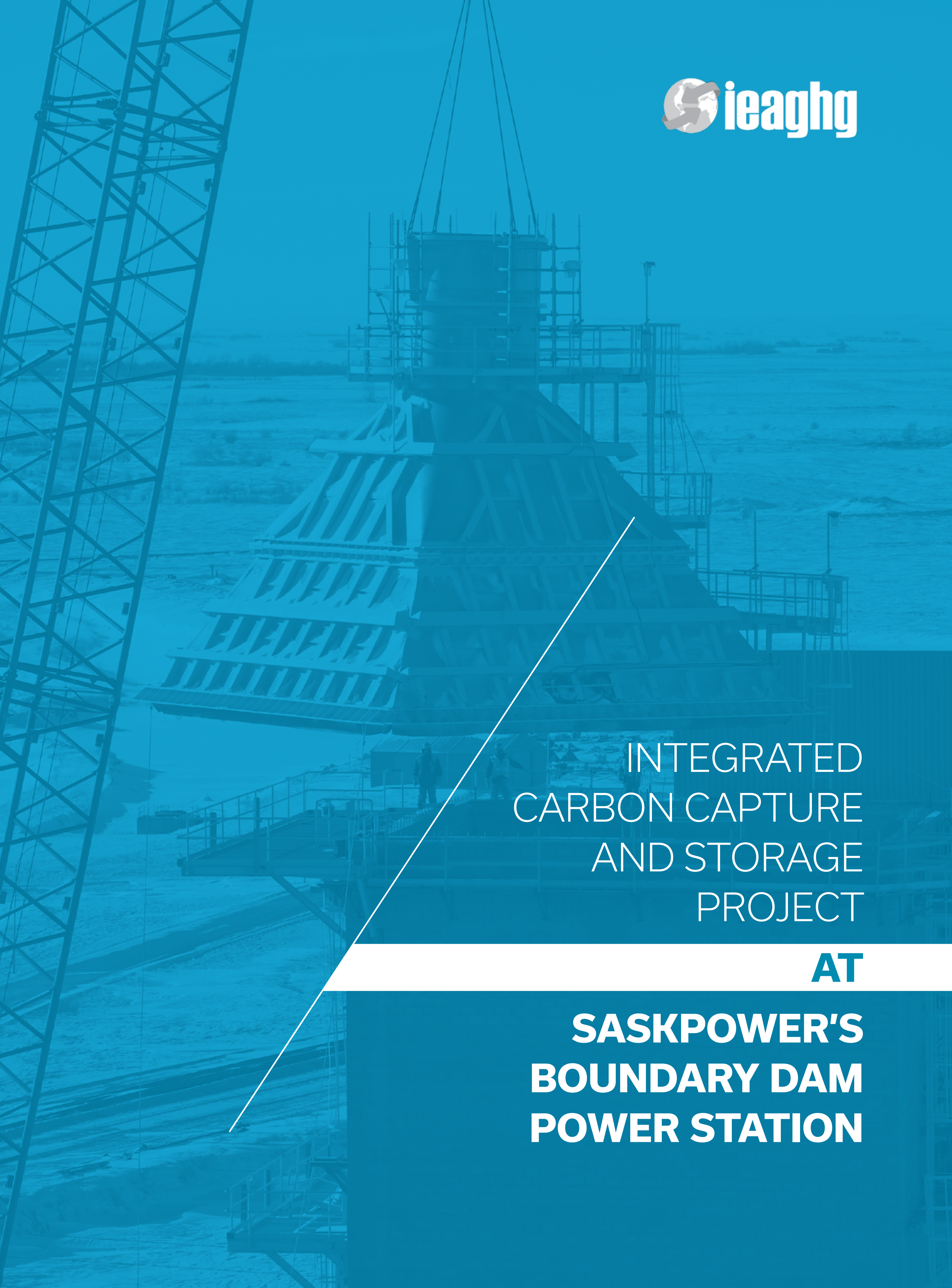

ieaghg

INTEGRATED CARBON CAPTURE AND STORAGE PROJECT

AT

SASKPOWER'S BOUNDARY DAM POWER STATION

A **WORLD'S FIRST** IN CARBON
CAPTURE AND STORAGE

INTERNATIONAL ENERGY AGENCY

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THE REPORT SHOULD BE CITED IN LITERATURE AS FOLLOWS:

'IEAGHG, "Integrated Carbon Capture and Storage Project at SaskPower's Boundary Dam Power Station", 2015/06 , August 2015'

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ISBN 978-0-9956163-0-1

EXECUTIVE **SUMMARY**

On October 2, 2014, the first-ever, commercial–scale, coal-fired power plant incorporating amine solvent absorption carbon capture began operation near Estevan, Saskatchewan, Canada. This was a global landmark event. Although carbon capture technologies had been pilot tested prior to this, a commercial–scale power plant now exists that has demonstrated that a number of high-risk technology and business issues have been overcome. This report summarizes the experience and learnings of SaskPower in a way that will hopefully provide insight to other clean-coal initiatives.

Two key factors contributed to the decision to retrofit BD3 to convert it to clean coal power:

1. The ability to continue to realize value from the sunk investment in the original 1970 BD3 power unit by retrofitting it with a modern boiler and turbine, rather than building a new power plant; and
2. The value that would be realized over the next 30 years of operating the retrofitted power plant from the sale of three valuable by-products: carbon dioxide, sulphuric acid and fly ash. This would help to offset the cost of capture.

FOR SASKPOWER, owner and operator of the retrofitted Boundary Dam Power Unit 3 (BD3) that now incorporates carbon capture and storage (CCS), this event was the culmination of decades of work to continue operating coal-fired power-generating stations, while at the same time mitigating the climate change impact of associated air emissions. The CO_2 captured at BD3 is geologically stored at **two** locations: in an oil reservoir approximately 1.4 kilometres deep at Cenovus' CO_2–EOR operation near Weyburn, Saskatchewan, and in a deep saline aquifer approximately 3.2 kilometres deep at the SaskPower Carbon Storage and Research Centre, located near the Boundary Dam Power Station. The latter geological storage site is the subject of the measurement, monitoring and verification (MMV) activities of the Aquistore Project that is managed by the Petroleum Technology Research Centre in Regina, Saskatchewan.

SaskPower had forged ahead with design and construction of the BD3 ICCS retrofit well in advance of GHG Regulations being enacted in Canada, which came into effect on July 1, 2015. This was a strategic and environmentally-responsible decision to ensure continued use of lignite coal reserves in Saskatchewan that could last 250–500 years. The investment in the approx. 120 MW (net) BD3 power unit's retrofit and carbon capture plant was approximately C$1.467 billion.

This report explores the journey that SaskPower made from the 1980s to mid-2015 in pursuit of clean-coal power generation. SaskPower pursued various technology options for carbon capture from oxyfuel combustion to amine solvent absorption that ultimately led to the decision to select the commercially unproven CANSOLV amine solvent carbon dioxide capture process. SaskPower then coupled that technology with Shell Cansolv's proven sulphur dioxide capture process to simplify the capture plant operation and to further reduce emissions.

The latter two by-products provide the off-taker market with essential materials for the production of fertilizer and cement, respectively. The captured CO_2 is geologically stored, as noted above, with an associated revenue stream from sale of a portion to oil producers deploying CO_2–EOR.

Construction challenges that were faced by SaskPower are explored in the report.
These included:

- complicated contracting issues by using multiple vendors;
- management of a retrofitting project at a "brown-field" site;
- orchestration of the complexities of integrating the power plant with the capture plant;
- safety, risk and permitting management and;
- transition to operations.

One of the most important recommendations for future retrofitting construction projects of this nature is to modularize the design to make the construction simpler and more cost-effective to implement.

Given SaskPower's status as a public power utility, it was critically important to ensure full engagement by its stakeholders in government and the public. SaskPower made dozens of presentations around the province to inform the public and address questions and concerns. Its design team ensured that technology options were kept open and available to enable key decision makers to build confidence in their technology choices so they could see their way to approving both the power unit's retrofit and the capture plant construction. SaskPower continues to engage its stakeholders in effective and meaningful discussion about BD3 and consideration of future power-generating options.

A summary of challenges that SaskPower faced from inception to operation of the BD3 ICCS project is presented.

KEY CHALLENGES INCLUDED:

- Choosing a CO_2 capture technology when no commercially-proven technology existed, and managing first-time operation of unfamiliar capture processes and equipment
- Proceeding with a high, targeted CO_2 capture level (90%) and the associated design and construction in the absence of any guidance from GHG regulation that had yet to be enacted
- Managing continual changes in design, equipment, and construction plans throughout the project due to a variety of technology, procurement and corporate policy requirements
- Technology risk and managing the costs associated with the redundancy in processes and equipment that was essential to managing that risk
- Controlling construction costs at a time of very high competition for materials and labour in western Canada, primarily due to a very high level of oil and gas activity

Consideration is given in the report to the issues SaskPower will face as it contemplates the future of its coal-power generation fleet, given new Regulations that require CCS retrofitting installation during 2019–2043:

Would retrofitting existing infrastructure to generate clean coal power be comparable to power generation alternatives such as NGCC, wind and hydro?

HAVE there been any regulatory changes that might impact decisions?

WHICH existing coal-fired power plants would be the best target(s) for retrofitting?

WOULD there be an opportunity to replicate the BD3 retrofitting design at other power plants?

WOULD there be any other commercially–proven carbon capture technologies to consider?

WHAT would be the appropriate level of capture? What would be the associated plant operating strategies?

WHAT efficiency improvements could be made?

WHAT technology risk-reducing, redundant equipment could be eliminated versus BD3?

HOW could construction costs be reduced?

HOW could SaskPower help build an enhanced market for by-products?

A series of issues and questions is presented in the report that could assist parties outside Saskatchewan contemplate the applicability of the BD3 ICCS project to their unique set of jurisdictional circumstances. These involve regulations, business and market factors, technical design, and construction.

The report concludes with a discussion of SaskPower's CCS research activities—past, present and future—to develop and validate new technologies to mitigate environmental impacts associated with GHGs, SO_2, NO_X, mercury and particulates. The aim has always been to reduce capital and operating costs, improve reliability and operability, enhance knowledge and understanding, and manage technology risk. These research activities have been/continue to be:

Bench and pilot-scale testing of capture technologies to further their development and/or to build a database of scalable engineering factors essential to commercialization through:

- The SaskPower Carbon Capture Test Facility (CCTF) that was opened at the Shand Power Station in June 2015.
- The SaskPower Emissions Control Research Facility (ECRF) at the Poplar River Power Station where mercury control technologies were validated in the early 2000s. It is used to continue the testing of capture technologies and associated systems.
- Investments in proving CO_2 geological storage through the IEAGHG Weyburn-Midale CO_2 Monitoring and Storage Project (2000–2012) and Aquistore (2009–2017).

AS OF MID-2015, SaskPower is contemplating a new CCS Consortium that may include collaborative opportunities for participants, pending suitable alignment, on: technology, research, regulatory affairs and government relations, and all aspects of project management through design and construction.

The BD3 ICCS project has, to date, garnered many awards. It can be regarded a success. The project has proven to the world that commercial–scale carbon dioxide capture at a coal-fired power generating station is possible rather than an elusive future option. SaskPower has led the way. It is now up to the rest of the world to follow this remarkable pioneer to ensure that the anthropogenic carbon emissions associated with fossil-fuel power generation and use are significantly reduced worldwide.

PREFACE

This report includes summaries of interviews undertaken by the author with former and current SaskPower project execution team members who were a part of creating the BD3 ICCS commercial project, as well as conclusions drawn therefrom by the author.

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ACKNOWLEDGEMENTS

The United States Department of Energy provided the funding required for preparation of this report. The IEA Greenhouse Gas R&D program (IEAGHG) facilitated production of this report.

The author is grateful to the following SaskPower team members for making themselves available for detailed interviews and commentary on the content of this report: Max Ball, Corwyn Bruce, Doug Daverne, Darcy Holderness, Mike Monea, Doug Nixon, and Ian Yeates.

The author also greatly appreciates the assistance of the following individuals during preparation of this report: Sandra Beingessner (SaskPower), David Tapp (SaskPower), John Gale (IEAGHG), Becky Kemp (IEAGHG), Norman Sacuta (PTRC), Kyle Worth (PTRC), Aleana Young (PTRC), Britt Markle (Design Spectacle), Kevin House (Kevin Creative), and Stephanie Sutton (Timely VA).

AUGUST
31
2015

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ABOUT

SASKPOWER

HISTORY & STRUCTURE OF **SASKPOWER**[1]

SaskPower can trace its history to 1929 when the Saskatchewan Power Commission was founded. In 1949, Saskatchewan Power Corporation was incorporated as a provincial Crown corporation (i.e. Government of Saskatchewan owned corporation) with its authority and mandate governed by The Power Corporation Act, which has been amended several times since its enactment.

SaskPower is a subsidiary of Crown Investments Corporation ("CIC"), which provides SaskPower with its strategic direction. Through the Chair, the SaskPower Board of Directors is directly accountable to the Government of Saskatchewan through the Minister Responsible for SaskPower, who is the link between SaskPower and the Cabinet of the Government of Saskatchewan. The President and CEO of SaskPower reports to a Board of Directors that is appointed by the Crown's representative in Saskatchewan, the Lieutenant Governor in Council.

SaskPower
Powering the future®

SASKPOWER **MANDATE**

SaskPower's corporate mission is to deliver power in a reliable, affordable, and sustainable manner. Essentially, it serves to "keep the lights on in Saskatchewan". The corporation has the exclusive right to generate power in the Province of Saskatchewan (except for the Cities of Saskatoon and Swift Current), and to transmit and distribute electricity, including retail services, to its customers. The electricity market in Saskatchewan was opened to competition in 2001 under an "open access transmission tariff", which allows competitors to schedule access to SaskPower's transmission system and to sell power to the grid.

FINANCIAL & OPERATING **SUMMARY**

Based on the financial and operating indicators reported for the year 2014[2]:

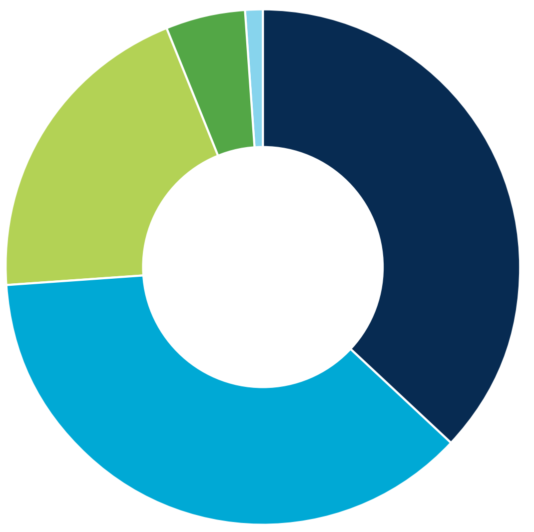
2014 (in millions)

Annual Revenue	C$2,157
Capital Expenditures[3]	C$1,279
Assets	C$9,700
Long-Term Debt	C$4,355
Return on Equity	2.0%
Percent Debt Ratio	73.1%
Net Electricity Generated	21,389 GWh
Generating Capacity	4,181 MW
Peak Load	3,561 MW
Number of Customers	511,941

POWER GENERATION AT **SASKPOWER**

To maintain reliability of service, SaskPower operates with a generating capacity greater than the province's peak demand. In order to ensure a stable supply of affordable electricity, the corporation operates assets generating 3,338 MW of power from natural gas (5), coal (3), hydroelectricity (7), and wind (2). It also has access to 843 MW of generating capacity through long-term power purchase agreements from four natural-gas power generating facilities, two wind power facilities and five heat recovery facilities. Figure 1 shows a breakdown of power generation by fuel supply type, while Figure 2 shows SaskPower's system map.

FIGURE 1 | SASKPOWER'S GENERATING CAPACITY BY TYPE



2014 AVAILABLE GENERATING CAPACITY - 4,181 MW

COAL **37%** HYDRO **20%** OTHER **1%**
GAS **37%** WIND **5%**

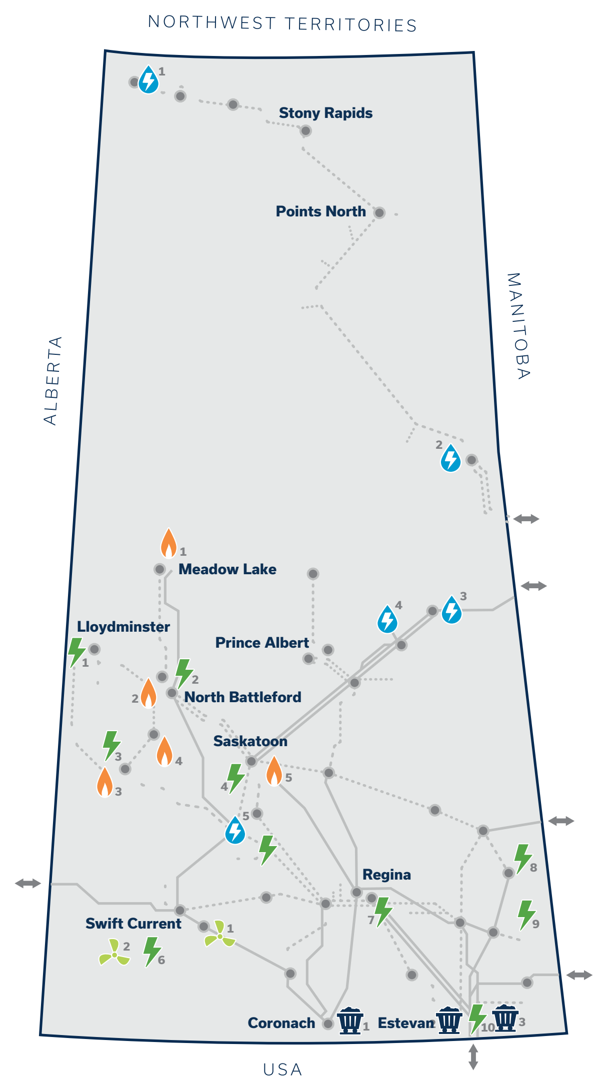


FIGURE 2 | SASKPOWER'S SYSTEM MAP (2014)

7 HYDRO FACILITIES / 3 COAL FACILITIES / 5 NATURAL GAS FACILITIES

2 WIND FACILITIES / 10 INDEPENDENT POWER PRODUCER FACILITIES

TRANSMISSION

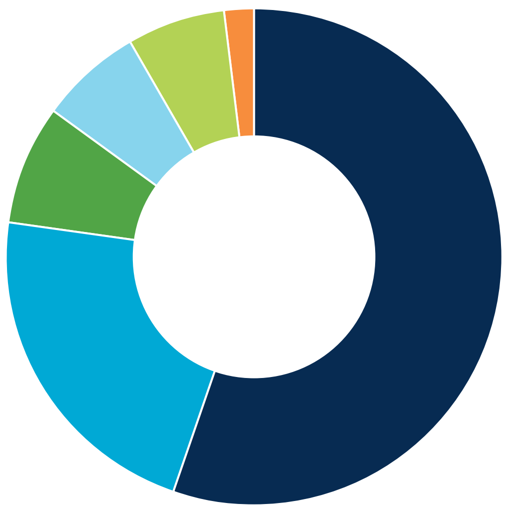
230 kV — Switching Station
180 kV/115 kV/110 kV — Interconnection

SASKATCHEWAN'S ECONOMY AND GHG EMISSIONS

Saskatchewan's population of approx. 1.1 million and its industry are growing at a rapid pace, especially in the southern two-thirds of its geography. The Saskatchewan economy is natural resource based and very diverse, with an annual GDP of C$60.1 billion in 2014 (2007 dollars). Its main industries include: agriculture (grain and value-added grain products), energy (oil, gas, coal, and chemicals), mining and minerals (potash and uranium), forestry, manufacturing, biomass (for fuel production), innovation and technology (life and physical sciences), and various value-added services [Figure 3].

FIGURE 3 | SASKATCHEWAN GDP BY SECTOR (2014)

Source: Statistics Canada, CANSIM Table 379-0030 & 379-0031

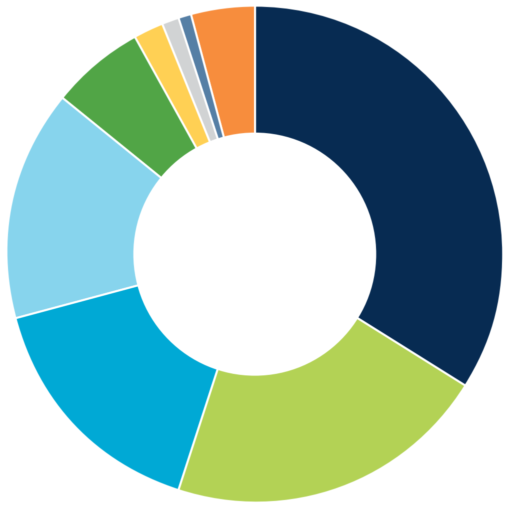


- SERVICES **55.4%**
- MINING, OIL & GAS **21.9%**
- CONSTRUCTION **7.9%**
- MANUFACTURING **6.5%**
- AGRICULTURE **6.5%**
- OTHER **1.8%**

Saskatchewan's GHG emissions profile [Figure 4] reflects its natural resource base and its reliance on fossil-energy-based power generation.

FIGURE 4 | SASKATCHEWAN'S GHG EMISSIONS PROFILE (2012)

Source: Environment Canada National Report, 1990-2012



TOTAL OF 74.8 MILLION TONNES (MT)

- MINING, OIL & GAS INDUSTRIES **34%**
- ELECTRICITY **21%**
- AGRICULTURE **16%**
- BUSINESS TRANSPORTATION **15%**
- PERSONAL TRANSPORTATION **6%**
- RESIDENTIAL **2%**
- COMMERCIAL & INSTITUTIONAL **1%**
- WASTE **1%**
- OTHER INDUSTRIES **4%**

EMISSIONS REGULATION APPLICABLE TO COAL-FIRED POWER GENERATION

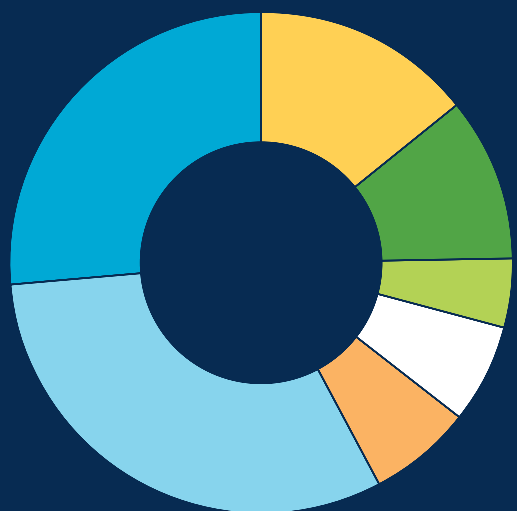
SaskPower began its clean coal power generation in the absence of regulatory direction. The Boundary Dam Unit 3 (BD3) retrofit was completed and operational by October 2014. The *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations* ("Regulations") were enacted in Canada in September 2012 pursuant to *The Canadian Environmental Protection Act*[4] *(CEPA)*. The Regulations came into effect on July 1, 2015. However this was well after the decision had been taken to proceed with the BD3 retrofit, and construction was in full swing.

The ***performance standard*** under the Regulations for all coal-fired power generation is a CO_2 emissions limit of 420 tonnes per GWh, which is equivalent to the emissions intensity level of a modern, high efficiency, base loaded Natural Gas Combined Cycle ("NGCC") power plant. This standard applies to new power plants constructed after July 2015 and End-of-life units constructed before July 2015.

Under the Regulations, ***Cumulative CO_2 Reduction*** from coal-fired power generation is estimated at 214 million tonnes of CO_2 across Canada by July 2036. As a point of reference, the GHG emissions for the energy sector in Canada in 2012 is shown in Figure 5. The electricity generation by fuel type in Canada for 2013 is shown in Figure 6.

FIGURES 5–7

FIGURE 5 | GREENHOUSE GAS (GHG) EMISSIONS IN CANADA FOR THE ENERGY SECTOR (2012)



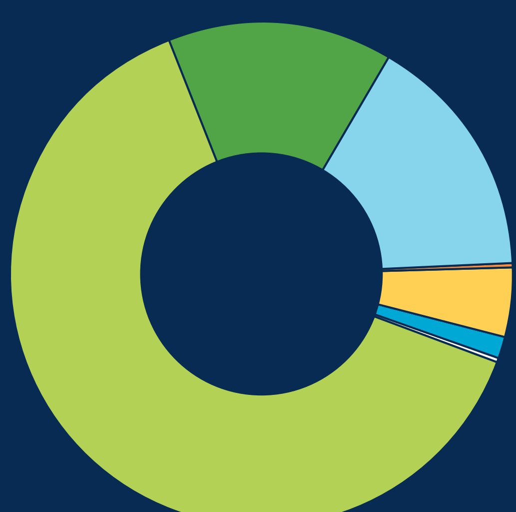
Source: Environment Canada National Report, 1990–2012

- TRANSPORTATION **31.5%**
- OTHER ENERGY* **26.3%**
- ELECTRICITY & HEAT GENERATION **14.3%**
- FOSSIL FUEL INDUSTRIES **10.5%**
- RESIDENTIAL **6.6%**
- BIOMASS **6.6%**
- COMMERCIAL & INSTITUTIONAL **4.5%**

**Includes all the other energy sector emission sources, such as mining, manufacturing, and construction, fugitive sources and agriculture/forestry/fisheries.*

TOTAL GHG EMISSIONS IN CANADA, 2012 = 699 MEGA TONNES CO_2 EQUIVALENT

FIGURE 6 | ELECTRICITY GENERATION IN CANADA BY FUEL TYPE (2013)



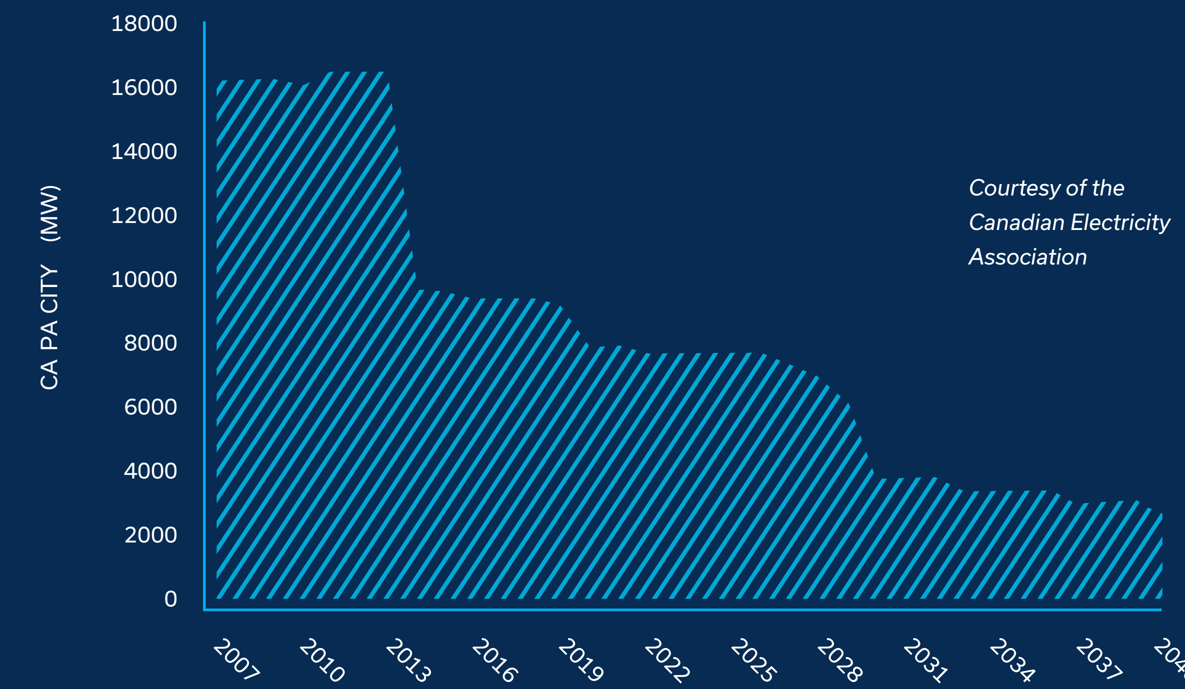
**Numbers may not total 100% due to rounding*

- HYDRO **63.4%**
- CONVENTIONAL STEAM **14.5%**
- NUCLEAR **15.9%**
- COMBUSTION TURBINE **4.5%**
- WIND **1.5%**
- INTERNAL COMBUSTION **0.2%**
- SOLAR **0.04%**
- TIDAL **0.0%**

TOTAL ELECTRICITY GENERATED IN CANADA, 2013 = 611.31 TWh

Courtesy of the Canadian Electricity Association

FIGURE 7 | ANTICIPATED CANADIAN COAL FLEET REDUCTION FROM 2007 ONWARD



*Retirement age 45–50 years as per the 2012 Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations. Includes Ontario voluntary coal shutdown by 2014.

