at its discretion with the sole exception of coal-fired power generation. The Government of Canada requires that all coal-fired power stations be shut down no later than 2030 unless CCS technology is deployed to reduce emissions in order to comply with the regulated GHG emission level.

The Alberta regulatory framework for controlling industrial GHG emissions from over 110 large stationary sources with greater than 100,000 tonnes CO_2e per year began in 2007 at $15 per tonne. This amounted to 47% of total industrial emissions in the province. Additionally, beginning in 2015, all large industrial facilities were required to immediately reduce GHGs by 12% per unit of output at a rate of 2% per year using a baseline GHG intensity from the period 2003-2005. The funds were used by the Climate Change and Emissions Management Fund to support development of new energy efficient technologies and innovations **[Rich, 2015]**. More than half of the funds were invested in alternative and renewable energy technologies by the end of 2014.

In 2016, taxes on energy usage in the commercial, industrial and residential sectors began in Alberta, starting at $15 per tonne. The tax doubled in 2018 and will continue to increase until a level of $50 per tonne is reached in 2022 in line with the federal carbon pricing plan and a uniform carbon tax for all Canadians **[FP, 2018]**. Carbon tax revenue collected by the province is invested in emissions reduction, renewable energy development and support for low income families. Additionally, the province has passed into law the elimination of coal-fired power generation by 2030. As of 2017, 40% of the province's electricity demand was sourced from coal. Provincial utilities began shutdowns in early 2018 **[Global News, 2018]**.

REGULATORY FRAMEWORK FOR CCS IN ALBERTA

When Shell Canada and its JV partners began planning the Quest Project, the regulatory frameworks in Alberta for the oil sands and carbon geological storage were fragmented and complicated to manage. The regulatory approval process has since been somewhat simplified with the establishment of the Alberta Energy Regulator (AER) that began operating in April 2014 **[AER, 2018a**]. AER brought together regulatory functions from a number of Government of Alberta departments and agencies, while absorbing the Energy Resources Conservation Board. AER is the regulatory authority for oil and gas wells, facilities and pipelines, including oil sands mines. Alberta Environment and Parks still serves as regulator for water resources and land and air impacts.

In the absence of specific carbon capture and geological storage regulation, Shell Canada looked to current global guidelines, insights and lessons learned from existing and developing carbon storage projects nationally and internationally, and Alberta's existing regulations for permitting and oversight of Acid Gas Disposal projects that were being effectively used for more than 40 commercial installations involving capture and storage of CO_2. Two Canadian geological storage projects that especially served as important precedents were the IEAGHG Weyburn-Midale CO_2 Monitoring and Storage Project and the Pembina Cardium CO_2-EOR Project **[Shell, 2011f]**. Internationally, the geological storage projects that served to provide useful guidance included: Sleipner and Snøhvit in Norway, In Salah in Algeria, and Rangely in the United States. International projects with mature Measurement, Monitoring and Verification (MMV) plans to offer guidance included: Gorgon in Australia and Goldeneye in the UK.

The relevant governing regulations in Alberta were covered under Directives 7, 17, 20, 51 and 65 **[AER, 2018b]**. Collectively, these regulations specify requirements for:

- measurement and reporting of injection;
- well abandonment, leakage detection and mitigation;
- design, operation and monitoring requirements of injection wells; and
- confinement and isolation requirements for injected acid gas.

Shell Canada regarded established regulations and standards as a minimum requirement for the Quest Project and further committed to any new regulations that followed a regulatory framework assessment that was underway through 2011-2013 during the planning for the project **[Shell, 2012a]**. The developing Canadian Standard for Geological Storage of Carbon Dioxide served as effective guidance.

In 2007, Alberta began controlling GHG emissions and imposing a carbon tax for all large stationary industrial sources.

CANADIAN STANDARD FOR GEOLOGICAL STORAGE OF CARBON DIOXIDE

In a world-leading effort, the Canadian Standards Association (CSA) worked with the International Performance Assessment Centre (IPAC-CO_2) to develop the first performance standard for geological carbon storage in sedimentary basins. CSA Z741-12 was released in 2012 and reaffirmed in 2017 **[CSA, 2018a]**. Although the standard cannot be enforced by law unless officially adopted by a regulatory agency, including any exceptions or additional requirements, the standard sets out all requirements and guidelines for industrial implementation to effectively manage carbon storage risk. The standard was built upon the vast experience gained through decades of CO_2-EOR operations, as well as pilot and demonstration CCS projects undertaken across North America prior to 2012, and is updated as appropriate thereafter.

The CSA standard provides guidelines for regulators and industry globally for scientific and industrial-scale CCS projects. The standard includes both ***requirements and recommendations*** for geological storage to assure safe, long-term containment of CO_2 that minimizes the risk to human health and the environment over the full life cycle of a storage project from pre-injection to closure. It notably does not include anything related to the post-closure period, which is initiated at the point at which the responsibility for the geological storage site is transferred to a designated authority.

Furthermore, the CSA standard does not include CO_2 geologically stored in: unmineable coal beds, basalt formations, shales, or salt caverns; underground storage in the form of containers; operational aspects related to hydrocarbon production at CO_2-EOR or CO_2-EGR operations, including incidental storage of associated CO_2; and disposal of acid gas (which includes significant levels of CO_2).

Notably, the standard provides guidelines for managing documents, community engagement processes, risk assessment and risk communication.

In a world-leading effort, the Canadian Standards Association worked with the International Performance Assessment Centre to develop the first performance standard for geological carbon storage in sedimentary basins.

CCS PROJECTS ACROSS CANADA

The Canadian energy sector, with strong support from Canadian governments, has been very active in funding and promoting the development of new and improved carbon capture technologies, MMV technologies and their demonstration and commercial application for enhanced oil recovery and dedicated geological storage utilizing carbon dioxide, particularly in Alberta and Saskatchewan, Canada's primary oil and gas producing provinces that also have the highest share of coal-fired power generating capacity in the country. In total, Canadian industry and governments have invested approximately $4.5 billion, excluding associated incentives and tax relief, in funding commercial CCS projects. These projects include **[NRCan, 2013; GOA, 2009; CCSA, 2012; Enhance, 2018** and **CH, 2011]**:

Commercial Projects

- Weyburn CO_2-EOR Commercial Operation (Saskatchewan) (2000 – ongoing)
- Midale CO_2-EOR Commercial Operation (Saskatchewan) (2005 – ongoing)
- Boundary Dam Power Station Carbon Capture and Storage Project (Saskatchewan) (2014 – ongoing)
- Shell Quest Carbon Capture and Storage Project (Alberta) (2015 – ongoing)
- Alberta Carbon Trunk Line (Alberta) (2018 – ongoing)

Demonstration and Pilot Projects

- IEAGHG Weyburn-Midale CO_2 Monitoring and Storage Project (2000 - 2012)
- Petroleum Technology Research Centre's Aquistore Project (2010 – ongoing)
- PennWest's Pembina Cardium CO_2-EOR Commercial Operation (Alberta) (2004 – 2008)
- Apache Canada's Zama Acid Gas CO_2-EOR Project (Alberta) (2005 - 2012)
- Husky Energy's Heavy Oil CO_2-EOR and Storage Project (Saskatchewan) (2017- ongoing)
- PennWest's Joffre Viking CO_2-EOR Project (Alberta) (1984 – ongoing)
- Glencoe Resources' Chigwell Viking CO_2-EOR Project (Alberta) (2007 – ongoing)
- TransAlta's Project Pioneer Feasibility Study (Alberta) (2009 – 2012)
- Capital Power's IGCC Feasibility Study (Alberta) (2006 – 2010)
- Swan Hills Synfuels Feasibility Study (Alberta) (2005 – 2013)
- Spectra Energy's CCS Exploratory Project (British Columbia) (2009 – 2016)

ALBERTA'S INVESTMENTS IN CCS

A $2 billion Carbon Capture and Storage Fund was announced by the Government of Alberta in July 2008 **[GOA, 2008]** with an ambitious goal to geologically store up to 5 million tonnes of CO_2e by 2015. In 2009, four projects were selected, including the Shell Quest Project and the Enhance Energy Alberta Carbon Trunk Line **[CH, 2009]**. Two projects were cancelled by 2015 following feasibility studies that determined the projects were too costly to undertake: Transalta's Project Pioneer and the Swan Hills Synfuels Project. The Shell Canada and Enhance Energy Projects amounted to an investment of $1.2 billion by the Government of Alberta with awards of $745 million and $495 million, respectively.

To date, Canadian industry and governments have invested over $4.5 billion in commercial-scale CCS projects.

THE SHELL SCOTFORD UPGRADER FACILITY

HISTORY OF THE SHELL SCOTFORD SITE

The Scotford site lies northeast of Alberta's capital city of Edmonton in Strathcona County. The operating facilities at the site include **[Shell, 2018a and OSM, 2018b]**:

- The Scotford Refinery that started up in 1984 with a throughput capacity of 18,125 m^3/day (114,000 barrels per day) of light, low-sulphur oil.

- Shell Chemicals Plant which began operation in 1984 with an ethylene glycol production capacity of 450 k tonnes per year and a styrene production capacity of 450 k tonnes per year. The plant uses by-products from the adjacent refinery for chemicals manufacture.

- The Shell Upgrader that started up in 2003 with a nameplate capacity of 24,645 m^3 per day (155,000 barrels per day). As of May 2018, it has a nameplate capacity of 40,540 m^3 per day (255,000 barrels per day) utilizing diluted bitumen from the Albian mining and extraction operations. The upgrader has been expanded twice since 2003 to accommodate planned increases in mining and extraction operations in Athabasca. As noted previously, the upgrader uses a hydrogen addition process to converted heavy bitumen oil into synthetic crude oil, rather than the thermal cracking or "coking" process preferred by other commercial upgraders in Canada. Shell's synthetic crude oil product has a slightly lighter API gravity of 31-32°.

- Shell Quest CCS Facility which was operational in the third quarter of 2015, with an official start-up date of August 23. It has a nameplate capacity of 1.2 million tonnes of CO_2 per year.

WHY DEPLOY CARBON CAPTURE AT SCOTFORD?

At the time Shell Canada undertook its investment decisions for the AOSP and subsequent expansions in the late 1990s into the 2000s, the so-called "shale revolution" which has resulted in a much higher level of light oil production than seen for many decades, had not emerged. In fact, it had become clear that untapped world oil resources were becoming heavier. Canada's oil sands were therefore tremendously attractive due to their lack of exploration risk, rapidly improving economics and profitability, and a healthy pace of associated technology development and commercialization.

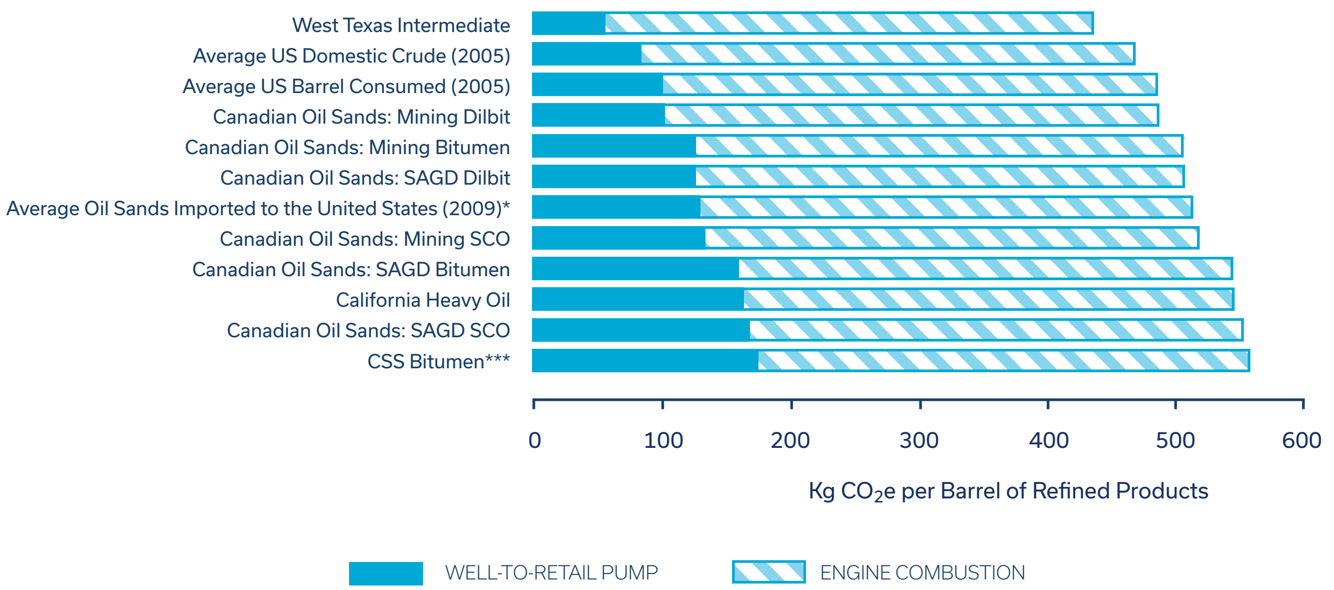
By 2000, it was becoming clear that use of fossil energy was having a significantly detrimental impact on the global climate and mitigation of emissions was desirable. It has been proven through what many have termed the "wells-to-wheels" lifecycle analysis that 70-80% of the GHG footprint associated with the use of fossil fuels, including bitumen, lies with the end-user who is responsible for energy demand and associated hydrocarbon combustion and emissions.

Approximately 250% more GHG emissions are associated with mining and upgrading of bitumen to produce synthetic crude oil vs. production of conventional US oil **[IHS CERA, 2010]** as shown in Figure 4. Bitumen-derived gasoline is 17.2% more GHG intensive to produce, while bitumen-derived diesel is 19.5% more GHG intensive to produce when compared with those transportation fuels derived from US conventional oil. On a life-cycle basis, it is estimated that the GHG emissions from combustion of refined products wholly derived from mined oil sands are 5% higher than the average crude consumed in the USA from well to pump. However, the refined products from mined oil sands burn more cleanly than WTI by approximately 2.5%.

On a global basis, RDS was an early supporter of CCS projects which aimed at reducing corporate and global footprints associated with fossil energy production and use. It was abundantly clear that Shell Canada's investments in oil sands had to become more sustainable. This was the beginning of thinking about commercial deployment of carbon capture and storage within AOSP, and the birth of the Shell Quest Project. With its thinking at a mature stage, Shell Canada acted quickly once the Government of Alberta announced creation of its $2 billion Carbon Capture and Storage Fund in mid-2008.

FIGURE 4 | WELLS-TO-WHEELS GHG EMISSIONS COMPARISON FOR OIL SANDS AND OTHER CRUDE OILS

[Source: IHS CERA, 2010]



Dilbit "diluted bitumen" using light hydrocarbons to enable pipeline transportation

SCO "synthetic crude oil", i.e. upgraded bitumen

SAGD "steam assisted gravity drainage" or in-situ production through traditional oilfield means utilizing horizontal wells and pumps (prevalent in Athabasca oil sands)

CSS "cyclic steam stimulation" or in-situ production through traditional oilfield means utilizing vertical wells and pumps (prevalent in Peace River and Cold Lake Oil Sands, as well as California Bakersfield)

GOVERNMENT SUPPORT FOR THE SHELL QUEST PROJECT

The Shell Quest Project received a total of $865 million in funding from federal and provincial governments and agencies. As noted above, the Government of Alberta will provide $745 million from the CCS Fund, enhanced carbon credits to support engineering design, construction and the first ten years of operating costs. Support from the CCS Fund began in April 2012 with payments made by milestone, as follows **[Senate, 2017]**:

A / Construction phase (by performance criteria): $298 million (40%)

B / Commercial testing (by performance criteria): $149 million (20%)

C / First 10 years of Operation (capture of 10.8 Mt): $298 million (40%)

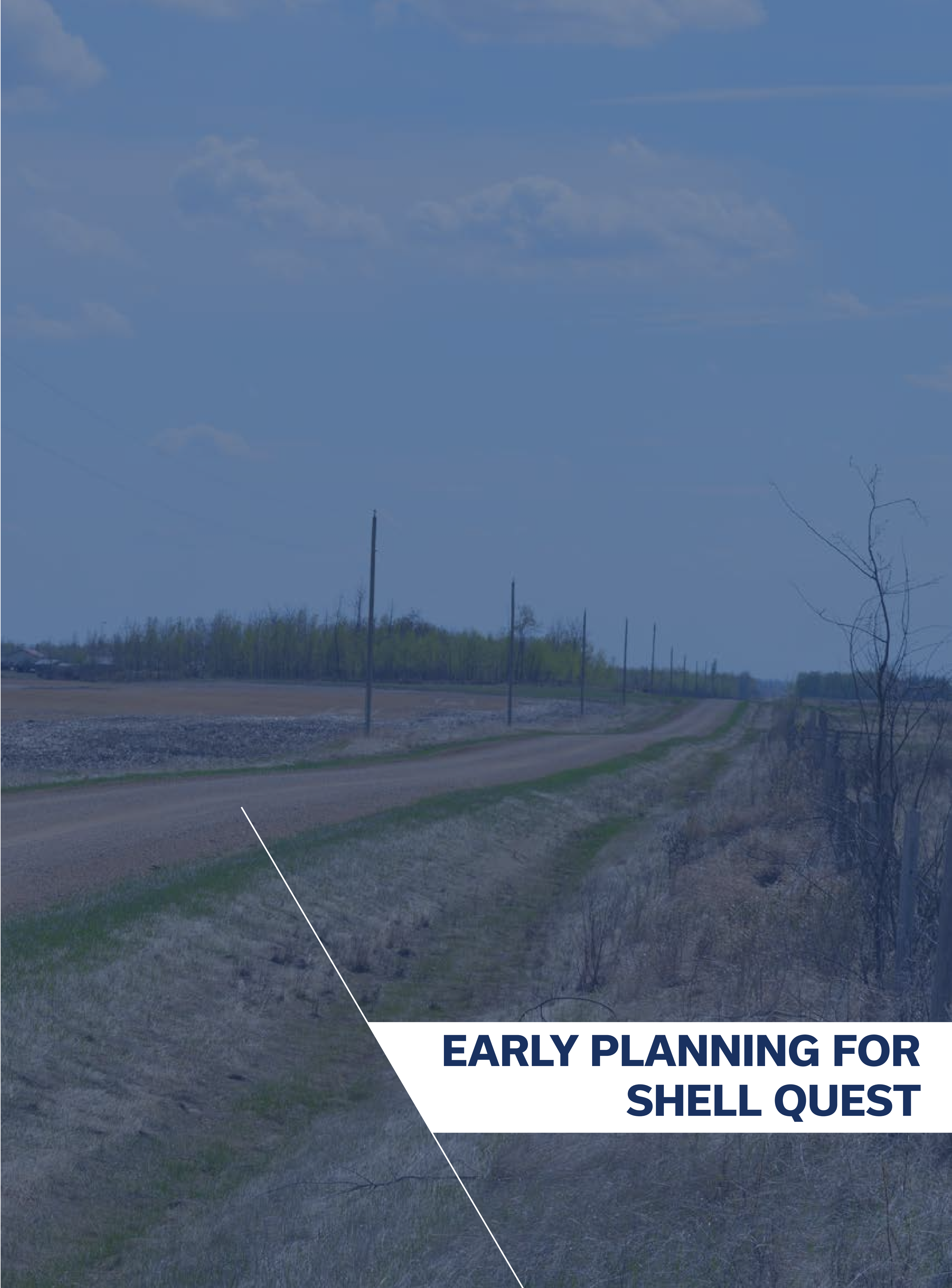
Additionally, Alberta Innovates contributed $6.6 million in funding for early stage planning work between April 2009 and March 2012. The Government of Canada, through Natural Resources Canada's Clean Energy Fund, supported the Shell Quest Project with $120 million between 2012 and 2015 to support FEED activities. Details of funds that have been and will be received up to March 2026 are shown in Table 3.

Under the terms of its agreement with the Government of Alberta, Shell Canada cannot receive government funds in excess of all costs for the life of the project that are offset by the sale of CO_2, the value of carbon credits, and other sources of revenue.

TABLE 3 | GOVERNMENT FUNDING PROVIDED TO THE SHELL QUEST PROJECT FROM JAN 2009 - MAR 2026
[Source: Shell, 2017b]

Government Funding	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**Operating**
				In Canadian Dollars (Actual to 2015)				
Alberta Innovates	3,225,847	1,817,101	1,302,507					
NRCan				108,000,000			12,000,000	
GOA				130,000,000	115,000,000	53,000,000	149,000,000	298,000,000
Total	**3,225,847**	**1,817,101**	**1,302,507**	**238,000,000**	**115,000,000**	**53,000,000**	**161,000,000**	**298,000,000**

Notes: All fiscal years run from April 1 to March 31 with the exception of 2009 which ran from Jan 1, 2009 to March 31, 2010 and 2015 which ran from April 1, 2015 to Sept 30, 2015. The Operating period runs from October 1, 2015 to March 31, 2026 for the purpose of government funding.



EARLY PLANNING FOR SHELL QUEST

Immediately following the 2008 Carbon Capture and Storage Fund announcement by the Government of Alberta (GOA), Shell began seriously contemplating a CCS project in conjunction with its Scotford Upgrader facility **[Shell, 2012a]**. At this early stage, Shell engaged the local and regional public, as well as the regulator, to determine the acceptability of the conceptual project. This early action demonstrated Shell Canada's long-standing reputation as a corporate good citizen in Alberta and Canada, and served the company by assuring a relatively unencumbered process through which it achieved regulatory approval to meet the rigorous schedule imposed by the funding process.

PROJECT OBJECTIVE

The overall objective of the Shell Quest CCS Project was to reduce the GHG footprint of the Scotford oil sands Upgrader by at least 1 million tonnes of CO_2e per year, representing 80% of the average annual emissions from hydrogen production at the facility with an on-stream factor of 90%, and 35% of the CO_2 produced from the Scotford Upgrader. Accordingly, the project was designed to capture a minimum of 1.2 million tonnes of CO_2e per year. The project was well-aligned with Royal Dutch Shell's overall objective to reduce GHG emissions from its global operations and represented the first-ever large-scale GHG reduction project undertaken in the Canadian oil sands industry.

Early in project planning, Shell actively engaged the public to determine acceptability.

TECHNICAL OVERVIEW OF THE SHELL QUEST PROJECT

Shell Canada embarked on the planning and execution of the Quest Project in the midst of an expansion of the upgrader to include a third train, along with an associated hydrogen manufacturing unit (HMU), which added significantly to the overall complexity of ongoing construction work at the site. However, this enabled Shell to reduce construction costs, incorporate process design efficiencies, reduce overall project footprint and attain a higher utilization rate for onsite construction labour.

A major investment was made in Shell Canada's first large-scale commercial CCS Project. While capital costs were originally estimated at $910 million in 2009, tight constraints on capital expenditures achieved through a rigorous risk-based approach to reduction of injection and monitoring wells and a modular construction strategy helped to achieve a final capital cost of $790 million in 2015. The breakdown of costs was the following:

- Overall management and commissioning: 18.7%
- Tie-ins and brownfield work: 4.7%
- CO_2 capture and conditioning: 55.4%
- Well drilling and completions, and MMV installation: 5.1%
- Pipeline engineering and construction: 16.1%

Operating costs for the project are approximately $30-35 million annually. The total estimated cost, including the first 10 years of operation was reported in 2017 as $1.35 billion **[EJ, 2015].**

By comparison, a recent study of the cost of installing CO_2 capture at less complex European oil refineries showed the cost breakdown as follows **[IEAGHG, 2017]:**

- CO_2 capture and conditioning – 30 to 40%
- Utilities production – 45 to 55%
- Interconnections – 10 to 20%

PROJECT ELEMENTS

The project was divided into three distinct, connected elements:

1. Capture, purification and compression;
2. Transportation; and
3. Injection, storage and MMV (measurement, monitoring and verification).

During design, construction and commissioning, each project element was separately managed by different groups within Shell, with an overall Quest manager responsible for oversight and reporting to governments. Shell Canada operated the Shell Quest Project on behalf of its joint-venture (JV) partners as part of its overall operation of the Scotford Upgrader within the upgrading, refining and chemicals Shell Scotford Complex. Shell Canada continues to operate the Quest Project, as well as the Scotford Complex, since the changes in JV ownership of the AOSP that occurred in early 2017.

Accordingly, this report is divided into various sections pertaining to capture, transportation, storage and MMV, and operations. The design and construction scope for the project consisted of the following:

CAPTURE

- Modifications and additions to three existing HMUs to incorporate CO_2 capture
- Modifications to three existing pressure swing adsorbers (PSAs) for CO_2 purification
- A CO_2 vent stack
- A CO_2 compression unit
- A CO_2 dehydration unit
- Utilities and offsite integration

TRANSPORTATION

- Pipeline
- Laterals
- Surface equipment

STORAGE

- Five to eight injection wells
- Installation of MMV equipment and associated monitoring wells

A map indicating the physical location of various elements of the project is shown in Figure 18.

Other significant project activities requiring due consideration in this report include:

REGULATORY APPLICATIONS

The regulatory application process for the Quest project was particularly complicated due to the lack of governing regulation at the time the project was approved for funding in 2009. As a consequence, Shell Canada expended significantly more time in preparing and amending applications, as well as addressing public concerns, than follow-on projects are likely to ever experience.

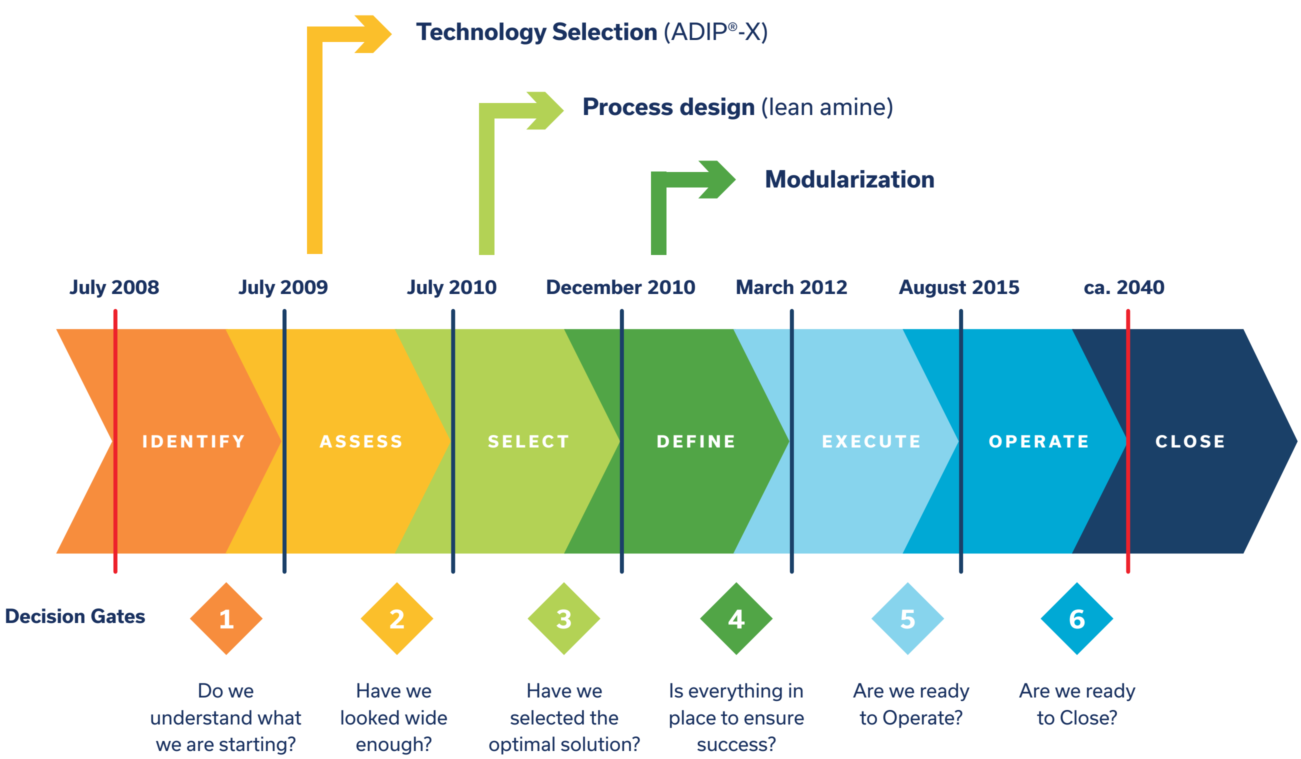
REPORTING TO GOVERNMENTS

As part of its commitment to sharing knowledge gleaned from the project from its inception in 2009 to the end of the funding period in 2025, Shell submits annual reports to the Government of Alberta website covering the engineering and business aspects of the integrated CCS project. This reporting includes design and construction data and drawings. These reports are subsequently made available at the following website: https://open.alberta.ca/dataset?tags=CCS+knowledge+sharing+program. Additionally, Shell Canada is required to submit detailed project expenditure reports in order for milestone payments to be made by the Governments of Alberta and Canada. This type of financial reporting at the federal level is no longer required as of the date of this report since funding by the Government of Canada ended on March 31, 2014.

PROJECT PHASING

The Shell-defined Opportunity Realization Manual Phases to which this report refers are shown in Figure 5, along with the Closure Period that is specific to the Shell Quest Project. The overall Quest Project timeline is shown in Figure 6.

FIGURE 5 | PHASES OF THE SHELL QUEST PROJECT [Sources: Shell, 2011d and CSLF, 2012]



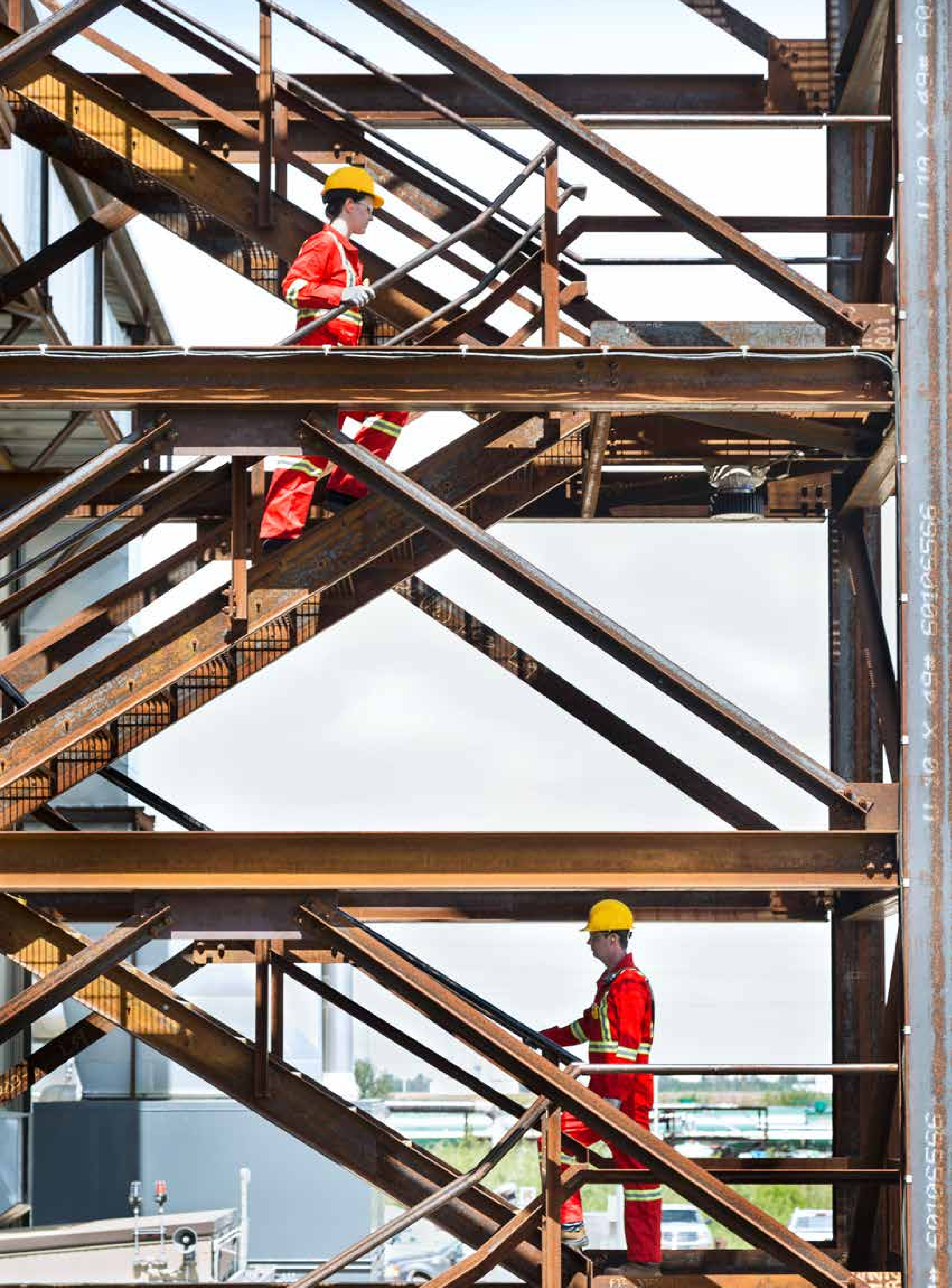
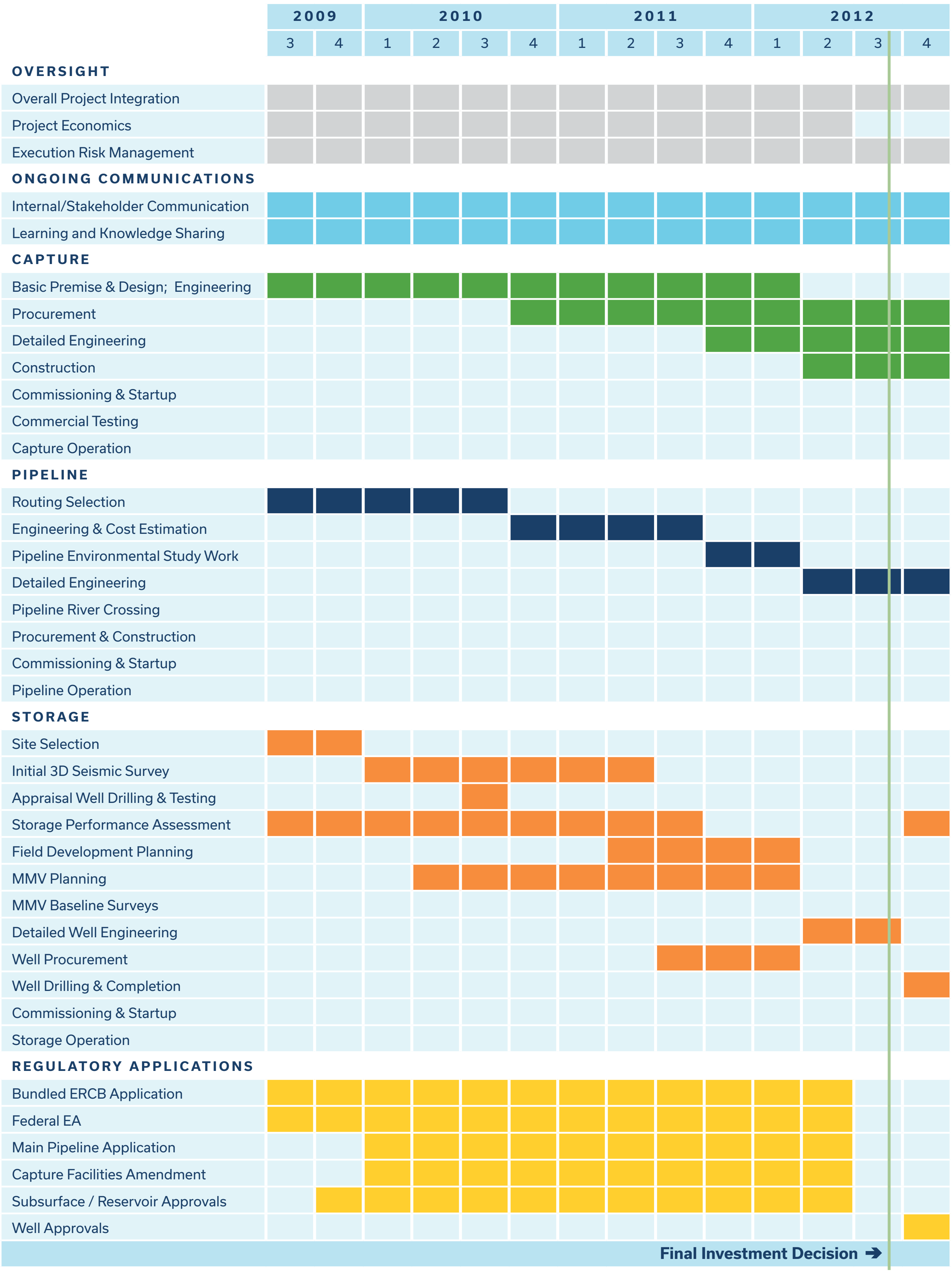
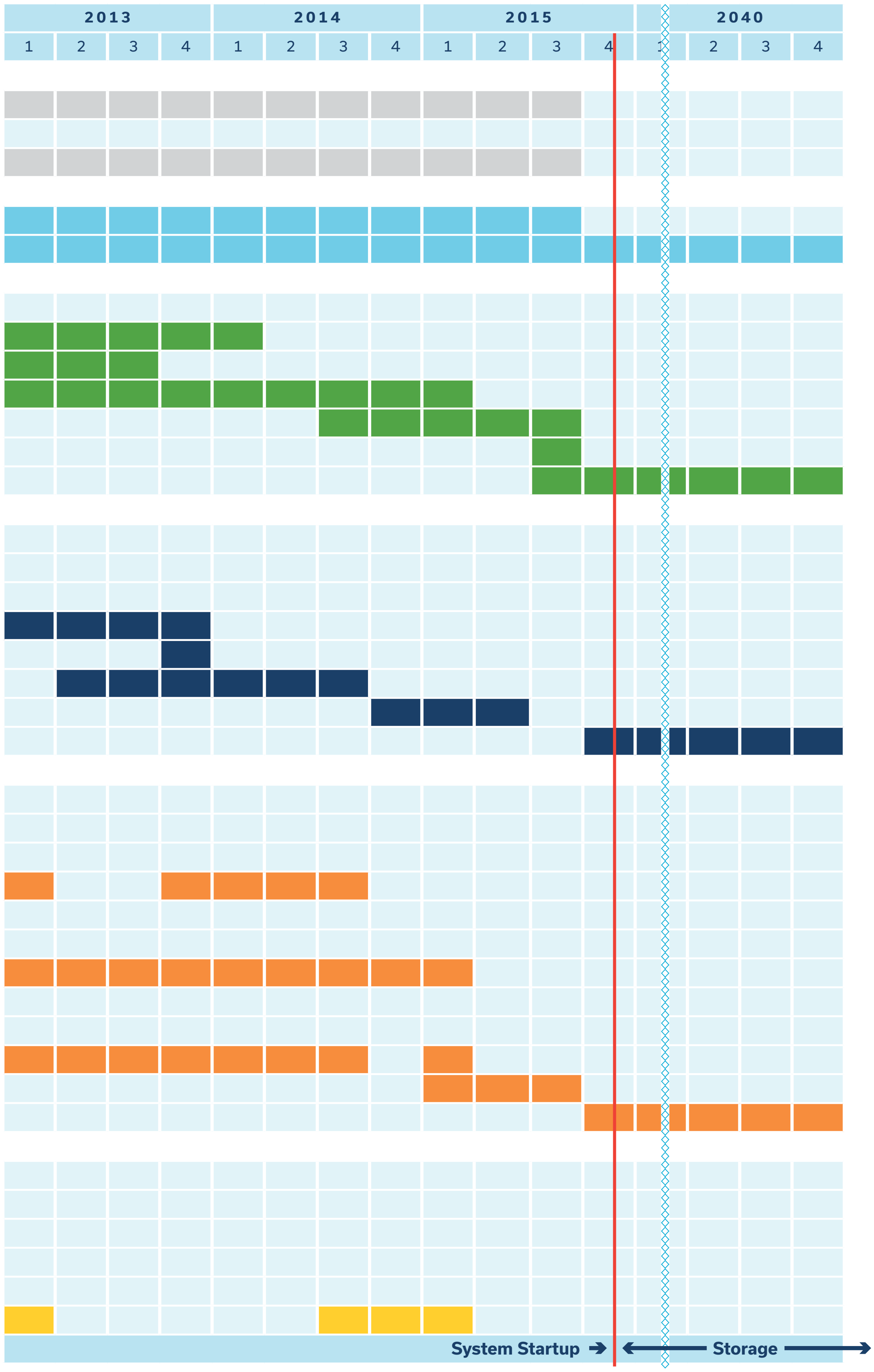


FIGURE 6 | SHELL QUEST PROJECT TIMELINE FROM 2009 TO 2040 [Source: Shell, 2017h]




2013
2014
2015
2040
1 2 3 4 1 2 3 4 1 2 3 4 1 2 3 4
System Startup
Storage

CONTRACTORS

Each project element had a single overall engineering, procurement and construction management entity responsible for delivery of the final, in-the-ground, operating unit.

The overall EPCM for ***capture*** was contracted to Fluor. Various elements of the capture infrastructure design and construction were subcontracted as follows:

1. Honeywell UOP and Krupp Uhde designed modifications to the PSA units for for CO_2 and H_2 purification
2. Bechtel designed utility modifications including: steam, boiler feedwater and condensate
3. Krupp Uhde designed modifications to the feed-gas desulphurization and steam reforming systems
4. Bantrel designed pressure management systems
5. Parsons and Krupp Uhde designed H_2 purification and reformer modifications for HMUs 1 and 2.
6. Fluor designed H_2 purification and reformer modifications for HMU 3 as part of the ongoing HMU design and construction project

Pipeline construction was contracted to TriOcean Engineering Ltd. SCADA systems were contracted to existing standing offers to ensure competitive pricing. Shell Canada managed the construction project, utilizing internal resources.

The ***storage*** site's infrastructure construction project was managed by Shell Upstream Americas' wells group to ensure consistency of HSSE. Existing standing offers were utilized to assure competitive pricing.

Nine contractors and subcontractors were involved in the design and construction of the Shell Quest Project.

CAPTURE TECHNOLOGY: CONCEPTUAL DESIGN

The overriding considerations during the pre-FEED technology selection and design of the carbon capture systems were:

- to ensure minimal disruption of operation of the HMUs and PSAs at the existing upgrader facility, as well as the planned expansion, namely HMU 3,
- to minimize impact on hydrogen production from the HMUs,
- to ensure cost-effectiveness in decision-making and technology selection, and
- to meet the government funding timeline requirements for design and construction **[Shell, 2010a]**.

DEFINING THE CARBON CAPTURE DESIGN REQUIREMENTS

FEED GAS

The feed gas specifications for the carbon capture design at Scotford were finalized by the end of 3Q2008 **[Shell, 2011c]** upon completion of the design for a third HMU on site as part of the upgrader expansion project. Those specifications are shown in Table 4, along with hydrogen and carbon dioxide production rates.

CARBON DIOXIDE GAS PRODUCT

In order to assure effective transportation and storage of the carbon dioxide and minimal hydrogen losses, the following product specifications were required for the selected capture and compression technologies:

- Purity: a minimum of 95 mol% CO_2 (dry)
- Pressure and temperature: 1.45 MPa (a)† and 43°C
- Water content: 102 mg/Nm^3 (6 lb/MMSCF) maximum; no free water
- Hydrocarbons: < 5 vol% with a dew point of less than -43 °C
- Hydrogen: As low as reasonably practicable (ALARP)

†Throughout this report absolute pressure measurements are indicated using "(a)" and gauge pressure measurements are indicated using "(g)".

