Scenario-Based Assessment and Projection of Water Use for the Canadian Oil and Gas Sector and Several Low-carbon Technologies Available to the Oil Sands

by

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Abstract

The Canadian oil and gas sector is a significant contributor to Canada's economy, greenhouse gas (GHG) emissions, and water use. Society is increasingly focused on GHG emissions, and it is broadly recognized that GHG reductions in the oil and gas sector have an important role in Canada's meeting its national targets. The oil and gas sector has set goals to reduce its GHG emissions by reducing the emissions intensity of its products. As the sector as a whole and the oil sands in particular are regionally significant water users, changes in sectoral activity or technological makeup due to these GHG emissions reduction options may have significant impacts on local water resources. There has been limited focus on the assessment of integrated GHG and water footprints of oil sands sector. This research is aimed at addressing these gaps.

This thesis describes the bottom-up modelling of long-term water use of the oil and gas sector under several production scenarios and long-term water-use impacts of several GHG-reducing technologies in the oil sands in order to develop integrated cost-GHG-water use impacts for those technologies. The Canadian Water Evaluation and Planning Model (WEAP-Canada) was expanded and used to project the long-term water use of six oil and gas subsectors in nine provinces. Nineteen rivers were considered, and water use was projected on an annual basis. The added features of the model include variable water-use intensities for several subsectors over the historic period, updated production scenarios, and additional baseline water-use data. The model outputs were validated using historic water-use data from 2005 to 2017, and the water-use projections are presented for 2020 to 2050.

Four water-use projection scenarios were established based on production projections from the Canadian Energy Regulator (CER) and represent their reference case, the evolving climate policies scenario, a low oil and gas price scenario, and a high oil and gas price scenario. The reference scenario water projection showed an increase from the sector's national annual water consumption of 317 million cubic metres (MCM) in 2020 to 409 MCM (+29%) by 2050. The subsectors with the largest contribution to this increase are natural gas and surface bitumen mining, which over this period increased their consumption

by 30 MCM (+104%) and 18 MCM (+11%), respectively. The low and high price scenarios had a 2050 sectoral consumption of 278 MCM and 526 MCM, representing increases from the 2020 total of -12% and +65%, respectively, and differences from the reference case 2050 total of -32% and +29%, respectively. A fifth water projection scenario was established based on assumed changes in the future water-use intensity of individual oil and gas subsectors.

WEAP-Canada was then integrated with the previously developed Canadian Low Emission Analysis Platform (LEAP-Canada) model to allow the water-use impacts of several oil sands low-carbon technologies to be projected. Nine low-carbon technologies were considered, and their previously developed adoption rates across three carbon price scenarios were used alongside newly introduced water-use intensity parameters to estimate each technology's annual water use under each carbon price. The cumulative 2020-2050 marginal water consumption by pathway ranged from +753 MCM (increased consumption) in the hydropower-electrolysis pathway, to +4 MCM in the biomass gasification pathway, to -182 MCM (decreased consumption) in the SAGD cogeneration pathway. An indicator representing the amount of water consumed to achieve GHG emission abatement for each pathway showed that between +188 m^3/tCO_2e (hydropower-electrolysis, increased consumption), +1.04 m^3/tCO_2e (biomass gasification), and -2.49 m^3/tCO_2e (SAGD cogeneration, decreased consumption) is required. The effects of several carbon price points between \$0/tCO_2e and \$50/tCO_2e were also quantified.

These results provide clarity on how technology and production outlook changes occurring in the sector will affect the less addressed but important measure of water use. This information ultimately provides a range of watershed-resolution annual water use information for the sector and quantified relationships among several environmental impacts of low-carbon technology options for industry leaders and policymakers.

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List of abbreviations and terms

AB	Alberta
AER	Alberta Energy Regulator
bbl	Barrel (volume)
BC	British Columbia
BCOGC	British Columbia Oil and Gas Commission
CAPP	Canadian Association of Petroleum Producers
CER	Canadian Energy Regulator
CER EF	Canadian Energy Regulator’s Canada’s Energy Future
CFA	Canadian Fuels Association
CNRL	Canadian Natural Resources Limited
CSS	Cyclic steam stimulation
HMSF	Hydraulic multistage fracturing
LEAP	Low Emission Analysis Platform
MAWCR	Marginal abatement water consumption rate
MCM	Million cubic metres
OSA	Oil sands area
PSAC	Petroleum Services Association of Canada
SAGD	Steam assisted gravity drainage
SCO	Synthetic crude oil
WEAP	Water Evaluation and Planning

1 Introduction

1.1 Background

1.1.1 Energy and water nexus

Oil and gas products play a crucial role in modern society as energy sources, flexible energy carriers, and feedstocks for many hydrocarbon-derivative products such as plastics. Oil accounted for 31.5% of global primary energy in 2018 according to the International Energy Agency (IEA) [1]. The IEA's modelling of several global development scenarios found that oil and gas will provide a significant portion of global energy for decades even in the most progressive scenarios [2]. It also notes that new upstream developments are required to replace decreases in existing capacity even in the most rapid energy transitions.

Water is a crucial resource for society, being a critical component of municipal life, agriculture, and industry. Water should be thought of as a regional resource, as its being in excess in an area does not provide a particular benefit, and water can be expensive and challenging to move to areas with water scarcity [3]. Long-term management of water resources is a prudent endeavour for the government, as managing demand is usually cheaper than increasing supply, and water shortages can be costly to environmental health and economic activity. An example of a particularly dire outcome of poor management is the shrinking of the Aral Sea, caused in large part by diverting water for agriculture, and the subsequent ecological and economic hardships that have followed [4]. The goal of water resource management could perhaps be described simply as allowing productive access to water for civil and industrial users while avoiding the negative outcomes associated with water shortages. Understanding various aspects of current and future water use is a crucial step in successful management.

The oil and gas sector is closely tied to water resources. Though the sector affects water resources in several different ways [5], this study is focused on its quantity of water use. Many parts of the sector require large volumes of water for normal operations, for instance, for steam generation, cooling, as an injection fluid, or other process needs. While some water-intensive industries may choose to locate their operations at a site with abundant access to water, many oil and gas operations do not have such an option. Much of the oil and gas sector's water use occurs during the extraction stages and is therefore located where the resource is rather than at a site selected for the availability of water. Since this water use is based on the geographic distribution of the hydrocarbon resource, in some cases it may be geographically concentrated in an area with limited water. In Canada, a significant portion of oil production occurs in the Athabasca watershed area, where the sector is responsible for around 67% of total societal water withdrawals [6]. Many methods of producing oil and gas involve large infrastructure assets that are stationary and have long lifespans. Development decisions can lock in water use and other environmental impacts in these cases for decades. This future impact of current development decisions accentuates the importance of long-term planning, especially considering that climate change is expected to continue to affect water resources in many regions [7].

It is broadly recognized that to meet the Paris Agreement targets, anthropogenic greenhouse gas emissions must be rapidly reduced in the coming decades. Placing a financial cost on the emission of GHGs (often referred to as carbon pricing or a carbon price) is one approach to encourage producers to reduce emissions. While Canada did not implement a federal carbon price until 2019 [8], several provinces implemented carbon price plans earlier. Alberta's first carbon-pricing regime was introduced in 2007 and required large industrial emitters to reduce their emission intensity over time or pay compliance fees [9], and that same year Quebec implemented flat prices on several common fossil fuels [10]. These measures and others have caused many industries, including the oil and gas sector, to recognize the importance of reducing GHG emissions, at least for fiscal reasons. One approach that several oil companies have taken is to reduce the per-barrel GHG emission intensity of their production rather than aiming for an absolute GHG emission reduction. This could allow continued expansion of annual production while meeting an emission intensity goal and allows novel technologies to be introduced in new projects rather than as potentially more expensive retrofits to existing projects. It is not immediately clear if this approach will support Canada's efforts to meet its GHG reduction goals, but it is a potentially viable business path to allow these for-profit companies to mitigate the effects of carbon pricing on their fiscal performance. The GHG emissions from the oil and gas sector accounted for over 20% of Canada's total GHG emissions from industry and households in 2019 [11], and thus a reduction in the GHG emissions of the sector may be a crucial facet of Canada meeting its national targets [12].

Numerous changes have occurred in the oil and gas industry in Canada in the past twenty years, including a tripling of overall production from the oil sands. This expansion has seen a significant shift in production techniques, with mined bitumen more than doubling in production and in situ bitumen quintupling [13, 14]. Today, the volume of production by the surface mining and in situ subsectors is similar, though in situ output is slightly higher. Various technologies that reduce the GHG intensity of oil production have been introduced or further embraced, including on-site natural gas cogeneration and paraffinic froth treatment [15]. Further GHG reduction efforts in the sector are expected to be driven by financial and industrial policy considerations and will likely involve multiple novel and emerging technologies.

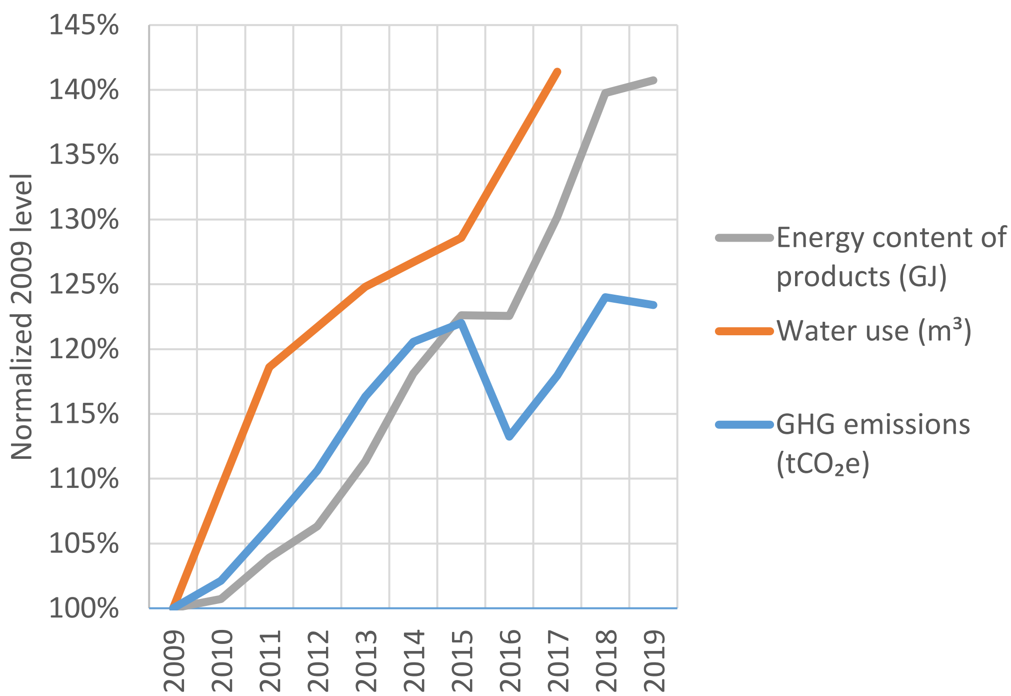

Figure 1: Canadian oil and gas sector energy content of products, water use, and GHG emissions normalized to 2009 levels [11, 16, 17]

Because of the sizeable increase in overall oil sands production in the last two decades, the water use and GHG emissions of the sector have significantly increased, as shown in Figure 1. Further expansion of oil sand production and the introduction of new lower-carbon technologies will further affect the water use of the sector. Understanding the interaction of these past and future changes is important for ongoing water resource management efforts to be effective.

1.1.2 Canadian water resources overview

Canada is by some measures extremely well endowed with fresh water. An estimated 76,000 m^3 of fresh water per capita is available annually, a ranking among the highest in the world [18]. These resources are, however, highly unevenly distributed throughout the country. For example, the Northwest Territories and Nunavut (34% of Canada by area) together have 18% of Canada's annual runoff but only 0.2% of its population [19]. The major north-flowing river system that makes up this flow is the Mackenzie River, of which the Athabasca and Peace rivers are tributaries. The St. Lawrence River in Ontario and Quebec and the Fraser River in BC are among the other large rivers in Canada. Canada also has many freshwater lakes, including Lake Huron, Great Bear Lake, Lake Superior, and Great Slave Lake.

The Earth's climate is changing, and Canada's is no exception. Temperatures are increasing across the entire country at a faster rate than the global average [20]. Precipitation and evapotranspiration changes will affect freshwater availability differently across Canada. Increases in annual flows in most northern basins and decreases in annual flows in most southern basins are projected [7]. The seasonal timing of flows is also expected to change, with higher winter flows and lower summer flows projected for many basins.

The distribution of water use in Canada by sector is approximately 66% in the power sector, 10% in agriculture, 9.4% in manufacturing, 7.4% in residential, 5% in commercial and institutional, and 1.5% and 0.7% in mining and oil and gas extraction, respectively [21]. The region-level distribution varies significantly. The power sector's water use is largely from once-through cooling, which is used in Ontario and Atlantic Canada. In Alberta, the sectors that use the most water are agriculture (44%), power (33%), residential (6.8%), manufacturing (6.8%), and oil and gas extraction (5.9%). Alberta is the province with the highest portion of its provincial water use occurring in the oil and gas extraction sector compared to the oil and gas extraction sectors in other provinces in Canada. The next highest portion of provincial water use dedicated to the oil and gas extraction sector is 1.6% in Saskatchewan, followed by 0.18% in British Columbia. The above numbers are based on categorizing oil and gas extraction separately from the activity of oil refining, which is included in the manufacturing sector. Nonetheless, the extraction of oil and gas is a relatively minor driver of water use in most provinces. Even in provinces with a large oil and gas sector, its water use is much lower than in other sectors. Watersheds where oil and gas activity is concentrated may locally experience a larger portion of their water use occurring in the oil and gas sector. The Athabasca River Basin is the location of the oil sands surface mines, and in 2005 nearly half of water-use allocations in the watershed have been for oil and gas activity, and this proportion has since grown [22]. Allocations for oil and gas in the Peace River watershed are aggregated into a single "industrial" category, which accounts for 10% of surface water allocations and 51% of groundwater allocations [23]. Development of in situ oil sands and heavy oil deposits are singled out as the main drivers of recent (2011 to 2015) growth in watershed-wide water use [23]. The Bow River Basin is among the most water-stressed regions in Alberta, though oil and gas water use amounts to less than 1% of total basin use [24].

Water management in Canada occurs at several jurisdictional levels, as the resource is considered to be owned and governed on a day-to-day basis by provinces, though the federal government has specific areas of jurisdiction, such as overseeing fisheries [25]. Alberta will be discussed here as an example of how provincial-level management can be formulated. Water in Alberta is formally managed under Alberta Environment through the Water Act, and various agreements have been made with neighbouring jurisdictions regarding border-crossing rivers [26]. Watershed Planning and Advisory Councils (WPACs) are multi-stakeholder organizations that can explore issues related to individual watersheds. Specific water-management issues may also be solved through projects involving the collaboration of the government, WPACs, and other stakeholders, such as the Bow River Project, which explored options for adjusting how the river is managed [27].

1.1.3 The oil and gas sector in Canada

Canada has a large oil and gas sector that ranks fourth in global crude oil production and fifth in natural gas production [28]. The sector also includes several activities and outputs other than the extraction of its two titular products. For this thesis, the refining of crude oil is considered part of the oil and gas sector. Various methods are used to produce these resources, and these methods have changed over time as new technologies or novel applications of old technologies have allowed access to new resources.

A key component of the oil and gas sector in Canada is the oil sands industry, whose production of bitumen has represented the majority of Canada's oil production since 2009. Bitumen is a heavy hydrocarbon that can be extracted from oil sand deposits. Oil sands are the naturally occurring mixed deposits of bitumen, water, sand, and clay, located primarily in parts of Alberta and Saskatchewan. Bitumen is in many ways dissimilar to more standard varieties of crude oil, with a viscosity high enough that it cannot be transported in a pipeline without diluents and requiring more complex infrastructure to refine. The two main methods of production are surface mining of oil sand deposits with excavating equipment and in situ production using steam to heat the bitumen sufficiently that it can be separated and extracted from the deposit. The primary immediate uses of bitumen are the production of synthetic crude oil for later refinement or the direct production of refined petroleum outputs (such as diesel and gasoline). Because of this, it is often described alongside other crude oils by groups like the CER and IEA [16, 29]. Throughout this thesis, the oil sands industry is broadly separated into bitumen mining (i.e., surface mining of bitumen deposits), in situ bitumen (which includes several technologies that use steam to extract bitumen from underground reservoirs), and bitumen upgrading (which is the processing of bitumen to produce a pipeline-capable product; upgrading may be integrated with surface mining sites or operated out of stand-alone facilities).

Though bitumen represents the majority of Canada's oil production, the oil and gas sector also produces large quantities of standard crude oil. The original methods for extracting crude oil used in-reservoir energy to move oil to the surface, referred to as primary production. The release of in-reservoir energy elicits images of famous oil gushers. Though modern technology has made oil spraying uncontrollably out of a drilling derrick a rare sight, the underlying phenomenon is similar. Additional oil can be produced from a reservoir by injecting water, gas, or steam. Such techniques are referred to as secondary and tertiary production. Recent advances in directional drilling and multistage hydraulic fracturing have allowed access to new oil reservoirs that were previously inaccessible. In this thesis, oil produced through primary, secondary, tertiary, and fracturing methods is generally referred to as conventional oil.

Natural gas is another major output of the oil and gas sector. Typically composed primarily of methane, natural gas is extracted from underground reservoirs through wells. Traditionally wells have been vertically drilled. Though several methods of fracturing have long been available, recent advances in directional drilling and other technologies have allowed multistage hydraulic fracturing to emerge as a commonly used well creation technique because it allows access to resources previously unobtainable. Fracturing techniques have long been used, but their recent expansion in use is a significant enough trend that this thesis addresses wells created by fracturing separately from other conventional means.

Figure 2 shows the recent and projected changes in several common products of the sector, which highlights the continued expansion of oil sands production and continued decline of light conventional crude.

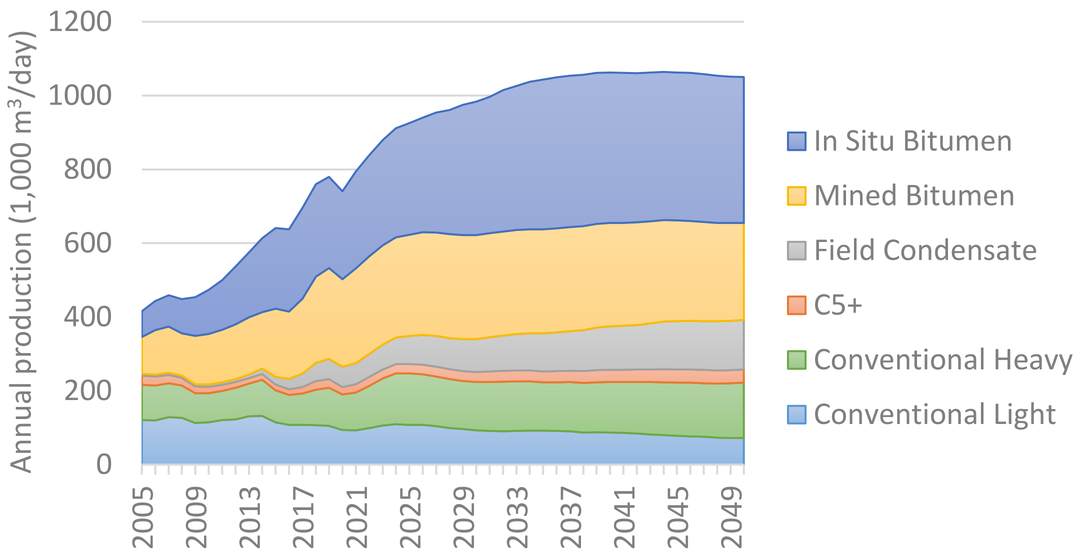

Figure 2: Historic and projected production of several types of crude oil or related products (from the CER [16])

1.1.4 The electricity sector in Alberta

Though the electricity sector is not the primary focus of this research, it does intersect in some important ways with the oil and gas sector in Alberta. Specifically, the constant need for process heat at some oil sand sites is an opportunity to use natural gas-fired cogeneration technologies to produce heat and electricity simultaneously. This electricity may be consumed on-site or exported to the rest of the grid, but, either way, the effect is generally to reduce electricity generated elsewhere in the province and thus the effects that generating electricity at oil sand sites has on water use depends on the nature of the provincial electricity grid.

The primary method of generating electricity in Alberta has long been through the combustion of coal. As recently as 2014, coal- and coke-based generation accounted for most of the electricity production in Alberta, and in 2021 it was approximately one-third [16]. Coal-based electricity generation throughout the province has been declining as a proportion of total generation since at least 2005, most significantly since 2018 as plants close or are retrofitted to use natural gas, with the remaining capacity scheduled to be taken off the grid in 2023 [30]. The main fuel replacing coal is natural gas, whose combustion is projected to make up 75% of electricity generation in Alberta by 2025 before slowly declining in the following decades [16]. The addition of natural gas combustion to the Alberta grid will consist of both coal power plants retrofitted to burn gas and greenfield natural gas power plants. In the decades approaching 2050, natural gas use will decline in part due to a rise in wind power. While wind power currently accounts for only about 5% of generation in Alberta; it is projected to account for 37% by 2050 [16].

These three types of electricity generation vary significantly in their GHG emissions. Coal is infamously GHG-intensive when used for power generation and typically operates at notably lower efficiency (~40%) than modern natural gas (~50%+) [31]. Wind power is a renewable source of electricity that has negligible direct GHG emissions, though some emissions are associated with materials and construction.

These three technologies also vary significantly in their water use. The largest use of water associated with thermal electricity generation is for plant cooling, though how this occurs varies by the type of cooling used. Once-through cooling technologies run a large volume of water through the plant with minimal heat rise before rejecting it to the environment. Though such cooling schemes typically withdraw huge amounts of water, they cause relatively little consumption because they do not directly require evaporation to reject the waste heat. Alternatives to once-through cooling include wet cooling towers and cooling ponds, which circulate withdrawn water through either an evaporative cooling tower or into an artificial pond. These two alternatives will have much higher consumption than once-through but much lower withdrawals. Dry cooling technologies are possible but are rarely used in Alberta because of their cost and the relative abundance of water. The fleet of older coal power plants commonly use once-through cooling, though newer thermal facilities typically use cooling towers or ponds. Non-thermal generation facilities such as wind plants also use water, though use is limited to plant operations such as cleaning and the volume is typically low.

1.1.5 Decarbonization in Canada's oil sands

Since the introduction of limited carbon pricing in Alberta in 2007, there has been an explicit financial incentive to reduce GHG emissions in several areas of the oil sands sector. As of the fall of 2022, additional emission pricing regulations specific to the sector were being developed by the federal government, though the details of these regulations have not yet been announced [32].

There are broadly three options for reducing GHG emissions: increasing the efficiency of how GHG-emitting energy is used, replacing GHG-emitting energy sources with non-GHG-emitting sources, and capturing produced GHGs and storing them, typically underground. All three are available in the oil sands.

Efficiency-related options include conventional industrial process improvements, cogeneration, and emerging higher-efficiency extraction technologies such as the in-pit extraction process and solvent-assisted SAGD [33]. Increased efficiency is projected to play an important role in reducing emissions through the 2030s [34].

Because the sector has numerous energy-intensive processes, there are many potential opportunities for the integration of renewable energy. Oil sand sites are significant consumers of electricity, and the generation of renewable electricity on or near the site could be a viable way to integrate renewable energy. A recent aspirational announcement from the Pathways Alliance [33] indicates that small modular nuclear reactors are an area of focus for oil sands operators as such a source of electricity. The generation of heat by renewable means has several points of application in the oil sands. Renewable technologies capable of producing steam may be of use for in situ mining operations, for which steam is a major input. Solar-powered steam generation is one such technology [35]. Nuclear reactors can certainly produce concentrated heat sufficient for generating steam, an option that has been explored academically [36]. Surface mines require a large volume of process water to be heated to 50-90°C, which may be suitable for technologies capable of producing high- or low-grade heat, such as geothermal energy [37]. As one of the major inputs in the upgrading process is hydrogen, low-carbon intensity hydrogen have also been presented as a possible option for decarbonization [38].

The use of carbon capture and storage has also been presented as an option for oil sands projects to meet their GHG reduction targets. Oil sands projects have many GHG streams, both mobile (typically in the form of vehicles) and stationary (process units, utility plants, etc.). Though carbon capture is still in its infancy, it is projected to make up a significant portion of the long-term GHG reductions required for the oil sands to meet their targets [34].

1.2 Research rationale

Effective water resource management requires an understanding of current and future water demand. Projections of future water demand from energy sectors have always been an important part of long-term water resources planning. It is increasingly important for energy-rich nations like Canada to understand the potential water impacts of their national energy industries, especially given the uncertainty inherent in the future market demand for hydrocarbon products, the technological transitions occurring in the oil and gas sector, and the industrial policies that national governments use to reduce GHG emissions.

The research presented in this thesis is split into two topics: topic 1 – water use in the oil and gas sector, and topic 2 – the water-use impacts of low-carbon pathways in the oil sands. The literature review summary for each topic is described separately. These literature review results are presented along with observations on the common approaches used and their relevance to this thesis.

1.2.1 Water use in the oil and gas sector (topic 1) literature review

A literature review was conducted to find studies that estimate or project water use of the oil and gas sector or a constituent activity. Many top-down studies attempted to estimate water use associated with oil and gas along with other sectors. Liu et al. [39] used a multi-regional input-output analysis to estimate the water embodied in the international energy trade. While their scope included oil and gas products, the study found that the vast majority of water embodied in traded energy was associated with electricity rather than fossil fuels. Ding et al. [40], also using a top-down method, estimated the life cycle blue water consumption footprint of crude oil and natural gas in China to be 0.29 m^3/GJ and 0.11 m^3/GJ, respectively. Other top-down studies that include oil and gas sectors have been performed for other jurisdictions [41-43] but generally do not produce results useable for a bottom-up study as the results are typically reported sector-wide and incorporate indirect water use.

Some studies assessing global water demand have included primary energy production and specifically oil and gas as a driver of water demand. Hejazi et al. [44] used the Global Change Assessment Model to explore water demand in multiple sectors across a variety of long-term socioeconomic scenarios. They present water-use intensities for crude oil, unconventional oil, and natural gas that are assumed to remain constant for the duration of the forecast. The authors assume a constant consumption of 31% for all these activities. Their assumed withdrawal intensity for crude oil (145 m^3/TJ) is significantly higher than that for unconventional oil (21 m^3/TJ). The 2050 results for the change in water used for producing primary energy range from approximately a 10% increase over current levels to a nearly 30% decrease. While these studies can be very informative, they can at times be unable to follow technological changes and trends that occur at a regional or local level. Later work by some of the same authors [45] focuses on technological advances across a variety of sectors and the resulting changes to water-use intensities used in large integrated models. The study does not account for advances in primary energy (e.g., oil and gas) water efficiency, likely in part due to the very small portion of global water use associated with this sector. Kaveh et al. [46] modelled global water use of energy, including oil and gas pathways. Their reference scenario found a 44-50% increase in global energy water use between 2012 and 2035, but low and high oil price scenarios saw increases of 37-41% and 59-66%, respectively.

Many of the bottom-up studies found were regional in scope. Fulton et al. [47] investigated how hydraulic fracturing and biofuel production changed regional water use in California and found that growth in the green water footprint driven by ethanol production was a major trend. Ikonnikova et al. [48] estimated the water use of shale and tight oil in the Eagle Ford Shale region in Texas. They projected water use to 2045 based on several factors including oil price and found water demand in their high price scenario ($100/bbl) was double that of their reference scenario ($50/bbl). Rosa et al. [49] investigated the water-energy-food nexus effects of unconventional oil and gas operations in a single region of Argentina. They found that per-well hydraulic fracturing water use more than doubled between 2012 and 2016, and total yearly water demand was 1.15 MCM by 2017. They forecast water use only to 2024 but included a reference scenario alongside an “energy boom” scenario representing a rapid increase in fracturing activity. Their reference scenario found a doubling of water use between 2017 and 2024, but under the energy boom scenario, water use increased tenfold.