BY COMPARISON, the UK carbon emissions performance standard for coal-fired power units was legislated in December 2013 at 450 tonnes per GWh. Although the EU has not set a performance standard for power plants, the European Investment Bank has adopted a policy that it will no longer fund any power plant that is designed to emit more than 550 tonnes per GWh. The EC has recommended a limit of 450 tonnes per GWh following the UK's lead. In the USA, while a target reduction in power-generation-related carbon emissions was set at 30% in 2013, the Environmental Protection Agency (EPA) is still working out the details of the impact on existing coal-fired power plants. Compliance in the USA will not be required until 2020.

In Canada, under CEPA, **End–of–life Coal Units** are defined as follows:

Units commissioned before 1975*, will reach their End–of–life on December 31, 2019, or on December 31 of the 50th year following commissioning, whichever comes first

Units commissioned after 1974 but before 1986† will reach their End–of–life on December 31, 2029 or on December 31 of the 50th year following commissioning, whichever comes first

Units commissioned in or after 1986‡ will reach their End–of–life on December 31 of the 50th year following commissioning

Under the Regulations, **Carbon Capture and Storage (CCS)** for new and End–of–life coal units incorporating CCS technology can apply to receive a temporary exemption from the performance standard until December 31, 2024 and must have documented evidence of the following construction milestones:

BY JANUARY 1
2020
Complete Front End Engineering and Design (FEED).

BY JANUARY 1
2021
Purchase all major carbon capture equipment.

BY JANUARY 1
2022
Obtain regulatory approvals for carbon capture.

BY JANUARY 1
2022
All contracts for transportation and storage of CO_2 in place.

BY JANUARY 1
2024
Begin commissioning of CO_2 capture, transportation and storage elements of the CCS system.

Substitution of a power plant to meet its performance standard compliance obligation at another power unit can only take place under the Regulations if the two power units have the same owner and they are of similar size (e.g. nominally 300 MW). The substitution will only last until the substituted unit reaches its own End–of–life. After June 30, 2015, a unit that is permanently shut down ahead of its End–of–life date may swap any leftover operating time to one or many other units with the same owner, in the same province, and with equivalent total potential power production over the period of the swap.

It may be possible for each province to negotiate a federal-provincial ***Equivalency Agreement*** with the Government of Canada to enable each provincial jurisdiction to regulate the reduction of carbon emissions by coal-fired power generation (i.e. possibly a different approach to meeting the overall targeted reduction in CO_2 emissions associated with coal-fired power generation for a province).

The Regulations that came into effect on July 1, 2015 are also expected to result in significant **reductions in SO_2 and NO_X emissions** as shown in Figure 8.

*Including Units 1 through 5 at SaskPower's Boundary Dam Power Station

†Including Unit 6 at SaskPower's Boundary Dam Power Station and Units 1 and 2 at SaskPower's Poplar River Power Station

‡Including SaskPower's Shand Power Station

FIGURE 8 | ANTICIPATED NO_X AND SO_2 REDUCTIONS DUE TO CO_2 REGULATION IN CANADA

Courtesy of the Canadian Electricity Association

Canada's GHG Regulations came into effect on July 1, 2015

Source and assumptions: NPRI data was used for existing unit emissions, forecast based on 2009–2011 operation, coal unit retirement from 45–50 years as outlined in the 2012 Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations

Other air emissions regulations pertaining to coal-fired power generation plants apply across Canada as follows:

Mercury (Hg) emissions standards were set for the year 2010 to ensure a reduction of 60% of the 2695 kg of Hg emitted in the baseline year of 2003. The Council of Canadian Ministers of Environment (CCME) is monitoring Hg emissions reductions to ensure the target is reached.

Proposed changes to CEPA as of July 2015 apply to other emissions as follows:

- Sulphur dioxide (SO_2) at 0.47 – 4.91 kg per MWh*
- Nitrogen oxides (NO_X) at 0.47 – 0.66 kg per MWh†
- Particulates (PM_{10} + $PM_{2.5}$) at 7.5 – 12 g per MWh†

*The precise limit imposed on a power plant depends upon the thermal output anticipated for the coal fuel used and its sulphur content.

†Regulatory harmonization with the USA is sought. The low end of the range is the current US EPA regulation. The higher end of the range is anticipated new US EPA regulation.

THE ROAD TO DEPLOYING **CARBON CAPTURE + STORAGE**

AT SASKPOWER

WHY CONTINUE TO GENERATE POWER FROM COAL IN **SASKATCHEWAN?**

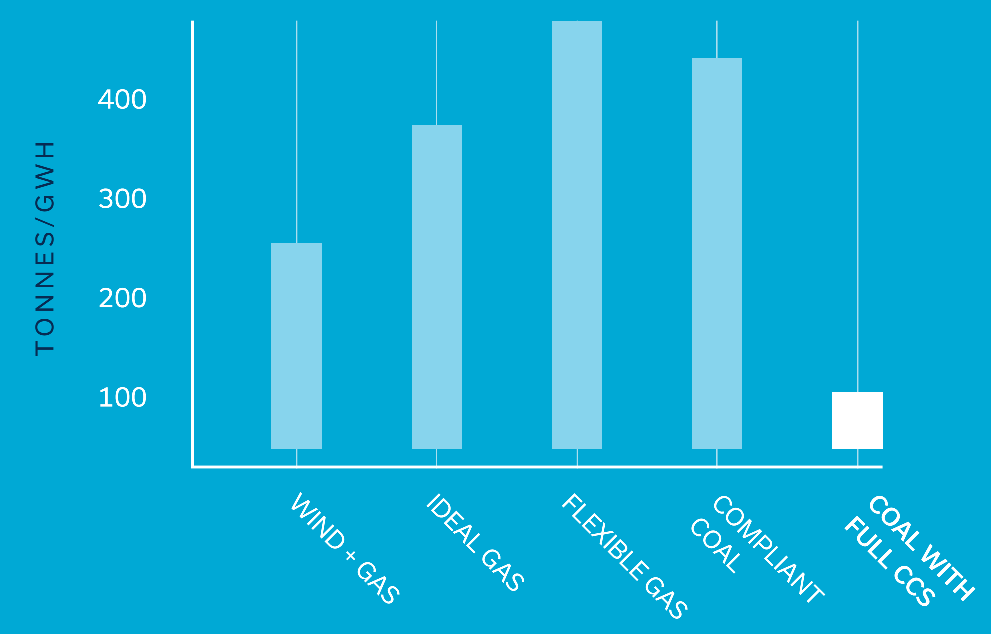
SaskPower generates electricity using a variety of energy sources: coal, natural gas, hydro and wind.

North America currently has a plentiful supply of inexpensive natural gas and a number of alternatives to coal-fired power generation, such as wind, solar, hydro and nuclear. Furthermore, when utilizing modern technology, all of these alternative power sources are considered cleaner, from a GHG perspective, than traditional coal-fired power generation. Natural gas, for instance, has no soot (particulates) to manage. Power plants run efficiently in the case of Natural Gas Combined Cycle (NGCC), and the fuel is consistent in quality. So you might well be asking yourself the question, "Why would SaskPower contemplate continuing to generate power from coal by making major investment(s) in clean coal?"

Natural gas has not always been as inexpensive in Saskatchewan, Canada and North America as it was in mid-2015. In some jurisdictions around the world, natural gas has been in short supply and therefore very expensive. That has made North America an easy target for production and transportation of natural gas in liquefied form (LNG) to other parts of the world where it has commanded a higher market price. This has put pressure on the supply of natural gas available in North America. Hence, natural gas pricing in the North American context will be unlikely to remain low in the future, implying that natural gas electrical power generation may not necessarily be the most cost-effective form of power going forward, assuming new and sufficient natural gas reserves could continue to be found and economically exploited to meet demand.

Wind power is an appealing alternative to coal power in Western Canada. There is, indeed, significant generating capacity in Saskatchewan and Alberta. But it is always subject to weather variations, with extreme wind being common on the Prairies, while too little wind is also frequent. Hence, wind power generation using existing turbine technology cannot be relied upon to provide stable base load power unless it is coupled with readily-dispatched power-generating backup systems, such as simple-cycle natural gas power generation, which is not as clean and efficient as NGCC. At some point, simple-cycle natural gas power generation may become the target of GHG emissions regulation, either federally or provincially, which must be taken into account when considering investment in future power generation options.

FIGURE 9 | ILLUSTRATIVE GHG INTENSITY BY ENERGY SUPPLY OPTION[5]



Although Saskatchewan is one of the largest global suppliers of high-grade uranium, no nuclear power station has ever been built in Western Canada. Consequently, the Saskatchewan regulatory permitting process for nuclear power, even for recently touted small scale nuclear reactors (SNRs), would likely be protracted. Doubtless, it would be worth the effort to begin that permitting process well before it would be required, but it would be time intensive the first time around.

Saskatchewan has a large, shallow, subsurface, lignite coal resource (the Ravenscrag formation) that is amenable to straightforward surface mining and is located in the southeast, relatively close to Regina, with its population of over 230,000. This coal reserve is expected to last for about 250–500 years[6] and is cost-effective for nearby thermal power generation. It is co-located with a good supply of surface water and is served by transmission facilities that integrate existing power stations into the grid for the supply of electricity to about one third to one half of the province's population. If executed properly, clean coal power generation has the potential to be cleaner than NGCC and cleaner than wind with simple-cycle natural gas power backup. The downside is that coal requires large infrastructure to be cost effective. This would entail major capital investment in clean coal-fired power generation if coal is to remain an acceptable and viable energy source in Saskatchewan.

SaskPower focuses its power generation choices on meeting service and regulatory obligations at the lowest expected cost when considered over the expected operating lifetime of a facility (i.e. the life-cycle cost of electricity). Preference may be given to installations that have superior environmental and/or socioeconomic outcomes. In order to ensure stable pricing and electricity supply to its customers, SaskPower must maintain a diverse portfolio of power generation capacity. Coal is plentiful and, if possible, should continue to form part of the power generation fleet, although it must be used more cleanly than has been the case historically.

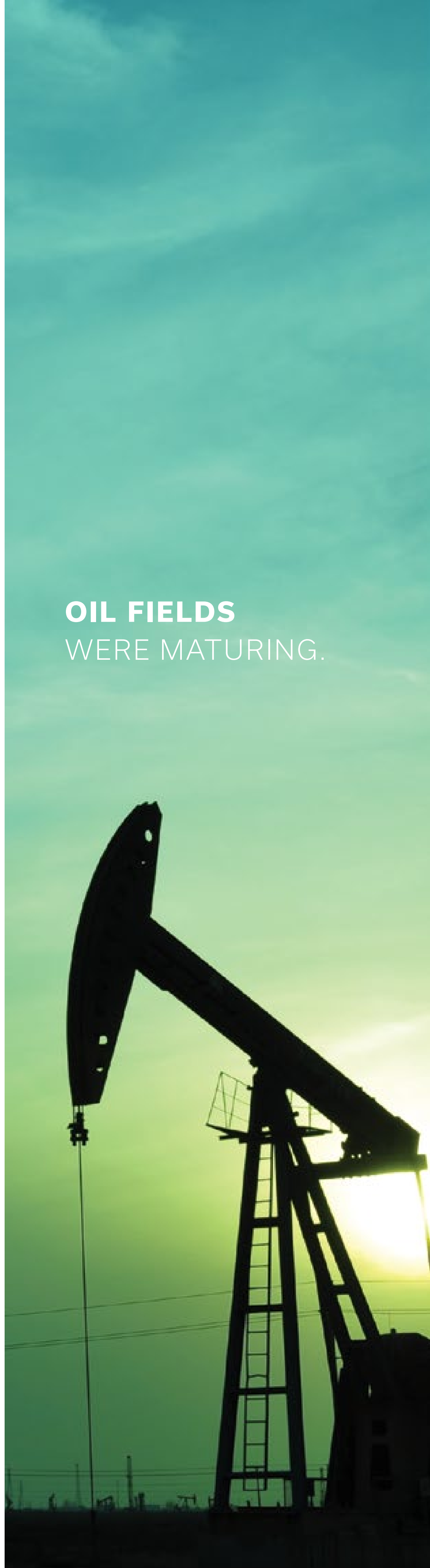
THE HISTORY OF CARBON CAPTURE AND STORAGE AT **SASKPOWER**

SaskPower's contemplation of CO_2 capture and storage (CCS) from its coal-fired power generation fleet was driven in large part by a number of external forces that came into play from the 1980s to the 2000s. However, SaskPower was clearly proactive in its approach to managing upcoming issues, seizing new technology opportunities, and anticipating regulatory changes.

THE 1980s

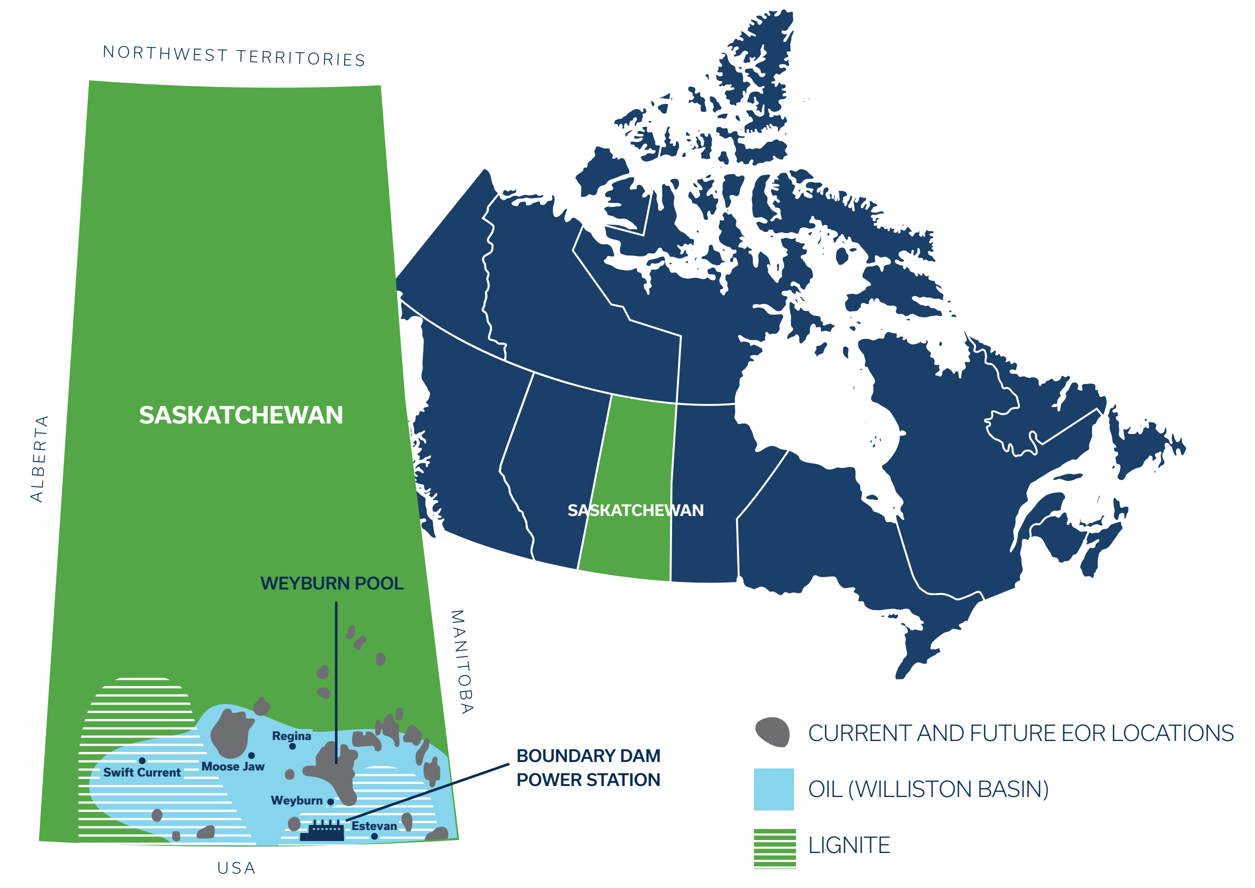
DURING THE 1980s, oil fields in southeastern Saskatchewan that had been in operation since the 1950s were maturing. Oil production associated with water-flooding practices was in decline[7] and water cuts were approaching 80%. The oil operators looked to the success of carbon dioxide enhanced oil recovery ("CO_2–EOR") in West Texas[8] as a model for the next generation of technology that could economically boost production. The Saskatchewan industry was fortunate that "unitization" of leased mineral rights had become common in order to support infrastructure investment in water flooding during the 1960s. That unitization was one of the keys to supporting CO_2–EOR development; lack of unitization[9] in some jurisdictions, such as Alberta, has hindered widespread implementation. Discussions began between interested oil operators and the Government of Saskatchewan on ways to provide incentives to the industry to support the business case of CO_2–EOR[10]. Supporting incentives emerged by the late 1990s.

What was immediately apparent to the Government of Saskatchewan was that generation of a sufficient supply of pure CO_2 was essential to support the oil industry and could result in significant socio-economic spin-off benefits in terms of sustained jobs in southeastern Saskatchewan associated with both the power and oil industries, as well as royalties on incremental oil production that would benefit the entire Province (see Figure 10 on the next page).



EOR IN SASKATCHEWAN

FIGURE 10 | SOUTHERN SASKATCHEWAN COAL-FIRED POWER STATIONS AND NEARBY OIL POOLS



CURRENT AND FUTURE EOR **LOCATIONS**

However, unlike the situation in Texas, there was a paucity of relatively short-distance, abundant and economic sources of natural or anthropogenic high-purity CO_2 gas to pipeline to southeast (SE) Saskatchewan to support EOR development. Pan Canadian[11], Shell Canada, and Numac Energy Inc.[12,13], began discussions with SaskPower about supplying high-purity CO_2 that might be captured from the flue gas at a coal-fired power station, contemplating CO_2 supply from the Boundary Dam Power Station near Estevan, Saskatchewan, a short distance from the oil operations.

AROUND THE MIDDLE OF THE DECADE, with support from SaskPower, interested oil industry parties installed an amine-based CO_2 recovery pilot plant at the Boundary Dam Power Station, Unit 6 (BD6). The pilot was operated for a year and left the oil companies with the unsatisfactory conclusion that the presence of fly ash and sulphur dioxide made the CO_2 recovery system ineffective. Adjustments were made to the pilot plant to manage these flue gas constituents, but the results were still unsatisfactory after a further year of operation. Amine absorption of CO_2 to recover the gas for other uses was deemed technically and economically unsuccessful.

MEANWHILE, IN 1985, Shand was selected as the site for a new coal-fired power station in Saskatchewan. It was located relatively close to the Boundary Dam Power Station in southeastern Saskatchewan, conveniently located near the Ravenscrag lignite coal formation. Procurement of major equipment began immediately, providing for two power units. In 1988, the second Shand power unit was cancelled and construction began on the 300 MW (nominal) Unit 1, with provision for future addition of other power units.

THE 1990s

EARLY IN THE 1990s, public concerns were being raised about CO_2 emissions and their greenhouse gas impact that was evidently resulting in global warming. These concerns were sparked by growing evidence from atmospheric scientists who had modelled global temperatures based on a variety of historical weather data[14]. Over the course of the 1990s, there were several international meetings on the subject, supported by continued knowledge development regarding the impact of rising levels of greenhouse gases on the world's climate. It had become clear that human industrial activity and widespread combustion of fossil energy was having a dramatically negative impact on the world's climate. Ultimately, the Kyoto Protocol[15] was signed in 1997, which was a binding and enforceable agreement amongst signatories to reduce national and global emissions of greenhouse gases relative to recorded emission levels in 1990.

IN 1992, the Shand Power Station construction was completed and the power plant was commissioned. Its engineering team was disbanded by SaskPower and reassigned to new projects elsewhere within the company.

IN 1994, a 2250 MW power station in Demkolec, The Netherlands was commissioned using next generation coal-fired power technology, namely, Integrated Coal Gasification with Combined Cycle (IGCC) from Shell Global Solutions[16]. IGCC involved oxidizing coal to produce syngas and removing impurities such as sulphur dioxide, mercury, and particulates[17]. IGCC was seen as producing electricity with fewer emissions than conventional coal power plant technology, with the added benefit that a relatively pure stream of CO_2 could be readily captured for sale to nearby oil producers for EOR. Around 1994, SaskPower negotiated licensing terms for IGCC technology from Shell Global Solutions, and received an environmental permit from the Government of Saskatchewan to construct an IGCC power plant at the Shand Power Station.

SASKPOWER HEADQUARTERS, REGINA

IN THE MID-1990s, with support from SaskPower, CanmetENERGY established a consortium to develop Oxyfuel coal combustion technology[18] at its laboratories in Ottawa. The goal of the consortium was to develop an efficient and economic next-generation coal combustion technology that could also provide a source of high-purity CO_2 for EOR from coal-fired power generation. A bench-scale pilot was constructed and began demonstrating positive results by 1996[19,20].

DURING 1995–1996, SaskPower revisited Shand 2 as a potential site for commercializing Oxyfuel combustion for power generation from coal. It began conducting technology screening studies to support a go no-go decision. Shortly thereafter, upon consideration of capital constraints, coupled with technology and business risks, SaskPower decided not to venture into the CO_2 supply business.

Shell Americas had been operating the world's largest CO_2–EOR flood at its Denver Unit in West Texas since 1983[21]. In the mid-1990s, Shell Canada successfully conducted a tertiary miscible CO_2–EOR pilot project at its Midale oil field in SE Saskatchewan using CO_2 trucked from an Air Liquide gas plant in Medicine Hat, Alberta[22]. As part owner of the Midale oil field, Pan Canadian had access to the pilot project data and used it to justify investing in the development of a technical and economic evaluation of full-scale CO_2–EOR at its Weyburn oil field immediately adjacent to the Midale oil field.

TOWARD THE END OF THE 1990s, Pan Canadian decided to proceed with commercial CO_2–EOR implementation, rolling out CO_2 injection across most of the Weyburn oil field over 25 years[23]. Pan Canadian negotiated a long-term commercial agreement with Dakota Gasification Company (DGC) for CO_2 to be captured at its Great Plains Synfuels Plant in Beulah, North Dakota and transported to Weyburn. A dedicated carbon steel pipeline was constructed to transport up to 8000 tonnes per day of supercritical, high-purity CO_2 to the Weyburn area in southeastern Saskatchewan[24]. Shell Canada elected not to proceed with commercial–scale CO_2–EOR at the smaller Midale oil field* and subsequently sold its interest in the oil field to Apache Canada[25].

* The Midale oil field produces approximately one-third of the oil production at the Weyburn oil field.

THE 2000s

IN SEPTEMBER 2000, Pan Canadian began injection of CO_2 at its Weyburn oil field. CO_2–EOR production at Weyburn exceeded expectations[26] [Figure 11], capturing the attention of other oil producers nearby with similarly maturing water-flood production. There appeared to be an assured steady and stable CO_2 market for many decades to come.

In conjunction with the Pan Canadian commercial CO_2–EOR project, the IEAGHG Weyburn CO_2 Monitoring and Storage Project began its work to monitor the migration of CO_2 within and around the oil field. The goal of the project was to prove that CO_2–EOR was an effective strategy to permanently sequester CO_2 away from the atmosphere as well as shallow subsurface geological formations, such as drinking well aquifers[27].

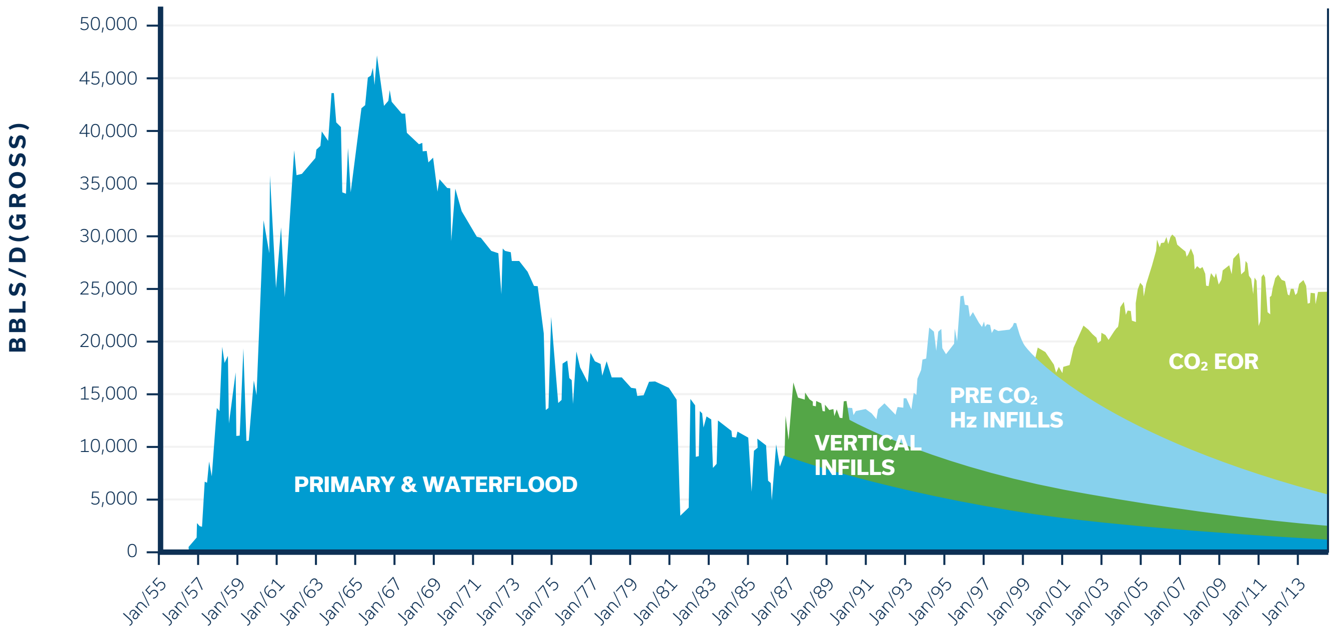
SaskPower was a funding sponsor of the IEAGHG Weyburn CO_2 Monitoring and Storage Project[28] from 2000–2012, as part of its long-term strategy of investing in development of its understanding and knowledge of CO_2 emissions mitigation technologies. This was a prudent course of action given that SaskPower had realized by this time that the public no longer accepted coal-fired power generation without deploying technology to reduce GHGs, mercury, SO_2, NO_X and particulates emissions. Ideally, these constituents could be removed from the stack and permanently sequestered as by-products or used for CO_2–EOR, representing an off-taker market for additional products beyond electricity.

EARLY IN THE 2000s, when it was collectively recognized that conventional coal-fired power plants could no longer be built, SaskPower, other power-generating utility companies, and coal-associated industries initiated the Canadian Clean Power Coalition (CCPC)[29]. In 2002, SaskPower commissioned its first Natural Gas Combined Cycle (NGCC) power generating station[30] as part of its overall strategy to diversify its power supply mix and to reduce its overall air emissions. Shortly thereafter, natural gas prices increased to unprecedented levels and SaskPower began seeking viable alternatives to NGCC as part of its power fleet, although desirous of maintaining the low carbon emissions profile associated with NGCC.