CAPTURE PROCESS DESIGN PREREQUISITES

The following process specifications were deemed critical to ensure seamless operation of the bitumen upgrading systems while maximizing GHG reduction:

- Carbon dioxide capture of up to 1.2 million tonnes annually, or 80% of the 1.5 million tonnes of total CO_2 generated by the three HMUs.
  - Accordingly, a target was set to capture a minimum 1.08 million tonnes per year which is approximately one third of the GHG emissions from the Scotford Upgrader.
- On-stream factor: 90%
- Pressure drop of the syngas across the capture facility: 70 kPa maximum
- Temperature of the PSA inlet gas: 35°C (unchanged)
- Amine solvent carryover into hydrogen production: less than 1 ppmw (to avoid PSA adsorbent contamination)

The design specification for the capacity of the capture facility for the Scotford Upgrader's HMUs was set at 1 million tonnes per year for a total hydrogen production capacity of 405,000 Nm^3/hr. As a comparison, the combined hydrogen production capacity of the two Air Products' steam methane reformers (SMR) at the Valero Port Arthur refinery is 240,000 Nm3/hr with a demonstrated carbon capture capacity of 0.925 million tonnes of CO_2 annually using Air Products' proprietary vacuum swing adsorption technology. The carbon dioxide at the latter site is utilized at a CO_2-EOR operation at the West Hastings oilfield located near Houston, Texas, USA **[IEAGHG, 2018a]**.

TABLE 4 | SCOTFORD UPGRADER HMU CARBON CAPTURE FEED GAS CHARACTERISTICS

[Source: Shell, 2010a and Shell, 2011c]

Specification	Unit	HMU 1			HMU 2			HMU 3		
Temperature	°C	35			35			35		
Pressure	kPa	3,057			3,057			3,097		
Flow (wt)	tonne/hr	74.6015			74.6015			114.312		
Flow (vol)	Nm^3/hr	159,150			159,150			230,683		
Molecular Wt	g/mol	10.5			10.5			11.1		
Feed Gas (Syngas) Composition										
UNIT		**kg-mol/hr**	**Vol%**	**Vol. Flow (Nm^3/hr)**	**kg-mol/hr**	**Vol%**	**Vol. Flow (Nm^3/hr)**	**kg-mol/hr**	**Vol%**	**Vol. Flow (Nm^3/hr)**
Water		12.8	0.18	286.7	12.8	0.18	286.7	18.6	0.18	414.9
Carbon Dioxide		1,173.3	16.51	26,276	1,173.3	16.51	26,276	1,766.6	17.08	39,402
Carbon Monoxide		171.3	2.41	3,836	171.3	2.41	3,836	302	2.92	6,736
Nitrogen		21.3	0.30	477	21.3	0.30	477	27.9	0.27	622
Hydrogen		5,314.9	74.79	119,027	5,314.9	74.79	119,027	7,486.1	72.38	166,968
Methane		412.9	5.81	9,247	412.9	5.81	9,247	741.6	7.17	16,540
Total		**7,106.5**	**100**	**159,150**	**7,106.5**	**100**	**159,150**	**10,342.8**	**100**	**230,683**

CAPTURE TECHNOLOGY EVALUATION AND SELECTION PROCESS

TECHNOLOGY SELECTION CRITERIA

During 2008-2009, Shell Canada followed a rigorous process to select the best technology that would be readily integrated with the existing upgrader. Several technology options were considered and compared, balancing pros and cons, potential for success and associated risks, and optimization of estimated costs of infrastructure and future ongoing operations. This involved a significant amount of process and cost modeling that was undertaken by the joint Shell-Fluor design team. Selection criteria for the carbon capture technology included the following considerations:

1. *Capital Expenditures (CAPEX)* were minimized and optimized with ongoing operating expenses over the 25+ year lifetime of the capture facilities.

2. *Operating Expenditures (OPEX)* were minimized, while opportunities were sought for synergy with existing upgrader operations in terms of utilities (power and steam) and chemical requirements.

3. *Operability and Reliability* requirements were focused on the impact of carbon capture on HMU operational reliability. Any incremental back pressure on the HMUs was one of the factors used to screen out any capture technologies under consideration.

4. *Footprint* and overall size within each HMU was especially critical for HMUs 1 and 2 given the pre-existing constraints within the upgrader. More flexibility existed to incorporate capture into HMU 3 that was at the design and construction stage during an ongoing expansion of the upgrader at the time of design, engineering and construction of the capture facility.

5. *Commercial* issues focused on whether a technology under consideration had any successful commercial-scale application(s) which would reduce technology deployment risk. Technologies that had only been demonstrated were considered less desirable and technologies under development at pilot or research scales were considered least desirable.

6. A *Constructability* evaluation focused on any known construction issues faced at commercial installations of a technology, including: space requirements, transportation and erection of vessels, and applicability of modularization approaches to minimize on-site construction costs that are typically higher than off-site manufacturing.

7. *HSSE* risks and known issues included odour, toxicity, and fire potential. A broad perspective on health and safety issues was considered in the technology screening process, including local and site-wide impacts.

TECHNOLOGY OPTIONS

Shell Canada, in partnership with Fluor, considered several types of carbon dioxide capture processes **[Shell, 2010a]**, including: chemical absorption, physical absorption, cryogenic and solid bed technologies. A summary of the general positive and negative attributes of these types of carbon capture processes is shown in Table 5.

Chemical absorption processes that were considered focused on amines, specifically Shell Global Solutions' ADIP®-X process, Fluor's Econamine process, and BASF's aMDEA process. Selexol™, and the Shell Global Solutions' methanol cryogenic absorption technologies were considered amongst physical absorption processes. Ammonia absorption and liquefaction cryogenic processes were included in the early technology evaluation process. Solid bed processing technology considerations included Membrane Technology and Research Inc.'s (MTR) and NATCO's membrane gas separation technologies, as well as Linde's Process Swing Adsorption (PSA) process. Each of the carbon capture technologies was considered both upstream and downstream of the pre-existing hydrogen-purification PSAs in each HMU, with the upstream location being determined to be most favourable due to higher gas pressure leading to a more efficient overall process for capturing and purifying both hydrogen and carbon dioxide.

Among the array of technology choices available to Shell Canada, those with more reliable, proven commercial application included ***chemical absorption*** by amine solution and ***physical adsorption*** by solvent. Some global examples of current installations are shown in Table 6.

The cost-savings advantages of chemical solvent absorption processes that were favourable for deployment at the Scotford Upgrader, which would lead to reduced CAPEX and OPEX included: operability at low partial pressure, low circulation rates, high CO_2 loading capability, and high CO_2 production purity. The key disadvantage of amine solvent absorption processes was identified as the high energy intensity of the regeneration of amine. In order to assure cost-effectiveness, amines must be recycled into the absorption process following release of the CO_2 in a stripping process. Nonetheless, amine capture systems were already in use at the Scotford site at the Sulphur Recovery Complex, hence the processes were familiar to the operations team, which was seen as a distinct advantage. The Shell Canada and Fluor team very quickly landed on selection of an amine solvent capture technology, favouring Shell Global Solution's ADIP®-X technology.

Shell Canada very quickly landed on the selection of Shell's own ADIP®-X amine solvent capture technology.

TABLE 5 | COMPARISON OF PERFORMANCE ATTRIBUTES OF VARIOUS CARBON CAPTURE PROCESSES

[Sources: Mumford et. al., 2015; Ji and Zhao, 2017; Baxter and Stitt, 2016; GCCSI, 2009; and **IEAGHG, 2018a]**

Process Type	Capture Mechanism	Pros	Cons	Typical Applications	Examples
Physical Solvent	• Absorption by CO_2 solubility • Henry's Law governs the process	• Ideal for high pressure flue gas, high partial pressure of CO_2 (>1 MPa) • Regeneration via low temperature flashing or pressure reduction • High absorption capacity, lower solvent recirculation rates • Low circulation rates required so higher energy efficiency for high pressure gases	• Lower energy efficiency for low partial pressure of CO_2. • Poor selectivity resulting in lower purity CO_2 product gas • H_2S often absorbed more effectively than CO_2	• Syngas and hydrogen production • Natural gas production • Pre-combustion capture such as IGCC power generation • CO_2-EOR	• Selexol • Rectisol • Morphysorb • Sepasolv-MPE • Fluor Propylene Carbonate • Purisol
Chemical Solvent	• Absorption by chemical reaction between solvents (typically amines) and CO_2 • Process governed by kinetics and thermodynamics	• Selective capture resulting in high purity CO_2 product. • High absorption at low partial pressure of CO_2 and low pressure feed gas	• High energy requirement for regeneration and recirculation of solvent	• High-purity CO_2 end-use such as chemicals manufacture • Dedicated CO_2 geological storage • CO_2-EOR	• BASF aMDEA • Shell ADIP®-X • Shell Sulfinol®-X • Benfield UOP (Potassium Carbonate)

Cryogenic Distillation	• Low temperature distillation effecting separation by liquefaction
	• Process governed by temperature change
		• High selectivity only for instances of widely varied boiling points of gas constituents
		• Simplicity
		• NO_x, SO_x and Hg reduction
			• High energy requirement for refrigeration
			• High operating pressure.
			• High concentration CO_2 streams.
			• High CAPEX
			• Still under development
				• Post-process capture at:
				  • Cement processing facilities
				  • Coal-fired power
				  • Natural gas processing
				  • LNG processing
					• Ammonia
					• Methanol

Physical Adsorption	• Physical adsorption to size-selective molecular sieve pore surfaces • Process governed by pressure change	• Selective capture resulting in high purity CO_2 product • Ability to effect separation and production of a range of gases	• Batch, discontinuous process often requiring complex pressure balancing management system	• Hydrogen production by reforming. • Dedicated CO_2 geological storage • CO_2-EOR • Chemicals manufacture	• Linde PSA • Air Products PSA • Air Products VSA • Praxair PSA For example, see reference **IEAGHG, 2018a**.
Membrane	• Gas separation by differential pressure across a selectively permeable membrane -or- gas absorption followed by liquid desorption • Process governed by diffusion, pore size, partial pressure of CO_2, and pressure differential	• Selective capture resulting in high purity CO_2 product • Continuous process rather than typical batch solvent absorption or physical adsorption processes • Low CAPEX and OPEX • Potential for simplicity with appropriate gas feed	• High gas compression ratios required entailing high power energy usage • Multi-stage process • Most CO_2 capture applications are still in early development except for a handful of natural gas processing installations	• Natural gas processing • Oxy-fuel combustion capture • Syngas and hydrogen production	• Polymeric • Carbon • Palladium • Zeolite • Inorganic

TABLE 6 | OPERATIONAL AND NEAR-TERM, LARGE-SCALE, PHYSICAL AND CHEMICAL-SOLVENT CARBON CAPTURE COMMERCIAL INSTALLATIONS
[Sources: Mumford et. al., 2015; Wang et. al., 2013; De et. al., 2018, Liu, 2014; Greig et. al. 2016; and **GCCSI, 2018]**

Facility	Location	Company	Volume CO_2e (Mt/yr)	CO_2 Source‡	Operation Date	Storage Type§	Solvent Type
Operating as of Mid-2018							
Boundary Dam Power Station	Saskatchewan, Canada	SaskPower	1.0	PCC Power Generation - Lignite Coal (post)	2014	EOR, DSF	Chemical: Shell Cansolv (MEA)
Century Plant	Texas, USA	Occidental Petroleum & Sandridge Energy	8.4	Natural Gas Processing (pre)	2010	EOR	Physical: Selexol™
Coffeyville Gasification Plant	Kansas, USA	Chaparral Energy	1.0	Fertilizer Production (pre)	2013	EOR	Physical: Selexol™
Enid Fertilizer CO_2-EOR Project	Oklahoma, USA	Chaparral Energy & Merit Energy	0.68	Fertilizer Production (pre)	1982	EOR	Chemical: Benfield
Gorgon Natural Gas & LNG Plant	Western Australia	Chevron, Shell, ExxonMobil, Osaka Gas, Tokyo Gas, Chubu Electric Power	3.4-4.0	Natural Gas Processing (pre)	2017	DSF	Chemical: aMDEA
Great Plains Synfuels Plant	North Dakota, USA & Saskatchewan, Canada	Dakota Gasification Company (USA) and Weyburn & Midale Oilfields (Canada)	3.0	IGCC Methane, Ammonia & Chemicals Production utilizing Lignite Coal (pre)	2000	EOR	Physical: Rectisol™
Lost Cabin Gas Plant	Wyoming, USA	ConocoPhillips, Denbury Resources	0.9	Natural Gas Processing (pre)	2013	EOR	Physical: Selexol™
Petra Nova Carbon Capture Project	Texas, USA	NRG Energy, JX Nippon Oil & Gas Exploration	1.4	PCC Power Generation - Sub-Bituminous (post)	2017	EOR	Chemical: MHI, KS-1™
Quest CCS Project	Alberta, Canada	Shell Canada, Chevron Canada, Marathon Oil Canada, Canadian Natural Resources Ltd.	1.08	Hydrogen Production (pre)	2015	DSF	Chemical: Shell ADIP®-X
Shute Creek Gas Processing Plant	Wyoming, USA	ExxonMobil	7.0	Natural Gas Processing (pre)	1986	EOR	Physical: Selexol™
Sleipner Gas Production	North Sea, Norway	Equinor**, ExxonMobil, E&P Norway, Total E&P Norge	0.9	Natural Gas Processing (pre)	1996	DSF	Chemical: MDEA
Snøhvit Gas Production	Barents Sea, Norway	Equinor, Petoro, Total E&P Norge, GDF Suez E&P Norge, RWE DEA Norge	0.7	Natural Gas Processing (pre)	2008	DSF	Chemical: BASF, aMDEA
Terrell Natural Gas Plant	Texas, USA	Occidental Petroleum	1.3	Natural Gas Processing (pre)	1972	EOR	Physical: Selexol™
Uthmaniyah CO_2 EOR Demonstration	Saudi Arabia	Saudi Aramco	0.8	Natural Gas-to-Liquids (pre)	2015	EOR	Physical: Selexol™ (likely)
To Be Operational After Mid-2018							
Alberta Carbon Trunk Line (ACTL) & Fertilizer Facility	Alberta, Canada	Enhance Energy and Agrium	0.3-0.6	Fertilizer Production (pre)	2018	EOR	Chemical: Benfield
Alberta Carbon Trunk Line (ACTL) & Refinery	Alberta, Canada	Enhance Energy and NWRP Sturgeon Refinery	1.2-1.4	IGCC at Heavy Oil Refinery (pre)	2018	EOR	Physical: Rectisol™
Lake Charles Methanol	Louisiana, USA Texas, USA (EOR)	Lake Charles Methanol LLC Denbury Resources	4.2	Methanol and Chemicals Production from Petroleum Coke (pre)	2021	EOR	Physical: Rectisol™
Riley Ridge Gas Plant	Wyoming, USA	Denbury Resources	2.5	Natural Gas and Helium Processing (pre)	2020 (restart)	EOR	Physical: Selexol™ (likely)
Sinopec Shengli Power Plant	China	Sinopec	1.0	Coal-Fired Power Generation (post)	2018	EOR	Chemical: Sinopec, MSA (MEA)
Sinopec Songnan Gas Production	China	Sinopec	0.5	Natural Gas Processing (pre)	2020	EOR	Chemical: MDEA
YanChang Integrated CCS Demonstration	China	Shaanxi YanChang Petroleum Group	0.4	IPCC (pre) and Natural Gas Processing (pre)	2020	EOR	Chemical: Low-Temp Methanol

‡ "post" = post-combustion; "pre" = pre-combustion
§ "EOR" = CO_2-enhanced oil reservoir ; "DSF" = Dedicated geological storage in deep saline aquifer formation
** As of March 16, 2018, Statoil has been renamed Equinor **[SPE, 2018]**.

The appeal of ***physical absorption*** processes to Shell was that regeneration of solvent could be achieved by low temperature flashing with very low levels of steam required thereby placing a lower demand on the utilities provided by the Scotford Upgrader. However, high feed gas partial pressure of CO_2 would have been required which would have had an undesirable impact on HMU reliability. Additionally, CO_2 purity could have been impacted by co-absorption of other components, potentially leading to a storage capacity risk due to the unacceptably high probability of not being able to attain supercritical CO_2 conditions using a lower purity product compared with amine-capture-generated CO_2. Fluor also advised that constructibility issues would arise from use of a physical solvent such as Selexol.

Cryogenic distillation processes considered included Shell Global Solutions' Cryogenic Methanol process. It was deemed both premature in its development stage, too complex to operate, had an undesirably large footprint, and had a higher estimated CAPEX due to the nature of the required equipment. Accordingly, this technology option was eliminated in the screening process.

Shell Canada ultimately select
technology (ADIP®-X) for

Membrane gas separation technologies from MTR and NATCO were evaluated. However, they were considered too immature in development for installation at Scotford. Additionally, it was estimated that the CO_2 product compression factor could be quite high, and would necessitate three times as much power to produce the required supercritical CO_2 product than an amine solvent. Furthermore, it was determined that operation of these capture technologies had the risk of being quite complex. Membrane gas separation technologies were eliminated from consideration.

Pressure swing adsorption (PSA) is an industrially-proven gas separation technology utilizing molecular sieves to separate CO_2 from feed gas **[IEAGHG, 2018a]**. Shell determined that the associated CAPEX and OPEX would be too high for carbon capture using PSA. Additionally, given limited space availability, the increased footprint required for PSA installation, as well as the piping integration complexity with existing facilities, would lead to complex construction issues, particularly in the midst of the upgrader expansion construction project.

ed amine chemical absorption
r carbon dioxide capture.

ADVANCING CAPTURE TECHNOLOGY SELECTION

The most appealing carbon capture technology to Shell Canada was an amine-based chemical absorption technology. Shell Global Solutions' ADIP®-X process was considered in detail for deployment at the Scotford Upgrader for carbon capture, with direct comparisons made between it and all other potential technology choices. Modeling studies were performed to determine which was the most desirable capture technology for the Scotford Upgrader to reduce its capital and operating expenditures yet ensure acceptable: reliability, integration with existing infrastructure, construction and HSSE implications. The results of the technology screening process are shown in Table 7 and clearly indicate that Shell Global Solutions' ADIP®-X was the most preferred technology choice **[Shell, 2010a]**.

TABLE 7 | SCREENING SELECTION CRITERIA FOR CAPTURE TECHNOLOGY [Source: Shell, 2010a]

Technology	CAPEX	OPEX	Reliability	Commercial	Constructability	HSSE
ADIP®-X						
aMDEA						
Selexol™						
Membranes						
PSA						
Chilled Ammonia						
Cyrogenic Methanol						
Liquefaction						

Legend	
Acceptable	
Acceptable With Reservations	
Unacceptable	

Shell Canada had a significant amount of previous experience utilizing the ADIP®-X process at its sour natural gas processing facilities. Furthermore, aMDEA amine-based CO_2 capture processes (either Shell or BASF) had been successfully deployed **[Rackley, 2017]** by Equinor (formerly Statoil) at both the Sleipner and Snøvhit natural gas operations offshore from Norway for CO_2 capture and deep saline aquifer geological storage, with several decades of combined operating experience and shared knowledge with RDS. ADIP®-X was also a serious contender for use at Australia's Gorgon natural gas production and LNG facility for capture and purification of CO_2 for deep saline aquifer geological storage, although ultimately an aMEA process was selected. Industrial applications of ADIP®-X were also similar enough to the Shell Quest Project's CO_2 capture design requirements to support selection of the technology, while recognizing that some modifications based on specific Scotford Upgrader operating conditions, facility design, and capture requirements would be required during engineering and construction. A constraint on this technology selection was the higher operating cost associated with ADIP®-X compared with BASF's aMDEA process. However, Shell Canada had every confidence that working with the Shell Global Solutions team would very quickly help realize a reduction in operating and capital expenditures for the ADIP®-X technology option.

COMPARING CARBON CAPTURE TECHNOLOGIES UTILIZING DIFFERENT MDEA SOLVENTS

Methyl diethanolamine (MDEA) is a stable tertiary amine that has a high CO_2 loading factor, making it a particularly efficient CO_2 capture solvent. However, like all tertiary amines, the absorption rate of CO_2 in an MDEA solution (Equation 1) is lower than desirable due to formation of bicarbonate (X-HCO_3^-) rather than the more efficient carbamate complex (X-$CH_2NO_2^-$). This less than desirable chemistry requires utilization of larger absorption columns, and therefore a higher CAPEX than economically viable, compared with primary amine carbon absorption with solvents such as MEA (monoethanolamine).

This chemical absorption process inefficiency may be overcome by judicious addition of a second amine, such as piperazine (diethylene diamine, or DEDA), which serves as a homogeneous catalyst, or "activating agent", to increase the CO_2 absorption rate in the ADIP®-X process as shown in Equations 2 and 3. Chemical structures for these amines are shown below in Figure 7. The additional amine catalyst facilitates the formation of the desirable carbamate complex, thereby catalyzing the more efficient capture of the CO_2 at a rate up to ten times faster than using the tertiary MDEA by itself **[Wilcox, 2012]**. BASF similarly accelerates MDEA performance in its aMDEA process with judicious addition of an accelerating catalytic component.

Reaction of CO_2 with MDEA (bicarbonate complex formation):

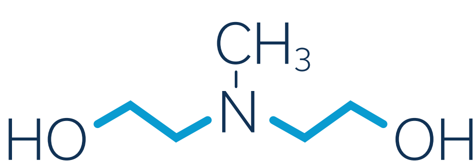
$$CO_2 + (MDEA) + H_2O \xrightarrow{\text{slow}} (MDEA)H^+ + HCO_3^- \qquad [1]$$

Reaction of CO_2 with MDEA and piperazine accelerator (carbamate complex formation):

$$CO_2 + (DEDA) \xrightarrow{\text{very fast}} (DEDA)COO^-H^+ + (MDEA) \overset{\text{fast}}{\longleftrightarrow} (DEDA)COO^- + (MDEA)H^+ \qquad [2]$$

$$(DEDA)COO^- + H_2O \overset{\text{fast}}{\longleftrightarrow} (DEDA) + HCO_3^- \qquad [3]$$

FIGURE 7 | CHEMICAL STRUCTURES AND FORMULAE FOR ADIP®-X AMINE COMPONENTS



Methyl Diethanolamine
$CH_3N(C_2H_4OH)_2$

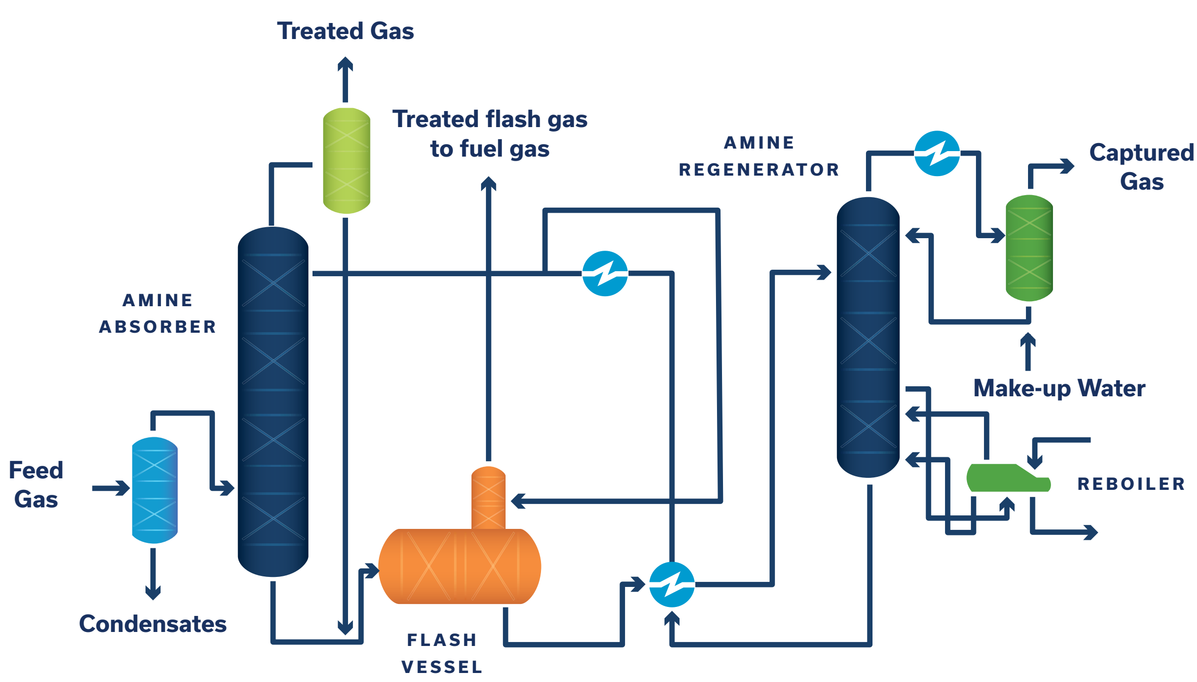
Piperazine
$C_4H_{10}N_2$

It has been demonstrated that the addition of piperazine to a tertiary amine, such as MEA, results in the better CO_2 capture performance in terms of: CO_2 absorption rate, CO_2 cyclic capacity, amine volatility, and thermal stability **[Du and Rochelle, 2016]**.

While the Shell Global Solutions and BASF processes are very similar, there is an important difference in the piperazine concentration between each proprietary amine absorption solution that affects the relative operating costs of the processes. The BASF aMDEA process utilizes a significantly higher piperazine catalyst level in order to achieve a higher CO_2 removal rate. However, Shell Canada deemed that a CO_2 removal rate of 80%, that was achievable with the ADIP®-X process, would be acceptable given that the company had immediate access to technical support from Shell Global Solutions to take advantage of the wealth of in-house operating experience that would facilitate rapid and expert design improvements to drive down operating costs. Recall, the intent was to operate the capture facility for 20-25 years, or longer, so cost-efficient operations were paramount.

Furthermore, the ADIP®-X process would necessitate a smaller absorption tower(s), lower back-pressure on the HMU reformers, and a lower solvent circulation rate, leading to improved energy efficiency and reduced impact on the existing upgrader facility. Accordingly, by late 2010, Shell Canada selected the ADIP®-X process for carbon capture in the Shell Quest Project. The simplified process flow diagram for ADIP®-X is shown in Figure 8 and a schematic of the integrated amine capture and regeneration, and CO_2 compression, dehydration and transportation system is shown in Figure 9.

FIGURE 8 | SHELL GLOBAL SOLUTION'S ADIP®-X PROCESS DIAGRAM [Source: Shell, 2018b]

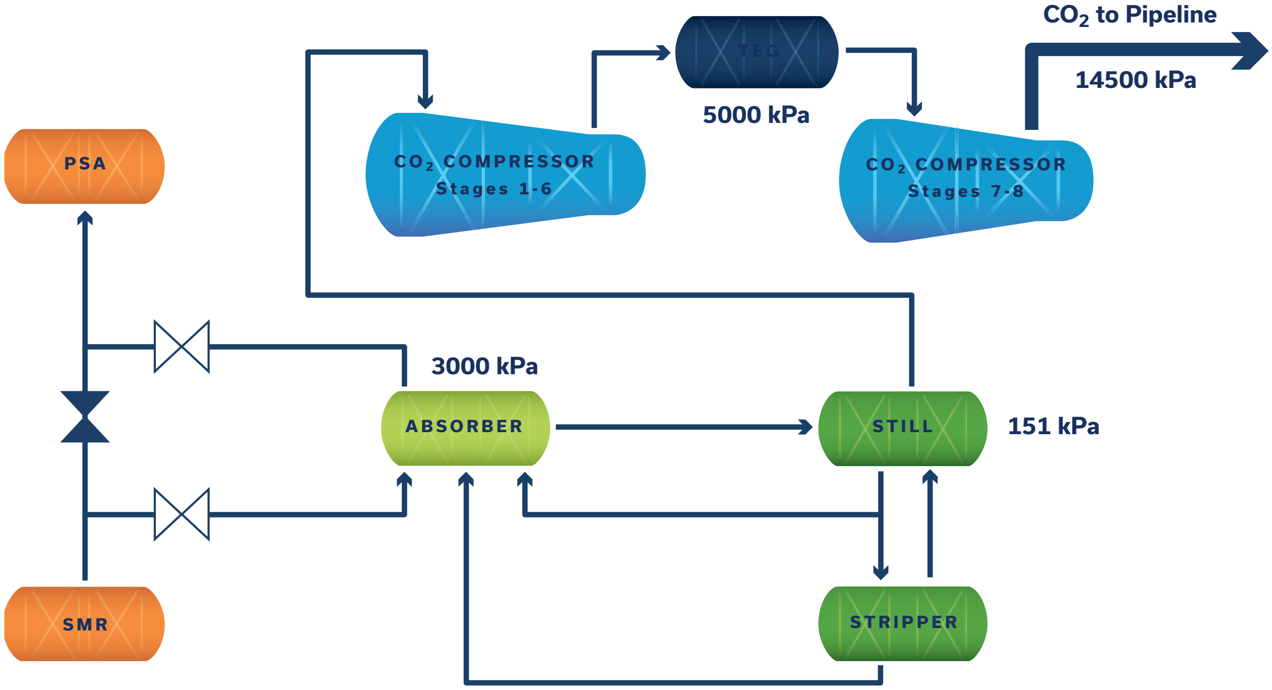


For *Acid Gas Treatment*, **"Treated Gas"** is typically methane or hydrogen and **"Captured Gas"** is H_2S

For *Carbon Capture Applications*, **"Treated Gas"** is either hydrogen or gaseous hydrocarbon (e.g. methane) and **"Captured Gas"** is CO_2

FIGURE 9 | ADIP®-X CAPTURE, COMPRESSION AND TRANSPORTATION SCHEMATIC FOR SHELL QUEST

[Source: Shell, 2012a]



ADVANCEMENT OF SHELL'S ADIP® CAPTURE TECHNOLOGIES

Despite the successful commercial deployment globally of ADIP for more than 60 years and, more recently, ADIP®-X, which was developed in the 2000s, at over 500 industrial facilities for managing H_2S and CO_2 flue gas emissions at natural gas processing and refinery facilities, the ADIP®-X process continues to be improved **[Shell, 2011a]**.

Shell Global Solutions has made significant improvements to the process to assure economically sustainable capture of CO_2 at the Scotford Upgrader, as follows **[Shell, 2017g]**:

- CO_2 removal capacity increased by up to 25%
- Up to 30% reduction in amine regeneration energy
- Up to 30% reduction on equipment costs, leading to improved project net present value (NPV):
    - ▹ Shorter, slimmer columns, absorbers, regenerators and reboilers to reduce mass transfer areas, reduce energy consumption, and assure more robust operation
    - ▹ Improved absorber trays ("Shell Turbo Trays")
- Reduction in circulation rates by utilizing smaller pumps, condensers, heat exchangers and piping to optimize energy efficiency
- Higher gas volumetric throughput
- Ability to handle more challenging gas mixtures

Flue gas conditioning utilizing amine capture solvents has been such a successful business for Shell Global Solutions, that it has continued to develop advanced solvents to better address tightening industrial waste gas management regulations in an economically sustainable manner. Its Sulfinol® technology, that employs a second generation, hybrid amine solvent, was developed in the mid-1960s. The more recent Sulfinol®-M and Sulfinol®-X technologies, developed in 1980 and 2004, respectively, were designed to bring together the advantages of Sulfinol® and ADIP®-X for more efficient acid gas removal through a combination of chemical improvements and equipment simplification that have led to significantly improved project economics **[Shell, 2011b]**. Additionally, Shell Global Solutions acquired Cansolv Technologies Inc. in 2008, adding Cansolv's SO_2 and SO_2/CO_2 amine capture systems to its flue gas management technology solution portfolio. The latter amine capture system was deployed at SaskPower's Boundary Dam Power Station, at one of its 150 MW coal-fired power units **[IEAGHG, 2015]**, to produce 1 million tonnes nameplate capacity annually for nearby CO_2-EOR and deep saline aquifer storage with operation that began in October 2014.

In the case of the ADIP®-X, design improvements for deployment at Scotford necessitated collaboration between Shell Global Solutions and Shell Canada during the period late 2008 to early 2011 in order to make modifications which would enable the incorporation of the following into the basic design package (FEED):

- ***Site-specific feed gas data***, namely composition, conditions, and flow rates for all three HMUs.
- Utilization of spare capacity at the upgrader to provide additional ***low pressure steam*** to the ADIP®-X process, enabling capital cost reductions compared with the original process which was based on minimizing steam consumption.
- Availability of ***fresh cooling water***, rather than following the typical ADIP®-X design that utilizes recycled cooling water enabled a lower lean amine cooling temperature of 30°C, down 5°C from original process design. This enabled a lower solvent circulation rate as well as lower steam consumption for regeneration. Consequently, the air coolers in the original design were replaced with cooling water heat exchangers.
- Reduction in ***absorber column*** height by using 25 Shell Hi Fi trays instead of more conventional column packing material. The original design necessitated loading of the columns with Mellapak 250Y structured packing to increase solvent flow rates.

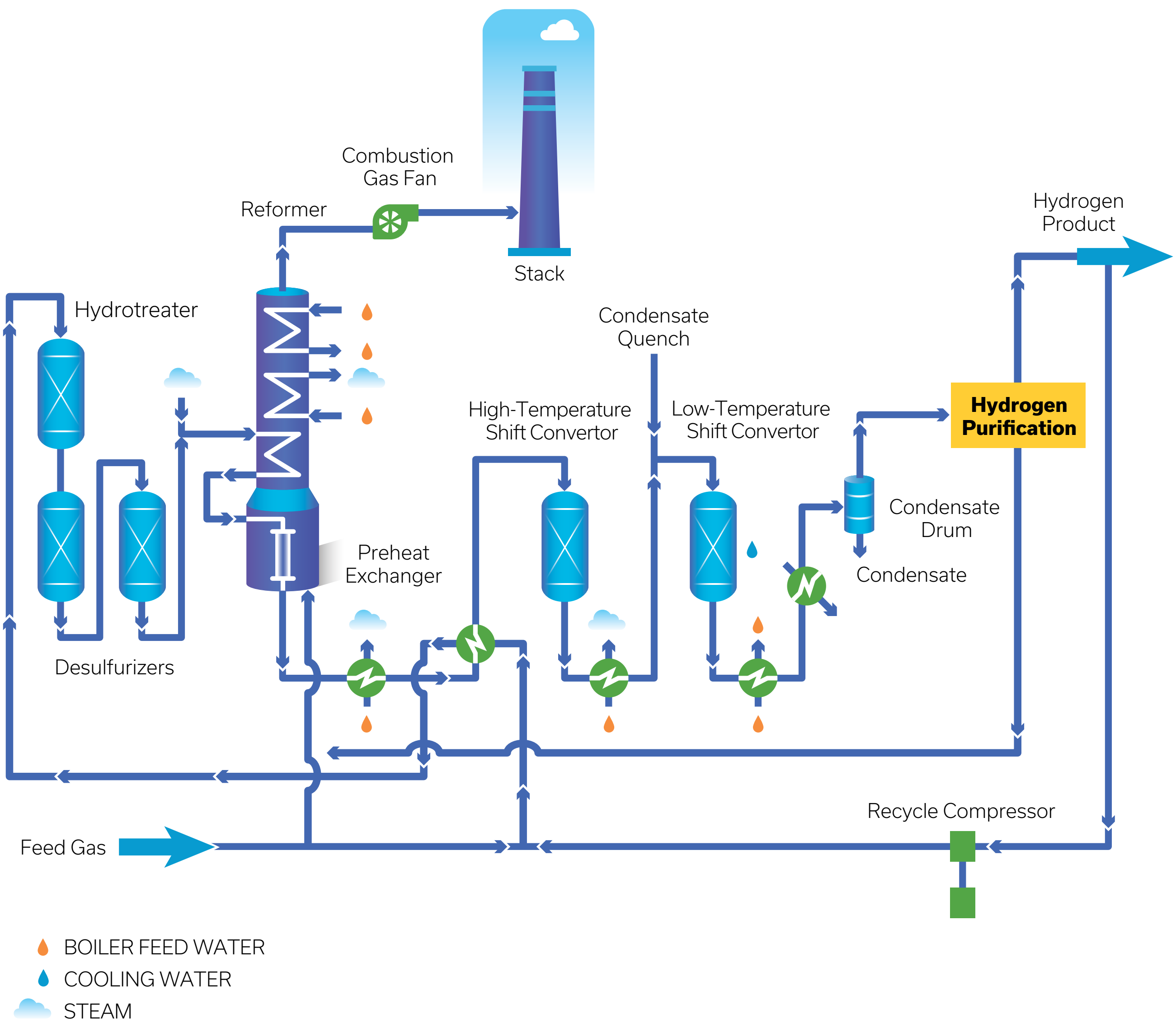
All of these improvements enabled Shell Canada to reduce CAPEX and OPEX for the Shell Quest CO_2 capture facility utilizing ADIP®-X, ensuring that it was the most cost-effective technology solution for this specific application.

IMPACT OF AMINE-SOLVENT CARBON DIOXIDE CAPTURE ON HMU OPERATION

During the pre-FEED design process, a major consideration was the impact of the amine capture process on the operation of the hydrogen manufacturing units (HMUs). These units produce hydrogen by steam reforming of refinery fuel gas. The steam-reforming process has been presented in detail in an earlier report **[IEAGHG, 2018a]**. Essentially, the main impact of removing large volumes of CO_2 from the tail gas of the reformer, due to carbon capture, is a reduction of the mass flowrate of gas fed into the reformer which has the potential to negatively impact reformer operational efficiency by performing outside normal design specifications. The PSA tail gas is recycled into the reformer by mixing it with the feed gas following hydrogen purification ***after*** carbon capture. This recycle process ensures three improvements in the hydrogen manufacturing process:

- capture of any remaining hydrogen,
- reduction of NO_x formation in the reformer furnace, and
- recovery of heat content from the PSA tail gas (see Figure 10).

FIGURE 10 | TYPICAL PROCESS FLOW DIAGRAM FOR STEAM METHANE REFORMING [Source: Eslhout, 2010]



The reduction in flow of CO_2 volumes back into the reformer impacts the design of its burners to address the lower flow rates and associated energy conservation, while continuing to ensure burner efficiency. Additionally, a NO_x-reducing system, such as selective catalytic reduction (SCR) **[Kunz et. al., 2006]** or flue gas recycling (FGR), is required in the reformer flue stack. Shell Canada opted to incorporate FGR into its capture facility.

CARBON DIOXIDE DRYING AND COMPRESSION

Shell Canada initially evaluated a CO_2 liquefaction and pumping scheme for a process using the Joule-Thompson effect based on a conceptual approach developed by Fluor. Due to anticipated higher CAPEX and OPEX, as well as safety and operational familiarity issues, Shell Canada ultimately took the tried-and-proven approach by opting for a more conventional CO_2 compressor. Shell also considered utilizing a molecular sieve dehydration system in conjunction with compression, but ultimately selected a more conventional triethylene (TEG) glycol drying unit that reduced steam demand by four-fold and minimized operational complexity. Both compression and dehydration systems equipped the capture-enabled Shell Quest facility to produce a dry supercritical CO_2 product that met the required pipeline specifications, as noted previously.

The eight-stage, integrally-geared CO_2 compressor with water intercooling selected by Shell Canada was identical to the one selected by SaskPower for its Boundary Dam Unit 3 CCS retrofit **[IEAGHG, 2015]**. It was a unit similar to the compressor that was put into service at the Dakota Gasification Facility in 2000 at the beginning of the Great Plains Synfuels Weyburn-Midale CO_2-EOR project **[IEAGHG WMP, 2012]**, the only exception being that the Dakota Gasification model uses air intercooling rather than water cooling. The selected TEG drying system was in common use throughout the energy industry, with similar units deployed at Boundary Dam and the Air Products' Port Arthur hydrogen production reformers that were retrofitted with CO_2 capture in 2012-2013 **[IEAGHG, 2018a]**. At the Shell Quest capture facility, it was estimated that the TEG carryover into CO_2 production would be approximately 27 ppmw, which was within acceptable limits for pipeline transportation to the injection site.

A conventional, eight-stage, integrally-geared CO_2 compressor with water intercooling was selected.

CAPTURE TECHNOLOGY FEED ACTIVITIES

With the technology selections made by Shell, Fluor, as the capture facility general contractor, undertook the preliminary design for the entire capture facility at the Scotford Upgrader during 2010-2011. During this period, procurement for long-lead items was initiated to advance the construction schedule that would provide for synergies with ongoing upgrader expansion construction, as well as meeting tight government funding timelines.

MODULARIZATION

Early in the preliminary design process, Shell Canada recognized that a straightforward approach to reducing capital expenditures would be modularization of the capture facility. Fluor Third Generation Modular™ design practices **[Fluor, 2018]** were utilized in the preliminary and subsequent designs. This approach split the facility into process blocks. The design was modularized in a manner that drove the plot plan for the facility. This approach had the following key benefits that decreased capital costs and reduced undesirable environmental impacts:

- Compact plant layout through equipment synergy and distributed controls
- Reduced bulk quantities of parts and supplies
- Transfer of labour off-site for construction, thereby leading to lower labour costs and improved quality and efficiency
- Reduced construction time and on-site safety risks.

On-site safety risk reduction was particularly appealing since capture facility construction was undertaken at a time of peak construction activity associated with the Scotford Upgrader expansion project.

The maximum module size in the Fluor design was 7.3 metres wide by 7.6 metres high by 36 metres long. The modules were to be assembled in Alberta and transported by road to the Scotford site. This particular modularization approach did not limit the size of modules to those that were truckable. Instead, components were transported and partially interconnected with mechanical, piping, electrical and control system equipment, then relocated within the complex to avoid complications with normal operations and any other construction activities that were underway there.

The capture facility design was award-winning. Fluor won the 2016 Construction Owners Association of Alberta (COAA) Best Practices Award for the Shell Quest capture facility modularization and construction project.

PRELIMINARY FEED DESIGN CONSIDERATIONS

The CO_2 capture facility was designed as follows, noting mass flow rates and product specifications in Table 8:

CO_2 ABSORPTION:

- An 80% capture rate has been achieved from the feed gas exiting the reformers at 3 HMUs.
- Stainless steel cladding was used to construct the absorber columns and stainless steel piping was used for rich amine service.
- One absorber is located inside each HMU facility for a total of 3 absorbers.
- Two identical absorbers were deployed at HMUs 1 and 2 to handle identical feed gases and volumetric flow rates
- A larger absorber was utilized at HMU 3 which was designed approximately 45% larger than HMUs 1 and 2. A larger-sized absorber was required to handle the higher mass flow rate of tail gas from HMU 3.
- Each absorber was designed with an operating pressure of 3 MPa(g) and was comprised of swaged columns which incorporated 25 Shell Hi Fi trays to improve solvent-gas contact time in order to maximize CO_2 capture rate.
- Low-pressure steam from excess utility capacity at the Upgrader is utilized in the capture processes for heating.
- Feed gas from the reformer inside every HMU is delivered in the bottom third section of each absorber column for treatment with semi-lean amine solution (72% of the amine solvent feed), followed by lean amine (28% of the amine-solvent feed) at the top section of the absorber as gas rises in the absorber column.
- Treated hydrogen-rich gas passes through a water-wash column which prevents solvent carryover and cools the gas before it leaves the HMU for PSA treatment prior to utilization at the upgrader.
- ADIP®-X solvent utilized in the preliminary design modeling is comprised of 35 wt% MDEA, 5 wt% piperazine (DEDA), and 60 wt% water. Total circulating volume is 315 m^3 with make-up, pre-formulated amine available in two dedicated heated storage tanks via pump. This amine supply is maintained under a nitrogen blanket to help minimize degradation.
- Anti-foaming agent has been incorporated for intermittent use in the event of foaming of the amine in the absorber tower due to the presence of particulates and/or amine degradation products. GE BETZ's Max-Amine 70B was selected for this purpose as per ADIP®-X process specifications.
- The capture system design incorporates carbon filtration to remove any degraded amine material from lean amine following stripping prior to recirculation into the absorber columns.

