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REDUCING THE CARBON FOOTPRINT OF OILSANDS PRODUCTION AND THE ALBERTA GRID

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CESAR

UNIVERSITY OF CALGARY

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Background and acknowledgements

CESAR's work on this report began in the spring of 2015 with a donation to the University of Calgary through the Edmonton Community Foundation that provided 60% of the project budget. In early 2016, Candor Engineering Ltd. provided valuable technical and engineering insights regarding cogeneration that were incorporated into our models. They also made it possible for CESAR to second Eric Shewchuk, a talented electrical engineer to assist with the modeling work.

In late May 2016, preliminary results were shared with Alberta Innovates – Energy and Environmental Solutions and a number of oil sands companies, five of which expressed an interest in providing financial support for the work. Together with Alberta Innovates – Energy and Environmental Solutions*, MEG Energy, Suncor Energy, Cenovus Energy, Nexen Energy ULC, and one anonymous corporation, provided the remaining 40% of the project budget. CESAR thanks them for their support of this work.

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The authors thank Bastiaan Straatman for assistance in compiling province wide cogeneration data, Mark Lowey for assistance in editing the report, numerous reviewers who provided critical feedback and constructive suggestions, and Benjamin Israel in preparing the document for publication.

About CESAR

CESAR (Canadian Energy Systems Analysis Research) is an initiative that was started at the University of Calgary in 2013 to understand and inform energy systems change in Canada. By building data resources and visualization tools, analyzing past and present energy systems, and modeling energy futures, CESAR researchers work to inform policy and investment decisions regarding the transformation of Canada's energy systems towards sustainability. To carry out its work, CESAR brings researchers, disciplines and sectors together from across Canada.

Through its website (www.cesarnet.ca), CESAR provides visualizations that communicate a wealth of information on the energy systems of Canada, and its provinces. The data behind many of these visualizations have been made available through a cooperative agreement between CESAR and whatIf? Technologies Inc, an Ottawa, Ontario systems modeling company, and the owner and developer of the Canadian Energy Systems Simulator (CanESS) model.

In addition to generating publications in the traditional academic literature, CESAR produces detailed, timely reports / discussion papers under the 'CESAR Scenarios' publication series. These reports are made available for free download on the cesarnet.ca website.

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David Layzell is a Professor at the University of Calgary and Director of the Canadian Energy Systems Analysis Research (CESAR) Initiative. In CESAR, he studies the energy systems of Canada and models the costs, benefits and tradeoffs of technologies and policies driving energy systems transformation. Between 2008 and 2012, he was Executive Director of the Institute for Sustainable Energy, Environment and Economy (ISEEE), a cross-faculty, graduate research and training institute at the University of Calgary.

Before going to Calgary, Dr. Layzell was a professor at Queen's University (Kingston) and the Executive Director of BIOCAP Canada, a research foundation focused on biological solutions to climate change. While at Queen's, he founded an scientific instrumentation company called Qubit Systems Inc. and was elected 'Fellow of the Royal Society of Canada' (FRSC) for his research contributions.

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Madhav Narendran is in a three-year graduate development program at BP Integrated Supply and Trading, where he works as an analyst supporting natural gas trading operations. Immediately prior to that, he completed a BSc in Electrical Engineering and a BA in Economics at the University of Calgary, where he graduated with distinction, made the Dean's honours list, and received several scholarships.

Madhav began his work with CESAR in the final year of his undergraduate studies where he was modeling future scenarios for the Alberta electrical grid. His expertise includes power engineering and energy economics. "The opportunity to shape the future of Alberta's grid is very exciting. Combining my two degrees in a single application is quite rewarding."

Madhav was born in India and grew up in Calgary. He is a member of the Institute of Electrical and Electronics Engineers, and the Association of Professional Engineerings and Geoscientists of Alberta.

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His areas of expertise include electrical engineering in power, controls, and instrumentation. One of the most rewarding aspects of his job is working within a team to get to a final product.

Eric has a BSc in Electrical Engineering from the University of Alberta, where he graduated with distinction. He is a member of the Association of Professional Engineers and Geoscientists of Alberta, the Association of Professional Engineers & Geoscientists of Saskatchewan, and the Association of Professional Engineers and Geoscientists of British Columbia.

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Song P. Sit is a Chemical Engineer with 40 years of industrial experience. In the last 20 years he has focused on improving Alberta oil sands performance. His various roles and accomplishments have included: Technology development in GHG reduction of, and new value-added products to, oil sands crude; Advocacy in oil sands environmental and royalty policies and regulations; Collaboration with peers to achieve our common goal of improving oil sands performance in CAPP and COSIA. He is the principal of GHG Reduction Consultancy founded in 2015.

Dr Sit has worked with CESAR since January 2016, bringing valuable insights and expertise from his years of work in the oil industry.

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Abbreviations used

BFW	Boiler Feed Water
BPD	Barrels Per Day
BTF	Behind The Fence
CAC	Criteria Air Contaminants
CAPEX	Capital Expenditure
CHP	Combined Heat and Power
Cogen	Cogeneration
COSIA	Canada's Oil Sands Innovation Alliance
CPF	Central Processing Facility
CWE	Cold Water Equivalent
DB	Duct Burning
DLN	Dry Low NOx
ECM	Electrochemical Membrane
EGT	Exhaust Gas Temperature
FA-DB	Forced Air-Duct Burning
GHG	Greenhouse Gas
GT	Gas Turbine
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
LF	Load Factor
LHV	Lower Heating Value
LPG	Liquefied Petroleum Gas
NG	Natural Gas
NGCC	Natural Gas Combined Cycle
NGSC	Natural Gas Single Cycle
NPV	Net Present Value
OTSG	Once Through Steam Generator
PCC	Post Combustion Carbon Capture
PG	Produced Gas
PM	Particulate Matter
ROI	Return on Investment
SAGD	Steam Assisted Gravity Drainage
SAP	Solvent Aided Process
SGER	Specified Gas Emitters Regulation
SOFC	Solid Oxide Fuel Cell
SOR	Steam to Oil Ratio
TRL	Technology Readiness Level
VIGV	Variable Inlet Guide Vanes
VOC	Volatile Organic Compound
WHR	Waste Heat Recovery

Executive Summary

To reduce greenhouse gas (GHG) emissions and address the serious challenge of climate change, governments around the world are using a range of policy options. The Alberta government's policy includes phasing out coal-fired power, significantly increasing renewables in the electrical grid, implementing an economy-wide carbon levy, and putting a limit on annual GHG emissions from the oil sands industry.

One objective of the Alberta government's 'Climate Leadership Plan' is to regain public support for the oil and pipeline industries that have been such important drivers for both the provincial and national economies. Concerns about oil sands production, especially from the steam assisted gravity drainage (SAGD) technology, have focused on the high GHG emissions associated with recovery when compared with more conventional types of crude oil. Reducing the GHG intensity associated with producing a barrel of SAGD oil is essential in the effort to regain public support for Alberta's oil sands operations.

This study shows how, over the next 14 years, the existing and planned SAGD operations in Alberta could use off-the-shelf technology to achieve the early retirement of coal from the electrical grid, make space for 12 TWh of new renewable generation, stabilize electricity prices and reduce GHG emissions by 170 Mt CO_2. If assigned to oil sands production, these emission reductions would reduce the GHG footprint of SAGD production to less than, or equivalent to, conventional oil.

"This study shows how, over the next 14 years, the existing and planned SAGD operations in Alberta could use off-the-shelf technology to:

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This report builds on a previous study[1] to explore the potential for large-scale deployment of cogeneration at oil sands crude-producing Steam Assisted Gravity Drainage (SAGD) facilities in the province to meet not only the heat and power requirements for SAGD, but to help the province achieve its objectives for the early retirement of coal-fired power and greatly enhance the contribution of renewable energy to the Alberta grid.

Using boundary conditions that include the energy and greenhouse gas (GHG) flows for both the entire electrical grid, and all of the SAGD production facilities in the province, five scenarios were generated and compared for the delivery of electrical power to the Alberta grid over the period from 2017 to 2030:

- The BAU 2015 scenario (**S1**) assumed the 50 year coal retirement policy established by the previous federal government.
- Scenario 2 (**S2** or BAU 2015 Rnw) assumed the same 50 year coal retirement policy, but included 12 TWh/year of new renewable generation by 2030. The backup power for the non-dispatchable renewables to maintain a 15% reserve margin was provided by natural gas single cycle (NGSC) generation at 10% capacity factor.
- In Scenario 3 (**S3** or BAU 2016) the enhanced renewable energy target from S2 was included along with the retirement of all coal generation in the province by 2030. In effect, S3 represents an approximation of the Alberta government's current policy direction in which the electrical baseload for power that was previously supplied by coal will be provided by natural gas combined cycle (NGCC) over the period ending in 2030.
- Scenario 4 (**S4** or SAGD Max) was identical to S3 except instead of NGCC providing the baseload replacement for coal, SAGD cogeneration provided this role while operating at ~89% load factor for 95% of the time.
- Scenario 5 (**S5** or SAGD Rnw) was similar to S4, but the province's SAGD cogeneration capacity was maximized and scaled to meet all heat demand for SAGD by 2030. This reduced the load factor for the gas turbines leaving spare capacity that could be used to provide the backup for the renewable energy portion of the grid, thereby displacing NGSC as well as NGCC generation capacity.

1 Layzell DB, Shewchuk E, Sit SP, Klein, M. 2016. Cogeneration options for a 33,000 BPD SAGD Facility: Greenhouse gas and economic implications. CESAR Scenarios Vol. 1, Issue 3: 1-52.

Comparing the GHG emissions associated with the various scenarios revealed that government's current policy direction (S3) should reduce systems level GHG emissions by 147 Mt CO_2 compared to the previous policy (S1) between now and 2030. However using SAGD cogeneration (S4) instead of NGCC (S3) to provide base load power as coal is retired has the potential to reduce GHG emissions by a further 23 Mt CO_2 between now and 2030.

With the existing policies for the allocation of emission reductions between heat and power generation, these additional emission reductions will reduce GHG intensity associated with the production of oil sands crude… but these reductions will not occur with S3. Moreover, since cogeneration typically bids into the grid at low or zero dollars price, power prices for consumers in a grid dominated by SAGD cogeneration should be both lower and more stable than power prices in a grid dominated by NGCC.

The use of SAGD cogeneration is aligned with the Alberta government's publicly stated desire (including in its Climate Leadership Plan) to find cost-effective, collaborative, multi-stakeholder solutions to address GHG emissions and climate change. The approach is also aligned with the oil sands industry's stated goal to become not only cost-competitive with crude oil producers in other countries but also carbon-competitive – and as quickly as possible.

To incentivize and get the maximum benefit from the large-scale use of SAGD cogeneration in the province, this report ends with a consideration of accounting systems and policies that would allow SAGD operators to claim temporary GHG reduction credits if their deployment of SAGD cogeneration were formally linked to the early retirement of coal and/or the back up of greatly expanded renewables on the Alberta grid.

With such an accounting system and policy in place, the calculations provided here show that it is possible to reduce the GHG intensity of SAGD oil sands crude production to be equivalent to or lower than conventional oil within the next five years. There is no other proven technology capable of achieving this goal on this timeline.

Given the importance of oil sands production and export to the economies of Alberta and Canada, industry, governments and environmental groups should explore the barriers and opportunities for large-scale deployment of SAGD cogeneration that would clearly position oil sands companies as being part of the solution to the challenges of climate change, not only part of the problem.

1. Introduction

To address concerns about greenhouse gas[2] (GHG) emissions contributing to climate change, major forces are in play to reduce global demand for oil and for refined petroleum products that currently fuel most of the world's transportation and chemical sectors. However, until a significant reduction in oil demand is achieved through changes in behaviour, fuel sources or end use technologies, crude oil will continue to be extracted and delivered to global markets.

Perhaps because of the challenges associated with changing human behaviour or end use technologies, there has been a focus in recent years on the GHG footprint associated with the extraction of different kinds of crude oil. For example, the recovery of oil sands crude using Steam Assisted Gravity Drainage[3] (SAGD, see box) has GHG emissions (typically 70-80 kilograms CO_2/barrel) that are about three times higher than the emissions associated with conventional crude oil extraction (20-30 kg CO_2/bbl).[4]

This differential in the carbon intensity of SAGD oil recovery has been an important factor in fueling environmental and community concerns about Alberta's oil sands operations, especially the building of new pipelines that would bring oil sands crude to markets in eastern Canada, the U.S. and around the world. Given the importance of oil production and export to the Albertan and Canadian economies, there is clearly an interest in developing and implementing technologies that will dramatically reduce the GHG footprint associated with SAGD production. Indeed, the stated goal of major oil sands producers through their Canada's Oil Sands Innovation Alliance (COSIA), is to produce oil sands crude that has the same or lower GHG intensity as conventional crude oils.

However, the emerging technologies needed to attain that goal will likely take at least another 10 to 15 years to develop, test and scale up for commercial use, based on typical technology development timelines. At the same time, there is an urgent need and growing public pressure to transform our energy systems to lower-carbon energy sources. Ideally, cost-effective, readily available 'off the shelf' (i.e. commercial) technologies should be implemented over the next few years to achieve the lowest possible GHG footprint for SAGD

2 The most important greenhouse gas (GHG) is carbon dioxide (CO_2) that is produced primarily from the combustion of fossil fuels like coal, oil and natural gas. Other GHGs include methane (CH_4) and nitrous oxide (N_2O).