BY 2004, the CCPC had demonstrated that clean coal might be cost competitive with NGCC[31]. Additionally, interim reports from the IEAGHG Weyburn CO_2 Monitoring and Storage Project demonstrated both the commercial value of CO_2 for EOR and the permanence of CO_2 geological storage in the oil reservoir[32,33]. SaskPower was gradually becoming convinced by EnCana, Apache and other oil operators to become a CO_2 supplier to the industry in southeastern Saskatchewan.

The public no longer accepted coal-fired power generation without deploying technology to reduce GHGs, mercury, SO_2, NO_X and particulates emissions.

FIGURE 11 – CENOVUS' WEYBURN OIL FIELD PRODUCTION, INCLUDING CO2–EOR



SEPTEMBER 30, 2014

EXPLORING OXYFUEL COMBUSTION

With strong evidence supporting a clean coal power generation approach, in 2005, SaskPower authorized engineering work to assemble commercial pricing for a clean coal power unit as a future power generation option. This work included preliminary engineering design and contracting with equipment suppliers for preparation of commercial proposals. After evaluating technology and equipment options, in 2006, SaskPower chose Oxyfuel combustion as the clean coal technology for a call for commercial proposals, naming the Shand Power Station as the location for the proposed power plant[34].

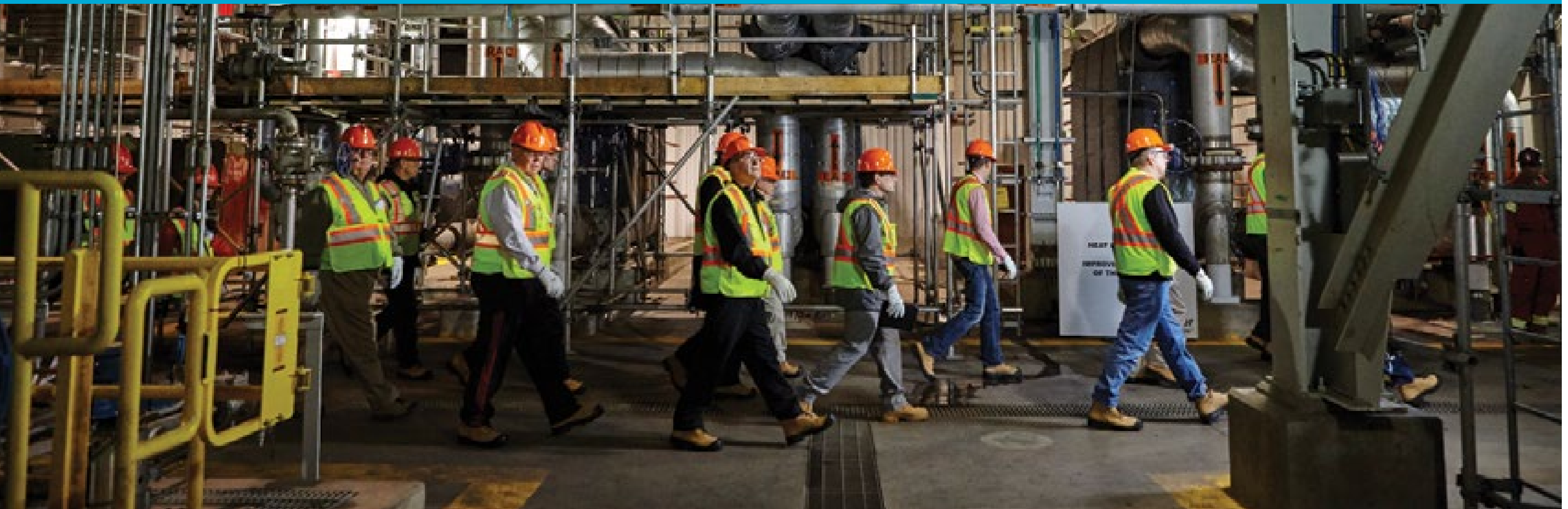
Following evaluation of the commercial proposals received from equipment suppliers, SaskPower determined that the cost to construct a coal-fired power plant incorporating carbon dioxide capture was at least two to three times more expensive than the vendors' original estimates. There were also incremental costs associated with a new coal mine, transmission and other infrastructure. The capital cost alone was going to run to several billion dollars! The SaskPower team concluded that the "new-build" Oxyfuel combustion concept was the wrong approach for pursuing clean coal power generation and stopped its work on the Shand 2 Oxyfuel power unit in mid-2007.

There were two important outcomes for SaskPower from its initial work on Oxyfuel-based clean coal power generation:

1 / Acquisition of the underpinning information necessary to develop a commercially realistic cost estimate for clean coal power generation; and

2 / Development of the internal capacity and business insight to better match technology choices with participation in the CO_2 supply chain.

This foundational work was critical to supporting SaskPower as it continued to pursue a clean coal power option using a different technology approach.



RETROFITTING AN EXISTING COAL-FIRED POWER STATION

In mid-2007, post-combustion capture (PCC) technology was chosen by SaskPower for the evaluation of a Boundary Dam Power Station retrofitting project. The power station had the oldest power units in the SaskPower coal electricity-generating fleet and they were approaching the end of their useful lifespan. SaskPower had recognized that Oxyfuel combustion was not operationally flexible enough to handle the ups and downs of a CO_2 commodity market. Its Achilles heel was the continual production of CO_2 when generating power, which necessitated a buyer(s) who could always buy CO_2, regardless of a buyer's demand needs, operating challenges or economics.

At this point in time, there was no option to permanently geologically sequester CO_2 in deep saline aquifers; it was an unproven practice and was not publicly accepted at the scale necessary to support reduction of CO_2 emissions from a large power station[35]. Quite conceivably, SaskPower could be "held captive" by its customer(s) if it had deployed Oxyfuel combustion that would necessitate the sale of CO_2 at deeply discounted prices and would erode the economics of clean coal power generation. Yet, the sale of CO_2 to the nearby oil industry was the key to the economics for CO_2 capture, particularly in the absence of a carbon tax or any regulation regarding emissions from coal-fired power plants.

If it deployed PCC at a coal-fired power generating plant, SaskPower could choose to capture CO_2 and sell it to oil producers when the gas could command a good price. Or it could choose to operate the power plant with partial or no CO_2 capture when either the gas did not command a good price in the market or when the capture plant was in the process of being maintained. The latter factor enabled SaskPower to consider PCC technologies that had not been operationally proven, which was the case for all technologies at the scale of operation required at Boundary Dam. Operational flexibility was the key to managing market dynamics and the risk of commercializing a new technology.

The engineering analysis that drove the decision by SaskPower to proceed with designing a retrofit of PCC at Boundary Dam included:

- The effort expended on evaluating Oxyfuel combustion at Shand clearly demonstrated that a newly-built clean coal-fired power plant was not competitive compared to alternatives.
- New generation by SaskPower was essential due to the expected retirements at Boundary Dam.
- When power plants were due to be retired in the near future, the infrastructure (the power plant, its transmission capacity, its fuel supply contracts, staffing, etc.) would become a salvageable asset that could be deployed on new power generation capacity.

Maintaining coal-fired power generation just made practical sense if it could be made affordable.

GOVERNMENT SUPPORT OF SASKPOWER'S PURSUIT OF **CLEAN COAL POWER**

The Government of Saskatchewan was highly supportive of SaskPower's pursuit of clean coal power. In early 2008, as part of its annual budget, the Government of Canada announced funding to support the Government of Saskatchewan's efforts in its pursuit of commercialization of carbon capture and storage. The Government granted most of these funds to SaskPower for the commercial-scale development of clean coal-fired electricity generation at the Boundary Dam Power Station[36]. The Government of Saskatchewan had worked hard to secure this funding on behalf of its power utility since late 2007. SaskPower had done its homework, presenting a compelling business case for a retrofitted PCC clean coal power unit to both levels of Government. That federal funding was the catalyst for converting SaskPower's clean coal power concept into a fully engineered design.

Federal funding was intended to offset the cost of developing a project that was anticipated to incur first-time, technology risk-mitigating costs. And pursuing a clean coal project at Boundary Dam had solid socio-economic justifications for the Province:

1. Captured CO_2 could be sold to the oil industry in southeastern Saskatchewan, which had been experiencing declining oil production in the past couple of decades. EnCana (now Cenovus) had proven at Weyburn that it could boost oil reserves by deploying CO_2–EOR [Figure 11].
2. Royalties from increased oil production would benefit the entire Province's population.
3. The province already had incentives in place to assist oil companies in developing commercial-scale CO_2–EOR[37] operations as a result of working closely with Pan Canadian in the late 1990s.
4. A healthy oil industry would assure continued direct and indirect jobs in a region with few alternatives for the workforce.
5. Clean coal power generation would assure the ability to maintain a diversity of fuel mix by retaining the social license to operate.
6. Being able to continue to generate power from coal would help realize the value of the vast lignite coal reserve in southeastern Saskatchewan.
7. Continuing to generate power at an established facility would reduce the capital cost of investing in clean power, while extending the useful life of the power plant by 30 years (equivalent to a newly built coal power plant).

As a reminder, at the time the SaskPower was provided financial support by the government for pursuing clean coal power, there were no regulations in place, federally or provincially, that required capture and storage of CO_2, provided for offsets against CO_2 emissions or required payment of penalties for CO_2 emissions. Federal regulation was not enacted by the Government of Canada until September 2012, and did not come into force until mid-2015.

Designing a post-combustion capture (PCC) coal-fired power plant was a bold and progressive move by SaskPower. But appropriate technology risk management was afforded by the federal funding should SaskPower deem their clean coal power approach to be a poor investment.

EARLY ENGINEERING WORK ON PCC TECHNOLOGY FOR BD3

Throughout the engineering and design process that took place well into 2010, comparisons with alternative power generation options, such as NGCC, were continually updated and refined. The overarching philosophy was that whatever option was chosen for the next large power plant at SaskPower, it had to continue to provide stable and moderately-priced electrical power to its customers well into the future.

If designed appropriately, the retrofitted unit would generate power with or without the capture plant operating. This would satisfy SaskPower's core mission to deliver steady power to its customers, while capturing CO_2, which would mitigate the environmental impact of coal use, with associated generation of a revenue stream to offset the cost of capture.

The initial question was: "Which unit in the coal fleet should be retrofitted (first)?" Boundary Dam and its six power units totaled over 800 MW of generating capacity[38]. The units had been built contemplating a 30-year lifetime each and all of the units had undergone at least one life extension. The units were approaching 50 years of operation and were nearing retirement [Table 1]. The recent operating history of Units 1 and 2 had clearly demonstrated they were at the end of their useful life. The equipment in these units was likely becoming unsafe to operate and the technology was so old, the units could not be retrofitted to accommodate CO_2 capture. Furthermore, these units were each too small to be economic to retrofit.

It was therefore reasonable to plan to shut down Units 1 and 2 within a matter of a few years and to plan to retrofit Unit 3 (BD3), which had sufficiently modern technology that it could be upgraded to be more efficient, and it was of sufficient size to likely be economical for the addition of a CO_2 capture plant.

TABLE 1 | BOUNDARY DAM POWER STATION

UNIT	GENERATING CAPACITY (MW)	DATE OF INSTALLATION	DATE OF RETIREMENT
1	62	1959	2013
2	62	1959	2014
3	139	1970	n/a
4	139	1970	TBD
5	139	1973	TBD
6	273	1978	TBD

Furthermore, the output of BD3 could be more easily replaced during the retrofit than a larger power plant, such as Shand or Poplar River, as well as following startup of operations, should the unit become less reliable with the addition of carbon capture. From a risk perspective, it was the prime target for implementation of clean coal technology.

In the late 2000s, power requirements were continuing to grow in the Province, and new power would have to come from either a retrofitted unit or an alternative source of power, such as NGCC, that would entail the shutdown of BD3 if its retrofit was not the best investment to make. A clear business decision about the future fate of BD3 had to be made very shortly, particularly in anticipation of upcoming federal GHG emissions regulation.

> In the late 2000s, power requirements were continuing to grow in the Province, and new power would have to come from either a retrofitted unit or an alternative source of power.

SaskPower was very clear that whatever path was chosen, it had to be the most economical, reliable and sustainable power generation choice for the province. BD3 supplied half of the power to the grid required to meet the needs of the City of Regina (or approximately one quarter of the population of Saskatchewan). A reliable power station with assured longevity, that delivered a low lifecycle cost of electricity, would be essential.

In the summer of 2008, following the federal cash infusion of C$240 million, SaskPower issued a request for commercial proposals (RFP) for post-combustion capture technologies to install at BD3. The SaskPower Board of Directors and Crown Investments Corporation approved development engineering for the project shortly thereafter, at which point SaskPower pulled together its Project Execution Team. Commercial development of clean coal-fired power generation in Saskatchewan had begun.

In order to support the deployment of PCC at BD3, it was a prerequisite to rebuild and upgrade the BD3 power plant both in order to assure an additional 30 years of operation, and to achieve effective integration with the carbon capture system. A thirty-year life of the retrofitted BD3 power unit would be a requirement to attain an acceptable lifecycle cost of electricity to support the business case. Modernization of the power unit was a separate design and approval process, and by necessity had to occur before the capture plant was approved. Engineered effective and efficient integration of the two plants was inherently essential.

The SaskPower technical team had narrowed down its choice of carbon capture technology vendors from the RFP by early 2009. They focused on liquid absorption/desorption capture technologies. Each of the top three vendors was contracted to develop detailed FEED proposals, involving engineering, procurement and construction (EPC) firms. It was anticipated that the FEED process would illuminate any technical scale-up or economic concerns and highlight key areas of risk for the first full-scale installation of CO_2 capture at a power plant in the world. During the FEED development, one of the vendors self-declared it could no longer proceed when it was clear its technology was not sufficiently advanced for commercialization.

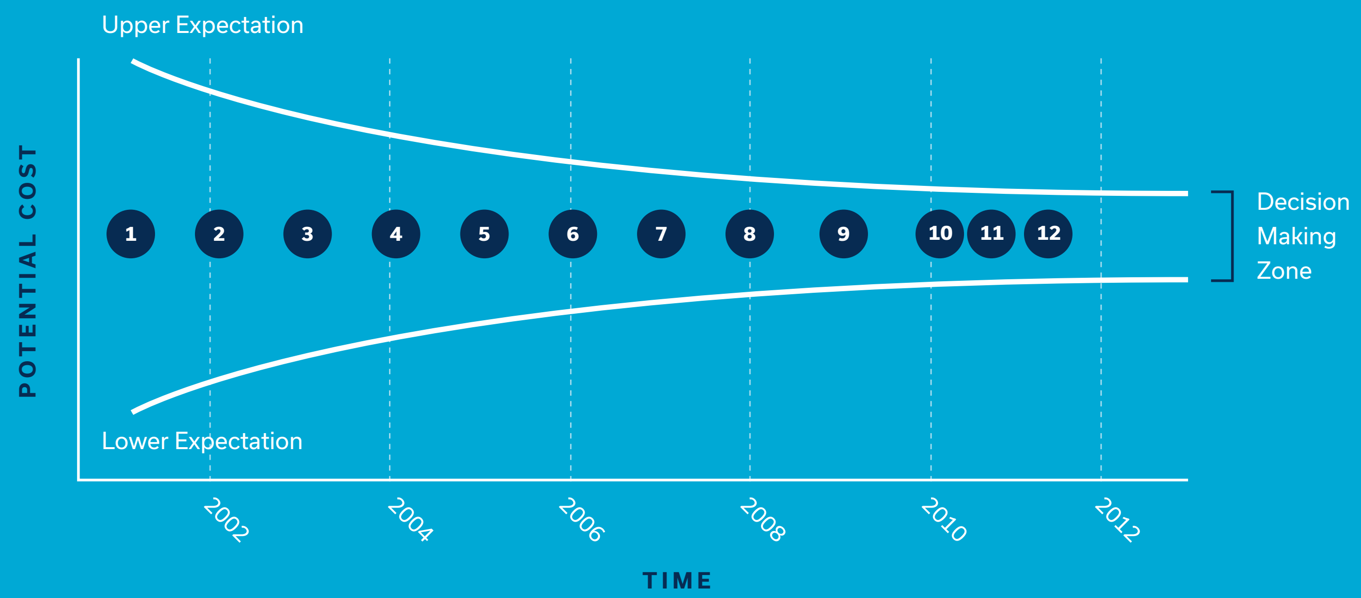
One of the main challenges in the technology evaluation was the lack of any commercial operating history for any of the competing CO_2 amine capture technologies. By the end of 2009, Shell Cansolv's CO_2 amine absorption capture process[39] was the leading technology option due, in part, to its proven record of deployment of very similar SO_2 capture technology in coal-fired power plants and other industrial facilities at various global locations. This assured SaskPower of a lower risk of scale-up by selection of the CANSOLV technology for CO_2 capture.

Furthermore, CANSOLV had developed an acceptable, reasonably-priced EPC arrangement with SNC-Lavalin, which could construct the combined SO_2 and CO_2 capture plant[40]. The Project Execution team selected SNC-Lavalin to proceed with construction, subject to approval by the SaskPower Board of Directors and Crown Investments Corporation. Figure 12 shows the go no-go decision time frame versus cost from the original SaskPower concept of CO_2 capture at a coal-fired power plant to the beginning of construction at BD3.

In order to support the approval process by senior leadership, the SaskPower team had, by the Fall 2009, converged on major equipment, finalized the design and construction plans, and had put out bids on the boiler, turbine and CO_2 compressors. Additionally, it had entered into EPC contracts for the construction of the capture facility with appropriate "exit", clauses should the project not get final approval. This assured solid pricing for the majority of the procurement and the construction work.

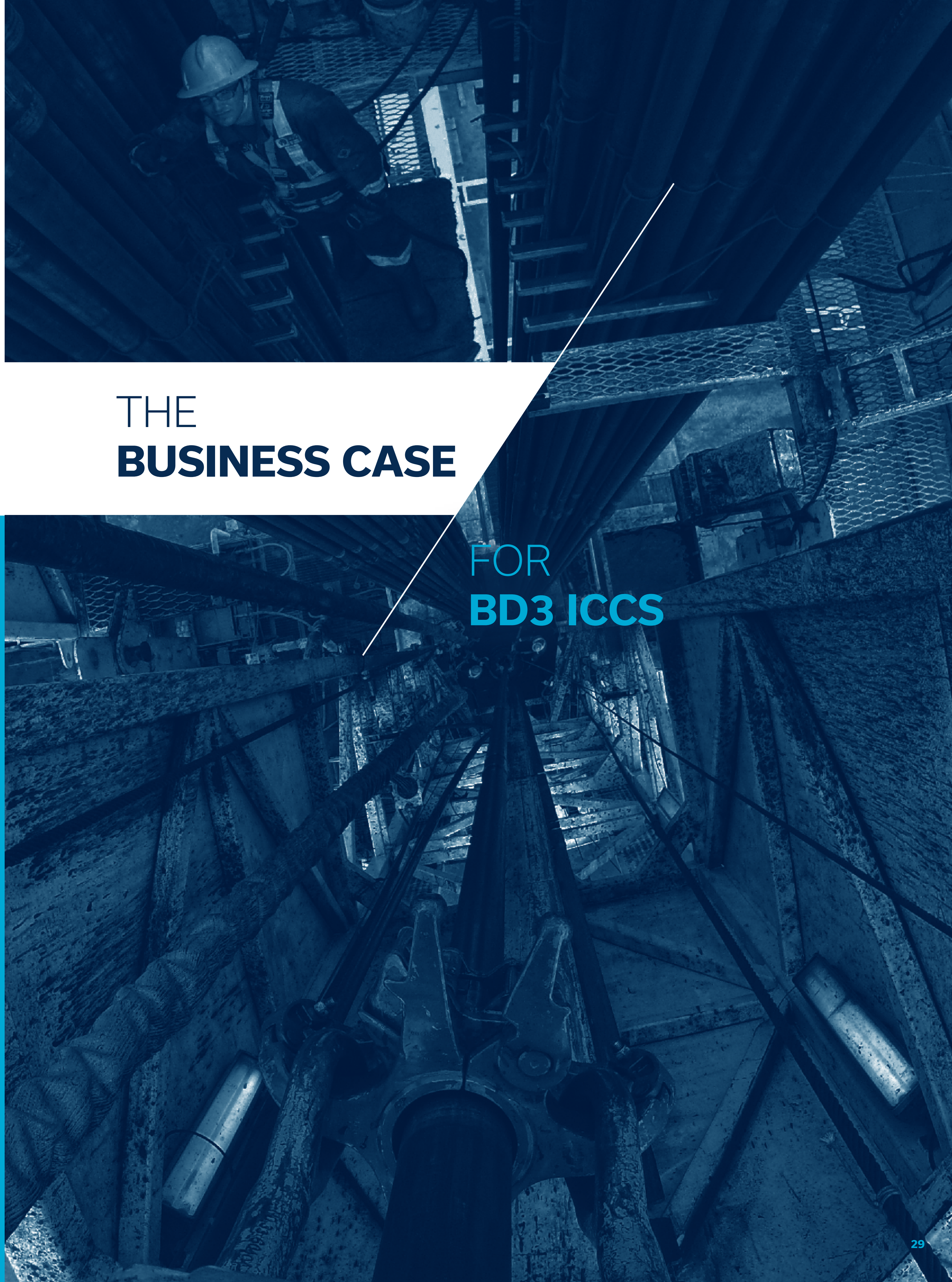
It would take a further year of work on the procurement and re-engineering cycle to narrow in on the final design for both the power plant and the capture plant. Overlapping this period, the SaskPower Board of Directors initiated a third-party technology and investment review in order to support stakeholders in the decision-making process.

FIGURE 12 | GO-NO GO DECISION "FUNNEL" FOR BOUNDARY DAM UNIT 3



LEGEND

1. Amine Oxyfuel Study, Phase 1
2. Coal-Fired Generation Option Study, (CCPC)
3. Oxyfuel Study, Phase 2
4. Pre-Commitment Engineering
5. Oxyfuel announcement
6. Amine PCC RFP
7. Amine PCC FEED begins
8. CANSOLV Amine PCC selected
9. Procurement and Engineering Continue
10. Third Party Review
11. CIC approves Power Plant
12. CIC approves Capture Plant and Construction Begins



THE BUSINESS CASE FOR BD3 ICCS

THE IMPACT OF BY-PRODUCTS

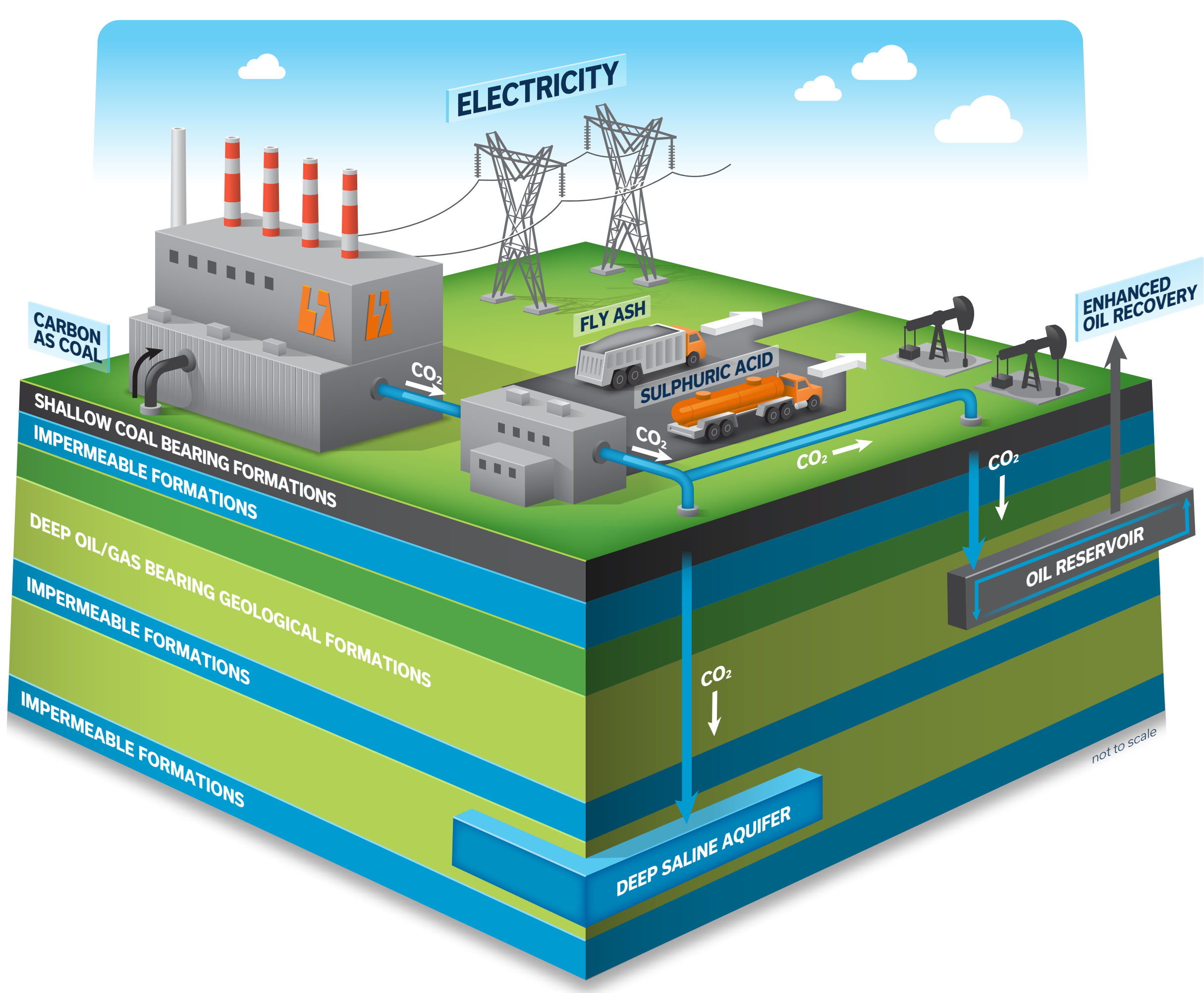
In its simplest form, the business case for the BD3 retrofit to convert to clean coal power generation boils down to making valuable by-products (CO_2, sulphuric acid and fly ash) to meet regional market demands, in addition to power generation [Figure 13]. Those very by-products had been determined from economic forecasts to have competitive pricing in Saskatchewan and the northern USA at the time the decision to construct the BD3 retrofit was made in late 2010/early 2011.

The projected, highly competitive market for by-products is expected to span the useful operating life of the retrofitted plant (i.e. 30–35 years), thereby offsetting a major part of the capture plant investment cost. The economic evaluation of the BD3 design(s) assumed that the capture plant would be operated at 85% capacity, and would produce 1 M tonnes per year of supercritical, high-purity CO_2 or approx. 3250 tonnes per day. This economic scenario could be characterized as the yield of a zero net present value for the Integrated Carbon Capture and Storage Project (ICCS) at BD3. A key component of the business case of BD3 was the rare injection of federal funding (C$240 million), that represented approx. 20% of the capital cost of the retrofit, and helped to offset the cost of engineering and design of the retrofit since it was a "first time ever" project in Canada.

In fact, so huge was the forecasted potential for CO_2 sales volume and price over the next few decades in the southeastern Saskatchewan region, it was not essential to have a long-term CO_2 sales contract in place to support the approval of construction of the project by CIC in early 2011. Market demand was effectively 100% assured. However, well before the first delivery of carbon dioxide by SaskPower in October 2014, the entire volume of CO_2 was sold to Cenovus under a ten-year contract[41]. Cenovus planned to use the CO_2 for its EOR operation at the Weyburn oil field. It seems entirely likely that should the value of CO_2 rise over time due to increased demand by the local oil industry, SaskPower would actually realize an unplanned financial gain from the BD3 retrofit that couldn't be predicted when the capital expenditure was approved in 2011.

The business case for the BD3's ICCS retrofit boils down to making valuable by-products, namely CO_2, sulphuric acid and fly ash, for off-taker markets.

FIGURE 13 | USING COAL TO GENERATE POWER AND VALUABLE BY-PRODUCTS



REALIZING CONTINUED VALUE FROM EXISTING **INFRASTRUCTURE**

What made the economic case so compelling for generation of power from clean coal using an existing power plant versus the unfavourable economics of power from a newly-built clean coal power plant was the sunk cost in existing infrastructure. The BD3 power plant was constructed in 1970, when skilled labour was plentiful and materials, like steel, were inexpensive. The prices of labour and materials were quite the opposite around 2010 when the business case for BD3 was finalized. Furthermore, as a consequence of SaskPower's long-term employment of skilled power engineers at Boundary Dam Power Station, there would likely be a suitable pool of workers in the region to staff the retrofitted power plant when it was completed. The situation could well be quite different at a new power station elsewhere in the Province.