The carbon capture rate at the Scotford upgrader is a minimum of 80%

AMINE REGENERATION:

- CO_2-rich amine from each absorber is sent to a regeneration section to remove the CO_2 through desorption by heating, flash regeneration and stripping processes. A single regenerator (CO_2 stripper) unit is used to generate lean amine for recycling to the absorber columns in the HMUs.
- The amine stripper column includes 20 Shell Hi Fi stripping trays.
- Stainless steel cladding was used in the construction of the top of the stripper column from trays 1-5 (rich amine section that is prone to corrosion from carbonic acid).
- Carbon steel construction and/or steel cladding was used in the construction of the bottom of the column from trays 6-25 (leaner to lean amine sections).
- Heated, rich amine from the three amine absorber columns at 106 °C and 162 kPa(a) (following depressurization upstream from 2572 kPa(a)) is separated into a wet-gas mixture and condensed water through a water-washing, rectifying, refluxing, and stripping process, with CO_2-rich gas being removed at the top of the stripper.
- Low pressure steam from the upgrader is used in the stripper for required heating.
- CO_2-rich gas is sent to the compressor at 36 °C and 144 kPa(a) following refluxing to remove entrained amine solvent.

COMPRESSION:

- An eight-stage integrally-geared CO_2 compressor is used to achieve supercritical conditions for pipelining the CO_2 gas to the injection site.
- Water knockout drums are incorporated between each compression stage.
- Drying is achieved by TEG unit between the 6^{th} and 7^{th} stages of compression.

DEHYDRATION:

- Water content in the CO_2 product gas is reduced to 102 mg H_2O/Nm3 to meet pipeline specifications.
- The TEG drying unit operates at 5 MPa(g).
- CO_2 captured in the TEG absorber is flashed from the water-rich TEG and returned to first-stage compression.
- TEG is regenerated in a stripper reboiler to remove water vapour.

EQUIPMENT FOR CHEMICAL STORAGE:

- Carbon-steel was used in the construction of the MDEA storage tank incorporating a heating coil to prevent freezing at outdoor temperatures colder than -21°C ††.
- A stainless-steel tank is used for DEDA (piperazine) storage.
- A carbon-steel tank is deployed for storage of TEG with a heating coil to prevent freezing at outdoor temperatures colder than -7°C.
- Nitrogen purging is used in all storage tanks to maintain solvent purity specifications.

†† Design temperature for the Scotford Complex is -43°C.

UTILITIES REQUIRED BY CAPTURE, DEHYDRATION AND COMPRESSION FACILITIES

The following on-site utilities are required by the Shell Quest capture facility:

- High-pressure steam for the TEG Stripper
- Low-pressure steam (300 kPa(g)) for the amine stripper
- Low-pressure boiler feed water for the amine stripper reboiler at 350 kPa(g) and 240 °C
- Cooling water at 5°C and 17°C for the absorbers' circulating coolers, amine stripper, and lean amine stream exiting the lean-rich amine heat exchanger
- Make-up water for absorbers 1 and 2 is provided by cooling condensate from the TEG dehydration unit and the amine stripper reboiler
- Make-up water for absorber 3 is provided by cooling condensate from HMU 3
- Total volume of make-up water required is approximately 2.4 m^3/hr
- High-pressure nitrogen for blanketing of amine make-up tanks and purging
- Compressed air for instruments
- Electrical power for rotating equipment
- City water for utilities and safety equipment

Much of the capture facility necessitated installation of stainless steel piping and cladding on vessels to prevent internal and external corrosion from process streams and ambient weather conditions.

TABLE 8 | SCOTFORD UPGRADER HMU CARBON CAPTURE PROCESS CHARACTERISTICS – BASIC DESIGN

[Source: Shell, 2010a and Shell, 2011c]

Feed Gas		**HMU 1**	**HMU 2**	**HMU 3**
Temperature	°C	35	35	35
Pressure	kPa(a)	3,057	3,057	3,097
Total Volumes Processed				
Raw CO_2-Rich Hydrogen Gas to	kg•mol/hr	7,106	7,106	10,343
Absorber	Nm^3/hr	159,150	159,150	230,683
	MM SCFD	142,629	142,629	206,736
Feed Gas CO_2 Flow Rate	kg•mol/hr	1,173	1,173	1,767
	mol%	16.51	16.51	17.00
Absorber Gas Produced				
CO_2 Mass Rate to PSA (raw H_2)	kg•mol/hr	234.7	234.7	353.3
CO_2-Rich Gas to Compressor	Nm^3/hr	79,556		
CO_2 Content in Product Gas	vol%	> 95		
CO_2 Product Gas Pressure	kPa(a)	114		
Hydrocarbons in CO_2-Rich Gas	vol%	< 5		
Gas Entrainment in Lean Amine	vol%	1		
Amine Carryover into CO_2 Product	ppm (wt)	< 1		
CO_2 Compression				
After 6th Stage of Compression	°C			36
	MPa(a)			5
	mg H_20/Nm^3			1,415 (approx)
After TEG Dehydration	mg H_20/Nm^3			102
After 8th Stage of Compression and	°C			43
After Cooler	MPa(a)			8.0 - 14.8
CO_2 Production	tonnes/day			3,564

OVERALL BASIC CAPTURE FACILITY DESIGN

The overall footprint is schematically represented in Figure 11. A detailed process flow diagram for the Shell Quest CO_2 Capture Facility is shown in Figure 12.

By the end of the FEED phase of the project, the estimate for the capital cost of the project was $910 million dollars with construction to be completed and the facility operational by the end of 2Q2015. The estimate for operating costs was $41 million per year. The revenue from the project at the time of start-up of capture and storage was estimated at $30 million per year from the sale of carbon credits.

FIGURE 11 | VISUAL REPRESENTATION OF THE CARBON CAPTURE FACILITIES AS INSTALLED AT THE SCOTFORD UPGRADER. CO_2 IS PRODUCED AT THE HYDROGEN MANUFACTURING UNIT (1), SEPARATED FROM EMISSIONS AT THE AMINE UNIT (2), COMPRESSED (3) AND PIPELINED FOR INJECTION (4) **[Source: CSA, 2017]**

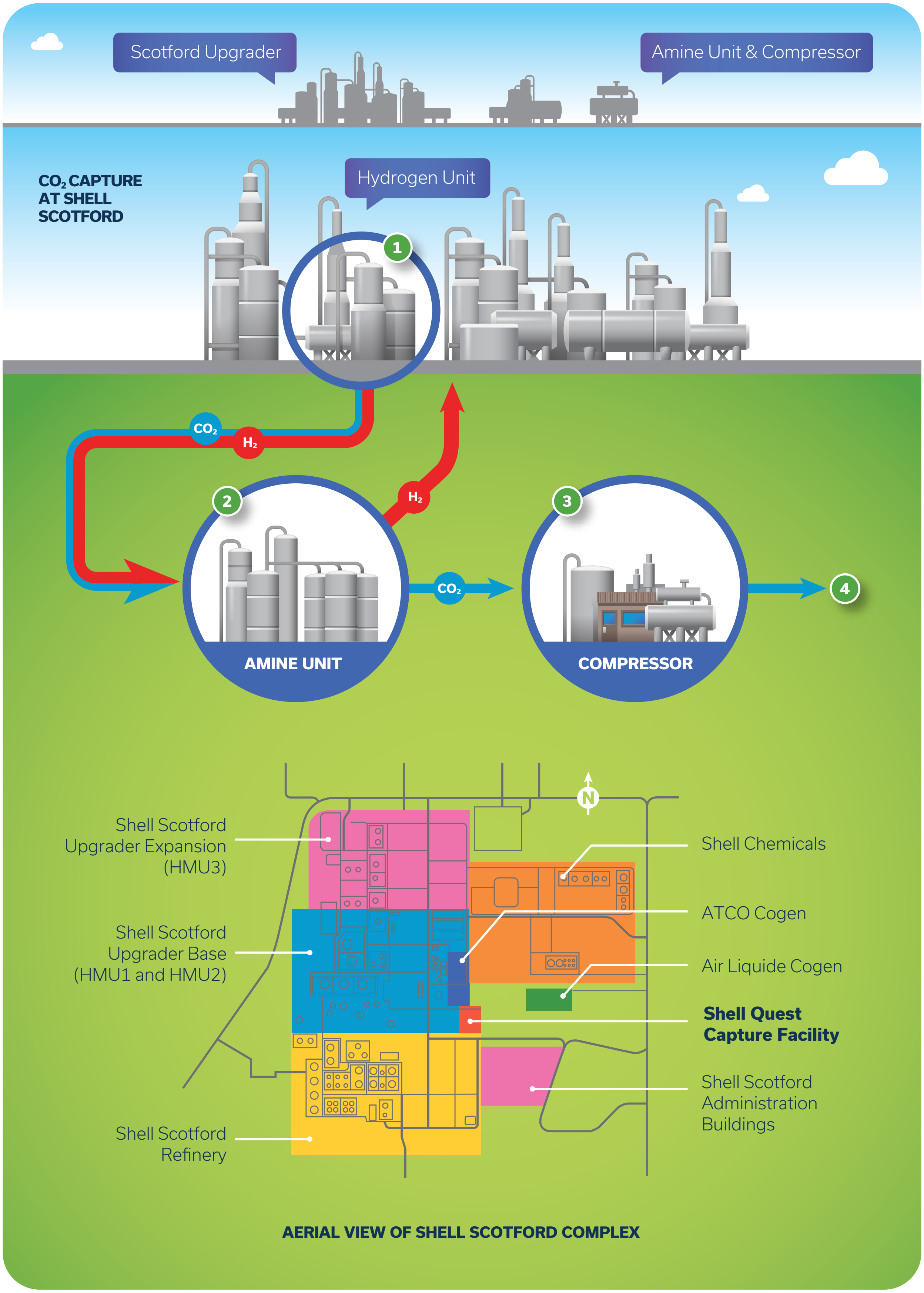
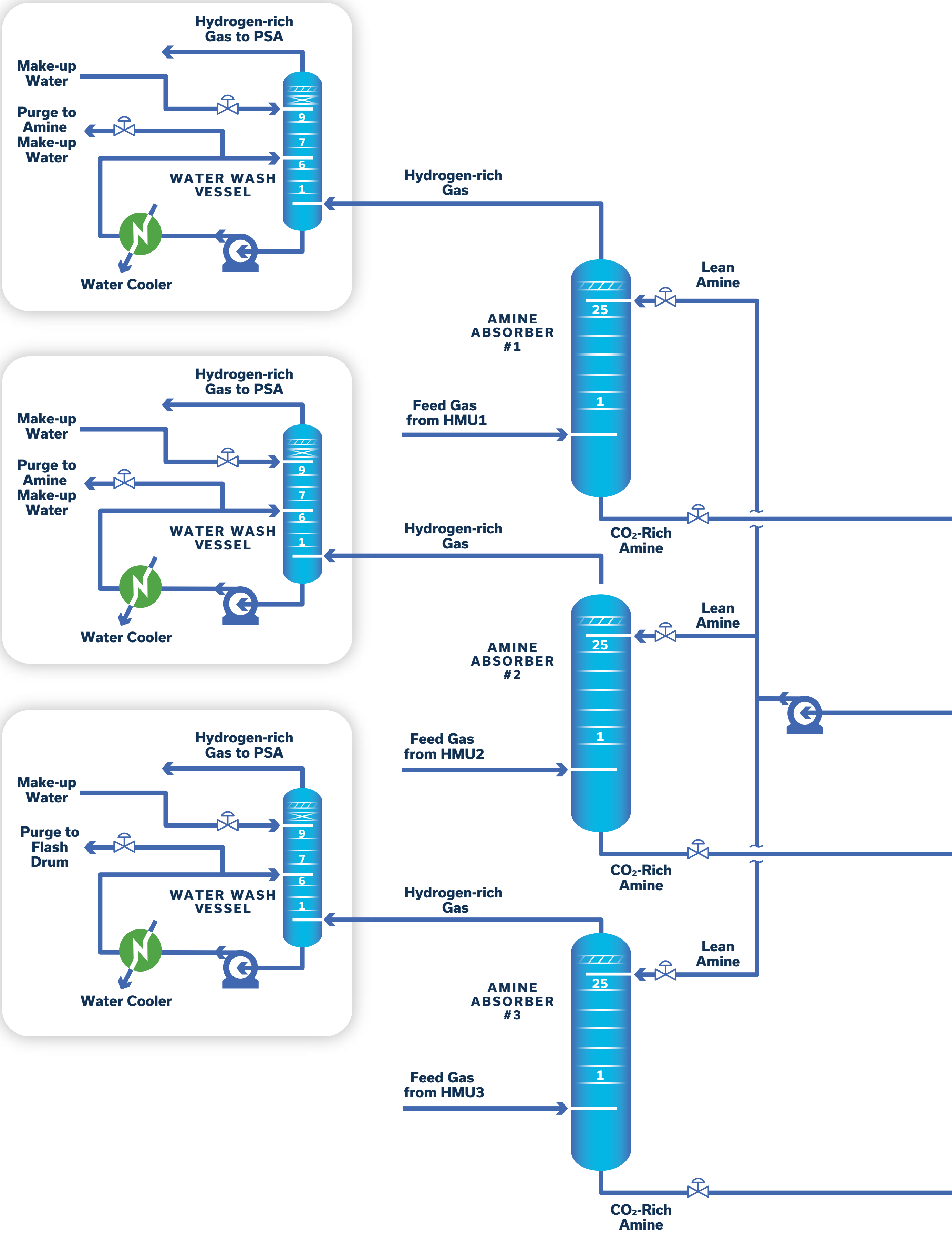
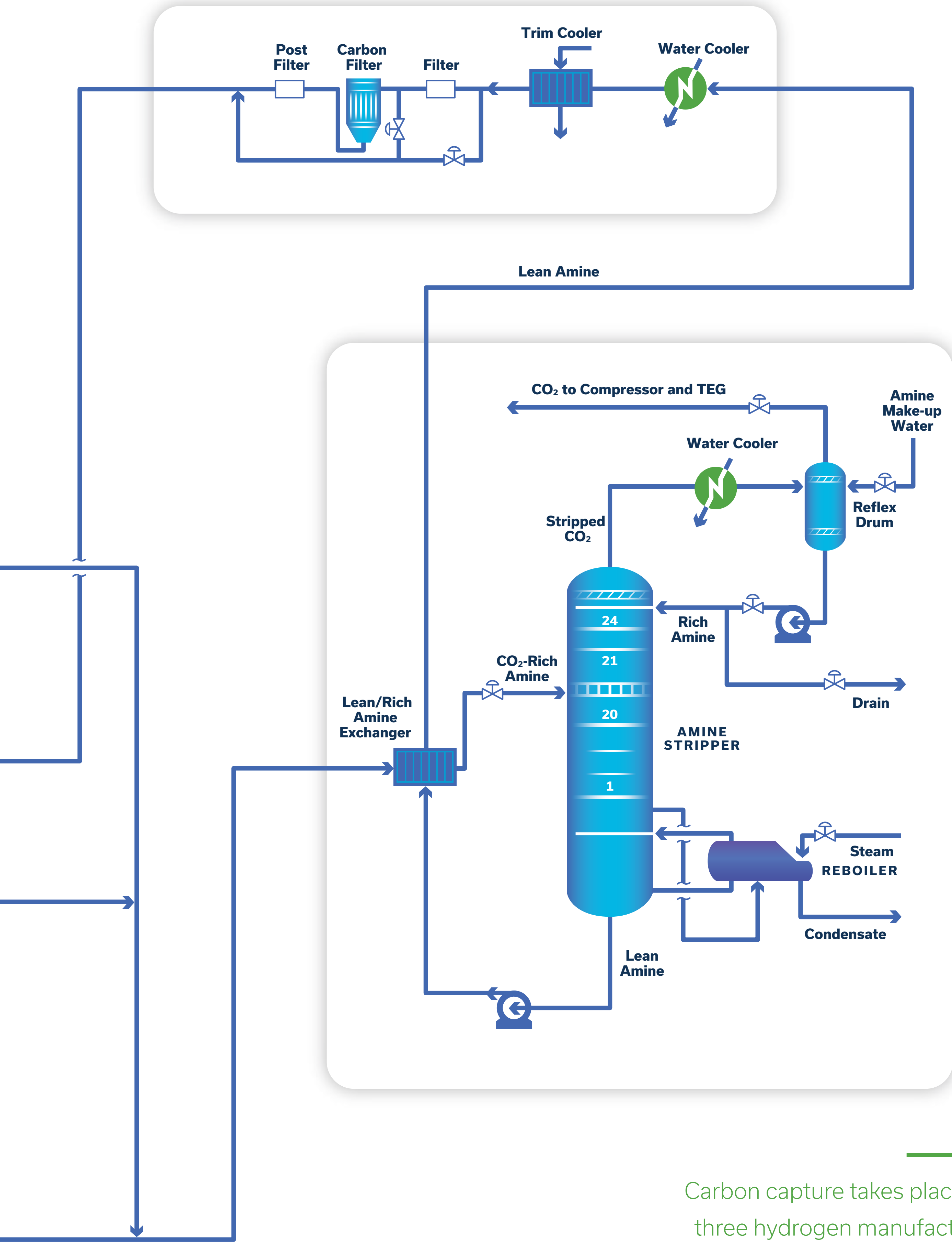


FIGURE 12 | BASIC DESIGN DIAGRAM FOR SHELL QUEST SCOTFORD UPGRADER CO_2 CAPTURE FACILITY [Source: Shell, 2011c]





Carbon capture takes place at three hydrogen manufacture units at the Scotford Upgrader

DETAILED ENGINEERING AND CONSTRUCTION FOR CARBON CAPTURE

The Execute phase of the work (see Figure 5) was initiated in early 2012 in advance of a Final Investment Decision (FID) being taken by the AOSP JV owners in August 2012. This unusual circumstance occurred because the more rapid advance of the Shell Quest Project design work outpaced the enactment of appropriate governing regulations pertaining to CO_2 geological storage and associated public hearings and approval of Shell's application for its CO_2 geological storage site, which were subject to delays.

In the absence of formal FID, Shell undertook some early construction of low-risk, but essential, surface site preparation. Nonetheless, the delay in getting regulatory approval resulted in slippage in the construction schedule by several months. Due to the delay in the timing of the FID, there was a one-quarter delay in the projected start-up and commencement of operation of Shell Quest, slipping from the end of 2Q2015 to the end of 3Q2015 **[Shell, 2013a]**. Furthermore, because of this delay, some construction began in the winter rather than the summer, which led to some construction complexity and an increase in capital cost of the capture facility. However, the capture facility construction schedule did not suffer any further schedule slippage. Major construction work was undertaken from August 2012 to February 2015. The construction schedule is shown in detail in Figure 13, with associated milestones listed in Table 9.

Mechanical completion of the capture facility was achieved on February 10, 2015, including resolution of all construction deficiencies, which was required before commissioning and start-up could begin **[Shell, 2016b]**. All deficiencies not affecting start-up were resolved by February 20, 2015. Turnover of all facilities to operations teams was completed by mid-April 2015.

Details about commissioning, start-up, performance testing, and operation of the capture facility up to the end of 2016 are considered in sections later in this report, along with pipeline and well operations for the same time period.

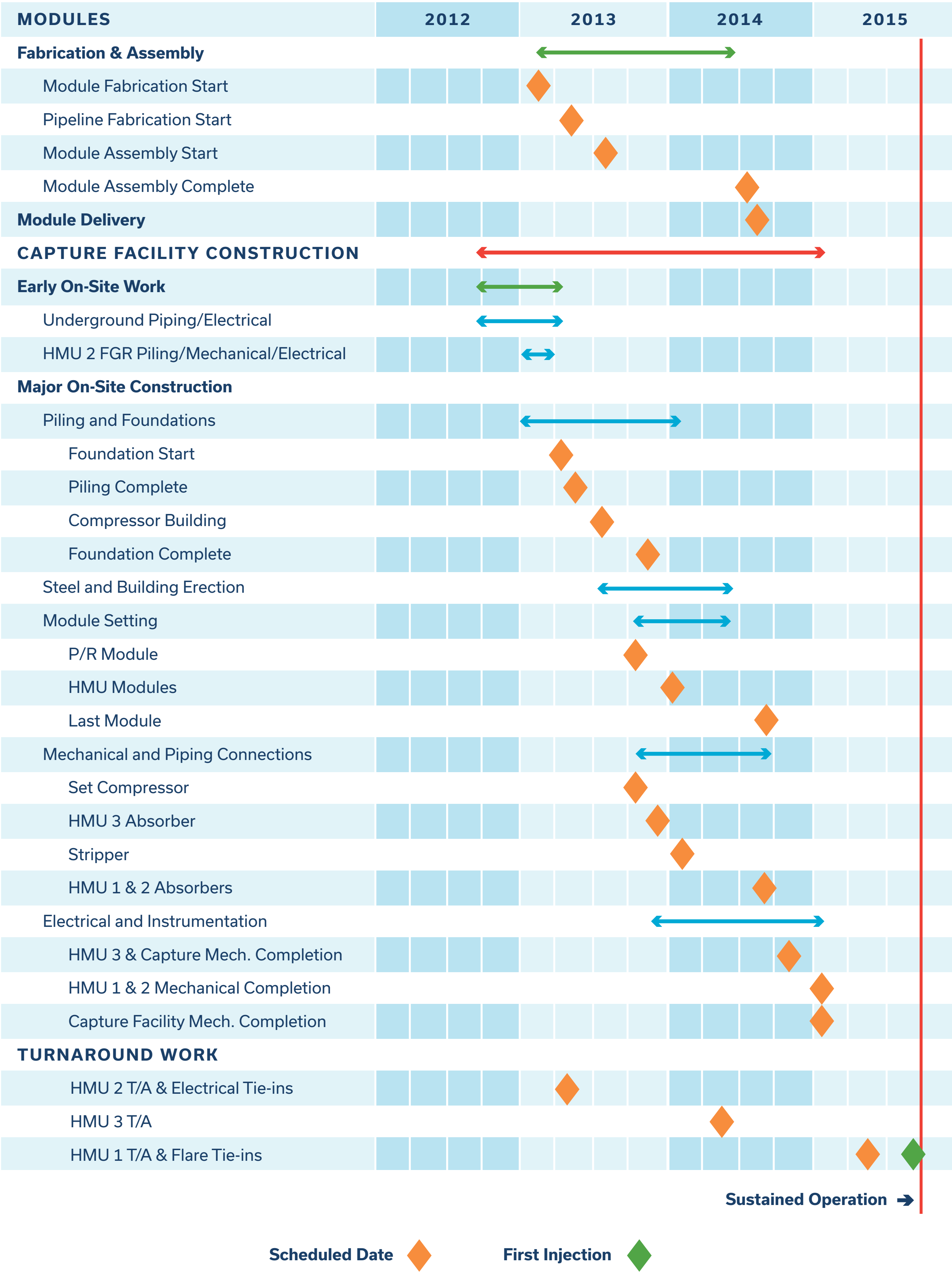
TABLE 9 | SHELL QUEST PROJECT CONSTRUCTION AND STARTUP MILESTONE

	CONSTRUCTION MILESTONE	TIMING			
2012		***Q1***	***Q2***	***Q3***	***Q4***
1	Request for proposal for module construction	■			
2	Early works (amine sump, underground cooling water, firewater, oil water) began				■
3	Drilling of injection wells 2 & 3, and deep MMV and shallow GW wells start				■
2013					
4	Contract for module construction (58 modules) awarded	■			
5	Pipe fabrication and module assembly contract awarded	■			
6	Module construction began	■			
7	Drilling of injection and monitoring wells completed	■			
8	Early works completed		■		
9	Capture on-site construction began with piling and foundation work		■		
10	Flue-gas recycle startup		■		
11	HMU 2 electrical tie-ins completed		■		
12	Delivery of HMU 3 amine absorber tower				
13	Installation of piles, concrete foundations and paving completed				■
14	First capture facility module set				■
15	Delivery of compressor				■
16	Pipeline construction begins with horizontal drilling across N. Sask. River				■
2014					
17	HMU amine modules 1 & 2 set	■			
18	Amine stripper installed	■			
19	HMU 1 & 2 amine absorber towers installed	■			
20	Pipeline main line welding completed	■			
21	Pipeline tie-ins and backfilling completed		■		
22	Installation of FGR[‡‡] at HMU 3		■		
23	New low-NO_x burners installed in HMU 3 steam methane reformer		■		
24	Compressor and motor installed		■		
25	Pipeline hydrotested, cleaned and dried			■	
26	Capture facility pipe and module fabrication completed			■	
27	Last capture facility module delivered to Scotford site and set in place			■	
28	Pipeline line-break valves installed			■	
29	Well site skids fabrication completed and installed			■	
30	All pipeline and well site electrical and instrumentation completed			■	
31	Pipeline preserved with nitrogen			■	
32	Commissioning of installed process units starts				■
33	Capture facility piping interconnections completed				■
34	Initial test of compressor motor				■
2015					
35	HMU 3 mechanical completion	■			
36	HMU 1 & 2 and capture facility mechanical completion	■			
37	FGR tie-ins at HMU 1 & 2 completed, along with low-NO_x SMR burner installations; PSA catalyst changeout		■		
38	HMU 2 SMR startup and testing, followed by HMU 3, then HMU 1			■	
39	Re-startup of entire capture facility			■	
40	Complete system startup and first injection				
41	Commercial testing and sustained operation of entire system				■

[‡‡] Flue Gas Recovery

FIGURE 13 | CAPTURE FACILITY CONSTRUCTION SCHEDULE AND MILESTONES

[Sources: Shell, 2012a; Shell, 2013a; Shell, 2014a; Shell, 2015a and Shell, 2016b]



CO_2 PIPELINE

The timeframe for routing selection through to the end of installation of a purpose-built CO_2 pipeline for the Shell Quest Project ran from mid-2009 to the end of 2014 when the pipeline was tested for integrity. The pipeline was at full capacity by that time but was not operational until the capture facility was completed and began full-time operation in the Fall 2015 **[Shell, 2012a]**.

PIPELINE ROUTING

During the Select phase of the project (see Figure 5), a detailed route selection process was undertaken in consultation with landowners and regulatory agencies. The project team set out to:

- Limit potential for power-line strikes, watercourse and infrastructure crossings;
- As much as possible, use existing pipeline rights-of-way and other existing linear, physical disturbances such as roadways;
- Maximize use of indisposed Crown rights;
- Assess fitness of geology to cross the North Saskatchewan River at a location amenable to horizontal directional drilling;
- Limit the total area of disturbance by limiting pipeline length;
- Avoid protected areas and wetlands and use appropriately-timed windows for construction;
- Align with the proposed Area of Interest (AOI) which was selected to be used for CO_2 geological storage (see Figure 18);
- Where possible and practical, accommodate landowner and governmental concerns;
- Within the Scotford Complex battery limits, incorporate HSE ALARP information that was prepared in partnership with Scotford Operations.

The pipeline was designed to be buried, with a length of 80 kilometres, including 5 laterals to injection wells, 336 crossings (roads, railroads, watercourses, pipelines and utilities) and running through four township counties located east and north of the Scotford Complex. The number of required crossings was determined to be quite high but necessary due to the significant number of industrial facilities and supporting infrastructure in the region. The pipeline follows a route extending east from the complex along existing pipeline rights-of-way through the industrial areas surrounding Fort Saskatchewan, then crosses the North Saskatchewan River north of the town of Bruderheim and continues north along an existing Enbridge pipeline corridor for 10 km before heading northwest to the endpoint injection well (IW) that lies 8 km north of the County of Thorhild. The routing is shown in Figure 18 later in a sub-section that follows entitled, "Site Selection Validation".

CONCEPTUAL AND PRELIMINARY DESIGN

Based on thermal-hydraulic modeling, an insulated, 30.48 cm (12-inch) diameter, 12.7 mm wall thickness, high vapour pressure, stainless steel pipeline was selected for transporting the dense-phase CO_2 from the Shell Quest capture facility at the Scotford Upgrader to the IWs lying to the northeast of the Scotford Complex. Lateral legs from the pipeline to IWs were sized at 15.24 cm (6 inches) in diameter.

As originally designed, the longest lateral runs 3.5 km, the shortest runs 30 m, while the total length of laterals for the full 80-km pipeline runs 12 km. The pipeline design included pigging facilities, line break valves and monitoring and control facilities. The pig launcher was to be located beside the compressor at the capture facility. The pipeline was designed to be buried 1.5 metres deep except at the installation points for above-ground, line-break valves.

BASIS OF DESIGN

The basis for design of the pipeline was an operating pressure of 14.0 MPa at 60 °C [§§] and minimum and maximum operating pressures of 8.0 MPa and 14.79 MPa, respectively, with an ANSI Class 900 mechanical rating. The minimum operating pressure was based upon a need to maintain supercritical conditions for 99% purity CO_2 that was to remain in a single phase and to maximize capacity during all pipeline operations. The maximum operating pressure was based on the highest allowable injection pressure into the Basal Cambrian Sands (BCS) which was limited by its fracture extension pressure and regional geological formations. The pipeline grade material chosen for pipeline construction was determined based on testing at Shell Canada's Calgary Research Centre and comprised pipeline grade steel CSA Z245.1 Grade 386 Cat II with a minimum wall thickness of 12.7 mm, including a corrosion allowance of 1.3 mm, and a minimum toughness of 60 J at -45 °C. The pipeline was designed for a lifespan of 25 years.

The design specifications for the composition of the pipeline fluid are shown in Table 10.

The operating range for the pipeline was required to be 0°C to 43°C to accommodate the higher temperature of the CO_2 at the exit of the Shell Quest capture and compression facility (43°C) to the lowest winter ground temperature surrounding the pipeline (0°C). It was expected that within 20 km of the upgrader, the CO_2 would have cooled to ground temperature. The pipeline was sized to accommodate up to 3.4 Mtonnes of CO_2 per year in the event that capture of additional CO_2 was installed at the Scotford Complex at a future date, in addition to the originally-planned 1.2 Mt/yr volumetric flowrate for the Quest Project. Water content specifications were based on the propensity for hydrate formation in the pipeline, which was to be avoided. Pipeline operating conditions are shown in Table 11. Due to more humid ambient conditions in the summer relative to winter, the dehydration of the captured CO_2 was specified more tightly than design stipulations utilized in more temperate climates.

[§§] Note that critical pressure of CO_2 at 43 °C is 7.4 MPa

TABLE 10 | PIPELINE FLUID COMPOSITION DESIGN SPECIFICATIONS [Source: Shell, 2012a]

CONSTITUENT	NORMAL COMPOSITION	UPSET COMPOSITION
CO_2	99.23 %	95.00 %
H_2	0.65	4.27
CH_4	0.1	0.57
CO	0.02	0.15
N_2	0.00	0.01
H_2O	84-126 ppm	> 126 ppm
Total	**100.00 %**	**100.00 %**

TABLE 11 | QUEST CO_2 PIPELINE OPERATING CONDITIONS [Source: Shell, 2012a]

PARAMETER	UNIT	WINTER CONDITIONS	SUMMER CONDITIONS
Pipeline Inlet Temperature	°C	43	49
Operating Pressure	MPa		
Normal Minimum		8.0	8.0
Normal Minimum		11.0	11.0
Maximum Rating		14.0	14.0
Flowrate	Mt/yr		
Minimum		0.1	0.1
Expected		1.2	1.2
Water Content	ppm	84	126
	MM SCFD	4	6
Ambient Temperature	°C	-40	35
Ground Temperature	°C	0	11
Heat Transfer Coefficient			
Minimum	J/s/m²/°K	1.99	1.99
	BTU/h/ft²/°F	0.35	0.35
Maximum	J/s/m²/°K	5.68	5.68
	BTU/h/ft²/°F	1.0	1.0

SAFEGUARDS

In the pipeline design, line-break valves (LBV) were spaced at least every 15 km following the Standard Class 2 requirements for CSA Z662. They were to be located near secondary roads at points with easy access for operations and maintenance personnel. Due to proximity of populated areas, line-break valves were fenced in for security reasons and encased in weather-protected enclosures. All LBVs are tripped closed in the event a single LBV closes for more than 30 seconds, to minimize a pressure surge across the length of the pipeline. Each LBV is provided with supplemental power to the LBV battery bank by methanol fuel cells **[Shell, 2017h]**. A photo of a line-break valve as installed in the Shell Quest pipeline is shown in Figure 14.

Alarms were installed in the pipeline for off-design conditions of low pressure, high pressure, high water content and low CO_2 purity. Leak detection was designed based on a material balance as described in CSA Z662 Standard, Annex E. Mass flow meters are located at the Scotford Complex boundary limit and the well head utilizing Coriolis-type meters. ATMOS Pipe™, a proven gas pipeline leak detection and location software, was deployed **[Atmos, 2011]**.

Emergency shutdowns of the pipeline are initiated automatically and manually. Automatic shutdown is initiated at pressure transmitter measurements outside acceptable operating limits. Manual initiation of shutdown is initiated at either Scotford or any of the well sites when pressure, temperature, and/or flow transmitters indicate upset conditions.

A Quest Pipeline Integrity Management Plan was developed. Both an external coating and cathodic protection, utilizing an impressed current system for the entire length, as per regulatory requirements, were installed on the pipeline to guard against external corrosion. Due to the design specifications for pipeline operating conditions, no corrosion inhibitor was deemed necessary for prevention of internal corrosion. A smart-pig, in-line inspection tool is deployed at regular intervals at a frequency based on the results of the first inspection that was conducted within a year of operation, along with other surface inspections and ongoing monitoring results to assure pipeline integrity. Additional surface inspections for corrosion include: non-destructive examination by ultrasonic thickness testing on above-ground piping; internal visual examination of open piping and equipment during routine maintenance; and pipeline right-of-way surveillance to detect any ground or soil disturbances. As a further safeguard, corrosion coupons were installed at IW sites to enable visual inspection of the pipeline's corrosion status.

FIGURE 14 | LINE-BREAK VALVE ON THE SHELL QUEST CO_2 PIPELINE [Source: Shell, 2018c]

EXECUTION PHASE OF PIPELINE ENGINEERING AND CONSTRUCTION

The first, 64-km phase of the pipeline was constructed by TriOcean Engineering Ltd., which was selected for the work following an open-bid selection process. Shell Canada managed the construction project utilizing in-house resources. Phase 1 construction was based on the approval of the first three IWs in 2011. Accordingly, only three laterals were constructed. Should additional IWs be necessary in future years, Phase 2 of the pipeline construction would proceed to accommodate 2 additional contingency IWs and Phase 3 of the pipeline construction would proceed at a later date to accommodate 3 additional contingency IWs. By early 2018, no expansion of the pipeline was required. Although unlikely, two additional IWs might be required before the end of the injection period in 2040 which would necessitate extension of the pipeline.

CO_2 INJECTION, STORAGE SITE AND MMV

While maintaining long-standing oil and gas operations in Canada and around the world for over a century, RDS and Shell Canada have also been involved in funding and participating in several globally-significant CCS projects for more than two decades. Consequently, professional staff were well-versed in the requirements for site selection, storage performance assessment, MMV technology selection, storage risk assessment, field development and operation, and GHG accounting and verification. The details of this critical element of the Shell Quest project are considered in this section of the report, along with several unique aspects, and comparisons with other large-scale CO_2 geological storage projects.

SITE SELECTION

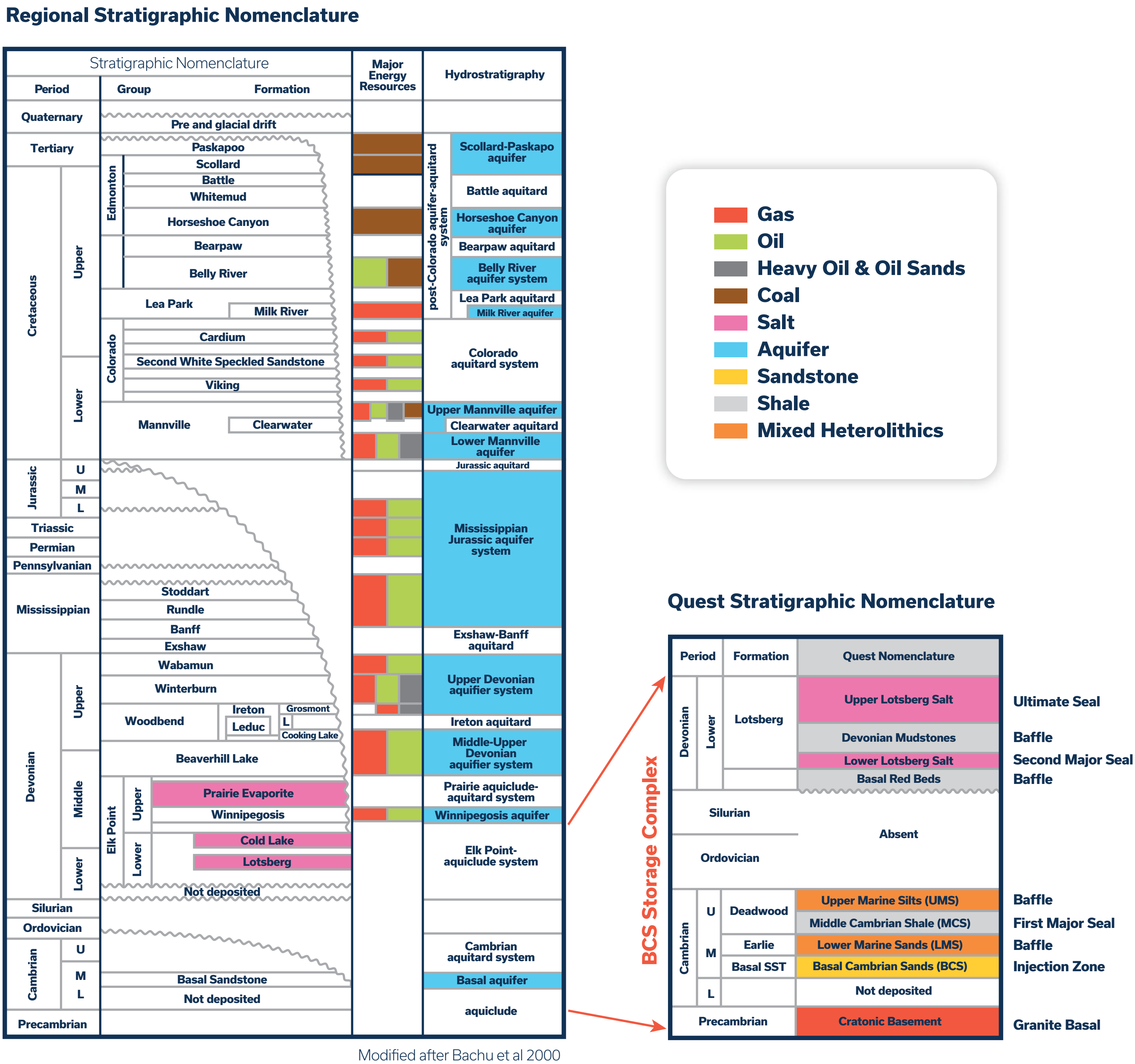
As part of the early planning for Shell Quest, in 1Q2009, two exploration wells were drilled (Redwater 11-32 and Redwater 3-4) to enable characterization of the Basal Cambrian Sands and (BCS) and siting of the injection locations and storage complex. The exploration wells were drilled within 16 km of the Scotford Upgrader. Their characterization included well logging, core sampling, and water injectivity testing, as well as incorporation of vintage data acquired from past and current oil and gas operations, drilling activities (oil and gas, and water supply wells), seismic surveys, etc. These wells showed acceptable CO_2 capacity, injectivity and containment within the "BCS Storage Complex". This evaluation was a key component of the proposal submitted to the Government of Alberta by Shell Canada on behalf of the AOSP JV partners in March 2009 seeking funding under the Alberta Carbon Capture and Storage Funding Program to help offset the high engineering, capital and operating expenses associated with this first-of-a-kind project.

REGIONAL GEOLOGICAL FRAMEWORK

The regional stratigraphy surrounding the Scotford Complex is shown in Figure 15, along with the Area of Interest (AOI) for the Shell Quest Storage Complex. There are three significant confining layers above the BCS Storage Complex including two Cambrian shales overlying the BCS within the storage complex pinch-out towards the northeast, while the higher Lotsberg salt seals thicken in the same direction. The BCS Storage Complex is regionally connected with widespread baffles, contiguous seals of salts (Lotsberg, Cold Lake, and Prairie Evaporite) and a completely sealing overburden. The region is tectonically quiet without any faults that crosscut the sealing layers identified by seismic data. The injection zone is a Basal Sandstone Formation lying unconformably atop the Precambrian granite basement.

Royal Dutch Shell has been involved in major CCS projects globally for more than 20 years.

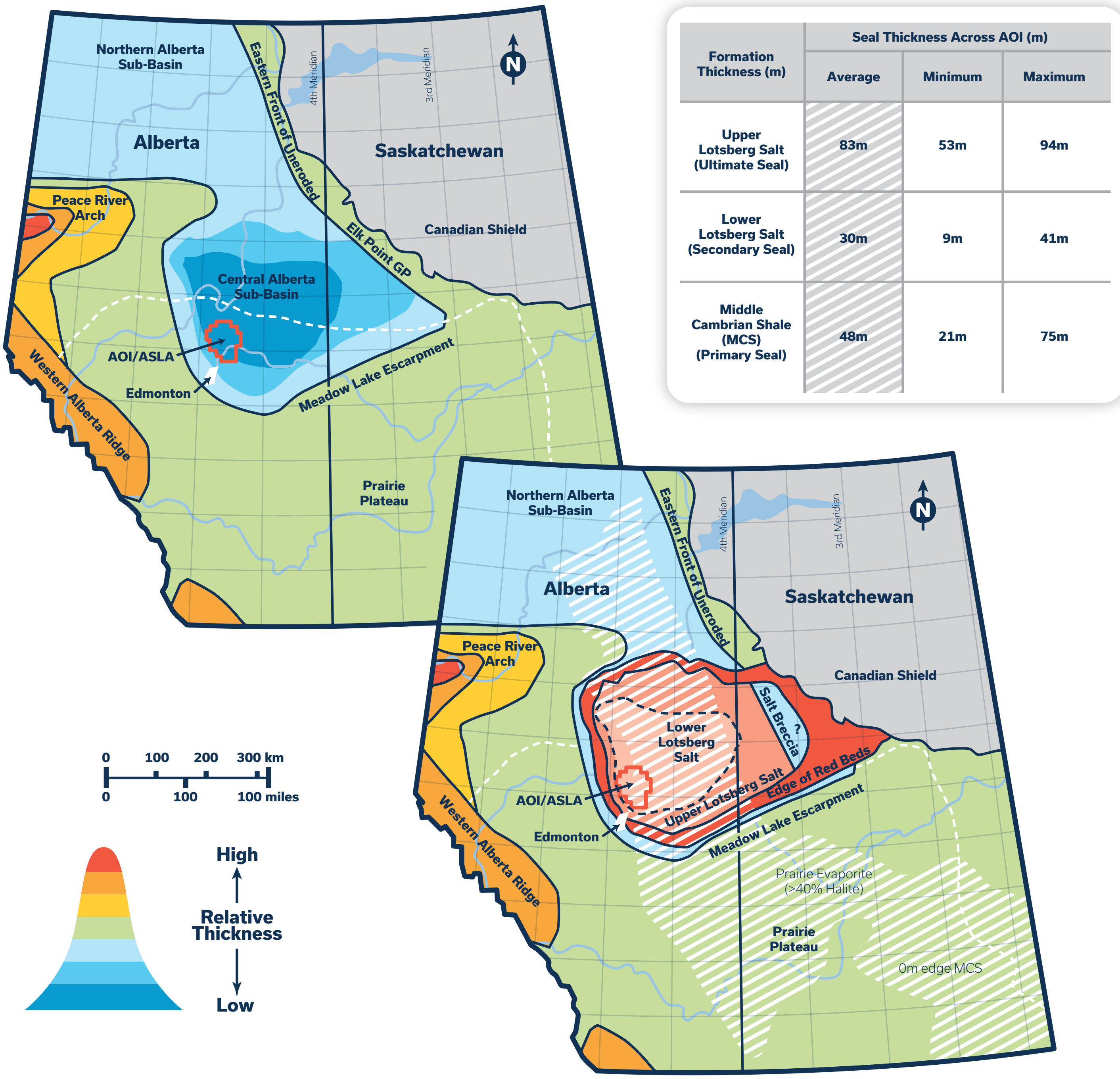
FIGURE 15 | REGIONAL STRATIGRAPHY FOR SHELL QUEST AREA OF INTEREST, INCLUDING THE BASAL CAMBRIAN SANDS STORAGE COMPLEX [Source: Shell, 2011d]



The Basal Cambrian Sands (BCS) consist of fine to coarse-grained sandstones with minor clay to silt-sized intercalations. The formation has a porosity of 17% and a permeability of 1000mD. It is a widespread formation with rare thin-to-absent sections of Precambrian highs that precluded deposition. The BCS sediments were deposited in a shallow marine tide-dominated bay margin (TDBM) environment with coarser sand grains with better reservoir quality at the bottom and finer material at the top. The BCS is approximately 35 to 50 metres in thickness that is deepest at the centre of the AOI, coinciding with the five initially-proposed IWs (see Figure 17 (a) through (d)). It is a saline aquifer without any accumulation of hydrocarbons (oil, gas and coal).