3 SAGD is the fastest growing technology for recovery of oil sands crude in Alberta. It currently produces about 1 M bbl/d and is the primary technology capable of accessing oil sands reserves too deep to be mined from the surface – which constitute about 80% of the oil sands reserves in Alberta.

4 IHS, CERA. 2012. Oil Sands, Greenhouse Gases, and US Oil Supply Getting the Numbers Right.

production. By doing so, the oil sands sector can show leadership in finding effective, collaborative solutions to reduce Alberta's GHG emissions, which should help the Alberta government and industry secure community and public acceptance of new oil sands infrastructure. Meanwhile, investments should continue to be made to develop more transformative technologies that will make oil sands extraction and production the international benchmark for low-GHG crude oil.

This report is the second in a series of studies by CESAR to explore the technical, environmental and economic implications of deploying a commercial technology on SAGD sites that can reduce system-level GHG emissions. CESAR's first report[5] in this series explored four different case studies for the operation of a 33,000 barrel per day SAGD facility having steam-to-oil ratios (SOR) of 2 to 4: (a) no cogeneration (Base Case); (b) one 85 MWe facility operating at 100% load factor[6]; (c) two 85 MWe facilities operating at 100% load factor; and (d) two 85 MWe facilities operating at 60% load factor.

For the same oil production and the public grid contribution that were observed in the three Cogen Cases, it was possible to compare the total energy input, conversion losses and GHG emissions of the

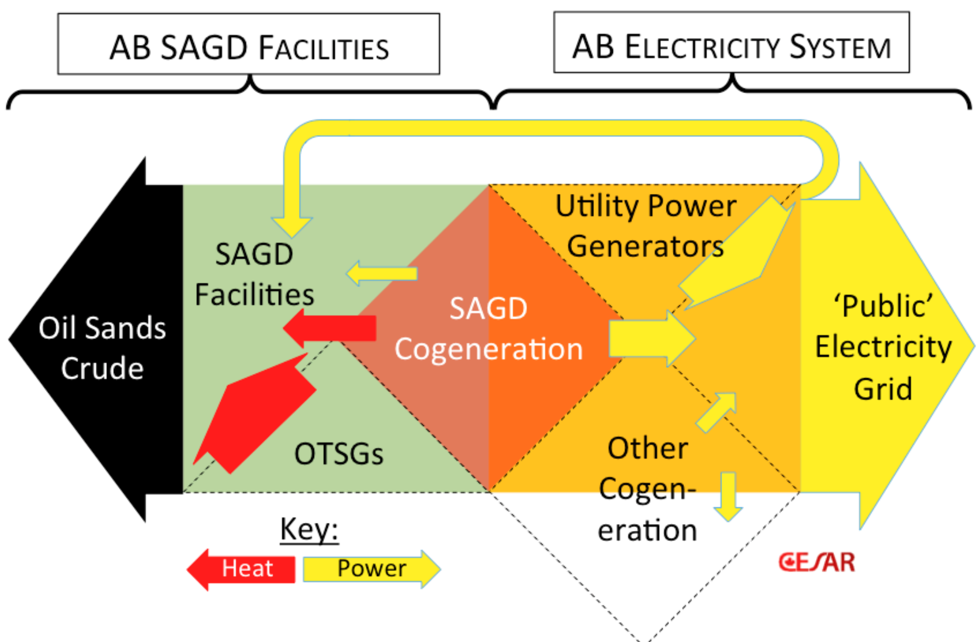

Figure 1. Project concept where the solid shaded area defines the boundary conditions of the modeling work carried out in this study.

5 Layzell DB, Shewchuk E, Sit SP, Klein, M. 2016. Cogeneration options for a 33,000 BPD SAGD Facility: Greenhouse gas and economic implications. CESAR Scenarios Vol. 1, Issue 3: 1-52.

6 Percent of maximum daily output.

Base Case with each Cogen Case. At an SOR of 3, Cogen was found to reduce fuel use by 11% to 16.5%, conversion losses by 31% to 40%, and GHG emissions by 26% to 37%. The GHG emission reductions were equivalent to 1.2-2 kt CO_2/day, or 421- 717 kt CO_2/ yr for each SAGD facility.

This report builds on the previous study to model the province-wide implications of SAGD-cogeneration on both the Alberta electrical grid and the production of SAGD oil sands crude.

To do this analysis, CESAR has built a technology-rich computer model that includes the energy, carbon and product flows associated with Alberta's past (from 2010), present and projected future (to 2030) production of both SAGD oil sands crude and the entire electrical grid (Figure 1).

This model is then used to explore 5 scenarios to 2030, and address the following questions:

1. Over the next 15 years, what role could SAGD cogeneration play in reducing the emission intensity of oil sands recovery and helping to transform Alberta's electrical grid through coal plant retirements and significantly expanding renewables?
2. What are the options for deployment and what impact would each scenario have on the flows of energy and carbon for both the Alberta electrical grid and the province's SAGD operations over the next 15 years?
3. What would be the system-level costs, benefits and trade-offs of such a transformation, when compared with the 'business-as-usual' alternative strategies to extract oil and transform the Alberta grid?
4. If cogeneration in the SAGD sector is a 'better' option, what are the barriers to deployment and how might these be overcome through policies and/or regulation?

About Steam Assisted Gravity Drainage (SAGD) and Cogeneration

Most of Alberta's oil sands reserves are too deep to be extracted using mining technology so they are extracted using 'in situ' technologies. The two proven in situ technologies are cyclic steam stimulation (CSS) and steam assisted gravity drainage (SAGD). Both technologies require the injection of high-pressure steam into the reservoir to heat up the oil sands crude in order to reduce its viscosity from almost 1 million centipoise (cP) to less than 10 cP. At this low viscosity the crude will flow to in situ production wells and then be lifted to a central processing facility (CPF) when it is separated from the steam condensate and blended with diluent for delivery to refineries. SAGD is currently the technology of choice by new projects for in situ extraction of oil sands crude.

In many SAGD facilities, high-pressure steam is generated in conventional boilers such as once through steam generators (OTSG) fired with natural gas while the electricity that is required on site is imported from Alberta's public grid. Other facilities have installed natural gas cogeneration units that deploy gas turbines (GT) for power generation and heat recovery steam generators (HRSGs) for high pressure steam production. Excess electricity not needed on site is exported to the grid. This requires the installation of a sub-station where the power generated in the GT is converted to that required by the grid.

Cogeneration makes a more efficient use of the energy embedded in the natural gas fuels than any separate systems for heat and power generation. And since natural gas represents a major cost for both the generation of electricity and the production of SAGD oil sands crude, cogeneration can potentially lower the cost of both oil production and electricity generation.

2. Scenario modeling approach and assumptions

2.1. Modeling approach

Figure 2 provides an overview of the modeling approach used to create various scenarios to 2030 for transforming the Alberta electrical grid, and reducing the carbon footprint of SAGD Facilities. After defining some basic socio-economic assumptions that were used to project future demand for electricity in the province (Figure 2A), five different scenarios were created for the Alberta grid to deliver on that demand (Figure 2B). Then, detailed information regarding

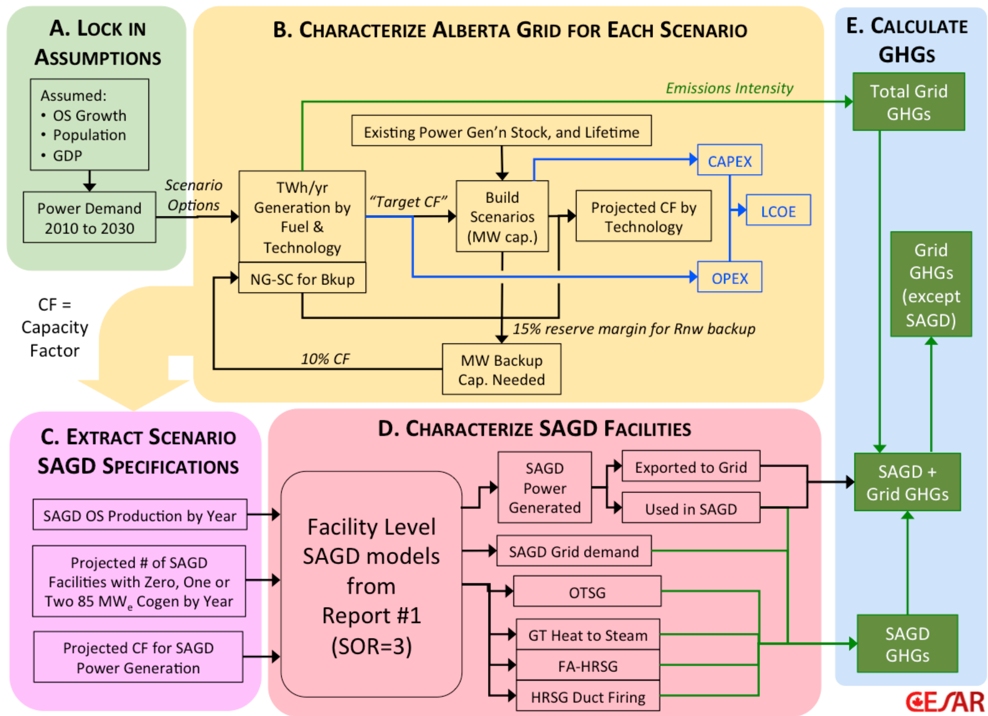

Figure 2. Schematic diagram outlining the flow of calculations used within a SAGD / Electrical grid model for creating and comparing a series of scenarios.

the complement of SAGD facilities in the province for each scenario (Figure 2C) were provided to the facility-based SAGD model described previously[7] to obtain detailed information for each year on the contribution of cogeneration power to the grid and heat to SAGD production (Figure 2D). These data were used to calculate and allocate GHG emissions to electricity and oil sands crude production (Figure 2E).

The following sections provide additional details on each stage in this process.

2.2. Lock in assumptions

Energy systems scenario models are built on historical data, and then project into the future using a number of assumptions to constrain or frame the scenario projection. Sometimes, detailed historical data are not available, so reasonable estimates must be made. In all cases, assumptions must be made about key drivers of growth and economic development. Historical data was obtained from the

7 Layzell DB, Shewchuk E, Sit SP, Klein, M. 2016. Cogeneration options for a 33,000 BPD SAGD Facility: Greenhouse gas and economic implications. CESAR Scenarios Vol. 1, Issue 3: 1-52.

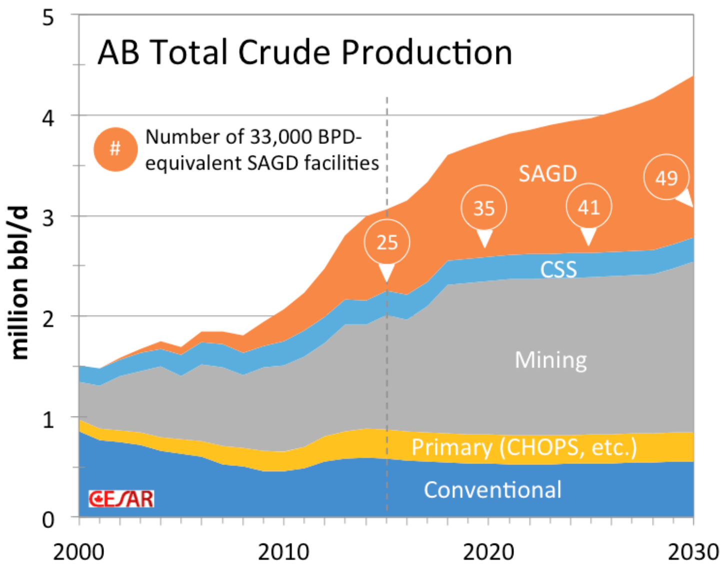

Figure 3. Past, present and projected crude oil production in Alberta separated by the technology used for extraction. For SAGD, estimates are given for the number of 33,000 bbl/day facilities between 2015 & 2030.

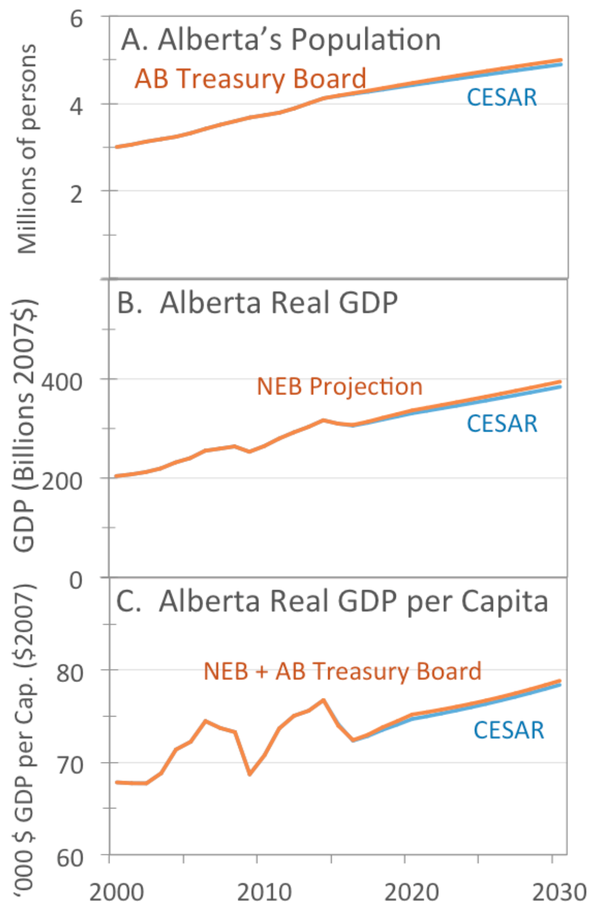

Figure 4. Actual and projected Alberta population, GDP, and GDP per capita.