In all likelihood, an aged, existing power plant incorporating technology targeted for conversion to clean power would have reached or nearly reached the end of its planned useful life, and its capital cost could be close to full depreciation, when a decision would have to be made about retrofit vs. retirement. Retrofitting presented a golden opportunity to install new power generation technology and equipment that would provide reliable and efficient service equivalent to a newly-built power plant without the associated infrastructure costs. Additionally, installation of new power generating equipment would also be an opportunity to more effectively and efficiently deploy thermodynamic integration of the power plant with the capture unit rather than integration of carbon capture equipment with an unmodified, though relatively new, power plant, such as Shand.

TIMING AND CONSIDERATIONS FOR A CAPITAL INVESTMENT DECISION

As stated previously, it is important to realize that the business case for BD3 was made in 2009–2010, when natural gas prices were higher than when the BD3 retrofit began generating power in June 2014. Those high natural gas prices made the comparison more favourable for the clean coal retrofit of BD3 versus a newly built NGCC power plant which supported the go-ahead decision for construction [Figure 14].

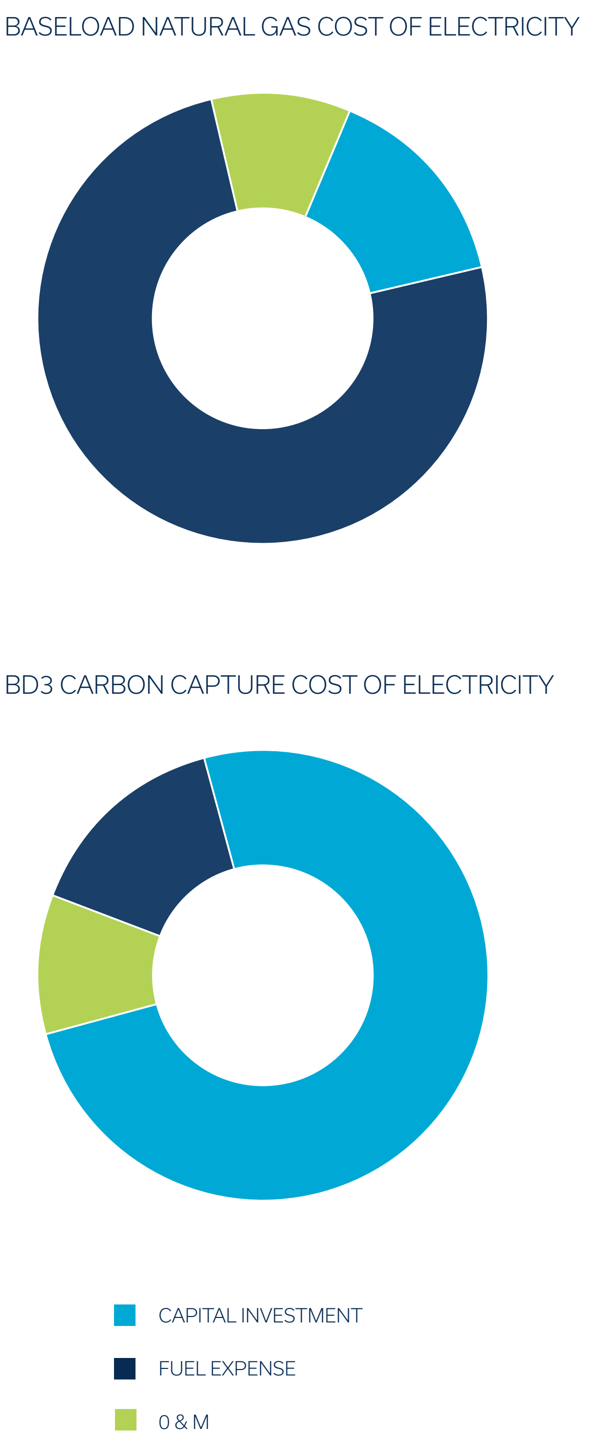
Intangibles that were difficult to pinpoint financially were also considered, given SaskPower's public ownership status, that included:

- better environmental footprint,
- positive socio-economic package, and
- a valuable learning opportunity.

The latter factor was particularly important for a first-time project like BD3 ICCS. The project would include insights upon which SaskPower and its partners could improve in the next old coal plant conversion project(s) to do the retrofit better, faster and cheaper.

It is important to note that as a publicly-owned utility, SaskPower is not a profit-driven organization. It is an electricity-rate-driven enterprise that considers the lowest cost next option to supply its customers with power, reliably and sustainably. Consequently, if two roughly equivalent options have the same rate impact, other considerations come into play such as socio-economic benefits. So while the aforementioned "side benefits" may make clean coal a better outcome than natural gas, SaskPower's role is to firstly quantify the economic, reliability, and sustainability values and then to supplement that information with pertinent socio-economic information to support the investment decision by the Government of Saskatchewan. To be clear, the decision to proceed with the BD3 ICCS project was the most strategic and sustainable choice at the time it was made.

FIGURE 14 | COMPARING THE COST OF NGCC WITH CLEAN COAL AND CCS (2009–2010)



CONTINUED ACCOUNTABILITY FOR MAJOR PUBLIC INVESTMENT DECISIONS

Narrowing in on a generation supply technology choice is not only difficult from investment, engineering and operating perspectives (see "Retrofitting an Aging Coal-Fired Power Plant"), but it is even more complicated when investors (shareholders or citizens in the case of a public utility like SaskPower) question the decision many years later when circumstances will undoubtedly have changed. The point in time when a technology choice is made is the only time when anyone can logically compare alternatives, such as NGCC or wind combined with simple-cycle gas power backup, AND any investment decision will be made a few years before the installation can be completed and operational.

By the time a power plant is operational, the economic and technical conditions for the project will most likely have changed and can potentially make its choice look poor relative to newer information. Almost certainly, the comparative cost of various fuel sources will have changed. This proved to be the case for BD3 as we can see from recent criticism of the project from a number of quarters, principally ENGOs[42].

Any debate about a power generation investment must also consider the complete suite of power generation capacity being operated by the utility.

> The decision to proceed with the BD3 ICCS project was the most strategic and sustainable choice at the time it was made

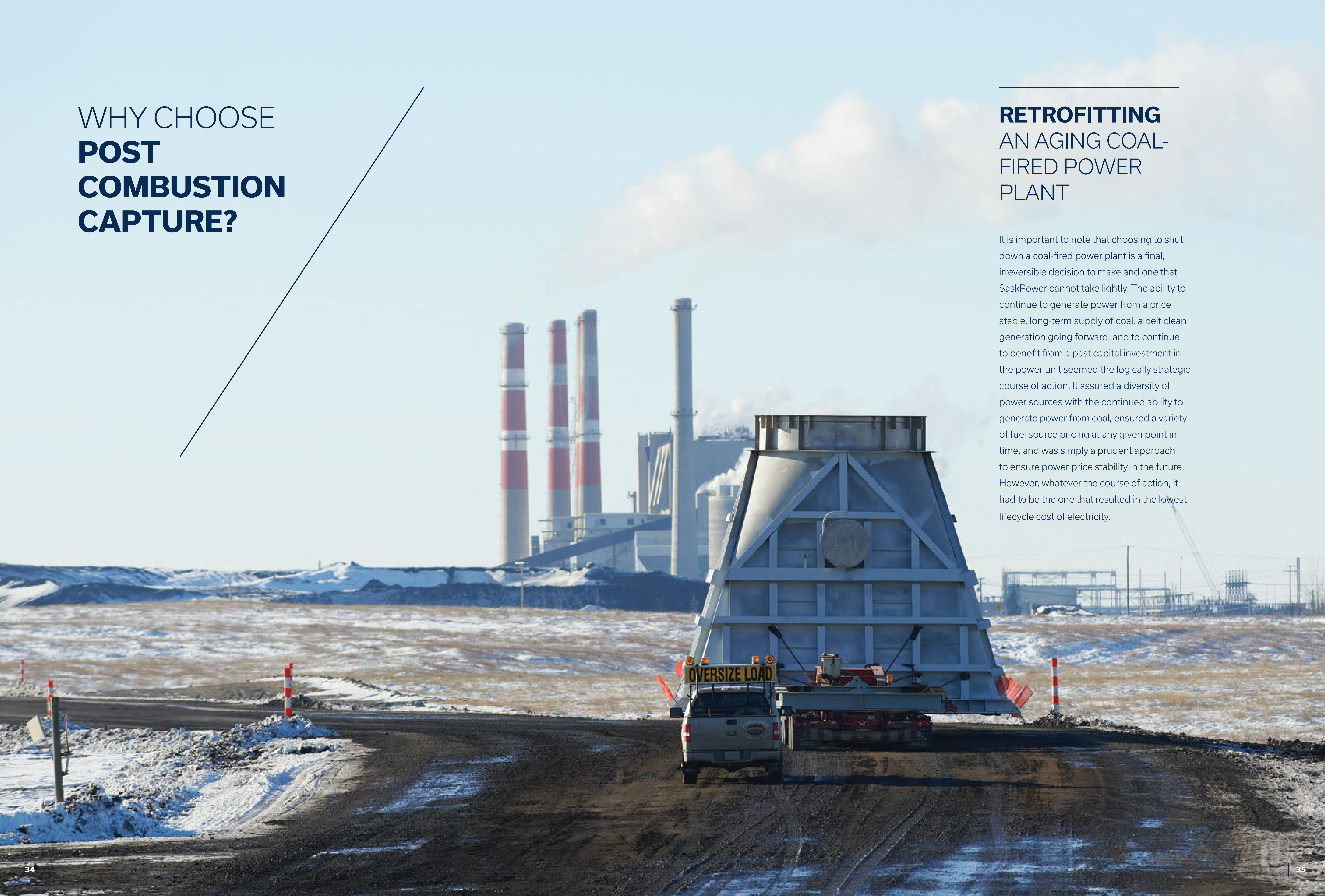
SaskPower's entire fleet clearly demonstrates that the power utility has a diverse power mix that ensures environmental and economic sustainability for many decades to come.

At the time SaskPower decided to pursue post-combustion capture in 2009–2010, retrofitting BD3 to convert it into a clean coal power facility was comparable to the cost of building another NGCC power plant, which would entail the shutdown of the original BD3 power unit. By the time power was generated from the upgraded BD3 in June 2014, natural gas prices had slumped and NGCC looked rosy in comparison to the retrofitted BD3 power unit. The total C$1.24 billion budget for the BD3 retrofit to incorporate CCS that was announced in April 2011 was overrun past plan, reaching C$1.467 billion[43] for reasons that will become apparent to the reader later in this report. The upgrade of the power plant was seriously over budget, while the capture plant cost was slightly over budget. The entire project schedule was delayed by several months compared to the original plan.

WHY CHOOSE **POST COMBUSTION CAPTURE?**

RETROFITTING AN AGING COAL-FIRED POWER PLANT

It is important to note that choosing to shut down a coal-fired power plant is a final, irreversible decision to make and one that SaskPower cannot take lightly. The ability to continue to generate power from a price-stable, long-term supply of coal, albeit clean generation going forward, and to continue to benefit from a past capital investment in the power unit seemed the logically strategic course of action. It assured a diversity of power sources with the continued ability to generate power from coal, ensured a variety of fuel source pricing at any given point in time, and was simply a prudent approach to ensure power price stability in the future. However, whatever the course of action, it had to be the one that resulted in the lowest lifecycle cost of electricity.



Retrofitting a coal-fired power plant with post-combustion capture (PCC) technology to convert to clean power generation involved the following analyses:

1. Would the entire retrofit (power plant rebuild and capture plant new build) compete on a lifecycle basis with alternative power generation options?
2. Would the chosen CO_2 capture technology compete against alternative capture technologies in terms of capital and operating cost, technical operating risk, lifecycle cost of electricity, etc.?

> When choosing a technology, its maturity will greatly impact how a project looks from inception to operation.

When choosing a technology, its maturity will greatly impact how a project looks from inception to operation. A mature technology would be preferred by any investor and strongly preferred by a power company like SaskPower that must deliver continuous service and the ability to generate the necessary power 24 hours each day, 7 days every week, 52 weeks of every year to meet demand needs.

All electric systems must maintain an "operating margin" that will keep the system operating in the event of a generation plant failure. Keeping that margin as small as practical is critical to keeping service costs under control. All potential sources of failure in a generating plant need to be assessed from a probability of failure perspective. Any significant probability of failure creates a high requirement for operating margins. Since the lifecycle cost assessment will reflect needs for operating margins, a project has little chance of being economically selected if an immature technology is carried forward.

From SaskPower's stewardship perspective, undertaking the risk of an immature technology without appropriate contingencies, and without recognition of operating margins, is irresponsible. This type of analysis figured heavily into the design ultimately chosen for the integrated BD3 retrofit project.

The evaluation to determine the technologies of choice for a particular power station requires that designing engineers take into account all aspects of operation. They need to assess how failure of each and every system or subsystem will impact overall electrical system operations. Modern power generation economic modeling tools for trading off reliability, capital and operating costs are used to determine optimal scenarios for various technology choices. But in general, the more uncertainty there is in the performance of a particular technology, the more a power company needs to spend on contingencies, whether that is backup equipment or backup power generating capacity elsewhere in its power supply system. Once those contingencies are factored in, one needs to choose the lowest lifecycle cost for a particular power generation option that is risk adjusted.

Furthermore, diversity of fuel supply will assure future electricity price stability that is important for adapting to many changing conditions, such as:

- Fuel price swings
- Evolving environmental expectations
- Changing consumption patterns
- Other macro-economic variations

The choice of post-combustion capture as a means to convert BD3 into a clean coal power plant was part of SaskPower's evolution from old coal power generation to an environmentally sustainable coal power fleet of the future. PCC technology allowed SaskPower to maximize the amount of CO_2 product available for sale to bolster the business case for the BD3 retrofit and enable power plant operation with or without carbon capture.

Given SaskPower's mission to consistently and reliably provide the Province's population with electricity, PCC power generation was the only way to deliver on that mission and maintain a coal-fired power fleet. Fortunately, there were relatively mature PCC technology options to choose from to reduce the risks of engineering scale-up and operation of full-size commercial plants.

To add to the complexity facing the company, SaskPower did not have the benefit of any guidance from regulation at the time of its construction decision and therefore opted for a technology that could reliably capture 90% of the CO_2 in the flue gas just in case anticipated regulation was very strict. To choose otherwise would risk the entire investment and its proposed 30-year lifetime.

Selection of the appropriate PCC technology, and the associated design choices in the power plant for integration with the capture plant, enabled SaskPower to optimize the power plant's operational flexibility at any given point in time.

The criteria for selecting the PCC technology and associated power plant retrofits were the following:

- technical needs,
- commercial cost,
- lifecycle cost of electricity,
- capability to remove 90% of effluent CO_2,
- operational flexibility,
- acceptable technical and financial risk, and
- a levelized cost of electricity[44] comparable to alternative forms of generation, such as NGCC.

The winning capture technology developed and owned by Shell Cansolv was chosen for CO_2 capture at BD3. It was an amine solvent absorption capture process.

WHY CHOOSE SHELL CANSOLV'S COMBINED SO_2–CO_2 CAPTURE PROCESS?

Both of the leading CO_2 amine capture technologies contemplated at the FEED stage required ultra-low levels of SO_2 in the flue gas prior to CO_2 capture due to preferential absorption of SO_2 by the amine solvent used in the CO_2 capture unit. Using an SO_2 capture system ahead of the CO_2 capture system would also facilitate the removal of flue gas contaminants, such as particulates, ahead of the less-proven, more technically risky amine-based CO_2 capture unit.

SaskPower had gained considerable experience in technologies to capture and remove SO_2 when designing the Shand Power Station, as a requirement of its environmental permit. However, such low SO_2 flue gas emission levels were not something that SaskPower had worried about before.

One logical and proven process that was considered for achieving low SO_2 flue gas emissions was high-performance Limestone Forced Oxidation (LFSO) scrubbing, an industry standard. While LFSO is an expensive process, it is a mature technology and commercially well understood, resulting in near zero risk of deployment. The LFSO process requires large quantities of limestone, which when reacted with SO_2 produces calcium sulphate. In favourable markets, the calcium sulphate can be used to produce wallboard. However, Saskatchewan was not a region where wallboard produced from LFSO by-product would be commercially viable due to the distance of a limestone source (1000 km away in western Alberta) and the equally long transportation distance to "off-takers" (the end-user market). Consequently, LFSO was dismissed as an option for removing sulphur dioxide from the flue gas at BD3.

Ultimately, the regenerating amine in the CANSOLV SO_2 capture process was appealing from a cost-effectiveness perspective in comparison to LFSO. The proven performance of the CANSOLV SO_2 capture process deployed at other coal-fired power stations in China and elsewhere was an important consideration. The SO_2 captured in the solvent absorption process could be recovered and converted into saleable sulphuric acid that could be used by Saskatchewan-based chemical manufacturers to make sulphur-based fertilizer. This additional value-added by-product contributed to the positive business case for the combined CANSOLV SO_2-CO_2 capture system.

Further risk-reducing and/or positive features that supported the selection of the combined CANSOLV capture system were as follows:

- Competitive pricing on the combined process package;
- Technical and operational simplicity by integration of a single, combined SO_2 and CO_2 capture plant with the power plant rather than use of separate capture systems;
- The CANSOLV combined capture process would incorporate an energy recovery system that would enable heat used to regenerate the SO_2 solvent to be used in the CO_2 capture system, which would reduce the parasitic load of the combined capture system on the power plant and make it the most energy-efficient technology choice for BD3; and
- The EPC contractor, SNC-Lavalin, backed up the new capture plant with written performance guarantees.

FINALIZING THE DESIGN AND APPROVAL FOR CONSTRUCTION

Many tasks were completed in parallel during 2010 in the sprint to gain final construction approval for the ICCS project at BD3. A number of hurdles were overcome and decisions were made in the face of uncertainty regarding the performance of the CO_2 capture unit. Some of these activities ultimately affected the overall schedule for completion of the project.

DEVELOPMENT OF A CUSTOMIZED PROCESS SIMULATOR

A high fidelity process simulator was developed somewhat late in the engineering design work to support integration of the power plant and capture plant, as well as incorporation of the distribution of by-products to "off-takers", principally high-purity CO_2. However, the simulator proved invaluable for training of the power plant and capture plant operators before the construction work was completed. By the time it came to commissioning and operating the retrofitted BD3 unit, they were all completely comfortable with operations and suitably experienced in normal operations to address surprises and initial startup "pains". The simulator will also be a critical tool to assist with the design and engineering of any future retrofits of additional coal-fired power units contemplated by SaskPower.

MANAGING UNCERTAINTY AND CHANGE

During the design stage, uncertainty was managed using bow-tie analysis on major pieces of equipment to define what-ifs, barriers, issues, actions and consequences, and specifications for related equipment. In the power plant, the 3D model of the pre-existing plant was a powerful tool to test possibilities, and reduce risk and uncertainty regarding choices in design, engineering and construction. Process unpredictability in the integrated power unit design was managed by performance margins that could be tolerated on each piece of equipment, which were the basis for selecting equipment for procurement. Uppermost in the decision-making process to manage uncertainty and change throughout the entire power unit was an overriding lack of compromise on the emissions standards for BD3 and requiring stable power generation with or without emissions capture.

PROCUREMENT

Procurement for the BD3 retrofit began early in the design and engineering process. The lead time on the power plant equipment was three years. SaskPower had a high bar to meet to ensure fairness of process and open competition, a requirement for any publicly-owned entity in Saskatchewan, as well as the need to meet the requirements of the New West Trade Partnership Agreement . Every major item selected during procurement had a ripple effect that impacted choices of other pieces of equipment and their specifications, which necessitated an engineering review by the SaskPower design team. The consequence was a laborious and time-consuming design and engineering exercise that took nearly two years to accomplish from late 2008 to the end of 2010.

All of the EPC contracts and the majority of the equipment procurement contracts were in place before the power plant and the capture plant construction plans were sent to the SaskPower Board of Directors and Crown Investments Corporation for approval. There was clear recognition that there was little tolerance for changes and overruns after approval. This advance planning was critical to assuage stakeholder concerns about design and associated costs, as well as to ensure that the construction schedule could be maintained.

> ...a laborious and time-consuming design and engineering exercise that took nearly two years to accomplish.

FIRST-TIME, ONE-TIME COSTS/ **EQUIPMENT**

It is hardly surprising there were some significant costs associated with undertaking a project that was the first of its kind. There were many uncertainties about the integration of a power plant with SO_2/CO_2 capture and there were technical risks associated with operation of CO_2 capture, something that had never been done at commercial power-plant scale previously.

The following areas were associated with first-time costs that could be significantly reduced in the next project(s) due to better understanding, operational experience, quicker decision making and fewer contingencies to mitigate risks:

> Built-in redundancy in the power plant and the capture plant to reduce the risk of technologies meeting performance specifications, or the "cost of ***performance uncertainty"***

> SaskPower ensured that technology and equipment choices were available until key stakeholders were comfortable enough to make a final decision on how to proceed, or the "cost of ***technology confidence"***

There were additional costs incurred that were partially due to the economic pressure placed on skilled labour resources in Western Canada[45]. The BD3 ICCS project was undertaken at a time when SaskPower had to compete for that labour with major oil and gas activities in Fort McMurray and Edmonton (oil sands related), in Western Alberta/ Eastern BC (high natural gas production activity using hydraulic fracturing), and locally (CO_2–EOR expansion at Weyburn and high Bakken oil production activity using hydraulic fracturing).

THIRD-PARTY REVIEW

The power plant retrofit was approved by the SaskPower Board of Directors at the end of 2010. As the time approached to face a decision to approve the capture plant construction, the SaskPower Board of Directors astutely initiated a third-party investment review in mid-2010. This was a fortuitous decision that proved critical to persuade Crown Investments Corporation, SaskPower's "owner", to approve the capture plant construction in Spring 2011, while it provided a compelling body of evidence to the public (SaskPower's "shareholders") that the selected capture plant technology was sensible. The need and requirements of the review had not been foreseen by the SaskPower engineering team. Quite simply, this was a first-time project and the decision makers hadn't understood what they might need to know in order to support a decision at the outset of the project.

A Chicago-based banking investment advisory firm, R.W. Beck[46], conducted the third-party review that included investment, business and technology considerations. This fell right in the middle of finalization of the design and engineering details for the integration of the power and capture plants in the lead-up to seek construction approval, as well as advanced procurement for major equipment. The SaskPower engineering team was consequently overworked during the period of the third-party review. However their efforts paid off. The third party review supported the capture technology recommendation by SaskPower and CIC approved the capture plant construction in April 2011, which began immediately.

It is anticipated that any future clean coal retrofit of an existing thermal plant will require a third-party review. However, the time required to support the review will be built into the planning schedule and the needs of the review will be anticipated based on the 2010 technology and business review of the BD3 retrofit.

DESIGN AND ENGINEERING **LEARNINGS**

SaskPower learned some important lessons during the design and engineering phases of the BD3 retrofit:

- A technology must be piloted at a level that allows for meaningful engineering scale-up to commercial size.
- The technology chosen must be commercially viable at the time it is selected NOT when operation begins. There will be a lag of 3–5 years between those dates.
- Commercial proposals for each technology are required before the costs of implementing each one can be understood.
- A fully-engineered cost estimate with a detailed process design is essential to be certain of the required capital investment and operating costs, as well as the associated environmental and operating implications.
- Simple and predictable are the best indicators for technology and equipment selection when required to expend significant capital funding.
- Plan for the time required to build confidence by the key stakeholders in the project. This would include the time required to conduct a third-party investment review.

CONSTRUCTION

OF THE CLEAN-COAL BD3 POWER PLANT UNIT

The retrofit of BD3 to convert from old technology to clean coal incorporating PCC was divided into four distinct, but related, projects:

1 / Power Plant Island (Upgrades and Replacements)

2 / Integration of the Power Plant with the Capture Plant (New)

3 / CANSOLV SO_2 and CO_2 Capture Plant (New)

4 / CO_2 Pipeline to geological injection sites (New)

Construction of the capture plant began in April 2011. Construction of the upgrades to the power plant was intentionally delayed for two reasons: manpower availability (staggered construction would put less strain on skilled trades availability) and long lead time on equipment orders (notably the steam turbine). Power plant construction began in February 2013 after the planned shutdown of BD3.

CONTRACTING

SaskPower entered into fixed-price-and-schedule Engineering, Procurement and Construction (EPC) contracts based on blocks of construction packages with Babcock and Wilcox for the boiler upgrade[47], and with SNC-Lavalin[48] for the capture plant final design and construction. Hitachi[49] was contracted to supply a new dual-mode steam turbine. SaskPower and its owner's engineer (Stantec[50]) undertook integration of the power plant and the capture plant through use of a design-build approach in order to effectively manage the complex "brown" field construction in the power plant that would have made an EPC approach uncompetitive.

Design-build contracts included the following:

1 Turbine island mechanical installation (AB Western)

2 Flue-gas cooler building (PCL and AECON)

3 Flue gas ducting and utilities bridge (Graham)

4 Supporting infrastructure in the power plant (e.g. elevators, building footing reinforcement, etc.)

5 Control system / simulator design, supply and installation

6 CO_2 pipeline to geological injection sites[51]

OVERALL, the project came in over schedule and over budget. Some contracts were delivered on time and on budget, others were not. This is not an unusual outcome for any project of this scale. The project's budget suffered some unplanned changes due to an inadvertent asbestos release and managing lead paint in the old 1970 boiler building[52], skilled labour shortages, and general construction delays. As one would expect with any major infrastructure project of this nature, SaskPower was, as of mid-2015, still settling outstanding claims with some of its vendors.

In future, modularization of the design and construction would be a more desirable approach to meet QA/QC and cost control needs.

POWER PLANT FINAL DESIGN AND CONSTRUCTION

Prior to any decommissioning and tear down of the pre-existing power unit, the owner's engineer, Stantec, completed a 3D computer model of the in-situ power plant. Many changes had been implemented since the unit was constructed in 1970, so the original blue prints were far from accurate. This 3D model was critical to enabling what-if modeling during design, made the implementation of changes to the plant far simpler during construction, and permitted any construction errors to be caught early and rectified.

SaskPower designed a 150 MW power plant that they had anticipated in 2009 would generate 90 MW of net power. Through design optimization and efficient integration of the capture plant with the power plant, SaskPower ultimately constructed a 161 MW power plant that will deliver approximately 120 MW to the power grid when the CO_2 capture plant is operated. The optimization and efficiency gains in power generation that reduced the burden of SO_2/CO_2 capture and maximized power generation were achieved in tiny increments—each one was a rewarding accomplishment. The entire accumulation of power improvements was a stellar achievement.

Ultimately, the parasitic load of PCC was reduced by one-third compared to what was expected at the outset of designing the BD3 retrofit in 2009. The key to this achievement was focusing on optimization of power generation and secondarily considering capture plant performance. Additionally, any economical opportunity to capture otherwise lost energy in either plant by conversion to power was seized.

At any point in the power plant design where there was a risk that power would not be generated due to uncertain capture plant performance, redundancy was designed and engineered into the power plant. This was considered "mission critical risk management". Through use of this approach, SaskPower focused closely on its core mission as a power utility.