The regional extent of the first three major seals overlying the BCS is shown, along with the Prairie Evaporite, in Figure 16. These regional sealing formations are also shown in Figure 17 (a) through (d).

FIGURE 16 | REGIONAL EXTENT OF THE MIDDLE CAMBRIAN SHALE, THE LOWER AND UPPER LOTSBERG SALTS AND THE PRAIRIE EVAPORITES [Source: Meijer-Drees, 1994]



Formation Thickness (m)	Seal Thickness Across AOI (m)		
	Average	Minimum	Maximum
Upper Lotsberg Salt (Ultimate Seal)	83m	53m	94m
Lower Lotsberg Salt (Secondary Seal)	30m	9m	41m
Middle Cambrian Shale (MCS) (Primary Seal)	48m	21m	75m

FIGURE 17 | THICKNESS MAPS OF MAJOR SEALS OVERLYING THE BCS (SHOWING LEGACY AND INJECTION WELLS IN AOI) [Source: Shell, 2011d]

(a) Basal Cambrian Sands, the storage reservoir

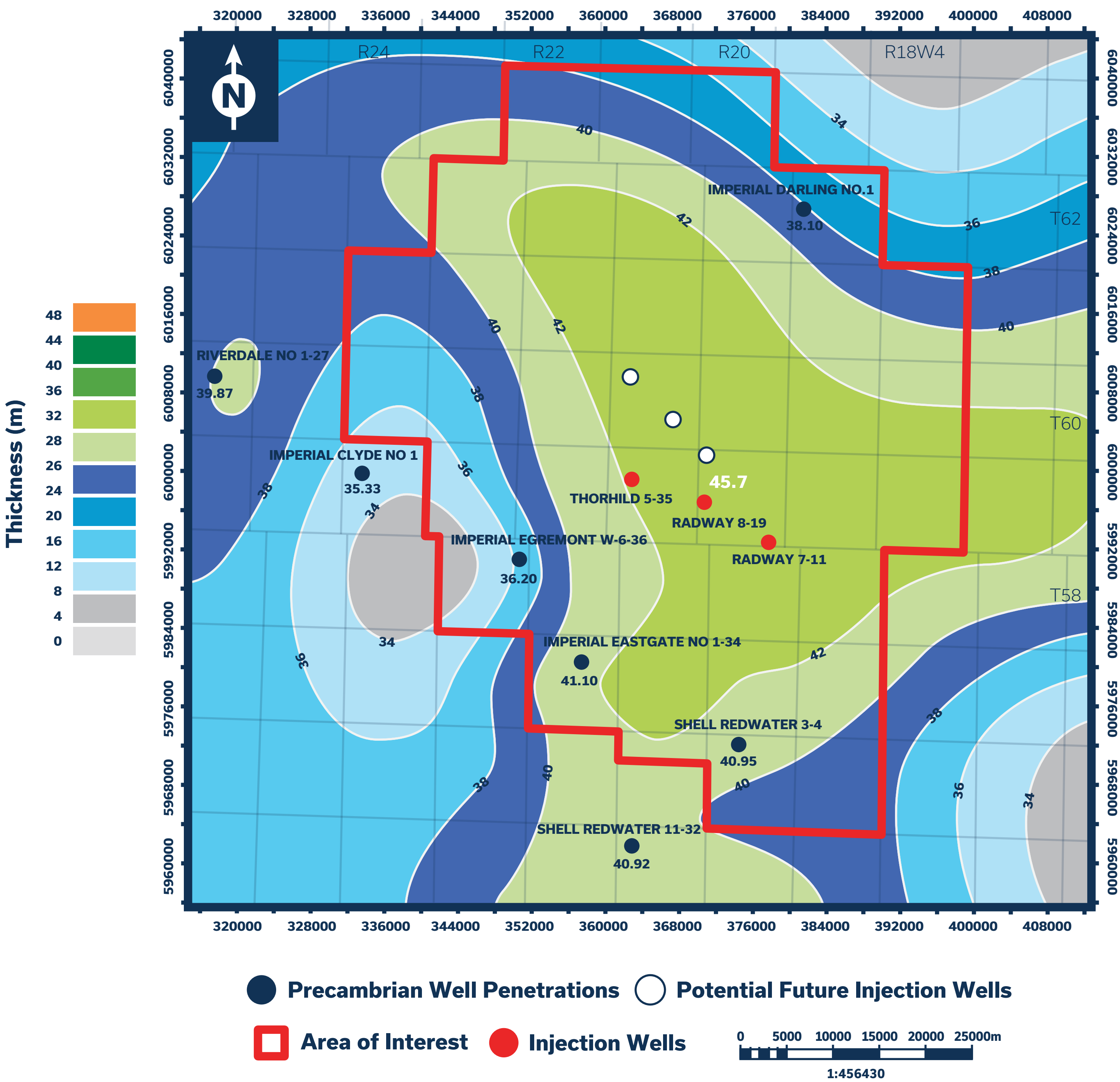


FIGURE 17 | THICKNESS MAPS OF MAJOR SEALS OVERLYING THE BCS (SHOWING LEGACY AND INJECTION WELLS IN AOI) **[Source: Shell, 2011d]**

(b) Middle Cambrian Shale, the first major seal overlying the BCS

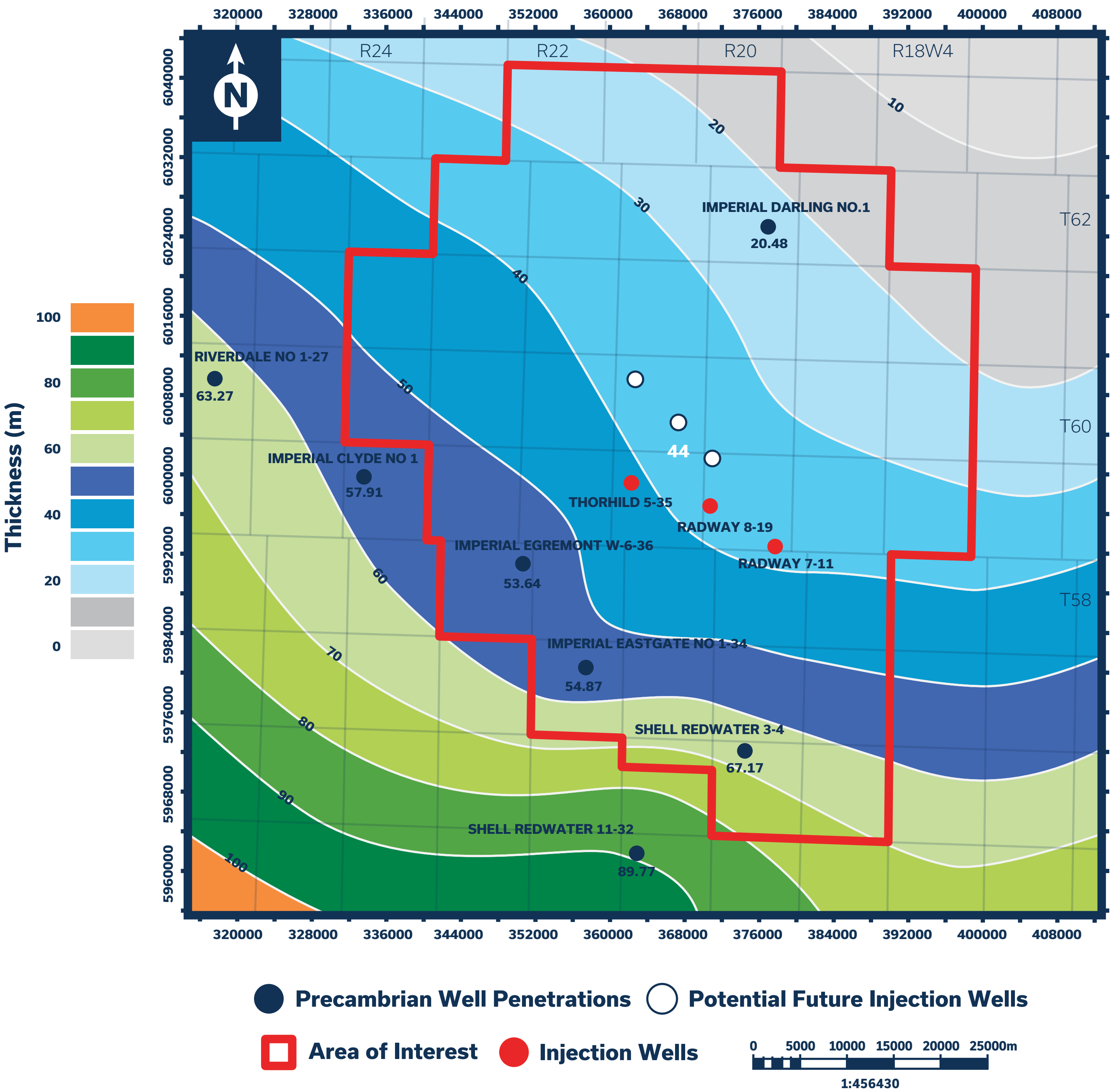


FIGURE 17 | THICKNESS MAPS OF MAJOR SEALS OVERLYING THE BCS (SHOWING LEGACY AND INJECTION WELLS IN AOI) **[Source: Shell, 2011d]**

(c) Lower Lotsberg Salts, the second major seal overlying the BCS

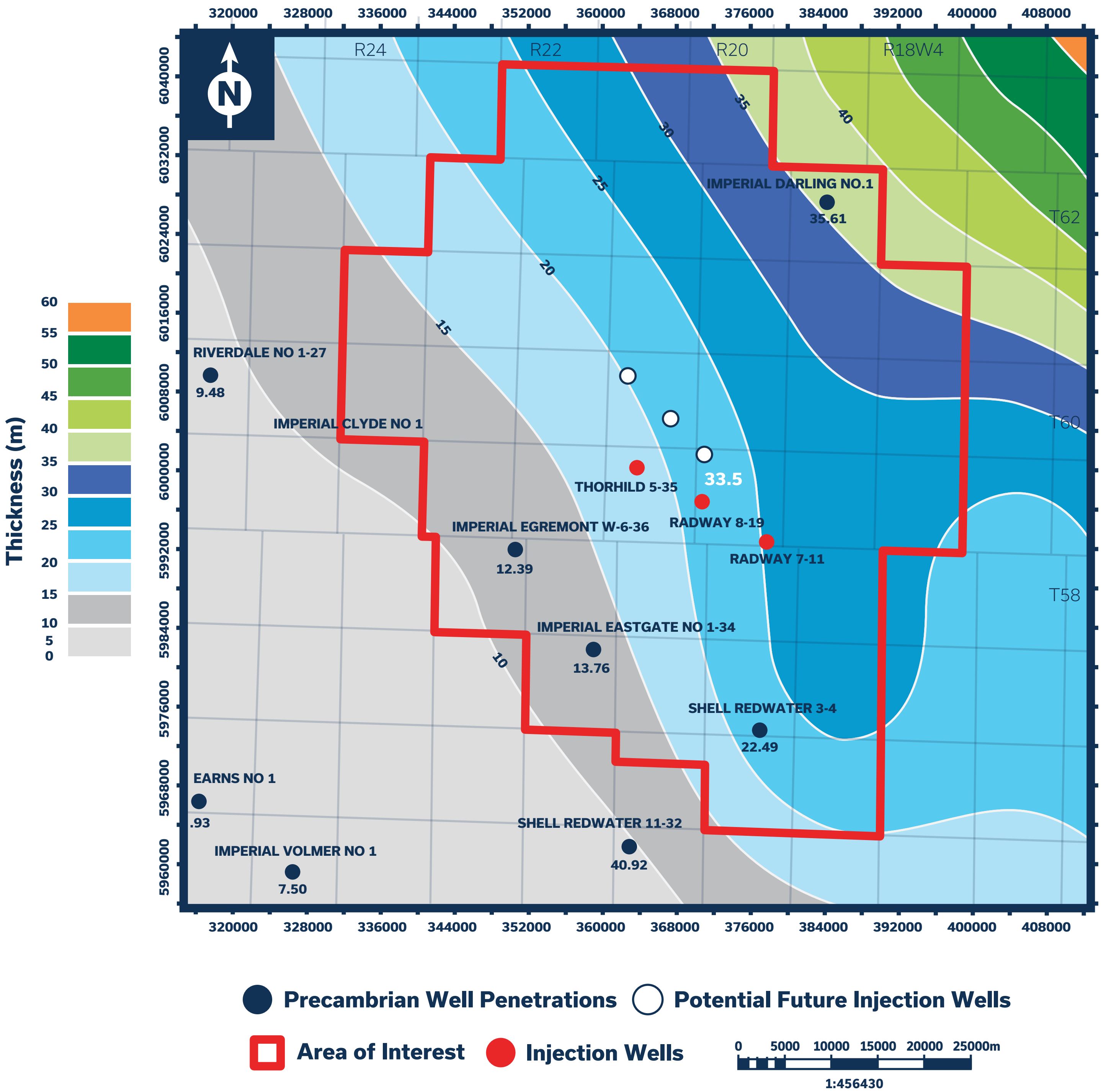
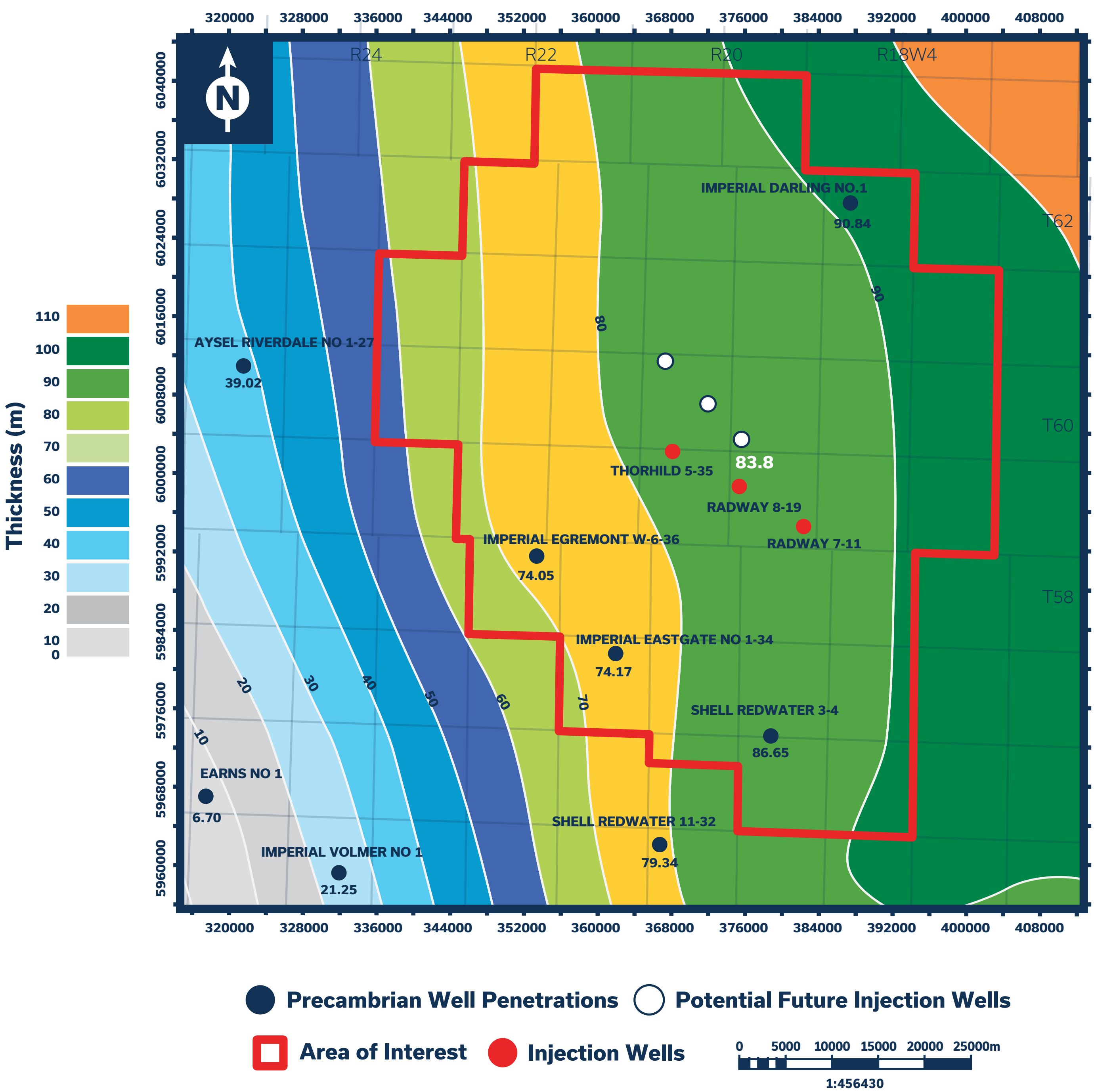


FIGURE 17 | THICKNESS MAPS OF MAJOR SEALS OVERLYING THE BCS (SHOWING LEGACY AND INJECTION WELLS IN AOI) [Source: Shell, 2011d]

(d) Upper Lotsberg Salts, the thirds and ultimate major seal overlying the BCS



SITE SCREENING

During the second half of 2009, Shell Canada undertook a site screening process to identify a preferred storage site. At the time, site selection criteria for CCS projects were in the process of being developed globally, nationally and provincially. Accordingly, it was necessary for Shell Canada to utilize a recommended set of criteria developed by the Alberta Research Council in 2009 **[ARC, 2009]**. These site selection criteria focus on storage safety and security during the injection period. The evaluation specific to the BCS Storage Complex is shown in Table 12. Three alternative areas were assessed before determination of the AOI. The alternative sites included:

- Site A – North of the North Saskatchewan River
- Site B – South of the North Saskatchewan River, 16 km east-southeast of the Scotford Complex
- Site C – North of the North Saskatchewan River, directly west-northwest of the Scotford Complex

Areas southwest of the Scotford Complex were deemed unsuitable due to less coverage by regional geological seals and significant levels of industrial as well as residential infrastructure that could impede MMV activities. Areas east and north of Sites A – C were unacceptable due to the excessive cost that would be incurred to install the dedicated CO_2 pipeline without resulting in any significant risk mitigation implications. The selection criteria used to determine the best of the three sites are shown in Table 13. The most distinctive differentiators among the three sites were determined to be containment, pore space access, cost and growth.

The selected Area of Interest (AOI), which was determined to be Site A, is shown in Figure 18. The areal extent of the AOI was based upon modeling of the boundaries of the brine pressure front after 25 years of injection using an outer pressure contour of ΔP = 890 kPa. In order to ensure control of capital expenditures for CO_2 storage, Shell Canada decided a minimum of three and a maximum of eight IWs would be utilized at the storage site. At the time of selection of the AOI, it should be noted there was no mechanism for granting of a saline aquifer pore space tenure permit*** by the Government of Alberta's (GOA) regulator. An exploration pore space tenure submission was submitted to the GOA in December 2009 to enable further evaluation of the storage site suitability as well as identifying appropriate MMV technologies.

In 2009, it was recognized that the Shell Quest project would be in jeopardy without the appropriate regulatory authority through a Pore Space Tenure permit to ensure unfettered rights to inject CO_2 into the BCS Storage Complex. Accordingly, continued site screening and evaluation supported the application for this permit. In order to successfully navigate the regulatory hearing process and assure public acceptance for the Shell Quest project, landowners were engaged early regarding the proposed CO_2 pipeline routing selection to the IWs located centrally within the AOI. Details of this engagement process are considered in the Public Communications and Outreach section of this report. Furthermore, early 3D seismic acquisition, appraisal drilling and completion of the subsurface evaluation were conducted in order to put into place a CCS Development Plan by early 2012 so that Shell Canada could meet the requirements to support the Final Investment Decision during 2012.

Site selection began in 3Q2009.

***The Carbon Sequestration Tenure Regulation of Alberta came into force in April 2011.

TABLE 12 | ASSESSMENT OF SAFETY AND SECURITY OF CO_2 STORAGE IN THE BCS STORAGE COMPLEX

[Sources: Shell, 2011d and ARC, 2009]

Criterion Level	No.	Criterion	Unfavourable	Preferred or Favourable	BCS Storage Complex
Critical	1	Reservoir-seal pairs; extensive and competent barrier to vertical flow	Poor, discontinuous, faulted and/or breached	Intermediate and excellent; many pairs (multi-layered system)	Three major seals (Middle Cambrian Shale [MCS], Lower Lotsberg and Upper Lotsberg Salts) continuous over entire CO_2 storage AOI. Salt aquicludes thicken up dip to NE.
	2	Pressure regime	Over-pressured pressure gradients > 14 kPa/m	Pressure gradients less than 12 kPa/m	Normally pressured < 12 kPa/m
	3	Monitoring potential	Absent	Present	Present
	4	Affecting protected groundwater quality	Yes	No	No
Essential	5	Seismicity	High	Moderate	Low
	6	Faulting and fracturing intensity	Extensive	Limited to moderate	Limited. No faults penetrating major seal observed on 2D or 3D seismic
	7	Hydrogeology	Short flow systems or compaction flow; Saline aquifers in communication with protected groundwater aquifers	Intermediate and regional-scale flow	Intermediate and regional scale flow-saline aquifer not in communication with groundwater
Desirable	8	Depth	< 750-800 m	> 800 m	> 2000 m
	9	Located within fold belts	Yes	No	No
	10	Adverse diagenesis	Significant	Low	Low
	11	Geothermal regime	Gradients ≥ 35°/*km* and low surface temperature	Gradients < 35°/*km* and low surface temperature	Gradients < 35°/*km* and low surface temperature
	12	Temperature	< 35 °C	≥ 35 °C	60 °C
	13	Pressure	< 7.5 MPa	≥ 7.5 MPa	20.45 MPa
	14	Thickness	< 20 m	≥ 20 m	> 35 m
	15	Porosity	< 10%	≥ 10%	16%
	16	Permeability	< 20 mD	≥ 20 mD	Average over AOI 20 - 500 mD
	17	Caprock thickness	< 10 m	≥ 10 m	Three caprocks MCS 21-75 m L. Lotsberg Salt 9-41 m U. Lotsberg Salt 53-94 m
	18	Well density	High	Low to moderate	Low

TABLE 13 | EVALUATION RESULTS MATRIX FOR SELECTION OF AOI **[Source: Shell, 2011d]**

Criteria	Differentiators	Site A	Site B	Site C	Assessment
Capacity	Highest is better	Suitable	Suitable	Suitable	No differentiation
Injectivity	Highest is better	Suitable	Suitable	Suitable	No differentiation
Containment	Quality of primary seal	Suitable	Less Desirable	Least Suitable	Site A is best
MMV	Minimal is ideal	Suitable	Suitable	Suitable	No differentiation
Pore Space Access	Predominantly owned by the Crown rather than freehold	Suitable	Less Desirable	Least Suitable	Site A is best
Cost	Distance from Scotford Complex	Less Desirable	Suitable	Suitable	Sites B & C are best
Growth	Ability to increase injection rate and total injection volume	Suitable	Suitable	Less Desirable	Site C is best

SITE SELECTION VALIDATION: WELL TESTING AND INITIAL MMV SURVEYS

As noted above, an exploration pore space tenure permit application was submitted to the Government of Alberta in late 2009. The purpose of this permit was to enable detailed site characterization during 2010-2011. Detailed storage site information was required to support regulatory submissions, as well as preparation of a Storage Development Plan and a Measurement, Monitoring and Verification (MMV) Plan. The detailed analysis of the AOI in terms of containment, injectivity and capacity entailed conducting initial MMV surveys and test well drilling and evaluation. A summary of associated work and a map of activities are shown in Table 14 and in Figure 18, respectively. This detailed assessment included determination of CO_2 injection pressure, number of IWs and finalizing the MMV strategy. The MMV strategy was also informed through a thorough risk assessment evaluation process, as outlined in a later sub-section of this report.

SHELL QUEST 3D SEISMIC SURVEY

While assuring detailed characterization of the BCS Storage Complex, a proprietary 3D seismic survey of a portion of the Shell Quest AOI also had the following critical purposes:

1. Validation of the proposed pipeline route by demonstrating the BCS Storage Complex would fulfill its intended purpose and meet expectations.
2. De-risking of placement of wells (appraisal, injection and monitoring) by identifying basement structures and BCS thickness variations.
3. Identification of potential leakage pathways, to support MMV planning.
4. Support for public acceptance of the Shell Quest Project by including the Towns of Radway and Thorhild within the areal extent of the survey.
5. Provision of a baseline survey to provide time-lapse data for future 3D seismic surveys to enable monitoring of CO_2 plume migration as required by the MMV Plan.

415 km^2 of proprietary 3D seismic data were collected that covered the maximum number of IW locations (8 in total) (see Figure 18). Data was acquired in two phases due to weather-related issues and an early Spring arrival in 2010.

FIGURE 18 | SHELL QUEST APPROVED SEQUESTRATION LEASE, OR ASLA (PREVIOUSLY AREA OF INTEREST, AOI), PROJECT INFRASTRUCTURE, AND DATA SURVEY ACQUISITION LOCATIONS

[Source: Shell, 2011d,and Shell, 2013a].

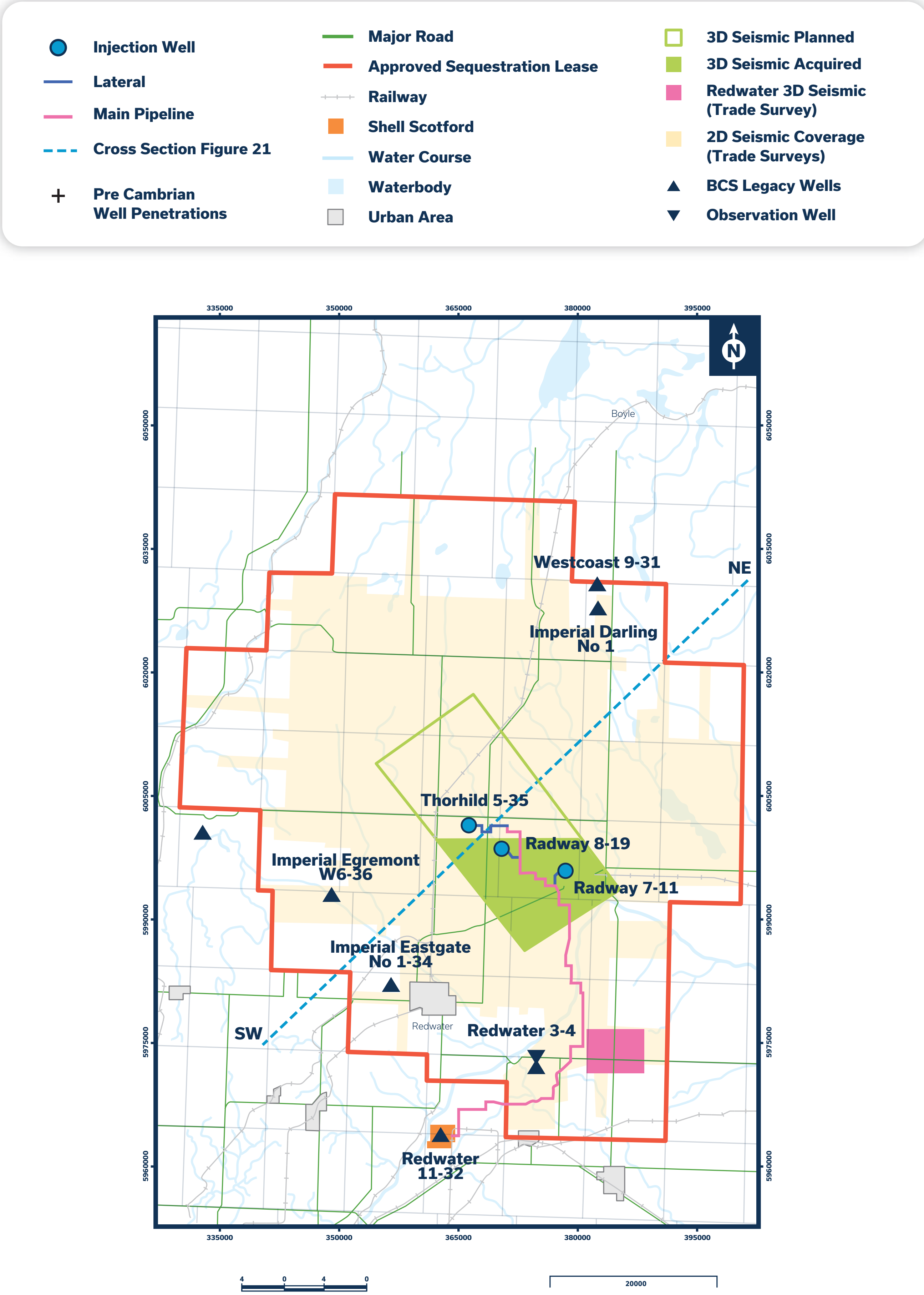


TABLE 14 | INITIAL MMV SURVEYS OF THE SHELL QUEST AOI [Source: Shell, 2011d]

No.	MMV Method	Purpose	Coverage	Resolution	Reliability	Relative Cost
1	High-Resolution Aeromagnetic Survey	• Forecast storage performance • Identify areas for 3D seismic acquisition	8,600 km^2	Lateral: ~ 2 - 3 km Vertical: ~ 1 km	• Potential magnetic anomalies unrelated to faulting • Required independent verification by 2D seismic and well-logging data	Low
2	2D Seismic Surveys	• Lateral extent of seals • Presence of significant faults with associated containment risk • Absence of BCS that might be a barrier to fluid flow • Identify areas for 3D seismic acquisition	55 lines over 3,700 km^2	Lateral: ~ 25 m Vertical: ~ 20 m	• Lack of contiguous areal coverage • Uncertainties regarding smaller-scale geological structures • Uncertainty regarding storage performance assessment	Medium
3	3D Seismic Surveys	• Identification of small faults in BCS storage complex • Trade surveys aided in assessing where proprietary surveys were required to reduce uncertainty	415 km^2	Lateral: ~ 25 m Vertical: ~ 10 m	• Trade surveys may have contained sparse data that were insufficient to fully characterize the BCS storage complex and associated faulting • Proprietary 3D surveys were ideal for assuring containment and injectivity	High
4	Appraisal Wells	• Support site selection and exploration tenure (2009) • Potential for conversion to CO_2 injector well(s)	3 locations	Lateral: n/a Vertical: ~ 1 m	• Sufficient to support exploration tenure permitting (2009)	High
5	Water Injection Tests	• Ascertain lower bound for CO_2 injectivity • Provide a firmer estimate of the number of CO_2 injectors required • Testing for flow barriers caused by small faults at the base of the BCS	< 1 km^2	n/a	• Number of injectors determined would require future confirmation of injection testing at first two CO_2 injectors • Data quality issues prevented determination of any flow barriers • Water quality issues led to wellbore damage	High

SITE PERFORMANCE ASSESSMENT

INITIAL SITE PERFORMANCE ASSESSMENT

Risk Assessment Process

Bow Tie Analysis was used to assess the barriers to reducing containment risk to ALARP in order to facilitate the development of a risk-based, site-specific MMV Plan. A Bow Tie Analysis process is typically used to analyze and document risk. It was developed by RDS in the 1970s and is commonly used by professionals in medicine, in financial and insurance institutions, and in the oil and gas, mining, and pharmaceutical industries to explore and communicate risk. It is a simple concept with a very comprehensive approach. Unwanted events (threats), consequences, and preventative and corrective safeguards (controls) and their interrelationships are explored in order to develop a risk management plan.

The Shell Quest risk management planning team considered passive and active safeguards in their Bow Tie Analysis. The former consisted of geological and engineered barriers, while the latter comprised an engineered safeguard that would be brought into service when triggered by an upset condition. An engineered safeguard would consist of a sensor use to detect change, decision logic to interpret the sensor data and a control response that would intervene in the case of undesirable change. A simple example of an event that would lead to the activation of an engineered safeguard would be a process vessel temperature gauge measurement in excess of maximum operating temperature that would lead to the heat source being turned off by a process control system.

The initial site performance assessment began in 3Q2010 to support the field development and MMV planning for the Quest storage site. The Bow Tie Analysis for containment risk focused on the threats and consequences of a loss of containment of CO_2 and/or brine from the BCS Storage Complex. The corrective controls and control response options for the Shell Quest Project containment risk that were considered are shown in Table 15. The associated Bow Tie diagram is shown in Figure 19.

Storage Capacity

Another significant consideration during the site performance assessment was ***capacity*** of the storage reservoir. Uncertainty regarding the total capacity of the reservoir was significantly reduced by researching known regional geology, then gathering well appraisal data and 2D and 3D seismic data to develop a 3D reservoir model in order to conduct feasibility studies. Shell Canada's studies showed that the BCS reservoir conservatively has sufficient capacity to store a minimum of 25 years of injected CO_2. However, there is a significant range of uncertainty in the ultimate storage capacity of the BCS, which is dependent on several factors, including:

- development strategy (and associated storage efficiency),
- dynamic constraints (compressibility and fracture gradients), and
- original brine-filled pore volume in place (which contains a range of uncertainty since it is estimated based on site-specific geological data).

The risk assessment methodology was based on Bow Tie Analysis

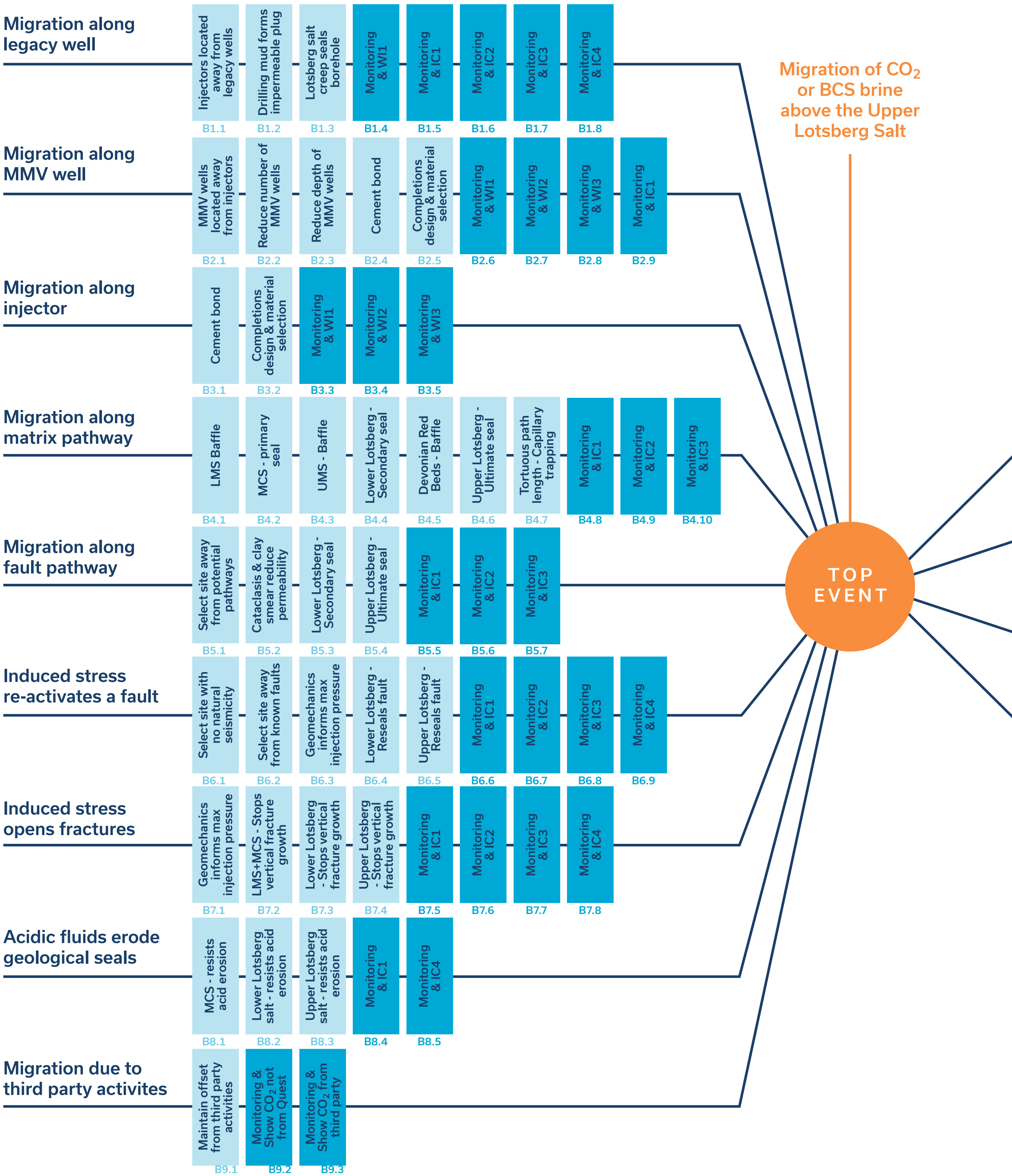
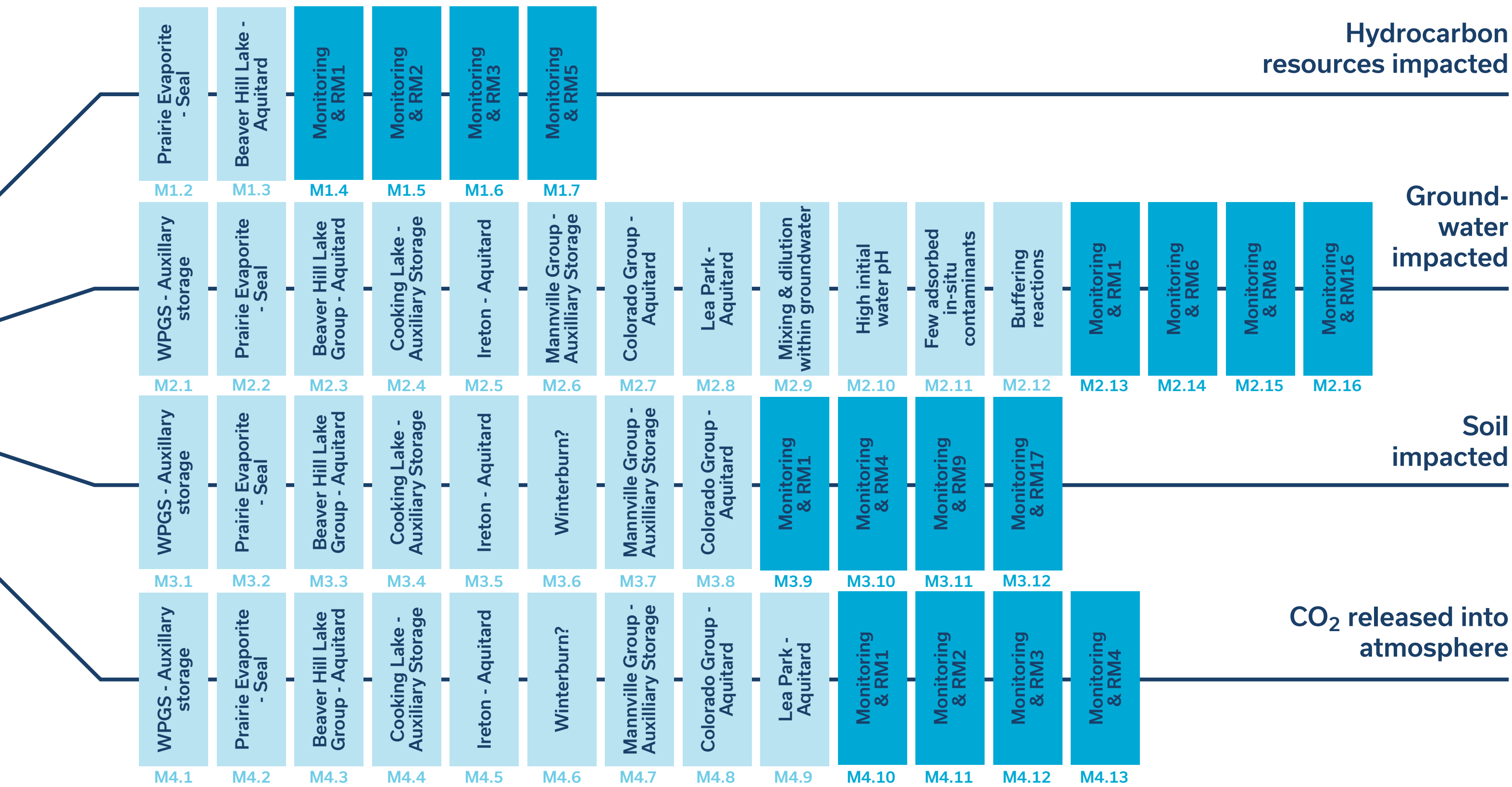

Migration along legacy well
Injectors located away from legacy wells
B1.1
Drilling mud forms impermeable plug
B1.2
Lotsberg salt creep seals borehole
B1.3
Monitoring & WI1
B1.4
Monitoring & IC1
B1.5
Monitoring & IC2
B1.6
Monitoring & IC3
B1.7
Monitoring & IC4
B1.8
Migration along MMV well
MMV wells located away from injectors
B2.1
Reduce number of MMV wells
B2.2
Reduce depth of MMV wells
B2.3
Cement bond
B2.4
Completions design & material selection
B2.5
Monitoring & WI1
B2.6
Monitoring & WI2
B2.7
Monitoring & WI3
B2.8
Monitoring & IC1
B2.9
Migration along injector
Cement bond
B3.1
Completions design & material selection
B3.2
Monitoring & WI1
B3.3
Monitoring & WI2
B3.4
Monitoring & WI3
B3.5
Migration along matrix pathway
LMS Baffle
B4.1
MCS - primary seal
B4.2
UMS - Baffle
B4.3
Lower Lotsberg - Secondary seal
B4.4
Devonian Red Beds - Baffle
B4.5
Upper Lotsberg - Ultimate seal
B4.6
Tortuous path length - Capillary trapping
B4.7
Monitoring & IC1
B4.8
Monitoring & IC2
B4.9
Monitoring & IC3
B4.10
Migration along fault pathway
Select site away from potential pathways
B5.1
Cataclasis & clay smear reduce permeability
B5.2
Lower Lotsberg - Secondary seal
B5.3
Upper Lotsberg - Ultimate seal
B5.4
Monitoring & IC1
B5.5
Monitoring & IC2
B5.6
Monitoring & IC3
B5.7
Induced stress re-activates a fault
Select site with no natural seismicity
B6.1
Select site away from known faults
B6.2
Geomechanics informs max injection pressure
B6.3
Lower Lotsberg - Reseals fault
B6.4
Upper Lotsberg - Reseals fault
B6.5
Monitoring & IC1
B6.6
Monitoring & IC2
B6.7
Monitoring & IC3
B6.8
Monitoring & IC4
B6.9
Induced stress opens fractures
Geomechanics informs max injection pressure
B7.1
LMS+MCS - Stops vertical fracture growth
B7.2
Lower Lotsberg - Stops vertical fracture growth
B7.3
Upper Lotsberg - Stops vertical fracture growth
B7.4
Monitoring & IC1
B7.5
Monitoring & IC2
B7.6
Monitoring & IC3
B7.7
Monitoring & IC4
B7.8
Acidic fluids erode geological seals
MCS - resists acid erosion
B8.1
Lower Lotsberg salt - resists acid erosion
B8.2
Upper Lotsberg salt - resists acid erosion
B8.3
Monitoring & IC1
B8.4
Monitoring & IC4
B8.5
Migration due to third party activites
Maintain offset from third party activities
B9.1
Monitoring & Show CO2 not from Quest
B9.2
Monitoring & Show CO2 from third party
B9.3
Migration of CO2 or BCS brine above the Upper Lotsberg Salt
TOP EVENT

FIGURE 19 | SHELL QUEST PROJECT CONTAINMENT LOSS AND RISK MITIGATION BOW TIE DIAGRAM

[Source: Shell, 2011d]



Refer to **Table 15** for a list of *Control Response Actions* noted herein

TABLE 15 | CONTROL RESPONSE ACTIONS TO PREVENT OR CORRECT UNEXPECTED MIGRATION OF FLUIDS OUTSIDE THE BCS STORAGE COMPLEX [Source: Shell, 2011d]

No.	Preventing Containment Loss	No.	Correcting Impacts From Containment Loss
	Injection Controls		*Well Interventions*
IC1	Re-distribute injection across existing wells	RM1	Repair leaking well by replugging with cement
IC2	Drill new vertical or horizontal injectors	RM2	Repair leaking injection by re-completion
IC3	Extract reservoir fluids to reduce pressure	RM3	Plug and abandon leaking wells that cannot be repaired
IC4	Stop injection		
	Well Interventions		*Exposure Controls*
WI1	Repair leaking well by replugging with cement	RM4	Inject fluids to increase pressure above leak
WI2	Repair leaking injection by re-completion	RM5	Inject chemical sealant to block leak
WI3	Plug and abandon leaking wells that cannot be repaired	RM6	Contain contaminated groundwater with hydraulic barriers
		RM7	Replacement of potable water supplies
			Remediation Measures
		RM8	Pump and treat
		RM9	Air sparging or vapour extraction
		RM10	Multi-phase extraction
		RM11	Chemical oxidation
		RM12	Bioremediation
		RM13	Electro-kinetic remediation
		RM14	Phytoremediation
		RM15	Monitored natural attenuation
		RM16	Permeable reactive barriers
		RM17	Treat acidified soils with alkaline supplements

In the likely event that the regional spread of pressurization of the BCS was found to be quite high due to known reservoir connectivity and quality, there would be an increase in the amount of CO_2 that could potentially be stored by as much as 50%, while remaining within the regulatory limit of the natural fracture pressure of the reservoir. However, when the Storage Development Plan was prepared along with the associated permit for the storage site, Shell Canada could not place any reliance on this potential storage volume when estimating the number of years the storage reservoir could be operated before closure. Accordingly, the estimated, conservative, ultimate storage capacity of the BCS within the storage site ranges from 19.83 to 29.74 Mt of total capacity, or 18.4 to 27.5 years at an average annual injection rate of 1.08 Mt/yr, the operating design specification for the Shell Quest capture facility assuming an operating time of 90% in any given year.