Alberta Energy Regulator[8] and forecasts to 2030 for the production of conventional oil, heavy oil and oil sands crude by mining, in situ CSS and SAGD were obtained from the Canadian Association of Petroleum Producers[9] (Figure 3).

In Alberta, the rate of oil sands development is a major determinant of population and GDP growth, as shown in Figure 4. For population and GDP projections, annual growth rates were assumed to be 1.01%, 1.02% and 1.00% for Alberta population, GDP and GDP per capita, respectively. The resulting forecast (Figure 4, labelled as CESAR) are slightly lower than recent forecasts from the Alberta Treasury Board (ATB)[10] and National Energy Board (NEB)[11].

These assumptions were used to project Alberta's electricity demand to 2030 as shown in Figure 5. Much of the historical data in Figure 5 were obtained from AESO[12], but since more detailed data were needed for our models than what was available from AESO (e.g.

8 Alberta Energy Regulator, ST98-2015, June 2015.

9 Canadian Association of Petroleum Producers, Crude Oil Forecast, Markets & Transportation, June 2015.

10 Alberta Treasury Board and Finance Office of Statistics and Information – Demography, Population Projection – Alberta 2015-2041, July 31, 2015.

11 National Energy Board, https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx, January 2016.

12 Alberta Electric System Operator, AESO 2016 Long-term Outlook, May 2016.

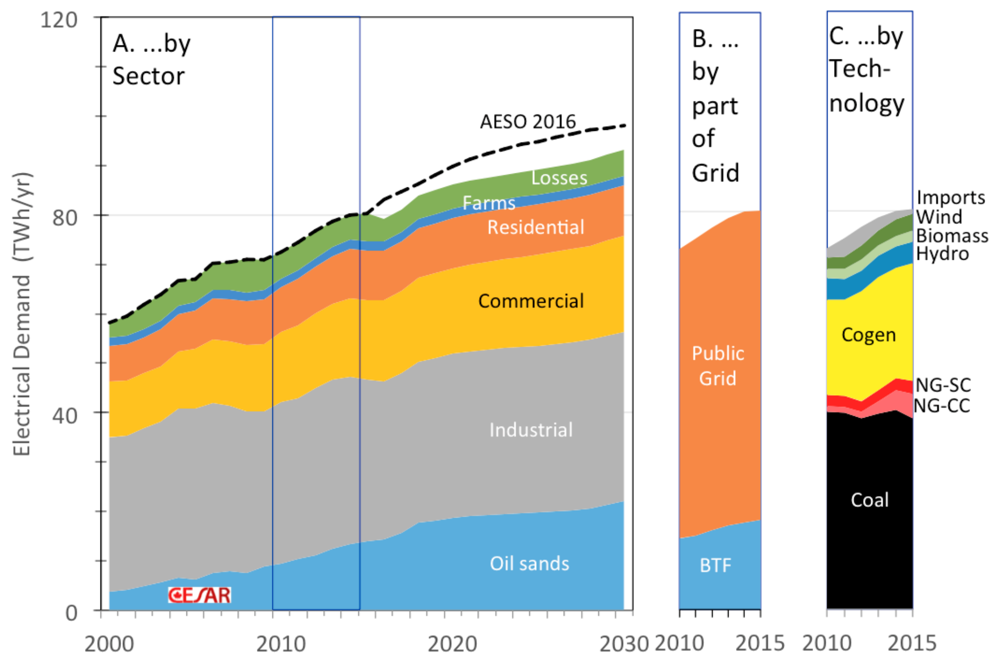

Figure 5. Historical and projected electrical demand by sector (A), and for the period 2010 to 2015 the proportion of total demand that was served by the public grid vs. BTF (B), or the contribution of various generation sources to meet the demand (C).

cogeneration, separation of behind the fence vs public grid, capacity factors), information was compiled from a range of sources (publications from OSCA[13], CIEEDAC[14], and McGarrigle[15]) to which assumptions were added. Ultimately, we forecasted the electricity demand shown in Figure 5A. By 2030, CESAR's estimated electrical demand was about 5% lower than a recent forecast from AESO[16].

Figure 5B shows in 2010 to 2015, 79% of the demand is satisfied by the public grid, with the remainder from so-called 'behind-the-fence' (BTF) generation. Also shown for the same six-year interval are the components of generation technologies that were estimated to meet this electricity demand (Figure 5C). It shows that coal-fired power supply was essentially flat; a growing portion was satisfied by natural gas-fired generation, of which cogeneration is the dominant source over natural gas combined cycle (NGCC) or single cycle (NGSC).

Cogeneration in Alberta. As noted above, obtaining accurate, detailed data on cogeneration was particularly challenging, so we drew on the publications used for Figure 5 and worked to reconstruct a

13 OSCA, 2014 Oil Sands Co-generation and Connection Report, June 2014.

14 CIEEDAC data can be found on their website http://www2.cieedac.sfu.ca/Databases

15 McGarrigle P, Cogeneration & Carbon Management, January 2014.

16 Alberta Electric System Operator, AESO 2016 Long-term Outlook, May 2016.

credible picture of cogeneration in the province in 2014. The results of this work are shown in Figure 6.

In 2014, total electricity provided by cogeneration in Alberta was estimated to be 23 TWh. Figure 6 dissects this total into the industry sectors of SAGD, industry, mining, upgrading, utilities and commercial. For each sector, it also shows the amount exported to the public grid and the amount used BTF. It shows that in the industry sectors, a significant portion of the larger sectors was consumed BTF. For example, of the largest sectors, 35%, 88% and 70% respectively of the Cogen electricity produced in SAGD, mining and industry, were consumed BTF.

The 'Average' SAGD Facility. The average SAGD facility has an oil output of 33,000 BPD and an SOR of 3. The total heat for all SAGD projects derived from each source (OTSG, duct burning, and from the gas turbine) as well as the electricity imported from the grid, consumed BTF, and exported to the grid were averaged and expressed for a typical facility. Figure 7 shows how the average amount of Cogen use per facility has declined since 2010, with the exception of 2012, and is expected to decline into the near future. This is because the majority of new SAGD facilities have not installed or are not installing cogeneration. Early users of SAGD technology typically installed Cogen on their site, but as growth in the industry increased fewer sites had installed Cogen. This has led to an increase in consumption of grid power and relatively more oil being produced from OTSGs.

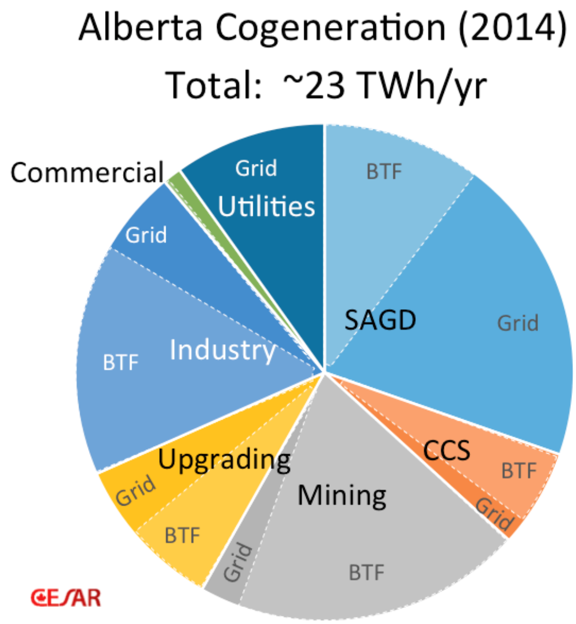

Figure 6. The calculated allocation of cogeneration in Alberta in 2014 to various sectors and, within each sector, the proportion of cogenerated power that is used 'Behind the Fence' (BTF, lighter shade) or exported to the public grid (Grid, darker shade).

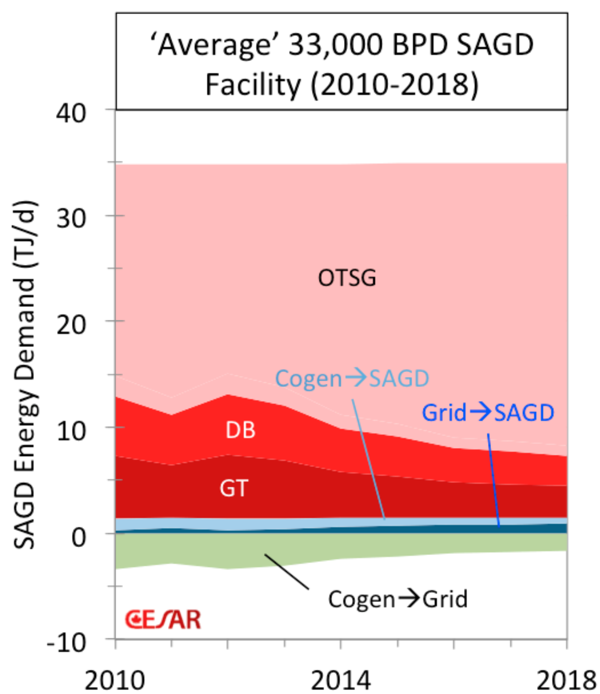

Figure 7. Heat (red shades) and power generation (light blue, light green), and grid power used (dark blue) from the 'average' 33,000 bpd SAGD facility in Alberta 2010-2018.

2.3. Characterize the Alberta grid for each Scenario

Given the electricity demand projection provided in Figure 5, five different scenarios were created to meet this demand. Recognizing that Alberta currently has significantly more generation capacity than it needs at the present time (reserve margin of ~27%), all of the scenarios included an assumption that the first coal plant retirements scheduled for 2019 would not be replaced by new generation capacity.

Table 1. Coal plant retirement schedules that were assumed in this study. Compared to the federally regulated 50 year retirement (BAU 2015), the 'early retirement' (BAU 2016) schedule was estimated to reduce coal plant-year operations by 151 years, resulting in up to 434 TWh of other generation, and potentially reducing GHGs by 268 Mt CO_2.

Plant Name	Capacity (MWh)	Build Year	BAU 2015 Retirement	BAU 2016 Retirement	Years Reduced	TWh Produced by Other Sources (TWh)	GHG Reduction[a,b] (Mt CO_2)
Battle River station unit 3	149	1969	2019	2019	0	0	0
Sundance station unit 1	288	1970	2019	2019	0	0	0
HR Milner station	144	1972	2019	2019	0	0	0
Sundance station unit 2	288	1973	2019	2019	0	0	0
Battle river station unit 4	155	1975	2025	2020	5	5.4	3.4
Sundance station unit 3	362	1976	2026	2021	5	12.7	7.8
Sundance station unit 4	406	1977	2027	2022	5	14.2	8.8
Sundance station unit 5	406	1978	2028	2022	6	17.1	10.6
Sundance station unit 6	389	1980	2029	2023	6	16.4	10.1
Battle river station unit 5	385	1981	2029	2024	5	13.5	8.3
Keephills station unit 2	395	1983	2029	2024	5	13.8	8.6
Keephills station unit 1	395	1983	2029	2025	4	11.1	6.8
Sheerness station unit 1	390	1986	2036	2025	11	30.1	18.6
Sheerness station unit 2	390	1990	2040	2026	14	38.3	23.6
Genesee station unit 1	400	1994	2044	2027	17	47.7	29.5
Genesee station unit 2	400	1989	2039	2028	11	30.8	19.1
Genesee station unit 3	466	2005	2055	2029	26	84.9	52.5
Keephills station unit 3	450	2011	2061	2030	31	97.8	60.4
Total					**151**	**433.7**	**268**

[a] Coal GHG intensity assumed to be 1008 kg CO_2e/MWh.
[b] Replacement GHG intensity assumed to be 390 kg CO_2e/MWh.

Rather, as those coal plants ceased to provide power for the public grid, the capacity factors would be increased in the other existing facilities so they were more in line with typical operational standards for those technologies. As a result, the reserve margin for the Alberta grid would be reduced to about 15%. Only after this criterion was met, we then implemented the five scenarios of building new capacity and bringing new generation onto the Alberta grid in order to meet growing demand, normal plant retirement dates, or early retirements of coal plants.

The generation technology most impacted by this assessment was NGCC which was allowed to increase to an annualized capacity factor of 85% (equivalent to a 90% load factor for 95% on stream, assuming that the units were down for maintenance for 5% of each year).

Other common principles used in creating the scenarios are summarized in Table 2. As shown in the schematic of Figure 2, the scenarios are built first by defining the annual contribution to generation (TWh) from each technology; then using a 'target' capacity factor, create a build scenario for new power plants. This build scenario also takes into consideration existing stock, and when that stock would normally be turned over (Figure 2).

The reserve margin is then calculated for the grid, and if new capacity is needed, it is provided as natural gas-single cycle (NGSC) that is assumed to have a capacity factor of 10%. The resulting NGSC generation modifies the original scenario generation profile

Table 2. Generation Parameters.