Nair et al. [50] modelled water use associated with fossil fuel production and electricity generation in Australia, using both withdrawal and consumption intensities for various energy pathways. They used water-use intensities from the literature and found a significant portion of water consumption (37%) supported the production of energy products for export.

Mielke et al. [51] compiled data on water-use intensities of various energy production pathways including many in the oil and gas sector. They found a range for each investigated pathway including conventional oil, oil sands, and hydraulic fracturing. Gallegos et al. [52] investigated the water consumption from hydraulic fracturing in the US, finding a median of 19,425 m^3 required per horizontally fractured gas well. They note that large variability exists within the average fractured well in part because a significant number of fractured wells are vertical or directional and typically require less than 2,600 m^3 water per well. This result of approximately 20,000 m^3 required per horizontal fractured well is similar to results found by the US Geological Survey [53].

Babkir [54] assessed various Alberta oil sand production pathways and compiled their impacts on water use, GHG emissions, and land use to create sustainability indicators. These indicators were then used to build a model that optimizes either the cost or the environmental impacts of the sector. This study distinguished water withdrawal and consumption intensity factors for each pathway but used static factors.

Of the studies identified in the review, several important study parameters were identified; these parameters differed among the studies depending on the study's focus. The scope of water use studied may be limited to direct use within an area of interest, such as the oil and gas sector, or may encompass upstream or downstream stages of the life cycle. Top-down input-output is an example of a framework that assesses water use throughout an economy and therefore includes direct and indirect water use associated with energy production. The advantage to assessing both direct and indirect water use over the entire life cycle is that it provides insight into the entire water-use impact associated with an activity or system of interest. A reason to restrain the study to only assess direct water demand is to aid a potentially significant feature of bottom-up methods: water use can more readily be mapped to the location of use. Overall water use at the national level is an indicator that does not easily map onto policy decisions, whereas water use within specific basins may be more readily integrated with policy decision-making. Top-down frameworks often aggregate industrial activity at a broad level (e.g., "unconventional oil production") and at times make these results hard to compare to studies that assess or acknowledge multiple individual unconventional oil production technologies.

The type of water use modelled also differs among studies. Water use may be split into withdrawal and consumption, representing the difference between water that is removed from a water body but later returned directly to the same or a similar body of water as it was removed from (withdrawal) versus that which is not returned directly due to evaporation, deep geological disposal, or incorporated into a product (consumption). Consumed water is generally described as a subset of withdrawn water. Another approach is to separately consider the consumption of blue (non-saline surface and groundwater sources), green (water precipitated and prevented from becoming runoff, generally through uptake by plants), and grey (the water required to dilute any released pollutants to acceptable levels) water footprints to describe the varying manners in which water resources are impacted by a given activity.

One of the shortcomings found in several of the modelling efforts identified in the literature review is the use of static water-use factors. Using water-use factors based on historic data is a standard approach, but rapid changes in the technological makeup of several oil and gas subsectors have created a risk that static factors will either fail to be validated against historic data and/or produce unrealistic long-term projections. By accounting for changes in the water-use intensity of several of the pathways in the oil and gas sector, the results will be more reliable. The research in this thesis addresses this gap. This is discussed in chapter 2 of this thesis.

1.2.2 Oil sands low-carbon pathway water-use (topic 2) literature review

If Canada is to meet its Paris climate goals, significant reductions in GHG emissions from several sectors are required. Reductions in the oil sands sector are possible, and there are many technology options currently available or at various stages of technology readiness [38]. The quantification of these technologies' potential is of interest to the sector. Several modelling efforts have approached this problem, usually basing their analysis on cost and emission abatement potential.

Elsholkami et al. [55] modelled the integration of renewable energy in the oil sands to meet various GHG emission constraints while minimizing cost. Bergero et al. [56] used an integrated model to assess oil sands-wide compliance with national and provincial GHG reduction targets and the relationship between the use of low-carbon technologies and the volume of production allowable within those GHG targets. Ashrafi et al. [57] modelled the optimal use of post-combustion carbon capture in a typical steam-assisted-gravity-drainage (SADG) facility. Several earlier studies have explored sets of low-carbon pathways available in the oil sands that could be integrated with expanding output capacity. These pathways are the integration of renewable energy [58], the integration of carbon capture technology [59], and further expansion of combined heat and power [60]. Their potential for GHG abatement and cost reduction was assessed under several carbon prices.

Numerous studies have focused on the tradeoffs between water-use impacts and GHG emissions within the oil and gas and adjacent sectors, often with a focus on a single technology or subsector. Yang et al. [61] explored the use of carbon capture and storage in power plants in China to determine whether their adoption would exacerbate regional water shortages. They found that water availability may be negatively impacted in many cases but several technology options are available to mitigate this, including advanced water treatment processes. Absar et al. [62] investigated tradeoffs between water consumption and GHG emissions in the production of shale gas in Texas, with a focus on the energy requirements of several considered water treatment options. Forshomi [63] produced integrated cost-water use-GHG saving results for several SAGD process designs, though all designs are existing industry standard options rather than specialized or experimental low-carbon designs. Part of their focus is on the energy required for water treatment.

The only study that was found that models the intersection between long-term water use and GHG emissions from the Albertan oil sands is the aforementioned study by Babkir [54], though it is limited to conventional oil sands pathways and does not include any emerging technologies. It identifies sector-wide tradeoffs between water consumption, GHG emissions, land use, and cost of supply, though it achieves these by changing the level of activity of the various conventional pathways considered.

Several other studies involving the intersection of GHG abatement and water use in the energy sector were identified, though their focus is typically the electricity generation sector or conventional oil and gas pathways and often with a focus on a single pathway or resource jurisdiction. Several studies focus on the tradeoffs between water use, GHGs, and cost resulting from different policies or the use of conventional technologies, which is a similar but distinct focus compared to exploring the tradeoffs by emerging technologies. The land area disrupted by oil and gas activity is a type of environmental impact considered by some studies, though its inclusion is atypical.

1.2.3 Knowledge gaps

As presented in the previous sections, various knowledge gaps were identified in the literature reviews conducted for each topic.

No peer-reviewed bottom-up water-use models for the Canadian oil and gas sector were identified, though data from several Canadian jurisdictions is well-suited to bottom-up modelling and various studies on the water use of individual oil and gas production techniques are available. No studies tracking changes in the water-use intensity of oil and gas production pathways at the national level were identified.

No studies were identified that assess the water-use impacts of the adoption of low-carbon pathways in the Canadian oil sands. Earlier investigations into the interaction between cost, GHG emissions, and water use in the Canadian oil and gas sector focus on typical production pathways rather than emerging technologies. The studies by Janzen et al. [58-60] are recent investigations into the unique circumstances of the Albertan oil sands and the unique technology options available therein, though they do not consider water use. This kind of earlier study allows access to various intermediate calculations in addition to published results, which can be vital to integrating water-use considerations into the explored pathways.

1.3 Research objectives

The objectives of topic 1 include improving the bottom-up water-use model of the Canadian oil and gas sector [64] by incorporating non-static water-use intensities for the main oil and gas products, adding additional scenarios, and updating the oil and gas production projections, all of which resulted in a higher fidelity model. This model was then used in topic 2 to assess the water-use impacts of the adoption of several low-carbon technologies in the oil sands. The specific objectives are summarized below.

- Update the WEAP-Canada oil and gas model with newer historic data and production projections.

- Expand the WEAP-Canada oil and gas model to account for changes in the water-use intensity of several oil and gas products over the historic period (2005-2019) and compare these results with Statistics Canada's historic water-use data.

- Create a water-use projection scenario based on further reductions in the water-use intensity of several oil and gas products.

- Produce annual water-use results at the national, provincial, and watershed levels in the base-case projection and three alternative projection scenarios between 2005 and 2050.

- Integrate several of the low-carbon technology pathways in the LEAP-Canada oil sands model with the WEAP-Canada oil and gas model and produce marginal water-use results for those pathways.

- Integrate these water-use results with the previously developed cost and GHG abatement results to produce integrated environmental impact results.

1.4 Limitations

The limitations of each topic are discussed in detail in their respective chapters, but several high-level limitations are introduced in the following paragraphs.

Both topics are based on modelling that operates on a yearly time step. This yearly time step was selected in part to match the time step used in the cost and GHG emission modelling studies, though it introduces unique challenges when applied to water rather than GHGs. Water availability varies significantly throughout the year, and the use of an annual time step limits the ability to assess actual water availability that may materially vary by season.

This project relies on external data for many key components of the models developed, including production projections, historic water use accounts, and published water-use intensities. Producing any of this kind of data is outside the scope of this study, and therefore where data limitations exist in the public record, so too will corresponding limitations exist in this project, though these types of limitations are discussed in more detail in their respective chapters.

The categorization of technologies and pathways used in this research has often been done to align with the most-used sources of external data and in some cases decided in the previous studies this research is a continuation of. While the categorization used in this research is deemed to be reasonably appropriate for its context, it is nonetheless a limitation of the work.

The watershed-level distribution of water use is an important aspect of the results of this work but is notably limited in its resolution and confidence. Public data sources for oil and gas production and water use are typically not organized by watershed, and aligning existing water-use allocations and other records with historic oil and gas production data is outside the scope of this study.

This research only assessed the quantity of water use. The effects the oil and gas industry has on water quality is a very important field of study but is not considered in this work.

1.5 Organization of thesis

This thesis has four chapters along with a list of tables, a list of figures, a list of abbreviations, references, and appendices.

Chapter 1 introduces Canada's water resources, the oil and gas sector, and the electricity sector; describes the results of a literature review; and defines the general objectives and limitations of this thesis.

Chapter 2 describes the research related to the WEAP-Canada oil and gas model, including the oil and gas sectors it incorporates, and the structure and operation of the model and also provides all the data sources used in detail. The conceptualization of the baseline and alternative scenarios along with their results are presented.

Chapter 3 describes the incorporation of several low-carbon oil sands pathways in the LEAP-Canada model into WEAP-Canada oil and gas. The chapter describes these pathways, their water use impacts and accompanying data sources for quantifying water use, how the pathways were adapted into the WEAP-Canada model, along with the water-use results and the integrated water-cost-GHG trade-offs and indicators. Given the nature of the integrated results presented, there is some overlap with the previous research this chapter is built upon, though it is made clear which methods and results are from previous works and which are novel to this thesis.

Chapter 4 describes how the presented research fulfils the thesis objectives, reiterates the thesis' key limitations, and provides recommendations for future research.

2 Developing a bottom-up model to project consumptive and non-consumptive water use associated with oil and gas activity in Canada through several oil and gas production scenarios

2.1 Introduction

For effective long-term water resources management, a jurisdiction must have information and projections on current and future water use across all economic sectors. The public availability of water-use data from the oil and gas sector varies considerably in scope and detail by regional jurisdiction. This chapter describes the creation of a Canada-wide bottom-up model of historic and projected water use.

2.1.1 Knowledge gap

The oil and gas sector includes a wide variety of water-using activities in many jurisdictions across Canada. The practice of collecting data on the sector's water use differs by jurisdiction and has led to a patchwork account that varies in detail and scope. There is scarcity of publicly available disaggregated yearly account of national water use in the Canadian oil and gas industry and also scarcity of projections of future water use. Many existing sources on water use, whether historic or projections, are specific to the province or the industry providing the data. The primary national source of statistics, Statistics Canada, provides a single aggregate water-use value biennially. This knowledge gap is addressed in this research through the development of detailed and disaggregated annual data on water withdrawal and consumption by subsector, province, and river basin between 2005 and 2050.

An earlier study on water use [64] and the associated water-use model were the starting point for some elements of the model developed for this study, including the general scope of oil and gas activities modelled and many of the water-basin distribution estimates of these activities. The earlier model did not validate well with the Statistics Canada dataset [65], and the reason given was differences in oil and gas activities in Statistics Canada's source compared to that used in the model. While different types of activity were included in the Statistics Canada account that were not included in this earlier model (e.g., coal pyrolysis at mine sites), the difference in water use was so large it is difficult to accept this as the only reason for the difference in results. This prior modelling effort used static water-use intensities taken from published sources for all oil and gas activities considered, which may be a factor contributing to the poor validation.

The earlier modelling work [64] used static oil and gas water-use intensities mostly sourced from a paper by Ali et al. [66]. The modelling study described in this chapter does not rely on these works to the same extent, as water-use intensities have been developed for several sectors based on publicly available water use data. Because of Ali and Kumar's focus on energy pathways that are relevant to the Canadian oil and gas sector and its accompanying nuances, these studies are still highly relevant and are used in some cases where there is a lack of publicly available data and water-use intensities cannot be calculated.

To the best of this author's knowledge, this is the first study that both projects long-term water use in the Canadian oil and gas sector and develops the water-use intensities used in the sector. This approach differs significantly from most other studies that use water-use intensities solely from public data sources, including the thesis that this study builds on. In addition to tracking a larger portion of water-use changes between years, the results allow the presentation of novel data on how the water-use intensity of different oil and gas activities has changed in recent years.

2.1.2 Objectives of this study

The goal of this study is to develop a bottom-up model of direct water use in the oil and gas sector in Canada and project the water use in the sector over the long term. The purpose of developing the model is to understand how water use might change in the coming decades as well as provide a bottom-up platform for further studies on water use in the oil and gas sector in Canada. The specific objectives of the present study are to:

(1) Assess the changing direct non-saline water withdrawal and consumption intensity in several oil and gas-related pathways over a number of years using historic data;

(2) Develop a long-term, bottom-up water-use model for Canada's oil and gas sector that uses an exogenous account of oil and gas activity to project water use at a river basin resolution on a yearly basis;
(3) Assess a range of exogenous projections for future oil and gas production in Canada to estimate geographic and process-specific water-use impacts.

This study does not attempt to develop projections of oil and gas activity. The Canada Energy Regulator (CER) has forecasted production accounts (i.e., scenarios) based on several factors, such as changing commodity prices or energy policies, and this study projects the water use associated with those accounts. This study includes details such as the price of oil or what energy policies are enacted in a given scenario, but these details are merely informative.

2.2 Method

2.2.1 Framework

The general framework of this study is shown in Figure 3. Water-use intensities for various technological pathways were calculated from the historic volume of water used by each pathway and the amount of product or output the pathway produced. These intensities were calculated for each pathway in the years for which there is sufficient data to do so. The availability of historic data varies by pathway but typically allowed a calculation for multiple consecutive years from the mid-2000s to approximately 2019. The exact years where data is available is shown later in the chapter in Figure 5. These intensities calculated from historic data are supplemented by intensity data from published sources where needed. The intensities are then used alongside an exogenous account of oil and gas activity across Canada to estimate water withdrawal and consumption in various oil and gas subsectors each year between 2005 and 2050.

The distribution of several oil and gas activities across watersheds is based entirely on a study by Gupta et al. [64]. The underlying assessments and assumptions used therein are detailed in each subsector's respective subsection in 2.2.2. The Water Evaluation and

Planning (WEAP) framework was used to create the WEAP-Canada oil and gas model, which was used to calculate yearly withdrawal and consumption in each river basin and sector. WEAP provides a robust framework fully sufficient for the requirements of this study as well as the ability to be integrated in future with models created in the Low Emissions Analysis Platform (LEAP) framework.

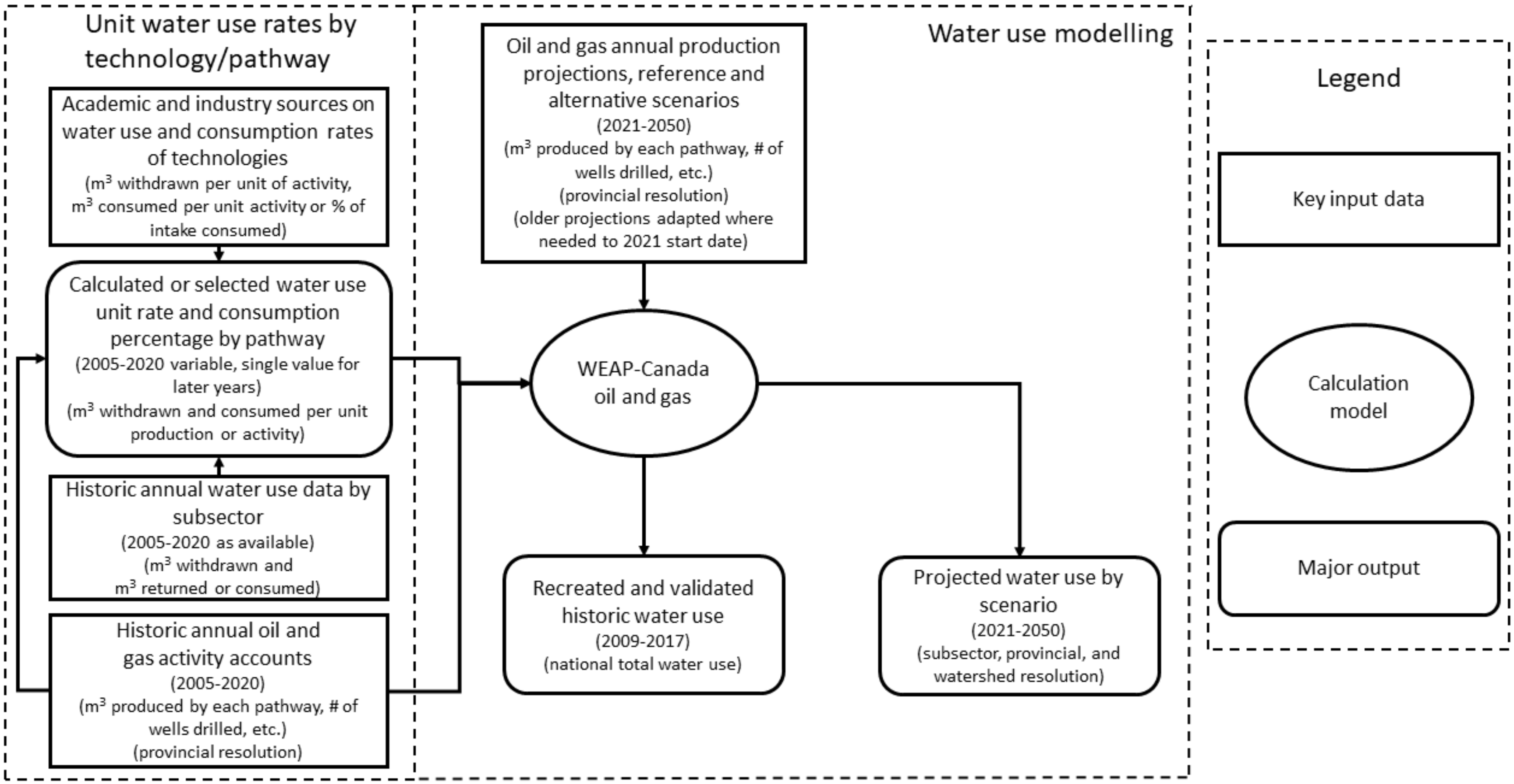

Figure 3: Overall study framework

2.2.2 Pathways, water uses, and the reference scenario

Many different oil and gas products are extracted or manufactured in Canada, some through multiple methods of production. Regulator reporting of products typically categorizes products as conventional light oil, conventional heavy oil, pentanes plus, field condensate, bitumen, synthetic crude oil, and natural gas [67]. The ways these different products use water and how they have been considered in this study's WEAP framework are described in the following sections.

Table 1: Abbreviations used for the oil and gas subsectors

Abbreviation	Meaning
Up	Upgrading subsector
IS	In situ subsector
BM	Bitumen mining subsector
NG	Natural gas subsector
CO	Conventional oil subsector

Conventional crude oil

Conventional crude oil is liquid oil extracted from reservoirs by drilled or hydraulically fractured wells. The drilling process uses water as a lubricating and cooling fluid and for removing rock and mud from the well. Many reservoirs have positive pressure, dissolved gas, or some other in-reservoir mechanism that can provide the energy to remove the oil, and this is referred to as primary production. Primary production can have a similar meaning in bitumen production, and this is discussed in the *in situ bitumen* section of 2.2.2. As these in-reservoir energy sources decline with the removal of oil, the natural flow slows. Reservoir pressure can be maintained by pumping water in through a separate well. There are a number of forms this can take; they are generally referred to as secondary production and add to water use in the production of crude oil [68].

The hydraulic fracturing of wells also contributes to water use in the production of crude. Even though hydraulic fracturing is considered an unconventional method, the product is often conventional crude oil. Generally performed after a horizontal well has been drilled, water, sand, and other additives are pumped into the well at high pressure to fracture the surrounding rock and create pores, allowing oil to flow. Hydraulic fracturing has existed for many decades and increased considerably in the early 2000s because of its combination with horizontal drilling and the introduction of multiple stages, giving access to resources previously unrecoverable.

The measure of activity for the conventional crude oil pathway is the volume of produced crude oil, measured in barrels or cubic metres [16]. Light and heavy conventional crude oils are considered a single aggregate "conventional crude oil." Condensate and pentanes plus are ignored in this study as they are largely a by-product of natural gas production [69, 70], whose water use is accounted for elsewhere. The provincial production series used is shown in Table 23 in the appendix.

The main conventional oil producing provinces in Canada are Alberta, Saskatchewan, and Newfoundland and Labrador; a full account of how much conventional oil is produced in each province is shown in Table 23 in the appendix. Water-use data for Saskatchewan's and Newfoundland and Labrador's oil production is unavailable, so their water-use intensity is assumed to be the same as Alberta's. Many sources give estimates of the water-use intensity for conventional oil. Canadian Association of Petroleum Producers (CAPP) estimated the intensity for oil excluding hydraulic fracturing and found that between 2004 and 2015 the intensity decreased from 0.7 m^3 water/m^3 oil to 0.38 [71]. The Alberta Energy Regulator (AER) provides water-use data for hydraulic fracturing as a method of producing oil and natural gas, with water-use intensity ranging from 0.35-0.73 m^3 water/m^3 oil between 2015 and 2019 [72]. Primary and EOR production in the oil sands is a process that can be technically very similar to conventional crude production [73]. An earlier study estimated the water intensity for primary and EOR production in the oilsands to be 0.46-1.00 m^3 water/m^3 oil [66]. For the model developed in this thesis, CAPP's conventional water-use data and fracturing water use estimates based on AER data were combined to estimate average water use for crude production with both conventional and fracturing uses for the years 2005 to 2014, the last year CAPP data is available. The base data for this and yearly results are shown in Table 26 in the appendix.

The earliest year AER fracturing water use data is available for is 2014. The AER does not distinguish between water used for fracturing for oil and water used for fracturing for natural gas, and it presents water-use intensity based on the energy content of products rather than volume. Although this approach is practical, because wells often produce several products, it does not easily fit with the framework used in this study. To address this, the portion of total fracturing water use attributable to producing oil in 2014 based on AER accounts of wells fractured primarily for conventional oil vs those fractured primarily for natural gas was estimated. The details and results of this estimate are in Table 25 in the appendix; the amount of water used for fracturing for oil production is 4.2 to 13.4 million cubic metres (MCM) per year. According to the AER [13], multistage hydraulic fracturing was introduced in Alberta in 2010, which is interpreted as negligible activity in 2009 in this study. Given the lack of specific data between 2009 and 2014, it was assumed that water use for fracturing for oil increased linearly in these intervening years, as shown in Table 26 in the appendix, with intensity dropping from 0.613 m^3/m^3 in 2005 to 0.566 m^3/m^3 in 2015. The percent of conventional oil's water demand that is consumed is assumed to be similar to the estimated consumption percentage of primary oil sands production, 92%, as assessed in an earlier study [66].

The assumed distribution of provincial activity in each basin is kept constant throughout the modelling period. Oil activity in BC is assumed to be entirely in the Peace River area because of the significant production in the region surrounding Fort St John [74]. Manitoba's oil activity occurs entirely within the Assiniboine River watershed [75]. Ontario's oil activity occurs entirely in the south [76], both on and offshore (Lake Erie). The water source is assumed to be Lake Erie. Newfoundland is assumed to use ocean water as the sole supply for its largely offshore oil production. As oil production in the Northwest Territories occurs entirely near Norman Wells [77], the water source is assumed to be the Mackenzie River.

The distributions in Alberta and Saskatchewan are split among multiple basins. The distribution assumed for Alberta's oil production is based on 2014 regional production data by Petroleum Services Association of Canada (PSAC) area [78] and on geographic approximations between PSAC areas and watersheds. Table 2 lists these assumed distributions. The distribution in Saskatchewan is based on production data from 2015 [79]. To accommodate the framework used in this study, oil production areas were assigned to watersheds, as listed in Table 3.

Table 2: Alberta crude oil production distribution by basin [78]

River basin	Assumed share of total conventional production	Notes
Bow	26.1%	Based on the AER's PSAC-2 share
North Saskatchewan	38.6%	Based on the AER's PSAC-4 and 5 share
South Saskatchewan	17.2%	Based on the AER's PSAC-3 share
Oldman	0.6%	Based on the AER's PSAC-1 share
Peace	17.5%	Based on the AER's PSAC-7 share

Table 3: Saskatchewan crude oil production distribution by basin [79]

River basin	Assumed share of total conventional oil production	Notes
North Saskatchewan	30.2%	Based on production in the Lloydminster area
South Saskatchewan	31.7%	Based production in the on Kindersley and Swift Current area
Souris	38.1%	Based on production in the Estevan area

Natural gas

Natural gas is a naturally occurring mix of gases, primarily methane, and can include ethane, propane, and larger hydrocarbons. It is extracted from underground reservoirs via wells. Drilling is the original method of well production. Hydraulic fracturing is a set of techniques with long historic precedence that with some modern innovations has allowed access to new unconventional reservoirs. Though some natural gas is produced in all Canadian provinces and territories, more than 99% is produced in the Western Canadian Sedimentary Basin in British Columbia, Alberta, and Saskatchewan. Water use associated with natural gas production in other provinces is ignored in this study because of the negligible amount of activity there and the corresponding lack of production and water-use data. Because water is primarily involved at the well creation stage, no other water uses associated with natural gas are considered for this study. The activity measure for this sector is therefore the number of wells created.

The CER projections include the number of wells created each year from 2005 to 2050 by province for each of the following technologies: conventional, conventional (tight), coalbed methane, and shale [16]. Conventional (non-tight) and coalbed methane are considered to be drilling-only wells and conventional (tight) and shale to be fractured wells. The yearly activity series thus used in the model is shown in Table 24 in the appendix.

The water demand for drilling is assumed to be 500 m^3/well, which is the average assumed for previous water use estimates by CAPP [71]. Hydraulic fracturing has more specific water-use data available than drilling, primarily from the two provinces where the technique is generally used, Alberta and British Columbia. The water intensity of fracturing is considered separately for these two jurisdictions. Water-use data collection in both provinces followed the introduction of the more intensive and ultimately more successful versions of fracturing (horizontal with multiple stages), and there is a significant gap in data on how much water was used per well prior to this.

Water use for fracturing in Alberta is aggregated for both oil and gas production. Table 25 in the appendix shows the estimate of hydraulic fracturing water attributable to natural gas. This volume was divided by the CER's record of the number of wells created by fracturing methods. The AER and CER record have slightly different numbers of natural gas wells created by fracturing, but the general trend is similar. In this thesis, the CER's number is used since the intensity will be applied to the CER count of wells for future years. The trend of per-well intensity increases markedly between 2014 and 2019; this might be explained by the technology advancements discussed above. As actual water-use data is unavailable for years prior to 2014, it was assumed that the per-well water use for fractured wells in 2005 was similar to drilling, i.e., 500 m^3/well, and the water intensity between 2005 and 2014 is interpolated. While there is insufficient data to determine the exact water intensity of fracturing in Canada in 2005, in the US vertical fractured gas wells used less than 670 m^3 in 2000 [52], so assuming this value for 2005 is conceivable. The 2017-2019 average intensity was applied to the years after 2019. This yearly water intensity series is shown in Table 4.