The key uncertainties considered in risk assessment were injectivity and conformance.

INJECTIVITY

A key uncertainty of the storage reservoir that was considered was ***injectivity***. To reduce this uncertainty to within acceptable limits required rigorous planning of the first IW in terms of placement and testing. The water injection tests at the Redwater 11-32 and Radway 8-19 appraisal wells had provided Shell Canada with a good benchmark for the injectivity of the reservoir based on the average pressures and flow rates for the stable flow periods of these tests that yielded injectivities of 41 and 379 m^3/d/MPa, respectively. However, it was recognized that the injectivity range was quite large due to water quality issues experienced during the Radway 8-19 tests. In order to effectively manage any future CO_2 IW failure or downtime, each of the IWs was designed to permit injection of the entire volume of captured CO_2, namely 1.2 Mt/yr .

Injectivity modeling was key to determining the number of wells required for the storage site. It was determined that 3 to 5 IWs would provide sufficient initial injectivity. Up to three additional IWs might be required if any future constraints on injection rate were ever experienced. Ideally, to keep operating costs at a minimum, three IWs would be sufficient. A number of factors were identified that could impact injectivity at an IW pad or across the reservoir, including:

- High injectivity due to better than anticipated near-wellbore reservoir properties
- Low injectivity due to poorer than anticipated near-wellbore reservoir properties
- Overestimation of CO_2 injectivity based on initial water injection tests at the Redwater 11-32 and Radway 8-19 appraisal wells
- Loss of injectivity due to:
    - ▹ Pressure buildup
    - ▹ Dropping bottom-hole pressure constraints
    - ▹ Operational upsets
    - ▹ Well intervention(s) for MMV and integrity issues
    - ▹ Geochemical alteration of the reservoir
    - ▹ Halite precipitation near the wellbore

CONFORMANCE CONTROL AND GEOLOGICAL MODELING

Loss of *conformance* was another significant risk to performance of the storage reservoir that was considered. Loss of conformance would result in CO_2 plumes spreading further than anticipated, or at a future date, entering geological zones that were not part of the storage complex. This could occur if the actual distribution of CO_2 and pressure build-up in the storage reservoir experienced during future operation were less than model-based predictions within the range of uncertainty, or if there was insufficient knowledge about actual storage performance to distinguish between permanent and stable or non-permanent storage of the total target mass of CO_2. It was therefore critical to have sufficient MMV data acquisition activities to determine if conformance could ever be lost and to aid in determining how best to re-establish it in that event. Should non-permanent or unstable storage performance ever occur, the site closure period following cessation of injection would be extended until storage risks were clearly understood and effective risk mitigation measures were put into place.

During the course of the risk assessment process and associated MMV activities, Shell Canada's geology team developed four increasingly better defined and more certain dynamic geological models. Accordingly, it was believed there was a very low risk of loss of conformance over the 25-year injection period and well beyond the site closure period.

PORE SPACE OWNERSHIP

In April 2011, the Carbon Sequestration Tenure Regulation came into force in Alberta. Shell Canada promptly applied for six Carbon Sequestration Leases that together comprise the Quest CCS Storage Site. Due to requirements of the Regulation, it was necessary to divide the AOI into six leases, even though they would be operated as a single CO_2 storage site. When making the application to the Government of Alberta, Shell Canada requested the exclusive right to the following:

1. Well drilling for the purpose of evaluating and testing, the injection of captured CO_2 into subsurface reservoirs and otherwise develop all geological horizons within the Zone of Interest (ZOI) located within the requested AOI. Restriction of third-party access to the ZOI was intended to assure the security of the Shell Quest CCS Project and its associated MMV program.
2. Testing and sampling of all zones from the ground surface to the Precambrian basement for MMV purposes within the AOI for the 25-year period of the Carbon Sequestration Leases.
    - Shell Canada was only granted the rights to test the Quest storage site from the Top of the Elk Point Group to the Precambrian basement

The Carbon Sequestration Leases cover 39 townships plus 12 sections that had comprised the AOI (the "Approved AOI", henceforward referred to as the Approved Sequestration Lease Area, or "ASLA" in this report). The leases were approved by the Government of Alberta in late May 2011, noting that the approved storage site was slightly different in the geological depth dimension than that for which Shell Canada had originally applied (see #2 above).

FIELD DEVELOPMENT PLANNING

Following the initial MMV surveys, detailed planning for the development of the Quest CCS storage site began in 2011.

SHELL QUEST CO_2 INJECTION WELLS

A third appraisal well had been drilled (Radway 8-19) during 2010 in order to acquire data to inform the pore space regulatory application, risk assessment and the Storage Development Plan. This appraisal well was later converted into a CO_2 injector well. A water injection test was conducted as a more cost-effective corollary to CO_2 injection testing. The water injection test had indicated good injectivity at 380 m^3/d/MPa, which was considered sufficient evidence of acceptable future CO_2 injection performance. The results suggested to Shell Canada that a total of three CO_2 injectors would likely be sufficient to operate the storage site pending confirmation from injectivity tests at the first two CO_2 IWs. However, the storage permit application under ERCB Directive 65 included 5 IWs with provision for a total of 8 IWs over the 25 years of CO_2 injection. The water injectivity testing also confirmed that Radway 8-19 would be a suitable candidate for conversion from an appraisal well to an IW.

The complicated process of applying for regulatory approval in the midst of an iterative evaluation of the proposed Quest storage site's static and dynamic geological characteristics required that Shell Canada use a conservative estimate of the number of required CO_2 IWs (3-10) when applying for an ERCB D65 Storage Application in November 2010. At the time, five IWs were specified. As a result of the injection testing, combined with 3D seismic data acquired in late 2010 that was processed by May 2011, the estimate for the number of wells required for CO_2 injection was reduced to the range of 3-8 in total, while the total number of IWs requiring immediate approval was reduced to three with two IWs potentially deployed in future years of the injection period. Consequently, Shell Canada submitted an updated version of the D65 Application in June 2011 reducing the number of IWs required, while including 5 IWs for approval. At the time, it was expected that the total number could be further reduced based on injection testing at the first two new CO_2 IWs that were drilled in 2012, although potentially 8 wells could ultimately be required. It is noteworthy that only three IWs were planned for and established initially.

Following identification of the potential IW sites, in early 2011 locations of the wells were ranked to determine the ideal drilling sequence with preferred locations having:

- landowner consent in place
- minimal offset from roads and other infrastructure (H_2S offset requirements were used in the absence of CCS regulation)
- at least 5 km distance from the Towns of Radway and Thorhild
- good injectivity (reservoir quality and thickness) indicators from 3D seismic data
- short distance from main CO_2 pipeline run (to reduce lateral pipeline cost)
- acceptable distance from edge of 3D survey to ensure a good understanding of future conformance and to reduce MMV costs
- optimum distance between IWs to assure sustained injectivity
- safe distance from legacy wells (LWs) to reduce leakage risk

A determination by the end of 2012 that only three IWs would be required, as a result of enhanced understanding and certainty regarding injection and storage site performance, resulted in the ranking of two IWs (Radway 7-11 and Thorhild 5-35) for drilling that began in early 2013, while Radway 8-19 was converted into an IW by re-completion (see Figure 18 for well locations). Water injection testing and the remainder of drilling activities, including MMV and groundwater observation wells, were completed by September 2013. Drilling activities were undertaken back to back to ensure cost savings.

It is possible that additional IWs might be required in future if any of the following situations were encountered during the 25-year injection period:

- injectivity of the three initial IWs was not sustained over time
- appropriate conformance of the CO_2 plume was not achieved (i.e. the plume is too tightly confined, that could increase reservoir pressure, or too widely dispersed, that could extend beyond the baseline 3D seismic survey)
- captured CO_2 volumes were increased upon potential future deployment of additional CO_2 capture infrastructure at the Scotford Complex

It is important to note that any additional IWs would inevitably increase MMV costs and result in more complicated management of stakeholder issues. A decision regarding the addition of extra IWs would likely be made some time between the third and the tenth years following initial injection (i.e. mid-2018 to 2025) once stable operation had been achieved and maintained for a sufficient period to enable prediction of future performance.

INDEPENDENT WELL INTEGRITY STUDY

Prior to drilling Radway 8-19, in late 2010 Shell Canada contracted OXAND Canada Inc., a recognized expert in cement degradation, to perform an independent well-integrity study based on the appraisal well design **[OXAND, 2010; Shell, 2011e]**. OXAND concluded that the Shell well design would not experience loss of cement integrity by exposure of the wellbore cement to CO_2. This study confirmed the ability to convert Radway 8-19 from an appraisal well into a CO_2 IW, as well as providing the basis for the design of the remaining CO_2 IWs.

SELECTION OF DEEP MMV OBSERVATION WELLS

Deep MMV observation wells (DMW) were planned to be drilled deeper than the base of the groundwater protection zone (BGWP) that defines the lower limit of potable shallow aquifers used as drinking water supply for regional rural infrastructure. Four observation wells were included in the Storage Development Plan.

A conceptual leak path model showed that loss of containment would be most effectively indicated by a pressure signal in an overlying formation. The Shell Quest team determined that pressure measurements in an overlying formation would have far greater sensitivity than any measurement of changes in fluid chemistry potentially caused by CO_2 or BCS brine migration out of the BCS Storage Complex. The top of the Winnipegosis formation was penetrated in Radway 8-19 at 1,600 metres depth, sitting 441 metres above the top of the BCS reservoir and 100 metres above the top of the BCS storage complex. The MDT pressure measurement made in the Winnipegosis was 326 kPa higher than the extrapolated BCS pressure gradient. Different chemical water signatures for the Winnipegosis and the BCS aquifers were also measured. Accordingly, the Winnipegosis was determined to be an aquifer suitably isolated from the BCS to be considered an appropriate target for monitoring, pending a later confirmation of pressure communication over long distances within this extensive aquifer.

Similar comparisons were made between the Cooking Lake, Rapids/Lower Winnipegosis, and Moberly formations and the BCS. DMWs were designed to terminate just below the Prairie Evaporites in the Winnipegosis that serve as the first seal above the BCS Storage Complex. DMW well completions were to be perforated in the appropriate aquifer formation to facilitate pressure monitoring.

During the Radway 8-19 appraisal well drilling in 2010, two deep saline aquifer formations, Cooking Lake and Winnipegosis, were identified as potential targets for the DMW observation wells **[Shell, 2012a]**. These wells were ultimately targeted at monitoring the Cooking Lake Formation following logging during the

IW drilling in the Fall 2012 **[Shell, 2014a]**. The three DMW observation wells were deployed for measuring CO_2 containment within the BCS Storage Complex. Measurements at the observation wells include: continuous downhole acoustic and pressure sensing on all three new DMWs and micro-seismic monitoring on DMW 8-19 (see Table 17).

One of the project exploration wells, Redwater 3-4, that is located near the Scotford Complex, was recompleted and converted into a BCS pressure observation well in the Cooking Lake formation **[Shell, 2014a]**. It serves as a means of measuring CO_2 conformance in the BCS Storage Complex since it is quite distant from the IWs and provides a far-field pressure measurement to compare with bottom hole pressures at the IWs. Pressure measurements at Redwater 3-4 (DMW 3-4) serve as the calibration point for determining the shape and extent of pressure distribution in the BCS utilizing InSAR monitoring. All IWs also serve as BCS observation wells since they have bottom hole pressure measurement through fibre-optic sensors. Additionally, all IWs were completed with distributed temperature-sensing systems outside the production casing for continuous monitoring purposes.

DEEP MMV OBSERVATION WELL TYPES AND LOCATIONS

Two monitoring well types were deployed during the DMW drilling program:

Complex, large well bore to include microseismic and pressure monitoring. This type was completed at the Radway 8-19 location.

1 Slim well bore solely for pressure monitoring. This type was deployed at the IW pads 2 and 3 (Radway 7-11 and Thorhild 5-35, respectively).

2 Shell Canada made a commitment to regulatory stakeholders to provide three observation wells along with the three initial IWs. However, no additional observation wells are anticipated in the event that five IWs are required at any point in the future. The first three IWs were placed centrally in the ASLA and were expected to be subject to the highest pressure increases during the entire injection period. Consequently, the DMWs (Cooking Lake for Radway 7-11 and Thorhild 5-35) situated on the same well pads as the second and third IWs are currently believed to be the most reliable for CO_2 containment measurements.

However, in the event a total of four or five IWs is determined at a future date(s) as essential for conformance control or potentially irreversible injector failure, the DMWs could be better located at the third and fourth IW pads or the third and fifth IW pads, respectively. 3D seismic profiles demonstrated a thinning of the BCS reservoir to the North which would mean that pressure sensitivity would be higher at these alternate DMW locations. Any decision regarding location of any future DMWs would be made at a later date.

The depth and location of the three DMWs was determined upon completion of the water injection tests at IWs 2 and 3 following drilling during early 2013. The final DMW design was completed in February 2013. Drilling took place later the same year. This was considered sufficiently well in advance of first CO_2 injection to establish an MMV baseline from the observation wells.

SHALLOW GROUNDWATER MONITORING WELLS

Shell Canada committed to the Alberta regulator to provide a minimum of three shallow groundwater monitoring wells (GWs) for each IW. The ideal location for the GWs was determined to be at the well pads for the IWs with one of the GWs having a separation distance from the injector or each LW of no more than 50 metres. Additional shallow GWs were drilled throughout the ASLA.

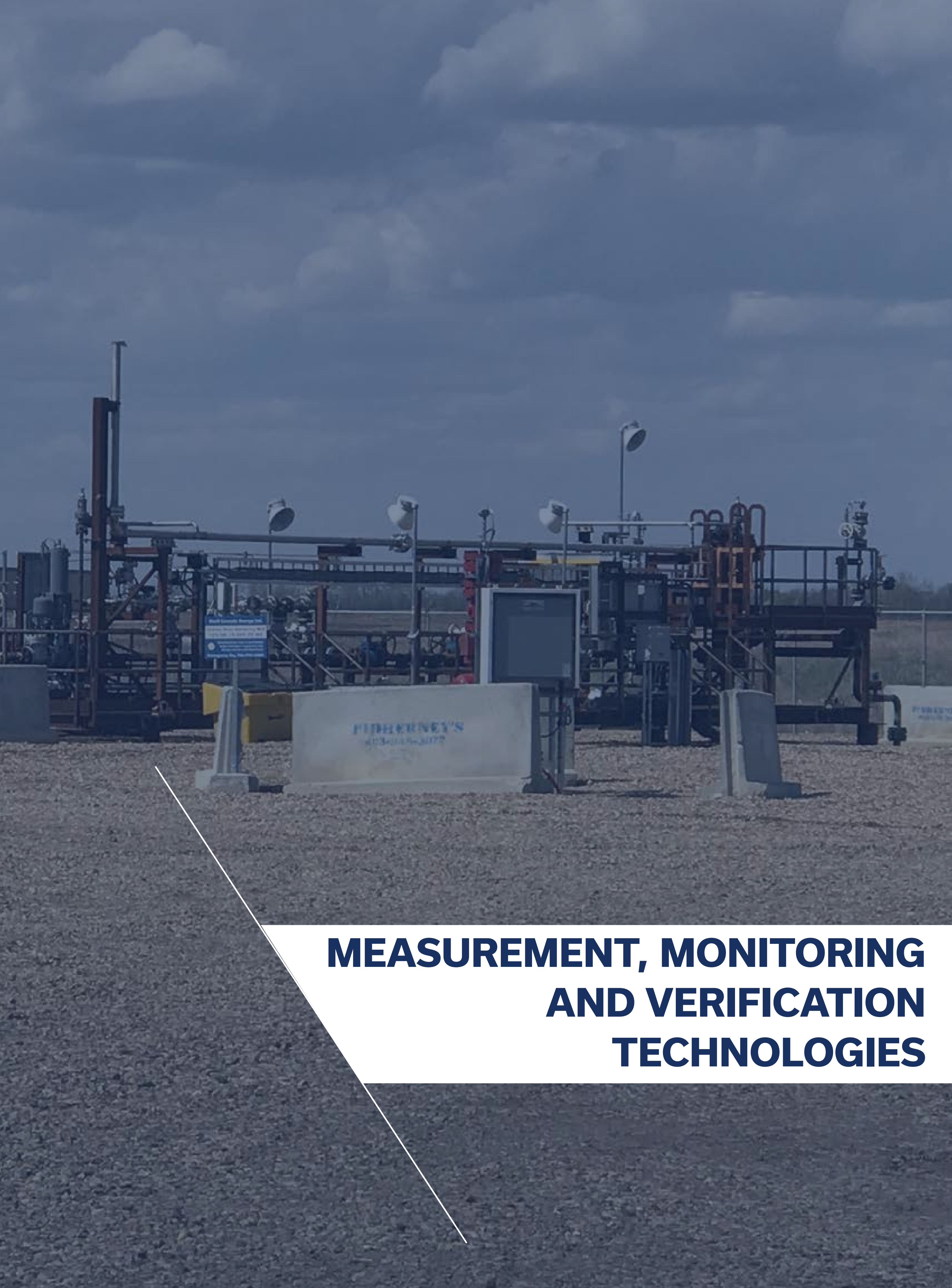
An independent well integrity study of the appraisal well design was conducted in 2010.

An additional 4 or 6 GWs, respectively, would be drilled in the event that in future a total of 4 or 5 IWs would be required. Placement of these additional GWs would be determined in consultation with municipalities located within the ASLA and other local stakeholders to assist in effectively managing public acceptance of the Shell Quest Project. Assuring groundwater quality near municipal water supplies, residential areas, protected environmental areas and higher-risk contamination sites (landfills, industrial activity, deep Prairie Evaporite pre-existing well bores) would be a high priority. Another potential consideration would be to use the remaining shallow GWs to triangulate around each IW pad to provide some knowledge regarding the desirability of three vs. one GW at any IW site.

Each of the initially-placed shallow GWs were drilled as deep as possible at 140 metres, which was less than the regulatory licensing depth of 150 metres. The wells were completed in the best aquifer zone with the highest porosity and permeability and above the BGWP but below the vadose zone (5-10 m). A permeable monitoring interval in each GW wellbore was chosen based upon the fluid most likely to migrate within the immediate vicinity of any particular GW. In the case of third-party LWs the most likely migration risk was the BCS brine, so it was determined that the permeable wellbore interval should overlie a competent barrier to brine flow. At IW locations, leakage and seepage risks are primarily associated with CO_2 migration from a potentially failed IW, hence GW wellbores were completed with permeable intervals directly below a competent barrier to CO_2 flow.

The GWs were drilled at approximately the same time as the Radway 7-11 and Thorhild 5-35 IWs during Fall 2012 to facilitate collection of a two-year baseline of monitoring data that would account for seasonal fluctuations. The first GWs were drilled at LW locations to avoid any conflict with drilling at the IWs. These first GWs were used to guide the final completion zone for the remaining GWs. The sole exception was the GW located at the Radway 8-19 well pad that was drilled at the end of 2010 to enable early MMV data acquisition.

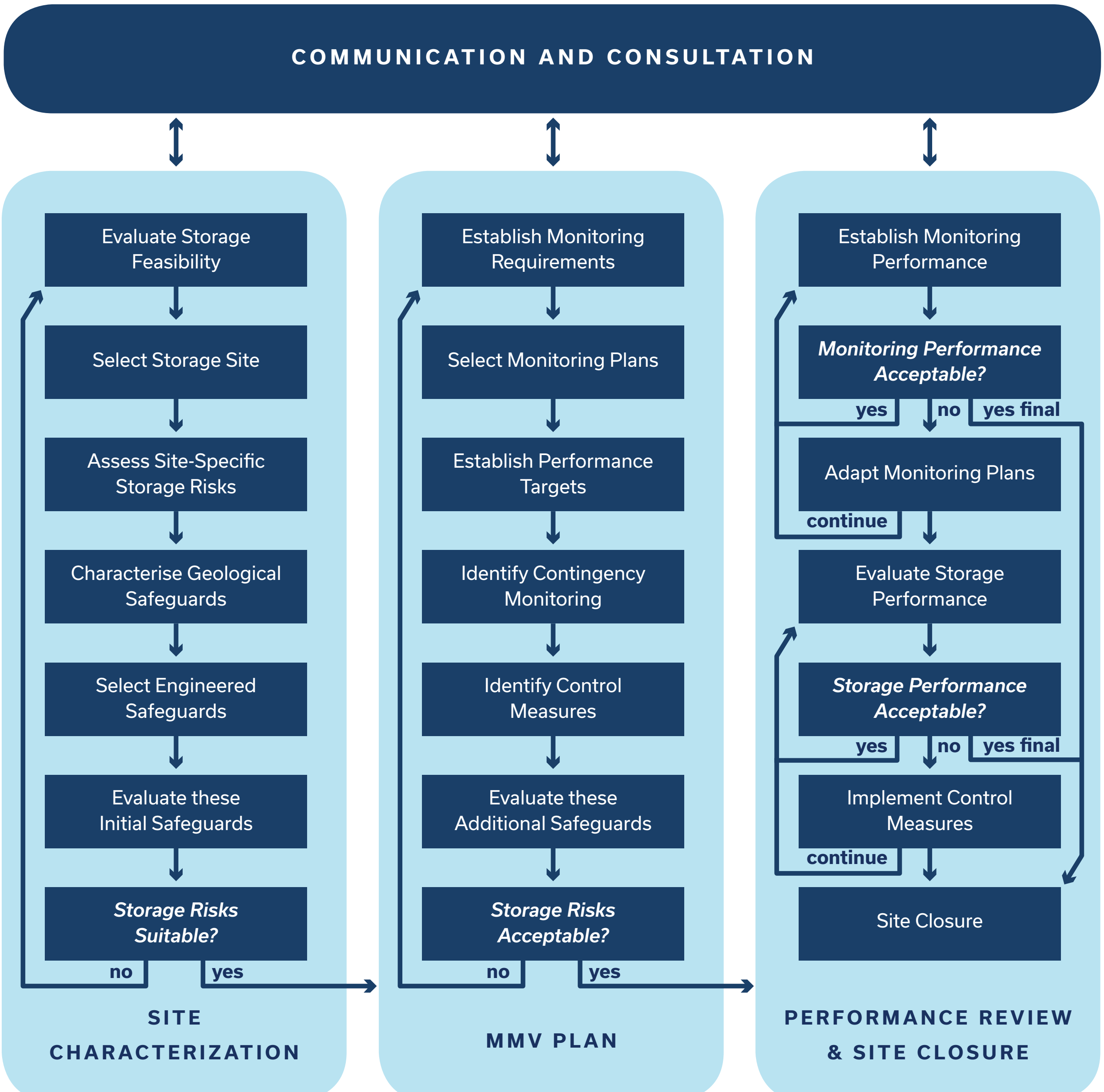
The network of GWs included in the MMV plan includes landowner groundwater wells, for which Shell Canada had gained early access approval for monitoring purposes. These monitored third-party groundwater wells lie within 3.2 km (2 miles) of each IW and abandoned BCS LW. Some additional landowner GWs are used within the ASLA to ensure coverage of at least one well within each township inside the ASLA boundary.



MEASUREMENT, MONITORING AND VERIFICATION TECHNOLOGIES

Identification and selection of measurement, monitoring and verification (MMV) technologies began in 2010 as part of the storage risk management framework developed by Shell Canada that would form the basis for selection of the storage site, the associated regulatory applications, and the field development plan (see Figure 20). This was one of the first integrated CCS projects globally to use a risk-based approach to develop an MMV plan. Previously, modifying an MMV plan due to a post-planning risk assessment process to mitigate previously unidentified future risks to security and integrity of CO_2 geological storage had been a standard practice. Accordingly, the approach was initially conservative with a view to updating the MMV plan on a regular basis to incorporate insights regarding the efficacy of the deployed MMV technologies.

FIGURE 20 | SHELL QUEST PROJECT STORAGE RISK MANAGEMENT FRAMEWORK [Source: Shell, 2015b]



The two key objectives of any viable MMV plan are to **[Bourne, et. al., 2014** and **Wiwchar, et. al., 2015]**:

1. Ensure Conformance, which indicates long-term effectiveness of CO_2 storage by demonstrating that storage performance aligns with expectations regarding injectivity, capacity, and CO_2 behaviour inside the storage complex.
2. Ensure Containment, which demonstrates security of CO_2 storage to protect human health, groundwater resources, hydrocarbon resources, and environment and to meet regulatory expectations.

These objectives were key considerations during the risk assessment evaluation that led to development of the Shell Quest MMV Plan.

The original Shell Quest MMV Plan **[Shell, 2011f]** was designed utilizing guidelines published by DNV **[Carpenter et. al., 2011; DNV, 2009;** and **DNV, 2012]** and the Alberta CCS Regulatory Framework that was emerging at the time Shell first began MMV planning for the Quest Project **[ADOE, 2013]**. The following attributes are ascribed to this type of MMV planning process:

Regulatory compliance to meet all applicable regulatory requirements, including those put into force at a future date

Risk-based MMV with:

- monitoring tasks identified through a systematic risk evaluation, including validation by independent experts
- scope and frequency of monitoring tasks that are dependent on the outcome of risk assessment, and
- project safeguards that are implemented to reduce storage risks to ALARP

Site-specific MMV with:

- monitoring technologies that are selected for each risk-management purpose and are dependent upon the outcome of site-specific feasibility assessments
- monitoring technologies that are custom designed to ensure optimal performance for the storage site

Adaptive MMV Plan entailing:

- continuous evaluation of the performance of the storage site and its monitoring systems; any monitoring technique that doesn't provide ongoing useful information or has any unacceptable performance limitations to enable assuring conformance and containment of the CO_2 will be eliminated from the MMV Plan going forward
- contingency planning utilizing triggers for implementing control measures to ensure effective response(s) to any unexpected events

The Shell Quest storage risk management framework consists of three components:

1. Site characterization
2. MMV activities
3. Performance reviews and site closure activities

These were used to build an appropriate MMV Plan and a Closure Plan that were approved by the Alberta regulator. Shell reports to the regulator annually on its MMV and risk-management activities and regularly updates its MMV plan based on the demonstrated value of various MMV activities to minimize storage risk and optimize understanding of the BCS Storage Complex.

A Bow Tie Analysis approach, that was described in an earlier section of this report, "Site Performance Assessment", formed the basis of the storage risk assessment framework and supported MMV objectives to assure containment. The containment-specific MMV objectives were the following:

1. Detect early warning signs for any loss of containment
2. Activate safeguards to reduce containment risks to ALARP
3. Demonstrate effectiveness of any control measures deployed.

The broader risk-based management approach to MMV planning utilized by the Shell Quest Project comprised:

- An iterative evaluation cycle to 'Identify-Monitor-Decide-Respond' to each risk outcome
- The use of a Bow Tie approach for the safety-critical risk, namely containment
- Selection of MMV options based on technical feasibility and value of information
- An adaptive MMV plan to manage lifecycle risks to ensure conformance and containment
- Bearing in mind cost-effectiveness vs. value of any MMV tool

The BCS Storage Complex and its regional geological framework include several natural geological formations that serve as contiguous bounding seals. Additionally, there was no detectable major faulting found in the ASLA and surrounding region. Consequently, the natural geology was expected to have containment integrity prior to initial CO_2 injection. Furthermore, the tectonically / seismically quiet region would be extremely unlikely to experience any natural event that could alter that natural containment integrity **[AGS, 2018]**. As a result, the major source of risk to containment was identified as any type of well failure, whether those arose from new wells or LWs.

An LW study was conducted prior to finalizing the location of the AOI to minimize the number of legacy wells within its boundaries and to maximize offset from legacy wells in selection of the actual injection sites within the ASLA, horizontally and vertically. None of the LWs was closer than 10 km to the proposed AOI **[Shell, 2012b]**. The Carbon Sequestration Lease approved by the Government of Alberta in May 2011 contains four third-party LWs that penetrate the Upper and Lower Lotsberg Salts which comprise the ultimate bounding seals overlying the BCS. These LWs have a number of known barriers to loss of containment:

- Multiple cement plugs of significant length at various intervals
- Open-hole abandonment across the Lotsberg salts that enables hole closure by salt creep
- Impermeable plugs that could have formed through settlement of solids from drilling mud in the wellbore

One of these LWs, Imperial Darling No. 1, represents the largest uncertainty to storage performance since it is well inside the ASLA and was not cemented across the seals of the BCS Storage Complex. In comparison with the IEAGHG Weyburn-Midale CO_2 Monitoring and Storage Project **[IEAGHG WMP, 2012]**, whose storage "container" included more than 5,000 LWs drilled, completed and often abandoned during more than 60 years of varying regulations, the risk presented by this single well is quite low. Effective management of this risk was taken into account in the MMV planning.

In addition to the aforementioned LWs, an abandoned salt cavern used for underground gas storage lying above the Top of the Elk Point Group, and its associated well, PLC Redwater 7-17, were excluded from the Carbon Sequestration Lease when issued by the Government of Alberta by virtue of limiting the geological horizons included in the lease, rather than including all of the horizons from the Precambrian basement up to the BGWP as per Shell Canada's lease application. This additional well presents a risk to leakage of CO_2 to the upper geosphere outside the regulated lease and the atmosphere above it should any injected CO_2 leave the BCS Storage Complex. Accordingly, the MMV plan takes this risk into consideration.

Four additional LWs and four additional salt caverns penetrate one or more seals in the BCS Storage Complex above the ultimate seal (Lotsberg salts). These have all been abandoned and are well understood. Shell Canada believes they don't pose any significant risk to the storage integrity of the BCS Storage Complex.

Site-specific containment risks considered in the development of the initial MMV plan of August 2011 **[Shell, 2011f]**, along with their associated risk levels, are shown in Table 16. The MMV technologies utilized in the Shell Quest Project and their contribution to understanding containment, conformance, injectivity and capacity are shown in Table 17 and Table 18. They comprise a combination of new and traditional monitoring technologies.

Nearly 60 different MMV technologies were originally screened into the MMV Plan in its first iteration. By 2017, that number of technologies had been reduced to 37, with several being reduced in frequency and many only utilized as required to provide additional assurance of containment, conformance, and integrity in the event of evidence of increased risk **[Shell, 2017j]**. It is fully expected that, as risks are reduced with ongoing monitoring, the number of MMV technologies essential to fully assess the safety and security of CO_2 storage within the Shell Quest leases will be further reduced during the 25 years of operation of the site. The maturing schedule for MMV activities prior to injection, during injection, post-injection and during the closure and post-closure periods is shown in Figure 21. The emphasis going forward is focused on downhole monitoring technologies.

TABLE 16 | CONTAINMENT RISKS CONSIDERED IN DEVELOPMENT OF INITIAL MMV PLAN [Source: Shell, 2011f]

	CONTAINMENT RISK	RISK LEVEL	MMV STRATEGIES
1	LWs penetrating the three major seals of the BCS Storage Complex	Moderate	GWs, 4D Seismic, InSAR
2	LWs penetrating upper seals of the BCS Storage Complex	Low	4D Seismic, InSAR
3	Dedicated DMW observation wells	Very Low	4D Seismic, InSAR
4	CO_2 IWs	Low	GWs, 4D Seismic, InSAR
5	Migration along a stratigraphic pathway	Very Low	2D Seismic
6	Migration along an open-fault pathway	Very Low	2D and 3D Seismic
7	Induced stress reactivates a fault	Low	Downhole micro-seismic
8	Induced stress opens fractures	Very Low	Downhole micro-seismic, InSAR
9	Acidic fluid erodes seals	Very Low	InSAR
10	Third-party induced migration (new wells drilled)	Very Low	Many MMV methods

TABLE 17 | SUMMARY OF MONITORING FREQUENCIES AND AMOUNTS USED FOR INITIAL MMV PLANNING **[Source: Shell, 2011f, Shell, 2014c**

	Monitoring Systems	Purpose	No. / Time	Availability
	In-Well Monitoring (Geosphere)			
1	Cement bond logs	Initial quality of cement bond	10	Once
2	Time-lapse ultrasonic casing imaging	Casing corrosion detection	10	Well intervention
3	Time-lapse electromagnetic casing imaging	Casing corrosion detection	10	Well intervention
4	Time-lapse multi-finger casing caliper	Tubing corrosion detection	10	On demand
5	Annulus pressure monitoring	Pressure leak detection	10	Continuously
6	Injection rate metering at wellhead	Rate and volume of CO_2 injected	5	Continuously
7	Wellhead pressure-temperature gauge	Injection pressure & temperature	5	Continuously
8	Downhole pressure-temperature gauge	Downhole pressure & temperature	10	Continuously
9	Mechanical well integrity pressure testing	Leak detection	5	On demand
10	Wellhead CO_2 detectors	CO_2 leak detection	10	Continuously
11	Tracer injection & wireline logging	Leak detection & CO_2 conformance	1	Continuously / on demand
12	Time-lapse reservoir saturation (RST) logging	Leak detection & injection profile	10	Well intervention
13	Time-lapse temperature logging	Leak detection outside casing	10	Well intervention
14	Packing isolation test	Leak detection outside casing	10	Well intervention
15	Fibre-optic distributed temperature sensing	Leak detection outside casing	10	Continuously
16	Tubing caliper logging	Leak detection outside casing	10	Well intervention
17	SCVF testing as per AER ID2003-01	Leak detection outside casing	10	On demand
18	Gas migration testing as per AER Directive 20	Leak detection outside casing	10	On demand
19	Routine well maintenance	Casing corrosion, leaks outside casing, equipment and instrument performance	1	On demand
20	Fibre-optic distributed acoustic sensing†††	Leak detection outside casing	10	Continuously
	Geochemical Monitoring (Biosphere, Hydrosphere and Geosphere)			
21	Water chemistry monitoring	Leak detection & storage mechanisms	15	On demand
22	Downhole electrical conductivity monitoring	Brine leak detection & impact assessment	15	Continuously
23	Downhole pH monitoring	CO_2 leak detection & impact assessment	15	Continuously
24	Artificial tracer monitoring†††	Leak detection & impact assessment	1	On demand
25	Natural isotope trace monitoring†††	Leak detection & impact assessment	15	On demand
26	Groundwater gas monitoring	Leak detection & impact assessment	15	On demand
27	Soil-gas CO_2 flux monitoring	CO_2 leak detection & impact assessment	1	On demand
28	Soil-gas CO_2 concentration monitoring	CO_2 leak detection & impact assessment	1	On demand
29	Soil-pH surveys	CO_2 leak detection & impact assessment	1	On demand
30	Soil-salinity surveys	Brine leak detection & impact assessment	1	On demand
	Geophysical Monitoring (Geosphere)			
31	Time-lapse 3D vertical seismic profiling (VSP)	3D distribution of subsurface CO_2 plume	5	On demand, winter
32	Time-lapse surface 3D seismic	3D distribution of subsurface CO_2 plume	5	On demand, winter only
33	Surface micro-seismic monitoring	Micro-seismic catalogue	5	Continuously / on demand
34	Downhole micro-seismic monitoring (DMW 8-19 only)	Micro-seismic catalogue	5	Continuously / on demand
35	InSAR†††	Pressure front & fault re-activation	1	Monthly
	Surface Monitoring (Atmosphere and Biosphere)			
36	Light Source (Line-of-sight gas flux) monitoring	CO_2 leakage rate to atmosphere	5	Continuously / on demand
37	Atmospheric eddy correlation‡‡‡	CO_2 leakage rate to atmosphere	1	On demand
38	Airborne infrared laser gas analysis‡‡‡	CO_2 leakage rate to atmosphere	1	On demand
39	Radar image analysis - RadarSat2 (RIA) ‡‡‡	Brine leak detection & impact assessment	1	Monthly
40	Satellite MIA	CO_2 Leak detection & impact assessment	1	Monthly

††† New MMV technology evaluated for the first time at Shell Quest

‡‡‡ Discontinued after baseline surveys due to poor calibration data and/or unacceptable feasibility study results.

and **Shell, 2015b]**

Coverage	Baseline	Injection Period	Closure Period
Entire well length	Once	-	-
IWs and DMWs	Once	Every 5 years	Every 10 years
IWs and DMWs	Once	Every 5 years	Every 10 years
IWs	Once	Every 5 years	Every 10 years
IWs and DMWs	Continuous	Continuous	Continuous
IWs	-	Continuous	-
IWs	-	Continuous	Continuous
IWs and DMWs	-	Continuous	Continuous
IWs and DMWs	Once	Annually	Annually
IWs and DMWs	-	Continuous	Continuous
IWs and DMWs	-	Every 5 years	Every 10 years
IWs and DMWs	-	Every 5 years	Every 10 years
IWs and DMWs	-	Every 5 years	Every 10 years
Entire borehole	Once	Annually	Every 3 years
Entire length of FO downhole	Continuous	Continuous	Continuous
Entire borehole	Once	Annually	Every 3 years
IWs and DMWs	Annually before April	Annually before July	Annually
IWs and DMWs	Annually before April	Annually before July	Annually
IWs and DMWs	Scheduled	Scheduled	As required
Entire length of FO downhole	Continuous	Continuous	Continuous
DMWs & GWs	Continuous	Continuous	Continuous
DMWs & GWs	Continuous	Continuous	Continuous
DMWs & GWs	Continuous	Continuous	Continuous
DMWs & GWs	Annually	Annually	Biannually
DMWs & GWs	Annually	Annually	Biannually
Discrete locations across ASLA	Annually	Annually	Biannually
Discrete locations across ASLA	Annually	Annually	Biannually
Discrete locations across ASLA	Annually	Annually	Biannually
Discrete locations across ASLA	Annually	Annually	Biannually
Discrete locations across ASLA	Annually	Annually	Biannually
Within 1 km of wellbore	Once	7 times	-
Entire subsurface CO_2 plume	Once	Every 5 years	Once
Underneath geophone array	-	Continuous	-
< 600 m of monitoring well geophones	-	Continuous	-
Entire region of elevated pressure	Monthly	Monthly	Monthly
Areal coverage over parts of ASLA	Continuous	Continuous	Continuous
Discrete locations across ASLA	Continuous	Continuous	Continuous
Areal coverage of entire ASLA	Once	Annually	Biannually
Entire ASLA and beyond	Annually	Annually	Biannually
Entire ASLA and beyond	Annually	Annually	Biannually

FIGURE 21 | MATURATION OF MMV PLANNING PRE-INJECTION TO POST-CLOSURE [Sources: Shell, 2011f, Shell, 2015b and Shell, 2017j]

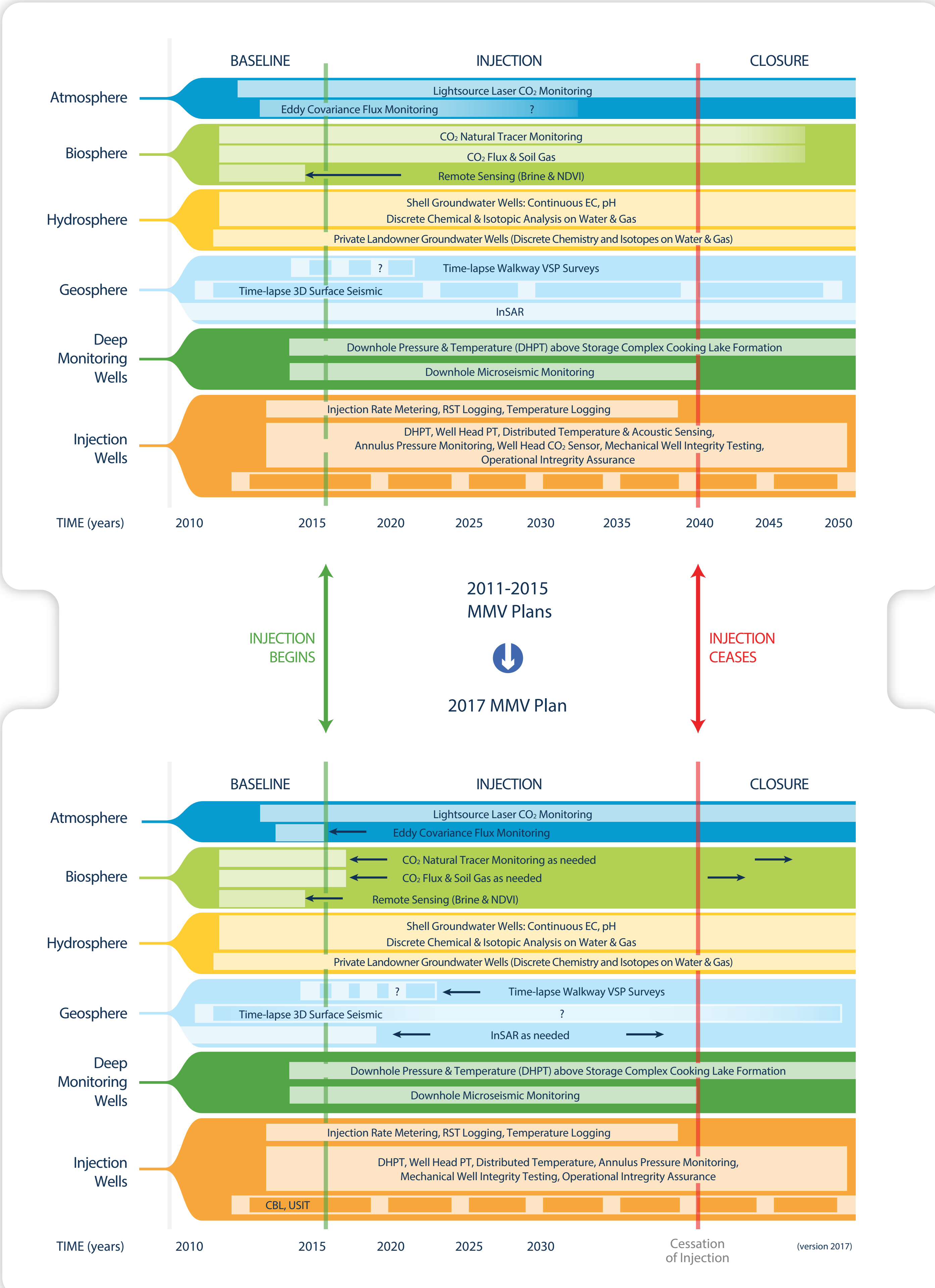


TABLE 18 | MMV ACTIVITIES FOR MEASURING KEY STORAGE PERFORMANCE INDICATORS (REFER TO TABLE 17)

[Source: Shell, 2011f and **Shell 2015b]**

INDICATOR	MEASUREMENT	MMV TECHNOLOGY										
Conformance	CO_2 Plume Development	8	32	35								
Containment	Injection Pressure	8										
	Fluid pressure in BCS storage complex	8	35									
Injectivity	Legacy Well Integrity	8	31	35								
	Injection & Monitoring Well Integrity	1	2	3	9	12	14	16	17	18	19	20
	Geological Seal Integrity	6	8	7	31	32	34	35				
	Monitoring Hydrosphere	22	23	24	25							
	Monitoring Biosphere	25	27	28	39	40						
	Monitoring Atmosphere	51										
Capacity	Static Reservoir Model	1 through 40										
	Dynamic Reservoir Model	1 through 40										
	Well Model	1 through 40										
	Integrated Production System Model	1 through 40, pipeline and capture data										

Coverage of most of the monitoring systems has been focused on the highest risk locations for leakage, namely well bores (see Figure 18 and Figure 22). The total number of monitoring devices that will be installed over the life of the project will depend upon whether or not additional IWs are required in future. There are additional monitoring systems situated at LWs and GWs, as well as those installed at the DMWs.