Generation Type	Build Size (MW)	Lifetime (years)	Target CF	CAPEX (2014$/kW)	Fixed OPEX (2014$/kW/y)	Variable OPEX (2014$/MWh)	Fuel Cost (2014$/GJt)	Fuel Cost (2014$/MWhe)	Heat Rate (GJt/MWhe)	Emission Intensity (kg CO_2/MWh)
Coal	450	50	80%	4350	37	7	$1.75	$16.80	9.6	1008
NGCC	300	25	85%	1725	23	5	$3.25	$24.85	7.6	390
NGSC	85	25	10%	1250	18	6	$3.25	$33.46	10.3	525
Cogen	85	25	85%	1750[a]	23	5	$3.25	$24.85	7.6	390
Hydro	100	100	54%	5550	21	0	$0.00	$0.00	0	0
Biomass	100	30	60%	4550	60	6	$0.00	$0.00	12	31
Wind	150	25	32%	2050	62	0	$0.00	$0.00	0	0
PV	100	25	15%	2500	46	0	$0.00	$0.00	0	0

[a] Cogen CAPEX is 75% of total capital cost (including HRSG).

and an iterative process is used to reach a balance of generation and capacity for each scenario and year. From these values, the 'actual' capacity factor is calculated for each technology and year, and calculations are also carried out for capital expenditure (CAPEX), operating costs (OPEX) and the levelized cost of electricity (LCOE).

The following five generation scenarios were created to explore the environmental and economic costs, benefits and trade-offs associated with possible energy futures for the Alberta grid.

S1. BAU 2015 – This scenario projects coal retirements after about 50 years, the policy that existed in early 2015, before the announcement of the new Alberta Climate Leadership Plan. Scenario S1 assumes that NGCC technology will be used to replace coal as the base load, and an additional 2 TWh per year of wind power will be added to the public grid by 2030. If more reserve capacity (to maintain 15%) is needed to back up the non-dispatchable wind power, it will be provided by NGSC generators.

S2. BAU 2015 Rnw – The BAU 2015 Rnw scenario is identical to S1, except it brings on an additional 12 TWh per year of wind and solar generation between now and 2030 to meet new demand and to replace the generation once provided by retiring coal plants. The 12 TWh value for renewable generation is chosen since it is one component of the government's new climate plan and it creates a reference scenario that can be used later to tease apart the environmental and economic implications associated with components of the new policy directive. In this scenario, NGCC technology will be used to replace retiring coal generation not satisfied by renewables. As with S1, this scenario uses NGSC generation to back up the non-dispatchable wind and solar power.

S3. BAU 2016 – The BAU 2016 scenario implements a version of the new Climate Leadership Plan in which all coal generation is retired by 2030, and two-thirds of coal capacity is replaced with renewables. For the renewables contribution, this is calculated as an additional 12 TWh per year of wind and solar generation by 2030, a value similar to that used in the recent AESO 2016 outlook[17]. NGCC technology will be used to replace retiring coal generation not satisfied by renewables. As with S1, this scenario uses NGSC generation to back up non-dispatchable wind and solar power.

17 Alberta Electric System Operator, AESO 2016 Long-term Outlook, May 2016.

S4. SAGD Max – The SAGD Max scenario is identical to the BAU 2016 scenario (S3) but instead of using NGCC to replace retiring coal generation not satisfied by renewables, this scenario expands the contribution of SAGD cogeneration (typically two 85 MWe Cogen units per 33,000 BPD facility) running with an annualized capacity factor of 85% (equivalent to a 90% load factor for 95% on-stream, assuming that the units were down for maintenance for 5% of each year). As with previous scenarios, NGSC generation is used to back up non-dispatchable wind and solar power.

S5 SAGD Rnw – The SAGD Rnw scenario is similar to the SAGD Max scenario (S4) but instead of scaling the number of SAGD Cogen units to meet the demand needs of the public grid, those units are scaled to maximize deployment, by 2030, based on two 85 MWe Cogen units operating at 55.3% Load Factor per 33,000 BPD facility. In doing so, the annualized capacity factor for the SAGD cogeneration units was only about 53%[18]. This leaves significant capacity that could provide the 15% reserve margin needed to back up renewables. If additional reserve margin is needed, NGSC generation can be called upon to back up non-dispatchable wind and solar power.

18 Equivalent to 55.3% load factor for SAGD cogeneration facilities running 95% of the time (down 5% for maintenance).

Table 3. Principles and assumptions for building the five scenarios for the Alberta electrical grid to 2030.

<table>
<tr><th colspan="2">Criteria</th><th>BAU 2015</th><th>BAU 2015 Rnw</th><th>BAU 2016</th><th>SAGD Max</th><th>SAGD Rnw</th></tr>
<tr><td rowspan="4">Overview</td><td>Coal Retire</td><td colspan="2">After ~50 years</td><td colspan="3">Coal retired by 2030 as per new policy</td></tr>
<tr><td>Renewables</td><td>Slow growth</td><td colspan="4">Rapid Growth to add ~12 TWhr of new Wind and Solar by 2030</td></tr>
<tr><td>Replacing coal?</td><td colspan="3">NGCC @ 85% CF</td><td>SAGD Cogen @ 85% CF</td><td rowspan="2">SAGD Cogen @ 53% CF then NGSC @10% CF</td></tr>
<tr><td>Renew. backup</td><td colspan="4">NGSC @10% CF</td></tr>
<tr><td colspan="7">Capacity and Generation Sources common to all scenarios</td></tr>
<tr><td colspan="2">Biomass</td><td colspan="5">Capacity projection increases from AESO 2016 LTO (from 409 to 658 MW in 2030) @ 60% CF</td></tr>
<tr><td colspan="2">Hydro</td><td colspan="5">Capacity projection increases from AESO 2016 LTO (hold at 894 MW) @ 54% CF</td></tr>
<tr><td colspan="2">Cogen: NonSAGD OS</td><td colspan="5">Includes CSS (from 252 to 422 MW in 2015), Mining (from 842 to 1011 MW in 2018), upgrading (371 MW); generation @ 65% CF</td></tr>
<tr><td colspan="2">Cogen: Industry</td><td colspan="5">809 MW @ 65% CF</td></tr>
<tr><td colspan="2">Cogen: Commercial</td><td colspan="5">44 MW @ 60% CF</td></tr>
<tr><td colspan="2">Cogen: Utilities</td><td colspan="5">421 MW @ 60% CF</td></tr>
<tr><td colspan="2">NGSC peaker</td><td colspan="5">996 MW @ 10% CF</td></tr>
<tr><td colspan="2">NGCC Existing</td><td colspan="5">1716 MW @26% CF in 2014. With first Coal retirement, CF rises to 85% CF as needed</td></tr>
<tr><td colspan="2">Cogen: SAGD basic</td><td colspan="5">'Average' Cogen as per Fig. 7 where AB has 1108 MW @ 75% CF in 2014. With first Coal retirement, CF rises to 85% CF as needed</td></tr>
<tr><td colspan="2">Imported Power</td><td colspan="5">Set at 1% of Alberta internal load</td></tr>
<tr><td colspan="7">Drivers for Scenario Differences in Grid supply</td></tr>
<tr><td colspan="2">Coal</td><td colspan="2">Declines from 6258 to 5389 MW in 2019, then from 2025-2030, declines to 2496 MW @ 75% CF</td><td colspan="3">Declines from 6258 in 2017 to 4060 MW in 2020, then gradually to 0 MW in 2030 @ 75% CF</td></tr>
<tr><td colspan="2">Wind</td><td>Rises slowly from 1178 MW in 2014 to 1943 MW in 2030 @ 32% CF</td><td colspan="4">Rises from 1178 MW in 2014 to 5100 MW in 2030 @32% CF</td></tr>
<tr><td colspan="2">PV</td><td>No PV in Scenario</td><td colspan="4">4-9 MW PV until 2025, then PV increases to 1009 MW between 2026 and 2030 @15% CF</td></tr>
<tr><td colspan="7">Scenario responses to above Drivers</td></tr>
<tr><td colspan="2">NGCC New</td><td colspan="3">New capacity built as needed, assuming 85% CF</td><td colspan="2">No new NGCC</td></tr>
<tr><td colspan="2">Cogen: SAGD New</td><td colspan="3">No New SAGD Cogen</td><td>New Capacity built as needed to meet power needs, assuming 85% CF</td><td>New capacity built as needed to max of ~8200 MW, but CF is ~53%.</td></tr>
<tr><td colspan="2">NGSC for Backup</td><td colspan="5">Capacity built in 85 MW steps to ensure ~15% reserve margin of dispatchable power, then generation calculated assuming 10% CF.</td></tr>
</table>

2.4. Extract Scenario SAGD Specifications

The facility model that was integrated into the grid model for the purposes of this paper is the same one that was used in Paper 1 [19]. It is based on a standard 33,000 BPD facility, and for the purposes of the current report, the SOR was fixed at 3.

This model uses industry data to calculate natural gas requirements, grid power requirements, BTF power requirements, power exported to the grid, the source of heat for steam production, and the GHG emissions associated with each of the calculated outputs. For a standard facility the heat demand for the steam is constant, but due to differences in efficiencies to create the steam from different technologies, the natural gas requirement changes. Also, adding Cogen reduces the amount of power demand for a plant as large fans are no longer required to move air through OTSGs for combustion, though smaller fans are required for the forced air duct burning.

Inputs into the facility model from the grid model include the capacity factor of the Cogen, the grid GHG intensity, and the number of Cogen units. The model then outputs the amount of energy going into steam production from the GT, from duct burning, from FA-DB, and from OTSGs, and the amount of electrical energy imported from the grid, used behind the fence, or exported to the grid for each type of facility (zero, one or two Cogen units). It also outputs the GHG emissions associated with the energy flows and the overall GHG intensity per barrel for each type of site.

GHG emissions are calculated by first determining the amount of heat produced by each technology. The heat produced by the gas turbine is variable based on the load factor of the turbine. A gas turbine has a heat-to-power ratio that can range from 1.19 at 100% load factor, to 1.79 at 50% load factor. The maximum fuel use allowable for duct burning is 40% of the fuel that goes into the gas turbine. Once this 40% limit is reached, all other heat must be produced by either forced air duct burning or OTSG. For sites with two Cogen units all of the additional heat required would be produced from FA-DB. For sites with only one Cogen unit only half of the steam comes from the gas turbine, duct burning, and forced air-duct burning, with the other half coming from OTSGs. Any produced gas consumed on the site was assumed to be consumed first by duct burning, then by forced air- duct burning, then by OTSG. For a typical site with Cogen, all of the produced gas would be consumed by duct burning. The produced gas has a higher GHG intensity of 99

19 Layzell DB, Shewchuk E, Sit SP, Klein, M. 2016. Cogeneration options for a 33,000 BPD SAGD Facility: Greenhouse gas and economic implications. CESAR Scenarios Vol. 1, Issue 3: 1-52.

kg CO_2/GJ compared to 49 kg CO_2/GJ for natural gas. All of the GHG emissions from duct burning, forced air-duct burning, and OTSGs are attributed to the SAGD operations. The GHG emissions from the gas turbine are split by assigning 390 kg CO_2/MWhe to the electrical power production, and the remainder is assigned to the SAGD operations.

2.5. Formula to Calculate Levelized Costs of Electricity

The levelized cost of electricity (LCOE) for the system was calculated by first calculating the levelized cost for each generation technology. The LCOE calculation is based on a standard formula that includes amortization of capital, fixed and variable operating costs, fuel cost and carbon levy as shown below[20]:

$$LCOE = \frac{Capital\ cost\ x\ CRF\ x\ (1-T\ x\ D_{PV})}{8760\ x\ CF\ x\ (1-T)} + \frac{Fixed\ O\&M}{8760\ x\ CF} + Variable\ O\&M + Fuel\ Price\ x\ Heat\ Rate + GHG\ Intensity\ x\ Carbon\ Price$$

and $$CRF = \frac{D(1+D)^N}{(1+D)^N - 1}$$

Where:

- Capital cost – The cost to build a new power plant in \$/MWe. For Cogen facilities only the portion attributed to power production was included. This was estimated to be 75% of the total capital cost.
- CRF – Capital recovery factor.
- T – Tax rate. Assumed to be 39.2% for all cases.
- D_{PV} – Present value of depreciation.
- CF – Capacity factor.
- 8760 – Number of hours per year.
- Fixed O & M – Fixed operations and maintenance cost of the plant per capacity in \$/MWe.
- Variable O&M – Variable operations and maintenance cost of the plant in \$/MWhe.
- Fuel Price – Fuel cost in \$/GJt
- Heat Rate – The efficiency of the generator in converting fuel into electricity in GJt/MWhe

20 LCOE formula and factors used are from http://en.openei.org/apps/TCDB/levelized_cost_calculations.html.

- GHG Intensity – Greenhouse gas intensity over the regulated limit in t CO_2/MWhe. The limit was set to 88% of emissions up to 2015, 85% emissions in 2016, 80% of emissions in 2017, and 390 kg CO_2/MWhe in 2018 and beyond.
- Carbon Price – The cost of GHG emissions in $/t CO_2. This price was set to $15/t CO_2 up to 2015, $20/t CO_2 in 2016, $30/t CO_2 in 2017 and 2018, increasing by 2% per year beyond 2018.
- D – Discount rate. Assumed xto be 7% for all cases.
- N – Life of the facility. This varies for each type of generation technology.

For the SAGD Cogen projects the LCOE was calculated before oil sands royalty. The overall grid LCOE was then calculated by summing up the LCOE for each technology multiplied by the percentage of the electricity produced by that technology over each year.

3. Scenario Results

3.1. Electricity Generation and Capacity Projections for Alberta

Using the approach defined in the previous sections of this report, five scenario projections were created for annual power generation in TWhe (Figure 8) along with the corresponding stock of generation capacity in GW (Figure 9). All of the scenarios meet the projected electricity demand in the province (Figure 5), and all maintain a reserve margin of about 15%.