Table 4: Alberta natural gas fracturing water use intensity calculations and parameters by year

Parameter:	Fractured NG wells	Water used for NG fracturing (MCM)	Water-use intensity (m^3/well)	Water-use intensity notes
Source:	[16]	Estimated; see Table 25	See notes	
2005	6,133	Not available	500	Assumed
2006	5,962	Not available	973	Interpolated
2007	4,873	Not available	1,447	
2008	3,843	Not available	1,920	
2009	3,689	Not available	2,394	
2010	2,719	Not available	2,867	
2011	1,598	Not available	3,341	
2012	1,587	Not available	3,814	
2013	797	Not available	4,287	
2014	797	3.79	4,761	Calculated from estimated data
2015	1,032	5.79	5,607	
2016	697	6.77	9,709	
2017	628	11.10	17,681	
2018	779	11.45	14,702	
2019	475	10.77	22,688	
2020 and later	N/A	Not available	18,357	Assumed average of 3 previous years

In British Columbia, the primary product obtained through hydraulic fracturing is natural gas and associated liquids. The total fracturing water use each year from 2012 to 2015 is provided by BCOGC reports [80-83]. Like in Alberta, the BCOGC and CER accounts of the number of natural gas wells made by fracturing differ slightly, and the CER count was used here in calculating the yearly intensity for those years. Like in Alberta, the water-use intensity assumed for 2005 matched that of drilling, and the intensity in the years between

2005 and 2012 was interpolated. No clear trend in intensity is apparent between 2012 and 2015, and thus the 2012-2015 average value was used for the years after 2015. This is shown in Table 5.

Table 5: British Columbia natural gas fracturing water-use intensity calculations and parameters by year

Parameter:	Water use (m^3)	Fractured wells (BCOGC account)	Fractured wells (CER account)	Fracturing demand intensity (m^3/well)	Fracturing demand intensity notes
Source:	[80-83]	[80-83]	[16]	See notes	
2005	Not available	Not available	308	500	Assumed
2006	Not available	Not available	355	2,863	Interpolated
2007	Not available	Not available	404	5,226	
2008	Not available	Not available	289	7,589	
2009	Not available	Not available	321	9,952	
2010	Not available	Not available	341	12,315	
2011	Not available	Not available	420	14,677	
2012	7,054,704	406	414	17,040	Calculated
2013	5,341,635	433	349	15,306	
2014	8,258,192	643	407	20,290	
2015	7,735,618	534	495	15,628	
2016 and later	Not available	Not available	N/A	17,066	Assumed Average of the last four years

Saskatchewan has long been a producer of natural gas but produces at much smaller quantities than Alberta or BC. There is no public data available on water use for natural gas or fracturing like what is available in Alberta and BC, and thus separate fracturing intensity specific to Saskatchewan was not developed in this study. Instead, the Alberta series for fracturing water-use intensity was used.

Historical accounts and future projections of wells created generally do not include the river basin or water source. To distribute well activity to the various river basins in each province, the same approach and assumptions have been used as were reported in an earlier study [64]. A constant portion of total well activity is assumed to occur in each basin based on the distribution of natural gas production by administrative area and approximations of administrative area proximity to nearby basins. The years natural gas production share was assessed by administrative area were 2014 for Alberta [78] and 2018 for BC [84] and Saskatchewan [85]. The assumed distribution of wells within the studied river basins is listed in Table 6, Table 7, and Table 8.

Table 6: Assumed distribution of natural gas wells in Alberta [78]

River basin	Share of total new AB natural gas wells	Notes
Athabasca	2.7%	Based on AER PSAC-6 production
Bow	55.0%	Based on AER PSAC-2 production
North Saskatchewan	10.2%	Based on AER PSAC-4 and 5 production
Oldman	5.8%	Based on AEL PSAC-1 production
Peace	11.9%	Based on AER PSAC-7 production
South Saskatchewan	14.4%	Based on AER PSAC-3 production

Table 7: Assumed distribution of natural gas wells in British Columbia [84]

River basin	Share of new wells	Notes
Liard	8.7%	Based on Liard, Horn, and Jean Marie production
Peace	78.1%	Based on Montney and Deep Basin production
Fraser	13.2%	Based on the remainder of production

Table 8: Assumed distribution of natural gas wells in Saskatchewan [85]

River basin	Share of wells	Notes
North Saskatchewan	11.1%	Based on Lloydminster production from natural gas wells
South Saskatchewan	88.9%	Based on Kindersley and Swift Current production from natural gas wells

Water consumption is assumed to be 100% because of regulations on the disposal of produced water that prohibit surface discharge in Alberta [86] and assumed similar legislation in other provinces.

Refining

Water is used in refining for a variety of purposes, such as a heating fluid, for desalting crude oil, or for cooling. Because of the different uses and the variety of water treatment options available to a refinery, there can be a substantial difference in water requirements between refineries. Refineries also vary in complexity depending on the intended feedstock (lighter vs heavier crudes) and the targeted products. This important technical information is often not publicly available from individual refineries.

For these reasons, the measure of refining activity was chosen to be the volume of feedstock processed, as this is how the capacity of a refinery is generally described. The research described in this chapter has not been able to lift the veil of this complex topic, but the simplification of using a single value to represent the average of different refining processes and operations has precedence in this area of study [87]. A federal government list of refineries [88] was used to estimate the capacity of all refining facilities nationwide. The only major refinery project planned is the expansion of the Sturgeon Redwater refinery, which is shown alongside the other modelled refineries in Table 9. The model assumes no other refineries are constructed or decommissioned during the modelled period.

Table 9: Canadian refineries and their associated capacity and water source [88]

Refinery	Province	River Basin	Capacity (m^3/d)
Prince George Husky Energy	BC	Fraser	1,910
Parkland Refining Burnaby	BC	Fraser	8,740
Imperial Edmonton	AB	North Saskatchewan	30,370
Sturgeon Redwater	AB	North Saskatchewan	8,000/16,000/24,000[1]
Suncor Edmonton	AB	North Saskatchewan	22,580
Shell Scotford Ft Saskatchewan	AB	North Saskatchewan	15,900
Coop Regina	SK	Qu'Appelle	21,460
Suncor Sarnia	ON	St. Clair	13,510
Imperial Sarnia	ON	St. Clair	18,920
Shell Sarnia	ON	St. Clair	11,610
Imperial Nanticoke	ON	Lake Erie	17,970
Valero Levis	QC	Saint Lawrence	42,130
Suncor Montreal	QC	Saint Lawrence	21,780
Irving Saint John	NB	Saint John	47,700
Silver Range Come By Chance	NF	Offshore	18,280

Historic use by the sector as a whole is available from CAPP yearly from 2005 to 2018 [89]. Each year after this is assumed to use the 2012 and 2018 average. The use ranges from 78% to 95%, with the average for 2019 and later taken to be 86%. A yearly account of these use rates is shown in Table 27 in the appendix.

[1] Three equal capacity phases of the refinery are planned and modelled as coming online in 2018, 2023, and 2028.

Annual withdrawal and consumption data for the subsector from 2005 to 2015 was taken from the Canadian Fuels Association (CFA) [90], though this data represents only the member refineries, i.e., approximately 95% of total capacity. The annual water withdrawal and consumption was divided by the estimated activity of CFA member refineries to produce withdrawal and consumption intensities for each year from 2005 to 2015. These intensities are listed in Table 10. The water intensity and consumption for 2015 are assumed to remain constant through future years.

Table 10: Refining water withdrawal intensity and consumption percentage by year (calculated with data from the CFA [90])

Year	Intake intensity (m^3 water/m^3 feedstock)	Consumption
2005	3.334	5.3%
2006	3.328	10.1%
2007	3.275	5.9%
2008	3.190	11.0%
2009	3.790	10.0%
2010	3.276	4.8%
2011	3.261	9.8%
2012	3.339	15.3%
2013	3.001	13.5%
2014	2.419	7.2%
2015	2.499	10.9%
2016-2050	2.499	10.9%

In situ bitumen

Bitumen can be recovered from underground deposits without the large-scale earth moving efforts of bitumen surface mining in a technique known as in situ recovery. In situ recovery is done by injecting steam into the reservoir to reduce the viscosity of the bitumen enough that it can be brought to surface through a well. Operations that use a single well cycling between injecting steam and removing water and bitumen are referred to as cyclic steam stimulation (CSS). This technology has largely fallen out of favour for new extraction projects, which typically use steam assisted gravity drainage (SAGD). SAGD uses two horizontal wells, one located above the other; the upper well injects steam and the lower well removes water and bitumen. SAGD generally shows better performance for most reservoirs and is now the dominant production method. Despite this, some reservoirs (especially in Cold Lake) may perform better with CSS [91], and therefore CSS may continue to be used in future projects.

The other source of in situ bitumen is primary production. The hydrocarbons recovered this way may be described as bitumen for reasons other than their physical and chemical properties. Royalty regimes may allow an operation to describe its product as bitumen based on its geographic location, even though an operation in a different location accessing the same reservoir, using the same recovery technology, and producing a product with identical properties could be required to classify the product as heavy conventional oil [73]. This means that some bitumen is extracted using technology primarily used with conventional crudes. Bitumen produced this way is generally described as primary bitumen, due to the use of energy sources from the reservoir in moving the oil to the surface. No published sources could be found that focus exclusively on the water use of primary bitumen production, though the work by Ali et al. [66] describes the water uses in these schemes as similar to some conventional crude schemes.

Water is used in SAGD and CSS primarily for steam generation. Even though the produced water is recycled, these schemes require continuous make-up water. The well creation phase uses water, but this is minor compared to the operation phase, and thus has been ignored here.

In situ recovery of bitumen occurs in all three of Alberta's oil sands areas (OSAs): Athabasca, Cold Lake, and Peace River. SAGD is used in Athabasca and Cold Lake; CSS is used in Cold Lake and Peace River; primary methods are used in each OSA [92, 93]. The water withdrawal and production of each SAGD and CSS operation is available through AER's Thermal In Situ Publication for the years 2012 to 2018 [92]. The average water demand intensity for SAGD and CSS in each OSA was calculated for these years; the results are in Table 11. The water intensity prior to 2012 is assumed to be the 2012 value, and no further decreases to the intensity are assumed past 2018 with the exception of Peace River CSS, which has an abnormally high water intensity and low production. The projected Peace River CSS intensity is instead the average of its withdrawal intensity from 2012 to 2018. The water demand from primary production is not directly available and therefore is taken from Ali and Kumar, 0.65 m^3 water/m^3 bitumen [66]. Water consumption for all methods is assumed to be 100%, as per AER regulations on produced water [86].

Table 11: Water demand intensity of in situ production by OSA, method, and year (m^3 water/m^3 bitumen) [92]

OSA:	Athabasca	Cold Lake		Peace River	All OSAs
In situ type:	SAGD	SAGD	CSS	CSS	Primary
2005-2011	0.48	1.13	0.91	4.10	0.65
2012	0.48	1.13	0.91	4.10	0.65
2013	0.41	0.64	0.75	5.94	0.65
2014	0.34	0.87	0.67	6.33	0.65
2015	0.31	0.53	0.62	5.90	0.65
2016	0.22	0.44	0.68	5.13	0.65
2017	0.23	0.49	0.56	7.23	0.65
2018	0.22	0.30	0.75	10.62	0.65
2019 and later	0.22	0.30	0.75	6.46[2]	0.65

[2] The average from 2012-2018.

The CER forecast was used for the historical and future total bitumen production by in situ [94]. The division of this production by method and OSA is shown in Table 28 in the appendix and includes both historic (years 2005-2018) and estimated (all other years) amounts. Production data by SAGD and CSS in each OSA each year between 2012 and 2018 is from The Thermal In Situ Publication [92]. Since total production for all methods is available for each OSA through AER's ST98 data [93], the amount of primary production in each OSA for those years can be inferred.

The CER in situ projection does not include the use of different in situ technologies; this information is from other modelling work of Canada's energy sector by Davis et al. [95]. The distribution of in situ technologies between river basins is based on the average distribution from 2017 and 2018.

This method used is given in Equation 1,

Equation 1: In situ distribution estimate

$$S_{m,y,a} = S_{m,y} * \frac{\sum_{i=2017}^{2018} PV_{m,i,a}}{\sum_{j=1}^{n} \sum_{i=2017}^{2018} PV_{m,i,j}}$$

where $S_{m,y,a}$ is the share of total in situ production by method *m*, in year *y*, in OSA a. $S_{m,y}$ is the share of total in situ production by method *m* in year *y*, taken from Davis et al.'s modelling work [95]. $PV_{m,y,a}$ is the production volume by method *m*, year *y*, and OSA *a*, taken or inferred from The Thermal In Situ Publication [92] between 2012 and 2018 as described above. The letters *j* and *n* are the sum of all three OSAs.

Bitumen mining

Deposits of oil sands (a mixture of bitumen, sand, water, and clay) close to the surface can be mined with conventional mining equipment such as excavators. Excavated lumps of oil sands are crushed and water is added to make a slurry, from which the bitumen can be separated. The remaining slurry is referred to as tailings. Some water can be recovered from the tailings, which are then disposed of in a pond along with some water that is unrecoverable. While water is mainly used to make the slurry, it is also used for dust control, machine cleaning, cooling, and other minor uses.

Bitumen is mined only in the Athabasca region in Alberta. The mines operating as of 2021 are listed in Table 12 [96]. Although there are several production sites, the activity and water use of this subsector are considered a single aggregate.

Table 12: Bitumen mining operation capacities in 2021 [96]

Company	Facility	Capacity (m^3 bitumen/day)
CNRL	Horizon	46,700
CNRL	Albian Sands	50,900
Suncor	Base plant	52,500
Suncor	Fort Hills	30,800
Imperial Oil	Kearl	38,200
Syncrude	Base plant	59,600

Syncrude, CNRL Horizon, and Suncor's base mine have facilities for upgrading bitumen into synthetic crude oil (SCO). CNRL Albian Sands, Suncor Fort Hills, and Imperial Oil Kearl do not have upgrading facilities and thus export diluted bitumen. Upgrading is considered a category separate from surface mining, and thus the activity series here is the amount of bitumen mined, irrespective of whether that bitumen is upgraded or not. CER data provides this amount for historic and future years [16], shown in Table 29 in the appendix.

The water use associated with bitumen mines is provided by the AER [97]. This includes the entire water use of all surface bitumen mines, including the water used for upgrading operations. The water use of mine-integrated upgrading facilities was estimated in this study; the details are discussed further in the *Bitumen Upgrading* section of 2.2.2. This estimate was subtracted from the total water use associated with mining to approximate the mining-only water use. This was then divided by the volume of bitumen mined that year to give the withdrawal intensity. This procedure was done for the years with historic data, i.e., 2015-2019, resulting in values of 1.89-2.38 m^3 water/m^3 bitumen. No significant trend was found between years, and thus for all other years the average intensity value was used. These calculations are shown in Table 13.

Table 13: Surface mining water use intensity calculations

Parameter:	Mined bitumen (1000 m^3/d)	Mining-associated water use (MCM)	Expected upgrading water use (MCM)	Mining-only water use (MCM)	Mining-only water intensity (m^3/m^3)
Source:	[16]	[97]	Calculated[3]	Calculated	Calculated
2014	N/A	N/A	N/A	N/A	2.19[4]
2015	184.65	180.80	31.64	149.16	2.21
2016	182.83	181.80	34.66	147.14	2.20
2017	202.82	205.80	38.33	167.47	2.26
2018	236.72	246.10	40.60	205.50	2.38
2019	255.24	218.40	42.32	176.08	1.89
2020	N/A	N/A	N/A	N/A	2.19[4]

The percentage of this water that is consumed is not available through the AER, and so the consumption percentage was taken from a paper by Ali and Kumar to be 92% [66].

[3] See section 0 for details

[4] Values assumed based on 2015-2019 average

Bitumen upgrading

The viscosity of bitumen makes it unsuitable for transportation by pipeline, and there are two general solutions for this. Bitumen can be mixed with a diluent to improve its viscosity and other physical properties enough that it can be transported by pipeline. Alternatively, the bitumen can be upgraded to SCO, which has properties closer to a conventional crude and is also suitable for transportation by pipeline.

Upgrading is a method of processing bitumen generally involving the removal of contaminants like sulphur and increasing the hydrogen-to-carbon ratio [98]. Upgrading requires water for numerous tasks, such as cooling, steam production, and hydrogen production.

Most of the bitumen produced from surface mines in Alberta is upgraded. Three of the oil sands mining operations (CNRL Horizon, Syncrude base, and Suncor base) have upgrading facilities incorporated into their mine sites in the Athabasca River Basin. The bitumen mined at CNRL Albian Sands is transported to the associated but geographically separate site of the Scotford Upgrader in the North Saskatchewan River Basin. The Sturgeon Refinery takes bitumen and produces diesel and various refinery inputs [99]. It is a one-of-a-kind facility in Canada, as most facilities in Canada are a conventional or SCO refinery (taking in crude oil/SCO and generate various products) or an upgrader (taking in bitumen and putting out SCO). For this reason, in addition to it using water as a refinery, The Sturgeon Refinery was assumed to use water both as a refinery and as an upgrader. This is assessed as the sum of the refining and upgrading withdrawal and consumption intensities.

The water used by surface mine-integrated upgrading facilities is captured by the AER's measure of bitumen mining water use [97], unlike the water use of the Scotford Upgrader and the Sturgeon Refinery, which is not provided by regulator reports. The yearly upgrading activity is calculated as two parts, the CER's projected production of upgraded bitumen [16] and the estimate of the activity associated with the Sturgeon Refinery. The upgrading activity associated with the CER projection has been split between the Athabasca and North Saskatchewan river basins according to the upgrading capacity in each basin, shown in Table 14. Equal capacity use in river basins is assumed, allowing the calculation of yearly production by river basin. The total upgraded bitumen produced and activity associated with the Sturgeon Refinery are shown in

Table 30 in the appendix. Water demand intensity for upgrading bitumen was assumed to be 0.79 m^3 water/m^3 product with a consumption rate of 85% based on averages from Ali and Kumar [66]. The volume of water calculated this way in the Athabasca Basin is the estimate mentioned in Table 13; this amount of water was removed from the bitumen mining subsector and re-assigned to the upgrading subsector to account for mine-integrated upgraders.

Table 14: Upgrader capacity and river basin (MCM/year) [100]

Upgrader:	CNRL Horizon	Suncor	Syncrude	Shell Scotford
River basin:	Athabasca	Athabasca	Athabasca	North Saskatchewan
2005-2008	0.0	25.5	23.6	0.0
2009-2010	18.0	25.5	23.6	0.0
2011 onward	18.0	25.5	23.6	15.6

2.2.3 Alternative production projection scenarios

Informative modelling does not seek to make exact predictions. Sometimes it is informative to make several differing predictions to gain insight into a variety of possible outcomes and their associated impacts. The reference scenario in this study is based on recent CER oil and gas production projections to 2050 [16], but the CER has made other production projections and the water use associated with them can be projected using the developed WEAP model. These alternative scenarios are typically formulated based on different macro-economic and policy forecasts. Note that the work presented in this study does not consider factors like energy policies or the price of oil, merely production projections. The policies and prices that inspire these projections are described in this study for informative purposes, but only the projections themselves are used in any quantitative way. A basic description of the projections associated with each scenario is shown in Table 15.

Table 15: Scenario descriptions [16]

Scenario name	Abbrev.	Original source of projection	Notes
Reference	ref	CER EF 2020	Based on Canadian climate efforts being limited to those currently in place
Low price	lp	CER EF 2018	Based on long-term suppressed oil and gas prices
High price	hp	CER EF 2018	Based on long-term elevated oil and gas prices
Evolving	ev	CER EF 2020	Based on a combination of slightly suppressed oil and gas prices combined with expanding Canadian climate efforts at a similar to current pace, despite this falling short of 2030 and 2050 emission targets

The reference scenario activity data is described in section 2.2.2. The evolving scenario includes additional policies that are currently in development or are likely to occur should further climate action be a goal. These include a carbon price that continues to rise throughout the modelled period, a low carbon fuel standard, a zero-emission vehicle standard, and additional support for other clean energy technology and infrastructure [14]. The CER production projection associated with their evolving scenario was used as-is with the exception of the number of natural gas wells created. The well creation data is identical for the reference and evolving scenarios as published by the CER despite a significantly lower production of natural gas in the evolving scenario. To account for this, an alternative set of data for drilling activity was created for the evolving scenario using Equation 2.

Equation 2: Estimation of the number of wells created in the evolving scenario

$$W_{ev,t} = \frac{P_{ev,t}}{P_{ref,t}} W_{ref,t}$$

$W_{ev,t}$ and $W_{ref,t}$ are the number of wells of type *t* produced in the evolving and reference scenario, respectively, and P_{ev} and P_{ref} are the production of natural gas by type *t* in the evolving and reference scenario, respectively. This equation is applied individually to each type in each province in each year of the forecast. Well types and their associated types of natural gas are shown in Table 16.

Table 16: Natural gas well types and their corresponding gas types

Well type	Gas type
Coalbed methane	Coalbed methane
Shale	Shale
Conventional (non-tight)	Non-associated
Conventional (tight)	Tight

The CER developed low and high price scenarios for the 2018 iteration of *Canada's Energy Future*. They represent the effects of varying hydrocarbon prices on the development of Canadian resources and include alternative yearly accounts of oil and gas activities to 2050. These accounts are the basis of the low and high price scenarios included in this chapter. The prices underlying the CER's projections are summarized in Table 17.

Table 17: Benchmark (Western Canadian Select) price by scenario for select years, from the CER [16]

Scenario	2020	2025	2030	2040	2050
Reference (2019 USD/bbl)	18	53.5	58.5	58.5	58.5
Evolving (2019 USD/bbl)	18	36.1	38.5	37.67	33.5
Low price (2016 USD/bbl)	19.44	21.97	22.5	22.5	22.5
High price (2016 USD/bbl)	50.07	100.16	102.5	102.5	102.5

As of early-2023, price-based scenarios have not been published as part of CER's *Canada's Energy Future* since 2018, and thus these scenarios are outdated. Because they show interesting effects on the sector, they are included here. The projections used in the model consider the following: (1) Data for 2005-2020 are the historic data from the CER 2020 reference case. (2) To avoid a hard shift between the 2020 historic data and a projection that at the time was several years ahead, the years 2021-2024 have activity that is a combination of the 2020 reference case projection and the 2018 price scenario. 2021 values were assessed as 80% the 2020 reference case plus 20% the 2018 price scenario value, 2022 values were assessed as 60% the 2020 reference case plus 40% the 2018 price scenario value, and so on in 20% increments. (3) Values for 2025-2050 were taken exactly as is from the 2018 scenarios. The above method was used for both the number of natural gas wells created and the volume of crude oil produced by each method (conventional, in situ, etc.)

2.2.4 Declining withdrawal intensities scenario

The forward projection of water use in this study's reference scenario relies on an assumption of no further improvements to water use efficiency for any of the studied pathways, which resulted in a constant water-use intensity being applied to each pathway beyond approximately 2020. This study cannot confidently assess future changes in water withdrawal and consumption intensity of technology pathways. This study also considers production through different technologies from a high level – major types of in situ technologies are considered, but different types of bitumen surface mine processing techniques are not. Despite this, there are observable trends in subsector-wide withdrawal intensity in some areas that are worth considering.

A scenario was constructed that assumes improvement in water withdrawal intensities for conventional oil, bitumen mining, in situ, and refining. The trends observed in years with historic data were extended using a calibrated exponential equation for each data series. To ensure that the values presented remain within the realm of reasonability, a minimum withdrawal intensity was identified and imposed on each series, such that the intensity used in the model would be the higher of either the projected (declining) intensity or the imposed minimum. Ali et al. [66] include “most likely” water-withdrawal intensities, which were the values used in the WEAP model where water-withdrawal intensities could not be calculated. Ali and Kumar also report “minimum” water-withdrawal intensities for each activity, and these were used as the imposed minimum value for each series except surface mining. The minimum surface mining withdrawal intensity is based on the lowest intensity at a single mine site observed in past years. This minimum occurred at the Albian Sands Mine in 2012 [101]. The minimum intensities considered are shown in Table 18 alongside the most recent intensity calculated with historic data. The only subsector where the exponential equation does not drop below the minimum considered intensity is refining. The calibrated exponential equations used in each subsector are provided in Table 31 in the appendix.

Conventional oil, SAGD, and surface mining are all high-consumption activities, and it was assumed that using the consumption percentage is a reasonable way to estimate the fraction of withdrawals consumed even in the withdrawal intensity reduction scenarios. As refining is a low-consumption activity, this method may not yield reasonable results, and thus a minimum consumption intensity was imposed. The consumption intensity was calculated for each year of CFA data [90], of which the minimum was 0.158 m^3 water/m^3 feedstock (occurring in 2010), and used this as the minimum consumption intensity for refining. In the WEAP framework, the consumption is calculated as a percentage of withdrawals, therefore this operative consumption percentage was recalculated each year to enforce the minimum consumption intensity for refining, whereas the same consumption percentage was used each year for the other subsectors. The fracturing pathways were not extended in this manner as they did not display a decreasing trend and they differ from the other pathways because activity was measured by an indicator other than the resource input or output. The withdrawal intensities for this scenario are shown in Figure 4.

Table 18: Exponential equations used for reducing water-use intensity scenario

Product (unit)	Most recent calculated withdrawal and year of data (m^3 water/unit)	Minimum enforced withdrawal (m^3 water/unit)
Conventional oil (m^3 oil)	0.57 (2014)	0.46
Refining (m^3 feedstock)	2.50 (2015)	0.98
Athabasca SAGD (m^3 bitumen)	0.22 (2018)	0.15
Cold Lake SAGD (m^3 bitumen)	0.30 (2018)	0.15
Cold Lake CSS (m^3 bitumen)	0.75 (2018)	0.35
Surface mining (m^3 bitumen)	1.89 (2019)	1.20

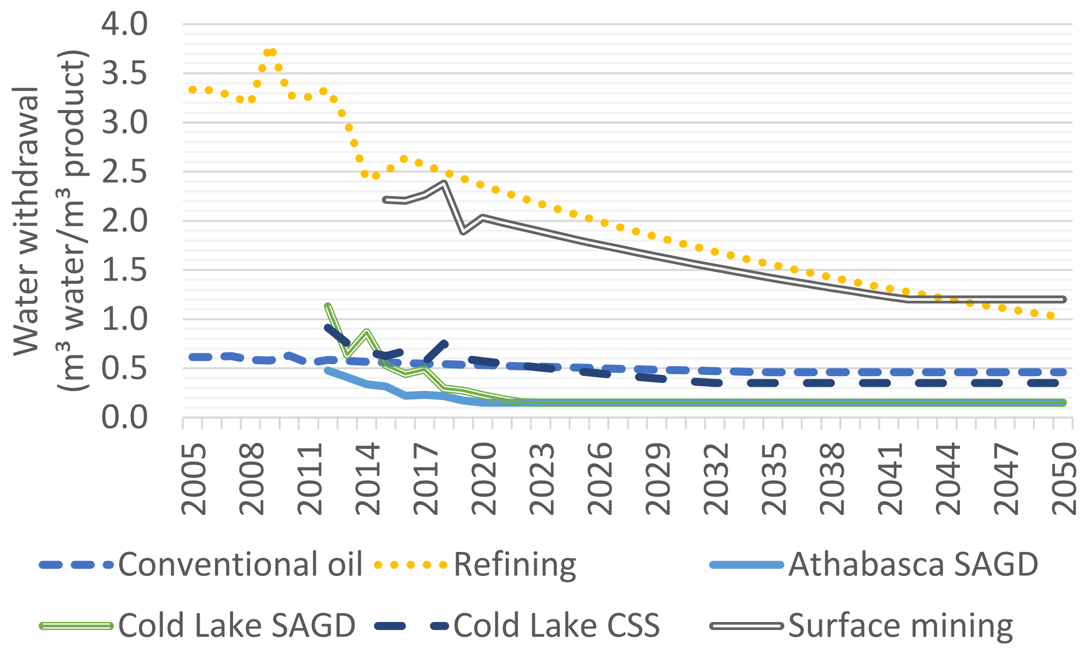

Figure 4: Calculated water-use intensities and the exponentially decreasing trendlines assumed for the decreasing water-use intensity scenario

2.3 Results and discussion

The results of this study include calculated water withdrawal intensities over various years as well as total withdrawals and consumption by basin, activity, and year.