MONITORING INJECTION WELL INTEGRITY

In addition to the MMV technologies outlined in Table 17 and Table 18 for measuring wellbore integrity, Shell Canada undertook the following to assure performance reliability at each IW:

1. Mechanical well integrity testing of packers as required by regulation. Shell utilized additional caliper surveys to measure potential tubing corrosion.

2. Corrosion coupons at the IWs to confirm dehydration specifications of the injected CO_2 and to serve as an indicator of potential corrosion of pipeline and wellbore completion.

3. Pressure measurement on different casing annuli during routine well maintenance.

4. Measurement of hold-up depths at every wireline entry in a well prior to logging activities. Well logging was scheduled every 5 years.

INDEPENDENT EVALUATION OF EFFECTIVENESS OF TIME-LAPSE 3D SEISMIC SURVEYS AT SHELL QUEST

An independent theoretical study was undertaken by the University of Calgary utilizing well log data gathered from the Radway 8-19 appraisal well. It was determined that time-lapse 3D seismic would effectively locate the vertical and horizontal size and extent of the CO_2 plume following a year of injection of 1.2 million tonnes of CO_2. This demonstrated that 3D seismic surveys conducted on an annual or multi-year basis would be an effective tool for assuring conformance control **[Moradi and Lawton, 2013 and Moradi** and **Lawton, 2014]**.

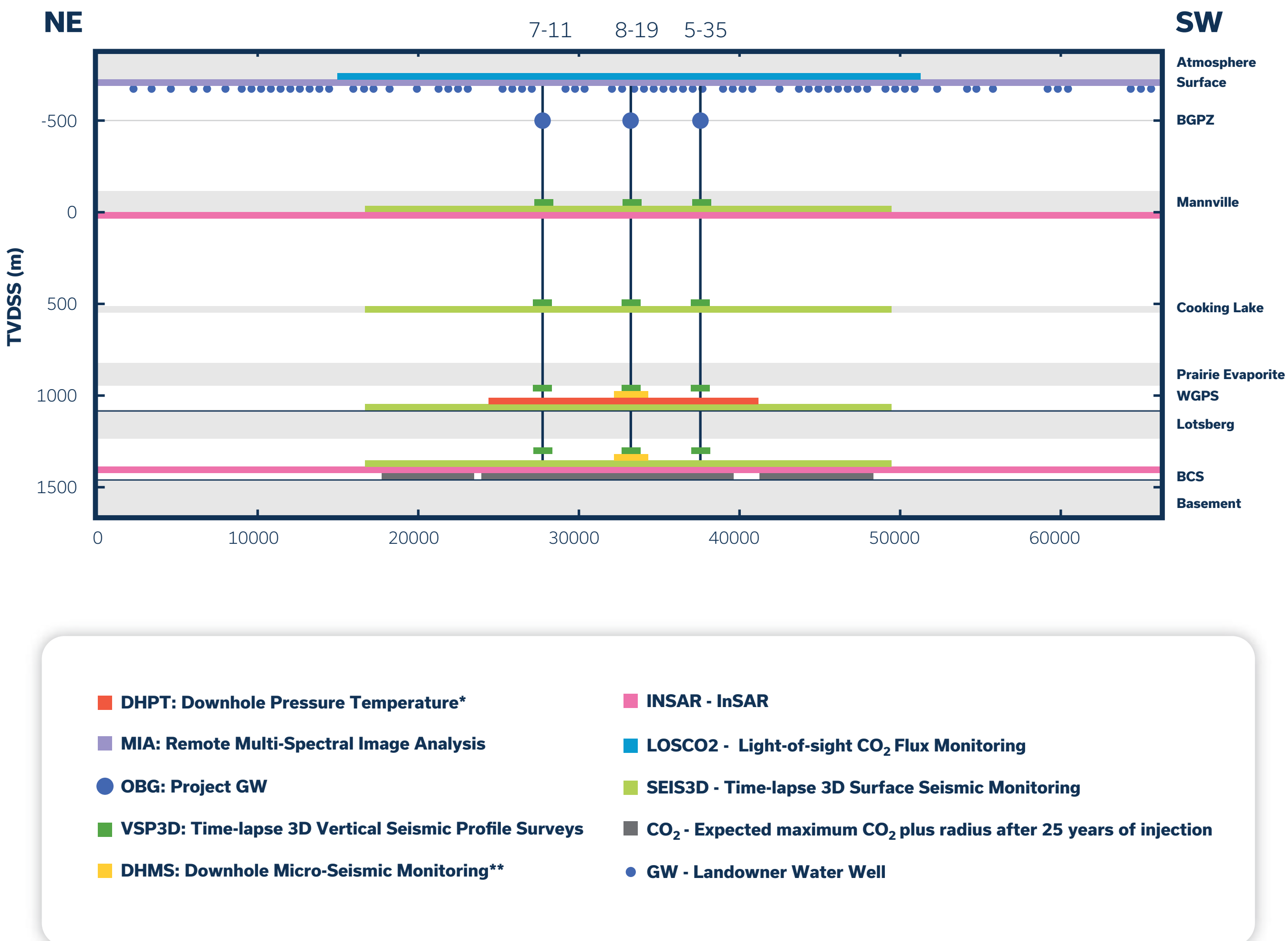
NEW MMV TECHNOLOGIES UTILIZED AT SHELL QUEST

Technologies applied for the first time in the context of MMV for CO_2 geological storage included **[Shell, 2011f, Shell, 2014c** and **Shell, 2015b]**:

In-Well Monitoring

1. Distributed acoustic sensing (DAS) vertical seismic profiling (VSP) in the wellbore was evaluated **[O'Brien, et. al., 2017]**. Conventional VSP surveys are used as a contingency MMV method and to better understand the DAS data. DAS-VSP is also being evaluated at the Aquistore Project in Saskatchewan as a potential cost-effective alternative to a permanent seismic array to support time-lapse 3D seismic surveys **[IEAGHG, 2018b]**.

FIGURE 22 | CROSS-SECTION A-B SHOWING THE SUBSURFACE COVERAGE OF VARIOUS DIFFERENT MMV TECHNOLOGIES IN THE CASE OF 3 INJECTION WELLS (SEE FIGURE 18) [Source: Shell, 2011f]



* At all DMWs ** At DMW 8-19 ONLY

Remote Monitoring

2 InSAR data collection has been conducted on a monthly schedule to measure temporal and areal changes in surface displacements which would indicate loss of containment[§§§]. Other MMV technologies specific to monitoring containment are used as a contingency. InSAR is also being evaluated at the Aquistore Project **[IEAGHG, 2018b]**.

3 LightSource, line-of-sight CO_2 flux monitoring (based on LIDAR technology) **[Hirst et. al., 2017]**, is in continuous operation at each IW pad. In the event of anomalous CO_2 detection, soil-gas measurements are made. This technology was trialed beginning in 4Q2011.

4 Atmospheric eddy correlation (or eddy covariance) was tested early in the MMV program to detect CO_2 leakage to the atmosphere **[Burba et. al., 2013]** at discrete locations across the ASLA. Other MMV technologies specific to monitoring containment are used as a contingency in the event this new technology proves less reliable.

5 Airborne infrared laser gas analysis to provide areal coverage over the entire ASLA has been utilized for measuring CO_2 leakage to the atmosphere **[Verkerke et. al., 2014** and **IEAGHG, 2012]**. Other MMV technologies specific to monitoring containment have been used to better understand this new MMV technology and as a monitoring contingency.

§§§ Despite use of InSAR for MMV to monitor CO_2 plume subsurface location at the InSalah CO_2 geological storage project **[Ansarizadeh et. al., 2015]**, Shell Canada, at the request of the Alberta Ministry of Environment, commissioned an InSAR Feasibility Study that was completed and submitted in January 2013 **[Shell, 2013b]**.

6 Radar image analysis (RIA) utilizing acquired RadarSat2 images for monitoring potential brine leakage outside the BCS over the ASLA was evaluated. The baseline calibration was poor for this technology. After a thorough risk assessment, it was determined the risk of brine leakage was too low to justify pursuing this MMV technology application **[Shell, 2015b]**.

7 Satellite multispectral image analysis (MIA) was used to provide areal coverage of the entire ASLA and beyond its boundaries for measuring CO_2 leakage to the atmosphere **[Litynski et. al., 2013]**. A feasibility study demonstrated that the technology was inadequate for real-time monitoring and CO_2 leak detection.

Geochemical Monitoring

8 Natural BCS fluid tracers in groundwater monitoring wells are utilized to demonstrate that the unique geochemistry of the BCS brine cannot be found in potable water horizons thereby demonstrating BCS Storage Complex containment of its natural brine **[McLing et. al., 2014]**.

9 CO_2 injection tracers have been widely used in CO_2 sequestration pilots. However, they have been normally utilized as one-off deployment rather than continuously or repeatedly as applied at Shell Quest. The purpose is to "tag" the injected CO_2 to avoid any uncertainty about the origin of CO_2 detected in the biosphere, hydrosphere or atmosphere that would pose a threat to human health and/or the environment. Perfluorocarbons were selected for this purpose****. This strategy was, in part, a learning from the Kerr case at the Weyburn CO_2 EOR operation that was the subject of a long-term, IEAGHG-sponsored MMV project **[IEAGHG WMP, 2012; Romanak, et. al., 2013** and **Romanak, et. al., 2014]**.

COMPLEMENTARITY OF MMV TECHNOLOGIES

The monitoring technologies selected for Shell Quest have some overlap in addition to complementing each other in terms of detection sensitivity, time and range (see Figure 23). The most sensitive technologies typically have a more limited coverage than less sensitive ones, necessitating deployment of a wide variety of tools for the same types of measurements.

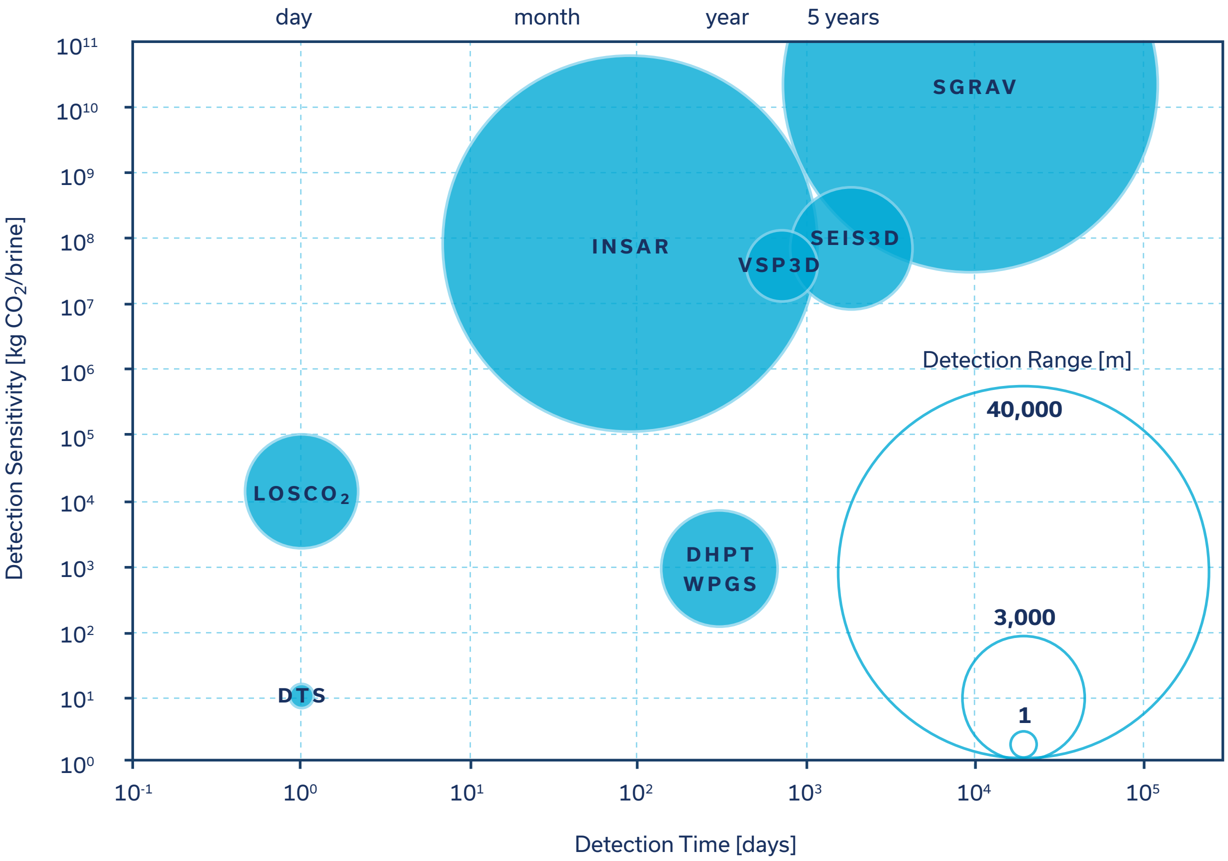
AN ITERATIVE MMV PLANNING PROCESS

It was fully expected that some of the technologies, either new or proven, originally included in the first MMV Plan from August 2011 would be found to be unreliable or considered unnecessary, duplicative or undesirable for any variety of reasons over the long term. New technologies that Shell Canada wishes to test at any date following start-up of Shell Quest could also be added to enhance the evergreen MMV Plan. Consequently, the MMV plan is updated approximately every 2 to 3 years based upon operational experience and new knowledge. Updated MMV plans are posted to the Government of Alberta's online CCS Knowledge portal: **https://open.alberta.ca/dataset?tags=CCS+knowledge+sharing+program** .

Shell Canada has utilized a rigorous wellbore monitoring program at the Quest injection sites.

**** A perfluorocarbon tracer feasibility study was conducted during 2013 **[Shell, 2013b]**.

FIGURE 23 | A COMPARISON OF EXPECTED DETECTION TIME, DETECTION SENSITIVITY AND DETECTION RANGE FOR VARIOUS MMV TECHNOLOGIES **[Source: Shell, 2011f]**



$LOSCO_2$ Light-of-sight CO_2 Flux Monitoring

DTS Distributed Temperatire Sensing

INSAR Interferometric Synthetic Aperture Radar**

DHPT WPGS Downhole Pressure-temperature Sensing*

SEIS3D Time-lapse 3D Surface Seismic Monitoring

VSP3D Time-lapse 3D Vertical Seismic Profiling

SGRAV Time-lapse surface gravity***

*At Deep WPGS DMW
**At feasibility stage. Surveys conducted at irregular intervals as of 2016.
***Eliminated due to unacceptable sensitivity and detection time

BASELINE MMV SURVEYS

Monitoring surveys to establish a baseline prior to CO_2 injection began in early 2013 and continued through to the end of March 2015. The following activities were undertaken to fully characterize the BCS Storage Complex:

- A Hydrosphere and Biosphere Field Monitoring Program was implemented by Golder Associates Ltd. in 2013 to enable calibration of hydrosphere and biosphere data as well as remote sensing. This included soil gas, vegetation, and soil surface sampling and analysis.
- A groundwater survey was conducted by Alberta Innovates - Technology Futures in April 2013.
- Perfluorocarbon (PFC) tracer feasibility studies were conducted in partnership with CSIRO from 2013-2014 to assure the Alberta Energy Regulator (AER, formerly ERCB) that it was a suitable method for distinguishing Scotford-derived CO_2 from other sources of CO_2 in the event of leakage from the BCS. It was proposed in the original regulatory applications that PFCs would be co-injected with CO_2.
- Analysis of log and core data from drilling activities during 2012-2015.
- Light Source (line-of-sight CO_2 gas flux) monitoring (LOSCO_2) and the Boreal Laser LOS CO_2 sensor were field trialed in September 2013 as part of a feasibility study to determine detection thresholds. This entailed controlled CO_2 release tests at IW pads.
- Digital acoustic and temperature sensors (DAS and DTS) were cemented into the IWs. These were tested annually to assure continued performance prior to injection, in addition to providing measurement baselines. The DAS system has been shown to be similar to conventional "walkaway" VSP surveys.
- A baseline 3D VSP survey was conducted in conjunction with the DAS system baseline survey.
- Acquisition of 15 RadarSat2 satellite images enabled defining the InSAR monitoring during 2013-2014. It was confirmed by AER in October 2013 that corner reflectors were not required for this monitoring.
- Continuous baseline pressure monitoring in the Cooking Lake Formation utilizing the DMWs on the IW pads began in early 2014 following appropriate perforations at well pads 7-11 and 5-35.

This information was used to improve static and dynamic geological models that were used to reduce containment and conformance risk, update the MMV Plan, improve project communications (internal and external), inform the development of the Closure Plan, provide assurance to regulators and the community regarding safety and security, and update mitigation measures in the event of unexpected storage performance.

Baseline monitoring activities were undertaken for more than four years prior to initiating CO_2 injection.

SHELL QUEST CORE SAMPLING SURVEY

Three cores from appraisal wells at Redwater 3-4, Redwater 11-32 and Radway 8-19 were obtained and analyzed to provide data to build and enhance the storage reservoir's geological model. Detailed sedimentological analysis of the Basal Cambrian Sandstone formation and its heterogeneities were incorporated into the reservoir model used for MMV planning, risk assessment and performance assessment of the BCS Storage Complex. The petrophysical properties, porosity and permeability, recorded from the cores provided clear evidence that the BCS had excellent reservoir properties to support its use as a CO_2 storage reservoir and had lateral continuity within the AOI **[Desjardins** and **Smith, 2013]**.

GEOLOGICAL AND GEOCHEMICAL SAMPLING SURVEYS

During the drilling campaign of the mid-winter in 2012-2013, geological and geochemical data were collected from new DMWs at depths in excess of 1500 metres and from project GWs at depths of approximately 250 metres **[Rock, 2013]**. This information was incorporated into the geological model for the BCS Storage Complex in order to better understand the injection reservoir properties, including porosity and permeability.

A formation fluid compositional database was accumulated to provide a baseline for four aquifers (Surficial, Oldman, Foremost and Basal Belly River Sandstone) overlying the BCS. Each aquifer demonstrated a unique brine composition as determined by chemical analysis (Na^+, K^+, Ca^{2+}, Mg^{2+}, Cl^-, Br^-, Sr^{2+}, etc.) and isotopic analysis ($^{87}Sr/^{86}Sr$, ^{18}O, and ^{13}C). These data that would be indicative of any loss of containment of the injected CO_2 were used to enhance the reservoir geological model and would support hydrological and geochemical monitoring during the operational and closure phases of the Shell Quest Project **[Brydie et. al., 2014]**.

Prior to injection at Shell Quest, it was determined that the Carbon-13 (^{13}C) signature of the injected CO_2 from the Scotford Upgrader would be an effective tracer of the manmade CO_2 in the subsurface through measurement of $\delta^{13}C$ in the reservoir and overlying aquifers during regular sampling surveys relative to the baseline **[Rock, et. al., 2014** and **Bayer, et. al., 2015]**. It was further determined that $\delta^{18}O$ in the injected CO_2 would not be an effective tracer outside the BCS Storage Complex but would be effective in revealing pore-space saturation in the BCS reservoir. This method of measuring $\delta^{13}C$ to trace the source of CO_2 had proved useful in the IEAGHG Weyburn-Midale CO_2 Monitoring and Storage Project in Saskatchewan **[Bayer, et. al., 2013]** and was critical in enabling Cenovus Energy to halt a damages claim by the Kerr family due to CO_2 seepage into surface water at their farm near the Weyburn oilfield **[Romanak, et. al., 2013** and **Romanak, et. al., 2014]**.

ATMOSPHERE AND BIOSPHERE BASELINE SURVEY

MMV activities undertaken to characterize the background levels of CO_2 in the biosphere and atmosphere, including isotopic data, were conducted using the following tools outlined in Table 17, Table 18 and Table 19. Not only was this information critical for establishing a baseline to build an effective geological storage model for the project, but it provided essential knowledge to project stakeholders. Communication with external parties began the development of awareness and understanding about the Shell Quest project concerning CO_2 levels in the ambient air and soil gas across the ASLA, and would help to allay any future concerns regarding leakage or seepage from the Shell Quest storage reservoir. This was the first time a carbon sequestration project had successfully measured repeatable, real-time $\delta^{13}C$-CO_2 measurements, including spatial and temporal variability, in the atmosphere and biosphere above a CO_2 storage reservoir **[Rock, et. al., 2017a]**.

*** Subsequent to the date of this report, new legislation was passed by the United States Congress in early 2018 updating both the credit dollar amounts and the volume cap originally established in 2008. These provisions had previously been introduced to Congress as part of the proposed FUTURE Act (S. 1535) of 2017 **[US Congress S.1535, 2017]**. The reader is advised to consult the following for further details for the Bipartisan Budget Act of 2018: **US Congress, 2018 and Gagnon, 2018**.

STORAGE SITE: DETAILED ENGINEERING, CONSTRUCTION, AND COMMISSIONING

The detailed designs of all new wells followed a risk-based approach. Each well was considered from a Bow Tie Analysis, risk management perspective to reduce the risk of loss of containment and ensure effective CO_2 conformance control within the BCS Storage Complex to ALARP.

INJECTION WELL PAD LOCATIONS

Each well pad and its access road were developed to limit land disturbance by using pre-existing access or clearings wherever possible. Each well pad location was optimized based upon:

- reservoir conformance control (based on reservoir modeling),
- distance to towns,
- residences and sensitive areas,
- reservoir quality of the vertical target,
- distance from the edge of the initial 3D seismic survey, and
- distance to the pipeline.

INJECTION WELL PAD DESIGN

The well pads for the new IWs at Radway 7-11 and Thorhild 5-35 were designed approximately 130 m by 130 m in size and located in a fenced-in area, similar to Radway 8-19. The well pads each consist of:

1. A vertical IW completed with L80 casing and 11.4 cm (4.5″) tubing.
2. One or more GWs.
3. One DMW (12.7 cm(5") L80 casing for Radway 7-11 and Thorhild 5-35; 17.8 cm (7″) L80 casing for Radway 8-19).
4. Protection for the BGWP and perforation only at the targeted injection zone.
5. Connection to power grid.
6. Enclosed skid to house computers for MMV instrumentation.
7. SCADA communication system for operational and critical safety elements, with independent communication to the Scotford Complex and Shell Canada staff located in Calgary.

One of the original appraisal wells, Redwater 3-4, located near the Scotford Complex, was converted to a deep pressure-monitoring well. It is the only DMW that penetrates the BCS.

To date, injection has taken place at two of the three injection wells.

EMERGENCY PLANNING

Emergency well-control processes were developed by Shell Americas Upstream - Well Engineering and Completion & Well Intervention Services. A third party, Wild Well Control Inc. (Houston, USA), developed a CO_2-specific Well Control Emergency Response Plan (ERP).

WELL DRILLING

Shell Americas Upstream planned, executed and delivered all well-site drilling, well-pad and connections to the CO_2 pipeline. All well drilling and completions work was finished by Fall 2013.

WELL ABANDONMENT PLANNING

Following the injection period, Shell Quest wells will be abandoned in a phased approach (see Figure 24) consisting of:

1. An observation period following the end of injection with continued monitoring of BCS conformance
2. Isolation of the BCS followed by continued observation to monitor containment, while ensuring re-entry is possible if required
3. Subsurface and surface abandonment of all wells when MMV will cease.

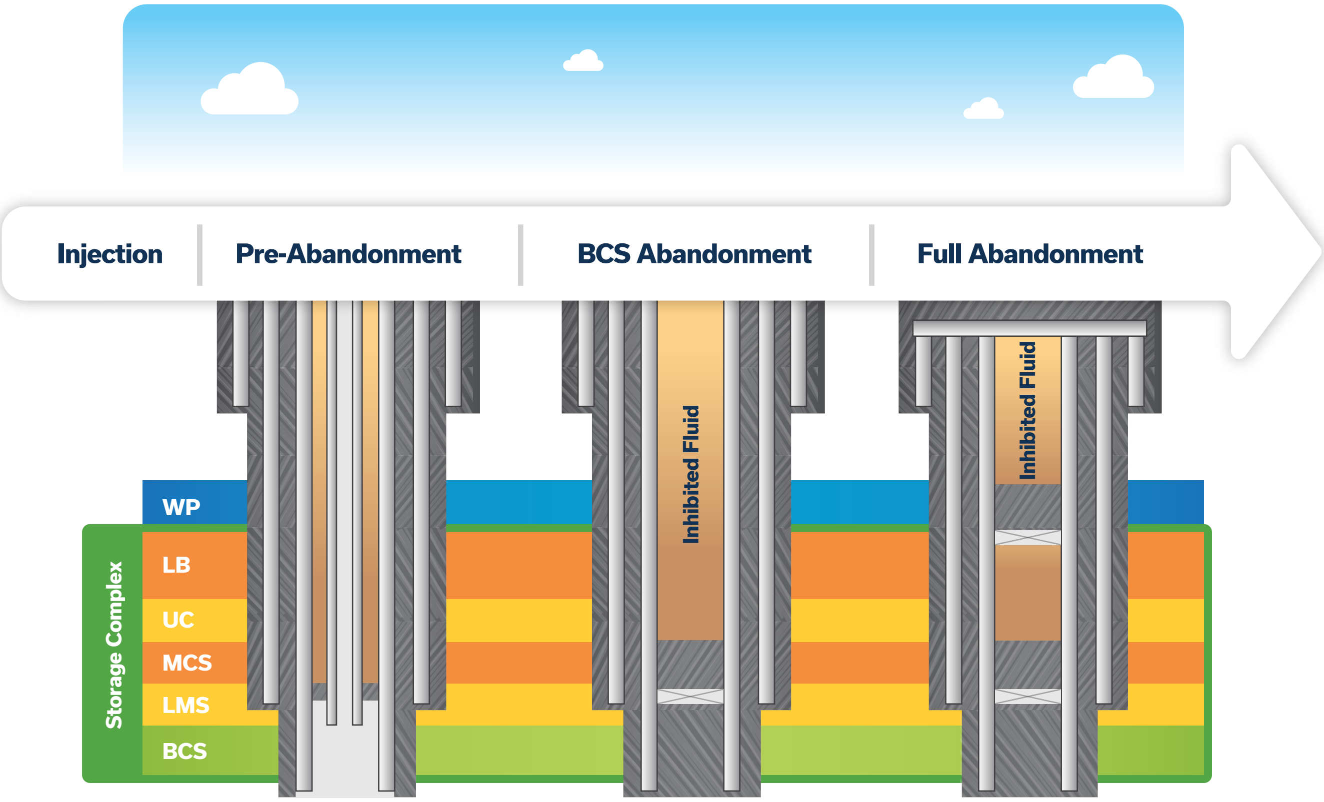
INDEPENDENT REVIEW OF STORAGE DEVELOPMENT PLAN

In November 2010, DNV completed an independent review **[Shell, 2010b]** of the Quest Storage Development Plan (SDP) **[Shell, 2011d]** and the associated Quest Measurement, Monitoring and Verification Plan **[Shell, 2011f]** dated August 2011 through an unaffiliated expert reviewer panel. DNV issued a certification of the Quest Storage Development Plan in October 2011 based on its extensive experience of pilot and full-scale CCS projects. Along with the Quest MMV Plan, the SDP was assessed as fully meeting the requirements of the Shell Quest Project by:

1. Demonstrating the selected site is naturally suitable for CO_2 geological storage:
    - There is sufficient pore space for the required 27 Mt of CO_2
    - Injectivity can be sustained for the 25-year duration of the project
    - Any migration of injection CO_2 or displaced reservoir brine outside the storage complex is extremely unlikely
2. Putting into place an appropriate risk and uncertainty management framework for the storage site by:
    - Conducting a thorough, comprehensive and systematic risk assessment
3. Pioneering work in risk management:
    - Systematic identification and management of uncertainty and its integration with risk assessment
    - Developing a risk-based MMV plan that sets a precedent for design of MMV programs for CCS globally

This was the first time ever that a commercial-scale CCS Project had its geological storage field development and MMV plan certified.

FIGURE 24 | INJECTION WELL SCHEMATIC INDICATING THE THREE PHASES OF ABANDONMENT [Source: Shell, 2011f]



COMMISSIONING AND START-UP

Due to early completion of the well systems and CO_2 pipeline, these critical components of the Shell Quest Project were commissioned early in Fall 2014. The pipeline commissioning took place following a hydro test and a first pigging run to establish a baseline for future corrosion inspections.

The wells telemetry system was evaluated to ensure that real-time injection pressures, temperatures and flow rates were recorded. Well commissioning took place in the Spring 2015 when sufficient system pressure for injection was achieved utilizing CO_2 from the HMU 3 amine absorber (see below)..

SYSTEM-WIDE COMMISSIONING AND START-UP ACTIVITIES

PRE-INJECTION MMV ACTIVITIES AND SURVEYS

Prior to injection, 2015 was a busy year with MMV activities being undertaken for collection of additional baseline data. Table 19 shows the activities conducted prior to initiating commercial-scale CO_2 injection in August 2015. A private, secure data network was installed between all well sites, the Scotford Upgrader, the Calgary office and relevant external parties in 1Q2015. During 2015, some measurements, such as DTS, required site visits to download data stored locally at well pads. Measurements were subsequently automated in 2016.

In March 2015, in preparation for the start-up of the capture facility and the pipeline later that year, each of the three IWs was prepared by pulling up the suspension string, running an RST log, performing a wellhead integrity test and installing a flapper valve. At this point, IW Radway 8-19 was converted from "test" mode to "injection" mode to enable system-wide commissioning activities. DMWs Radway 8-19 and Redwater 3-4 were perforated in the Cooking Lake Formation and a pressure-temperature gauge was installed at each location. The microseismic array (MSM) was run downhole into DMW Radway 8-19.

Commissioning took place across the CCS system over 6 months from Fall 2014 to Spring 2015.

CAPTURE FACILITY COMMISSIONING AND START-UP

Steam blowing of large low-pressure steam headers and chemical cleaning of the amine system were completed as pre-commissioning activities at the Capture Facility. These were followed by pre-commissioning the CO_2 compressor.

Mechanical work for HMU 3 was completed first along with completion of the upgrader expansion, followed by mechanical completion of the capture facility equipment for HMU 1 and HMU 2. Construction reached mechanical completion on February 10, 2015, including addressing all A and B deficiencies, which was a requirement for initiating commissioning and start-up. By February 20th all C deficiencies were addressed enabling demobilization by Fluor and its sub-contractors.

The associated commissioning activities were phased and initiated as soon as sufficient systems were handed over to the commissioning and start-up team to sustain work. Commissioning was completed by the end of 1Q2015. Following a turnaround at Base Plant, including HMU 1 and 2, the amine absorbers were started in series, including reliability testing conducted individually. The capture facility was operated for two months prior to full system start-up. In the interim, the injection wells were each conditioned by displacement of test water with CO_2 delivered by tanker truck.

The entire capture, compression, dehydration, pipeline and injection system was started up with the pipeline first being filled and pressured up between August 19-22, 2015. The Radway 8-19 IW was started up after the Radway 7-11 IW achieved stable injectivity and there was a pressure response from the first injection well. The third IW (Thorhild 5-35) had not been required up to the end of 2016 but had been maintained in the event it might be required in future.

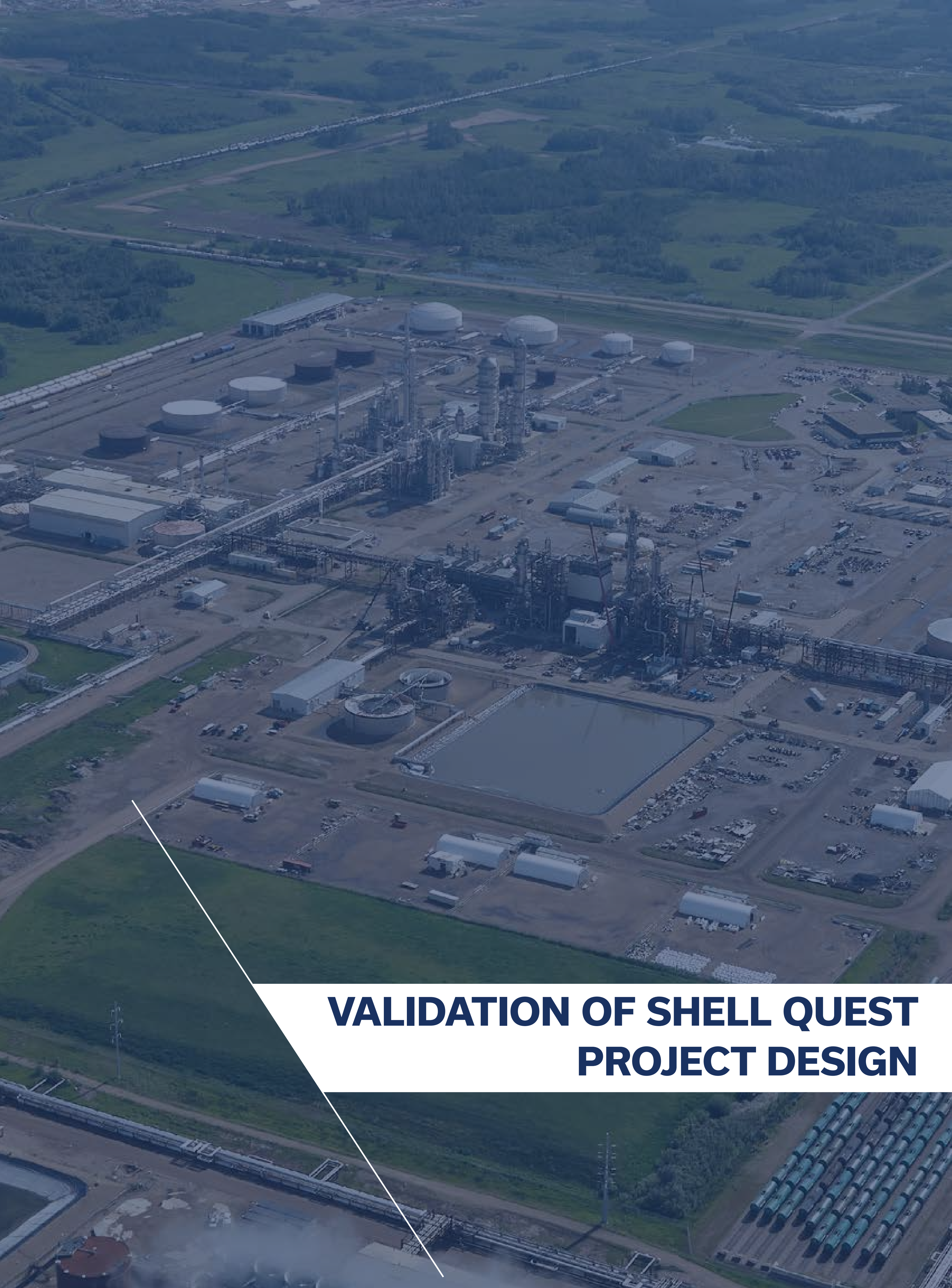
ISSUES ENCOUNTERED DURING COMMISSIONING

Upon first-time shutdown of the CO_2 compressor in late May 2015, a rapid deceleration of the motor and a reverse rotation of 500 RPM occurred. While there was no damage to the motor, this situation was considered a high risk for potential future shutdowns. The problem that was encountered involved the high back pressure of CO_2 within the pipeline braking the compressor impeller blades due to insufficient pressure relief.

An immediate temporary solution was deployed in the process control system to prevent operation of the compressor at any discharge pressure in excess of 12 MPa(g). The compressor was successfully restarted in mid-August 2015 when the complete system was operational. Late in 2015, the Scotford Complex Engineering team developed and deployed a more desirable long-term solution by modifying the setup of the compressor blowdown system to incorporate blow-off capacity to the 4th, 5th and 6th stages. This modification enables more rapid de-pressurization upon shutdown. This procedure has enabled compressor operation up to the discharge pressure specification of 14 MPa(g) **[Shell, 2016b** and **Rock, et. al., 2017b]**.

TABLE 19 | PRE-INJECTION MMV ACTIVITIES AT SHELL QUEST STORAGE SITE [Source: Shell, 2016b]

	MMV Activity	Date	Details
	Atmospheric Testing		
1	LightSource ($LOSCO_2$)	June 2015	CO_2 release test at IW pads; 27 releases of 30 mins at 300 kg/h. Demonstrated detectability of the releases.
2	Eddy Covariance	Jan-Dec 2015	Continuous data collection at well 8-19.
	Hydrosphere and Biosphere Testing		
3	Groundwater well sampling as well as pH and EC monitoring at project and landowner wells.	Quarterly	Tests within 1 km of IW pads (anticipated CO_2 plume size) as per standard testing detailed in ***Measurement, Monitoring and Verification*** subsection of ***CO_2 Storage*** section of this report.
4	Groundwater well sampling as well as pH and EC monitoring at project and landowner wells (two surveys).	February 2015	All landowner and IW monitoring groundwater wells within the VSP survey area. A sampling survey was conducted pre- and post-VSP measurement survey.
5	Soil-gas sampling at IWs	August 2015	Probes installed at depth of 0.8-1.0 m. Tests within 6 km radius of IW pads as per aforementioned testing protocol.
6	Soil surface CO_2 flux at IWs	August 2015	As per aforementioned test protocol.
	Geosphere Testing		
7	VSP baseline survey	February 2015	8 walkaway VSP lines acquired at each IW location utilizing DAS fibres in each well.
8	DAS monitoring	February 2015	Conducted in conjunction with VSP survey
9	MSM calibration	April 2015	Array reinstalled at well 8-19 and calibrated with vibroseis surface shots at four locations around the DMW 8-19
10	InSAR	Monthly	As per aforementioned test protocol.
	Wellbore Integrity Testing		
11	RST logging at IWs	March 2015	As per standard wellbore logging test procedure.
12	Wellhead integrity testing at IWs	March 2015	As per standard wellbore logging test procedure.



VALIDATION OF SHELL QUEST PROJECT DESIGN

Following stable operation of the entire capture facility for two months, performance guarantee tests were run on the facility to assure compliance. Any non-compliance was addressed under the warranties provided by various contractors.

Three performance tests were conducted during 2Q2015 to 3Q2015, as required by the milestones included in the funding agreement with the GOA:

- ***Capture Capacity*** – September 4, 2015
  - ▹ Required: 24 consecutive hours of operation of the entire capture facility by processing a minimum of 2,960 tonnes, equivalent to 1.08 million tonnes per annum of capture
  - ▹ Achieved: 3,094 tonnes of CO_2 injection at the storage site, equivalent to 1.1 Mt/yr
- ***Capture Efficiency*** – August 31 to September 20, 2015
  - ▹ Required: Operation of the entire capture facility for 20 consecutive days at a capture efficiency of more than 75% of the total CO_2 produced by the HMU facilities during that period
    - » The minimum production rate during that period would be 35 tonnes/hour or 840 tonnes per day
    - » The average production rate during that period would be at least 58 tonnes/hour or 1,392 tonnes per day
  - ▹ Achieved: 20 days of continuous operation with an average capture ratio of 81% and injection of 3,115 tonnes per day, with a CO_2 composition of more than 95% and a water content of less than 168 ppmv
- ***Integrated Project Reliability*** – August 29 to September 28, 2015
  - ▹ Required: 30 days of consecutive operation of the entire Quest Project without shutdowns
    - » Total tonnage of CO_2 stored in the BCS formation was required to be a minimum of 30% of the expected daily production rate equivalent to an annual production rate of 1.08 million tonnes of CO_2, or 26,640 tonnes during the 30-day period (or 888 tonnes per day).
    - » This test was required to prove commercial operation was a reality.
  - ▹ Achieved: Continuous integrated operation for 30 days at a throughput rate of 3,122 tonnes of CO_2 per day, or 93,660 tonnes during the 30-day period. This was equivalent to 1.14 million tonnes of CO_2 on an annual basis.

Following successful performance testing, the Shell Quest capture facility was handed over by the commissioning and start-up team, which was supported by Fluor and its subcontractors, to the Scotford Operations team.

Three performance tests of the Shell Quest Project were required by government funders to demonstrate full-scale, commercial operation.