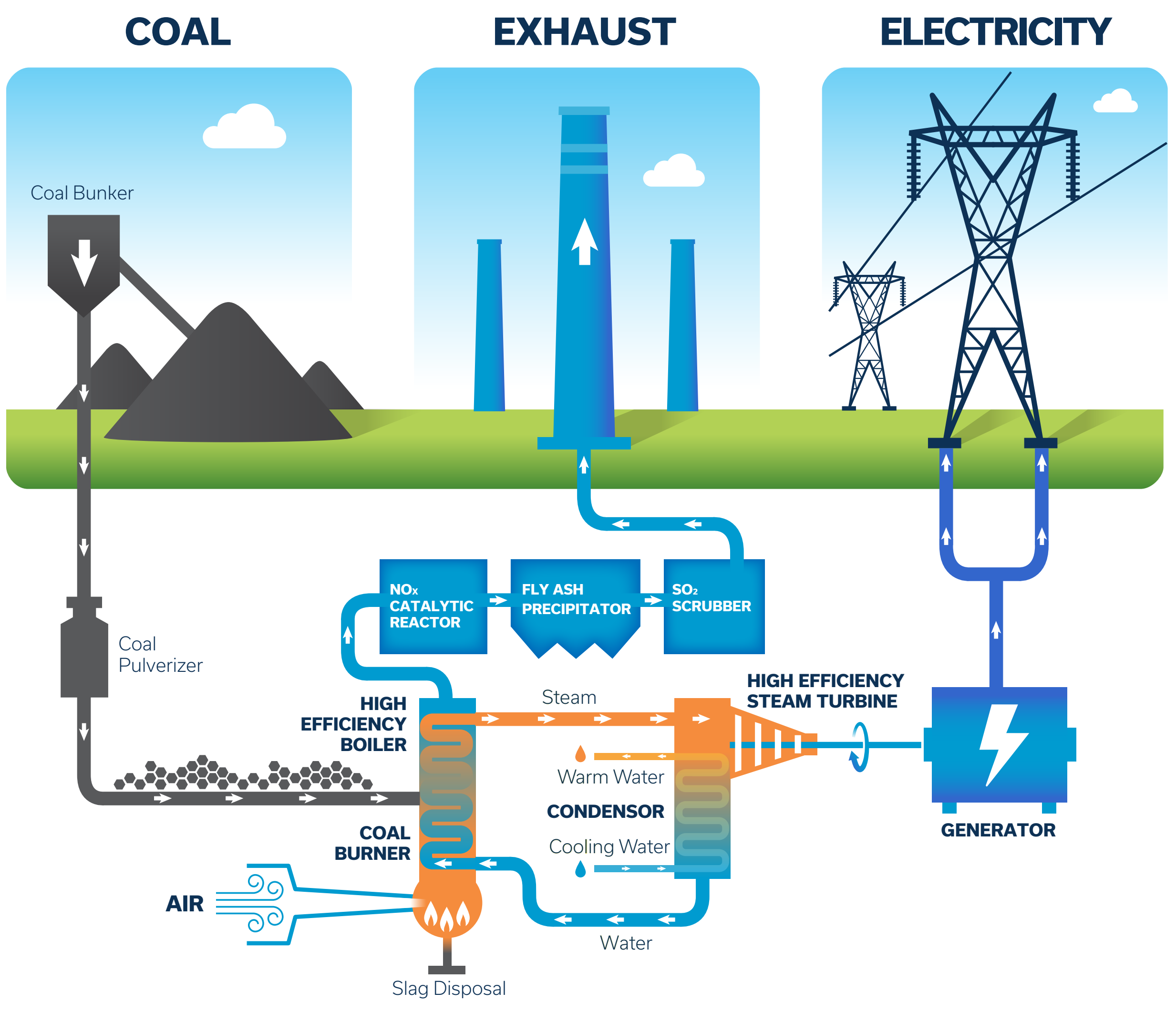
Two major upgrades were undertaken in the power plant:

> The ***boiler*** was upgraded from 1000F to 1050F, and contained significantly more surface area to increase the efficiency of the boiler compared to its performance prior to retrofit. The upgrade of the boiler was accomplished by removal of the boiler's internal heat transfer components and effectively rebuild a new boiler. Due to the additional weight of the upgraded boiler, this process was complicated by the necessity of reinforcement of the columns that support the boiler's weight from the top of the building to the footings.

> The 1969 ***turbine*** was replaced with a modern Hitachi, dual-mode turbine that incorporated better steam and thermal integration, as well as the capability to handle power up or down of the capture plant. Given the requirement for stable and secure power, the power plant was required to operate at full load whether or not the capture plant was in operation, and had to remain operational if the capture plant was suddenly turned on or off. This had a major impact on the turbine selection.

> The power unit's output in non-capture mode was increased by 11.1 MW (7.4%) over the original retrofit design as a result of the combined improvements in the boiler and the turbine.

FIGURE 15 | TYPICAL MODERN POWER PLANT PROCESS FLOW DIAGRAM



Other improvements to the power plant included:

> The power plant equipment cooling system was converted to a closed loop in order to prevent oil and other contaminants from potential discharge to the Boundary Dam reservoir, and to ensure the new equipment was not contaminated by the organic material that may be present in the reservoir water intake.

> A complete rework of the piping throughout the power plant was undertaken.

A typical modern power plant process flow diagram is shown in Figure 15.

> The parasitic load of PCC was reduced by one-third compared to what was expected at the outset of designing the BD3 retrofit.

INTEGRATION OF THE POWER PLANT AND THE SO_2/CO_2 CAPTURE PLANT

The connections and interactions between the power plant and the capture plant were an area of intense focus from concept through design and engineering and then construction. This will continue to be fine-tuned over the next year or two to realize improvements in power generation at BD3. This optimization process is typical of the period immediately following the startup of any new power plant.

The following integration equipment components were considered essential to meet the technical specifications of the capture plant and to mitigate technical risk since the CANSOLV CO_2 capture process had not yet been operated at commercial scale:

Flue-gas cooling was required to reduce the flue gas temperature to the operation temperature required by the CANSOLV SO_2 capture process. SaskPower enhanced this process by addition of a polymer heat exchanger to recover heat from the cooling process. The captured heat could then be used to pre-heat the condenser water used for steam generation in the power plant, which thereby improved the efficiency of power generation by about 3.5 MW through reduction of the demand on low pressure feed-water heaters during capture plant operation.

A Direct-Contact Cooler (DCC) was added as a pre-scrubber to further reduce flue gas temperature prior to entry to the capture plant, and to remove particulates and other contaminants that could negatively impact the performance of the amines in the SO_2 and CO_2 absorption towers. Recall: the feedstock for the capture plant was the flue gas. Its constituent specifications were required by CANSOLV in order to meet performance guarantees for the capture processes. Preconditioning by the DCC was considered an essential step to meet those flue gas specifications.

Steam supply from the power plant to the amine reboilers presented a challenge to the design and engineering teams. Steam flow would start or stop when the capture plant was turned on or off, that would complicate the requirements of the steam turbine power generator. Temperature control was critical at the capture plant's reboilers to prevent degradation of the amines and production of toxic by-products. This is one area that continues to be worked on during 2015–2016 to ensure optimal functionality.

Steam supply from the power plant to the amine reboilers presented a challenge to the design and engineering teams.

A flue-gas diverter was installed to divert flue gas to the pre-existing BD3 stack when the capture plant was not in operation, which would be the case when the power plant was operating at less than 50% load. The diverter dampers were designed to allow incremental adjustment between fully open to the carbon capture plant, and fully open to the stack. This adjustability allowed for smoother start-up and shutdown, and enabled the capture plant to be run at partial capacity independent of the power plant.

A new feed water system was installed due to additional use of steam by the capture plant and its significant impact on steam pressures in the turbine and feed water heaters.

CAPTURE PLANT

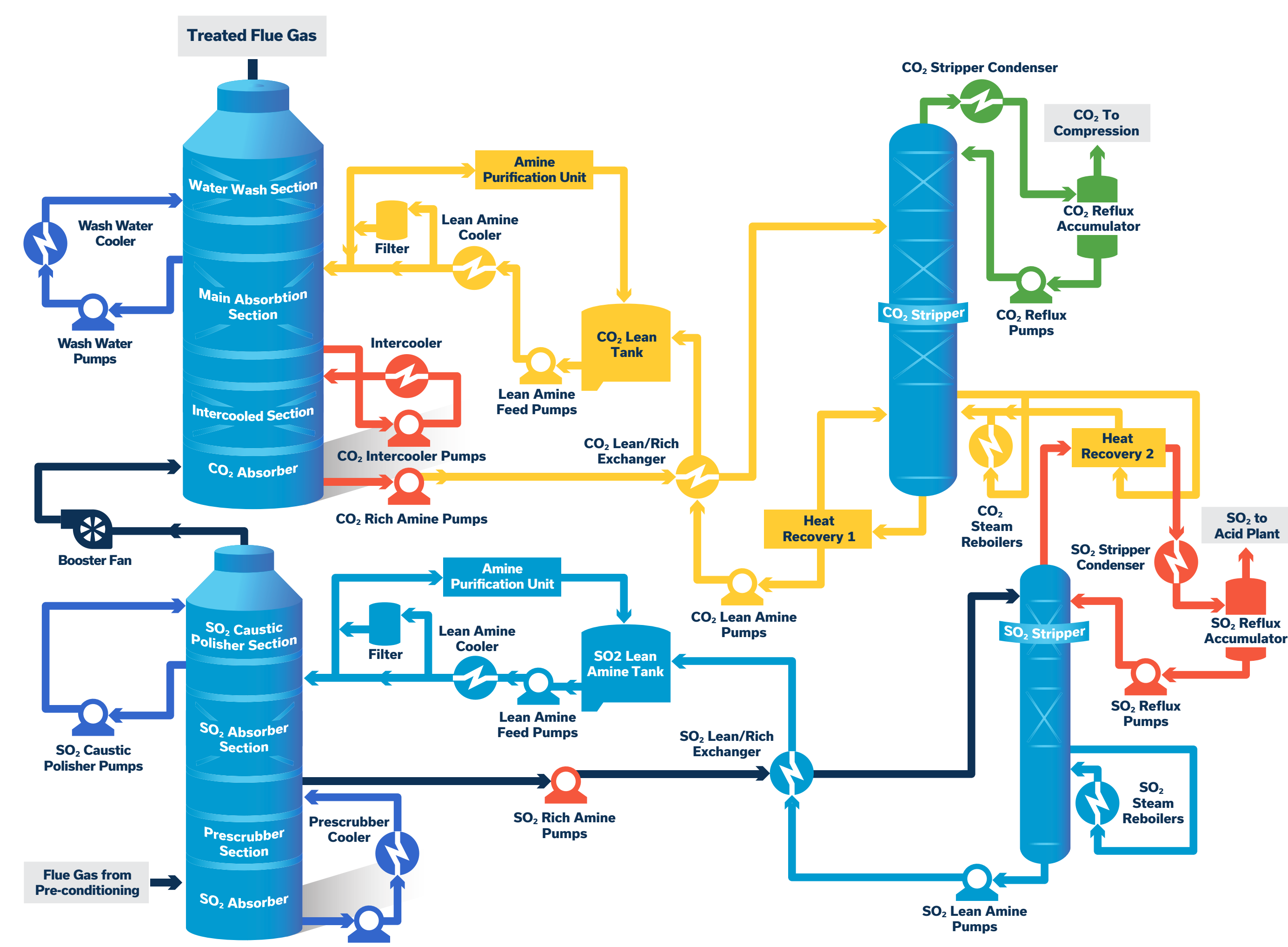
SNC-Lavalin performed the detailed EPC of the overall capture plant, with CANSOLV providing the SO_2 and CO_2 capture technology, including the process design and related performance package for the capture facility. The EPC was divided into three sub-facilities:

1 / Capture facility

2 / Heat rejection system

3 / CO_2 compression and balance of the plant

FIGURE 16 | SHELL CANSOLV'S COMBINED SO_2 AND CO_2 CAPTURE PROCESS



CONSTRUCTION of the capture plant began in April 2011. The following processes and equipment/infrastructure are associated with the capture plant and its by-products:

> After scrubbing SO_2 from the flue gas in the amine absorption process, the clean SO_2 is sent to a new acid plant to produce sulphuric acid, which is then shipped to end users via an on-site truck-loading facility.

> Following CO_2 capture from the flue gas, the CO_2 is dehydrated, and compressed to produce a supercritical, 99% pure CO_2 product lacking the water, hydrogen sulphide and other trace impurities present in CO_2 from the Dakota Gasification Facility (DGC) (these undesirable constituents are due to the nature of the latter's coal gasification process)[53] . The compressor used at BD3 is similar to those that have been in service at DGC in Beulah, North Dakota since 2000. It is an eight stage, integral-geared centrifugal compressor, with a capacity of 55 mmscf/d (1.58 million m^3/d) and electricity driven by a 14.5 MW fixed-speed motor. The supercritical CO_2 is pipelined to the injection site hosting Aquistore and Weyburn for CO_2 geological storage and CO_2–EOR, respectively.

> The flue gas that has been stripped of CO_2, SO_2, particulates and other contaminants is water washed and released to the atmosphere from the capture plant through a new venting stack at the top of the CO_2 absorber vessel.

The capture plant was originally intended to be operated remotely from the power plant with limited internal staff. However, during construction it was recognized that controlling the chemistry in the capture plant would be critical to its performance. Furthermore, when data was received from the CO_2 Technology Centre Mongstad[54] in 2013–14, it was recognized that SaskPower would need to carefully manage amine chemistry, and study its reactions and side-reactions, to assist in developing strategies to better manage the risk associated with off-specification behavior.

Consequently, the capture plant has its own custom on-site laboratory that is used for quality control and assurance in the capture plant and for research purposes to study nitrosamine chemistry and amine solvent reactions, particularly those facilitated by the presence of any flue gas contaminants entering the capture plant. The capture plant manager is a chemist and works closely with the on-site lab and other SaskPower labs to develop knowledge and understanding of the amine chemistry associated with the SO_2 and CO_2 capture absorber systems.

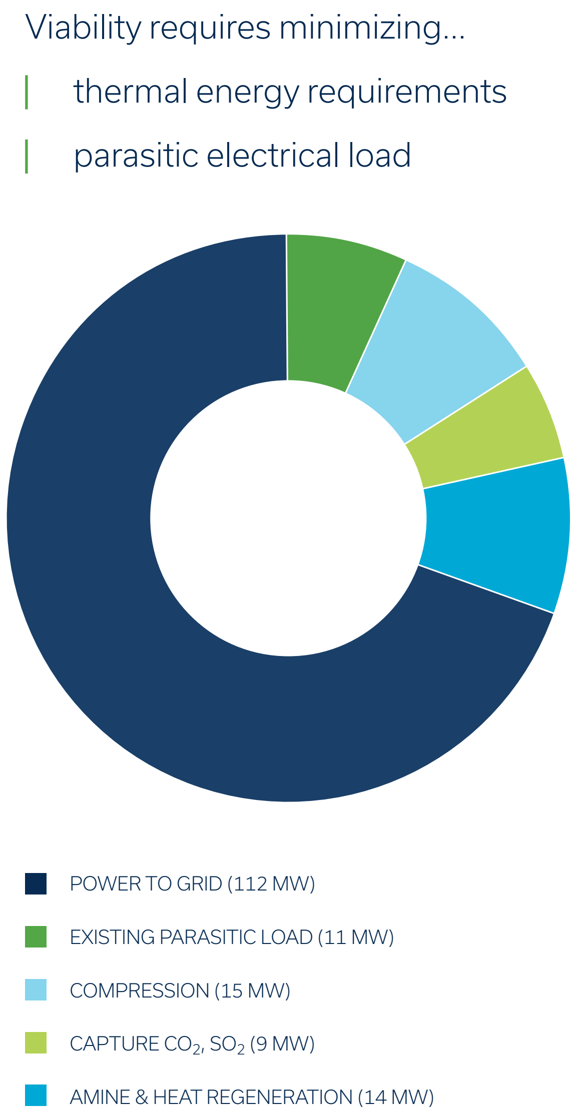
OVERALL EFFICIENCY **IMPROVEMENTS**

All of the iterations to maximize power generation and minimize parasitic load of SO_2 and CO_2 capture paid off. SaskPower will be able to generate 115–120 MW of power using a 161 MW turbine once the construction deficiencies have been rectified and the initial troubleshooting and optimization have been completed. The improvements as of Spring 2015 are shown in Figure 17.

CO_2 **PIPELINE**

SaskPower constructed, owns and operates a custom-built, carbon steel, supercritical CO_2 pipeline that runs approximately 8 km to the northern edge of its property. Cenovus built the pipeline from that point to its Weyburn CO_2–EOR operation. Just prior to the change of custody at the property line, a 2 km pipeline leg runs to SaskPower's CO_2 injection site at its Carbon Storage and Research Centre that is located on the Boundary Dam Power Station property. That pipeline leg is capable of handling the entire volume of CO_2 produced at the power station should that become necessary or desirable at some point in the future.

FIGURE 17 | OPTIMIZING THE PERFORMANCE OF BD3 TO MAXIMIZE POWER GENERATION



SAFETY MANAGEMENT

SaskPower places the highest priority on safety in all of its construction projects. The very large size of the BD3 construction work force created a more challenging situation than usual. Numerous proactive and day-to-day steps were taken to ensure the highest possible safety standard was maintained.

Parallel to the construction activities, there was a keen focus on operational readiness. A dedicated HSE team prepared new standard operating procedures (SOPs) for the capture plant and worked with the operations team to perform rigorous HAZOPs to identify and rectify any anticipated hazards or operational issues. The overarching philosophies of the safety process were the following:

> A "zero leak" standard for power plant and capture plant operations

> Development and delivery of an unprecedented training program that led to all operators being trained and proficient prior to commissioning and startup. The training program constituted over 80 modules on safety and fully utilized the custom process simulator.

This safety preparation took over three years to accomplish but ultimately set up the combined power plant and capture plant operating team for success.

The ICCS project had a stellar safety record. There were no lost time injuries during the 4.5 million person hours of construction time. That is not to state there were no construction-related safety hurdles to overcome. Those safety challenges were successfully resolved, and included:

During the 4.5 million person hours of construction time there were no lost-time injuries.

> Despite a rigorous asbestos abatement program conducted at the Boundary Dam Power Plant in the years leading up to the power plant shutdown, there was an asbestos release from the old 1970 boiler building during the power plant construction. This resulted in a significant work stoppage to ensure asbestos cleanup that lasted several weeks.

> Due to a poor safety track record, the man lifts were decommissioned at the site just prior to the main construction period in the power plant. This necessitated construction of temporary elevators in the middle of the BD3 unit, and outside the plant walls to allow the efficient movement/circulation of tradespeople and materials at the power plant construction site, to thereby minimize impact to the overall construction schedule.

> Amine capture solvents and chemistry were foreign to the company and its operators. Consequently, SaskPower developed a world-class chemical safety program and set of standard operating procedures (SOPs). Due to its unfamiliarity with the subject matter, the company was able to think "outside the box" during SOP development from its perspective as a non-chemical user prior to the start-up of the capture plant.

RISK MANAGEMENT

Risk was managed throughout design, engineering and construction with rigorous use of risk registers. Risk management was a daily focus during construction. There was continual monitoring of construction productivity, coupled with ongoing labour availability risk assessment and planning.

Accommodation risk was a concern. Due to labour shortages, SaskPower had to ensure it was an "employer of choice". This meant compensation had to be maximized to attract construction labour, which included subsistence allowances. Consequently, SaskPower had to find cost-effective, off-site accommodations for up to 1500 staff at a time when the oil industry also had peak labour demand in the region. Temporary on-site labour accommodations were not an option and were not utilized.

PERMITTING

Throughout the period from 2008 to late 2014, that spanned the first request for capture technology proposals in 2008 through design to engineering and finally through construction of the BD3 retrofit, SaskPower worked closely with the Saskatchewan Ministry of Environment on regulatory permits. Any changes in the design that could impact permitting were promptly provided to the Ministry's Assessment Branch and any issues that might impact permits were transmitted internally within the Ministry to the Permitting Branch through a seamless review/assess/approve/update process. Despite the unusual first-time nature of the project, the entire reporting and permitting process was swift and efficient.

The permitting and regulatory process associated with the CO_2 injection and monitoring wells at the SaskPower Carbon Storage and Research Centre regarding deep saline storage/disposal of CO_2 was handled similarly, although the permits for the injection and monitoring wells were issued by the Ministry of Economy that regulated oil and gas activity in Saskatchewan and hence all deep well drilling activity.

KNOWLEDGE BUILDING

Throughout the entire BD3 ICCS project, SaskPower managed uncertainty well through a "can-do" attitude that has been ingrained in its corporate culture. A lot of activities were undertaken in parallel, that led to schedule gains at the cost of efficiency and some re-work. Effective communication was the key to a productive work environment. Challenges were observed from many different angles and resolution was achieved as a team effort rather than by any one particular individual.

As a result of the BD3 ICCS project, including its prerequisite exploratory work, SaskPower has developed a strong and capable engineering team. Knowledge and insights have been carefully documented, along with the entire BD3 retrofit design, to support option analyses for potential future coal-fired power plant retrofits. In fact, this effort is already assisting the business case decision planning regarding BD4 and BD5 that is ongoing as of mid-2015. An illustration of the time frame for CO_2 capture technology maturation within SaskPower is shown in Figure 18 on the next page.

FIGURE 18

TIMELINE OF CO_2 CAPTURE AND STORAGE TECHNOLOGY MATURATION AT SASKPOWER

1976 · 1980 · 1986 · 1990 · 1996 · 2000 · 2006 · 2010 · 2016

1978
Chevron SACROC CO_2–EOR begins

1984
Shell and Pan Canadian seek CO_2 from SaskPower for Midale and Weyburn

1985/86
Early amine capture pilot plant at BD6

1994
IGCC
SaskPower gains IGCC license and permit for Shand 2

1995/96
Shell operates CO_2–EOR pilot at Midale

1996
CanmetENERGY™ oxyfuel com-bustion piloting begins

1996
SaskPower begins oxyfuel screening study for Shand 2

1999
CO_2 pipeline from DGC to Weyburn area completed

2000
Pan Canadian operates commercial CO_2–EOR at Weyburn

2000
IEAGHG™ Weyburn CO_2 monitoring project begins

2001
CCPC begins

2002
SaskPower begins operating first NGCC power plant

2002
Natural gas prices soar

2004
CCPC demonstrates clean coal competitive with NGCC

2005/06
SaskPower collects commercial pricing for oxyfuel at Shand 2

MID 2007
SaskPower decides to plan for a PCC retrofit at BD3

EARLY 2008
Federal funding for BD3 retrofit engineering

MID 2008
RFP for PCC CO_2 Absorption Capture Technologies

2009
CANSOLV SO_2-CO_2 capture system selected for BD3

LATE 2010
BD3 power plant rebuild approved by CIC

APRIL 2011
BD3 capture plant approved by CIC

APRIL 2011
Capture plant construction begins

FEB 2013
Power Plant Rebuild Construction Begins

JUNE 2014
BD3 Rebuilt Power Unit Generates First Power

OCT 2014
BD3 capture plant generates first CO_2

2015
BD3 retrofit improvements continue

APRIL 2015
Aquistore begins monitoring injected CO_2

JULY 2015
CEPA regulation requires CCS at old coal power plants in Canada

2015/16
Business case for BD4 and BD5 retrofits developed

TRANSITION TO **OPERATION**

THE APPROACH TO ACHIEVING A SUCCESSFUL **TRANSITION TO OPERATION**

The fundamental elements of SaskPower's success in the resumption of operation of the BD3 power unit in 2014, along with its new capture facility were:

- A separate transition team was established with its own project manager
- A comprehensive training program was developed, comprised of over 80 modules that relied heavily on the process simulator developed for the design and engineering stage of the project.
- Operational readiness involved preparation of a wide array of documentation covering SOPs, a customized Quality Management System and a new pressure system integrity process.
- A thorough HAZOP process supported the development of SOPs and identified potential hazards that would be mitigated.
- Construction was sequenced and scheduled to ensure equipment was installed in the order of use.
- Commissioning was led by SaskPower's project engineering team and plant operations team on each piece of equipment upon completion of installation. This staged approach ensured a safe and thorough commissioning and that operations teams had hands-on experience when the plants were ready for full-time operation.
- Operation of the power plant began in June 2014 before the capture plant was put into service in October 2014. This ensured any major operational issues associated with the power plant were addressed before the team took on the challenge of the capture plant operation.
- Systematic resolution of operational issues in order of financial priority in the first couple of years of operation.

THE AFOREMENTIONED STEPS ensured that the power plant, the capture plant and the operations team were all well prepared for full-time operations, to enable swift action to address any issues and challenges that arose in the transition to operation.

During design, engineering and construction, the key challenges that could be foreseen for the capture plant were associated with the new technology and its inherent risk due to lack of operating history within the power industry to inform design and equipment choices. However, from startup of the capture plant, it has produced saleable CO_2, albeit initially at lower volumes than the maximum planned, output that has been successfully pipelined to Cenovus' Weyburn oil field for CO_2–EOR. Once the power plant was in operation, its key challenges were expected to be behind it as they were solely related to construction. This has indeed been the case.

Nevertheless, streamlining, troubleshooting, and construction deficiency rectification is underway to improve overall operation and performance. It will likely take a couple of years to clear all of the issues associated with operation and maintenance of the capture plant to assure reliable performance and integration with the power plant. Once that work is behind SaskPower, it is expected that the retrofitted BD3 power unit will run for its full 30-year lifespan with very few issues.

The power plant and the capture plant have been operated with slightly different focuses. Both plants have been operated by power engineers. The capture plant has been managed by a chemist and has been fully integrated with the on-site laboratory that was established for quality assurance purposes regarding the amine chemistry. The plants have been operated by separate teams but they work toward the same end goals for the entire BD3 power unit, namely power delivery to customers and secondarily management of the saleable by-products. Each of the two control rooms enable visualization of the entire power unit, so that key learnings about each plant and their integration are absorbed and utilized to ensure a unified and efficient operations team.

The capture plant process optimization that was ongoing as of mid-2015 necessitated a solid understanding of the chemical processes during the CO_2 and SO_2 capture, whether the plant performs well or whether there are unintended chemical reactions that could result from off-spec performance. It is anticipated that once the chemistry is thoroughly understood in the capture plant and it becomes a standard plant for SaskPower to operate, the operations teams will amalgamate and operators will seamlessly be able to work in either part of the facility.

ANTICIPATED ISSUES

Some issues were expected during the transition from commissioning to full-time operation of the power and capture plants. These included:

> A washing system with significant over-capacity margins and extensive instrumentation was installed anticipating fly ash problems in the Flue Gas Cooler. No fly ash issues have been observed to date.

> Heat recovery from the Flue Gas Cooler has met expectations that has meant only four of six feed water heaters in the power plant have been required when the capture plant is in operation. The backup two heaters have only been required in order to deliver full power to the grid (i.e. 161 MW) when the capture plant is not in operation. If a future retrofit were designed to deliver constant power to the grid regardless of capture plant operation (i.e. 115 – 120 MW), the additional 2 heaters would not be required.

The latter outcome is a learning that will assist in the design of the next retrofit and also represents an opportunity to make a choice between operation in full-time capture mode (which would mean a design to generate the same power regardless of capture plant operation and thereby would require fewer feed water heaters) or to assume flexible capture plant operation would be the norm. In other words the latter approach would require a design to generate more power when the capture plant is off, which would require the full complement of feed water heaters deployed at BD3 that is operated in this fashion.

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UNANTICIPATED ISSUES

Some issues were unexpected during the transition from commissioning to full-time operation of the power and capture plants that included:

> The capture chemistry worked "right out of the box", which was a bonus for SaskPower and its contractors. As the operations mature, chemistry will become more complex. Managing the full range of chemistry through all of the processes will require ongoing focus throughout the life of the plant, but initial operations are, of course, the most challenging. A highly talented joint SaskPower–vendor chemistry team, with external support as needed, is working to stay on top of amine chemistry.

> The more complicated the equipment, the more reliable its operation has been. The more mundane equipment challenges are part of the construction deficiency rectification schedule for 2015. Both the new steam turbine and the CO_2 compressor have presented very few problems.

> The Amine Purification Units have been particularly difficult to manage. It is uncertain whether this is due to vendor design or an EPC implementation issue. Managing this concern is part of the construction deficiency rectification schedule for 2015.

> A few mechanical issues like tube leaks had to be repaired immediately. These have been completed.

> Although varying coal quality has always been an ongoing issue at the power plant, it is believed that the waste incineration system may have contributed to additional slagging. Twice since the restart of BD3, slagging problems have required the power units to come off line. Careful control of the waste water pH has largely eliminated this issue.