Highlights of specific scenarios include:

- **In S1 (BAU 2015),** NGCC replaces coal generation as the coal plants retire after about 50 years (Figure 8), and in 2019, the generation capacity of the Alberta grid declines slightly (Figure 9) reflecting a decrease of the reserve margin to about 15%.
- **In S2 (BAU 2015 Rnw)** wind and solar are projected to add an additional 12 TWh of renewable power to the grid primarily at the expense of NGCC (Figure 8). As a result, a significant amount of new NGSC capacity is required (Figure 9) to

maintain the reserve margin at 15%. By 2030, grid capacity is at 21.7 GW in S2 compared to 17.1 GW in S1.

- **In S3 (BAU 2016),** the generation decline associated with the early retirement of coal plants (by 2030) is replaced by NGCC and new renewable generation (Figure 8), although the need to back up renewables required a significant build of new NGSC capacity (Figure 9). By 2030, grid capacity is at 21.9 GW.
- **In S4 (SAGD Max),** Cogeneration and renewables replace much of the generation lost through coal retirements (Figure 8), resulting in an increase in the capacity builds for Cogeneration, renewables and NGSC (Figure 9). By 2030, grid capacity is at 22.0 GW (Figure 9) and Cogen (including SAGD) accounts for 56% of total generation in the province (Figure 8).
- **In S5 (SAGD Rnw),** a much larger build of Cogeneration capacity is projected instead of NGCC and NGSC capacity (Figure 9), but much of this is used to back up renewables. The resulting generation profile is similar to S4 (Figure 8). By 2030, the total grid capacity is at 22.5 GW (Figure 9) and Cogen (including SAGD) accounts for 59% of total generation in the province (Figure 8).

3.2. SAGD Energy Flows and the Effect of Cogeneration

The projected role of Alberta's SAGD facilities in electricity production and end use for the five scenarios is provided in Figure 10. In the first three scenario projections (S1, S2 and S3), the existing SAGD Cogen facilities continue to meet their own power needs while providing surplus electricity to the grid, but new SAGD facilities are assumed to draw from the grid (Figure 10).

However, in the scenarios in which SAGD Cogeneration plays a major role in displacing coal-fired power (S4 and S5), there is projected to be an additional 28 (S4) or 31 (S5) TWhe per year of Cogenerated power being supplied to the public grid in the province by 2030 (Figure 10). Between 2020 and 2030, for every TWhe of SAGD Cogen power that is used behind the fence (BTF), 6.0 (S4) or 4.4 (S5) TWh of power is delivered to the public grid. That represents an increase from the current situation (and the S3 projection) where power to the public grid is only about 3.5 TWh for every TWh used BTF.

When the data on electrical energy flows in Figure 10 are converted from MWhe/yr to PJ/yr and plotted together with the flows of energy as steam for SAGD (also in PJ/yr), the results (Figure 11) show that the heat energy or steam demands dwarf those for electricity.

In this study, Cogen heat is assumed to include the heat that is captured from the gas turbine (GT) exhaust, duct burner (DB) and forced air-duct burner (FA-DB). Given that, in S1, S2 and S3, Cogen heat accounts for 27% of total heat demand for SAGD in 2015; this declines to 13% by 2030 (Figure 11).

However, in the SAGD Max Scenario (S4), by 2030 SAGD Cogen provides 58% of total heat demand for SAGD operations in the province. In this scenario in 2030, 85 MWe SAGD facilities occupied approximately 26 of the potential 98 locations (in 2030, there are approximately 49 SAGD facilities, each with two locations for 85 MWe Cogen units) for SAGD Cogen in Alberta (Figure 11).

In the BAU Rnw scenario (S5), SAGD cogeneration was scaled to occupy virtually all of the 98 potential sites in the province by 2030. In that year, Cogen-derived heat accounted for 100% of the total SAGD heat demand (Figure 11).

These results illustrate the potential for SAGD cogeneration to play a major role in delivering both large amounts of low-cost electricity to the public grid, as well as all the heat and power requirements for SAGD production.

3.3. Greenhouse Gas (GHG) Emissions (AB Grid + SAGD)

In 2015, the GHG emissions associated with the Alberta electrical grid and SAGD production are estimated to be 71 Mt CO_2/yr (Figure 12). In S1, these emissions were projected to peak at 83 Mt CO_2/yr in 2025 and then settle to 80 Mt CO_2/yr by 2030. By implementing a more rapid coal retirement by 2030 and committing to 12 TWh/yr of additional renewable generation, the BAU 2016 scenario (S3) projected total GHG emissions to peak at 76 Mt CO_2/yr in 2018 and then decline to 66 Mt CO_2/yr by 2030 (Figure 12).

Using the S1 scenario as a reference, by 2030, the S3 scenario would have an accumulated GHG emission reduction of 147 Mt CO_2 (Figure 12). Deconstructing these emissions for the BAU 2016 scenario (S3) it shows that over this period (2015 to 2030), annual emissions from SAGD production were projected to rise from 21 to 40 Mt CO_2/yr, reflecting the projected two-fold increase in SAGD production (Figure 3).

However, electricity-related GHG emissions between 2015 and 2030 were projected to decline from 53 to 28 Mt CO_2e/yr (Figure 12), despite a projected 1.2-fold increase in electricity demand over this period (Figure 5). Clearly, the decisions to speed the retirement of Alberta's fleet of coal plants, have a carbon tax on any generation with a GHG intensity at higher than 390 kg CO_2/MWhr, and integrate more renewables in the generation mix, all work together to account for this significant projected reduction in provincial GHG emissions.

By comparing S2 to the S1 reference, it is possible to estimate the separate contribution of the renewables policy and the early coal retirement policy to the projected cumulative 147 Mt CO_2 emission reduction (see Figure 12). The calculations show that about 28 Mt CO_2 of the reduction can be attributed to the renewables policy, so the remaining 119 Mt CO_2 can be attributed to the early retirement of the coal-fired power plants and their replacement with NGCC generation (Figure 12).

Comparing the SAGD Max scenario (S4) with the BAU 2016 scenario (S3) and the reference scenario (S1) shows that using SAGD cogeneration to replace coal instead of NGCC delivers an additional 23 Mt CO_2 in GHG emission reductions (Figure 12). In 2030, the total GHG emissions in the S4 scenario are 63 Mt CO_2/yr, versus 66 Mt CO_2/yr in the S3 scenario.

The additional 23 Mt CO_2 cumulative GHG reductions can be attributed to the SAGD cogeneration operations. While 2030 GHG emissions from the grid were similar in S3 and S4, 2030 SAGD emissions in S4 were 37.8 Mt CO_2/yr, 2.6 Mt CO_2/yr lower than that projected to occur in the BAU 2016 scenario (S3, 40.4 Mt CO_2/yr) (Figure 12).

The lower SAGD emissions were attributed to the greater efficiency associated with heat generation from GT and DB, and the lower electricity demand in SAGD cogeneration facilities than in those relying on the public grid and OTSGs for power and heat, respectively.

When SAGD cogeneration installations are maximized to both replace coal, and create a low-cost backup capacity for renewables (Scenario S5), the cumulative GHG emission reductions are, at 162 Mt CO_2, 15 Mt CO_2 lower than that for Scenario S3 (147 Mt CO_2) (Figure 12). The slightly higher emissions in S5 than in S4 can be attributed to the less efficient forced air duct burning, and the resulting higher electricity demand in these SAGD facilities.

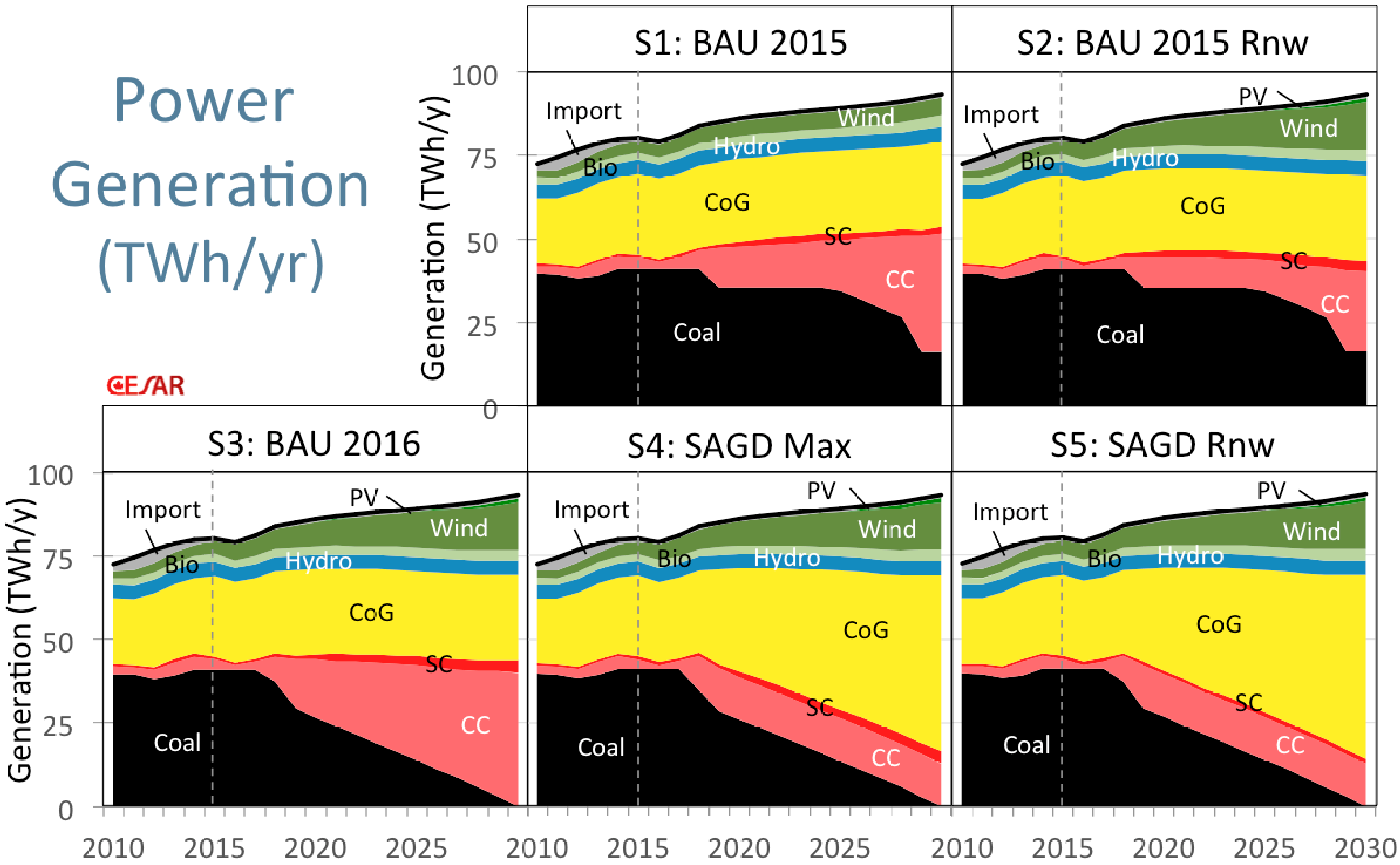

Figure 8. Comparison of five scenario projections (S1 to S5) for the generation of electricity in Alberta to 2030. The annual contribution of electricity to the entire Alberta grid in TWh is shown as stacked area plots. CC, natural gas combined cycle; SC, natural gas single cycle, CoG, Cogeneration (including all kinds as per Figure 6).

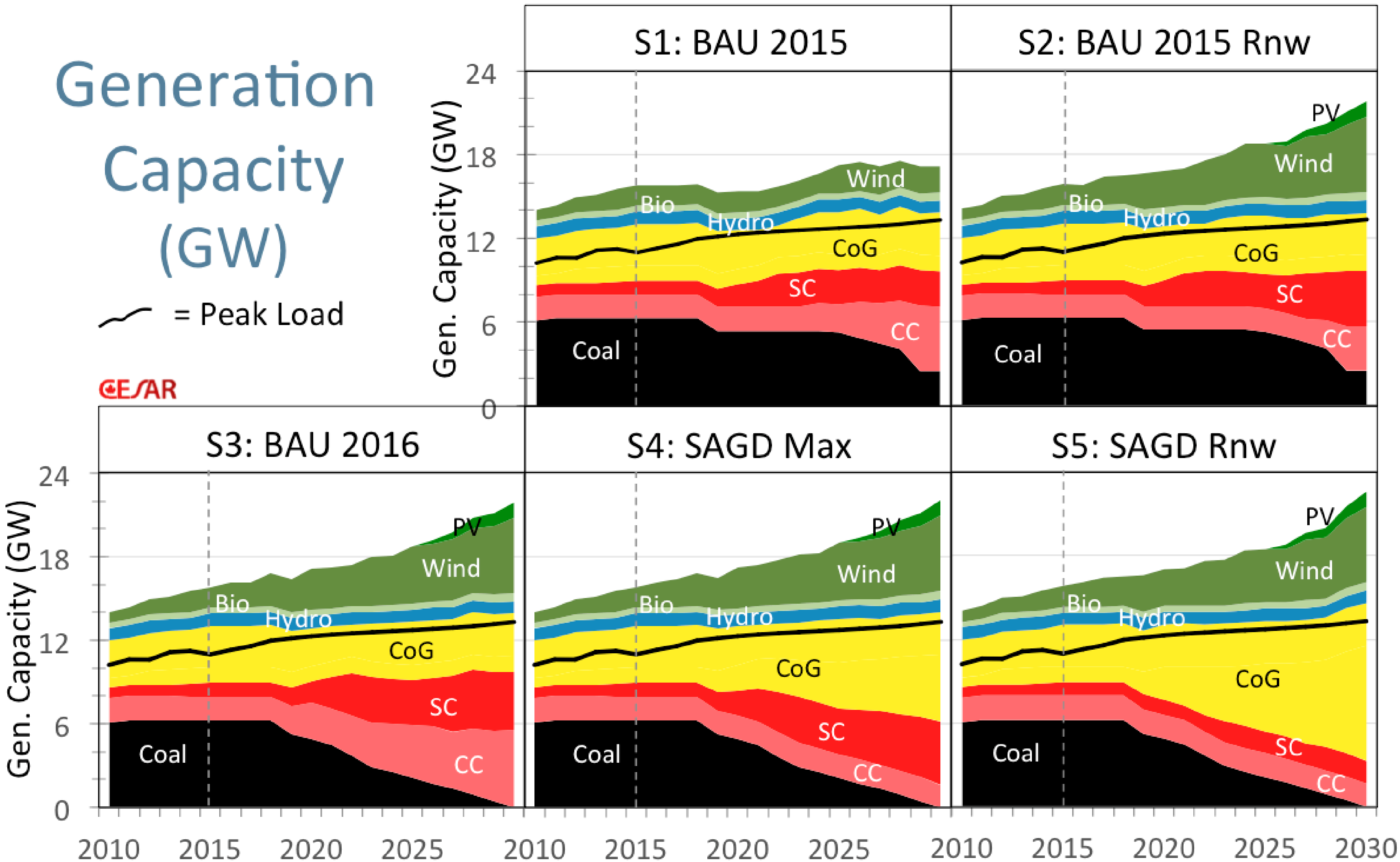

Figure 9. Comparison of five scenario projections (S1 to S5) for electricity generation capacity in Alberta to 2030. The capital stock of generation capacity in GW are shown as stacked area plots. CC, natural gas combined cycle; SC, natural gas single cycle, CoG, Cogeneration (including all kinds as per Figure 6).