2.3.1 Water withdrawal intensities

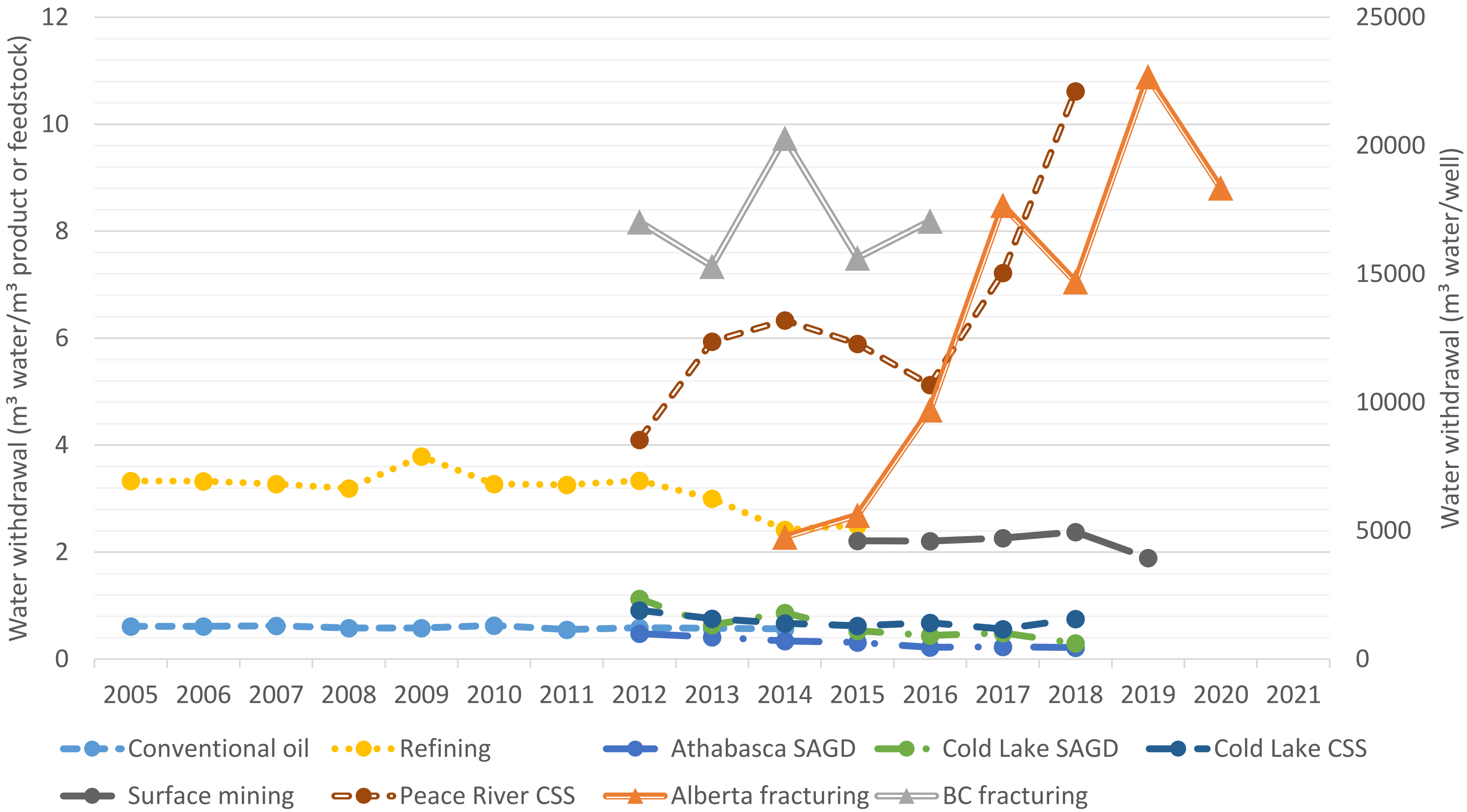

Figure 5: Direct water withdrawal intensity calculated by year for various energy pathways per cubic metre of product or feedstock (circles, left axis) or per well (triangles, right axis)

Figure 5 shows the yearly withdrawal intensities calculated with historic data. The subsectors that show a clear downward trend over the years for which data is available are refining, bitumen surface mining, and in situ other than Peace River CSS. This is likely due to technological advancements to increase the water efficiency of the processes or reduce their environmental impact. Advances in refining likely vary by site but at the subsector level include improved wastewater treatment in the refinery, increased use of recycled water from other sources such as municipal wastewater re-use, and the move to use air fin coolers rather than or in conjunction with evaporative cooling towers [90].

Bitumen surface mines show a slight decline in water-use intensity. More years of data may be required to confirm this trend. A number of factors influence the intensity, including recycle rate, bitumen production, and make-up water taken from the three sources (the Athabasca River, groundwater, and surface runoff).

In situ bitumen operations have increased their use of recycled water while keeping make-up water consistent despite increasing production, as shown in Table 32 in the appendix. While the subsector does use alternative (typically saline) water sources, the improvements seen in recent years to non-saline water-use intensity do not stem from increased use of these alternatives.

The subsectors that show an increasing trend are hydraulic fracturing in Alberta and Peace River CSS. Though not shown in the table, CSS in the Peace River region does not have much activity (<1% of in situ production), which makes a calculated intensity less informative. It is not clear whether there is an actual phenomenon driving increases in water intensity for these projects during normal operations or whether operational changes or some other unconsidered factor plays a role. The increasing trend of the water-use intensity of hydraulic fracturing in Alberta, on the other hand, is not surprising, as the general technical trend during this period of increasing the application of hydraulic multistage fracturing (HMSF) would account for this. It should be noted that though the assumption of an increasing intensity is part of producing the 2005-2013 fracturing water-use intensity series, the data points showing the increasing trend in Figure 5 include only those for 2014 and later, which are based on observed water use.

The water-use intensity of hydraulic fracturing in BC and conventional oil do not show a clear increasing or decreasing trend. These are unexpected results in both cases. There was a distinct technological shift in conventional oil in the years for which there is data for water-use intensity, i.e., the introduction of hydraulic fracturing from 2005-2014. Though the calculation of the conventional oil water-use intensity does not directly account for fracturing activity, with the inclusion of fracturing water use, the water-use intensity was expected to increase.

Hydraulic fracturing in BC shows a very different trend than fracturing in Alberta. It is well established that the water required to fracture a well varies greatly with geology, yet it was expected that the intensity of the water required, the approximate volume, and the trend would be more similar to Alberta's than the results show. It could be because horizontal fracturing entered the BC natural gas industry earlier than in Alberta and vertical fracturing is less common. Horizontal fracturing began in BC in the mid-1990s, and virtually all of the wells in the highly important Montney play are horizontal [102]. In Alberta, since 2005 the number of tight wells produced each year has dropped by over 90% with only a slight decline in gas production, which may indicate significant use of the less productive and less water-intensive vertical well fracturing prior to the adoption of horizontal well fracturing.

Comparison of calculated water-use intensities with those from other sources

Conventional oil

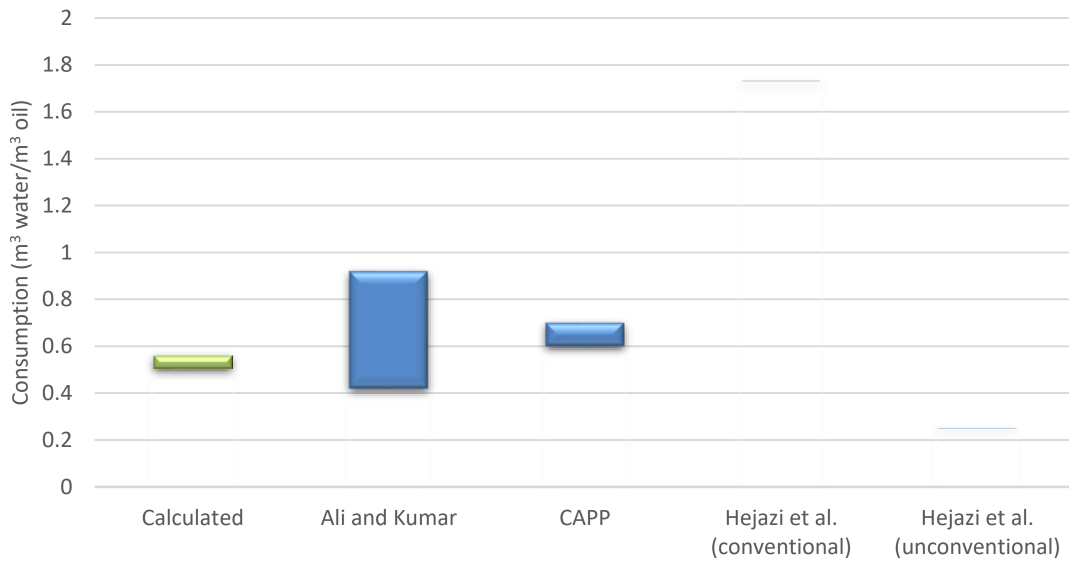

Figure 6: Consumptive intensity of conventional oil calculated in this study and taken from other sources

In this study, annual water-use intensity of conventional oil was calculated with data from the province of Alberta. The results, ranging from 0.51-0.56 m^3/m^3, are shown in the figure. Ali et al. [66] represents the minimum and maximum estimated water-use intensity for primary and enhanced bitumen extraction, which is similar to conventional oil production. The results from CAPP represent the range between their estimated water-use intensity from 2002-2004, 0.7 m^3/m^3 [103], and their estimate for 2015, 0.6 m^3/m^3 [71]. Both sources are specific to Alberta. The single data points from Hejazi et al. [44] show the water-use intensities used in their assessment. The calculated water-use intensity is within the range estimated by Ali and Kumar and similar to that estimated by CAPP. While these values diverge considerably from Hejazi et al.'s values [44], this may be appropriate given the non-local nature of their data. Not pictured is the range used by Kaveh et al. [46] for the aggregated conventional and unconventional liquids, as even the lower end is significantly higher than those presented here. The category Kaveh and Saeed consider is broad and has different boundaries than ours, which likely explains some of this discrepancy.

Bitumen surface mining

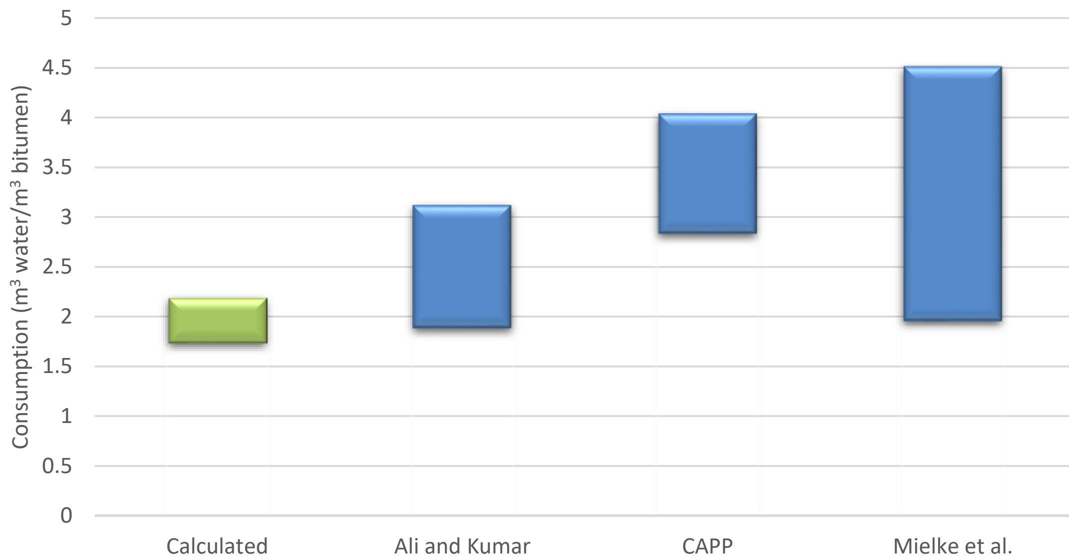

Figure 7: Consumptive intensity of surface-mined bitumen calculated in this study and from other sources

The water-use intensity of bitumen produced at surface mines was calculated in this study for various years based on the water use of the subsector reported by the AER [97], with an amount removed to disaggregate water used by integrated upgrading facilities. The range of "Calculated" in Figure 7 indicates the extent to which the calculated water-use intensity varies, generally decreasing year-over-year. Ali et al. [66] values show their range of estimates (minimum to maximum) for surface mining. CAPP's range [71] shows the difference between their use intensity between 2002 and 2004, 4.04 m^3/m^3, and their use intensity in 2015, 2.83 m^3/m^3. Mielke et al. [51] estimated low and high water-use intensities for bitumen mining are also shown.

The water-use intensity calculated in this study overlaps with two of the sources it is compared with but in some years is lower than any other source estimated. This could be due to the disaggregation of water used for upgrading. The use of more recent data than these other sources could contribute as well, as the calculated intensity exhibits a consistent downward trend over the last decade.

In situ bitumen

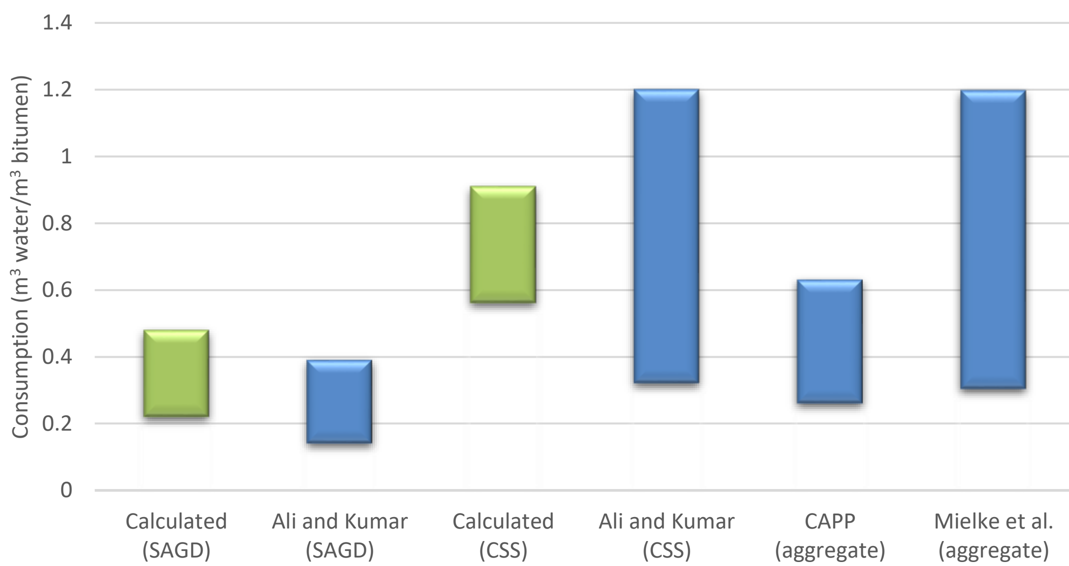

Figure 8: Consumptive water-use intensity of in situ bitumen production calculated in this study and from other sources

The range of yearly water-use intensities for SAGD and CSS calculated in the study is shown with other estimates in Figure 8. Ali and Kumar's [66] SAGD and CSS water-use intensity ranges show the estimated minimum and maximum intensity for each technology. The CAPP [71] intensity shows the range between their 2002-2004 baseline intensity (high) and 2015 (low) estimates for the in situ subsector as a whole. The range shown for Mielke et al. [51] represents their estimate of the intensities of different in situ technologies.

There is strong agreement between calculated intensities in this study and Ali and Kumar's estimates for both SAGD and CSS. CAPP's estimate and Mielke et al.'s lower range are reasonable given that the mix of in situ technologies in use is significantly weighed towards SAGD.

Well hydraulic fracturing

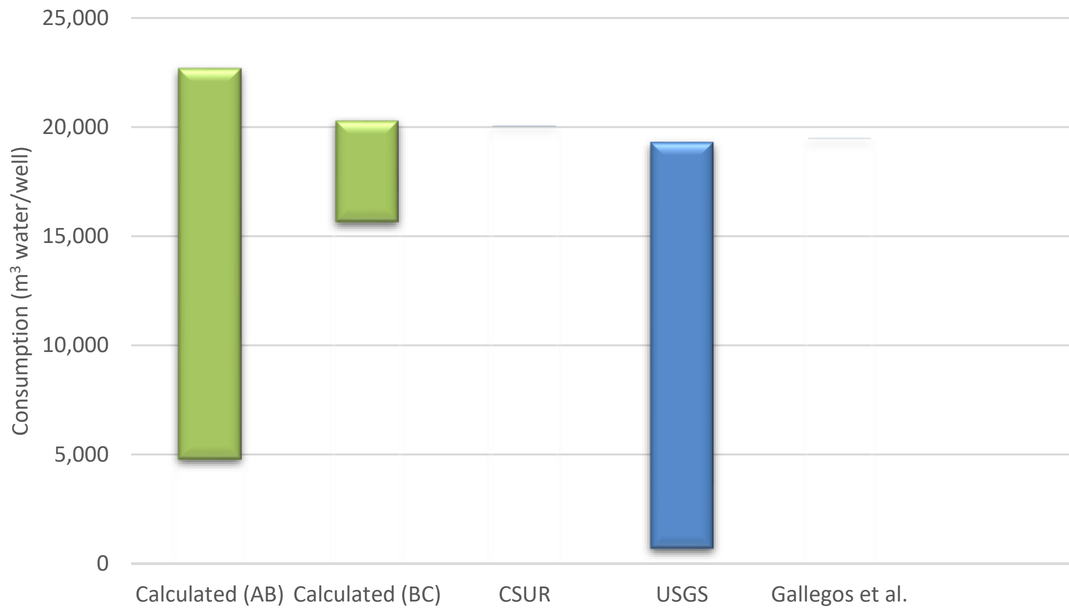

Figure 9: Consumptive intensity of hydraulic fracturing of wells calculated in this project and from other sources

Figure 9 gives the range of yearly consumptive intensities of fracturing a natural gas well as calculated in this study for AB and BC. The intensity suggested by the Canadian Society for Unconventional Resources (CSUR) falls near the top of both ranges calculated but still within their bounds. The median consumption of horizontal fractured natural gas wells found by Gallegos et al. [52] is likewise near the top of the ranges calculated in this study. Gallegos et al. [52] note that nearly half the fractured natural gas wells from which they collected data were vertical or directional, and that these other types consume significantly less water than horizontal wells. The range of water-use intensities presented by United States Geological Survey [53] shows the difference between the median consumption of horizontal fractured natural gas wells in 2000 (low) and in 2014 (high). While the calculated water-use intensities do not cover such a wide range in years, in Alberta a similar significantly increasing trend is found.

2.3.2 Historic period validation

For validation the developed model results were compared with Statistics Canada's (StatCan) account of water use associated with oil and gas extraction [17]. Even though StatCan is likely one of the most authoritative sources of Canadian data, there is some uncertainty about what their oil and gas water-use data represents, as descriptions of the data collection method differ and at times it is unclear the extent to which saline water use is included in their reported values [65, 104]. StatsCan's website indicates that their data is based solely on input from CAPP and represents both fresh and saline water; the WEAP model developed for this research does not include saline water intake.

The comparison of results for historic years where StatCan data is available is shown in Figure 10. The WEAP model results are shown with water use for conventional oil, natural gas, bitumen surface mining, in situ, and either including or excluding bitumen upgrading. Upgrading does not fit the classification of oil and gas extraction, but for data collection reasons the total water use of mines with on-site upgrading infrastructure may be counted as oil and gas extraction, whereas the water use of off-site upgrading would likely not. The WEAP results for water withdrawals from refining were excluded from this comparison as they would have been excluded from the StatCan values for oil and gas extraction and instead counted in StatCan's values on petroleum and coal product manufacturing.

There is a consistent difference in the data series of 23% to 31%, with the WEAP model producing a significantly lower total than Statistics Canada's. This general trend is expected as there may be saline water included by Statistics Canada that was not included in the WEAP model. Based on our method of analysis and the lack of disaggregated data from Statistics Canada, the author was not able to develop a more thorough explanation of this discrepancy beyond the question of saline water.

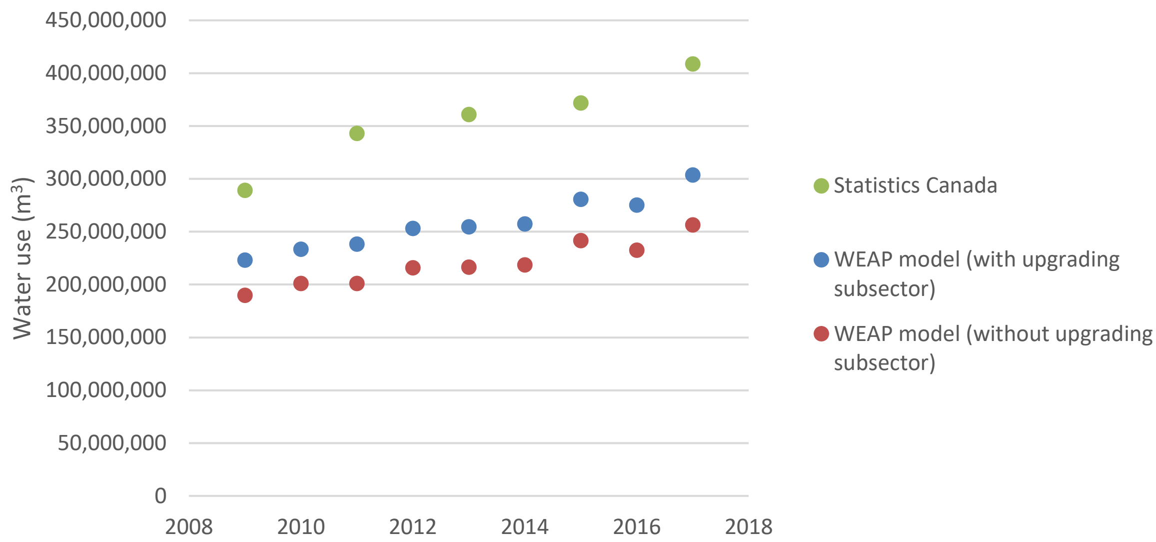

Figure 10: Water demand of oil and gas extraction from the WEAP model and Statistics Canada data

2.3.3 Reference scenario

The results for the reference scenario are given in Figure 11 and Figure 12, which show withdrawal and consumption, respectively. The same data is shown for a greater selection of years in the appendix in Table 34 and Table 35.

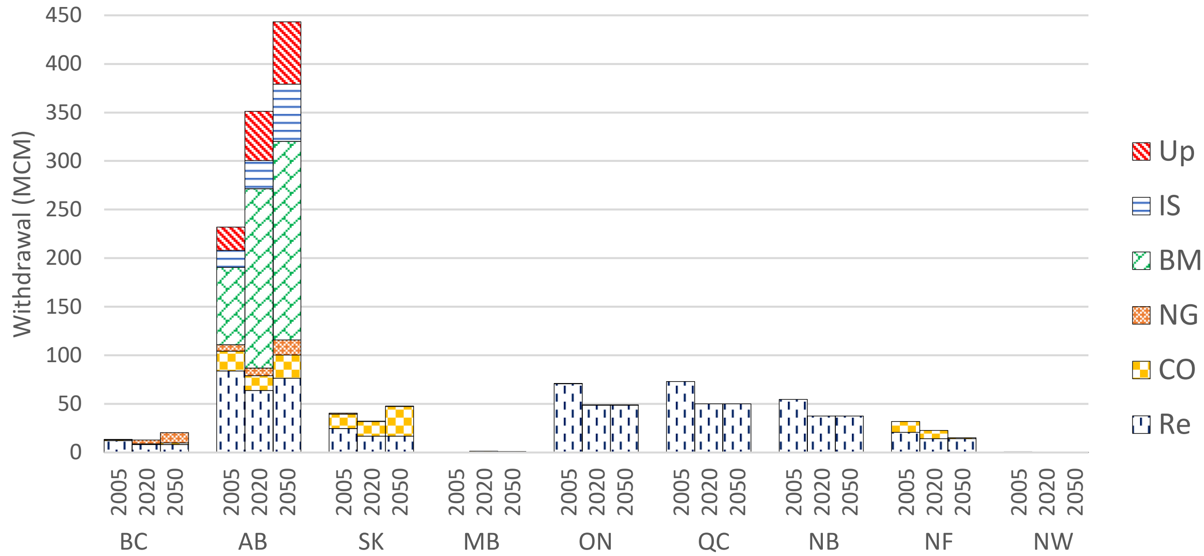

Figure 11: Withdrawal by province and subsector. BM is bitumen mining, CO is conventional oil, IS is in situ, NG is natural gas, Re is refining, and Up is upgrading

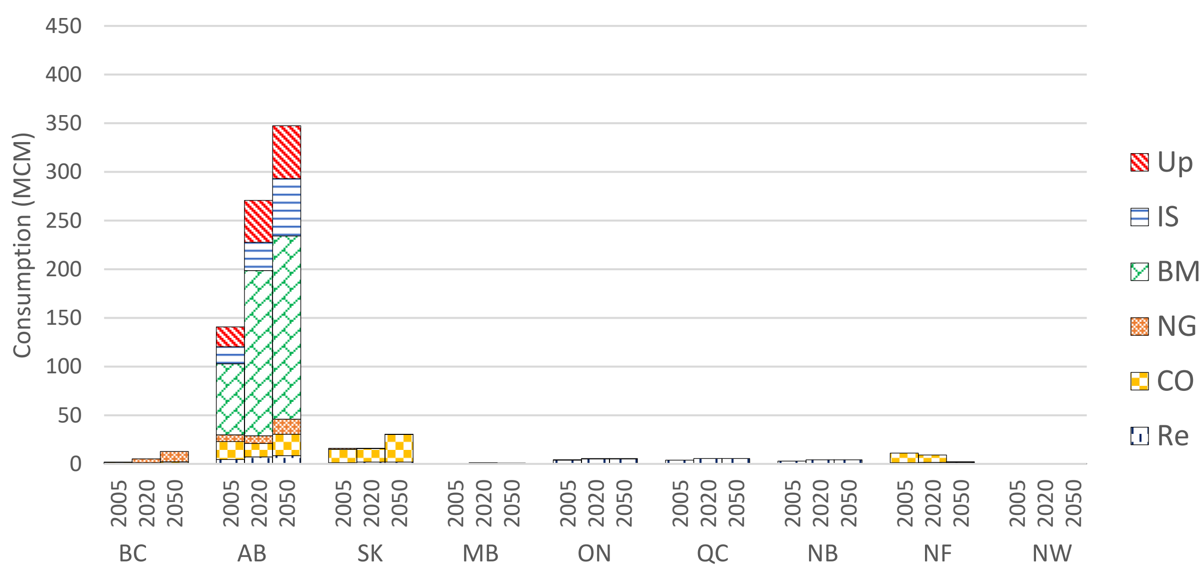

Figure 12: Consumption by province and subsector. BM is bitumen mining, CO is conventional oil, IS is in situ, NG is natural gas, Re is refining, and Up is upgrading

By subsector

Nationally, the water demand by subsector in 2005 was dominated by refining, which was responsible for over 65% of the total oil and gas water demand in that year. Refining reduced its water withdrawal significantly between 2005 and 2015, largely by improving water efficiency, as refining activity has remained steady or increased over this period. Activity in the sector varied from one year to the next because of differing yearly capacity use, but it was not until 2018 when the Sturgeon Refinery near Edmonton began operating that the underlying refining capacity increases in the WEAP model. The planned expansions of this refinery will further increase water demand in the 2020s before stabilizing in the 2030s, beyond which no changes to the subsector's water use are modelled. The significance of refining water demand differs across Canada.

Bitumen mining is the next subsector with the largest demand in 2005 and the highest consumption. The significant increases in bitumen production between 2005 and 2020 more than offset the improvements in water efficiency, and thus both demand and consumption grew substantially between these years. Mining expansion opportunities are expected past 2020, and thus demand will grow slightly before starting to decline in the 2040s. This demand is located solely in Alberta in the Athabasca River Basin and makes it not only a significant national water use but a very significant local water use as well.