This list of anticipated and unanticipated issues is surprisingly short given the immaturity of the CO_2 capture technology installed at BD3, and the low level of associated engineering knowledge and operating history related to integrating that technology with modern coal-fired power generation.

Combined with the pre-conditioning of the flue gas before entry to the capture plant, the new flue gas emitted from the stack at BD3, as designed when the capture plant is in operation, shows significant improvement in the quality of all air emissions compared to BD3's pre-retrofit emission performance [Table 2].

TABLE 2 | BD3: PRE AND POST CCS DESIGN PERFORMANCE

CONSTITUENT	PRE-CCS	POST-CCS*	CHANGE
Power	139 MW	120 MW	13.6%
CO_2	3604 tonnes/day	354 tonnes/day	90%
SO_2	7 tonnes/day	0 tonnes/day	100%
NO_X	2.4 tonnes/day	1.05 tonnes/day	56%
PM_{10}	190 kg/day	15 kg/day	92%
$PM_{2.5}$	65 kg/day	7 kg/day	70%

**Design Values*

PUBLIC ENGAGEMENT **AND PUBLIC OPINION**

ABOUT THE CLEAN-COAL BD3 ICCS PROJECT

Social research needs to be an important priority going forward as we consider more complicated decisions regarding energy.

FROM START TO FINISH of the retrofit project, SaskPower was very proactive in its efforts to publicize the upgrade at BD3 to convert it to clean coal power generation. More than 100 presentations about BD3 were made locally at Chambers of Commerce and Rotary clubs, as well as at various venues and to a wide variety of audiences around the Province. The aim was to educate and build understanding amongst the public utility's "shareholders". Since the construction at BD3 was completed in the Fall 2014, SaskPower has continued to be proactive about engaging its stakeholders with many public announcements about the awards BD3 has earned, by hosting a 2014 CCS Symposium and the 2015 IEAGHG PCCC3 Conference, and by ensuring ongoing media and public awareness of new initiatives to support the future of clean power generation.

The local consensus surrounding the BD3 ICCS project, including storage of CO_2 at Weyburn and the site hosting the Aquistore Project, has been positive. Retrofitting BD3 was certainly seen as preferable to the closures of BD1 and BD2 in 2013 and 2014, with associated negative impacts on jobs and the longevity of the Estevan Coal Mine (operated by Westmoreland Coal Company). In fact, the CO_2 by-product sales were seen positively because they would boost the local oil industry in the Estevan and Weyburn region. Since Pan Canadian's first injection at Weyburn in 2000, the local public had become very comfortable with the notion of CO_2 injection underground.

The construction period also had positive spin-offs for local businesses and for homeowners who were willing to temporarily run bed and breakfast accommodations for construction workers brought to the site. Province-wide, the benefits of increased royalty revenue from oil production were regarded in a positive light.

More distant stakeholders were more likely to have negative and outspoken opinions regarding the environmental impact of use of coal for power generation and the project delays and cost overruns experienced by SaskPower that played heavily in the press. Unfair comparisons have been drawn to natural gas and "green" power options such as wind power, without regard to availability, grid impacts, operability and life cycle costs of these options. The continued decay in the price of natural gas since the BD3 retrofit investment decision was made in 2009–2010 has served to erode the economics of the project. It is not uncommon for public entities to face this challenge, which is akin to having a "crystal ball" to predict future energy pricing!

The recurring negativity about the project from some quarters, particularly Saskatchewan and Canada-based ENGOs, has made it clear to SaskPower that social research needs to be an important priority going forward as we, as a society, consider more complicated decisions regarding energy production and power generation choices. Some initial questions about social barriers to CCS that we might contemplate include the following:

What is the perception of cost?

- Capital cost
- Social cost
- Lifecycle cost
- Operating cost

What is the perception of health risk?

What is the perception of environmental risk?

What is the preference for alternative energy solutions?

Additionally, continually updated and robust socio-economic assessments relevant to specific projects and a portfolio of project investments would help support public engagement on the important issue of future energy options.

Every coal-related power project in the future will face the same kinds of issues experienced by SaskPower's BD3 ICCS clean coal retrofit, so, too, will any other "mega" energy project. It is critical that we, as a society, collectively understand how people think and then develop opinions on important public issues.

From this understanding we will learn how to most effectively engage the public so they internalize, assess, acknowledge and approve how and why public investment and regulatory approval decisions are made regarding energy projects.

SUMMARY OF THE CHALLENGES ENCOUNTERED FROM INCEPTION TO OPERATION OF THE BD3 RETROFIT

ORGANIZATION

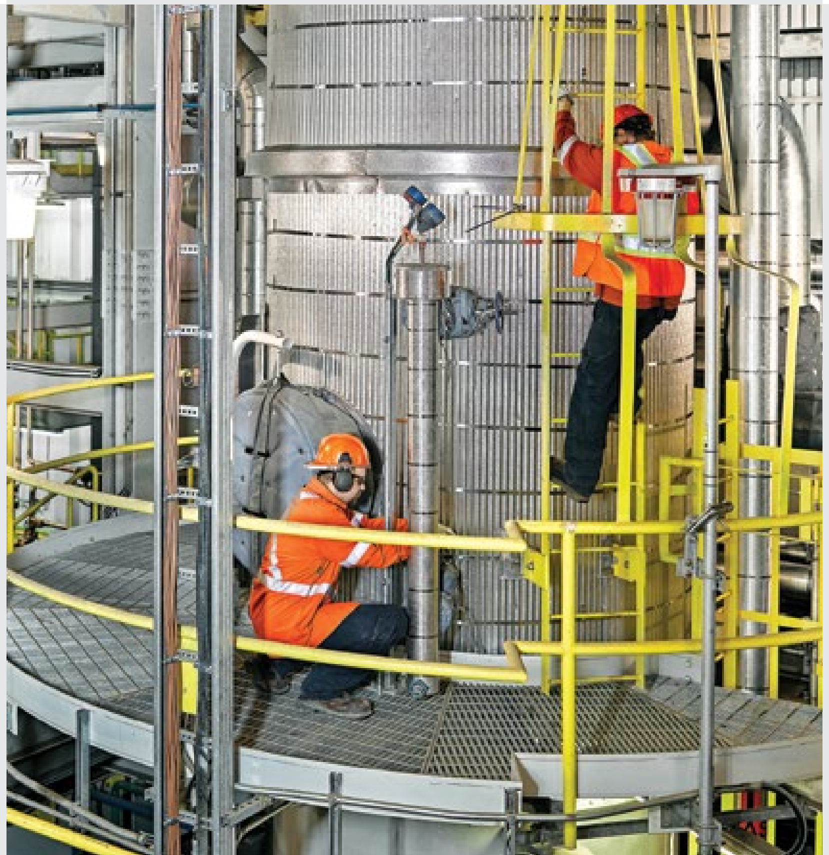
By 2008, SaskPower was no longer organized to manage a "mega" energy project. The last project of this size was the design, engineering and construction of the Shand Power Station that was completed in 1992. The Shand engineering team had long since been disbanded and most team members had retired or left the company.

POWER PLANT AND CAPTURE PLANT INTEGRATION

The most complicated part of the design and engineering process was integration of the power plant with the capture plant. This was a custom design and completely new territory as the first project of its kind in the world. Accordingly, the project bore unusual expenses associated with first-time technology risk mitigation. This was expected and was the justification for seeking the C$240 million federal funding. It is expected that these costs will not be incurred on the next similar project.

TECHNOLOGY CHOICE

Making the carbon capture technology choice was particularly problematic because it was difficult to visualize any of the processes under consideration and its integration with the power plant due to lack of scalable engineering data and operational history.



CHANGE MANAGEMENT AND PROCUREMENT

Change management during design and engineering was a particular challenge that was complicated by procurement requirements:

> The open procurement process necessitated by the public ownership of SaskPower required tight technical specifications for appropriate and timely management of purchasing to avoid unnecessarily extensive lists of bidders and the associated SaskPower workload to evaluate their proposals. Regardless, a longer list of potential options for each piece of equipment than desirable was considered in most instances.

> Each equipment selection inevitably slightly changed the overall engineering design and impacted choices of other pieces of equipment. This could be termed a "ripple effect" that lengthened the time required to complete the engineering design prior to construction approval in December 2010..

> Technology risk for CO_2 capture was mitigated by keeping a tight rein on performance specifications for the integrated equipment in the power plant as well as the capture equipment. Changes in equipment choices, with associated differing performance specifications, made technology risk management difficult.

TECHNOLOGY RISK MANAGEMENT

Risk management during design and engineering meant building a considerable amount of equipment redundancy into the capture plant. The successful operation of the power plant during upsets and trips in the capture plant has meant that some of this equipment was not ultimately required. The associated challenges were:

> to determine how much redundancy was sufficient to effectively manage the technology risk AND satisfy stakeholders, and

> to keep capital costs within reason so that the BD3 ICCS project was affordable.

This was typical for a first-time project leading to a one-time ***cost of performance uncertainty.***

LENGTHY PROCUREMENT

Procurement processes were often protracted due to multiple levels of approval required each time a piece of equipment was selected. It took approximately 2 years to complete the final design and engineering as a consequence of the procurement time and its impact on overall design.

THIRD PARTY REVIEW

The third-party review by R.W. Beck came at a challenging time in mid-2010 when workload was at a high level as the SaskPower team tried to complete the engineering for the project. This led to a very high workload for the engineering team.

SUMMARY OF THE CHALLENGES ENCOUNTERED FROM INCEPTION TO OPERATION OF THE BD3 RETROFIT

CONTINUED

KEEPING OPTIONS OPEN

SaskPower needed to keep technology and equipment options open for an extended period of time until decision makers were comfortable with the recommended course of action. This was typical for a first-time project to ***build technology confidence.***

CORPORATE POLICY CHANGES

Several policies within SaskPower changed during the project period (2008–2014), including: new safety standards (e.g. banning man lifts, asbestos management); a new quality assurance program; and a new procurement process.

COMPLEXITY OF "BROWN-FIELD" CONSTRUCTION

SaskPower and its owner's engineer (Stantec) undertook the integration of the power plant and the capture plant using a design-build approach, in order to manage the complex "brown" field construction in the power plant that would have made an EPC approach uncompetitive. There was a significant amount of additional scope that was discovered as the design was progressed.

LOCATION OF BD3 WITHIN THE POWER STATION

Unit 3 is located in the middle of the Boundary Dam Power Station. This complicated the ability to physically move tradespeople and materials around the construction site, necessitating construction of two people elevators and one mechanical elevator, as well as roof-top lunch rooms and roof-top openings that were used solely for the construction period.

MANAGING LABOUR

Due to the high level of competition for skilled labour in Western Canada, SaskPower had to ensure it was an "employer of choice" by effectively managing a myriad of unusual details, including: accommodations, on-site infrastructure, parking, ease of manpower movement at site, etc. Additionally, operator staffing for the capture plant had not been foreseen and had to be undertaken at a time when the skilled labour shortage was at its peak in the early-2010s in Western Canada.

UNFAMILIARITY WITH CAPTURE EQUIPMENT

First-time projects typically require the time to gain experience in the operation of unfamiliar equipment and processes. Added to this was the complication of working with unexpected amine chemistry, which was completely foreign territory for a power company. During 2015–2016, SaskPower is correcting construction deficiencies and building knowledge and understanding about amine-based capture chemistry to help optimize the chemical processes in the capture plant.

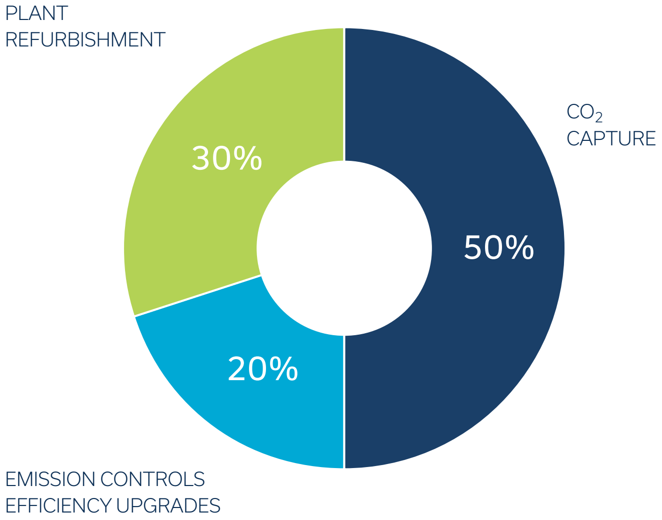
IMPACT OF TIMING OF CONSTRUCTION

Construction costs had doubled from 2004–2007 in Western Canada[55]. This was partly due to a shortage of skilled trades labour and many competing "mega" energy projects in the region, as well as record prices for construction materials such as steel.

MEGA PROJECT INVESTMENT DECISION

A technology decision, and its associated investment approval by stakeholders, is made at a fixed point in time. Technical, business and economic conditions will most likely change from that decision time until the project is completed. However, the company will be held accountable by its shareholders for the investment decision when the facility is operational.

FIGURE 19 | BD3 RETROFIT CAPITAL COST BREAKDOWN



CO_2 GEOLOGICAL **STORAGE**

OVER the past couple of decades, SaskPower has taken a long-term view on the final fate of any CO_2 that it might capture to ensure it is safely and securely removed from the atmosphere for a long period of time, thereby eliminating any associated GHG impact on climate. CO_2–EOR is a near-term measure for storing CO_2 while there is a market for the gas and while sale of the CO_2 is critical to the economics of clean coal power generation. In the CO_2–EOR production process, approximately 50% of the injected CO_2 returns to the surface with the produced oil, is separated and is then re-injected. Many decades from now, the target CO_2–EOR oil fields in southeastern Saskatchewan, and elsewhere in the Williston Basin, will be depleted, that will necessitate permanent storage of CO_2 elsewhere in order to avoid emitting it to the atmosphere. We could additionally find ourselves at a time of natural gas shortages that would mean high prices for fuel to support NGCC power generation, making coal a very inexpensive fuel source for power generation. Presumably at some point in the future, it will be economical to simply "dispose" of the CO_2 geologically in a deep saline aquifer, much like the oil industry has managed produced water for decades.

In order to assure that the risk of CO_2 storage in deep geological formations is low and to assure the public that it is a safe and acceptable practice, SaskPower invested in the IEAGHG Weyburn-Midale CO_2 Monitoring and Storage Project from 2000–2012. The logical next step beyond that project was to conduct similar research to build upon its acquired knowledge with the focus on CO_2 storage in a deep saline aquifer. Aquistore is such a project. SaskPower was a founding member of the Petroleum Technology Research Centre's (PTRC) Aquistore research development and demonstration project that is studying injection and storage of CO_2 in a deep saline aquifer near the Boundary Dam Power Station from 2010–2017.

A plethora of papers and documents about Aquistore have been published in peer-reviewed scientific journals, presented at international conferences and posted on the Internet since 2009. A short summary of the project is provided in the Appendix. If readers are interested in learning more about Aquistore, visit www.aquistore.ca and/or contact the PTRC (www.ptrc.ca)

WHAT WILL SASKPOWER **DO NEXT TIME?**

PLANNING FOR FUTURE CLEAN COAL POWER PLANTS

While SaskPower continues to ensure construction deficiencies are rectified at BD3 during 2015–16 to improve overall performance and efficiency of power generation, as well as regeneration of the amine in the capture plant, aiming to achieve 115 to 120 MW of net power generation, the retrofit can clearly be deemed a success. But SaskPower cannot rest on its laurels. Time is marching on. There is now regulatory clarity in Canada requiring immediate action. The new federal Regulations require that SaskPower make decisions regarding the fate of the remainder of its coal-fired power fleet over the next decade or so. Table 3 lists the plants that are affected and SaskPower's decision window, including the potential implementation schedule [Figure 20]. It can be seen that a decision must be made by the fourth quarter of 2016 regarding the fate of BD4 and BD5!

IN PARALLEL with SaskPower's planning for its future power plant options, the Government of Saskatchewan may negotiate an "Equivalency Agreement" with the Government of Canada. A negotiated Saskatchewan-specific interpretation of the federal Regulations governing coal-fired power generation could include consideration of any or all of the following:

The intent of the Regulations is to reduce GHG emissions from coal-fired power generation nationwide.

In 2012, Saskatchewan had a GHG footprint of approx. 12 million tonnes per year of CO_2e emissions associated with coal-fired power generation.

At 90% capture, the BD3 upgrade has far exceeded the regulatory requirement for its own regulated reduction in emissions, or approximately 67%.

An argument could be made that holding each of SaskPower's coal-fired power units to the regulated performance standard is not the only or most sustainable approach to meeting the targeted reduction in emissions.

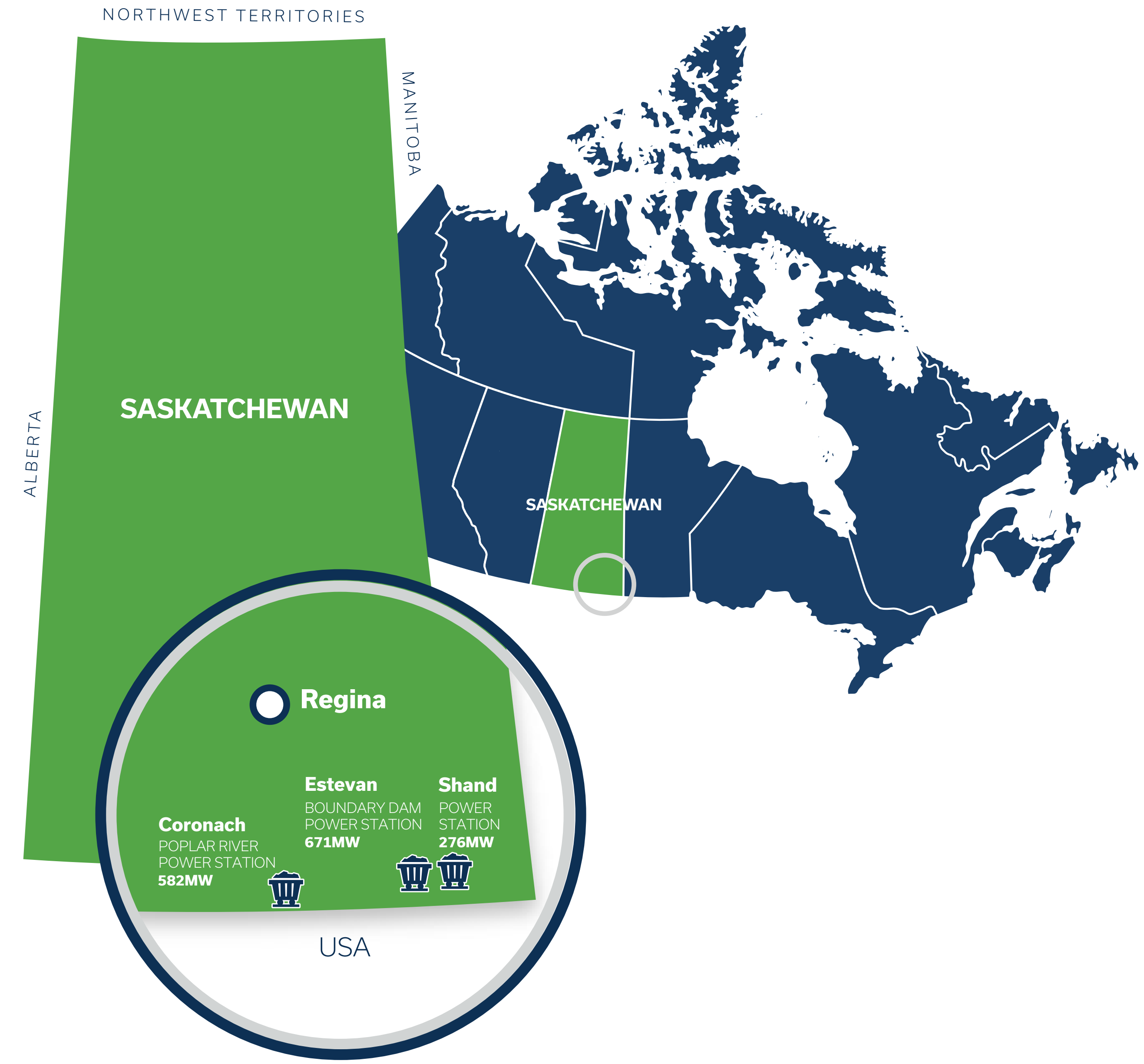
Saskatchewan could achieve the intended reductions differently. Perhaps meeting a 90% reduction standard in GHG emissions at SaskPower's larger power stations (Poplar River Units 1 and 2, Shand), which each generate 300 MW, are newer and more amenable / economical to retrofit, well ahead of schedule and foregoing the retrofits of the remaining BD power units, could permit SaskPower to continue to operate some or all of the BD 4, 5, and 6 units without CO_2 capture for a few years beyond their CEPA-required retirement dates.

Additionally, SaskPower voluntarily retired BD1 and BD2 early (in 2013 and 2014 respectively); each had an emissions reduction value that could be acknowledged by the Government of Canada, even though they would not qualify under CEPA's substitution rules.

TABLE 3 | SASKPOWER CLEAN COAL RETROFITTING SCHEDULE

UNIT	DATE OF CONSTRUC-TION	ACTUAL SIZE (NOMINAL SIZE)	REGULATORY SHUTDOWN DATE	INITIAL INVEST-MENT	FINAL INVEST-MENT	CCS RETROFIT IN SERVICE
BD4	1970	139 (150) MW	2019*	2016	2019*	2025†
BD5	1973	139 (150) MW	2019*	2016	2019*	2025†
BD6	1978	273 (300) MW	2028‡	2022	2024	2028†
PR1	1980	291 (300) MW	2029‡	2024	2026	2030†
PR2	1980	291 (300) MW	2029‡	2026	2026	2030†
SHAND1	1993	276 (300) MW	2043§	2037	2039	2043†

FIGURE 20 | MAPPING THE FUTURE OF CLEAN COAL POWER GENERATION AT SASKPOWER



*CCS Clean Coal retrofit plans must be filed with the Government of Canada no later than the end of 2019, or the power plant must be retired by Dec 31, 2019 or 50 years from plant commissioning (whichever is earlier). Construction and commissioning must be completed by the end of 2024.

†Fixed by federal regulation

‡CCS Clean Coal retrofit plans must be filed with the Government of Canada no later than the end of 2024, or the power plant must be retired by Dec 31, 2029 or 50 years from plant commissioning (whichever is earlier). Construction and commissioning must be completed by the end of 2029.

§CCS Clean Coal retrofit plans must be filed with the Government of Canada no later than the end of 2024, or the power plant must be retired by 50 years from plant commissioning. Construction and commissioning must be completed by the regulated retirement date.

DEVELOPING THE BUSINESS CASE FOR **THE NEXT COAL POWER PLANT RETROFIT**

When it comes to considering the specifics of what SaskPower would do the same way for the next retrofit and what would be done differently, the following checklist would be considered:

1 Capital costs make or break any project for a small power utility like SaskPower. With the intent of reducing capital costs, conduct an ***equivalent availability study*** to ascertain how much "up time" would be required on the capture plant to meet regulations.

2 Would it be necessary to capture 90% of the CO_2 in the flue gas or would 80% be acceptable?

3 What on-line timing and on-off delays would be required to operate both of the plants (power and capture)?

4 What efficiency improvements could be made in the power plant to generate the steam required for capture?

5 What would be the impact of coal quality and availability on the operation of both plants?

6 Simplify the power and capture plants. For instance:

> Would operation of the capture plant be required every day in a climate where there are only a handful of days where temperatures exceed 30 °C? Or could one simply shut down the capture plant on those days and emit?

> What equipment used at BD3 to mitigate operational risk and uncertainty would be considered redundant now that SaskPower has operating experience? For example, would six feed water heaters be required in the power plant when very often only four would be in service due to energy savings associated with heat transfer from the amine regeneration units in the capture plant?

7 What equipment was added to BD3 after construction in order to improve operation on the basis of safety, ease of use, maintainability, reliability, and efficiency of overall power generation?

8 What would be the critical pieces of equipment, and what would be their reliability in terms of maintenance and repair? Consequently, how many replacement units must be on site in the event of equipment breakdown?

9 Has there been a change in regulations or interpretation of regulations that might impact the level of required CO_2 capture or even the need for CO_2 capture (e.g. Equivalency Agreement)? Future regulations could be imposed upon emissions from alternative power generating facilities that could change the economics of comparisons.

10 Would it be better to over-achieve the regulated capture target or just meet the target? A smaller capture unit would require a lower parasitic load on the power plant, and somewhat lower capital costs. A larger capture unit would have the economic benefit of scale and could have an emission profile that would be significantly cleaner than NGCC.

11 Would the 300 MW units at Poplar River and Shand Power Stations, which already operate with more efficient turbines and are almost identical in design, be better, more cost effective targets for future retrofitting than the power units at Boundary Dam Power Station?

12 Modularize the plant so that large sections of it could be constructed elsewhere by more highly-skilled tradespeople than could be enticed to work at the construction site. This could likely be achieved at a much lower construction cost. Site installation would also become simpler and would likely entail a much lower risk for cost overrun(s).

13 Continue the good work on operational standards and safety procedures that began with BD3 (e.g. new confined space procedure, new PPEs, new chemical handling SOP, etc.).

14 Perform a labour market assessment for skilled trades and map out a construction schedule that would eliminate the impact of any possible shortage of skilled labour.

15 Fully develop design and engineering and let fixed-price contracts to eliminate cost overruns.

16 Reduce construction costs. This could entail packaging engineering and construction activities differently than BD3 and potentially modularization.

17 Ensure the next PCC unit would be similar enough to reduce technical, construction and operating risks based on the insights from BD3.

18 Continue to have the flexibility to generate power without capture and still meet regulatory requirements. This would likely necessitate PCC technology in the near term and most likely focus technology choices on amine-based capture as they would be the most mature and less technically and operationally risky.

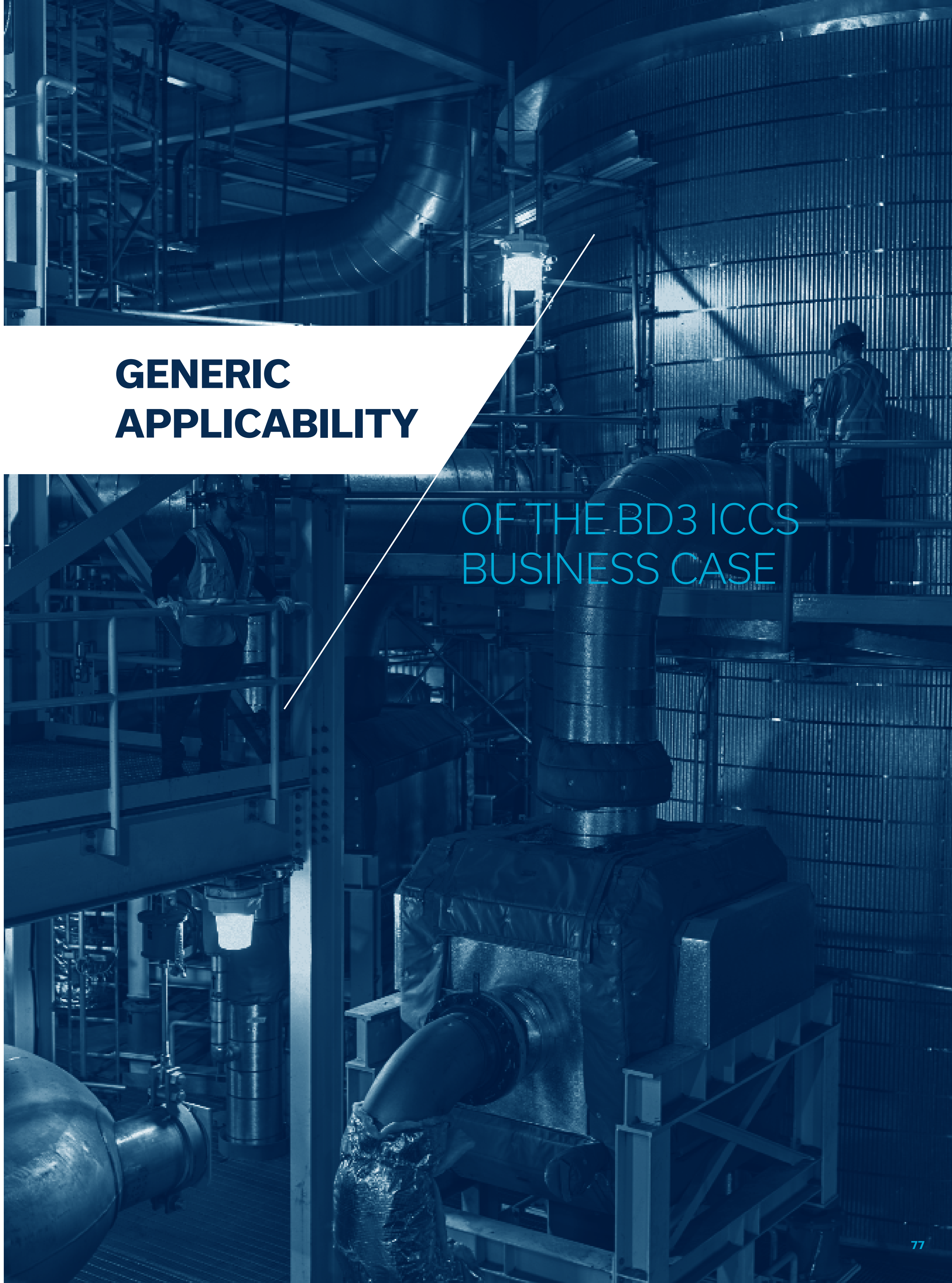
19 Utilize a solid staff retention plan to avoid critical shortages in SaskPower staff that have gained invaluable experience from the BD3 ICCS project. This would include developing a SaskPower culture that would reward the behaviours and the stamina that would create a successful project outcome.