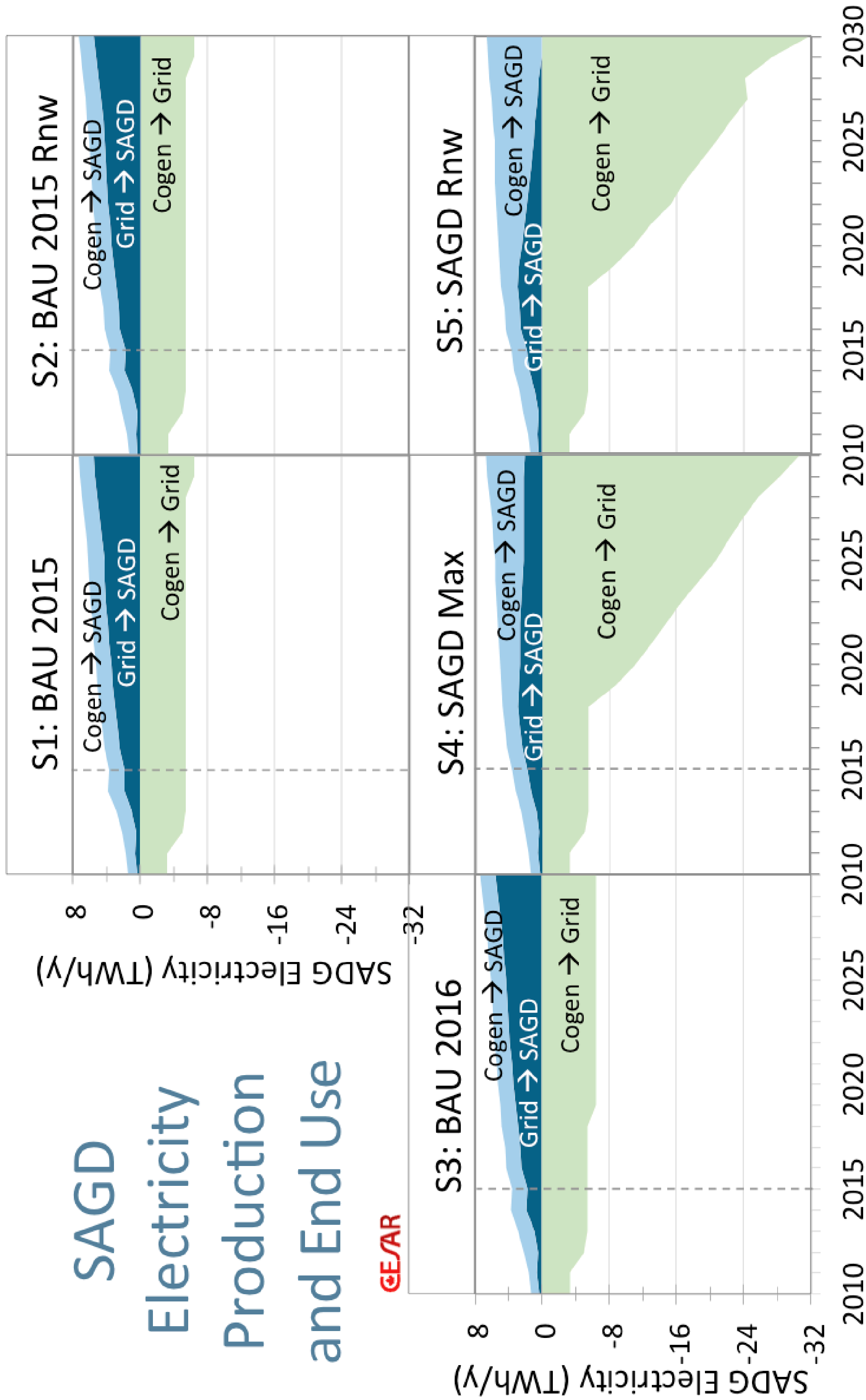

Figure 10. Comparison of five scenario projections (S1 to S5) for SAGD electricity production and end use in Alberta to 2030. Positive values represent that used within the SAGD facilities, whether imported from the public grid (dark blue) or generated on site (light blue). Negative values (light green) are generated on site and exported to the public grid.

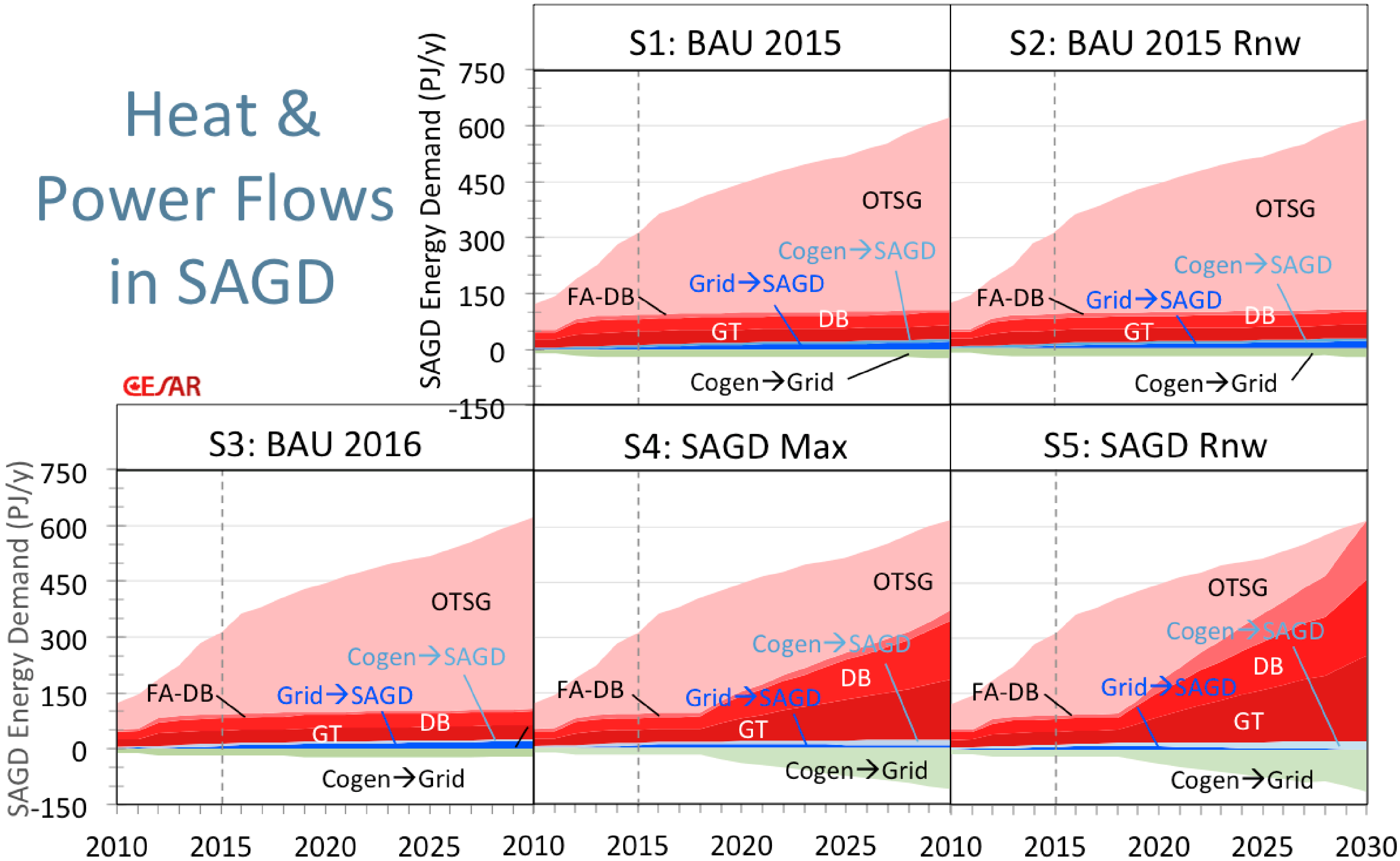

Figure 11. Comparison of five scenario projections (S1 to S5) for all heat and power flowing through SAGD facilities in Alberta to 2030. The electricity components are in green and blue and are the same as Figure 10 but converted to PJ from TWh. Heat for SAGD (PJ/yr) are in shades of red and include gas turbine (GT), duct burning (DB), forced air-duct burning (FA-DB) and once through steam generation (OTSG).

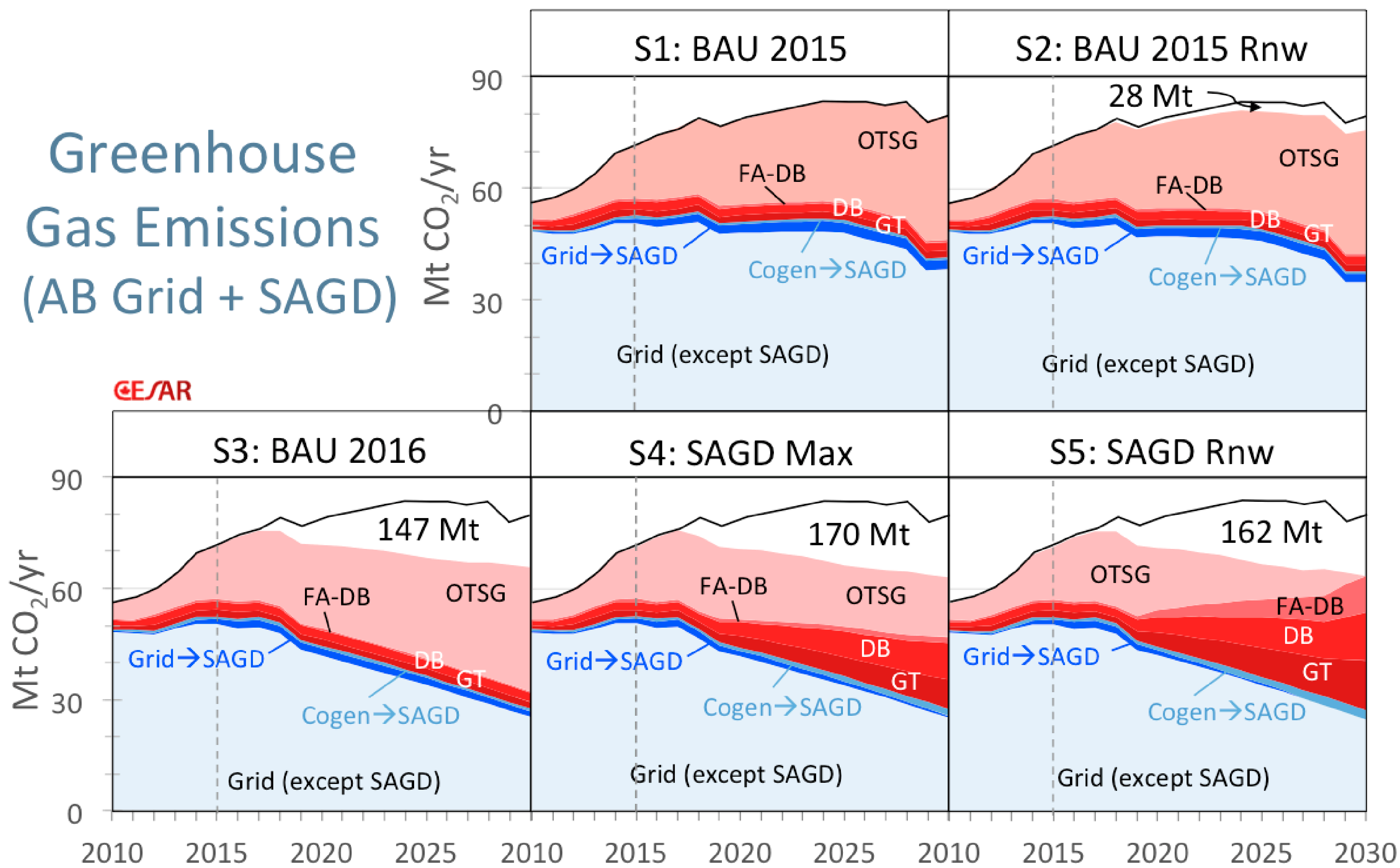

Figure 12. Comparison of five scenario projections (S1 to S5) for greenhouse gas emissions from the entire Alberta grid plus all SAGD facilities to 2030. The SAGD emissions for heat are in shades of red and are assigned to gas turbine (GT), duct burning (DB), forced air-duct burning (FA-DB) and once through steam generation (OTSG). The emissions for electricity are in shades of blue. The solid black line represents the total emissions from S1, and the number associated with the spaces on S2 to S5 represents the cumulative emission reductions in Mt CO_2 with respect to S1.