REGULATORY, PERMITTING, RISK AND SAFETY MANAGEMENT

The Shell Quest CCS Project was undertaken at a time of regulatory uncertainty regarding large-scale geological storage of CO_2 in deep saline aquifers in Alberta. Nonetheless, there was an effective regulatory system in place for oil and gas activities, including smaller-scale acid-gas reinjection sites across Alberta. The system at the time of initiating Shell Quest was fragmented with several agencies responsible for various elements of the regulatory approvals process. Quest was the first project to apply for regulatory approval of a large-scale geological storage site under a number of regulations. It was a complicated and time-consuming process that delayed the Final Investment Decision by several months, as previously discussed.

APPLICABLE REGULATIONS AND RELATED PROCESSES

Over 20 federal and provincial acts and regulations either applied or required clearance for the Shell Quest Project (see Table 20). The entire process from initial applications through supplemental information requests and amendments to approval took nearly two years to reach completion between March 2011 and February 2013. The regulatory approvals necessary to undertake a Final Investment Decision by AOSP were made by early August 2012. The regulatory approval process within Alberta has since been somewhat simplified with the establishment of the Alberta Energy Regulator (AER) that was operational in April 2014.

REGULATORY HURDLES

A bundled application for provincial approvals of the capture, transportation and drilling activities was assessed by the Government of Alberta during 2011. Three rounds of information requests were responded to by Shell.

The first hurdle was associated with the Pipeline Agreements that underwent an Enhanced Approval Process by ASRD. These were some of the first applications to go through the new process. Consequently, there was delayed processing and approval.

The second hurdle related to the timing of the Carbon Sequestration Tenure Regulation coming into force. The Quest Carbon Sequestration Tenure Leases could not be applied for nor approved until after April 27, 2011. Shell promptly applied for its leases. The leases were granted on May 27, 2011. This enabled the Alberta regulator to begin processing related applications for the project.

A public regulatory hearing was held in 2012 by the regulator — the Energy Resources Conservation Board (ERCB). From early 2014 the Alberta Energy Regulator (AER) considered the bundled application submitted in early March 2012. In a parallel activity, the Project was deemed to be within the federal jurisdiction of the Canadian Environmental Assessment Act (CEAA). Two reports were issued as a result of these reviews: a federal CEAA assessment report was completed, including a public review, by June 20, 2012, while the ERCB Decision Report was issued on July 10, 2012. Approval of the Shell Quest CCS Project was issued by the Alberta Minister of Energy in August 2012, following which a Final Investment Decision (FID) was taken by the AOSP JV partners to proceed with the Project. A public announcement of intention to proceed with construction, start-up and operation of the project was made in early September that year **[Shell, 2013a]**.

The FID timing shifted from March 2012 to mid-2012 as a result of protracted regulatory processes (see Table 20). A risk-based decision was taken to proceed with the detailed engineering in the Execute phase of the project, prior to the FID, in order to meet the commitment to a mid-2015 start-up date.

TABLE 20 | REGULATORY APPLICATIONS REQUIRED FOR THE SHELL QUEST PROJECT

[Source: Shell, 2011d, Shell, 2012a, and **Shell, 2013a]**

NO.	REGULATION / PURPOSE	AGENCY	APPROVED
Overall Project			
1	CEAA, Part 20	NRCan	June 2012 Approval 10-0155916
CO_2 Capture Facility			
2	OSCA, Sec. 13	ERCB	August 2012 Approval 8552D
3	EPEA, Div. 2, Pt. 2	AEW	August 2012 Approval 49587-01-05
CO_2 Pipeline			
4	Pipeline Act, Pt. 4	ERCB	August 2012 Approval 11837C
5	EPEA (pipelines - conservation & reclamation)	AEW	February 2013 Approval 284507-00-00
6	Historical Resources Act	ACCS	
7	Canada Transportation Act (railway crossings)	Canadian Transportation Agency	June 2012
8	Navigable Waters Protection Act, Sec. 5(1) 5(3) (water crossings)	Transport Canada	March 2011
9	Fisheries Act - Horizontal directional drilling river crossing	DFO	August 2011
10	Horizontal directional drilling river crossing	Transport Canada	March 2011
11	Horizontal directional drilling river crossing	ASRD	
12	Public Lands Act (pipeline agreements for river crossing)	ASRD	April-May 2011
13	River crossing alternative (potential, 2013)	AEW	May 2011
14	Pipeline lateral line approvals	ERCB	2011
CO_2 Storage			
15	Directive D56 (well licences)	ERCB	2011 License 54407
16	Historical Resources Act (well pads and access roads)	ACCS	October 2011
17	Water Act (well pads, access roads)	AEW	
18	EPEA Sec. 53 (storage scheme, EIA)	AEW	December 2011
19	Directive D65	ERCB	August 2012 Approval 11837C
20	Oil and Gas Conservation Act, Sec, 39	ERCB	August 2012 Approval 11837C
21	Mines and Minerals Act, Carbon Sequestration Tenure Regulation	Alberta Energy	May 2011
22	CO_2 Disposal Class II Wells	ERCB	August 2012 Approval 11837C
23	Well licenses for injection, MMV & GW monitoring	ERCB	September 2012
24	Directive 51 (disposal)	ERCB	Licenses 0448521, 0448520, 0421182

"Over 20 federal and provincial acts and regulations either applied or required clearance for the Shell Quest Project."

Following regulatory approval by GOA, Shell Canada had an ongoing obligation to report in January of each year on progress of the Shell Quest project in terms of construction, well drilling and appraisal activities, MMV data acquisition and results, and stakeholder engagement activities. Since this was the first CCS project approved by the regulator under the new Carbon Storage Tenure Act, Shell Canada provided a significant amount of information to the provincial regulator to support learning and understanding by its staff. In addition to normal annual reporting, supporting information and studies were undertaken by Shell Canada to inform the regulator regarding:

- Pipeline leak audibility study **[Stantec, 2013a]**
- Pipeline leak detection (software and odorant injection) **[Atmos, 2011; Shell, 2013c** and **Stantec, 2013b]**
- Geomechanics of the Middle Cambrian Shale **[Shell, 2012c]**
- Perfluorocarbon Artificial Tracer Feasibility Reports **[Shell, 2014b** and **Shell, 2015c]**
- InSAR Feasibility and Detection Capability Studies **[Shell, 2013b; Shell, 2015d;** and **TRE, 2015]**
- LightSource Detectability Limits **[Shell, 2015c]**

The foregoing information has served to better inform AER about future requirements for CCS projects.

GHG EMISSIONS OFFSET PLAN

In December 2015, Shell submitted an offset project plan for the Quest CCS project to the Alberta Emission Offset Registry, to quantify emission reductions generated under the Alberta Offset System **[CSA, 2015, AEP, 2015,** and **CSA, 2018b]**. A quantification protocol was put into place in June 2015 to govern carbon credits for dedicated CO_2 geological storage in deep saline aquifers **[GOA, 2015]**.

Within Alberta, four methods of compliance exist under the Carbon Competitiveness Incentive Regulation (formerly the Specified Gas Emitters Regulation 139/2007) **[AEP, 2007** and **AEP, 2017]**. Among these, offset credits may be sold to other large industrial emitters to meet their reduction obligations. However, in order for credits to be available for sale, they must be verified and quantified by a registered independent third party. Shell annually reports its verified net emissions reduction volumes, which were estimated in the original offset plan at 881,000 tonnes CO_2e per year (net). The independent party verifying the emissions reduction is Cap-Op Energy Inc.

In Alberta, GHG offset credits may be sold to other large industrial emitters.

CLOSURE AND POST-CLOSURE PERIODS

Closure, post-closure, decommissioning and abandonment plans were originally prepared during 2010-2011 and filed with the appropriate regulatory authorities at the provincial and federal government levels. Reclamation, decommissioning and abandonment of the Project elements must be completed in compliance with the OSCA and EPEA provincial regulatory frameworks. Reclamation and closure of the storage site fall under the Carbon Sequestration Tenure Regulation. Conservation and Reclamation Plans for the wells and pipeline were submitted as part of the Environmental Assessment filed with the Governments of Canada and Alberta in November 2010. The Capture Facility portion of the Quest Project falls within the Reclamation activities of the Scotford Upgrader. Accordingly, the Reclamation Plan for the Scotford Upgrader was updated during the approvals stage of the Quest Project.

CO_2 capture, transportation and injection are expected to cease 25 years after achieving full, sustained operations in 4Q2015. Storage site closure activities will begin at that time. It is expected this post-injection period will last approximately 10 years. All MMV activities to ensure containment and conformance during this period will be conducted in compliance with the current Alberta CCS Act in the 2040-2050 time frame. The purpose of MMV activities during the closure period will be to verify that storage performance conforms with CO_2 plume location modelling forecasts and is consistent with secure long-term storage of CO_2 within acceptable risk tolerance **[Shell, 2013a]**. A final closure plan will be submitted to the regulator for approval three years prior to cessation of injection under the current CCS regulatory framework in the province.

At the end of the closure period, if the regulator is satisfied that the CO_2 geological storage site is secure, ownership of the site will be transferred to the Government of Alberta, or its delegated agency. This will transfer long-term liability for any potential future leakage from the storage site to the GOA. Sufficient, effective and reliable MMV systems will remain in place at the Quest storage site to provide early warning of loss of conformance or containment during post-closure.

Alberta's recently enacted Carbon Sequestration Tenure Regulation applies to all CO_2 geological storage projects undertaken in the province.

PUBLIC COMMUNICATION AND OUTREACH


OTTAWA 4098km
ST.PAUL 644km
LA BICHE 508km
LAMONT 639 km
682km
SADDLE LAKE 637km
746km

Shell conducted comprehensive public engagement and consultation for every aspect of the Quest Project and continues to maintain open and proactive communication with the public and other interested groups.

SHELL CANADA'S GOOD NEIGHBOUR POLICY

The approach taken in communication and outreach in the Quest Project as outlined in its 2013 Stakeholder Engagement Plan was guided by Shell Canada's Good Neighbour Policy **[Shell, 2013d]**, which commits the company to fostering long-term relationships with its neighbours through trust and respect, open and proactive communication, participative decision-making processes, environmental sustainability practices, utilization of local business services, and creation of local jobs.

COMMUNITY ENGAGEMENT STRATEGIES

When it began contemplating the Quest Project in 2008, Shell Canada actively engaged the local community. A particularly active period of interaction with neighbours occurred from January 2010 until the Quest Project applications were filed in November 2011. External stakeholders included:

- Landowners and occupants along the proposed pipeline route and within 450 metres of the right of way
- Landowners and occupants within the seismic survey activity area
- Landowners and occupants within a 5 kilometre radius of the Scotford Complex
- Municipal districts, town councils and local authorities within the AOI / ASLA
- Industry stakeholders within the Fort Saskatchewan and northeast Edmonton industrial region, as well as other oil sands operators
- Provincial and federal regulators
- Aboriginal communities

Shell Canada held open houses during this period in the nearby communities of Thorhild, Lamont, Bruderheim and Fort Saskatchewan. Open houses were regularly conducted from that time to provide updates to the communities on project approvals and progress on construction at the capture facility and local drilling activities. Invitations to interested Aboriginal groups were made to these open house events, along with being provided direct-mail project updates.

"Quest Cafés" were held from mid-2011 once or twice each year in local community halls. These events were aimed at engaging in meaningful conversation with community leaders in a small-group setting, and enabling engagement with Shell staff and researchers working on the Quest Project. Shell has attended local community events to provide information and updates about the Quest Project, which broadened its reach to the community. Local landowners, industrial and residential neighbours, and county/town councils were provided high-level project updates twice annually at community meetings, from 2008 until the project began operating in mid-2015.

A Community Advisory Panel was convened in November 2012 with participation by local residents. This move enabled a greater level of stakeholder engagement in the continued development of the MMV plan and enabled open discussion of results of ongoing MMV survey work.

A number of mechanisms were made available to the concerned public enabling them to ask questions and voice concerns through:

- A toll-free (1-800) project information phone line
- A project-specific email address
- Posting of project updates on a Quest sub-site of **www.shell.ca**
- Comment cards and evaluation forms that were made available when Shell attended community events

INFORMATION PACKAGES

Shell prepared and distributed comprehensive information packages to landowners and occupants along the pipeline route and within the 3D seismic survey activity area during 2012. The packages included basic information about the Quest project and the Scotford Complex, pipeline routing, planned seismic activities, and information regarding regulatory applications and associated public hearings **[Shell, 2013a]**.

COMMUNITY CONCERNS

Stakeholders have raised a few concerns that focused on the following:

- pipeline, well and storage failures;
- pipeline routing;
- containment and leakage;
- groundwater contamination.
- project perception given the newness and unfamiliarity of CCS technologies;
- land-use value and conflicts; and
- incident management, emergency response preparedness, and safety.

Concerns have been promptly and respectfully addressed by the Quest Project team.

The few community concerns raised concerning Shell Quest have been promptly addressed by the project team.

PROACTIVE RESOLUTION OF CONCERNS

Shell Canada established a "Shell Quest Project Issue Resolution Team" that met regularly beginning with the engagement of landowners in advance of the initial 3D seismic survey in 2011. Issues that arose from all forms of community engagement underwent a mitigation and resolution process wherever possible. Based on landowner feedback, the pipeline routing was altered several times in order to avoid the Bruderheim Natural Area. There were also several instances of repositioning the North Saskatchewan River crossing to address concerns.

ONGOING OPERATIONS

First commercial-scale injection of CO_2 into the BCS reservoir occurred on August 23, 2015 with industrial-scale operation beginning on September 28, 2015 after the successful completion of the three performance tests. Several milestones have been achieved since commercial operation began, including **[Shell, 2016b; Shell, 2017h; Shell, 2017m;** and **FSR, 2017]**:

- Operation at commercial scale: September 28, 2015
- 1 million tonnes CO_2 captured, transported and injected: August 8, 2016
- Capture facility reached nameplate capacity of 1.2 Mt/yr: September 24, 2016
- CO_2 pipeline in-line inspection completed: December 13, 2016
- Summit Award for Environment and Sustainability, 2017 – Association of Professional Engineers and Geoscientists of Alberta (APEGA) [‡‡‡‡] :
- 2 million tonnes CO_2 captured, transported and injected: July 13, 2017
- Successful completion of two audits during 2017 by the Alberta Energy Injection Certification and Alberta Climate Change Office under the Specified Gas Emitters Regulation Offset Program.

The following subsections of this report outline the observations and results from facility operations, MMV activities, knowledge sharing and regulatory processes from start-up until the end of December 2016, using publicly available information as of the date of this report.

CAPTURE OPERATIONS

OPERATING SUMMARY

Table 21 includes a capture facility performance summary, operational data for the compressor, as well as energy and utilities consumption, for the last three months of 2015 and the full year of 2016.

The amine stripper performed exceptionally well up to the end of 2016, with solvent regeneration meeting design specifications. Energy and utilities consumption also met design specifications. Nitrogen use was significantly lower than expected as a result of optimization of the TEG unit. Heat recovery from the CO_2 stripper reboiler steam condensate was on design target.

CO_2 injection at Quest began in August 2015.

‡‡‡‡ Provincial regulatory body for certification of practicing professional engineers and geoscientists.

TABLE 21 | SHELL QUEST CAPTURE PERFORMANCE AND OPERATING DATA UP TO DECEMBER 31, 2016

[Source: Shell, 2017h]

CO_2 CCS System	Units	2015§§§§	2016
Total CO_2 Injected	Mt CO_2	0.371	1.11
CO_2 Capture Ratio	%	77.4	83.0
CO_2 Emissions from Capture, Transport and Storage	Mt CO_2	0.057	0.161
Net Amount of CO_2 Avoided	Mt CO_2	0.314	0.947
CO_2 Capture, Compression & Dehydration – Utilities Consumption			
Electricity	MWh_e	12,300	32,800
Low Pressure Steam	kT	410	1,263
Low Temperature, High Pressure Steam	kT	1.96	5.52
Nitrogen	ksm^3	178	230
Wastewater	m^3	24,900	80,900
Energy / Heat Recovered	MWh_{th}	33,600	96,260
CO_2 Emissions (Capture, Compression & Dehydration)	Mt CO_2	0.030	0.083
CO_2 Compressor Operating Data			
Suction Pressure	MPa (g)	0.03	0.03
Discharge Pressure	MPa (g)	9.6	10.0
Motor Electricity Demand	MW_e	13.3	13.8
Upgrader HMU NO_x Emissions †††††			
HMU 1	kg/h	30 – 40	17 – 41
HMU 2	kg/h	25 – 25	12 – 34
HMU 3	kg/h	35 – 55	20 – 110

§§§§ For three months only: October – December, 2015

††††† Regulatory Limit for HMU 1 and 2 is 76.5 kg/h; regulatory limit for HMU 3 is 130 kg/h.

EARLY OPERATIONAL SUCCESSES ACHIEVED

In addition to the aforementioned milestones, the following achievements were made during the first 17 months of commercial operation **[Shell, 2016b** and **Shell, 2017h]**:

1. Overall capture performance was successful with a few early control system modifications to control amine flow, SMR firing and reformer fuel makeup rate.

2. ADIP®-X amine solvent composition met the design specification. Solvent loss was very low, averaging 5 tonnes monthly, or 50% below design level. Total amine consumption in 2016 was 38 tonnes.

3. The TEG dehydration unit exceeded expectations resulting in an average water content of 46 ppmv in the CO_2 product gas, nearly 50% improvement over design (84 ppmv).

4. Carryover of TEG into the CO_2 product gas was significantly lower than designed at less than 5 ppmv versus the design level of 27 ppmv.

5. Annual capture ratio exceeded the design target of 72%. The capture ratio improved in 2016 vs. 2015 due to increased amine circulation rates.

6. TEG losses amounted to 6,000 kg annually versus the design level of 46,000 kg/yr.

7. Flame stability in the HMU reformers following replacement of the burners with low-NO_x burners in 2015 met expectations. Higher capture ratios led to improved burner performance. Note: This has meant that in the event of low hydrogen demand, performance will be sub-optimal and capture ratios will decline.

8. Hydrogen production losses due to hydrogen entrainment in the amine absorbers was low, with an approximately 0.1% loss of total hydrogen and a 0.5 vol% content in the CO_2 product gas.

9. HMU performance was relatively unaffected from a reliability perspective versus the period before carbon capture facility operation.

10. NO_x emissions, while slightly elevated from baseline, remained below regulatory limits due to the incorporation of low-NO_x burners in the SMRs and flue-gas recirculation. This accounted for the lower reformer gas flowrates resulting from the incorporation of CO_2 capture at the HMUs that would otherwise have led to higher NO_x without appropriate mitigation measures.

11. There were no reportable emissions to air, soil or water from amine or wastewater spills or leaks.

In summary, the Shell Quest capture facility has exceeded expectations by operating at lower cost and higher capture performance and reliability than originally designed.

The Shell Quest capture facility has exceeded expectations by operating at lower cost and higher capture performance and reliability than originally designed.

CHALLENGES ENCOUNTERED DURING EARLY OPERATION

Shell has met its projected 1.08 million tonnes of CO_2 captured on average per year, reaching 2 million tonnes of CO_2 captured and stored by July 2017. Nonetheless, reduced capture volumes were experienced from time to time during capture facility operation up to the end of 2016 for the following reasons **[Shell, 2016b, Shell, 2017h,** and **FSR, 2017]**:

- An outage at the capture facility occurred on October 6, 2015 due to compressor anti-surge valve repairs.
- A pipeline outage necessitated a capture facility shutdown from November 24-25, 2015.
- Periods of low hydrogen demand from the upgrader necessitated operating at reduced hydrogen production that led to reduced burner performance in the HMU reformers. This occurred in November 2015, April-May 2016, and October 2016.
- Loss of amine circulation due to a pump trip resulted in suspension of CO_2 capture during several hours of June 21, 2016.
- The lean amine trim cooler underwent a plate-packing reassembly and cleaning from October 9-19, 2016 as part of the regular maintenance schedule. This procedure necessitated shutdown of the capture process.
- Retrieval of an in-line CO_2 pipeline inspection tool resulted in a suspension of injection from December 1-6, 2016.

The capture operational issues encountered were fewer than expected for a new facility **[Shell, 2016b** and **Shell, 2017h]**. Foaming of the ADIP®-X in the HMU amine absorber towers was the most significant operational issue encountered, resulting in tray flooding and temporary reduction in CO_2 capture rate, yet without significant impact on the stability of the HMUs. Several potential causes for amine foaming include:

- rapid changes and/or high gas flows in the amine absorbers,
- carbon fines entrainment from carbon filters that were originally included in the design to control foaming, and
- system impurities.

A temporary solution to foaming in late 2015 was determined to be more frequent carbon filter changes. By June 2016, this tactic proved ineffective, so the carbon filters were taken offline to test the impact on absorber foaming. Anti-foaming agent was also suspended in June 2016 and amine quality monitoring increased. Carryover of carbon fines from the filters into the amine was suspected to be the main culprit responsible for foaming. Back flushing of the carbon filters at the time of filter media change before putting the filter back into service has minimized carbon fines carryover thereby reducing foaming. As of the end of 2016, foaming issues had been resolved. An inspection of the carbon filter and a change of the filter medium was planned for 2017.

Fouling of the lean/rich amine exchangers which was noticed in late 2016 resulted in a gradual 2°C drop in rich amine temperature during the year, thereby increasing reboiler duty. Accordingly, cleaning of the heat exchanger was added to regular maintenance procedures.

A significant success has been the relatively low loss of hydrogen production as a result of incorporating carbon capture at the HMUs. Less than 0.1% of hydrogen production is lost, resulting in a 0.5 vol% content of hydrogen in the gas sent to the CO_2 pipeline. The reliability of the HMUs has not been impacted by the addition of CO_2 capture to the upgrader. Furthermore, a marginal improvement in fuel efficiency has been achieved as a result of removing CO_2 from the reformer burner fuel. The CO_2 had previously behaved as a heat sink and required the combustion of additional natural gas to fuel the reforming reaction.

EARLY PIPELINE OPERATIONS

Pipeline operations were stable from the beginning of system-wide operation to the end of 2016. A chart of design and operating conditions is shown in Table 22. The pipeline has been operated with CO_2 entering the system at supercritical conditions (9.7 MPa(g), 43 °C) and leaving the main pipeline at laterals for each IW site in liquid phase (9.1 MPa(g), 15 °C). Cooling occurs due to the ground temperature surrounding the buried pipeline. Based on a field temperature survey conducted in 2015, phase transition of the CO_2 occurs approximately 15-30 km from the outlet at the capture facility. Fluid composition in the pipeline up to the end of 2016 is shown in Table 23.

The pipeline is currently 64 km in length from the inlet to the last, unused IW, Thorhild 5-35. CO_2 emissions associated with transportation of the captured carbon dioxide are attributed to electrical power used to operate the compressor. These power-related emissions account for 99% of transportation GHGs (see Table 22).

TABLE 22 | QUEST CO2 PIPELINE DESIGN AND OPERATING CONDITIONS [Source: Shell, 2017h]

CHARACTERISTIC	SPECIFICATIONS	UNITS	AVERAGE OPERATING DATA/ ACTUAL LIMITATIONS 2015	AVERAGE OPERATING DATA/ ACTUAL LIMITATIONS 2016	ORIGINAL DESIGN
Pipeline Inlet Pressure	Normal	MPa(g)	9.4	9.8	10
	Max Operating	MPa(g)	12	12	14
	Min Operating*****	MPa(g)	8.5	8.8	8
	Design Max	MPa(g)	-	-	14.8 (at 60°C)
Pressure Loss from Inlet to Well Site	Normal	MPa	0.6	0.6	0.4 (for 3 IWs)
Temperature	Compressor Discharge	°C	130	130	130
	Pipeline Inlet After Cooler	°C	43	43	43
	Upset Condition at Inlet	°C	-	-	60
	IW 7-11 Inlet Temp	°C	15	16	-
	IW 8-19 Inlet Temp	°C	12	12	-
Flow Rates	Normal Transport Rate	Mt/a	1.04	1.11	1.2
	Design Min	Mt/a	-	-	0.36
	Total Transported	Mt	0.371	1.11	-
Energy and Emissions	Total Power for Transport (compression)	MWh_e	41,527	119,426	-
	Total Transport Emissions (incl. compression)	Mt CO_2e	0.027	0.077	-

The Shell Quest pipeline is 64 km long extending from the Upgrader to the third, unused injection well.

***** Based on a CO_2 critical pressure of 7.38 MPa

TABLE 23 | SHELL QUEST PIPELINE FLUID COMPOSITION [Source: Shell, 2017h]

COMPONENT	ACTUAL OPERATING 2015 VOL%	ACTUAL OPERATING 2016 VOL%	DESIGN NORMAL COMPOSITION	DESIGN UPSET COMPOSITION
CO_2	99.45	99.38	99.23	95.00
H_2	0.48	0.51	0.65	4.27
CH_4	0.06	0.06	0.09	0.57
CO	0.02	0.02	0.02	0.15
N_2	0	0	0.00	0.01
TOTAL	**100**	**100**	**100**	**100**

PIPELINE INSPECTION

An in-line pipeline inspection tool (a smart pig) was used to inspect the first 34 km of the pipeline (launcher to receiver at LBV 3) in December 2016 as per requirements by the Alberta Energy Regulator (AER). There was no flow in the second section of the pipeline since IW 5-35 was not in operation. A short drive-cup section prevented the inspection tool from progressing past the isolation Orbit valve at LBV 1 (15 km). This necessitated de-pressuring the pipeline to retrieve the smart pig, thereby venting 600 tonnes of CO_2 to the atmosphere during an outage at the capture facility that had resulted in a lost capture opportunity of 15,000 tonnes.

A second run of the inspection tool was successfully completed following modifications to the drive-end of the smart pig. The inspection determined there was no active internal corrosion of the pipeline due to exposure to CO_2. Five external wall loss anomalies associated with piping fabrication were identified during the inspection. These anomalies all lay outside the 1.3 mm corrosion allowance of the pipeline design as well as the minimum fracture toughness limits. An evaluation was being made in 2017 to determine if any remediation action would be necessary. No results of this evaluation were publicly available as of the date of this report.

Routine inspection and monitoring of the pipeline to ensure its ongoing integrity was conducted as previously described in the "CO_2 Pipeline" section of this report.

EARLY OPERATIONAL ISSUES

Only one pipeline-related operational issue was encountered up to the end of 2016. From November 24-25, 2015, a pipeline trip at line-break valve 3 due to power issues was experienced for a period of 2 days. This resulted in shutdown of the pipeline, including CO_2 injection.

ACTUAL STORAGE PERFORMANCE UP TO DECEMBER 2016

INJECTION

CO_2 injection utilizing two IWs, Radway 8-19 and Radway 7-11, began on August 23, 2015 **[Shell, 2016b]**. To date, no injection has been required at the third IW, Thorhild 5-35. Sufficient injection capacity for 1.2 Mt/yr has been afforded by two injectors. Since CO_2 injection began, MMV data indicates that no CO_2 has migrated outside the BCS reservoir.

Until the end of 2016, the ability to operate the third IW was assured through regular maintenance in the event it might be required due to any operating issue that might be encountered at either of the other two IWs. It is well understood that fluctuating injection rates at CO_2 wells reduce injectivity significantly, resulting in halite precipitation in the near wellbore region of the storage complex **[Spitz et. al., 2017]**. Loss of injectivity has been demonstrated to become more problematic following long periods without any injection. This challenge may be partially addressed by initially injecting water, when a well is made operational, to clear any halite precipitation near the wellbore. This process may, however, only be partially successful.

In order to simplify the continuous downhole pressure monitoring at IW 5-35, which also serves as a far-field calibration point for the reservoir model, injection at the IW 8-19, which is closer to IW 5-35, is held at approximately 70 tonnes/hr, while injection at IW 7-11 is permitted to vary along with any fluctuation in capture facility output volumetric rates. By the end of 2016, 0.701 Mt of CO_2 had been injected at IW 7-11, and 0.778 Mt of CO_2 had been injected at IW 8-19, totalling 1.479 Mt of CO_2 since the beginning of operation of the Shell Quest Project. Figure 25 shows the daily flowrates at both IWs and the total volume of injected CO_2, while Figure 26 shows the average daily pressure and temperature measurements at the injection wellheads and downhole, covering the period of start-up to the end of 2016. Fluctuations in pressure, temperature and flow rate (see Figure 26) reflect periodic shut downs previously described.

Since IW 5-35 has not been used for injection, the number of MMV activities at that wellsite have been reduced, including VSP surveys, which provide reservoir saturation measurements. This has enabled a reduction in MMV operating costs.

WELLBORE INTEGRITY

Wellbore integrity was normal as of mid-2016. Surface casing vent flow tests indicated levels within acceptable limits, ranging from a nil reading at IW Radway 8-19, very low levels at IW Radway 7-11, and unchanged levels at unused IW Thorhild 5-35. The predominant gas present in the surface casing was methane. Gas-migration testing of the wells indicated gas migration at IWs declined from the initiation of CO_2 injection in 2015 to the end of 2016. IW 7-11 has shown no sign of gas migration, while IW 5-35 showed a nearly 50% decline compared with 2015, although well within regulatory limits and contained within the ASLA (approved Shell Quest lease area).

"Sufficient injection capacity for 1.2 Mt/yr has been afforded by two injectors."

FIGURE 25 | SHELL QUEST DAILY INJECTION RATES AT EACH INJECTION WELL, ALONG WITH TOTAL INJECTION VOLUMES UP TO THE END OF DECEMBER 2016 [Source: Shell, 2017h]

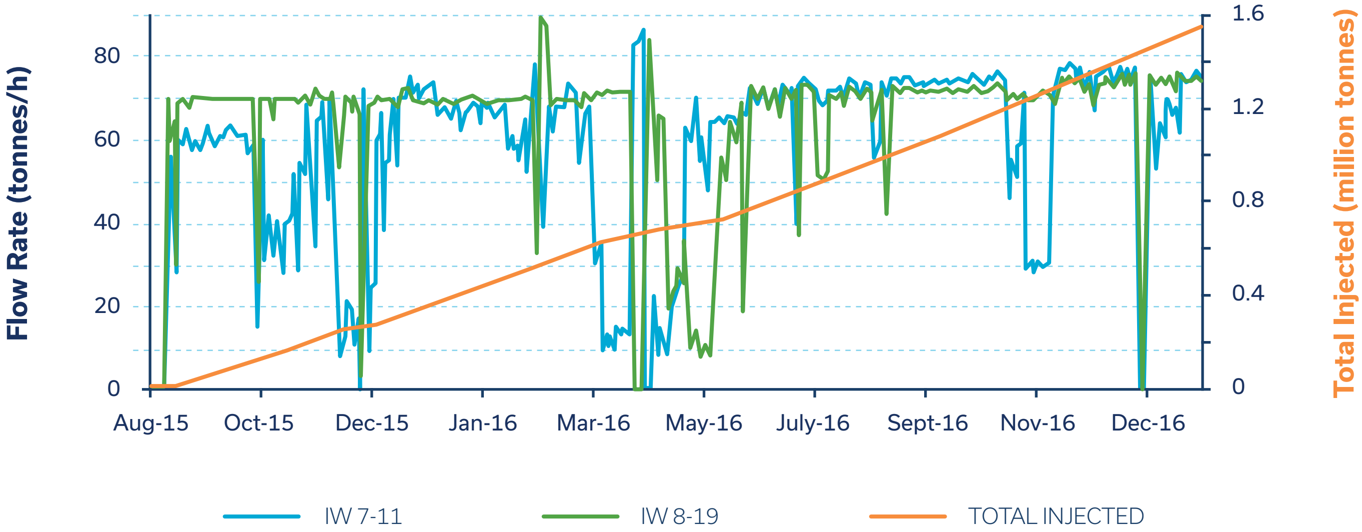
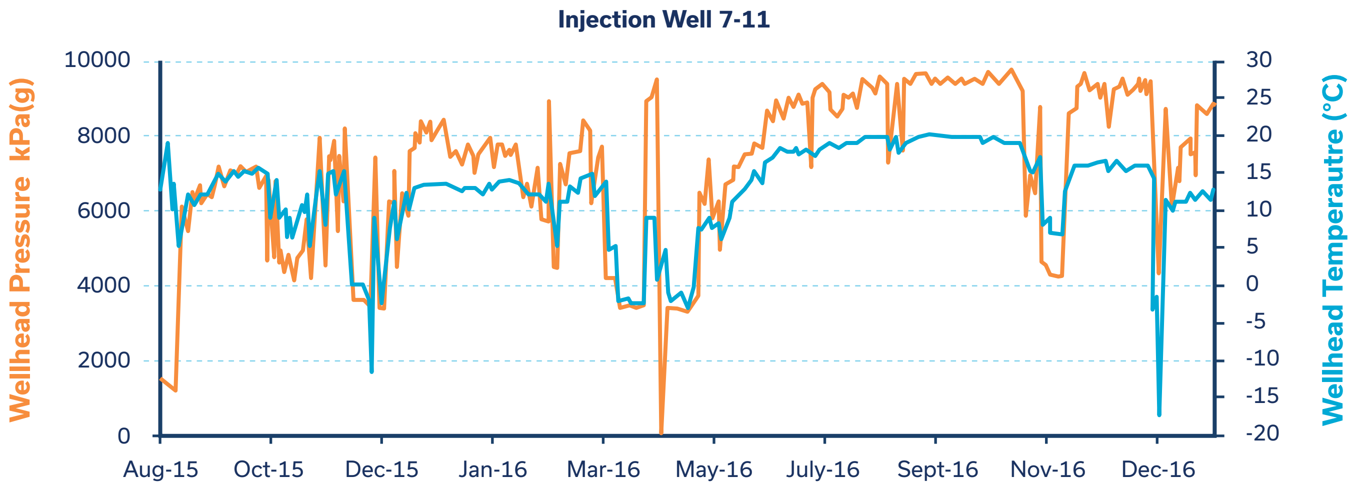
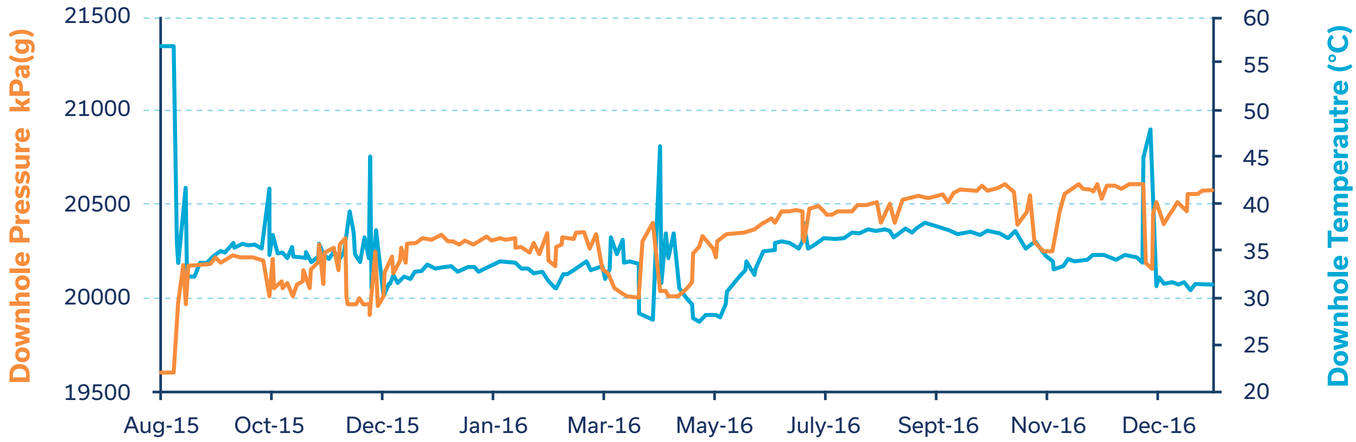
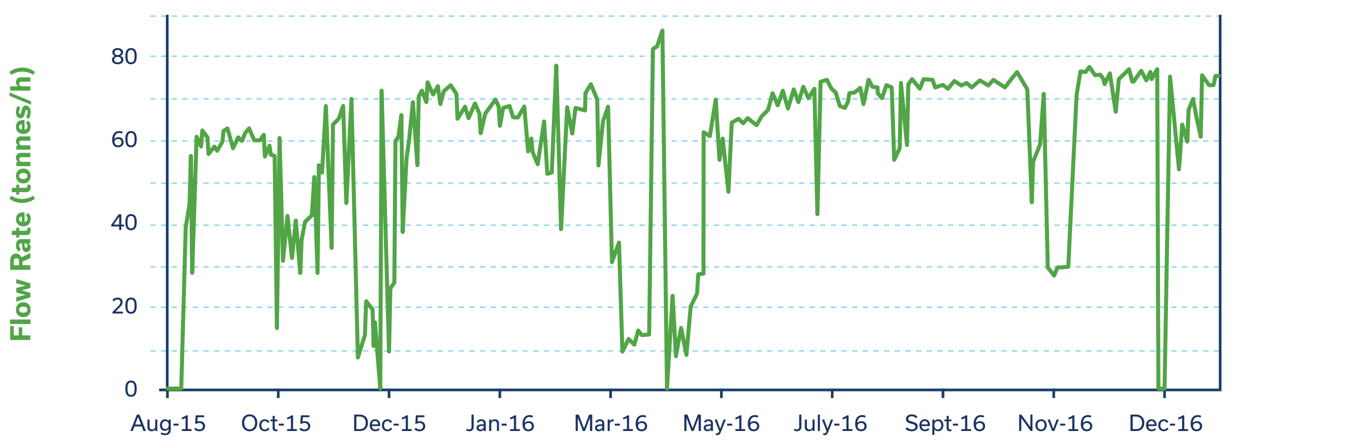


FIGURE 26 | INJECTION WELL PRESSURE, TEMPERATURE AND FLOW RATE AT SHELL QUEST UP TO THE END OF DECEMBER 2016 [Sou

rce: Shell, 2017h]







STORAGE CAPACITY

Since the beginning of injection, the uncertainty in the total capacity of the BCS reservoir within the ASLA has been reduced through continual updating of the reservoir model with operating data. It has been demonstrated that by reducing the uncertainty in the pore volume, the reservoir has more than the required 30 Mt of capacity to support 25 years of CO_2 injection at 1.2 Mt/yr. Shell has determined that after 25 years, it will use about 5-7% of the available pore space in the BCS Storage Complex **[Shell, 2017k** and **Shell, 2017m]**.

The pressure build-up in the BCS by the end of the project has been calculated to be less than 2 MPa of the differential pressure at the IWs, which would be less than 12% of the pressure differential that would be required to exceed the BCS fracture extension pressure, and less than 20% of the regulatory constraint on bottom-hole pressure required by AER Directive 65 **[AER, 2016]**. Consequently, the risk of fracturing or CO_2 leakage due to reservoir caprock integrity issues has been reduced to negligible levels. This determination has been supported by InSAR data which has shown that the surface deformation over the ASLA is only one-third (approximately 3mm) of the original estimate **[Shell, 2017j]**. Accordingly, InSAR will only be used in future as a contingency MMV technology in the event an unexpected situation arises as determined by other monitoring methods **[Shell, 2017j]**.

INITIAL INJECTIVITY ASSESSMENT

The Shell Quest Project was designed for a maximum injection rate of 145 tonnes per hour utilizing three IWs. During the initial injection period up to the end of 2015, injection rates up to 140 tonnes per hour were sustained at two IWs. It was determined that, based on initial operation, it is unlikely that IW Thorhild 5-35 would ever be needed, to meet injectivity requirements **[Shell, 2016b]**. However, maintaining its operability is a key risk management strategy in the event of failure of either of the operating two IWs.

Operation for the year of 2016 didn't alter from the initial injectivity assessment **[Shell, 2017h]**, which has essentially shown that injectivity is comparable to high estimates made prior to injection. Consequently, no further well development is anticipated during the life of the project despite the initial planning for 3-8 IWs. This has led to a significant reduction in well and MMV OPEX costs **[Shell, 2017j]**.

OPERATIONAL MMV ACTIVITIES

Further to the commitments that Shell Canada made for the Quest Project to the Alberta Energy Regulator in its January 2015 MMV Plan **[Shell, 2015b]**, once injection was initiated in late August 2015, MMV activities initially proceeded according to regular operational schedules in that plan (see Table 24).

TABLE 24 | SHELL QUEST OPERATIONAL MMV ACTIVITIES AS PER 2015 MMV PLAN FROM 2015-2016

[Sources: Shell, 2015b; Shell, 2016b; and **Shell, 2017i]**

	MMV ACTIVITY	DATES	COMMENT
	Atmosphere		
1	LightSource on wells 8-19, 7-11 & 5-35	2016	System upgrades in 2016
2	Eddy Covariance at well 8-19	2015	Not undertaken in 2016
	Biosphere		
3	Soil-gas sampling around IWs	2015, 2016	Survey included all IW pads
	Hydrosphere		
4	Downhole pH and EC monitoring at project GW wells	2015, 2016	Downhole gauges replaced mid-2016
5	Discrete water and gas sampling at project GW wells	2015, 2016	Conducted quarterly
6	Discrete water and gas sampling at landowner GW wells at < 1 km from IWs	2015, 2016	Quarterly; in 2016 only 3 surveys around well 5-35 as it was not being used for injection
7	Landowner wells associated with VSP surveys	2015, 2016	Conducted pre- and post-surveys
	Geosphere		
8	Injection rate monitoring	2015, 2016	Continuous
9	Annulus pressure monitoring	2015, 2016	Continuous
10	DHPT monitoring at all DMWs and IWs	2015, 2016	Continuous
11	DHP monitoring at Redwater DMW 3-4	2015, 2016	Continuous
12	WHPT monitoring at 3 IWs	2015, 2016	Continuous
13	Mechanical well integrity testing of 3 IWs	2Q2016	Once
14	Tubing caliper logging at 3 IWs	2Q2016	Once
15	Routine maintenance, including RST and temperature logs, measurement of hold-up depths of IWs 8-19 and 7-11	2Q2016	Once
16	MSM at DMW 8-19	2015, 2016	Continuous
17	DST monitoring at 3 IWs	2015, 2016	Continuous; work in progress for automated data download
18	DAS monitoring at 3 IWs	1Q2016	Used for VSP data survey collection
19	VSP Survey at 3 IWs	1Q2016	In conjunction with VSP survey
20	InSAR	2015, 2016	Monthly
	Wellbore Integrity		
21	Corrosion probes at IWs and DMWs	2015, 2016	
22	SCVF at IWs, DMWs, project GWs	2Q2016	
23	GM at IWs, DMWs, project GWs	2Q2016	
	CO_2 Product Gas		
24	Analysis of captured CO_2	2015, 2016	Done at Scotford Upgrader capture facility

The Shell Quest storage reservoir has ample capacity to store 30 MT over 25 years of operation.

Shell adopted a tiered approach to all monitoring parameters including groundwater quality within the ASLA to enable detection and pinpointing the location of any potential BCS brine leakage **[Shell, 2013a]**:

Shell Quest 2013 MMV Plan

Tier 0 Continuous monitoring of water electrical conductivity.

Tier 1 Groundwater sampling from Project and landowner GWs. Standard water quality analysis for bulk parameters, major ions, nutrients and halogens. Headspace gas sampling for analysis of composition and presence of PFC tracer co-injected with CO_2.

Tier 2 Repeat Tier 1 sample collection and analysis. Additional analysis for halogens and standard analysis for dissolved metals (potentially indicating CO_2 leakage from the BCS Storage Complex).

Tier 3 Repeat Tier 1 sample collection and analysis. Additional analysis for standard isotopes (e.g. strontium, oxygen, hydrogen, carbon, halogen ratios).

Tier 4 In the event of Tiers 0, 1, 2, and 3 indicating a change in water quality potentially attributable to the project, a variety of site-specific measurements would be acquired to delineate the contaminant plume and support risk management and mitigation activities.