20 Ensure meaningful public engagement about the costs and benefits of clean coal broadly throughout the Province. Expect that public engagement would be more critical in a region where there would be no oil industry presence to support infrastructure to capture CO_2 that could be used for EOR. Develop a communications and engagement plan accordingly. Public acceptance would doubtless necessitate a third party business investment and technology review for each proposed clean coal project.

21 Invest in the establishment of a CO_2 end-use market amongst oil producers. This could require building a CO_2 trucking infrastructure at the BD3 capture plant to support CO_2–EOR pilots in SE Saskatchewan and to provide CO_2 at a reasonable cost to oil producers that wish to pilot CO_2–EOR at their operations.

22 Consider a change of “ownership” of the retrofitting projects. SaskPower is a power generation utility whose main job is to maintain facilities to ensure the “lights stay on”. It is not an EPC company that designs and builds major facilities on a regular basis.

23 Deploy a larger SaskPower group to work on the planning phase of the project if it would be reasonably certain the project would be approved. This would shorten the time from inception to operation and would minimize the burnout experienced during the BD3 ICCS retrofit project.



GENERIC APPLICABILITY

OF THE BD3 ICCS BUSINESS CASE

AT THIS POINT, you are likely pondering the following question: "How do I transfer the business model from BD3 ICCS to a different power plant and likely a different jurisdiction?"

The reality is that, in Canada at least, coal-fired power plants are quickly becoming stranded assets that must either be turned off or converted to clean coal with carbon capture and storage over the next two decades, with the oldest plants (pre-1966) to be retired by December 31, 2015 if CCS retrofitting plans have not been filed with the Government of Canada. Those are the requirements of the new GHG Regulations under CEPA for coal-fired power generation in Canada.

If it makes technical and economic sense to retrofit End–of–life power plants with CCS to generate power cleanly, it seems a logical step to continue to reap the benefits of infrastructure investments made in the 1960s to 1990s, an era when a large number of big-budget coal-fired thermal power plants were built, particularly in Western Canada where lignite coal was plentiful and could be economically mined. Most of the coal-fired power plants built from 1970 onward employed very similar technologies and equipment that would make the application of the BD3 ICCS business case particularly suitable.

The following are some considerations that must be taken into account when considering the adaptation of the BD3 ICCS business model to a particular power plant in a particular jurisdiction:

REGULATORY

WHAT, if any, GHG emissions and air quality regulations apply and what would be the targeted emissions levels? How would these impact your technology choice(s)? How would your technology choice(s) impact dates for construction and commissioning a retrofit?

WOULD there be room to negotiate with your regulator to come up with creative solutions that meet the same GHG reduction goals, objectives and outcomes?

FINANCIAL

WHAT, if any, carbon tax or incentive(s) apply(ies) to your situation?

There might be "first-time" funding available in your jurisdiction if you proposed a leading project. **WOULD** there be any government grants that you could use to offset design, engineering, capital or operating costs that might improve the economics of your business case?

WHAT type of innovative financing could you employ? For instance, would it make sense to contemplate a public-private partnership (P3)?

WHAT would be the capital and operating costs of alternative power generation such as NGCC? This would include the cost of fuel (such as natural gas) vs. coal, including future pricing forecasts.

HOW MUCH redundancy would you require in your power and capture plants to satisfy the risk management requirements of your company? How would this impact capital cost?

MARKET

WOULD there be unsatisfied demand for CO_2 in your region and would the market pricing be sufficient to pay enough for the capture plant to offset all or part of its cost when coupled with any applicable carbon tax or incentive? That CO_2 market must ensure the CO_2 would be sequestered from the environment to be a viable GHG emission mitigation option (i.e. CO_2 enhanced oil or natural gas production).

WHAT potential market would exist for other by-products such as sulphuric acid and fly ash?

WOULD your jurisdiction be a regulated or an unregulated electricity market? This would be an important consideration in forecasting future prices for electrical power.

TECHNICAL DESIGN

WOULD you have skilled and experienced internal engineering teams to manage technology choices and oversee design and engineering work? If not, could you broker strong and healthy relationships with appropriate engineering companies?

WHAT would be your technology choices?

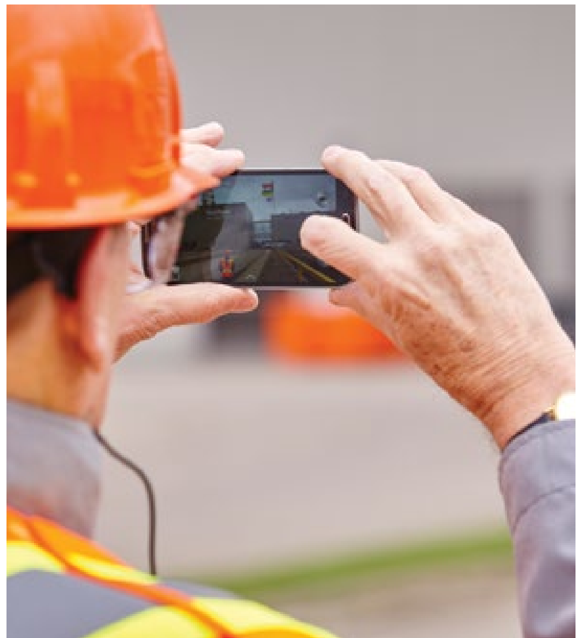
WOULD your company value reliability, maintainability, and operability? If yes, how would these be impacted by technology maturity and therefore your capture technology options?

WOULD you have a reference plant to provide a basis for operational forecasts?

WHAT would be the risk tolerance of your organization and how would that impact technology choices and their required maturity in terms of operational track record?

WHAT would be the minimum number of changes that could be made to the power plant to optimize efficiency when a capture plant would be "tacked on", that would necessitate a reduction in power generation efficiency (i.e. parasitic load that would reduce net power generated and available to consumers)?

WOULD there be an opportunity to design the retrofit so that it would be appropriate for modular construction? Would there be a regional location for module manufacture that would make transportation costs reasonable?



"How do I transfer the business model from BD3 ICCS to a different power plant and likely a different jurisdiction?"

CONSTRUCTION

WHAT would be the availability of appropriately skilled and experienced labour in your jurisdiction? If there were labour shortages or intense competition for labour in critical areas, these would likely lead to higher construction costs. How could you effectively manage the associated labour risks?

WOULD you have sufficient internal experience to manage a "mega" energy construction project?

WOULD there be experienced, reputable construction or EPC firms willing and able to work in your jurisdiction?

WOULD there be modularization yards within reasonable transportation distance from your site?

NOTE: This is not an exhaustive list of considerations. Each power utility must consider its own set of peculiar jurisdictional limitations, regulations and CO_2 market conditions plus any potential geological storage options.

WHAT WILL BE SASKPOWER'S **NEXT POWER PLANT?**

CLEAN COAL OR AN ALTERNATIVE?

AS OF MID-2015, SaskPower is already developing a business case for BD4 and BD5, considering clean coal power as well as comparable alternatives. An initial decision regarding the fate of these two power units (i.e. to retrofit or to retire) must be made by 2016–17 in order for them to be retrofitted as per the CEPA regulatory schedule by the end of 2024 or they must be decommissioned by the end of 2019. Construction time required for any of the power generation options under consideration to replace the total generation capacity of BD4 and BD5 (300 MW nominal) would be similar no matter the fuel choice. The decision-making schedule is rather inflexible.

In addition to the foregoing considerations, SaskPower is also undertaking / considering the following activities / issues:

1 The owner's engineer, Stantec, is conducting an equivalent availability study as per the checklist in "Developing the Business Case for the Next Coal Power Plant Retrofit" (Item 1).

2 A cost benefit analysis is being conducted on all equipment used to integrate the BD3 power plant island with the capture plant, focusing on elimination of unnecessary redundancy and optional equipment. Those items were completely justified at BD3 when there was perceived to be considerable operational risk associated with construction of an unproven technology (i.e. CANSOLV CO_2 capture). With operating experience "under its belt", SaskPower may not find net value in risk-mitigating equipment that serves no other reasonable purpose. Consequently, capital costs could be significantly reduced by rationalizing the value of various pieces of redundant equipment.

3 As the saying goes, "There is nothing as constant as change", which always complicates planning for the future. The decision regarding construction of the retrofitted BD3 power unit was made in late 2010-early 2011. The economic, technical and regulatory environments have changed since that time:

There is now regulatory clarity regarding GHG emissions from coal-fired power plants. However, there is still regulatory uncertainty regarding simple-cycle, natural gas power, NGCC, and other alternatives such as small modular nuclear reactors.

The price of natural gas has declined relative to thermal coal in the past couple of years. Future natural gas price stability remains uncertain as LNG projects are planned on the East Coast and the West Coast of North America[56], which could likely result in increased future natural gas market pricing within the continent as demand would increase. Increased supply would result in the reverse pricing situation. Various future energy supply pricing scenarios would have to be contemplated in any business case for a future coal power plant retrofit.

The lifecycle cost of electricity from NGCC is currently lower than for the retrofitted BD3 clean coal power plant. But there is room to trim the capital cost of retrofitting the next aging coal-fired power plant compared to the capital cost of the BD3 ICCS project. The end result could still be in favour of a future coal power plant retrofit rather than a replacement NGCC unit for either of BD4 or BD5.

As a result of operating experience from BD3, there would now be confidence in the amine-based capture technology that would assure stakeholders about risk management and consequently support more rapid decision making in future.

There would be no need to take the same risk-averse attitude as "the first man walking on the moon" that applied to the BD3 ICCS project. Experience, knowledge and understanding have built confidence not only in the capture technology but also on the power generation side of BD3. There would be far fewer surprises associated with the next retrofitted unit(s). SaskPower would continue to learn but the major hurdles have likely been overcome.

4 One thing that hasn't changed is SaskPower's mission to provide steady, reliable and cost-effective power to its customers, with emphasis on "steady":

Would it make sense to operate the power plant at 161 MW without the capture unit in operation (as in the case of retrofitted BD3)?

Or would it make more sense to generate the same amount of power regardless of the operation of the capture unit (i.e. generate 115–120 MW of power) and continue to provide the same power output to the grid?

What would be the equipment and capital cost implications of the latter strategy?

5 What would be the impact(s) of any potential future Equivalency Agreement signed between the Governments of Saskatchewan and Canada? Which coal-fired power plant could or should be retrofitted next within that context?

6 Power supply planning would have to be considered (although this would be the subject of an entirely separate report).

7 There is growing demand for power in Saskatchewan due to continued population and industrial growth. Power plants must be built in addition to any possible retrofits of existing, aging coal-fired power generating capacity. Plans to construct at least one NGCC unit shortly to replace BD1 and BD2 have already been approved. There is an ambitious construction schedule facing the SaskPower engineering teams (with associated internal workload conflicts). What impact would internal competition for skilled and experienced engineers have on future clean coal power retrofitting projects?

PLANNING FOR THE FUTURE: SASKPOWER'S CCS RESEARCH ACTIVITIES

FOR MORE THAN THREE DECADES, SaskPower has been conducting internal research and supporting external research to develop and validate new technologies to mitigate environmental impacts associated with GHGs, SO_2, NO_X, mercury, and particulates. These undertakings have included:

- Providing a custom-built facility at Boundary Dam to facilitate the demonstration of promising amine-based capture technologies by the International Test Centre for CO_2 Capture at the University of Regina.
- Founding and supporting the Oxyfuel Combustion technology development program at CanmetENERGY in Ottawa, Canada[57].
- Financial support and technical participation in the IEAGHG Weyburn-Midale CO_2 Monitoring and Storage Project (2000–2012).
- Founding and supporting the Canadian Clean Power Coalition (CCPC) (early 2000s to present), an organization dedicated to investigation and advancement of technologies related to clean use of coal for power generation.
- Being the founding funder of the Aquistore deep saline aquifer CO_2 geological storage monitoring project (2009–2017) managed by the Petroleum Technology Research Centre in Regina, SK. This project is currently monitoring the geological storage of CO_2 from BD3 as of April 2015. That daily injection volume is expected to increase over time as injectivity improves.
- Initiating and managing the Emissions Control Research Facility (ECRF) at the Poplar River Power Station near Coronach, SK. Mercury control technologies were validated at this facility prior to being implemented. During the design and engineering of BD3, SaskPower recognized that there was a paucity of validated data to support new capture technologies and thereby reduce the risk of scale up and other uncertainties. ECRF may be part of advancing and maturing some of those technologies.

THESE EFFORTS have not been simply about developing new technologies but have been more importantly about reduction of the risk of decision making for future clean coal power plant technology and equipment options. Providing venues to demonstrate and validate technologies has the advantages of:

- reducing capital and operating costs;
- improving reliability and operability;
- enhancing and reinforcing understanding;
- building knowledge and know-how; and
- assuring stakeholders about the risks associated with choosing new technology.

The SaskPower Carbon Capture Test Facility is validating new power systems developed by Mitsubishi Hitachi as its first project to be completed by the end of 2016.

Consequently, since 2012 SaskPower has ramped up its clean coal technology development activities in support of finding and proving the next best CO_2 capture technology. Additional new activities include:

1 It has designed, constructed and is operating the Carbon Capture Test Facility (CCTF) at the 300 MW Shand Power Station, which officially opened in June 2015.

The facility incorporates a 2-meter diameter CO_2 absorption tower capable of capturing 120 tonnes per day of the gas. This is at engineering validation scale.

The facility is validating new power systems developed by Mitsubishi Hitachi as its first project to be completed by the end of 2016.

It will continue to test vendor technologies on a confidential basis in future years and will also consider non-confidential testing in collaboration with other partners.

The facility will ensure that future SaskPower projects will benefit from a selection of validated commercial technology that will considerably reduce the risk of commercialization and provide the essential data to design and engineer the associated full-scale facilities.

Since the facility is part of a full-scale power plant, there will be the opportunity to evaluate entire systems upstream of carbon capture and their impacts on capture technologies. This will present an opportunity to adjust each piece of equipment and monitor the impact on the entire power generation system. For instance:

WHAT would be the power levers?

WHAT would the capture levers?

HOW would we need to optimally integrate both sides of the power plant to, for example, reduce steam consumption in capture?

HOW would we manage flue gas? Fly ash?

2 The ECRF continues to be operated at Poplar River to validate other emissions control technologies.

3 Tracking and troubleshooting amine chemistry is an ongoing process at two field laboratories (Boundary Dam and Shand) and at the Central Amine Chemistry Laboratory in Regina. The goals of this research are to understand degradation mechanisms and reaction pathways to mitigate "bad actors" like SO_3 and other flue gas constituents that impact both SO_2 and CO_2 amine-based capture processes, and to understand the formation and toxicity of nitrosamines in the amine capture system to help mitigate their formation and/or develop appropriate disposal strategies. SaskPower is also collaborating in complementary work at the University of Regina.

4 An annual SaskPower Symposium on Post-Combustion Capture for Coal-Fired Power Generation has been held twice in Regina during 2013 and 2014[58]. SaskPower will also be hosting the 2015 IEAGHG PCCC3 Conference. These have been/will be public knowledge and information exchange vehicles to maximize collaboration and information exchange, while minimizing any unnecessary duplication of effort.

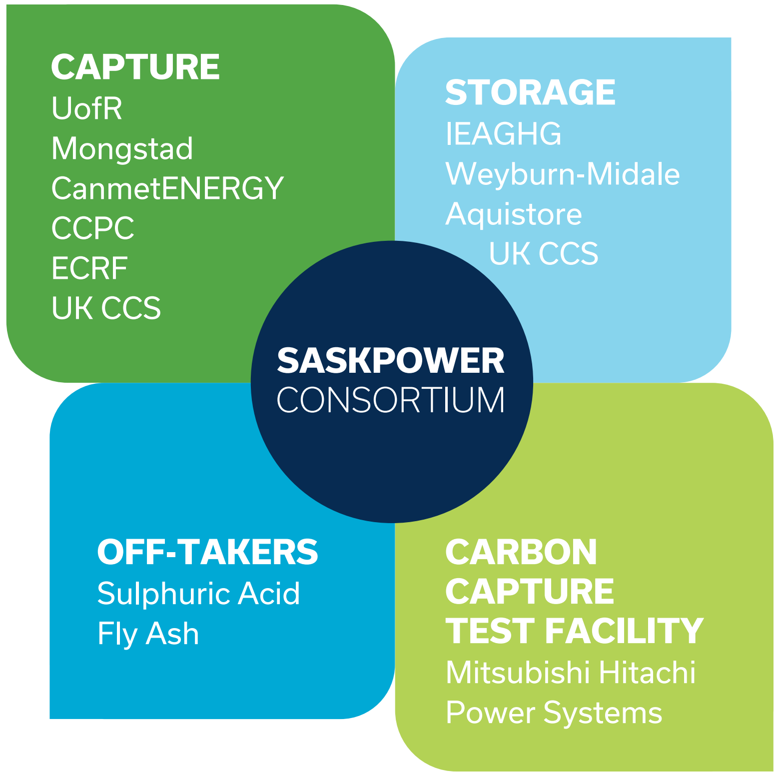
5 SaskPower intends to share non-commercial insights and data from designing, constructing and operating the PCC facility at BD3, the only fully cost-validated model for clean coal power generation combined with integrated commercial CCS technologies in the world. This will be the site for "ground truthing" the details of integrated amine-based post-combustion CO_2 capture. Although the mechanics of cooperation remains a subject of discussion, there is interest in collaboration with technology vendors and various research organizations such as the University of Regina[59], the UK CCS Research Centre[60], CO_2 Technology Centre Mongstad, and others.

6 SaskPower is contemplating a new CCS Consortium that may include opportunities to collaborate in the following areas, providing the necessary alignment between participants can be achieved:

- Technology
- Research
- Procurement
- Supplier management
- Project management
- Training
- Regulatory affairs
- Government relations

All of the aforementioned activities are timely given the need to make a technology decision for BD4 and BD5 by 2019, should it be decided in two years' time that the units will be retrofitted rather than decommissioned.

FIGURE 21 | SASKPOWER'S STRATEGIC CCS INITIATIVES AND RELATIONSHIPS



HONOURS AND AWARDS FOR THE BD3 ICCS PROJECT

The SaskPower BD3 ICCS Project is less than a year old but it has already garnered many awards for its pioneering work in commercializing CCS at a coal-fired power station.

TABLE 4 | AWARDS FOR THE SASKPOWER BD3 ICCS PROJECT

TYPE OF AWARD	PRESENTING ASSOCIATION	REASON
2015 CSCE Award for Governmental Leadership in Sustainable Infrastructure	Canadian Society for Civil Engineering	
2015 Edison Award 2015	Edison Electric Institute	Impressive pioneering work to demonstrate CCS technology
2015 Exceptional Engineering / Geoscience Project Award	APEGS	
2015 Power Magazine's Plant of The Year	Power Magazine	
2015 Power Engineering's Project of the Year	Renewable Energy World Magazine	
2015 Clean Air Leadership Award	Southeast Saskatchewan Airshed Association (SESAA)	
2015 Coal Association of Canada Special Recognition Award	Coal Association of Canada	Environmental and technological achievements
2015 ITT Goulds Heart of the Industry Award	Goulds Pumps	Use of pump technology to improve the efficiency and reliability of industrial processes.
2014 MarCom Awards – Gold	International Competition for Marketing and Communications Professionals	Awarded for the development of a virtual tour using a custom experiential website.
2015 Award of Excellence	The Communicator Awards, Academy of Visual Arts	Excellence Award in web / experiential
2014 Emerging Media Award – Summit International Awards		Awarded for the development of a virtual tour using a custom experiential website.
2014 CCBJ – Business Achievement Award	Climate Change Business Journal	Other Renewable and Low Carbon Power
2012 CEA -Environmental Commitment Award	Canadian Electricity Association	Leading edge project that will define technical, environmental and economic performance of CCUS.
2012 Distinguished Service Award – Research & Development	Lignite Energy Council	Leadership in the lignite industry for CCS.
2011 CCBJ – Business Achievement Award	Climate Change Business Journal	Carbon Capture & Storage

FINAL THOUGHTS & CLOSING REMARKS

ON OCTOBER 2, 2014, the first-ever, commercial–scale, coal-fired power plant incorporating amine solvent absorption carbon capture began operation near Estevan, Saskatchewan, Canada. This was a global landmark event.

This report has explored the journey that SaskPower made from the 1980s to mid-2015 in pursuit of clean-coal power generation.

ALTHOUGH CARBON CAPTURE technologies had been pilot tested prior to this, a commercial–scale power plant now exists that has demonstrated that a number of high-risk technology and business issues have been overcome. This report has summarized the experience and learnings of SaskPower in a way that will hopefully provide insight to its readers and other clean-coal initiatives. SaskPower will continue to learn from its newly retrofitted clean coal power plant and use that body of knowledge to improve the technology and design choices, construction and operation of its power fleet.

SaskPower had forged ahead with design and construction of the BD3 ICCS retrofit well in advance of GHG Regulations being enacted in Canada, which came into effect on July 1, 2015. This was a strategic and environmentally-responsible decision to ensure continued use of lignite coal reserves in Saskatchewan that could last 250–500 years. The investment in the approx. 120 MW (net) BD3 power unit's retrofit and carbon capture plant was approximately C$1.467 billion.

This report has explored the journey that SaskPower made from the 1980s to mid-2015 in pursuit of clean-coal power generation. SaskPower pursued various technology options for carbon capture from oxyfuel combustion to amine solvent absorption that ultimately led to the decision to select the commercially unproven CANSOLV amine solvent carbon dioxide capture process. SaskPower then coupled that technology with Shell Cansolv's proven sulphur dioxide capture process to simplify the capture plant operation and to further reduce emissions.

Two key factors contributed to the decision to retrofit BD3 to convert it to clean coal power versus replacement and decommissioning:

1. The ability to continue to realize value from the sunk investment in the original 1970 BD3 power unit by retrofitting it with a modern boiler and turbine, rather than building a new power plant; and

2. The value that would be realized over the next 30 years of operating the retrofitted power plant from the sale of three valuable by-products: carbon dioxide, sulphuric acid and fly ash. This would help to offset the cost of capture.

The latter two by-products provide the off-taker market with essential materials for the production of fertilizer and cement, respectively. The captured CO_2 is geologically stored with an associated revenue stream from sale of a portion to oil producers deploying CO_2–EOR, currently at Cenovus' Weyburn oil field. As of April 2015, another portion of the CO_2 is sequestered at the SaskPower Carbon Storage and Research Centre, which is the subject of the MMV activities of the Aquistore Project (2009–2017).

SaskPower faced several construction challenges during the BD3 ICCS project. As a consequence, one of the most important recommendations for future retrofitting construction projects of this nature is to modularize the design to make the construction simpler and more cost-effective to implement.

Other challenges that confronted SaskPower included:

- Choosing an immature CO_2 capture technology with no operating history, and managing first-time operation of unfamiliar capture processes and equipment
- Proceeding with a high, targeted CO_2 capture level (90%) and the associated design and construction without guidance from GHG regulation that had yet to be enacted
- Managing continual changes in design, equipment, and construction plans throughout the project due to a variety of technology, procurement and corporate policy requirements
- Technology de-risking and managing the costs associated with the redundancy in processes and equipment that was essential to managing that risk
- Controlling construction costs at a time of very high competition for materials and labour in western Canada, primarily due to a very high level of oil and gas activity

Consideration was given in this report to the issues that SaskPower will face as it considers the fate of its remaining coal-fired power generating units that are required to be retrofitted to incorporate CCS technology during the period 2019–2043. This is a daunting task but SaskPower is well on its way to meeting the associated challenges. In parallel, SaskPower is continuing its research activities on CCS with the aim to reduce capital and operating costs, improve reliability and operability, enhance knowledge and understanding, and manage technology risk.

A series of issues and questions was presented in the report that could assist parties outside Saskatchewan in their contemplation of the applicability of the BD3 ICCS project to their unique set of jurisdictional circumstances. These involve regulations, business and market factors, technical design, and construction. Hopefully, these will be useful topics for other entities to consider as they contemplate their particular set of technical and business challenges for installation of CCS at new or retrofitted coal-fired power plants.

As of mid-2015, SaskPower is contemplating a new CCS Consortium that may include collaborative opportunities for participants, pending suitable alignment, on: technology, research, regulatory affairs and government relations, and all aspects of project management through design and construction.

The BD3 ICCS project can be regarded a success. The project has proven to the world that commercial–scale carbon dioxide capture at a coal-fired power generating station is possible rather than an elusive future option. SaskPower has led the way. It is now up to the rest of the world to follow this remarkable pioneer to ensure that the anthropogenic carbon emissions associated with fossil-fuel power generation and use are significantly reduced worldwide.

GRAND OPENING OF A **WORLD'S FIRST**

APPENDIX: THE AQUISTORE RESEARCH PROJECT

IN ORDER to assure that the risk of CO_2 storage in deep geological formations is low and to assure the public that it is a safe and acceptable practice, governments and industry invested in the IEAGHG Weyburn-Midale CO_2 Monitoring and Storage Project from 2000–2012[61]. The logical next step beyond that project was to conduct similar research to build upon its acquired knowledge with the focus on CO_2 storage in a deep saline aquifer. Aquistore is such a project. The Petroleum Technology Research Centre (PTRC) manages the Aquistore research, development and demonstration project that is studying injection and storage of CO_2 in a deep saline aquifer near the Boundary Dam Power Station from 2010–2017.

AQUISTORE is funded by industry and government agencies from Saskatchewan, Canada and the USA as part of a portfolio of national and international commercial-scale CCS demonstration projects aimed at supporting the development of appropriate public policy and regulation, and especially gaining social acceptance of CCS as a means of reducing greenhouse gas emissions associated with industrial activities such as power generation.

In late 2010, SaskPower proposed Aquistore select its injection and monitoring site at a location near its Boundary Dam Power Station, now called the SaskPower Carbon Storage and Research Centre. Taking a long-term view, beyond the end of the Aquistore research project, the location will be used by SaskPower—the site owner and operator—as a dedicated CO_2 geological storage site for BD3. The SaskPower Carbon Storage and Research Centre site has capacity to store some of the CO_2 from SaskPower's operations for many decades, possibly centuries (pending results of the Aquistore monitoring project). However, in the absence of a carbon price or a carbon tax that incentivizes CO_2 disposal into a deep saline aquifer, it is expected that most of the carbon dioxide captured by SaskPower at Boundary Dam will be sold to nearby oil producers for CO_2-enhanced oil recovery in order to support the business investment case for the capital cost of retrofitting the power station units to generate clean coal power with PCC. Nevertheless, the CO_2 injection well provides some buffer storage capacity to SaskPower in the event that any oil producer that purchased captured CO_2 is unable to take some or all of the purchased CO_2, particularly if wellbore injectivity at the storage site improves as has been predicted[62].