4. Levelized Cost of Electricity

The levelized cost of electricity was calculated for the entire grid for each of the 5 scenarios. Figure 13 shows how the cost is expected to peak in 2018 for all cases due, in part, to an increase in the carbon tax and the continuation of a grid with excess capacity. The price starts to fall after 2018 due to some coal retirements that are not replaced by new capacity, making the grid more efficient. Also, with these retirements, coal is a smaller portion of the overall grid and therefore the carbon taxes have a lower impact on LCOE. The cost of natural gas was assumed to be 2014$3.25/GJ and would hold steady from 2016 to 2030. This is a fairly low assumption, but the LCOE increases for all scenarios relatively equally with the increase in natural gas price, due to the fact that natural gas is a large component of generation in all scenarios.

The most expensive option is the BAU 2015 with renewables scenario (S2). This is because coal becomes more expensive due to the carbon tax and with more wind, there is need for NGSC to maintain the 15% reserve margin.

The least expensive options over the 2020 to 2030 period are the BAU 2016 (S3) and SAGD Max (S4) scenarios, due to the fact that the grid is more efficient (i.e. high capacity factor for NGCC and Cogen), and expensive coal is being retired by 2030.

It is important to note that these calculations do not consider the cost of transporting the electricity from the sites of generation to where it will be utilized within the province.

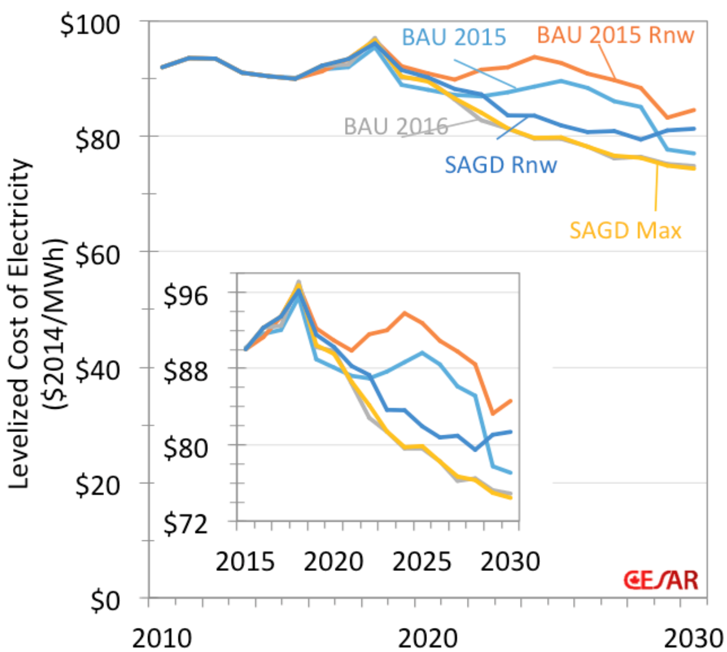

Figure 13. Levelized cost of electricity for the five scenarios. The insert figure provides additional detail.

5. GHG Intensity for SAGD & the Public Grid: Scenario Impacts

Standard Allocation of Emissions to SAGD and the Electrical Grid. In 2015 the average GHG emission intensity from SAGD production was 70.7 kg CO_2/bbl of crude oil, which is approximately three times higher than conventional oil production (Figure 14A). Assuming no new SAGD cogeneration in the next 15 years (S1 to S3; BAU 2015, BAU 2015 Rnw and BAU 2016), the GHG intensity is not projected to change in any substantive way (Figure 14A, solid lines).

However, with the addition of new SAGD cogeneration capacity in S4 (SAGD Max) and S5 (SAGD Rnw) scenarios, the average GHG intensity of SAGD oil sands crude is projected to decline slightly to 65 kg CO/bbl by 2030 (Figure 14A, solid lines).

If the GHG savings from SAGD cogen were only assigned to those barrels of oil sands crude that were produced from the heat generated by cogeneration (i.e. gas turbine + duct burning), GHG intensities as low as 60 kg CO_2/bbl could be obtained (Figure 14A, dashed line).

As noted previously (Figure 12), the systems level benefit of using SAGD cogeneration (S4, SAGD Max) instead of NGCC (S3, BAU 2016) to enable the early retirement coal by 2030 was estimated to be 23 Mt CO_2 between now and 2030, with presumably even more benefits accruing after 2030.

The calculations described above assume that the GHG intensity associated with putting electricity on the

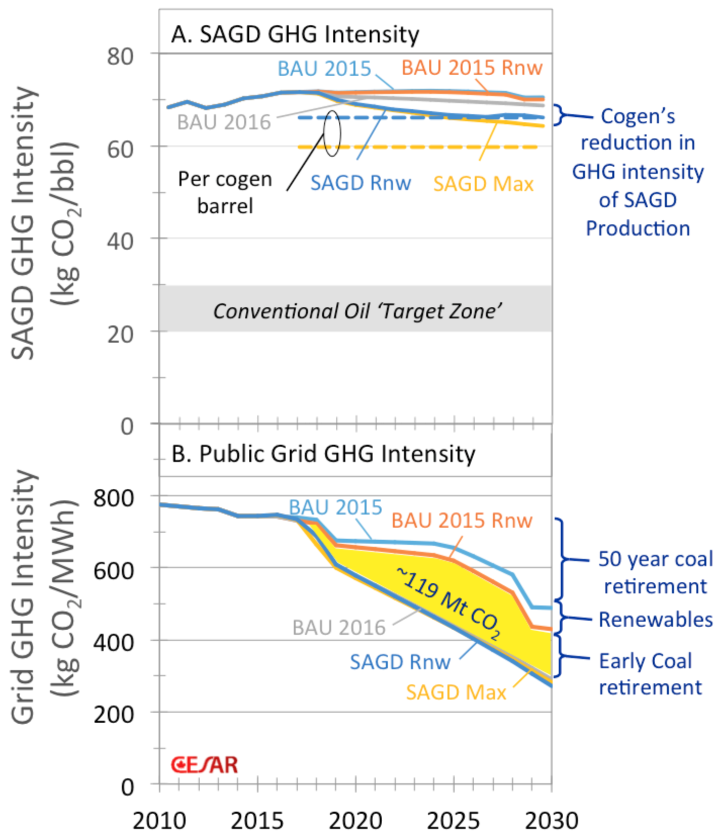

Figure 14. Comparison of the five scenarios for the GHG intensity of SAGD production (SOR=3) in kg CO_2/bbl (A), and of the public electrical grid in kg CO_2/MWh (B) assuming a standard allocation of emissions to the grid vs. oil sands crude production. In panel A, the shaded area shows the range of GHG intensities for conventional oil production. In panel B, the 119 Mt CO_2 comes from multiplying the highlighted area by the electricity consumption between now and 2030.

grid is 390 kg CO_2/MWh for both natural gas combined cycle and cogeneration. Given this assumption, scenarios S3 (BAU 2016), S4 (SAGD Max) and S5 (SAGD Rnw) show a significantly lower grid GHG intensity than S1 (BAU 2015) or S2 (BAU 2015 Rnw), scenarios that have a greater contribution from coal (Figure 14B). Over the period from 2017 to 2030, scenarios S3 to S5 have approximately 119 Mt CO_2 lower GHG emissions than, scenario S2 (Figure 14B). This number represents the GHG benefit associated with the early retirement of coal.

Allowing SAGD cogeneration operators to take temporary credit for the GHG reductions associated with the early retirement of coal. With the large scale incorporation of cogeneration in Alberta over the next 15 years, SAGD operators could play a major role in enabling the early retirement of coal plants in the province. If the resulting system level emission reductions were assigned to all SAGD oil sands crude production in the province, the GHG intensity would be between 40-50 kg CO_2/bbl (Figure 15A, solid line). However if the GHG benefits were only assigned to oil sands crude produced from cogen heat, then SAGD GHG intensity declines to between 2 and 30 kilograms of CO_2 per barrel, values equivalent to or better than conventional oil (Figure 15A, dashed lines).

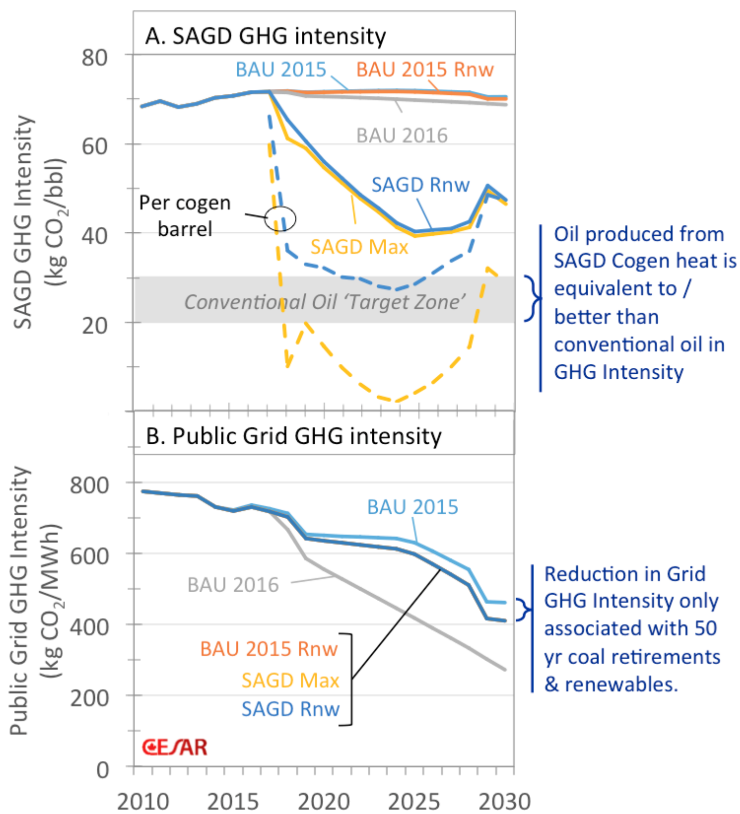

Figure 15. Comparison of the five scenarios for the GHG intensity of SAGD production (SOR=3) in kg CO_2/bbl (A), and of the public electrical grid in kg CO_2/MWh (B) when emission reductions resulting from the early retirement of coal are temporarily assigned to oil sands crude production. In panel A, the shaded area shows the range of GHG intensities for conventional oil production and the dashed line shows intensity values when emission reductions are assigned only to those barrels recovered with the heat from SAGD cogeneration. See text for other details.

Note that the calculated SAGD GHG intensities first decline and then rise again, reflecting the temporary nature of the GHG benefits. In other words, benefits from early coal retirement only accrue to SAGD production up to the point that the coal plants would have retired in any case. This would allow the SAGD facilities with Cogen to meet or surpass the GHG intensity of conventional oil production for about 10 years.

It would be important that during this time there was a strong incentive for SAGD companies to reduce the GHG intensity of oil sands recovery through other technologies so that their emissions do not spike once the credits begin to expire.

By assigning the GHG reductions to SAGD production, these reductions are no longer available to be assigned to the public electrical grid (Figure 15B). While the public grid's GHG intensity continues to decline over this period, its decline is not as rapid as in S3 (BAU 2016).

Figure 16 summarized the results of an accounting system that is in between the extremes envisaged in Figure 14 and 15. It assumes that 60% of the emission reductions on the grid for removing coal could be credited to the SAGD facilities. Average over all SAGD production, GHG emissions are a low of 50 kg CO_2/bbl in 2025 for S4 (SAGD Max), and 51 kg CO_2/MWh in 2025 in S5 (SAGD Rnw).

However, if the emission reductions are only attributed to oil produced from cogeneration heat, the intensity would go down to a low of 25 kg CO_2/MWh in 2024 for S4 (SAGD Max), and 43 kg CO_2/MWh in 2024 for S5 (SAGD Rnw). This puts the SAGD Max sites into the same GHG intensity range as conventional oil while at the same time reducing the public grid GHG intensity below S2 levels (Figure 16B).