Like bitumen mining, water use for upgrading follows a general increasing trend from 2005 to a relatively steady output in 2020 with modest increases possible thereafter. As it was modelled with a water intensity that does not change with time, associated water demand and consumption change solely with production. Water demand for upgrading is located primarily in the Athabasca River Basin with a minor site in the North Saskatchewan River Basin, also located in Alberta.

In 2005 conventional oil was the subsector with the second largest water consumption. Steady water intensity and production levels have led to relatively stable water demand for conventional oil since then, and only minor production increases are expected in the reference scenario. This water demand is concentrated in the Western Canadian Sedimentary Basin, an area that spans three provinces and numerous watersheds.

The water demand of in situ production experienced significant growth between 2005 and 2020 despite the intensity dropping for the most commonly used technologies. Though use was only 18 MCM in 2005, demand increased to double that by 2012-2015 before declining slightly to around 33 MCM for 2016-2019. Though demand fell to 29 MCM in 2020, it is expected to rise to pre-COVID-19 levels in 2021 and will continue increasing steadily thereafter, to nearly 60 MCM by 2040. This water demand is entirely in Alberta, split between Athabasca River, Peace River, and Cold Lake.

Natural gas is the subsector with the lowest water withdrawal and consumption in 2005 and for much of the modelling period. Water use in the early modelled years reflects the year-to-year variability in drilling activity. The transition from older fracturing methods to HMSF was a source of uncertainty, and thus it is unclear the degree to which these early year results reflect actual historic use or are simply the product of the assumed model inputs. For example, the model results show increasing water use between 2005 and 2009, followed by a decrease until 2013, but no data sources were found that showed that this actually occurred. Water-use intensity is established properly by 2015, and despite a low period of activity from 2020-2023, water use started increasing thereafter to approximately 26 MCM by 2030. Water use by natural gas was originally concentrated in Alberta but the arrival of HMSF led to a substantial increase in demand in BC.

By province

Alberta is the province with the highest water withdrawal and by far the most consumption. This is driven largely by oilsands activities, though all the oil and gas subsectors are found in Alberta in abundance. Alberta is also the location of most of the water use growth that is expected over the next three decades. This is driven by the only expected expansion in refining capacity, growth in the oil sands, and further potential for conventional oil and natural gas.

Three subsectors are found in British Columbia: conventional oil, natural gas, and refining. The capacity for refining is limited, and conventional oil production is projected to be relatively minor. Natural gas is the major source of water demand. While there was very little activity at the start of the historic period, a significant ramp up in activity and water intensity means that there will be more than 10 MCM of natural gas-related water demand and consumption by 2025. This is expected to peak briefly at 14 MCM in 2030 before returning to a stable 10 MCM for the remainder of the forecast.

The water withdrawals in Saskatchewan are split between refining and conventional oil. The consumption in the province is almost entirely from conventional oil. The outlook for conventional oil in the province is steady increases throughout the forecast period, which drive withdrawals and consumption continually higher. The creation of natural gas wells decreased drastically from 1564 wells in 2005 to only four wells in 2020, with no rebound in production projected. The corresponding water use was a minor component of the province's total oil and gas water use even in 2005, but quickly became near negligible.

Water withdrawal in Ontario and Quebec is primarily from refining demand. This is reflected in the small percentage consumed and the general outlook of water demand in these provinces. Because of the lack of expansion in the refining sector and improved water-use intensity throughout the historical years, water demand in these two provinces dropped significantly and is expected to remain near 2020 levels for the remainder of the projection.

The volume of withdrawals in the Atlantic is similar to that in Ontario and Quebec in the early years of the study period, though demand is from both refining and conventional oil, making the average consumption rate much higher. The long-term outlook for conventional oil in the Atlantic, specifically Newfoundland, is that there will be declining production rates throughout the forecast period, and thus overall water demand decreases.

Manitoba and the Northwest Territories have only the conventional oil subsector and produce oil in very small quantities throughout the modelled period.

By river basin

The total withdrawal and consumption by river and province are shown in Table 33 in the appendix. It should be noted that a number of watersheds are tributaries directly or indirectly. For example, withdrawals from the North Saskatchewan River are listed separately for Alberta and Saskatchewan. Similarly, the St. Claire River in Ontario, Lake Erie, and the St. Lawrence River are all part of the same watershed, yet water use is listed separately for each.

The Athabasca River is by far the most heavily used by the oil and gas sector in Canada. It is also one of the larger rivers in the country, does not have a significant population, and flows north away from most other water users. A projected 16% growth in water consumption will occur on the river between 2020 and 2050; this warrants further study to determine whether this amount will impact water availability.

2.3.4 Decreasing intensities scenario

The annual withdrawal and consumption in the decreasing intensities scenario are shown in Figure 13. The top two charts show withdrawal in each scenario by subsector. The lower two charts show withdrawal by province or region.

When decreasing water-use intensities are considered, steady decreases in total water withdrawal are experienced annually starting around 2021 despite the increasing production in these sectors. The difference in sectoral withdrawals between this scenario and the reference is quite significant, as the lowest water-use intensity considered is achieved or nearly achieved by all four sectors and is notably lower than that seen in historic years. Compared to the reference scenario results for 2050, the decreasing intensities scenario withdrawals in 2050 are 41% lower across the oil and gas sector as a whole and 19% to 51% lower in individual subsectors. Unlike in the reference scenario, the decreasing intensities scenario would also see a reduction in the volume of water used over time. Where the reference scenario sees in 2050 an increase of 22% from 2005 levels and 11% from 2021 levels, the decreasing intensities scenario sees in 2050 a 32% decrease from 2005 levels and 38% from 2021 levels.

To achieve these reductions in water use, a significant expansion of water-efficient technologies would likely be required throughout the sector. Minimum water-use intensities were typically assumed based on the most water-efficient sites in each subsector, and sites in locations with abundant water supply may not see value in achieving the water efficiency of a site in a water-stressed location. In addition, the effects of resource geology have not been considered, and thus variations in water intensity may be a feature that technology cannot entirely even out.

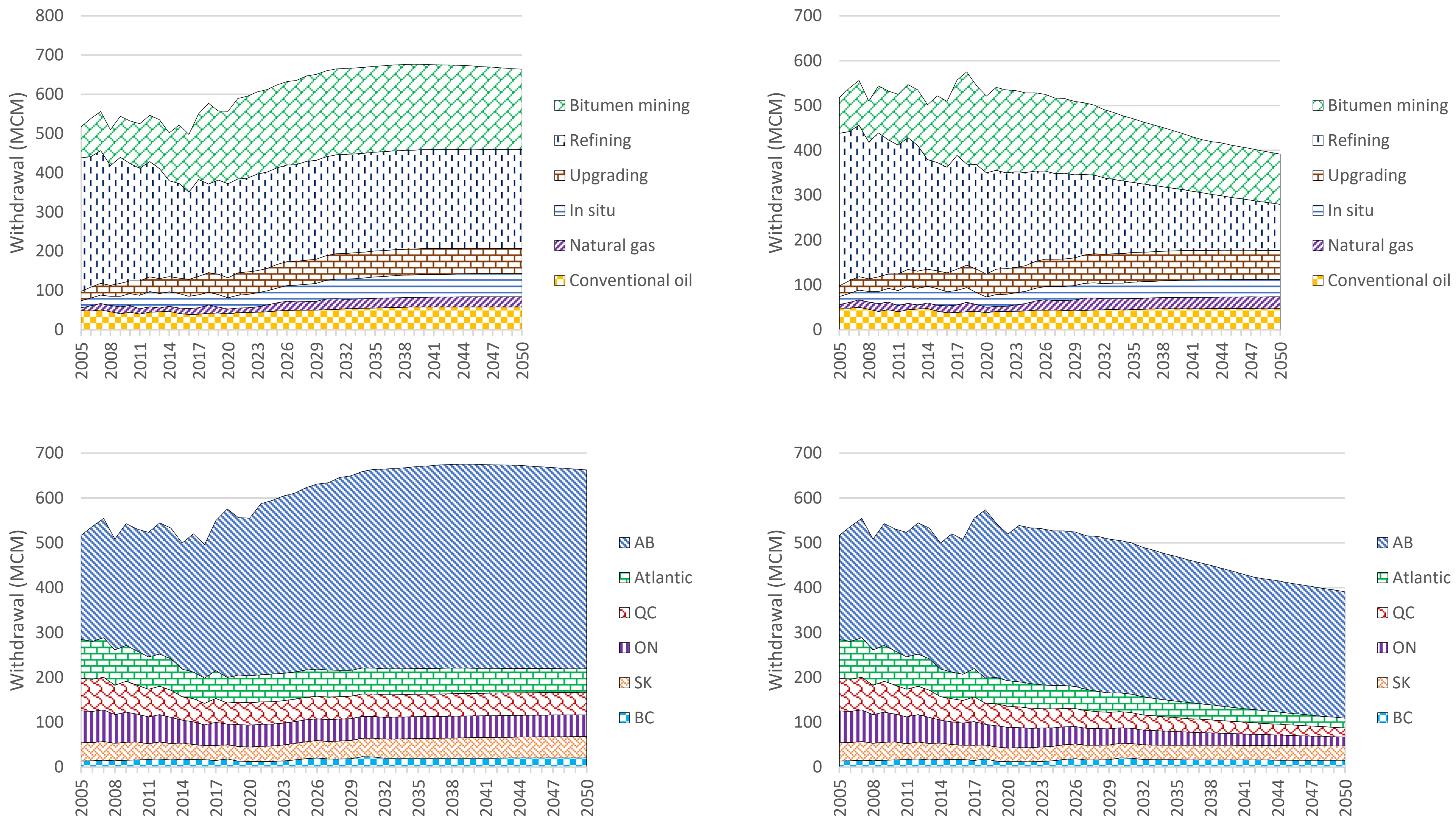

Figure 13: Annual national water withdrawal by subsector (top), province (bottom), reference scenario (left), decreasing water-use intensity scenario (right)

2.3.5 Alternative scenarios

The withdrawal and consumption by province and subsector under the three alternative scenarios in 2050 are shown in Figure 14 and Figure 15 alongside the reference scenario in 2020 and 2050. Refining is not listed because it was not altered for any of the alternative scenarios. The results of the alternative scenarios are shown for a greater selection in years in the appendix in Table 36.

The general trend observed is that the evolving scenario has a lower water demand than the reference scenario, the low-price scenario has a lower demand still, and the high price scenario has the highest demand. The bitumen mining and upgrading subsectors are notable in how little they differ among all scenarios. Water withdrawals in the high- and low-price alternatives for bitumen mining in 2050 range from +17% to -14% compared to the reference scenario and upgrading from +17% to -13%. These ranges contrast considerably with the other three sectors. Conventional oil ranges from +60% to -81%, natural gas from +65% to -50%, and in situ from +46% to -69%. These extremes occur in the low- and high-price scenarios, which are based on drastic oil and other hydrocarbon prices. The more tempered evolving scenario sees a change of between -5% and -19% in demand in all subsectors except for the conventional oil subsector, which sees a -60% change.

Table 19: Abbreviations used for alternative production account scenarios

Abbreviation	Meaning
Ref20	Reference scenario in 2020
Ref50	Reference scenario in 2050
Ev50	Evolving scenario in 2050
Lp50	Low prince scenario in 2050
Hp50	High price scenario in 2050

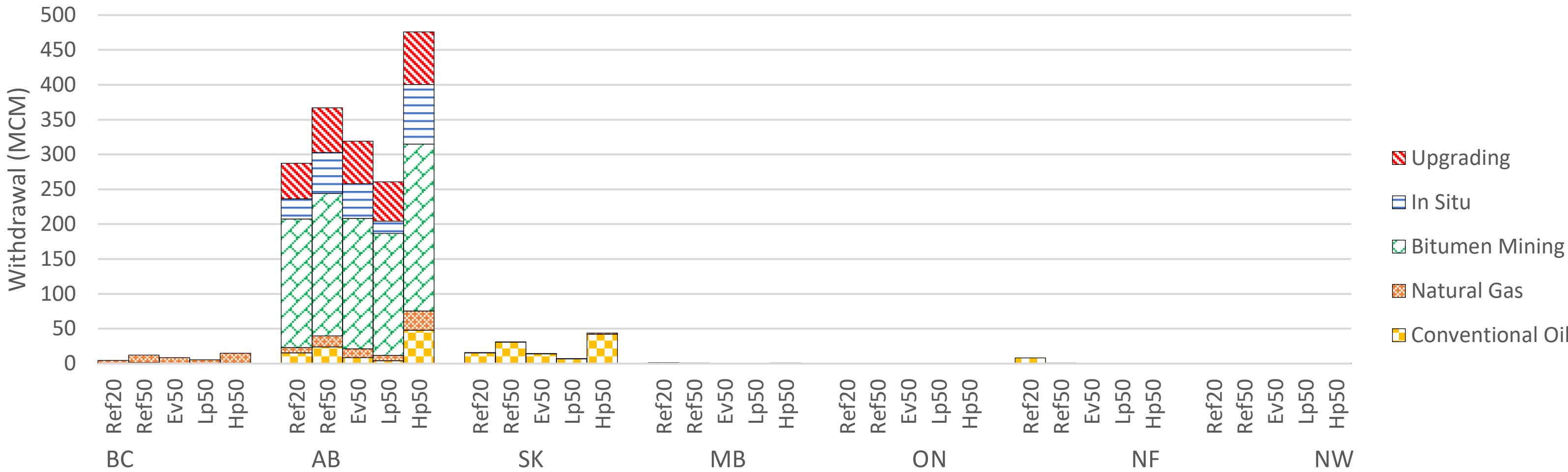

Figure 14: Withdrawal by province and subsector in the reference scenario in 2020 and all scenarios in 2050

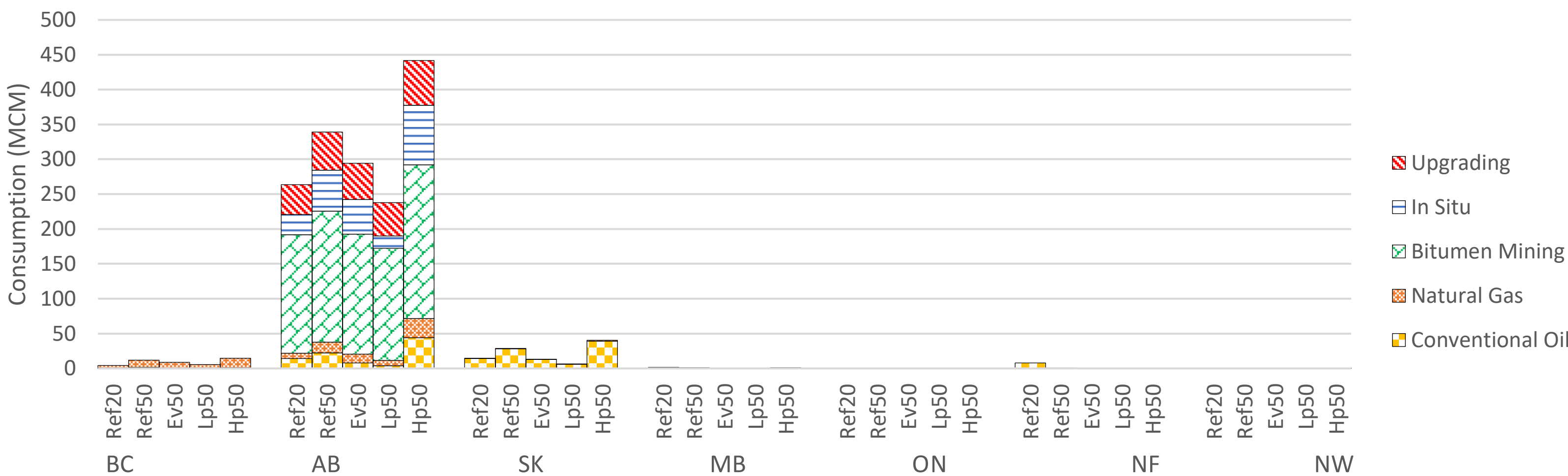

Figure 15: Consumption by province and subsector in the reference scenario in 2020 and all scenarios in 2050

2.3.6 Limitations

Comprehensive water use data for the oil and gas sector in Canada is unavailable to the public. Detailed breakdowns of technologies used, water intake and discharge by site, and production data of different products by site provided in sub-year intervals would have allowed a more interesting modelling approach. The fact that this data is not publicly available in any consistent manner leads to certain limitations such as having to use a yearly timestep, broad categorization of technologies (e.g., natural gas fracturing as a single entity), and imprecise geographic accounts of where water use occurs. While these limitations affected this study and leave room for obvious improvements should access to information improve for future researchers, they have not prevented the fulfilment of the objectives laid out.

Another limitation of this study is the extensive use of exogenous input parameters. Developing the relationships between global economic development and demand for oil and gas would allow for a model that can project water use under a greater set of interesting scenarios. As it stands, the developed model requires detailed accounts of future production of each considered oil and gas product, limiting the set of scenarios that can be recreated in the model.

2.4 Conclusion

This study used a bottom-up water use framework to model the direct non-saline water withdrawal and consumption of the oil and gas sector in Canada. The water-use intensities of various pathways were calculated for a number of historical years and were typically found to be decreasing over time. The improvement of water efficiency in many pathways was expected, as water conservation is an area of industrial and societal interest.

Despite improvements in water efficiency, the absolute water used by the sector has increased steadily since the model's base year of 2005. Absolute water withdrawals and consumption are expected to rise through to 2050 in the reference and high-price production scenarios. The low-price production scenario, however, will see slight decreases in absolute water withdrawals. Bitumen mining is the extraction method with the highest water-use intensity and the least variability in activity across the different production projections changes. This leads to variations in the sector's absolute water withdrawals to be attenuated relative to the volume of oil produced among the various production pathways, i.e., average water use per unit of oil produced decreases as absolute water use increases and vice versa.

The previous work this study built on used static water-use intensities of technologies taken from published sources rather than from observed water use. To improve the accuracy of the model, water-use intensities were developed that track observed water use over the historic period (2005-2020). Even with these improvements, efforts to validate the model's historic period results with Statistics Canada data produced imperfect results. The magnitude of the difference in results likely indicates differences in the scope of water use considered, though it cannot be determined with certainty what this difference is.

Due to the ever-changing economic, geopolitical, and technological environments in which this sector operates, its outlook changes constantly. Production projections from the CER are periodically updated to reflect this. The results presented in this chapter are based on production projections that were current at the time, though updates will be required for results to remain up to date. Future work could include further disaggregating the technologies used within subsectors to more finely project water use based on technological change, the creation of additional production projection scenarios, changing the model to use a sub-annual timestep, or the incorporation of hydrology and other water-use sectors to allow the assessment of physical water limitations and the oil and gas sector's effect on them. This model also provides a platform for analysing other aspects of water use in the oil and gas sector, such as the water use implications of adopting carbon emission mitigation technologies.

This analysis found many data limitations with respect to oil and gas production and its associated water use. These limitations should be remedied and more data made broadly available to increase the accuracy of academic and other civic efforts to understand and project future water-use impacts of the sector.

3 Projecting the water use of low carbon pathways in the oil sands under three carbon price scenarios

3.1 Introduction

Several levels of the Canadian government and companies operating in the Canadian oil sands are interested in reducing oil sands GHG emissions, whether to support Canada's meeting its national climate-related targets or as risk management measures aimed to secure the sector's ability to continue operating in an increasingly GHG-conscious world. Though reducing GHG emissions in an industrial sector can often lead to a focus on only cost and GHG emissions abatement, a large-scale change in the technologies used can affect how the sector uses water. This chapter explores the water-use impacts for several proposed low-carbon pathways at various stages of readiness or current deployment in the Canadian oil sands.

3.1.1 Knowledge gaps

Many low-carbon pathways have been suggested for the oil sands in Alberta. While the unit water-use rate has been estimated for some of the proposed technologies, the long-term water use of these pathways has not been modelled in an integrated bottom-up environment. This study fills the gap between the previously developed knowledge on how much water these technologies use on a per-unit basis and the long-term potential of these pathways to enter the oil industry and mitigate carbon emissions.

3.1.2 Objectives of this study

The specific objectives of this study are to:

(1) Integrate water-use considerations into a previous modelling effort on the GHG and cost impacts of several low-carbon oil sands pathways;

(2) Project the cumulative marginal water use associated with these pathways between 2019 and 2050;

(3) Quantify the pathways’ water use per unit of carbon abatement.

3.2 Methods

3.2.1 Definitions

Throughout this chapter the terms “pathway” and “scenario” are used. “Pathway” is used to refer to an application of a technology in the oil sands to reduce GHG emissions. The term “scenario” is used primarily to refer to the simulated carbon price levels.

3.2.2 Modelling framework

The methodological framework of this study is shown in Figure 16. The modelling done for this project was based on an earlier study by [58], Janzen et al. [59], [60], who used the Low Emission Analysis Platform (LEAP) modelling framework, among others, and for the most part considered GHG emissions and cost through an activity-intensity representation, e.g., X kg CO_2e/m^3 oil produced by SAGD. Several of these studies’ identified pathways and their technology deployment/penetration modelling results were used in the modelling portion of this study. These past studies’ results were used to develop indicators that combine the water use results established in this study with the previously developed cost and GHG abatement results.

This study has three stages: pathway development, modelling the water use of the pathways across several carbon price scenarios, and the integration of the model’s water-use results with the cost and GHG abatement results generated by the studies the pathways were sourced from. The pathway development stage considers how pathways were developed in earlier studies and either identifies or develops parameters based on those studies and the pathways in question that are required for the modelling of the pathways’ water use. The pathways are then modelled using the Water Evaluation And Planning (WEAP) framework to project their yearly marginal water consumption. The non-consumptive water use of the electricity pathways is also considered. Where possible, pathway activity and its corresponding water use is projected onto individual river basins. Integrated results and trade-off indicators are then developed from the average marginal water consumption of each pathway and the marginal cost and GHG abatement results developed in the pathways' source studies.

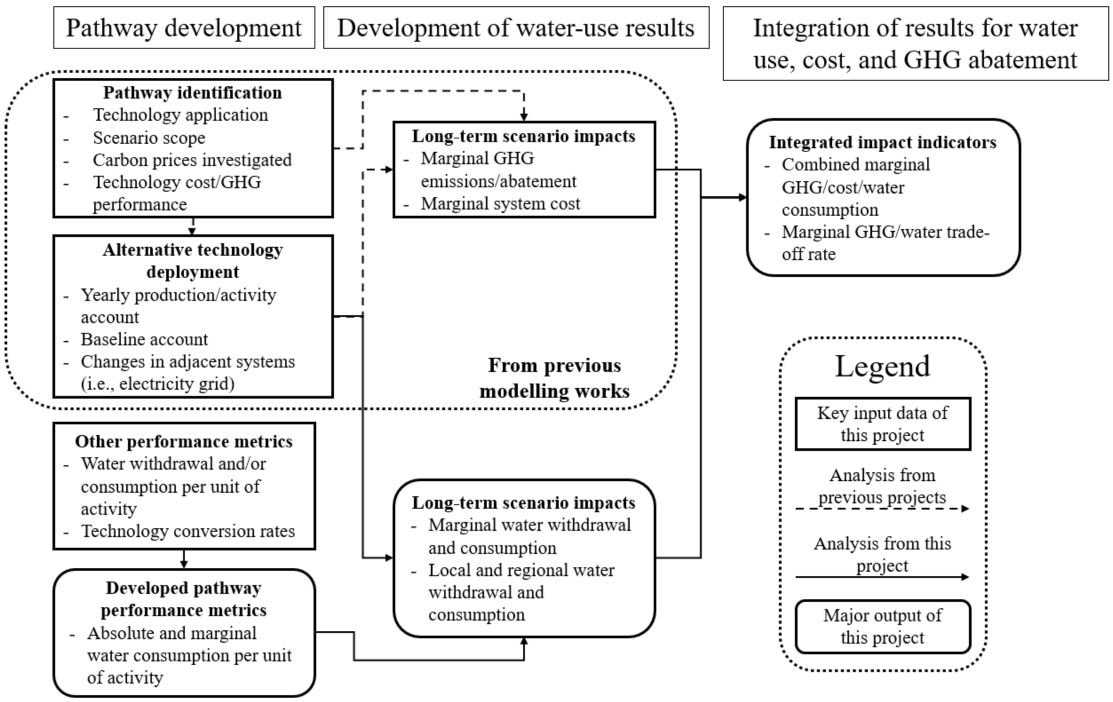

Figure 16: Study framework illustrating this project's workflow and integration with modelling by others

The carbon price scenarios used by Janzen et al. – a no-price scenario (\$0/t CO_2e), \$30/t CO_2e, and \$50/t CO_2e [58-60] – were adapted for this study and are denoted here as CP0, CP30, and CP50, respectively.

3.2.3 General introduction to the explored pathways

The low-carbon pathways assessed in this study can be integrated into the oil sands to produce hydrogen or electricity. The pathways of each type are discussed in sections 3.2.4 and 3.2.5, starting with a high-level description of each technology and the qualitative ways they change water use. The quantitative water footprint of each technology is also discussed, along with the sources or methods of estimating it. The pathways included in this study and the carbon price scenarios they are considered in are summarized in Table 20.

Table 20: Low-carbon pathways considered

Pathway name	Source	Sector[1]	Application notes	CP scenarios
SMR with carbon capture	[59]	U	Considered for use in oil sands upgrading	All
SAGD cogeneration	[60]	E	Expansion of cogeneration beyond existing capacity	All
Surface mining cogeneration	[60]	E	Expansion of cogeneration beyond existing capacity	All
Upgrading cogeneration	[60]	E	Expansion of cogeneration beyond existing capacity	All
Hydropower electrolysis	[58]	U	Expansion of hydroelectricity generation for use in electrolyzer farms	All
Wind electrolysis	[58]	U	Expansion of wind power generation for use in electrolyzer farms	None (negligible penetration)
Biomass gasification	[58]	U	Whole-tree biomass gasification to produce hydrogen	All
Biomass pyrolysis	[58]	U	Whole-tree biomass pyrolyzed into bio-oil, then reformed to produce hydrogen	All
Nuclear power	[58]	E	Construction of a 703 MW nuclear electricity plant at an oil sands mine	CP30 and CP50

[1]U is the upgrading sector, E is the electricity sector, CP refers to carbon price.

3.2.4 Hydrogen pathways

Low-carbon methods of producing hydrogen to offset hydrogen produced through steam methane reforming (SMR) were considered. The GHG reduction of the pathways was based on the comparatively low emission intensity of the given pathway compared to SMR.

The water use of the hydrogen pathways was likewise based on the net change caused by producing hydrogen from the given pathway instead of SMR. SMR uses process water from which some portion of the produced hydrogen is derived. Process water needs to be pure, and the water treatment process produces some wastewater that is assumed to be disposed of. SMR often requires cooling as well. The total consumption footprint represents a combination of these uses and was considered to be 11.55 L/kg H_2 based on work by Lampert et al. [105]. These water uses occur at the upgrading facility, which, for the hydrogen pathways considered, is within the North Saskatchewan River Basin.

Biomass gasification

Gasification is a process capable of producing hydrogen. The process typically involves heating plant matter in the presence of steam and limited oxygen to produce syngas, a mixture of hydrogen, carbon monoxide, and carbon dioxide [106]. The carbon monoxide can be reacted with steam over a catalyst to produce additional hydrogen. The specific application modelled in this study involves the use of whole-tree biomass feedstock. The gasification facility would be located approximately 500 km from upgrading facilities in Fort Saskatchewan and would use a pipeline to deliver the produced hydrogen.

The production account and long-term integrated cost and GHG emissions of the pathway are based on work by Janzen et al. [58], who used data from a techno-economic study by Sarkar et al. [107]. As the carbon in the biomass would have originated in the atmosphere, the carbon dioxide emissions from the feedstock are ignored, though emissions from fuel use associated with the facility are considered.

Water is consumed in gasification partially for process needs, including being split into oxygen and the hydrogen product, as well as for cooling purposes. The water consumption intensity of this pathway is taken to be 16.43 L/kg H_2, based on work by Lampert et al. [105]. This water use is assumed to be split evenly between the Athabasca and Peace river basins based on the 500 km pipeline transportation distance assumed in the study, allowing either river basin to be the source of biomass, and because both river basins having appropriate biomass resources.