Aquistore's technical and monitoring program development and progress has oversight from a Scientific and Engineering Research Committee (SERC) that includes geoscience and engineering experts from across North America, both from the preceding IEA GHG Weyburn-Midale CO_2 Monitoring and Storage Project and from the US Department of Energy's Regional Carbon Sequestration Partnerships.

The technical and monitoring program was established to achieve the following goals that were set by the Project's funders and key stakeholders:

- Predict the movement of the CO_2 plume over time, including various probable scenarios.
- Monitor the performance of the storage reservoir in terms of injectivity, capacity and containment.
- Compare field data with predictions to assist in developing and refining predictive models used to forecast probable long-term performance of the storage reservoir.
- Determine whether (or not) the project has served to enhance social understanding and acceptance of CO_2 geological storage as an option to reduce anthropogenic GHG emissions.

The technical program involves the following tasks:

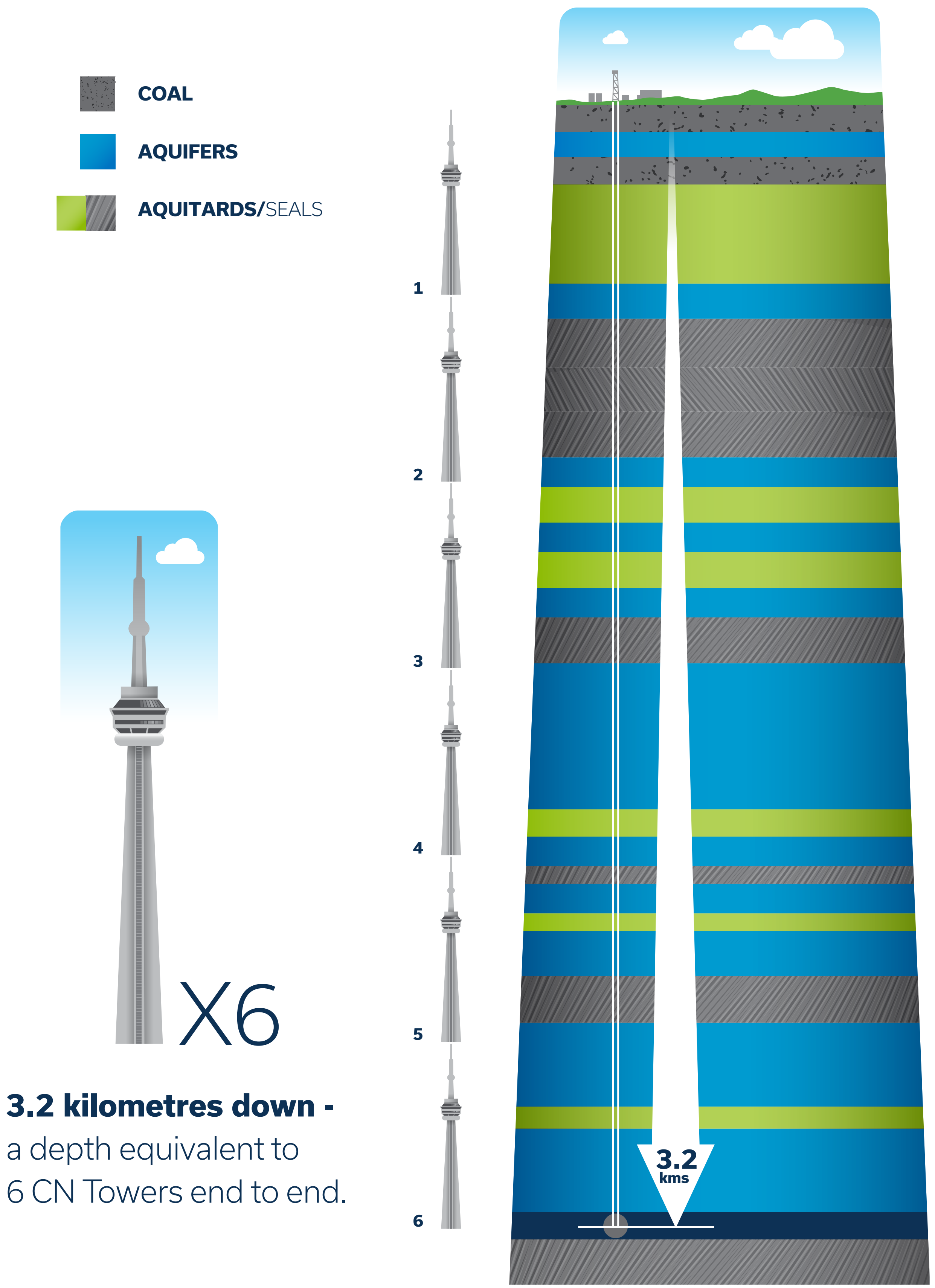
1. Site Suitability
2. Detailed Site Characterization*
3. Geophysical Monitoring*
4. Geochemical Sampling and Analysis*
5. Reservoir Surveillance Wells*
6. Numerical Simulations*
7. Risk Assessment Management Framework
8. Commercialization / Economic Analysis

The Aquistore team has also undertaken comprehensive associated public communications, knowledge-sharing and outreach activities.

*These portions of the technical and monitoring program are considered the Measurement, Monitoring and Verification (MMV) activities.

FIGURE 22 | REGIONAL GEOLOGY AT THE SASKPOWER CARBON STORAGE AND RESEARCH CENTRE

Courtesy of the PTRC



DURING 2011–2012, PTRC and its team of research scientists and engineers from across North America and globally conducted a rigorous site selection process to determine the appropriate target reservoir (a deep saline aquifer) that would provide safe and reliable storage for hundreds of years. The storage reservoir selected for the site was in the Deadwood and Winnipeg formations, which are predominantly sandstone formations with suitable injectivity, porosity, and permeability properties. The reservoir underlies an impervious shale caprock seal in the upper Winnipeg formation that will assure the injected carbon dioxide remains in place. A pre-Cambrian basement metamorphic formation underlies the reservoir, forming an impenetrable barrier to any CO_2 flow away from the storage reservoir. Figure 22 is an artist's interpretation of the geology at the site, including the injection horizon, aquifers, and aquitards.

Traditionally, CO_2 is tracked underground using 2D and 3D seismic surveys as a primary monitoring tool; this has certainly been the case over the past 30+ years of CO_2–EOR operations in North America. A 3D baseline seismic survey was performed by the Aquistore geophysics team in early 2012 as part of the detailed site characterization, prior to drilling and completion of the injection well and the observation well in September 2012 and January 2013, respectively. Before this initial seismic survey was conducted, a permanent seismic array of geophones was installed across a 2.5 x 2.5 km area around the injection well at the CO_2 storage site. This permanent monitoring setup is unique to the Aquistore monitoring project. Typically, seismic surveys are conducted using temporary installation of portable geophones that are installed prior to each survey and then removed. This can be problematic for repeatability of precise geophone location to enable accurate comparisons of time-lapsed seismic surveys. A permanent seismic array enables increased sensitivity for monitoring the subsurface CO_2, reduces surface interference effects, and could potentially lead to reduced operating costs for seismic surveys. An artistic interpretation of the activation of the geophone array at the SaskPower Carbon Storage and Research Centre is shown in Figure 23.

Approximately C$15 million was spent on drilling and instrumentation for the injection and monitoring wellbores. The distance between the two wells is 150 metres, which is expected to provide the data necessary to validate simulation models for predicting the extent of the CO_2 "plume" for several decades. The wells are 3.4 kilometres deep, and they are the deepest wells ever drilled in Saskatchewan. Wellbore logging, sampling and testing of the wells assured SaskPower that the target sandstone reservoir had appropriate storage capacity, injectivity and containment to meet its long-term storage needs for the site. Injection of the carbon dioxide into the deep saline aquifer occurs at depths between 3,173 metres and 3,366 metres through a section of perforated wellbore casing in the injection well. Carbon dioxide was first received from BD3 and injected in April 2015. As injectivity of the storage aquifer improves, it is expected that flow will increase significantly from the initially low injection rate. A detailed graphic of the injection well can be found in Figure 24.

FIGURE 23 | ACTIVATION OF GEOPHONES IN PERMANENT SEISMIC ARRAY

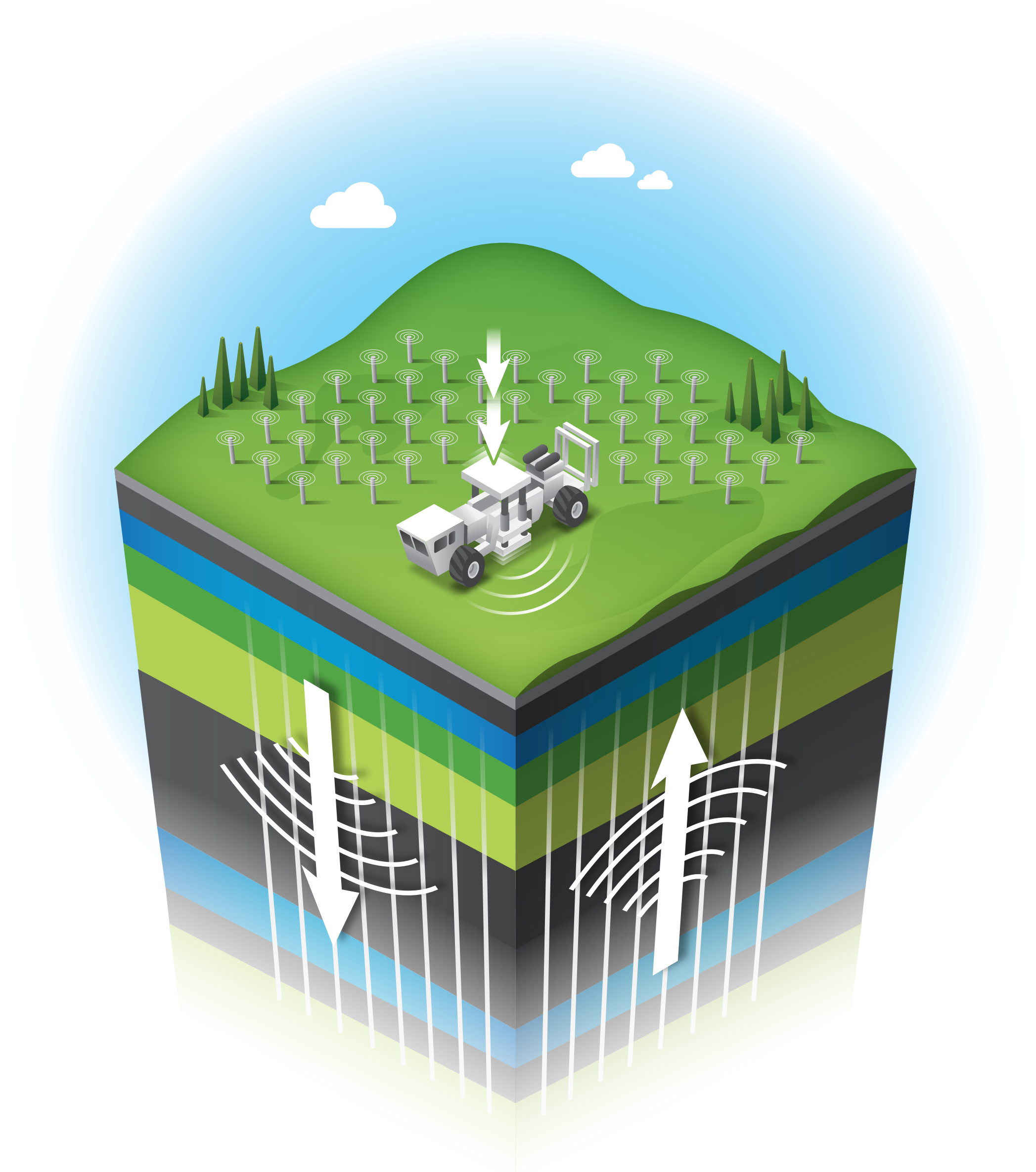
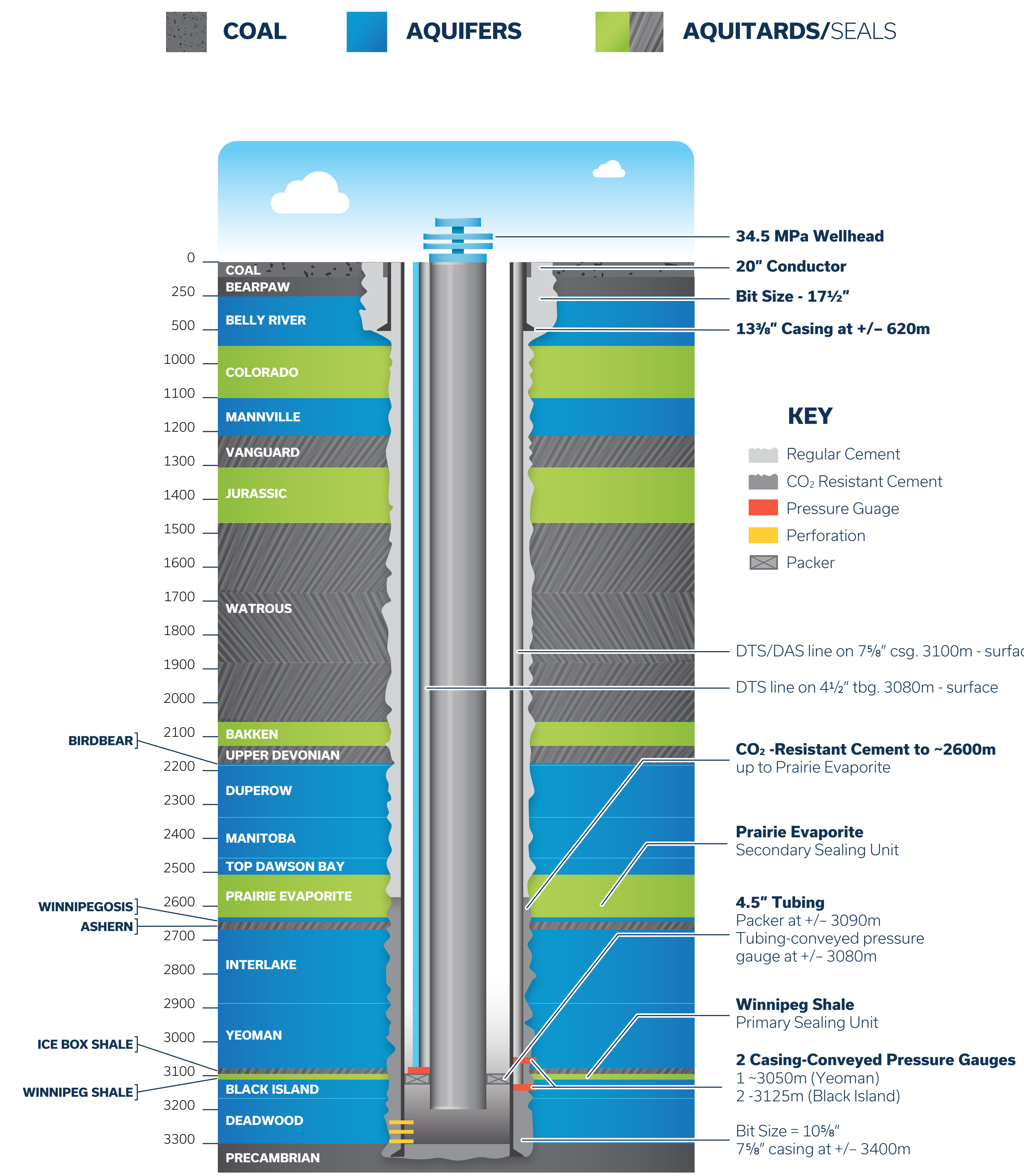


FIGURE 24 | INJECTION WELL DESIGN AT SASKPOWER CARBON STORAGE AND RESEARCH CENTRE

Courtesy of the PTRC



AQUISTORE MONITORING TECHNIQUES

FROM 2012–2015, prior to injection, comprehensive baseline monitoring surveys of the reservoir and storage site were undertaken. A wide variety of proven and experimental techniques has been deployed in addition to the 3D seismic array, at permanent monitoring stations and using temporary monitoring techniques. Multiple monitoring technologies help to assure the public about safety and security of CO_2 geological storage, and are the basis for comparing (and proving) more experimental techniques with more generally accepted monitoring techniques. Table 5 lists the monitoring techniques utilized by the Aquistore Project as of mid-2015.

A qualitative risk assessment was undertaken by the Project using a panel of experts. The process involved building of a comprehensive Features, Events and Processes (FEPs) database and qualitative evaluation of likelihood and probability of various risks. Accordingly, the environmental impacts of CO_2 injection at the site were determined to be low due to the multiple sealing geological formations above and below the reservoir, and the absence of any significant faults or fractures and any aging oil or gas wells in the area.

TABLE 5 | AQUISTORE MONITORING TECHNIQUES*

TYPE	Surface	Shallow Subsurface	Downhole Instrumentation	Seismic
PURPOSE	Surface deformation	Ground water quality changes	Geophysical logging	Plume location
	CO_2 plume location	Near-surface atmospheric changes	Cross-well electrical and seismic tomography	Induced seismic activity
			Rock–fluid properties	Geological changes
			Reservoir fluid chemistry	
MONITORING TECHNOLOGY	Tiltmeters	Piezometers	Fibre-optic distributed temperature systems	Cross-well seismic tomography
	inSAR satellite interferometry	Groundwater chemistry monitoring	Fibre-optic distributed acoustic systems	Broadband seismography
	Electromagnetics	Soil-gas monitoring	Fluid recovery systems	Permanent areal seismic array
	GPS	Multi-species atmospheric surveys	Pressure gauges	Time-lapse 3D seismic imaging
	Gravimeters		Temperature gauges	Continuous passive microseismic monitoring
				Vertical seismic profiling (VSP)

The Aquistore Project undertook a thorough series of public outreach activities beginning in February 2012. The communications plan included engaging:

- Individuals and the local community through "kitchen table" discussions, open houses and educational events. Knowledge dissemination is a key activity of the project and its many international researchers.
- Provincial stakeholders in the Legislative Assembly, local Members of Parliament, civil servants and regional media.
- National and international stakeholders in governments and governmental agencies, environmental non-governmental organizations (ENGOs), national and international media, scientific journals.
- PTRC employees and research partners.

Knowledge sharing has been extensive to date, including conference attendance and presentations, hosting industry conferences, tours of the SaskPower Carbon Storage and Research Centre, publication in peer-reviewed scientific journals and a high-profile social and printed media presence.

*Regular monitoring is undertaken over the same area at and around the CO_2 injection site.

ABBREVIATIONS

This is not a comprehensive list.

BD3 – Boundary Power Plant Station Unit 3

CCS – Carbon Capture, Transportation and Storage

CCPC – Canadian Clean Power Coalition

CCTF – SaskPower's Carbon Capture Test Facility (at Shand Power Station)

CEPA – The Canadian Environmental Protection Act

CIC – Crown Investments Corporation of the Government of Saskatchewan (owner of all Crown corporations such as SaskPower)

CO_2e – The climate forcing factor associated with a greenhouse gas expressed as "carbon dioxide equivalents". For example, the climate forcing factor of methane (CH4) is 21 times the factor for CO_2. Hence, one methane molecule is equivalent to 21 carbon dioxide molecules in terms of greenhouse impact on the climate.

C$ – Canadian Dollars

EC – European Commission

ECRF – SaskPower's Emissions Control Research Facility (at Poplar River Power Station)

EOR – Enhanced Oil Recovery

EU – European Union

GHG – Greenhouse Gas

GWh – Giga-Watt-Hour, the energy unit of total power generation

ICCS – Integrated Carbon Capture and Storage, which is the name of the combined BD3 power plant retrofit project and the geological storage of its captured CO_2.

IEAGHG – IEA Greenhouse Gas R&D Programme

MW – Mega-Watt, the energy unit used for power-generating capacity

PCC – Post-Combustion Capture

$PM_{2.5}$ – Fine Particulate Matter found in the air that is less than or equal to 2.5 mm (micrometres) in diameter and normally only observed by electron microscope. This material is often associated with energy combustion and the fine particulate matter is believed to cause serious health issues upon entering lungs of air-breathing animals.

PM_{10} – Coarse Particulate Matter found in the air that is less than or equal to 10 (mm) micrometres in diameter. It can be seen with the human eye in the air as soot, dust, dirt and liquid droplets. This material is often associated with energy combustion.

PTRC – Petroleum Technology Research Centre, a non-profit R&D corporation located in Regina, Saskatchewan

R&D – Research and Development

QA/QC – Quality Assurance and Quality Control

SE - Southeast

SaskPower – Saskatchewan Power Corporation

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[1] 2014 SaskPower Annual Report

[2] SaskPower's fiscal year runs from January 1 to December 31.

[3] From 2010–2014, SaskPower invested C$4.7 billion in capital assets (upgrades, new construction)

[4] Canada Gazette, Vol. 146, No. 19 — September 12, 2012 (Government of Canada)

[5] Provided by SaskPower

[6] http://www.ir.gov.sk.ca/coal

[7] The Encyclopedia of Saskatchewan. The Oil and Gas Industry. http://esask.uregina.ca/entry/oil_and_gas_industry.html

[8] Melzer, Stephen, 2012. Report for the National Enhanced Oil Recovery Initiative, Center for Climate and Energy Solutions Carbon Dioxide Enhanced Oil Recovery (CO_2 EOR): Factors Involved in Adding Carbon Capture, Utilization and Storage (CCUS) to Enhanced Oil Recovery

[9] From Leasing Mineral Rights: "Unitization of a producing field: The purpose of unitization is to produce oil or gas more efficiently and effectively by bringing together an area involving a large number of sections. Unitization is used where the industry feels that a large portion of the oil and gas can be produced with fewer wells. Upon unitization, an owner within the boundaries of the unitized field is entitled to participate in production, even though no well is located on his land. The provisions of a lease may therefore permit "pooling," in which case you receive a portion of the royalty, based on the number of acres you put in the pool. The lease may permit "unitization," which converts your royalty into a "tract factor," based on a complex formula. Even though unitization in the vast majority of cases provides a better total income for the mineral owner, an owner should not grant the right to unitize automatically; nor should he leave it up to the company's discretion. Because participation in a unit is not based on the number of acres you have in the unit but is determined by the company, based on geological factors, you should very carefully assess your position. For example, while you may hold five per cent of the area in a unit, you may be allocated only two per cent of the production."

[10] http://www.economy.gov.sk.ca/PR-IC11

[11] Pan Canadian was a subsidiary company of Canadian Pacific Railway until it merged with Alberta Energy Company in 2002 to form EnCana Corporation, an independent oil and gas corporation. In December 2009, Cenovus Corporation split from EnCana to operate as an independent integrated oil company, including all of the oil assets from the original firm. EnCana continues to operate the natural gas assets of the original firm and is a leading independent Canadian natural gas producer.

[12] Numac Energy Inc. was incorporated in Alberta in 1971 and was an independent oil producing company until it was purchased by Anderson Exploration Inc. in early 2010. Anderson was subsequently purchased by Devon Energy (USA) to form Devon Canada Corporation in late 2010. Numac, in partnership with Nexen Inc., operated a CO_2–EOR pilot at its Elswick Midale oil leases in 2001 using trucked CO_2 from the Air Liquide plant in Medicine Hat, Alberta. It ultimately decided not to proceed with full-scale operation of CO_2–EOR due to various technical issues it encountered during the pilot as well as poor economics due, in part, to the lack of a pipelined source of CO_2. The Elswick oil field is one of many potential CO_2–EOR targets in SE Saskatchewan.

[13] http://www.economy.gov.sk.ca/adx/aspx/adxGetMedia.aspx?DocID=10290,10289,3384,5460,2936,Documents&MediaID=26122&Filename=SPRI+CO_2+Pilot+Injection+Test.pdf

[14] http://www.ucsusa.org/global_warming/science_and_impacts/impacts/early-warning-signs-of-global-1.html#.Va6YMnnbKTM

[15] http://unfccc.int/kyoto_protocol/items/2830.php ; The agreement came into force in 2005 upon ratification by 55 signatory parties belonging to the UNFCCC. Those signatories include Canada but notably exclude the USA as of mid-2015.

[16] Clift, R. and J. Seville (Editors), 1993. Proceedings of the Second International Symposium on Gas Cleaning at High Temperatures. University of Surrey, UK. Springer Science and Business Media. P. 129.

[17] https://en.wikipedia.org/wiki/Integrated_gasification_combined_cycle

[18] http://www.nrcan.gc.ca/energy/coal/carbon-capture-storage/4307

[19] http://www.nrcan.gc.ca/energy/coal/carbon-capture-storage/4333

[20] http://cornerstonemag.net/exploring-the-status-of-oxy-fuel-technology-globally-and-in-china/

[21] Tanner, C. S., Baxley, P. T., Crump, J. G., & Miller, W. C. (1992, January 1). Production Performance of the Wasson Denver Unit CO_2 Flood. Society of Petroleum Engineers. doi:10.2118/24156-MS

[22] Beliveau, D. A. (1987, November 1). Midale CO_2 Flood Pilot. Petroleum Society of Canada. doi:10.2118/87-06-05

[23] The Midale and Weyburn oil fields are operated in the same geological formation, along with several surrounding oil leases/operations. Each of the two oil fields is owned by approximately 30 owners but each field was "unitized" in the 1960s to support water flooding infrastructure investment. Each unitized oil field is operated by one major oil company on behalf of the owners. Pan Canadian was an owner of part of the Midale oil field and consequently had access to the CO_2–EOR pilot program undertaken by Shell Canada.

[24] http://www.dakotagas.com/CO2_Capture_and_Storage/Pipeline_Information/index.html

[25] Apache Canada began a commercial CO_2–EOR flood at Midale in 2006 using approx. 1800 tonnes per day of CO_2 supplied by DGC. At that time Apache Canada contributed data and sponsorship to the renamed IEAGHG Weyburn-Midale CO_2 Monitoring and Storage Project.

[26] Hitchon, Brian (Editor), 2012. Best Practices for Validating CO_2 Geological Storage: Observations and Guidance from the IEAGHG Weyburn Midale CO_2 Monitoring and Storage Project. Chapter 1. Updated data from Cenovus and PTRC as of 2014.

[27] Approximately one-third of the CO_2 injected in a given oil production cycle is "lost" to the reservoir. The uncertainty prior to the IEAGHG Weyburn CO_2 Monitoring Project beginning its work was, "Where does the CO_2 go?"

[28] http://ptrc.ca/projects/weyburn-midale

[29] http://www.canadiancleanpowercoalition.com/

[30] http://www.SaskPower.com/our-power-future/our-electricity/our-electrical-system/cory-cogeneration-station/

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[32] Wilson, M. and M. Monea (Editors), 2004. IEAGHG Weyburn CO_2 Monitoring and Storage Project Summary Report 2000–2004. From the Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies, September 5–9, 2004, Vancouver, Canada. Petroleum Technology Research Centre, Regina.

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[34] http://www.environment.gov.sk.ca/adx/aspx/adxGetMedia.aspx?DocID=1273,1272,929,928,926,240,94,88,Documents&MediaID=619&Filename=2007-052_project_description.pdf

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[41] Johnstone, Bruce, 2012. From Regina Leader-Post and Saskatoon StarPhoenix newspapers. "SaskPower, Cenovus sign CO_2 supply deal". December 20, 2012.

[42] There are many sources of ENGO criticism of the BD3 ICCS Project. One example from the Sierra Club of Canada is embedded in the newspaper article noted in reference 51.

[43] Zinchuk, B., 2015. Pipeline News. "Report critical of Boundary Dam suggests the answer is wind". April 1, 2015.

[44] http://large.stanford.edu/courses/2010/ph240/vasudev1/

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[47] http://www.babcock.com/products/Pages/Subcritical-Radiant-Boilers.aspx

[48] http://www.snclavalin.com/en/

[49] http://www.mhps.com/en/products/generator/

[50] http://www.stantec.com/

[51] http://www.cenovus.com/operations/oil/docs/rafferty-landowner.pdf

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ISBN 978-0-9956163-0-1