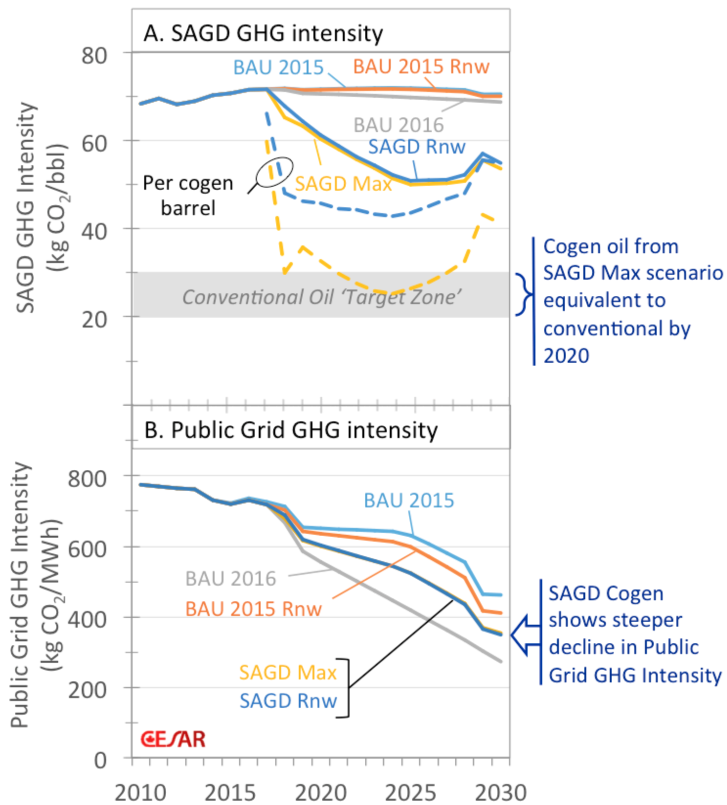

Figure 16. Comparison of the five scenarios for the GHG intensity of SAGD production (SOR=3) in kg CO_2/bbl (A), and of the public electrical grid in kg CO_2/MWh (B) when 60% of the emission reductions resulting from the early retirement of coal are temporarily assigned to oil sands crude production. In panel A, the shaded area shows the range of GHG intensities for conventional oil production and the dashed line shows intensity values when emission reductions are assigned only to those barrels recovered with the heat from SAGD cogeneration. See text for other details.

6. Allocation of GHG Emission Reductions from SAGD Cogeneration: Policy Considerations

The government of Alberta's climate leadership plan has identified multiple objectives, including phasing out coal-fired power, significantly increasing renewables in the electrical grid, implementing an economy-wide carbon levy, and putting an annual GHG emissions limit on the oil sands industry. To achieve these objectives, they have committed to finding cost-effective, collaborative, multi-stakeholder solutions.

The large-scale use of SAGD cogeneration not only aligns with these objectives and strategies, but also aligns with the oil sands industry's stated goal to become both 'cost-competitive' and 'carbon-competitive' with producers from around the world.

Between now and 2030, Alberta's existing and planned SAGD facilities have the potential to simultaneously:

- Replace coal-fired power generation on the Alberta electrical grid, at a lower cost and with lower GHG emissions compared to other sources of natural gas generation (e.g. combined cycle, single cycle);
- Allow for, and even provide a cost-effective backup for at least 12 TWh per year of additional, non-dispatchable renewable power generation like wind and solar;
- Reduce greenhouse gas (GHG) emissions by 15-23 Mt CO_2 more than would be achieved by Alberta's electrical grid assuming natural gas combined cycle (NGCC) is used to replace coal power instead of SAGD cogeneration;
- Provide reliable, base load generation to the Alberta grid that can stabilize supply and lower the cost to the users of electricity; and
- Reduce the greenhouse gas intensity associated with both the electricity grid, and the production of a barrel of SAGD oil sands crude.

The default strategy for early coal retirement is typically considered to involve the large-scale deployment of natural gas combined cycle (NGCC) technology to provide the base power for the province.[21]

21 Alberta Electric System Operator, AESO 2016 Long-term Outlook, May 2016.

With NGCC, coal could be eliminated from the grid and allowances could be made for an additional 12 TWh of renewables. However, the overall GHG reductions would not be as large as if SAGD cogeneration was deployed, and there would be no contribution to reducing the GHG intensity associated with producing oil sands.

Also, unlike NGCC, SAGD cogeneration would typically bid into the grid at a low or even zero dollars price to ensure steam supplies, so the province's electricity prices would probably be higher and less stable under the default NGCC strategy than under a SAGD cogeneration strategy. Clearly, compared to the default strategy of using NGCC and NGSC to transform the Alberta grid, SAGD cogeneration promises more benefits and therefore, it may be a better strategy.

"Clearly, compared to the default strategy of using NGCC and NGSC to transform the Alberta grid, SAGD cogeneration promises more benefits and therefore, it may be a better strategy."

While there may be some good economic and risk avoidance reasons for SAGD operators to install cogeneration on their facilities (especially to protect themselves from high and/or unstable electricity prices in the future), it is highly unlikely that SAGD operators would deploy cogeneration at the scale needed to achieve the government's policies for early coal retirement and/or enhanced renewables without some sort of policy incentive and certainty.

From a public policy perspective, the Alberta government has an opportunity to combine their objectives for greening the Alberta grid, and reducing the carbon footprint of the oil sands production. For example, if SAGD companies were to play a major role in achieving the early retirement of coal and the increase in renewables, perhaps they could be given the benefit to temporarily assign GHG reductions to the intensity of oil sands production. Eventually – for example, when the coal plants would have reached their retirement anyhow, or after a pre-determined number of years - those GHG emission reductions will no longer flow to oilsands production, but instead to the electrical grid. Hopefully, by that time new innovative more GHG-friendly technologies would be ready for deployment in oil sands operations.

"From a public policy perspective, the Alberta government has an opportunity to combine their objectives for greening the Alberta grid, and reducing the carbon footprint of the oil sands production."

After all, it is strategically more important to both the Canadian and the Alberta economies, that the province achieves a major reduction in the GHG intensity of its oil sands crude production, than a major reduction in the GHG intensity of the Alberta grid. Oil, after all, is a major export commodity while electricity is simply a domestic energy currency. From a climate change perspective, the atmosphere does not 'care' about the origin of the emission reduction, only that it occurs.

"...it is strategically more important to both the Canadian and Albertan economies, that the province achieves a major reduction in the GHG intensity of its oil sands crude production, than a major reduction in the GHG intensity of the Alberta grid."

Table 4 provides the pros and cons for granting to SAGD oil sands crude, a portion of GHG reductions that SAGD cogeneration achieves for the grid through early retirement of coal. While the creation of a major eco-industrial cluster in Alberta is not without significant challenges, the upside opportunity for both the province and its most important industry, demands that options for deployment be carefully considered.

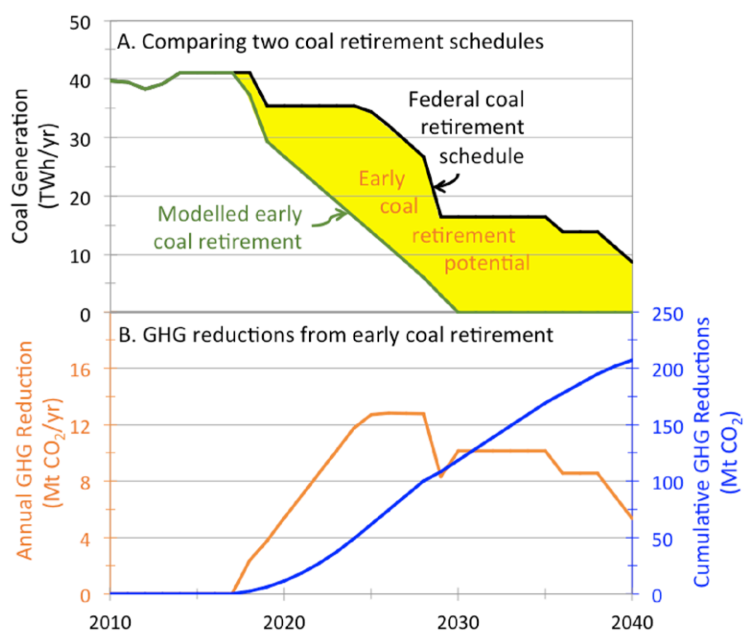

Figure 17. Comparison of two coal retirement schedules for Alberta (A), and the impacts on annual and cumulative GHG emissions reductions (B). Calculated from the data provided in Table 1.

Some of the policy options for consideration that are offered in Table 4, include:

- **Temporary credits.** If new SAGD cogeneration capacity is formally linked to the early retirement of a coal plant, GHG credits would only be allowed for the years ahead of scheduled plant retirement (Figure 17A, yellow shaded section), with additional restrictions that might include a maximum number of years of credit that would be allowed per plant (e.g. 8-10 years), or no credits of this nature allowed past a given date (e.g. 2035). Figure 17B (blue line) shows that the cumulative GHG reduction benefit of the modelled scenario would rise from 119 Mt CO_2 by 2030, to 169 Mt CO_2 by 2035, and 207 Mt CO_2 by 2040.

- **Creation of Low GHG 'cogen' barrels.** To incentivize SAGD companies to maximize cogeneration on their facilities, the proportion of the total facility's crude output that was produced from the gas turbine heat, or duct burning heat could receive all the GHG credit, thereby branding them low GHG 'cogen' barrels. Such barrels could attract a premium price in a way that is similar to the premium price that is paid for wind power sold into the electrical grid. However, a market would need to be developed for such a product.
- **Energy Efficiency Standard for Power Generators.** Given the scale of the industrial and commercial heat demand in Alberta, possibly require all new base load thermal power generation to use at least 70% of the energy in the fuel. This would create a barrier for the deployment of stand along NGCC generation, and stimulate cogeneration in sectors across Alberta, including SAGD oil sands operations.

The purpose of this report is not to prescribe government policy in this area, but to identify a significant, but largely overlooked opportunity for the Alberta government to achieve a number of the stated objectives under its climate leadership plan.

Given the importance of oil sands production and export to the economies of Alberta and Canada, industry, governments and environmental groups should explore the barriers and opportunities for large-scale deployment of SAGD cogeneration that would clearly position oil sands companies as being part of the solution to the challenges of climate change, not only part of the problem.

Table 4. Pros, cons and policy considerations for granting to SAGD oil sands, GHG reductions that SAGD operations achieve in supporting early retirement of coal. The assumption in preparing this table is that if SAGD Cogeneration is not involved in the early retirement of coal, it would be achieved by the utility level deployment of natural gas combined cycle (NGCC) plants to provide base power, and natural gas single cycle (NGSC) plants to provide the backup plants/reserve margin needed to support renewables.

Criteria	Pros	Cons	Policy Considerations
ENVIRONMENTAL	Compared to NGCC, SAGD Cogen is more efficient and reduces Alberta's overall GHG emissions, by an additional 15-23 Mt CO_2 between now and 2030. [This is in addition to the ~119 Mt CO_2 of emission reductions that early coal retirement will deliver to the public grid regardless of whether the coal is replaced by NGCC or SAGD Cogen.]	In the late 2020s, early retirement of a coal facility, could mean that SAGD facilities would receive from 11 to 31 years of GHG credits (Table 1, Figure 17), and that would reduce incentives for them to invest in transformative technologies that will actually reduce direct GHG emissions from oil sands production.	Possibly restrict the number of years the credits can be transferred (e.g. 8-10 yrs), the end date that transfers would be allowed (e.g. 2035), or the proportion of grid emission reductions that could be transferred. Should these temporary credits be allowed to reduce the oil sands sector's calculation of the 100 Mt annual cap? To incentivize individual operators, the temporary credits could allow them to market their cogen-produced oil as equivalent to or lower than conventional oil in terms of GHG footprint. Given the scale of the industrial and commercial heat demand in Alberta, possibly require all new base load thermal power generation to use at least 70% of the energy in the fuel.
ECONOMIC	SAGD cogen should reduce and stabilize cost of power compared to NGCC. Provides SAGD operators with a second source of income, and reduces exposure to high NG cost, both important in a world of low oil prices Positive net present value ($90M-$190M) in all Cogen Cases relative to Base Case (no Cogen)	While NGCC can be strategically placed in the province, SAGD cogen must be located at SAGD sites, potentially increasing the transmission cost (not calculated here); Requires cooperation between utilities and SAGD companies to coordinate retirement of coal assets with new SAGD cogeneration facilities and government policies (potentially involving financial or other forms of compensation) Changes may be needed in the market system for electricity in the province Requires innovative, 'out-of-the-box' thinking by government on policies	A study is needed to assess the implications of a SAGD cogeneration strategy on the power grid infrastructure in the province, especially when there is to be a major growth in renewables. More detailed economic analyses are needed to bring together issues around coal retirement polices, Power Purchase Agreements etc

Criteria	Pros	Cons	Policy Considerations
SOCIAL LICENSE/ PUBLIC ACCEPTANCE	The oil sands industry is currently only seen as 'part of the problem' of climate change: SAGD Cogen positions them as 'part of the solution.' With SAGD cogen coupled to early coal retirement, large emission reductions can be seen quickly (within a few years) Encourages multi-stakeholder collaboration (oil sands and utilities sectors) to provide solutions, which aligns with Alberta government's objectives in finding solutions to climate challenges Enhances Alberta's reputation as an environmental leader in the forefront of transitioning to lower-carbon energy systems	Historical reluctance by oil sands industry and utilities to work together as they can consider themselves as competitors regarding power generation. Potential opposition by some individuals or groups who want to stop oil sands development regardless of performance improvements. No guarantee that this approach would secure public/ENGO acceptance of new oil sands infrastructure, including bitumen export pipelines.	Gain support of industry sectors and ENGOs before announcing any new policy (use the sort of multi-stakeholder collaboration approach that led to Alberta Climate Leadership Plan) Have in place a strategic communication plan/rationale to accompany public announcement of any new policy. Government could provide non-financial incentives (e.g. reallocation of carbon credits, innovative PPAs, etc.) for industry sectors to work together. Perhaps provide incentives through province's royalty regime or a reduction in carbon tax to SAGD operators who invest in expanded and new SAGD Cogen.

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