Biomass pyrolysis and reforming

Hydrogen can be produced from biomass by converting the biomass to bio-oil using fast pyrolysis then steam reforming the bio-oil to produce hydrogen. The application simulated in the techno-economic assessment underlying the data used in the cost and GHG abatement modelling work involves the use of whole trees chipped and converted to bio-oil in the field, then transported by truck to the oil sands upgrading facility, where the bio-oil is steam reformed to produce hydrogen. The production account and long-term integrated cost and abatement potential are based on modelling work by Janzen et al. [58], which used techno-economic performance results from Sarkar et al. [108]. GHGs are emitted during biomass production and transportation, facility construction, bio-oil transportation, and other minor stages.

In this pathway, water is consumed at the pyrolysis and reforming stages. The water requirement of the pyrolysis process per produced unit of bio-oil is based on Wong et al.'s study on renewable diesel production [109]. The mass ratio of producing hydrogen from bio-oil and the water consumed at the steam-reforming stage were based on work by Sarkar et al. [108]. This calculation is shown in Equation 3. The production of biomass was not assigned a water consumption intensity because tree growth is rain-fed rather than associated with water withdrawn from bodies of water. The water used for pyrolysis (8.16 L/kg H_2) is deemed to be split evenly between the Athabasca and Peace river basins, similar to the biomass gasification pathway. The water used during reformation (20 L/kg H_2) is from in the North Saskatchewan River Basin.

Equation 3: Estimated water footprint for hydrogen production through pyrolysis and steam reformation

$$28.17\frac{L\ water}{kg\ H_2} = 1.336\frac{L}{kg\ bio\ oil} * 6.11\frac{kg\ bio\ oil}{kg\ H_2} + 20\frac{L\ water}{kg\ H_2}$$

Hydropower and electrolysis

Electrolysis is the process of splitting water molecules into oxygen and hydrogen using electricity. Depending on the source of electricity, replacing SMR with hydrogen produced by electrolysis may or may not reduce GHGs. This pathway requires the construction of a hydroelectric dam and an electrolyzer farm to produce green hydrogen, and the use of pipelines to deliver the hydrogen to upgrading facilities in Fort Saskatchewan. The production account and long-term integrated cost and GHG abatement potential of the pathway are based on modelling by Janzen et al. [58]. The techno-economic performance of the pathway is based on a site near Grande Cache, Alberta [110, 111] and assumes some minor GHG emissions associated with hydropower generation.

The water-use intensity of electrolysis is estimated through the water treatment, cooling, and process water data taken from work by Lampert et al. [105] to be 30.3 L/kg H_2.

Upstream water consumption associated with generating the energy for the electrolyzer was also considered, as the evaporation of water in hydroelectric reservoirs can be significant. The electrolysis electricity requirement of 4.8 kWh/Nm^3 H_2 (53.4 kWh/kg H_2) was taken from Olateju and Kumar's techno-economic assessment [111]. The simulated hydroelectric site near Grande Cache does not have a specific water consumption estimate, so a regionally based consumption intensity was used. A study by ATCO Power et al. [112] estimated the water evaporation rates of Albertan reservoir hydroelectric sites to be between 14.5 and 21.9 L/kWh. This study uses the midpoint of this range (18.2 L/kWh) as a consumption rate for the electricity consumed by the electrolyzer farm. This produces an upstream water consumption intensity of 972.0 L/kg H_2, for a total consumption intensity of the pathway of 1002.3 L/kg H_2. Grand Cache is in the Peace River Basin; therefore, the water use of this pathway has been assigned there.

Wind power and electrolysis

This pathway simulates the expansion of an existing wind farm near Pincher Creek, Alberta with additional turbines that supply a newly added electrolyzer farm. The produced hydrogen would be transported to upgrading facilities in Fort Saskatchewan by pipeline. The techno-economic performance of this pathway is based on work by Olateju et al. [113]. Minor GHG emissions are associated with the pathway resulting from building the facility and operating the hydrogen pipeline. Modelling work by Janzen et al. [58] found that the poor economics of the pathway led to negligible adoption even in the CP50 scenario.

Despite this pathway's negligible adoption making it ill-suited for inclusion in the modelling portion of this study, its water-use intensity has been estimated. Due to the relatively simple way hydrogen pathways have been modelled, this single parameter will allow this pathway to be included in one part of this study's results, specifically Figure 33.

This pathway has an electrolyzer stage similar to that of the hydropower and electrolysis pathway, i.e., 30.3 L/kg H_2 direct water use and an energy requirement of 53.4 kWh/kg H_2. The upstream water use associated with wind power is significantly lower than for hydropower, estimated to be 0.006 L/kWh by Ali et al. [114]. This results in an upstream water use intensity of 0.26 L/kg H_2 and a total water intensity of 30.54 L/kg H_2. Pincher Creek is located in the South Saskatchewan River Basin; therefore, the water use of this pathway would be assigned to that basin were it not negligible.

Steam methane reforming with carbon capture

The typical SMR configuration would exhaust its produced carbon dioxide to the atmosphere, but the concentrated stream of produced CO_2 makes it a viable candidate for carbon capture. The application simulated in this project involves SMR with carbon capture located at upgrading facilities in Fort Saskatchewan and a pipeline to transport captured CO_2 to a nearby sequestration site.

The production account and long-term integrated cost and GHG abatement potential are based on modelling by Janzen et al. [59], which used techno-economic data from Verma et al. [115]. Minor GHG emissions associated with this pathway include the CO_2 that escapes the capture process and emissions associated with electricity consumed. Water is consumed in this pathway in the same processes as in the standard SMR pathway, i.e., water treatment, production, and cooling processes. The water intensity of each process is based on work by Lampert et al. [105]. Increases in consumption during water treatment and cooling contribute to the total intensity of 13.63 L/kg H_2, slightly more than the 11.55 L/kg H_2 consumed in the standard SMR process. As this process occurs at or near the upgrading facility, the water use associated with this pathway is deemed to occur in the North Saskatchewan River Basin.

Hydrogen pathway water use intensities

Table 21 shows the net marginal water use intensity of each hydrogen pathway technology considered, broken down by river basin. As the baseline technology, SMR has no marginal water use. The underlying water use of SMR is 11.55 L/kg H_2, located entirely in the North Saskatchewan Basin. Pathways showing this quantity as a negative in the North Saskatchewan Basin therefore entirely offset the water use of SMR and do not cause any other water use in that basin.

Table 21: Net water use intensity of each pathway in L/kg H_2 compared to SMR

Technology	North Saskatchewan	South Saskatchewan	Athabasca	Peace
SMR	0	0	0	0
SMR with carbon capture	2.08	0	0	0
Biomass gasification	-11.55	0	8.21	8.21
Biomass pyrolysis	8.45	0	4.08	4.08
Wind electrolysis	-11.55	30.60	0	0
Hydro electrolysis	-11.55	0	0	1,002.25

3.2.5 Electricity pathways

By producing electricity for local consumption or export, oil sands operations can reduce activity and resulting GHG emissions and water consumption elsewhere in the Alberta electricity grid. Depending on the increase in emissions and water consumption associated with the production of the electricity in the oil sands, the net change in either measure may be either positive or negative.

The activity account of each electricity pathway is the amount of electricity generated each year by the pathway in question and the set of existing grid technologies affected by this generation. These accounts were developed in earlier studies in a Canada-wide Low Emission Analysis Platform (LEAP) model. This model included several economic sectors and a robust representation of the electrical systems of many provinces, including Alberta. The basic LEAP model used is described in detail in other works [116, 117].

This study developed a WEAP model that integrates these previously developed baseline and pathway activity accounts. The water withdrawal and consumption intensities of different fuel and cooling technology combinations were taken from previous works focused on coal [118], natural gas [119], and renewable technologies [114], and are listed in Table 37 in section 6.1.1 of the appendix. The model is used differently for each electricity pathway to determine baseline water withdrawal and consumption and is described in the sections below. Electricity generation and the resulting water use are assigned to river basins based on a constant distribution by technology, as given in Table 22. This distribution was made based on a list of Alberta power stations of various types, their generation capacity in MW, and their river basin location (generalized to the four basins shown in the table). This list was originally compiled in an earlier study [64]. This list has been reviewed and expanded before it’s use in this study. The entries in this list with a capacity greater than 50 MW are shown in Table 39 in the appendix.

Table 22: Distribution of water use by electricity generation technology

Technology	North Saskatchewan	South Saskatchewan	Athabasca	Peace	Source
Oil combustion plant	50.0%	50.0%	0.0%	0.0%	Assumed
Oil sands cogeneration	0.0%	0.0%	96.1%	3.9%	Manually compiled power station list
Natural gas simple cycle	27.4%	24.1%	10.6%	37.9%	Manually compiled power station list
Natural gas combined cycle	0.0%	95.7%	0.0%	4.3%	Manually compiled power station list
Converted coal-to-gas	79.9%	20.1%	0.0%	0.0%	Manually compiled power station list
Coal plant	85.1%	12.6%	0.0%	2.3%	Manually compiled power station list

Cogeneration

Cogeneration in the oil sands has long been used to produce electricity alongside the steam production of in situ and upgrading or process water heating of surface mining. The three pathways considered here are cogeneration in each oil sands subsector: surface mining, in situ, and cogeneration. Cogeneration is unique in this study as it is the only pathway currently in use at scale in the sector. In this study, the effects of expanding the pathway are modelled, in contrast to the modelled reference case in which existing cogeneration continues to operate but no new capacity is built.

The activity account of the pathway is based on previous modelling work in the Canada-wide LEAP model [60]. In that work, the expansion of electricity generated in the oil sands by cogeneration offsets other generation elsewhere, and the specific technologies and degree to which they increased or decreased in activity were modelled in LEAP while the total demand on the electricity grid remained constant. An example of this effect is given in

Figure 17, which shows the change in generation from each affected technology in the SAGD cogeneration CP30 scenario. Figure 45 - Figure 53 in section 6.1.3 in the appendix show a comparable net generation change account for each cogeneration application and carbon price.

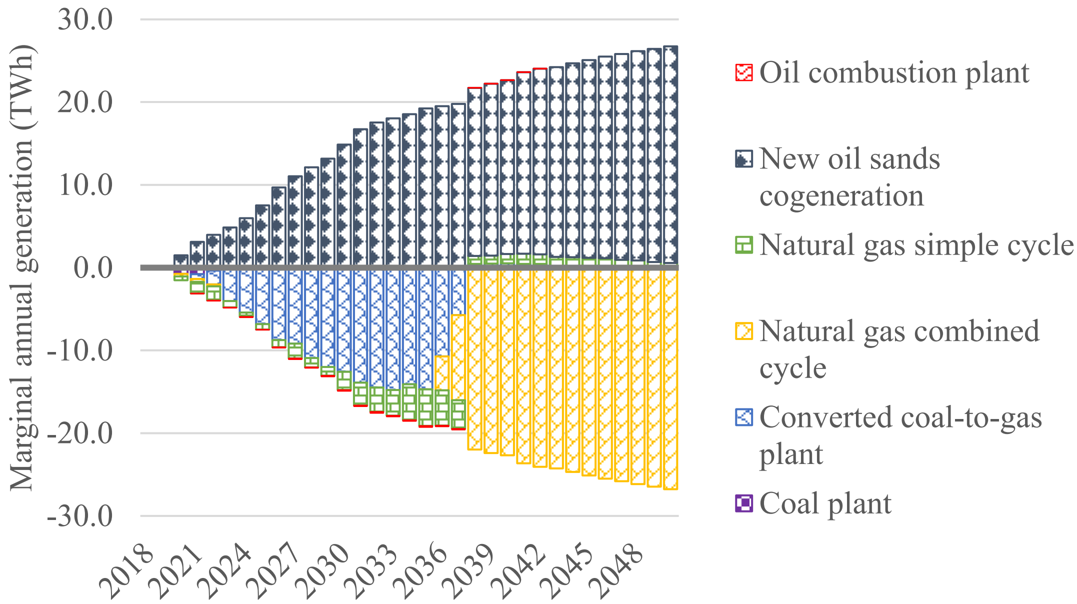

Figure 17: Marginal Alberta-wide electricity generation by generating technology and year in the SAGD-cogeneration CP30 scenario [60, 117]

The water withdrawal and consumption intensities of cogeneration used in this analysis (0.58 m^3/MWh and 0.28 m^3/MWh, respectively) are based on work by Ali et al. [119], where they were calculated based on a comparison to natural gas combined cycle with a scaling factor to adjust for cogeneration's higher thermal efficiency. Withdrawal and consumption intensities of other technologies were based on those shown in Table 37 and Table 38 in the appendix.

For each year, the net change in withdrawal or consumption was calculated using the equation below:

$$\Delta V = \sum_i W_i * \Delta G_i$$

where ΔV is the total change in water withdrawal or consumption in m^3 in the cogeneration pathway in question, W_i is the withdrawal intensity of technology i in m^3/MWh, ΔG_i is the change in electricity generated with technology i in MWh due to the adoption of the pathway in question, and i represents the set of technologies affected by the pathway's adoption in the given scenario.

Nuclear power

The integration of nuclear power with oil sands facilities has long been considered because of the sector's immense energy needs and the potentially abundant energy available through nuclear processes [120]. The only application of nuclear power considered in this work is the generation of electricity, though nuclear power has been proposed for other applications including the production of low-grade process heat and steam.

This pathway simulates a 703 MW nuclear power generation facility constructed at an oil sands mine that would supply power to the mine and export excess power generated to the grid. The long-term pathway activity, emission reduction, and cost are based on Janzen et al.'s study, in which the emission reduction was calculated as the amount of electricity generated by the pathway multiplied by the average emission factor of the Alberta grid in a baseline scenario and assessed each year from 2018 to 2050 using the Canada-wide LEAP model [58]. That study did not include GHG emissions from nuclear power generating activities. This baseline account of electricity generation was used to estimate the average annual water withdrawal and consumption of the grid from 2018 to 2050 and is provided in Table 40 in section 6.1.2 of the appendix. The average grid withdrawal and consumption intensities are shown in Figure 18. As these grid-average water-use intensities were used rather than modelling discrete effects on different generation technologies, the water use is not associated with a river basin location and thus no associated results of this type are included here. The water withdrawal and consumption intensities for nuclear were based on generation using a cooling tower, assessed by an earlier study to be 4.17 m^3/MWh and 2.71 m^3/MWh, respectively [114].

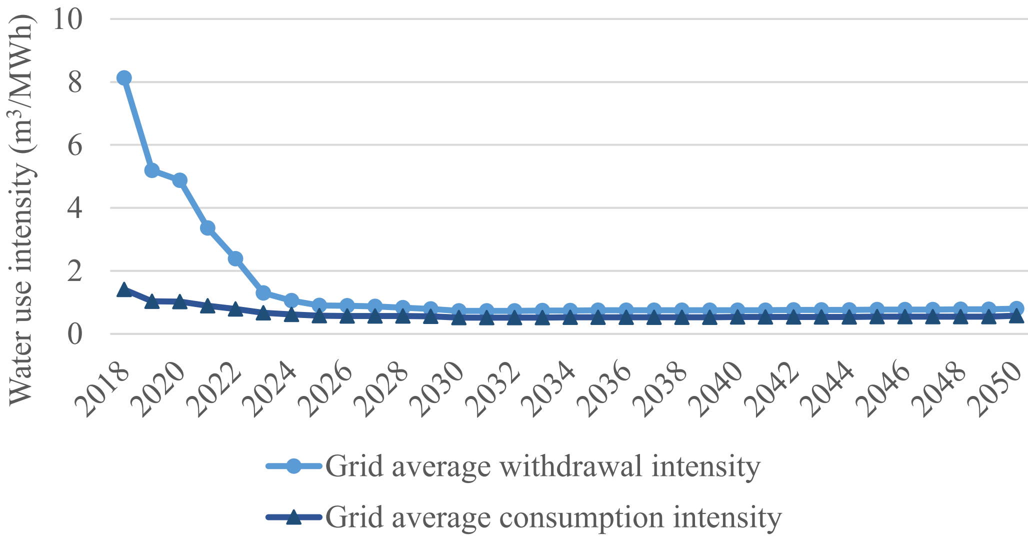

Figure 18: Alberta electricity grid average withdrawal and consumption intensity by year assumed to be offset by the adoption of nuclear generation

It should be noted that the previous modelling work for this pathway found no penetration in the absence of a carbon price (CP0). Under a \$30/tCO_2e or \$50/tCO_2e carbon price (CP30 and CP50, respectively), the modelling showed that the nuclear power facility will begin operating in 2035 or 2031, respectively.

3.3 Results and discussion

3.3.1 Water-use results

Hydrogen pathways results

The total water consumption from the hydrogen pathways combined is shown by year for each carbon price in Figure 19. These results are presented by technology in Figure 20,

Figure 21, and Figure 22 for select years. The total water consumption increases with increasing carbon price, which is expected. The annual consumption is characterized by multi-year periods of rapid growth and periods of relatively small intra-year change. This follows a similar trend in the underlying projections of bitumen upgrading activity, as annual water consumption only increases when new upgrading capacity is added. Very little upgrading capacity is projected to be added after 2030, and thus annual water consumption will plateau for the last two decades of the projection. At this projected maximum annual water consumption, there is a 165% higher marginal consumption with CP30 than with CP0, and a 43% higher marginal consumption with CP50 than with CP30. The general trends observed are similar in all carbon price scenarios.

The technology accounting for the vast majority (~97%) of water consumption is hydropower and electrolysis, primarily caused by the upstream consumption associated with generating the hydropower. SMR with carbon capture, biomass pyrolysis, and biomass gasification are the next highest consuming pathways in descending order. All three show a similar net consumption of water.

The net consumption of water increases in every river basin except the North Saskatchewan, where water consumption decreases due to lower activity of the reference hydrogen production pathway, SMR. Most of the water consumption in the hydrogen pathways is in the Peace River Basin because of hydropower electrolysis. The water consumption in the Athabasca River Basin is of a similar order of magnitude as the consumption in the North Saskatchewan River Basin. The consumption in these two basins is shown in Figure 23, Figure 24, and Figure 25 for select years.

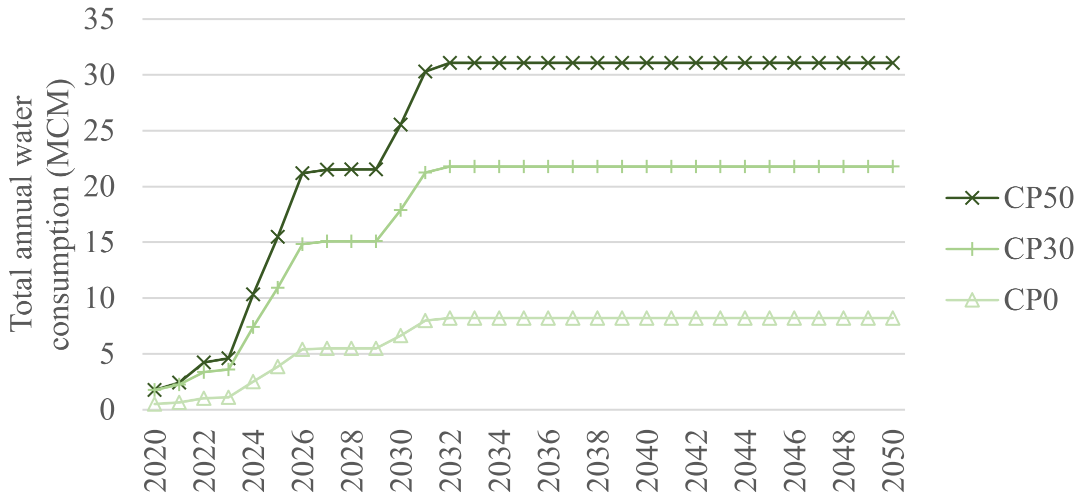

Figure 19: Annual marginal water consumption of the four hydrogen pathways combined, shown for each carbon price scenario

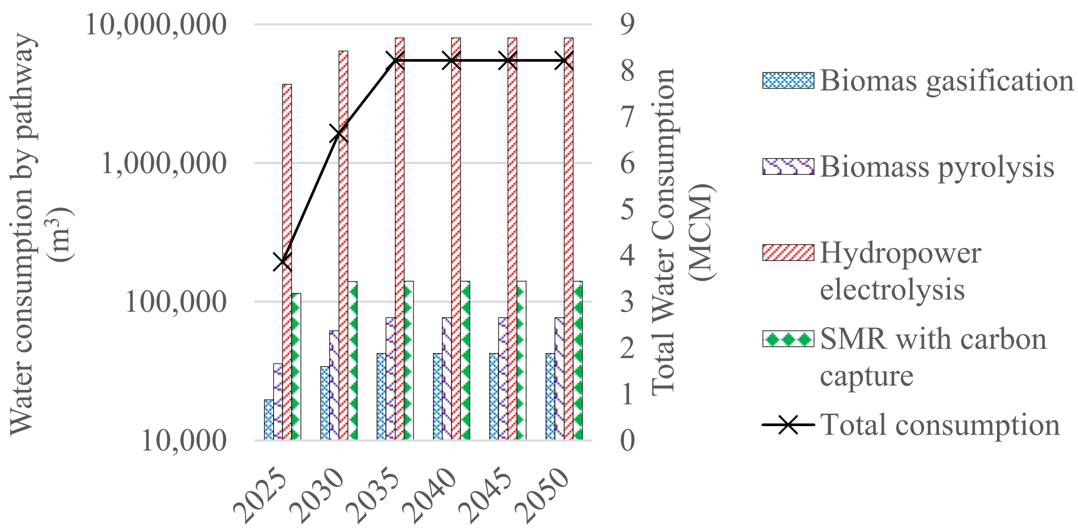

Figure 20: Marginal water consumption of the hydrogen pathways (total and disaggregated by pathway) in select years in the CP0 scenario

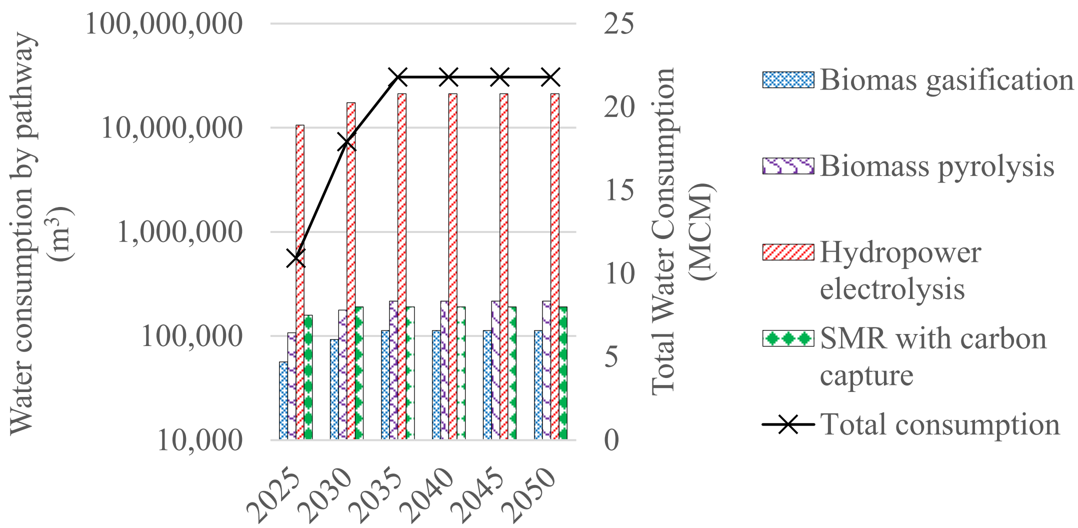

Figure 21: Marginal water consumption of the hydrogen pathways (total and disaggregated by pathway) in select years in the CP30 scenario

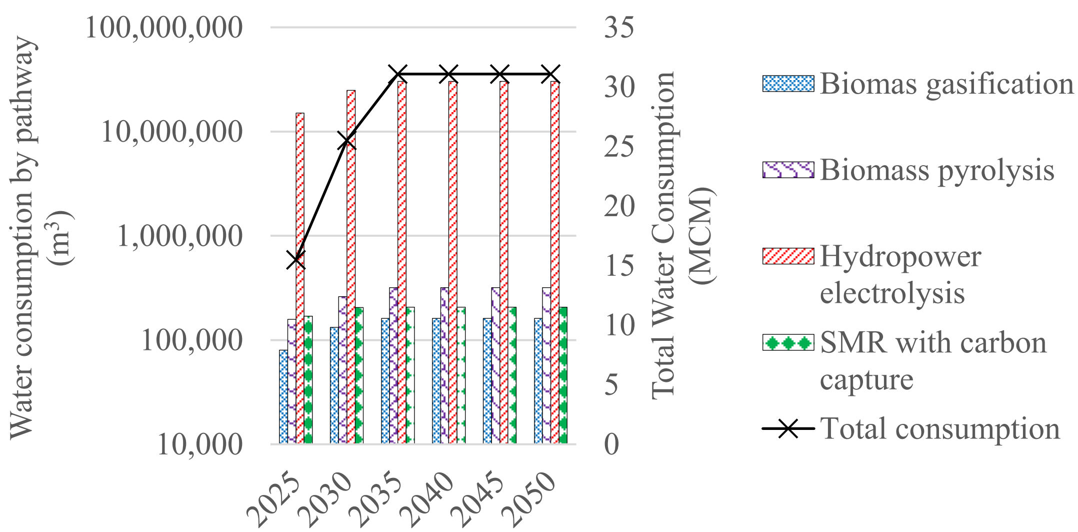

Figure 22: Marginal water consumption of the hydrogen pathways (total and disaggregated by pathway) in select years in the CP50 scenario

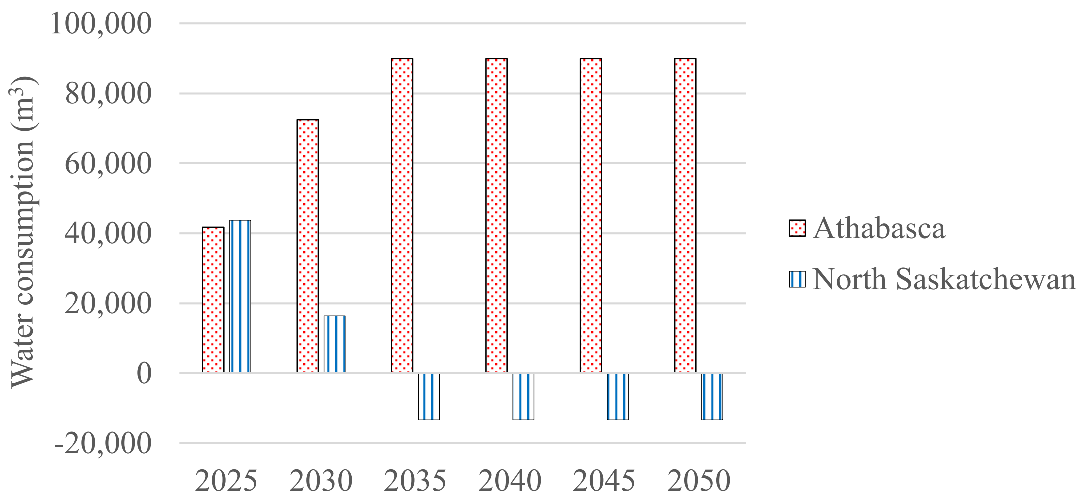

Figure 23: Marginal water consumption of the hydrogen pathways in the North Saskatchewan and Athabasca river basins in select years in the CP0 scenario

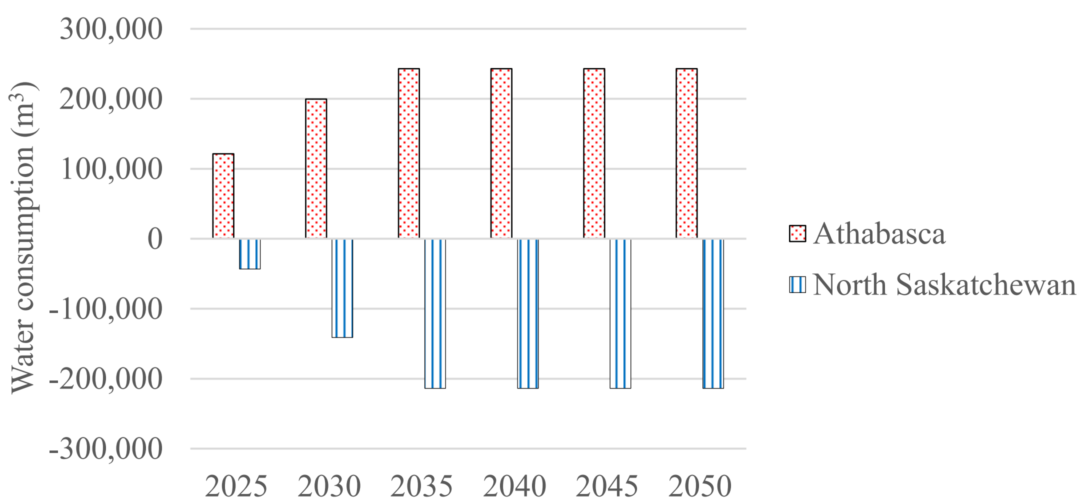

Figure 24: Marginal water consumption of the hydrogen pathways in the North Saskatchewan and Athabasca river basins in select years in the CP30 scenario

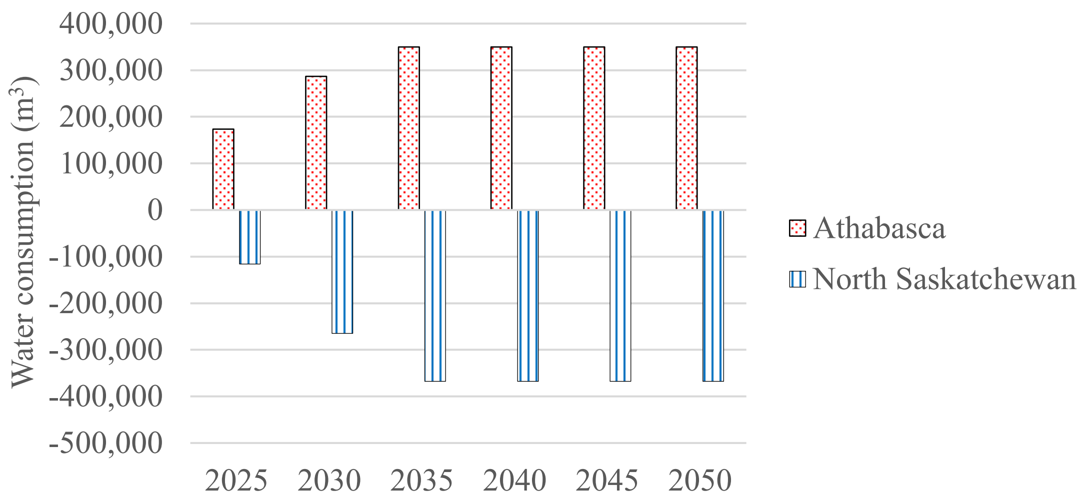

Figure 25: Marginal water consumption of the hydrogen pathways in the North Saskatchewan and Athabasca river basins in select years in the CP50 scenario

Electricity – nuclear pathway results

The water-use results for the electricity-nuclear pathway consist of the water withdrawal and consumption of the nuclear generation and the withdrawal and consumption of the rest of the grid that are offset. The results of this pathway were developed with grid average emissions, water withdrawal, and water consumption factors based on a baseline scenario. One implication of this is that while the simulated carbon price level determines which year the nuclear power facility begins operating, water withdrawal and consumption in each year are based only on the year. The annual withdrawal and consumption of nuclear generation are constant values, though the grid average withdrawal and consumption increase slightly over the projected period and thus the net withdrawal and consumption decline from approximately 19.1 and 12.2 MCM, respectively, in 2031 to 18.6 and 11.9 MCM by 2050. This is shown in Figure 26, where the first year shown is 2031, as that is the first year of activity in the CP50 scenario; activity starts in 2035 in the CP30 scenario. No activity occurs in the CP0 scenario.