Tiers 1, 2, and 3 of this groundwater sampling plan have been measured at regular intervals of at least once every two years since the baseline survey. Each tier represents an independent set of water quality measurements thereby providing successively increasing levels of confidence in the data. New GW sensors were installed at the Shell Quest well pads in early 2017 that improved measurement sensitivity and reliability. Regular field sampling surveys at landowner GWs have been maintained.

The Shell Quest Project team has continued to look for MMV technology improvements to enhance understanding, while reducing risks, uncertainty and operating costs. During 2015, Shell Canada, on behalf of the AOSP JV partners, signed an agreement with a US DOE-funded entity to develop and deploy MMV technologies for real-time ground water monitoring **[Shell, 2016a]**.

VSP surveys prior to and following 560,000 tonnes of CO_2 injection have shown that, at that time in Spring 2016, the plume extended 200 metres across and was smaller than originally estimated. Regular VSP surveys will continue, to assist in determining the size and extent of the subsurface CO_2 plume.

The micro-seismic array has worked well and shown excellent sensitivity. During 2016, three locatable micro-seismic events were recorded. However, all of them occurred hundreds of metres below the BCS Storage Complex in the Precambrian basement and were low magnitude (average Mw = 0.7), thereby presenting no risk to CO_2 containment **[Shell, 2018c]**.

The LightSource MMV technology was determined to be effective in monitoring CO_2 at the injection sites to indicate any leakage of project CO_2 from wells. It was confirmed as the primary technology to be utilized for atmospheric monitoring of the Shell Quest Project **[Shell, 2017k** and **Hirst, B., et. al., 2017]**.

A pulsed neutron log was conducted in the IW Radway 8-19 prior to injection and 6 months following start-up of Shell Quest. No change in the log response was observed above or below the perforated interval nor through the primary seal (Lower Marine Sands – see Figure 15). This provides assurance that the CO_2 is contained within the BCS reservoir.

Once sufficient data was collected to determine that the risk of leakage from the BCS Storage Complex was fairly low, a more conservative monitoring approach was taken, which was also tiered as follows **[Shell, 2017j]** (refer to Table 25):

Shell Quest 2017 MMV Plan

Tier 1 Monitoring technologies include downhole instruments that are in continuous operation, as well as periodic integrity tests and acquisition of seismic data. Anomalies in any Tier 1 data trigger further analysis of other data and potentially additional monitoring by Tier 2 MMV technologies.

Tier 2 Monitoring technologies that focus on air and water impacts. Anomalies in Tier 2 data trigger additional data analysis and potentially additional monitoring utilizing Tier 3 MMV technologies.

Tier 3 Monitoring technologies that enhance the understanding of potential air and water impacts.

The reservoir model for the BCS Storage Complex has been improved as a result of the acquired MMV data. It has been estimated that the maximum CO_2 plume extent after 25 years of injection will be 2 to 4 km in radius utilizing injection at only IWs 8-19 and 7-11, although the pressure gradient would spread far wider.

TABLE 25 | MONITORING APPROACH AS PER 2017 MMV PLAN [Source: Shell, 2017j]

TIER	TECHNOLOGY	INDICATOR	SURVEILLANCE FREQUENCY	TRIGGER	MAGNITUDE OF CO_2 DETECTION CAPABILITY
Tier 1	IW DHP	Pressure	Continuous	Measurement greater than 26 MPa	N/A
	DMW DHP	Pressure	Daily	Anomalous pressure increase above background	Deca tonne/day
	Micro-seismic	Locatable events	Daily	Sustained clustering of events with a spatial pattern that is indicative of upward fracturing	N/A
	DTS	Temperature outside casing	Daily	Sustained temperature anomaly outside casing	Qualitative
	Pulsed Neutron Logging	Log response	Every 5 years per AER directive	Indication of CO_2 outside BCS Storage Complex	Qualitative
	SCVF	Geochemical composition	Annually	Change in geochemical composition indicated presence of injected CO_2	Qualitative
	VSP2D	Seismic amplitude	Annually or bi-annually	Identification of a coherent and continuous amplitude anomaly above BCS	Kilo tonne/day
	SEIS3D, SEIS2D	Seismic amplitude	As required	Identification of a coherent and continuous amplitude anomaly above BCS	Kilo tonne/day
Tier 2	WPH	Water pH	Daily	Sustained decrease below baseline water pH value	Qualitative
	WEC	Electrical conductivity	Daily	Sustained increase above baseline water salinity value	Qualitative
	$LOSCO_2$	CO_2 emission rate	Daily	Sustained locatable anomaly above background level	Tonne/day at well pad
Tier 3	Water, Gas geochemical analyses	Various chem ical signatures	Variable dependent upon GW type	Outside expected range	Qualitative
Feasibility Stage	InSAR	Surface deformation	TBD	Unexpected localized surface heave	Qualitative

"Shell Canada estimated the cost of avoided CO_2 emissions was approximately $92.70 per tonne in 2016."

ACTUAL COSTS TO OPERATE SHELL QUEST

Shell has reported the breakdown of costs for operating the Quest Project as shown in Table 26. Also shown in this table are revenue sources. Shell Canada estimated the cost of avoided CO_2 emissions was approximately $92.70 per tonne in 2016, using a discount rate of 75% towards Alberta's 10-year term bond rate and 25% towards the industry standard discount rate **[Shell, 2017m]**.

ONGOING REGULATORY APPROVAL MANAGEMENT

Periodic regulatory approvals have been required for the Shell Quest Project to continue to comply with the overall approval of the project in mid-2012 (prior to the FID). These include:

1. Annual submissions of Quest CCS Project Status Reports until end of GOA funding period on March 31, 2026. This includes annual reporting on:
    a. Emissions (CO_2, NO_x)
    b. Energy and material balances, heat integration and parasitic losses
    c. CO_2 capture ratio and dehydration performance
    d. Funding, costs and revenues
    e. Design changes
    f. Operational reliability
    g. Operating summaries for each of capture, pipeline and storage, including maintenance and repair activities
    h. MMV Plan updates
    i. MMV activities
    j. Regulatory updates
    k. Public-engagement and knowledge-sharing activities
2. InSAR efficacy reports since InSAR is an unproven MMV technology. These reports are intended to confirm the value of the tool to indicate the size and extent of the subsurface CO_2 plume.
3. Submission of updated MMV and Closure Plans approximately every two to three years for approval (2012, 2015, 2017, etc.). These include improvements in understanding and assurance of reduced uncertainty and risk as a result of improved understanding regarding the size and extent of the injected subsurface CO_2 plume.
4. Approval of surface-casing vent flow (SCVF) and gas migration (GM) test reports annually as indications of potential wellbore and casing failures.

TABLE 26 | ACTUAL FEED, CAPEX AND OPEX COSTS AND REVENUE FOR SHELL QUEST

[Source: Shell, 2016a and **Shell, 2017m]**

PROJECT PHASE		MILLIONS OF DOLLARS, CANADIAN ($)
COSTS		
FEED		139.4
CAPEX	Labour and commissioning	147.9
	Tie-ins	37.1
	Capture	437.5
	Transporation	127.4
	Storage	40.4
Total CAPEX		790.3
Total CAPEX + FEED		929.7
Annual OPEX	2016 (Actual)	30.2
	2018 (Estimate)	35
REVENUE		
Government Grants		
Alberta	2012-2014[†††††]	298
	2015	149
	2016 and beyond	298
Canada	2009-2014	108
	2015	12
Total Grants		865
CO_2 Credits	2016 (Actual)	3.3
Total REVENUE	To end of 2016 (Actual)	600.1

Other regulatory submissions are made on a regular basis to ensure compliance with EPEA and the AER Well Integrity Directive D80 **[AER, 2014]**.

During 2017, due to operational needs, the Shell Quest Project submitted a request to AER for suspension of the third IW, Thorhild 5-35, which has not been required to operate the storage site at current volumetric injection rates. The intent is that IW 5-35 will continue to be used for continuous downhole pressure monitoring of the BCS but will not be maintained in order to assure backup injection capability. This will assist in calibrating the reservoir model as a far-field response to injection at the other two IWs.

Regulatory approval was sought in 2017 to convert the unused, third injection well to a monitoring well.

[†††††] An additional $6.6 million was provided by Alberta Innovates – Technology Futures in support of early site assessment work between 2009-2012

ONGOING KNOWLEDGE SHARING

Once the Quest Project moved into the operational phase, there was enhanced international interest in the project experience and insights. The project team began attending several conferences annually to share its knowledge with professionals in industry, governments, academia, and non-government associations in Canada, the USA, Asia, Europe and the Middle East. The Scotford operations team also began providing tours regularly to professional groups who made special visits to the Quest capture and storage sites **[Shell, 2017h]**. These knowledge-sharing activities numbered over 50 in 2016 alone, including a dozen site tours.

This level of interest is expected to continue for several years due to the low number of large-scale CCS commercial projects in operation globally and until there is familiarity and comfort with CO_2 geological storage and associated MMV activities.

ADDRESSING ONGOING PUBLIC INTEREST AND CONCERNS

Shell Canada has continued **[Shell, 2017h]** to maintain avenues for the community to provide feedback on the Quest Project operations and associated impacts, as noted previously. During 2016, over 40 recorded concerns were raised; some were repeated enquiries. Most concerns related to:

- timely payment of compensation for pipeline construction activities,
- ongoing MMV activities, and
- perceived safety of the CO_2 pipeline.

Shell Canada has continued to take these concerns and enquiries seriously. The company is sensitive to all requests, replies promptly, and puts into place action plans to address any identified issues.

Additionally, Shell Canada has continued to maintain the Community Advisory Panel that was formed in 2012 during development of the MMV Plan. This avenue continues to enable the community (residential and commercial), educators, emergency responders, academics and regulatory agencies with the ability to provide input on the design and implementation of the evergreen, adaptive MMV Plan that is updated every three years.

Shell Canada, on behalf of the Quest Project and its JV Partners, continues to hold twice-annual open houses in the region and attends community events to provide project progress updates.

CARBON DIOXIDE OFFSET CREDITS

In order to offset operating costs of the Shell Quest Project, Shell Canada, on behalf of the AOSP JV partners generates two revenue streams, as follows:

1. $298 million in aggregate government funding from the Government of Alberta for the first ten years of operation of the project.
2. Offset credits for the net CO_2 stored in the BCS Storage Complex and an additional offset credit for the CO_2 captured at the Quest capture facility. These were generated under Alberta's Specified Gas Emitters Regulation up to December 31, 2017 and are currently generated under the Carbon Competitiveness Incentive Regulation.

The value of offset credits has increased since they were first established for large emitters in 2007, as follows [**Blakes, 2015** and **GOA, 2018c**]:

a. Up to December 31, 2015: $15/tonne

b. 2016-2017: $20/tonne

c. 2018 and beyond: $30/tonne

As noted in the introductory section of this report, Shell Canada cannot receive government funds in excess of all costs for the life of the project offset by the sale of CO_2, the value of carbon credits, and other sources of revenue. Total government support for the project amounted to $865 million from the federal and provincial governments.

OVERALL GUIDANCE FROM EARLY OPERATIONS

Several lessons emerged from the project during its early operational period as shown in Table 27. These useful insights will serve as valuable guidance to other carbon capture and storage projects during design, engineering, construction and operational phases.

"Shell Quest will use 5-7% of available pore space over 25 years of CO_2 injection."

TABLE 27 | LESSONS LEARNED FROM EARLY OPERATION OF THE SHELL QUEST PROJECT

[Sources: Rock, L., et. al., 2017b, Shell, 2017k and **Shell, 2017m]**

Project Element	Description	Lesson Learned
Capture and Hydrogen Production	Reformer firing control improvements	HMUs required control logic modification to assure reliable operation during CO_2 capture. A turndown assessment was required on the fuel-gas circuit.
	Carbon steel used in low pH water service	Piping specification changes between greenfield and brownfield assets were required in design stage.
	Filtration management	Foaming and tray flooding in amine absorbers was encountered due to carbon entrainment from filters and throughput management.
	Compressor reverse rotation	Shutdown de-pressuring studies were required in design stage based on installed vessel and piping arrangement.
	Reliability performance plan	Good design and operating philosophies led to better than expected uptime and high CO_2 capture performance.
	Chemical losses	Losses were below budget for TEG and amine that led to operating cost savings.
Transportation - Pipeline	Pipeline pigging receiver design	Need to design to accommodate all pig sizes, including cleaning, maintenance and inspection smart pigs.
	Solar panel reliability	Solar panels must be supplemented with fuel cells to allow for short winter days. Locate in shade-free areas.
	Pig receiver location	Current receiver locations only enables pigging up to LBV3 since IW Thorhild 5-35 is not in service, so no flow to LBV6.
Storage	Reservoir performance	
	Injectivity	Better than expected injectivity was achieved.
	Pore space utilization	It has been estimated that Shell Quest would use 5-7% of available pore space over 25 years of CO_2 injection.
	Reservoir pressure	Reservoir pressure would only increase over that period by about 2 MPa, which would be under regulatory requirements.
	Injection Wells	
	Number of required injectors	Two IWs were sufficient for available CO_2.
	Water in wellbores post CO_2 injection	Nitrogen must be used instead of water for logging equipment testing prior to lowering downhole.
	Pulse neutron logging	Confirmation that the injected CO_2 is geologically located as predicted prior to injection.
Stakeholder Engagement	Listen	Perceived risk has as much merit and importance as actual risk.
	Accommodate feedback	Legitimize concerns from the community and be open to changing the project plan accordingly.
	Hold stakeholder meetings on their terms	Meet where the community is comfortable. Don't expect concerned parties to come to you.
	Be consistent and genuine	Build deep relationships. Acknowledge there is distrust of corporations. Build trust through people-people interactions.
	Communicate using the broader project team	The community wants to build relationships with project leaders and experts not simply the corporate community relations team.

SUMMARY OF CHALLENGES ENCOUNTERED FROM INCEPTION TO EARLY OPERATION

Several challenges were encountered during the project design, construction and early operational periods as outlined below.

TECHNICAL

From a technical perspective the following represented significant challenges:

- Integration of the project into an existing bitumen upgrader facility during a peak period of construction to expand the operation;
- Rapid modification of the ADIP®-X amine carbon capture technology to minimize impact on the upgrader performance, reliability and throughput
- Implementation of a new approach to MMV planning and risk assessment
- Design and performance of essential MMV baseline surveys, and
- Design, engineering and construction of appropriate capture, pipeline and storage site infrastructure.

Furthermore, a few start-up and early operational challenges associated with the CO_2 compressor, HMU burner design, and amine foaming, which impacted capture efficiency, were quickly and efficiently addressed through sustainable long-term solutions with minimal impact on overall operations. Clearly, the Shell Quest team had the essential knowledge and experience to successfully navigate technical hurdles with which it was presented.

REGULATORY UNCERTAINTY

Shell Canada and its AOSP JV partners embarked on the Quest Project in advance of a solid regulatory regime being put into place in Alberta for dedicated carbon capture and storage operations. The regulatory hurdles encountered by the project took almost two years to overcome. Nonetheless, the project team successfully navigated a complex array of regulations at the federal and provincial levels of government, both existing and emerging, to secure all the necessary approvals with minimal impact on the project schedule and budget.

TIMING AND PROJECT SCHEDULE

The schedule Shell Canada committed to the federal and provincial governments was tight and highly demanding. It was even more grueling given the complexity of the regulatory requirements to secure government and AOSP JV partner approvals to proceed with the project. The team demonstrated an exception level of dedication to overcome both the obstacles and the demanding pace of work in the period leading up to the FID. Very small schedule slippage occurred as a result – a delay of less than three months was experienced from the early commitment in 2009 to initiating operation in May 2015 that moved into late August 2015. Essential performance and capacity testing of the integrated CCUS project were completed shortly thereafter by the end of September 2015, thereby meeting provincial funding requirements.

CONSTRUCTION LOGISTICS

The Shell Quest Project was undertaken at a time of considerable activity at the Scotford Complex. The Upgrader was undergoing a massive expansion to add a new, larger bitumen conversion train, including a new steam methane reformer (HMU3). To minimize the complexity of construction and the risks associated with increased levels of labour on site at the Upgrader, Shell Canada elected to construct the Quest Capture Facility using a modular approach. This proved to be a highly successful strategy to minimize schedule delays and to keep a tight lid on equipment and labour costs, while effectively managing on-site construction complexity and safety. This differs quite dramatically from the situation experienced by SaskPower during the construction of the Boundary Dam Unit 3 CCS Facility during 2011-2014 at a period of high construction labour demand and rising capital equipment costs **[IEAGHG, 2015]**.

Implementation of a new approach to MMV planning and risk assessment was successful at Shell Quest.

STORAGE RISK MANAGEMENT

The Shell Quest Project undertook a comprehensive risk assessment approach in the development of its MMV and storage development plans. That approach resulted in a large number of proven and new MMV technologies being screened into the monitoring plan for the project. Furthermore, this conservative approach led to a large number of initially proposed injection wells (8). Detailed characterization and monitoring data surveys during the baseline period from 2011-2015 enabled the project team to reduce the number of injection wells to three and reduce the number of MMV tools that minimized the risks of uncertainty related to storage containment, conformance, and capacity. With a continued focus on feasibility, value and cost of various MMV tools, Shell Quest had reduced the number of MMV tools by nearly 40% by the end of 2016. Additionally, the number of injection wells will likely be reduced in the near term to two since injectivity, containment and conformance control have proven more successful than initial conservative estimates. The project has proven that technical skill and experience, coupled with a rigorous approach to risk and cost management, will assure continued future performance and stakeholder acceptance.

ECONOMICS

Tight controls on engineering, capital and operating expenditures proved critical to minimizing the cost of implementing a carbon capture and storage operation at the Scotford Upgrader. Nonetheless, Shell Canada's strict discipline in implementing cost control measures has demonstrated that deploying CCUS at a heavy oil upgrader or refinery is not yet economic without considerable support in the form of government or other external funding. This is due to the high capital and operating costs typically experienced by early adopters. That situation could well change with continued operation and replication of the technology that will help drive down both operating and capital costs through experience and associated incremental improvements that are typical of industrial facilities deploying new technologies [e.g. see **NETL, 2013]**.

FEASIBILITY OF REPLICATION

As of 2016, Alberta-based industry has greater certainty concerning carbon credits issued under the Carbon Competitiveness Incentive Regulation **[AEP, 2017]** with prices having risen from $15/tonne as recently as 2015 to $30/tonne in 2018, and rising further to as much as $50/tonne nationally by 2022 **[FP, 2018]**. With a solid regulatory regime in place in the province and emerging nationally to encourage carbon emissions reduction by large industrial emitters, the increasing value of avoided emissions will incentivize industry to adopt CCUS. Furthermore, the ADIP®-X amine carbon capture technology chosen by Shell Canada for the Quest Project has a long record of successful commercial installation. With Shell's commitment to knowledge sharing provincially, nationally and globally, there is a very high probability that Shell Quest Project technologies will be replicated elsewhere in the years to come.

Detailed characterization and monitoring during the baseline period led to a reduction in the number of injection wells from as high as 11 down to 3. Up to the end of the reporting period, only 2 of the three injection wells installed were put into service.

GENERIC APPLICABILITY AND REPLICABILITY

The Shell Quest Project has significant replicability potential at oil sands or heavy oil upgraders and refineries globally that have in recent years come under considerable environmental scrutiny. In Canada alone, more than 265,000 cubic metres (1.67 million barrels) per day of synthetic crude oil is converted from bitumen and heavy oil (BHO) at upgraders **[NEB, 2018]**.

Globally, heavy oil and bitumen oil in place amount to nearly 1.43 billion cubic metres (9,000 billion barrels), with over 70% of that heavy crude distributed amongst North and South American nations **[Frost, 2018]**. In 2016, heavy oil and bitumen reserves comprised 53% of total crude oil reserves globally, with production amounting to 1.75 million m^3 per day (11 million barrels per day) at 14% of total global production **[ENI, 2017]** and expected to rise to nearly 20 million barrels per day by 2035, outpacing the growth of conventional oil production.

The Shell Upgrader processes 40,540 m^3 per day (255,000 barrels per day), or approximately 16% of Canada's bitumen and heavy oil conversion capacity **[OSM, 2018b]**. The Quest Project entails a carbon capture of 35% of total CO_2e emissions from the Scotford Upgrader, or 1.2 million tonnes of CO_2 per year. In Canada alone, the CCUS replication potential of Shell Quest technology ranges between 8 and 22 million tonnes of CO_2e per year, depending upon whether capture were to be installed solely on hydrogen production or an entire heavy oil upgrader/refinery. Canada holds approximately 50% of the world's heavy oil and bitumen conversion capacity. Consequently, consideration of only heavier oil grades implies the replication potential of the Shell Quest CCS technology would be fairly modest on a global scale.

Hydrogen production is also required at refineries processing oil of lighter grades than heavy oil and bitumen. It is useful to consider the total global fluid catalytic cracking (FCC) capacity to ascertain an upper estimate of the replication potential of Shell Quest CCS technology worldwide. Globally, 2.585 million m^3 per day of FCC conversion capacity was operating in 2016 **[ENI, 2017]**. Assuming all of that FCC capacity is within pipeline or shipping distance of a suitable geological storage formation, the total worldwide replication potential of Shell Quest in 2016 was up to 76 million tonnes of CO_2e per year. It is worth noting that FCC capacity grew a staggering 20% between 2010 and 2016 as world oil resources grew heavier. Consequently, with every passing year, the replication potential of Shell Quest CCS technology will climb accordingly.

"The Shell Quest Project has significant replicability potential at oil sands or heavy oil upgraders and refineries globally."

SUCCESSES ACHIEVED BY SHELL QUEST UP TO THE END OF DECEMBER 2016

Well into early operation, the Shell Quest Project had been tremendously successful. It is anticipated the project will continue on that trajectory throughout the operation and closure periods into 2040 and beyond. Amongst the successes achieved to the end of 2016 are the following:

1. Successfully deployed the first commercial-scale, integrated CCUS project in the global heavy oil and the Canadian oil sands industries.

2. Secured federal and provincial government support amounting to $865 million to defray up to 63% of the total $1.35 billion in project costs incurred from 2012 to 2026.

3. Navigated a complicated and changing regulatory regime during the critical early planning stages of the project to successfully secure all required regulatory approvals from the federal and provincial governments.

4. Successfully secured the first carbon sequestration storage lease in Alberta immediately following enactment of new legislation.

5. Led a significant change in global best practice for MMV through a thorough risk assessment process to proactively address potential undesirable events in a comprehensive plan rather than reactively addressing them following project start-up.

6. Obtained the first-ever independent certification of a carbon storage development plan, including its associated MMV plan.

7. Successfully designed, constructed and began operating a first-of-a-kind, modularized carbon capture facility.

8. Achieved start-up of a new facility within three months of original schedule, despite the complexity of managing the project in the midst of major expansion construction at the site, significant regulatory changes, and an economic downturn in the oil industry.

9. Rigorously applied control measures to drive down capital and construction costs by 20-30% from $958 million to $790 million ‡‡‡‡‡ (2015 dollars).

10. Held capital and construction costs and schedule in line with the final investment decision taken by the AOSP JV partners in August 2012.

11. Significantly reduced OPEX by more than 20% through:

    - Minimization of solvent losses,
    - Enhancement of capture efficiency and hydrogen production reliability,
    - Reduction of the number of MMV technologies utilized, yet achieved reduction of risk and uncertainty
    - Reduction of the number of injector wells from as high as eleven down to two
    - Acquisition of critical scientific and engineering evidence that adequate injectivity would be sustained for the full operational period (25 years) without further injection and monitoring well development

12. Took a staged facility-wide commissioning approach in the order of each unit's construction completion that enabled rapid transition to sustained operation.

13. Successfully completed performance and reliability testing within a month of initiating full-scale operation. The nameplate capacity of the capture facility achieved its design target of 1.2 million tonnes per year of CO_2 from hydrogen production at the upgrader.

‡‡‡‡‡ Cited in 2015 Canadian dollars by inflating from Shell Canada's $910 million reported in 2011 dollars using: https://www.bankofcanada.ca/rates/related/inflation-calculator/

14 Product gas from the capture facility exceeded design specifications with:

- CO_2 purity of more than 95%
- Water content of less than 50 ppmv, an improvement of more than 50%
- TEG solvent content of less than 5 ppmv compared with a design level of 27 ppmv
- Hydrogen content of less than 0.5%, resulting in loss of production of less than 0.1% compared with performance prior to carbon capture installation at the HMUs

15 Successfully achieved a sustained capture rate of more than 80% of the emissions from the Scotford Upgrader's HMUs, thereby reducing the footprint of hydrogen production at the upgrader by more than 80%, equivalent to 35% of the entire upgrader operation.

16 Achieved very low parasitic energy losses associated with the installation of CCUS at the Upgrader amounting to 12-15% of the total CO_2e emissions.

17 Achieved an operational uptime of 99% due to minimal maintenance issues as a result of implementing:

- an efficient process design,
- construction with an acceptable number of deficiencies that were readily addressed, and
- a thorough operations and maintenance strategy.

18 Sustained an injection rate at the Quest storage site of up to 150 tonnes per hour during operation to successfully reach 1.5 million tonnes of CO_2 injection at the Shell Quest storage site by the end of 2016, which was ahead of target by about two months.

19 Successfully reduced the number of injection wells from 8 to 3 with near-term plans to reduce that number to 2 because of better than expected injectivity. This was a direct result of rigorous characterization of the geological formations comprising the Shell Quest storage complex prior to injection, to achieve optimal injectivity and containment.

20 In less than two years of operation, progressed from a conservative, comprehensive MMV Plan to a tailor-made, cost-efficient MMV Plan to rigorously address ongoing risks. This was achieved by successfully homing in on the essential, valuable MMV tools which would reduce real and perceived risks, while eliminating those technologies that proved unreliable or of limited value.

21 Implemented a widely-reaching and successful public engagement strategy to obtain positive and supportive stakeholder engagement from local communities and businesses at inception through to present day, with a view to maintaining open communication well into the closure period in 2040 and beyond.

22 Successfully engaged international governments, regulators and organizations to build dialogue about the lessons learned from Shell Quest.

The Shell Quest Project team navigated a complicated and changing regulatory regime during the planning of the project.

FINAL THOUGHTS AND CONCLUDING REMARKS

This report has followed the early journey of Shell and its AOSP JV partners in developing, designing, engineering, constructing and initiating early operation of the Shell Quest Carbon Capture and Storage Project. Many firsts were achieved by the project team:

- design, construction, and operation of an efficient, operating amine capture facility at an oil sands upgrader;
- transportation of the produced CO_2 to a suitable site for long-term storage at a nearby deep saline aquifer geological formation within 64 km of the Scotford Upgrader;
- development, deployment and management of a world-class geological storage site and;
- attainment of local, regional, national and international key stakeholder support and engagement for the undertaking.

In late August 2015, Shell Canada began sustained, commercial-scale operation of the first-in-the world CO_2 capture facility at an oil sands bitumen or heavy oil upgrader. Carbon capture and compression were integrated into three steam methane reformers at the Scotford Upgrader with minimal impact on the operation and performance of the facility. The selected Shell Global Solutions' ADIP®-X amine carbon capture technology was re-designed and engineered to assure continued reliability of hydrogen production and seamless integration with upgrader processes and services, while minimizing energy losses associated with capture.

The overall parasitic energy losses associated with capture and storage have been reported as 12-15% of total CO_2e emissions associated with the upgrader and the newly-incorporated CCS project. Pipeline design and construction were readily undertaken activities given they were within Shell Canada's long-established areas of expertise. Geological storage of the captured CO_2 takes place at a world-class storage site that has undertaken MMV activities using a plan that was a global first since it was based on a thorough risk assessment process at project inception.

The key factors that led to the success of this project included:

1. A dedicated, technically-proven and experienced team of engineers and scientists at Shell Canada and its global corporate and research partners, contractors who took a carefully-crafted concept and built that into a first-of-a-kind commercial operation.
2. Supportive JV partners that changed during the reporting period.
3. A deep financial commitment by governments through significant funding from the Alberta Carbon Capture and Storage Fund and the Government of Canada's Clean Energy Fund.
4. An effective key stakeholder engagement strategy and project-wide team that succeeded in securing positive support for Shell Quest from the local community and businesses, regulators, governments and international organizations.

The key to assuring continued exceptional performance of Shell Quest will lie in:

- maintaining a rigorous control of expenses to continue to reduce operating costs;
- continuing to operate infrastructure with technical skill and attention to details;
- seizing opportunities for improved efficiency through utilization of new practices and technologies;
- staying abreast of any changes in regulatory regimes and adjusting monitoring and closure plans, as well as operations, accordingly; and
- maintaining a high level of engagement with key stakeholders.

"The Shell Quest Carbon Capture and Storage Project may be considered a success and a model of scientific, engineering and operational excellence."

A series of issues and challenges faced by Shell Canada and its partners during the course of the Quest Project was considered in this report to assist other parties in their contemplation of the applicability of ADIP®-X amine carbon capture technology, as well as the project's transportation and storage infrastructure, MVA activities, and stakeholder engagement strategy to their unique set of jurisdictional and operational circumstances. These considerations involve regulations, financial, business and market factors, technical design and engineering, project site specifics, modular construction, risk assessment, and communication. The details in this report should assist future CCS deployment initiatives in considering the depth and breadth of complex issues involved in undertaking a commercial project of this nature.

The Shell Quest Carbon Capture and Storage Project may be considered a success and a model of scientific, engineering and operational excellence. The Project has proven to the world that commercial-scale carbon dioxide capture at a bitumen and heavy oil upgrader, and more widely at oil refineries, is possible without compromising the quality or quantity of conversion and production of synthetic crude oil, transportation fuels, and other petroleum products.

Global demand for oil and its products is continuing to grow at a remarkable pace despite decades of dire warnings about peak oil. Over time, world oil resources and production will continue to become increasingly heavy and consequently require relatively more processing than lighter oils. The carbon footprint of heavy crude oil upgraders and, indeed, all refineries must be significantly reduced if natural gas and other fossil energy resources will continue to be the sources for production of hydrogen and steam. Sustainability of oil processing and conversion facilities is key to future profitability and the social license to operate as the world embarks on the transition to a better balance between fossil and renewable energies to mitigate the impacts of climate change. The Shell Quest Carbon Capture and Storage Project has set a carbon sustainability benchmark within the oil sands and heavy oil industry. It now lies with the rest of the oil industry to follow the example of this world-leading project team, its corporate investors, and project partners to assure a continued trajectory toward meaningful reductions in GHG emissions associated with the utilization of heavy fossil energy resources.

GLOSSARY OF TERMS, ABBREVIATIONS AND ACRONYMS

AB - Province of Alberta

ACCS - Alberta Ministry of Culture and Community Spirit

AER - Alberta Energy Regulator, a combined regulatory authority established in 2013 that amalgamated the ERCB and regulatory parts of the Alberta Department of Energy. Certain environmental regulations related to water and air still fall under the jurisdiction of the Alberta Department of Environment and Parks.

AEW - Alberta Ministry of Environment and Water. Named variously over the past decade as: Alberta Ministry of Environment, Alberta Ministry of Environment and Water, Alberta Ministry of Environment and Sustainable Resource Development, and Alberta Ministry of Environment and Parks (current, as of 2018). www.aep.alberta.ca

AGS - Alberta Geological Survey

ALARP - "As low as reasonably practicable" is an environmental and safety model developed by the UK Health and Safety Executive to establish and justify risk acceptability limits. The basic principle is to reduce the residual risk as much as reasonably possible by weighing risk against time, expense and effort required to control the risk **[HSE UK, 2017]**

AOI - Area of Interest which was the three-dimensional geological storage complex around the proposed Shell Quest storage site until the sequestration lease was approved in mid-2012 which reduced the depth of the storage complex. This term was used prior to regulatory approval of CO_2 storage and was based upon geological modeling and prediction, in addition to risk assessment.

AOSP - Athabasca (or Albian) Oil Sands Project which consists of the oil sands mines near Fort McMurray that produce bitumen and the Scotford Upgrader near Fort Saskatchewan that converts bitumen into synthetic crude oil. The AOSP is a joint venture (JV) of partners, including Shell Canada Energy, as detailed in the introductory section of this report.

ASL / ASLA - Approved Sequestration Lease (Area) is a term used for the monitoring area that includes the three-dimensional geological storage complex and surface monitoring, as well as any future region of elevated pressures due to CO_2 injection that might be sufficient to cause movement of formation fluids into the Groundwater Protection Zone. The ASLA approved by the Government of Alberta in August 2012 for the Shell Quest storage site includes the geological horizons from the Precambrian basement up to the Top of the Elk Point Group and all surface facilities and MMV systems within a specified areal location northwest of the Scotford Upgrader (see Figure 18).

ASRD - Alberta Ministry of Sustainable Resource Development. Now part of Alberta Ministry of Environment and Parks. www.aep.alberta.ca

bbl - Barrel of oil. A "blue barrel" of oil is 42 US gallons.

BC - Province of British Columbia

BFD - Block Flow Diagram, an engineering process drawing often termed a PFD, or process flow diagram

BGWP - Bottom of Groundwater Protection Zone, approximately 150 m below ground surface in the Western Canadian Sedimentary Basin. It is the maximum depth of the bottom of any potable water wells in a region.

BHP - Bottom Hole Pressure

BOE - Barrels of oil equivalent, a term used to summarize the energy value of various grades of oil and natural gas in terms of a barrel of crude oil; used to describe the combined hydrocarbon reserves (asset value) of a company, region or nation with a mixed reserve base. Gas volumes are converted using a factor of 5,800 scf/bbl. **[Shell, 2016a** and **Investopedia, 2017]**.

BPD - Barrels per day, a commonly used Imperial measure of oil production rate

CAPEX - Capital Expenditures

CEAA - Canadian Environmental Assessment Agency that manages the Canadian Environmental Assessment Act of 2012.

CCS - Carbon Capture and Storage / Sequestration

CCUS - Carbon Capture, Utilization and Storage / Sequestration

CO_2e - "CO_2 equivalents", a measure of GHG emissions expressed as equivalent climate forcing impact of carbon dioxide

CO_2-EOR - Enhanced oil recovery utilizing CO_2 as a tertiary production method following primary production at natural reservoir pressure and secondary production using water injection to increase reservoir pressure.

DAS - Distributed Acoustic Sensing, which is an in-well MMV technology

DFO - Department of Fisheries and Oceans, Government of Canada

DHPT - DownHole Pressure and Temperature monitoring

DMW - Deep MMV monitoring Well utilized in Shell Quest project

DOE - United States Department of Energy

DSF - Deep Saline Formation geological storage of CO_2

DST - Drill Stem Test is a procedure for isolating and testing the pressure and permeability of a geological formation

EIA - Environmental Impact Assessment as required by CEAA, AER, and the Alberta Department of Environment and Parks.

EM - Electromagnetic

EOR - Enhanced oil recovery, typically a tertiary recovery method utilizing a solvent (such as miscible, supercritical CO_2), immiscible gas(es), polymers, or other fluid materials to improve recovery, following production at natural reservoir pressure or water-flooding.

EPCM - Engineering, Procurement, and Construction Management firm

EPEA - Environmental Protection and Enhancement Act of Alberta

ERCB - Alberta's Energy Resources Conservation Board, the regulatory authority for oil and gas operations, as well as electrical power operations, until amalgamation of regulatory bodies in 2013 to form the Alberta Energy Regulator (AER). The ERCB also included the Alberta Geological Survey (AGS).

ERP - Emergency Response Plan

FCC - Fluid Catalytic Cracking conversion at oil refineries to convert oil into end-user products, such as transportation fuels. The process involves thermal cracking using steam that is typically generated by burning natural gas to produce heat to boil water.

FEED - Front-End Engineering and Design

FID - Final Investment Decision by the AOSP JV Partners

GHG - Greenhouse Gas, normally measured as metric tonnes of 'CO_2 equivalents' or CO_2e, although comprised of a number of gases defined under the UNFCCC's Kyoto Protocol (1997) as having 96% of climate-forcing (or radiative-forcing) capacity. The climate-forcing GHGs of interest to regulators include: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), chlorofluorcarbons (CFCs), hydrofluorocarbons (HFCs), perfluorinated compounds (PFCs), sulphur hexafluoride (SF6), and nitrogen trifluoride (NF_3). These gases notably exclude the most powerful greenhouse gas, namely, water (H_2O).

GM - Gas Migration well testing as required by AER's oil and gas regulations

GOA - Government of Alberta (provincial)

GOC - Government of Canada (federal / national)

GPS - Global Positioning System

GSC - Geological Survey of Canada, that is currently part of the federal Department of Natural Resources Canada (NRCan)

GW - Groundwater well used for monitoring at Shell Quest, including project and landowner wells in the BGWP zone

HAZOP - Hazard and Operability assessment

HMU - Hydrogen Manufacturing Unit comprising a steam reformer and associated purification and compression systems

HSIA - Hyperspectral image analysis, a non-invasive analytical tool for chemical characterization

HSSE / HSE - Health, Safety, Security and Environment(al)

InSAR - Interferometric Synthetic Aperature Radar, an MMV tool

IW - Injection Well for industrial carbon dioxide pipelined from the capture facility

JV - Joint Venture

LBV - Line-Break Valve utilized in a pipeline to stop service when required

LNG - Liquified Natural Gas

LW - Legacy Well is a well that penetrates either or both of the CO_2 storage reservoir or any bounding seals above or below the storage reservoir. A legacy well poses an element of risk to containment of the CO_2 and/or storage reservoir fluids, such as brine.

MDEA - Methyl diethylamine (chemical forumula: $CH_3N(C_2H_4OH)_2$), a tertiary amine solvent commonly used by industry to capture CO_2 and/or SO_2 from flue gas. "aMDEA" is activated MDEA.

MDT - Modular Formation Dynamic Tester is a wireline tool used to determine formation permeability, take samples, and measure pressure and temperature during well testing and evaluation **[Ireland et. al., 1992]**.

MM - Million. This abbreviation is common in the oil and gas and chemicals industries for reference to hydrocarbon (gas or liquid) units of measure.

MM SCFD - Million standard cubic feet per day (of gas)

Mt - Million tonnes (of carbon dioxide or other gas)

MMV - Measurement, Monitoring and Verification, a term used to describe instruments and systems put into place to monitor, quantify and verify the amount and location of CO_2 stored in the subsurface.

MSM - Microseismic monitoring

NO_x - Nitrogen oxides, including nitric oxide (NO), nitrous oxide (N_2O), nitrogen dioxide (NO_2), etc.

NRCan - Department of Natural Resources Canada, Government of Canada

NWT - Northwest Territories

OPEX - Operating Expenditures

O&M - Operations and Maintenance

OSCA - Oil Sands Conservation Act of Alberta

PFD - Process Flow Diagram, an engineering process drawing often termed a BFD, or block flow diagram.

PSA - Pressure Swing Adsorption, a process used to separate different gases using a high surface area, inert adsorbent solid material and different elevated operating pressures (i.e. above atmospheric pressure)

SCADA - Supervisory control and data acquisition control system utilizing a computer network and data communications system for remote process and system management.

SCFD - Standard cubic feet per day (of gas)

SCM or Sm³ - Standard cubic metre of gas at the reference conditions 15°C and 101.325 kPa.

SCO - Synthetic Crude Oil, a light, sweet oil product mimicking conventional light oil produced by upgrading bitumen through thermal cracking and hydrogen addition processes similar to refining. SCO has an API gravity of 30-35°

SCVF - Surface Casing Vent Flow well testing as required by AER oil and gas regulation

SMR - Steam methane reformer used to produce hydrogen and/or syngas

Syngas - Synthesis gas, a mixture of carbon monoxide and hydrogen, which is an intermediate gas resulting from steam methane reforming that is also an important gas for production of synthetic liquid hydrocarbons utilizing the Fischer-Tropsch Process

TEG - Triethyelene glycol which is used for dehydration of CO_2 product gas

TOE - Metric tonne of oil equivalent

VSP - Vertical Seismic Profile, an MMV geophysical measurement

WHPT - WellHead Pressure and Temperature monitoring

WTI - West Texas Intermediate, a standard market price for conventional light, sweet crude oil in North America. WTI pricing is typically lower than the price of Brent crude oil. Like the price of Brent crude, WTI price is set by spot pricing of oil on the open market.

PHOTOGRAPH REFERENCES

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Helbig, Louis. Beautiful Destruction. Rocky Mountain Books. November, 2014. ISBN-10: 1771600543 / ISBN-13: 978-1771600545

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CONVERSIONS AND CONVENTIONS

The International System of Units (SI) is used throughout this report. Conversions from commonly reported Imperial and US units were made as follows.

IMPERIAL	FACTOR	METRIC (SI)	MEASUREMENT TYPE
From		*To*	
°F	5*(T-32)/9	°C	Temperature
(short) tons	0.925	Tonnes (T)	Weight
(short) tons	2000	Pounds (lb)	Weight
tonnes (T)	1000	Kilogram (kg)	Weight
standard cubic foot (ft^3, SCF)	0.02678	Normal cubic metres (Nm^3)	Volume (gas)[§§§§§]
cubic feet (ft^3, SCF)	28.317	Litres (L)	Volume (liquid)
Standard cubic foot per day (SCFD)	1.1159×10^{-3}	Normal cubic metre per hour (Nm^3/hr)	Volumetric flow rate (gas)
SCF of H_2 (ft^3)	2.407×10^{-6}	Tonne of hydrogen	Volume to weight (gas)
SCF of CO_2 (ft^3)	5.286×10^{-5}	Tonne of CO_2	Volume to weight (gas)
Tonne of hydrogen	11,126	Nm^3	Volume of hydrogen
Normal cubic metres (Nm^3)	1.0549	Standard cubic metres (Sm^3)	Volume (gas)
Tonne of CO_2	506.63	Nm^3	Volume of CO_2
million BTU	1.0551	Giga Joule (GJ)	Energy
pounds per hour	0.454	kg/hr	Energy Flow Rate (steam)
psi (or psia)	6894.77	Pascal (Pa)	Pressure
atm	101.325	kPa	Pressure
miles	1.609	Kilometres (km)	Distance
barrel	0.159	Cubic metre (m^3)	Volume of oil
acres	0.4047	Hectares (ha)	Area (of land)
square miles	259.00	Hectares (ha)	Area (of land)
SI Prefixes for Multiples of SI Units			
Million (1e+6), MM	1	Mega (M)	Number
Billion (1e+9), B	1	Giga (G)	Number
Trillion (1e+12), T	1	Tera (T)	Number
Quadrillion (1e+15)	1	Peta (P)	Number

Conversion tables used in this report are located at the following URLs (valid as of August 15, 2018):

- Energy conversion units provided by the National Energy Board of Canada: https://www.neb-one.gc.ca/nrg/tl/cnvrsntbl/cnvrsntbl-eng.html#s_auto2
- Online Conversion.com http://www.onlineconversion.com/
- Abraxas Energy Conversion Calculators http://www.abraxasenergy.com/energy-resources/toolbox/conversion-calculators/
- SI Brochure: http://www.bipm.org/en/publications/si-brochure/download.html
- Carbon Dioxide -Weight and Volume Equivalents: http://www.airproducts.com/Products/Gases/gas-facts/conversion-formulas/weight-and-volume-equivalents/carbon-dioxide.aspx
- Unit Conversion Data for Hydrogen: http://www.uigi.com/h2_conv.html

[§§§§§] The ISO standard for a standard cubic foot of gas is measured at 15.6°C (60°F) and 101.560 kPa(a) (14.73 psia). The DIN standard for a normal cubic metre of gas corresponds to 1 cubic metre at 0°C and 101.325 kPa(a). The ISO standard cubic metre of gas is measured at 15°C and 101.325 kPa(a).

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