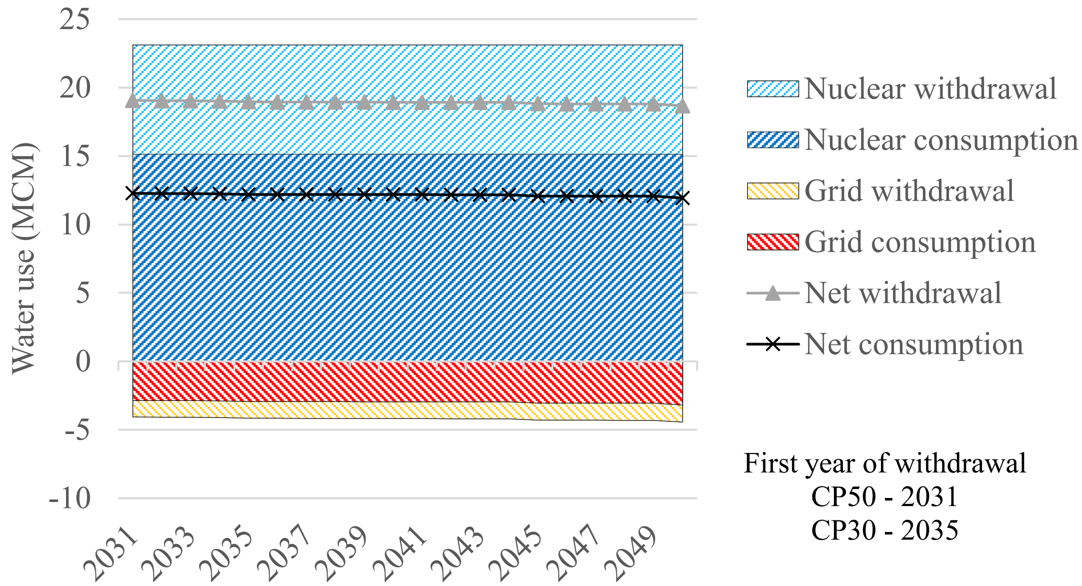

Figure 26: Marginal water withdrawal and consumption of nuclear generation and the rest of the AB grid

Electricity – cogeneration pathways results

The water-use results from the cogeneration pathways consist of annual water withdrawal and consumption from five technologies spread across four river basins. The results for the pathway under different carbon prices are shown side-by-side for select years. The SAGD cogeneration pathway in shown in Figure 27, the surface mining cogeneration pathway in Figure 28, and the upgrading cogeneration pathway in Figure 29. The net withdrawal and consumption totals are negative in all scenarios, indicating reductions in total water use. The cogeneration activity added occurs primarily in the Athabasca River Basin, where there is a net increase in withdrawal and consumption in all scenarios. The rest of the added cogeneration activity is in the Peace River Basin, where there is a net decrease in withdrawal and consumption in the SAGD cogeneration scenarios and increases in all other scenarios. The North and South Saskatchewan river basins show decreases in withdrawal and consumption in all scenarios, though by 2040 the decreases are concentrated in the

South Saskatchewan Basin. This is because early in the projection period, converted coal-to-gas is the generation technology that sees the largest reductions in activity, and this technology is located primarily in the North Saskatchewan River Basin, but by the end of the projection period the main technology being offset is purpose-built natural gas combined cycle, which is located primarily in the South Saskatchewan River Basin. Starting in about 2040, the coal-to-gas converted plants see slightly increased activity because of the cogeneration pathways. The natural gas simple cycle technology sees much smaller changes in water use compared to coal-to-gas converted plants, though it follows a broadly similar pattern of decreased water use pre-2040 and an increase from 2040 onward.

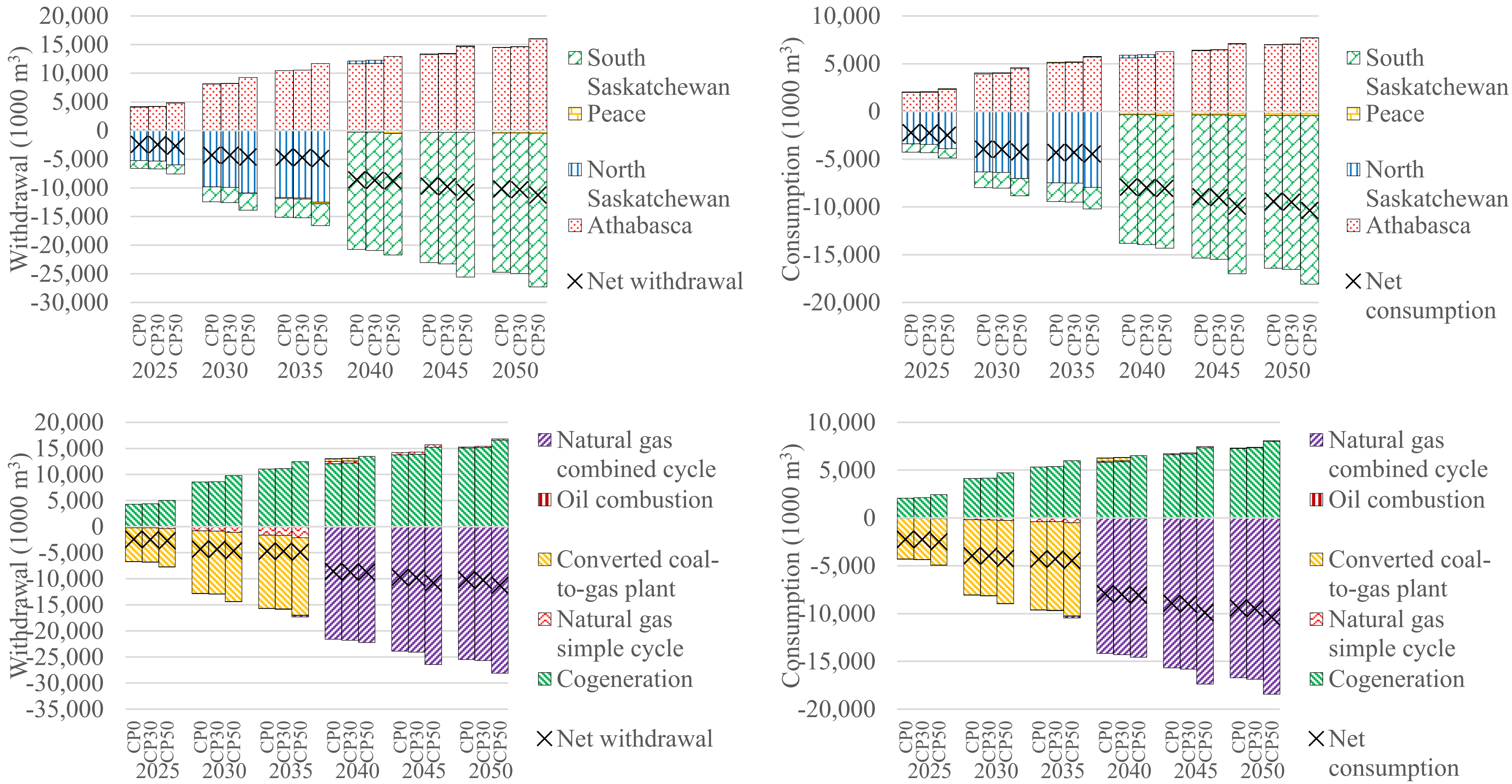

Figure 27: Marginal water withdrawal (left) and consumption (right) in the SAGD cogeneration pathway by carbon price and river basin (top) and generation technology (bottom) for select years

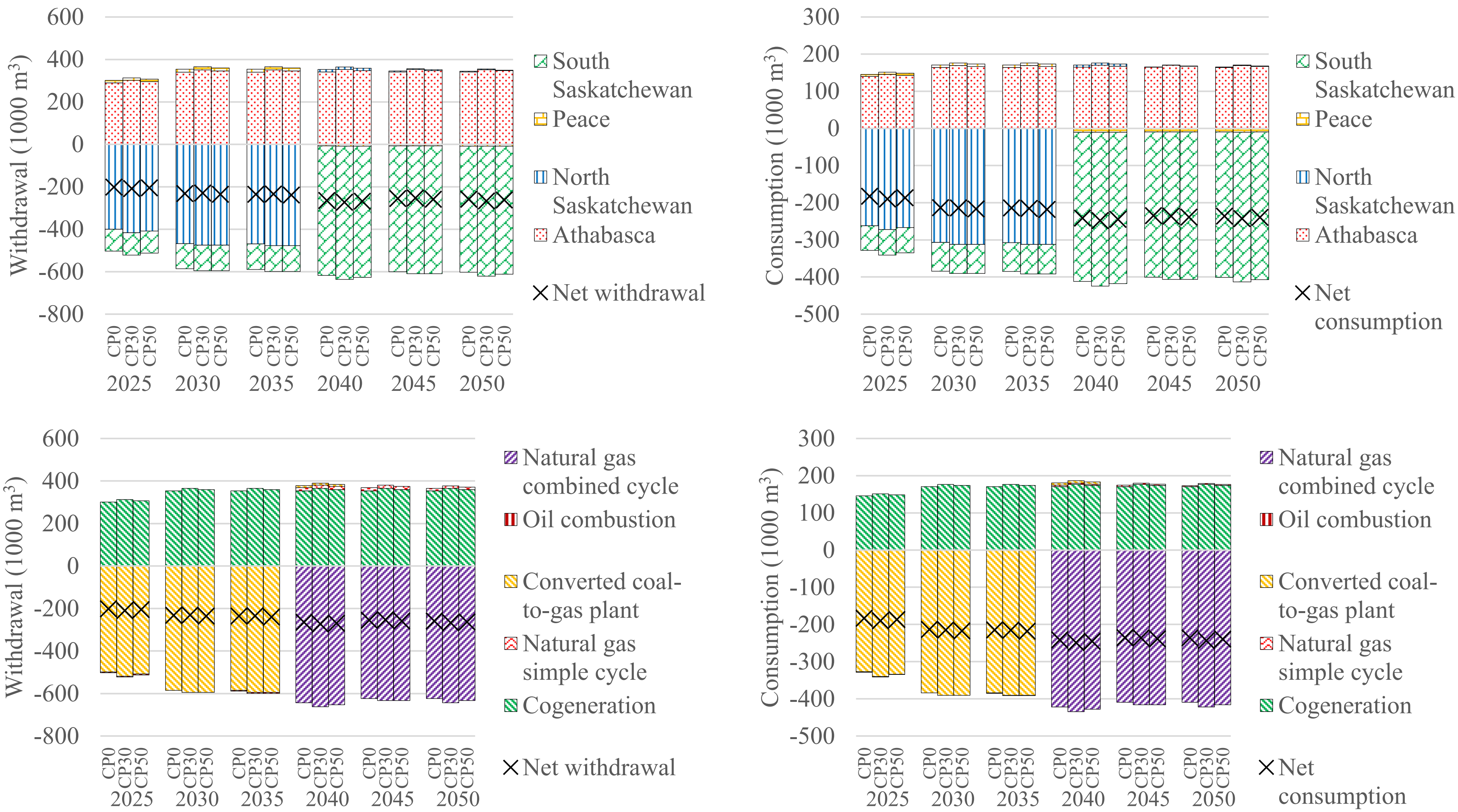

Figure 28: Marginal water withdrawal (left) and consumption (right) in the surface mining cogeneration pathway by carbon price and river basin (top) and generation technology (bottom) for select years

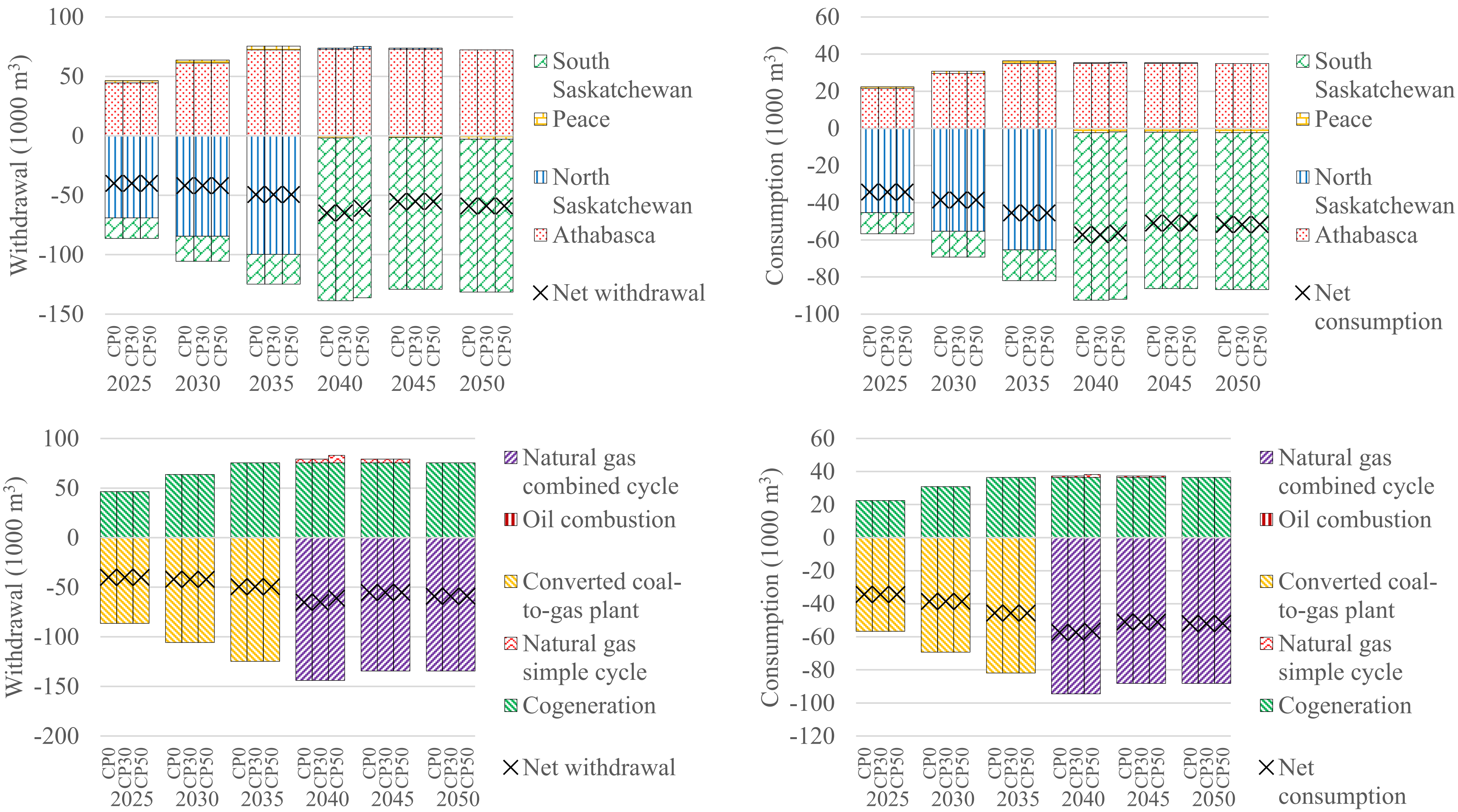

Figure 29: Marginal water withdrawal (left) and consumption (right) in the upgrading cogeneration pathway by carbon price and river basin (top) and generation technology (bottom) for select years

3.3.2 Integrated water use, GHG abatement, and cost results

This section presents the water consumption results from the previous section along with the GHG abatement and cost results developed in the earlier modelling projects on which this work is based.

Water consumption – GHG abatement results

Water consumption associated with the pathways presented in this study is a byproduct of their primary purpose, the abatement of GHG emissions. In this sense, increases in water consumption can be thought of as a cost, and the results presented in this section will follow this paradigm. The measure of a pathway's average marginal water consumption divided by its marginal abatement will be referred to as the marginal abatement water consumption rate (MAWCR), with units of m^3 (water)/t CO_2e. Figure 30, Figure 31, and Figure 32 show the pathways as a series of blocks. The height of each block is based on the pathway's MAWCR, and pathways are arranged by MAWCR magnitude from negative (i.e., pathways that reduce water consumption through their implementation) to the positive. Each block's width is based on the total cumulative abatement potential of the pathway. The area of each block, therefore, shows the total cumulative marginal water consumption. This chart format is based on a similar form for presenting GHG abatement and monetary cost results, typically referred to as an abatement cost curve, but in this case monetary cost has been replaced with water consumption. Figure 30, Figure 31, and Figure 32 show the performance of all pathways under CP0, CP30, and CP50, respectively.

The cogeneration pathways show water savings in all scenarios, though the MAWCR of individual cogeneration pathways ranges from -2.2 m^3/t CO_2e to -2.5 m^3/t CO_2e. The adoption of cogeneration increases with increasing carbon taxes, though the effect is relatively minor and therefore the total water consumption of the pathway likewise is relatively consistent across carbon prices. The nuclear power pathway does not experience any activity in its CP0 scenario. The pathway has a slightly lower MAWCR in the CP50 scenario than in the CP30. The average grid water withdrawal and consumption are slightly lower in the period 2031-2034 compared to 2035-2050, meaning the absolute volumes of water withdrawal and consumption offset by the nuclear pathway are lower in these years, but because of the rapidly decreasing grid emission factor in these years (not modelled in this project but considered in the underlying emissions and cost modelling), the water consumed per unit of abatement is lower in the CP50 pathway because it started sooner. Stated another way, the difference between the nuclear pathway in the CP30 and CP50 scenarios is the activity in 2031-2034, during which time the water consumption in the grid offset by the pathway will be slightly less per MWh of activity, but the CO_2e emissions per MWh are higher by enough that the net effect is a decrease in the pathway's average net water consumed per unit of CO_2e abatement.

The MAWCR of the SMR with carbon capture pathway is 0.52 m^3/t CO_2e in all carbon price scenarios, though the total water consumption of the pathway increases with increasing carbon price because of increased adoption. The other hydrogen pathways show a slight decrease in marginal water consumption rate in CP30 compared to CP0, though no further change occurs in CP50. The hydropower hydrogen pathway has a marginal water consumption rate an order of magnitude higher than the other pathways in all carbon price scenarios, whose peak was removed from the graphs for easier viewing of the other pathways.

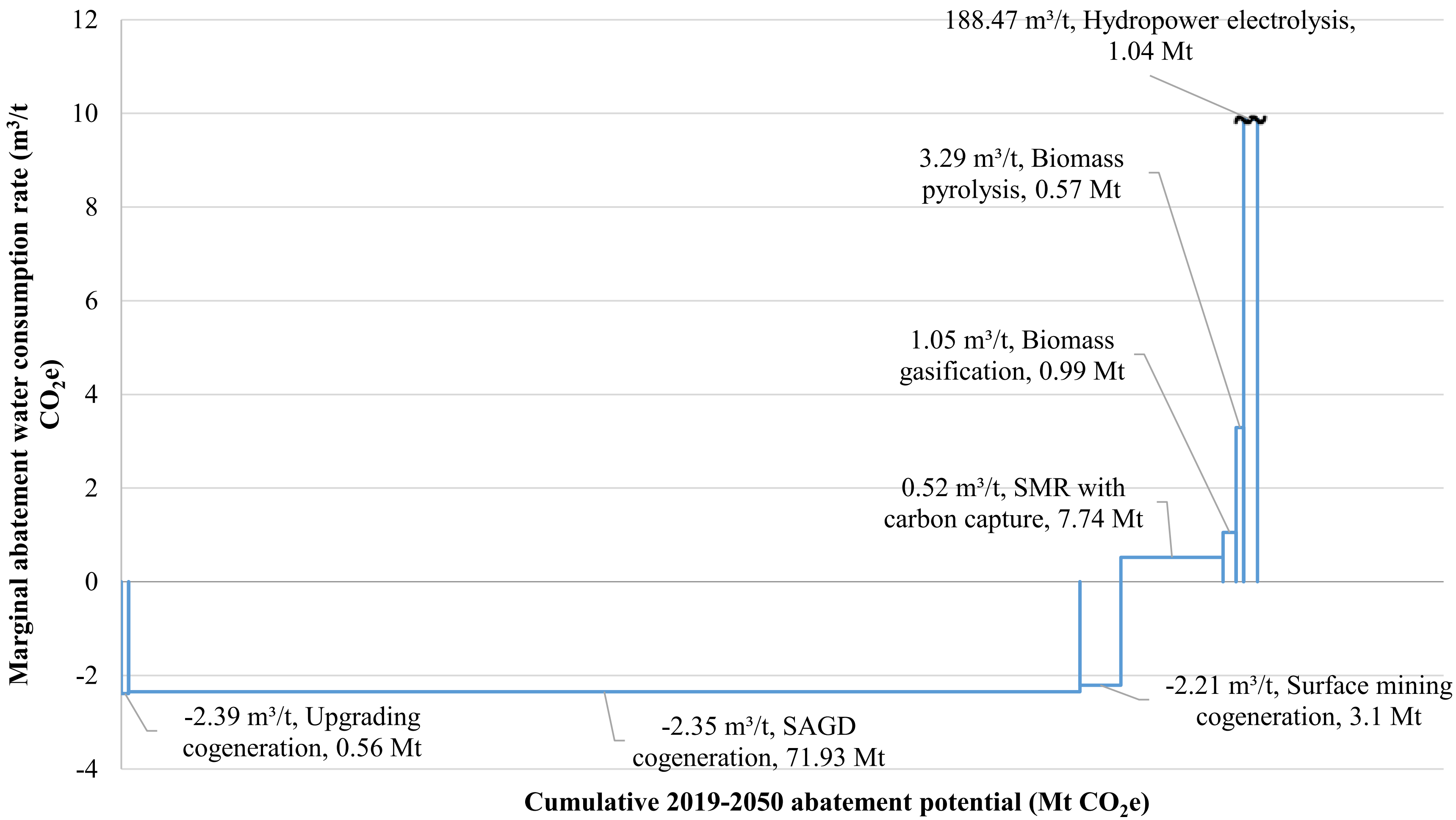

Figure 30: Marginal water consumption curve for pathways with CP0

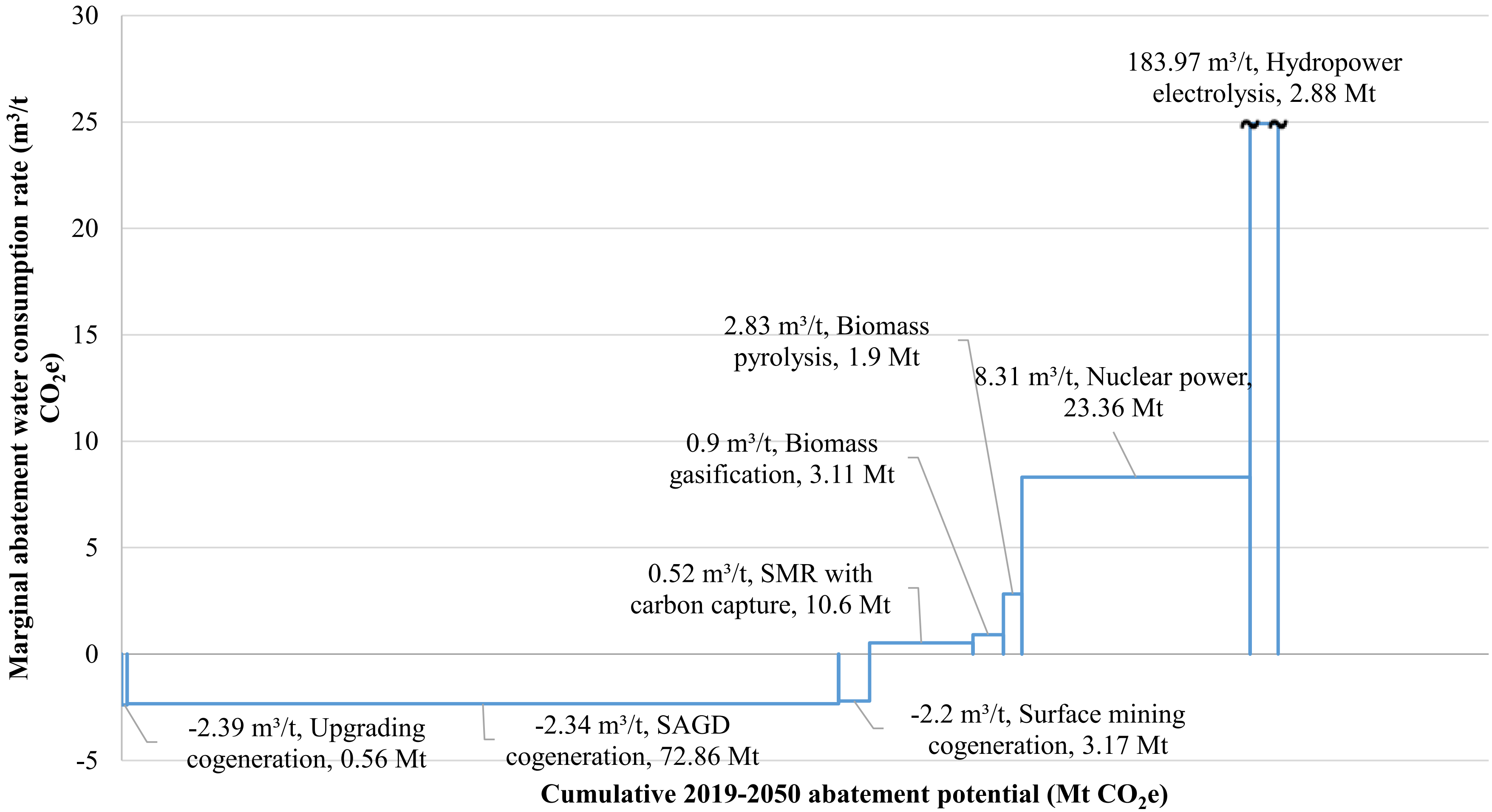

Figure 31: Marginal water consumption curve for pathways with CP30

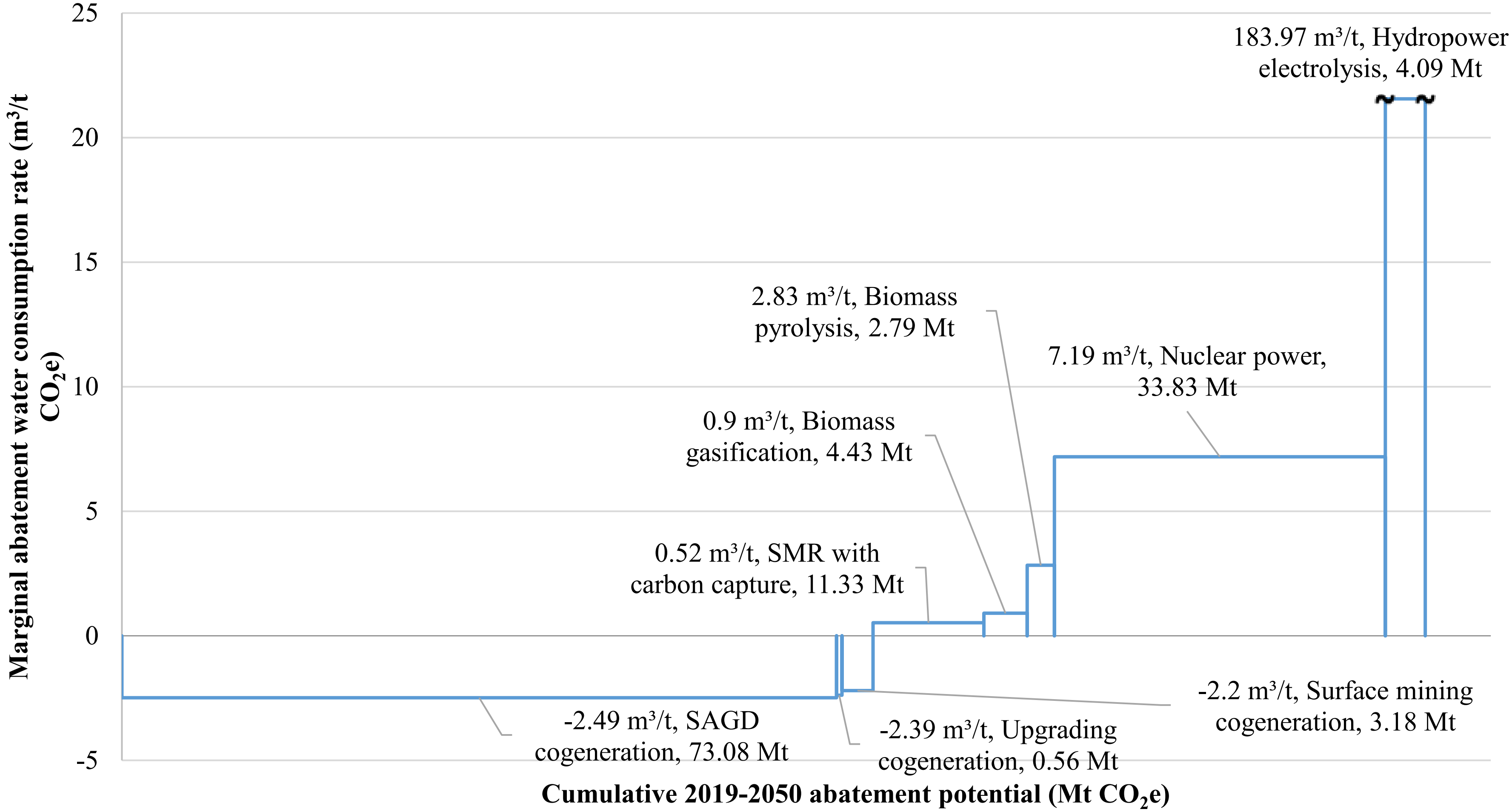

Figure 32: Marginal water consumption curve for pathways with CP50

While Figure 30, Figure 31, and Figure 32 allow us to compare the pathways while contextualizing their total abatement potential within a specific carbon price, they do not allow easy comparison of the effect of different carbon prices. MAWCR for each pathway is presented for such a comparison in Figure 33. Hydropower electrolysis was excluded as its rate is significantly higher than the others: 198 m^3/t CO_2e in CP0 and 184 m^3/t CO_2e in CP30 and CP50. In the cogeneration and nuclear power pathways, water consumption is based on a dynamic electrical system and as a result the MAWCR differs in the carbon price scenarios, though in the case of cogeneration the difference is minor. The MAWCR in the SMR with carbon capture scenarios is the same across carbon prices, which is expected, as the unit emissions of the baseline and pathway technologies are constant. The MAWCR of the biomass pyrolysis, biomass gasification, and hydropower electrolysis pathways were expected to be constant for the same reason as with SMR with carbon capture, but all show a different MAWCR under CP0 than under CP30 and CP50. This was unexpected and the cause has not been uncovered, though the three pathways showing this behavior are sourced from the same modelling effort [58].

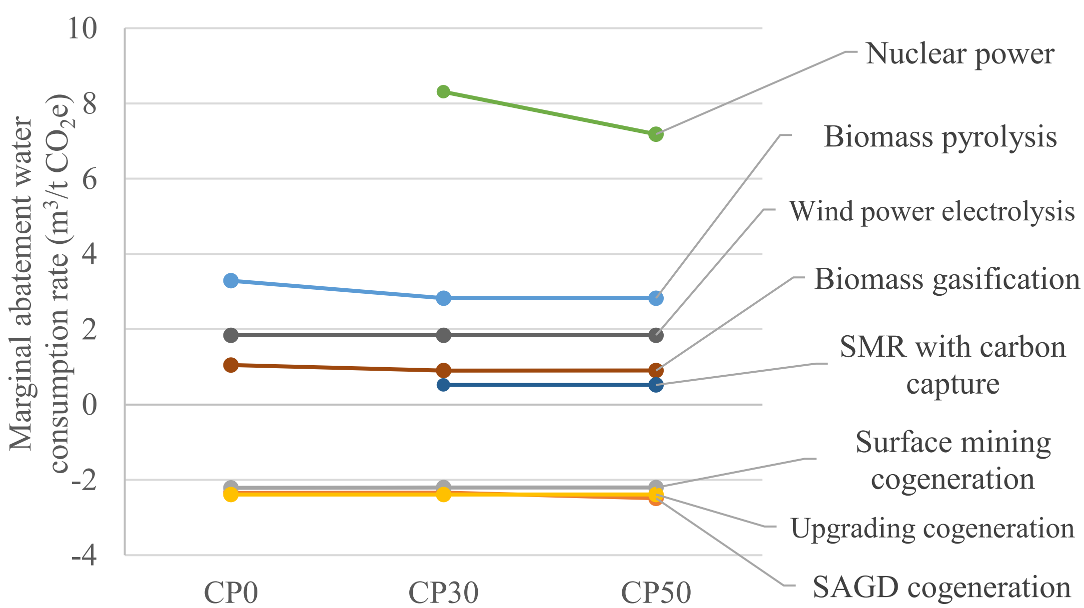

Figure 33: Average marginal abatement water consumption rate for pathways by carbon price (excluding hydropower electrolysis)

The wind power electrolysis pathway has been presented based on the bottom-up performance characteristics of the technology as used in the underlying modelling effort and as described in section 3.2.4. This approach differs from how the MAWCRs of other pathways are assessed, which are based on a top-down average of cumulative model results. Given the negligible penetration of the technology, cumulative modelled results were not presented in the underlying modelling effort and thus the approach used elsewhere is not possible here. Although they follow different methods, both approaches should produce the same MAWCR as they follow the same reasoning. The formulas used in both approaches are shown below for comparison:

$$MAWCR_{wind}\left(\frac{m^3\ water}{t\ CO_2e}\right) = \frac{(W_{wind} - W_{SMR})\left(\frac{L\ water}{kg\ H_2}\right)}{(E_{SMR} - E_{wind})\left(\frac{kg\ CO_2e}{kg\ H_2}\right)}$$

where W_x is the water consumption rate of pathway x and E_x is the GHG emission rate of pathway x.

$$MAWCR_{path}\left(\frac{m^3\ water}{t\ CO_2e}\right) = \frac{CMW_{path}(m^3)}{CME_{path}(t\ CO_2e)}$$

where CMW_{path} is the cumulative marginal water consumption of a pathway and CME_{path} is the cumulative marginal emissions of a pathway. Both measures are relative to the baseline pathway, which is SMR for all hydrogen pathways.

The results of the wind power electrolysis pathway have been included in Figure 33 alongside the results of the other hydrogen pathways despite the difference in the MAWCR calculation approach used.

Water consumption – GHG abatement – cost results

Figure 34, Figure 35, and Figure 36 are bubble charts that show the cumulative water consumption, GHG abatement, and cost results for the CP0, CP30, and CP50 scenarios, respectively. The cumulative marginal effect of each pathway is represented by a bubble. A bubble's area correlates with the water consumption and is blue or white if consumption increases or decreases, respectively. The horizontal position of the centre of the bubble indicates the cumulative abatement potential of the pathway, and the vertical position the average marginal abatement cost of the pathway. Note that though the area of each bubble is represented in the x- and y-axes, it does not denote any meaning related to those axes.

While there are interesting trends that could be discussed regarding the relationship between carbon price and the abatement potential and monetary cost of the pathways in question, these results were developed and have been discussed by the authors who conducted the study [58-60] and thus the discussion here focusses on their relationship with water consumption. Upgrading cogeneration and surface mining cogeneration are the only pathways with the ideal qualities of reducing both cost and water consumption, though they both suffer from low abatement potential. The other cost-saving pathway, nuclear power, shows a notable increase in water consumption, though its significant abatement potential is a desirable quality. The SAGD cogeneration pathway is associated with an increase in system cost and reduced water consumption and shows the greatest abatement of all the pathways. The four hydrogen pathways all have the same basic properties of increasing cost, increasing water consumption, and having only mild abatement potential relative to the reference scenario. Hydropower is the obvious outlier due to its significantly higher MAWCR compared to the other pathways, but because consumption is in the Peace River Basin, the effective cost of this water consumption may be acceptable.

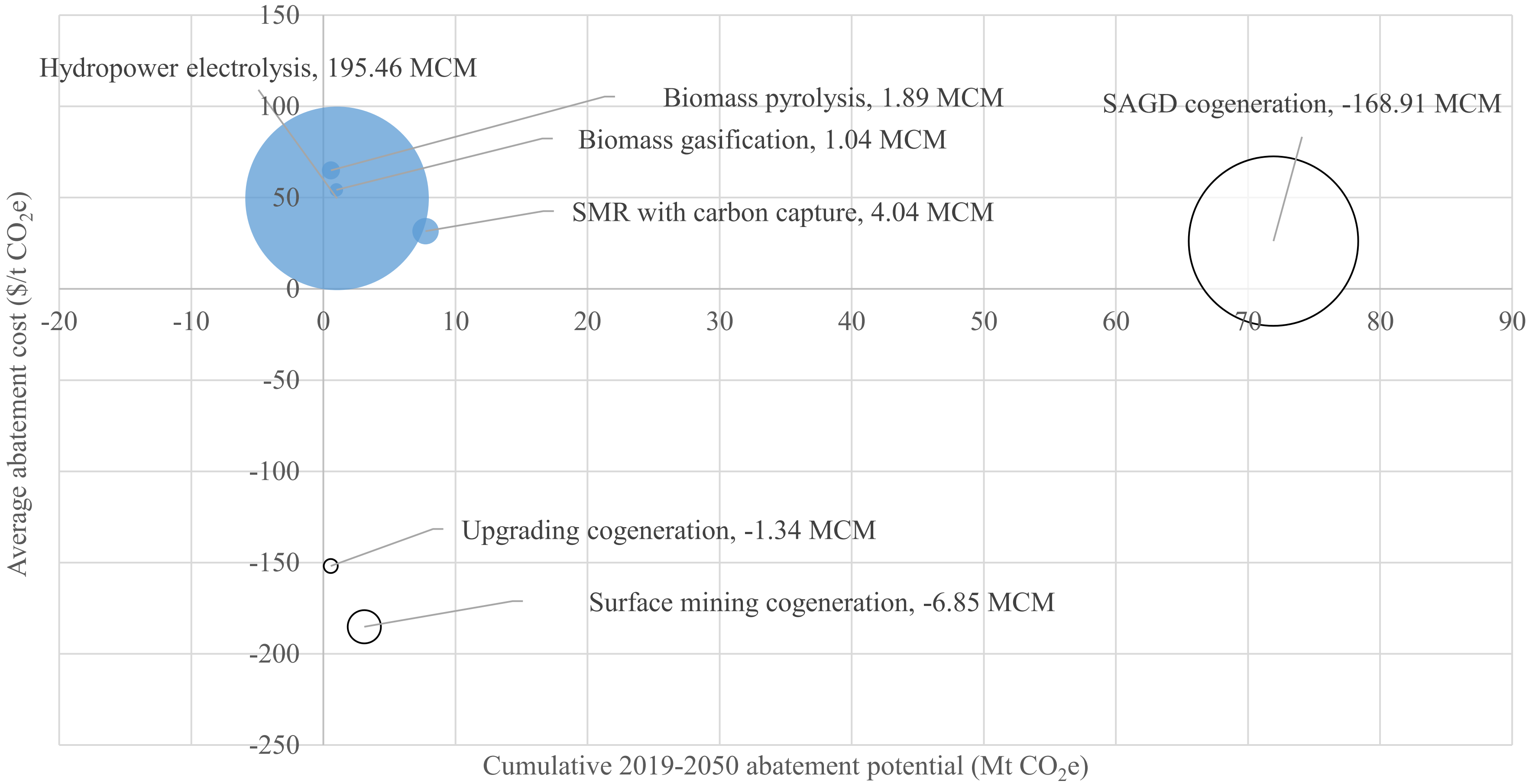

Figure 34: Cumulative 2019-2050 marginal water consumption, cumulative GHG abatement potential, and average abatement cost by pathway in CP0 scenarios

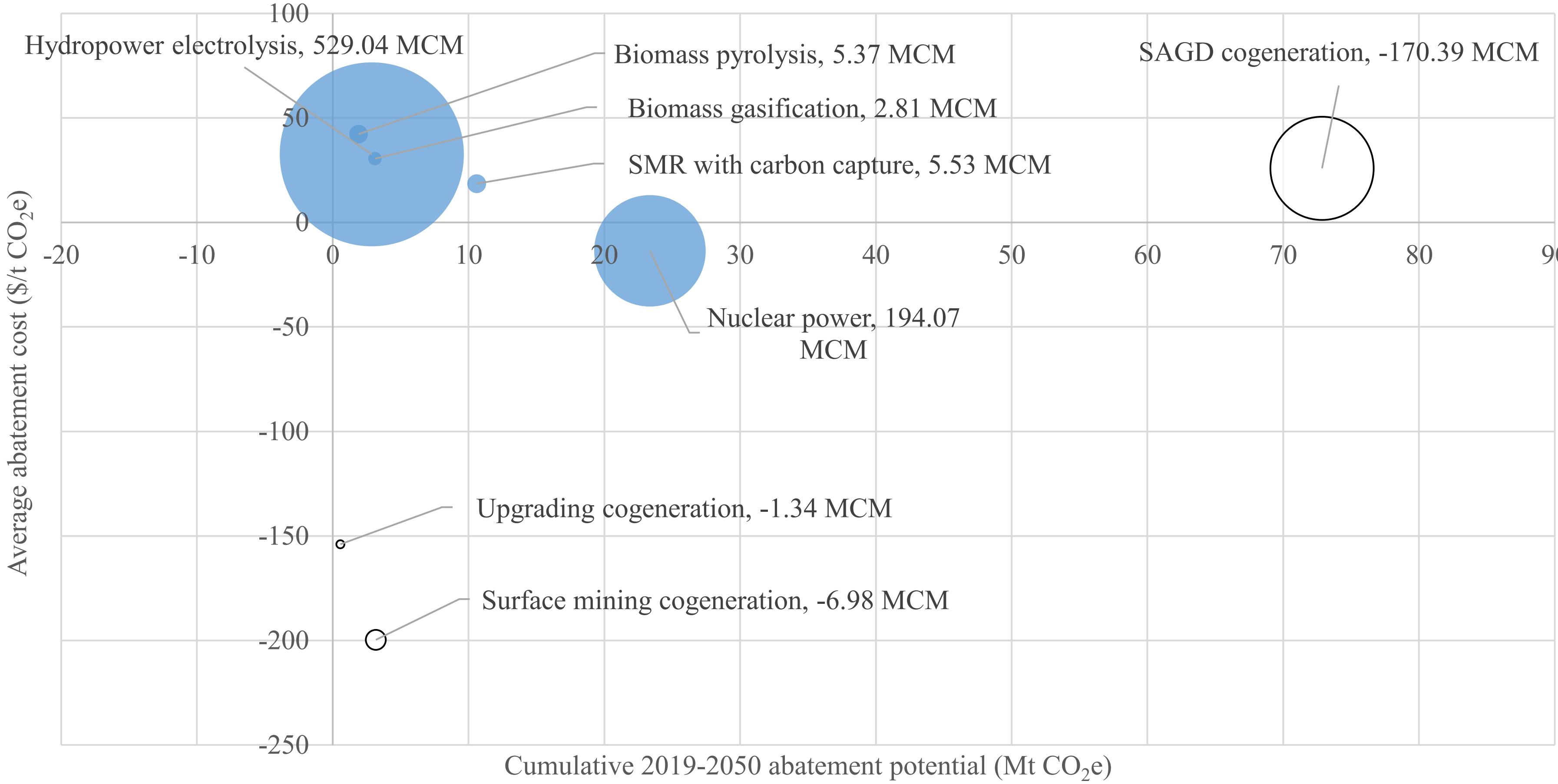

Figure 35: Cumulative 2019-2050 marginal water consumption, cumulative GHG abatement potential, and average abatement cost by pathway in CP30 scenarios

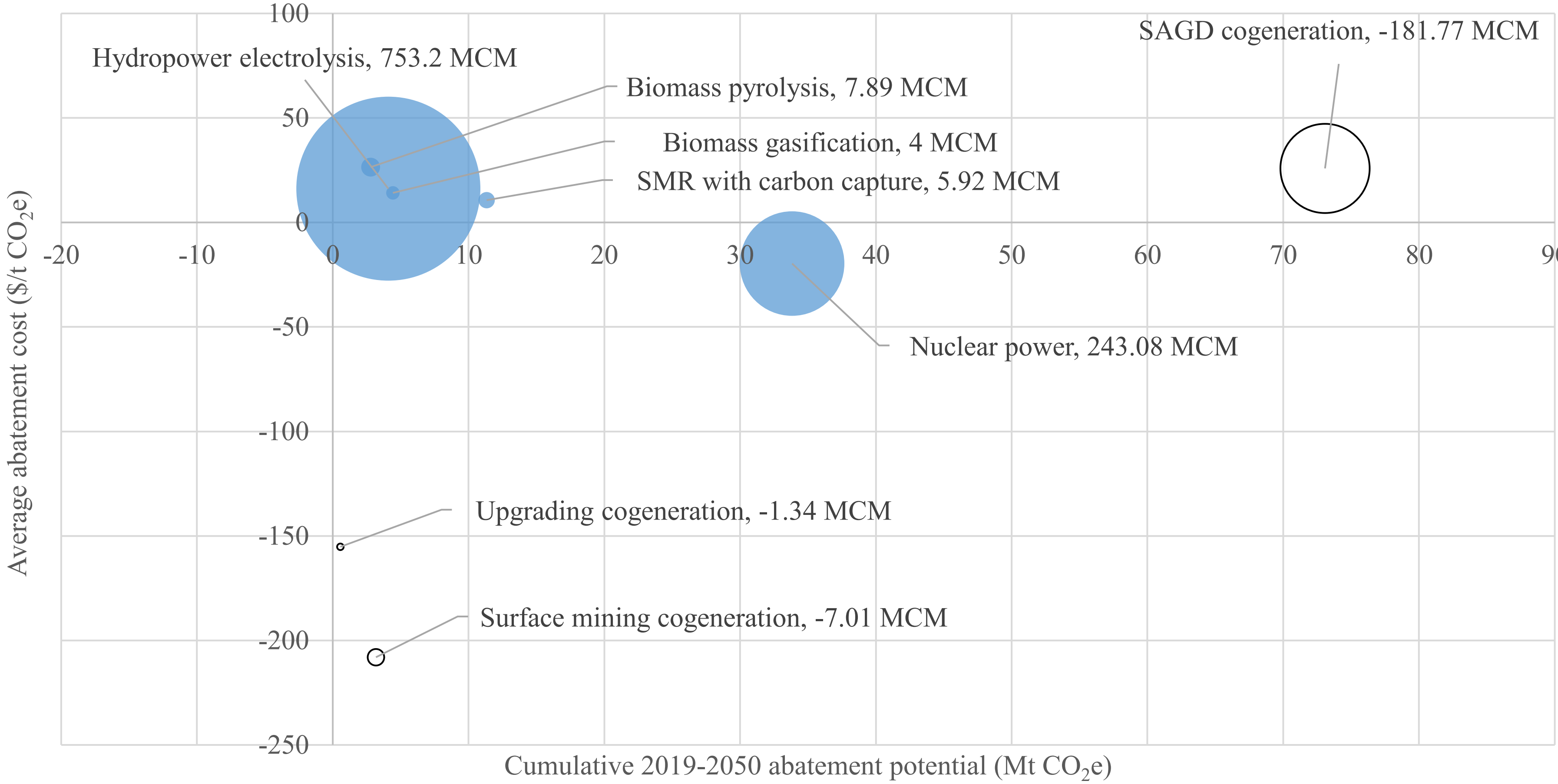

Figure 36: Cumulative 2019-2050 marginal water consumption, cumulative GHG abatement potential, and average abatement cost by pathway in CP50 scenarios

The results in these figures are repeated in Figure 37 and Figure 38 to show performance across carbon prices, each including a set of pathways selected to enhance readability. Figure 37 shows the three cogeneration pathways and hydropower electrolysis. Figure 38 shows biomass gasification and biomass pyrolysis. Both figures show nuclear power and SMR with carbon capture.

As would be expected for a policy tool used to drive decarbonization, higher carbon prices drive increased activity in the low-carbon pathways explored. This then increases their water-consumption effect, i.e., pathways that marginally increase water consumption show greater cumulative water consumption, while pathways that marginally reduce water consumption show greater cumulative water savings. Not all pathways show the same sensitivity to changing carbon price, but all follow this general trend.

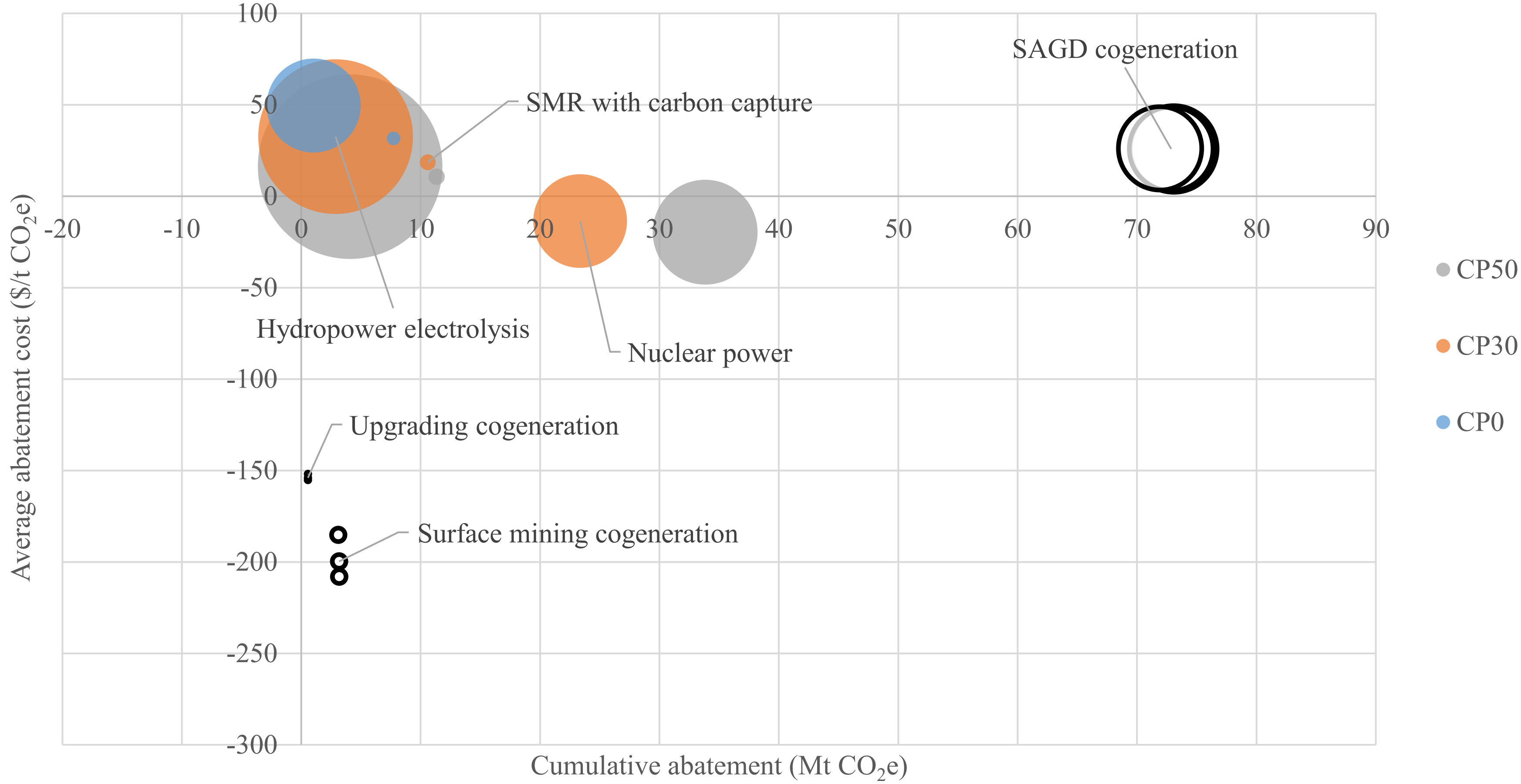

Figure 37: Cumulative 2019-2050 marginal water consumption, cumulative GHG abatement potential, and average abatement cost for select pathways under all carbon prices (excludes biomass gasification and biomass pyrolysis)

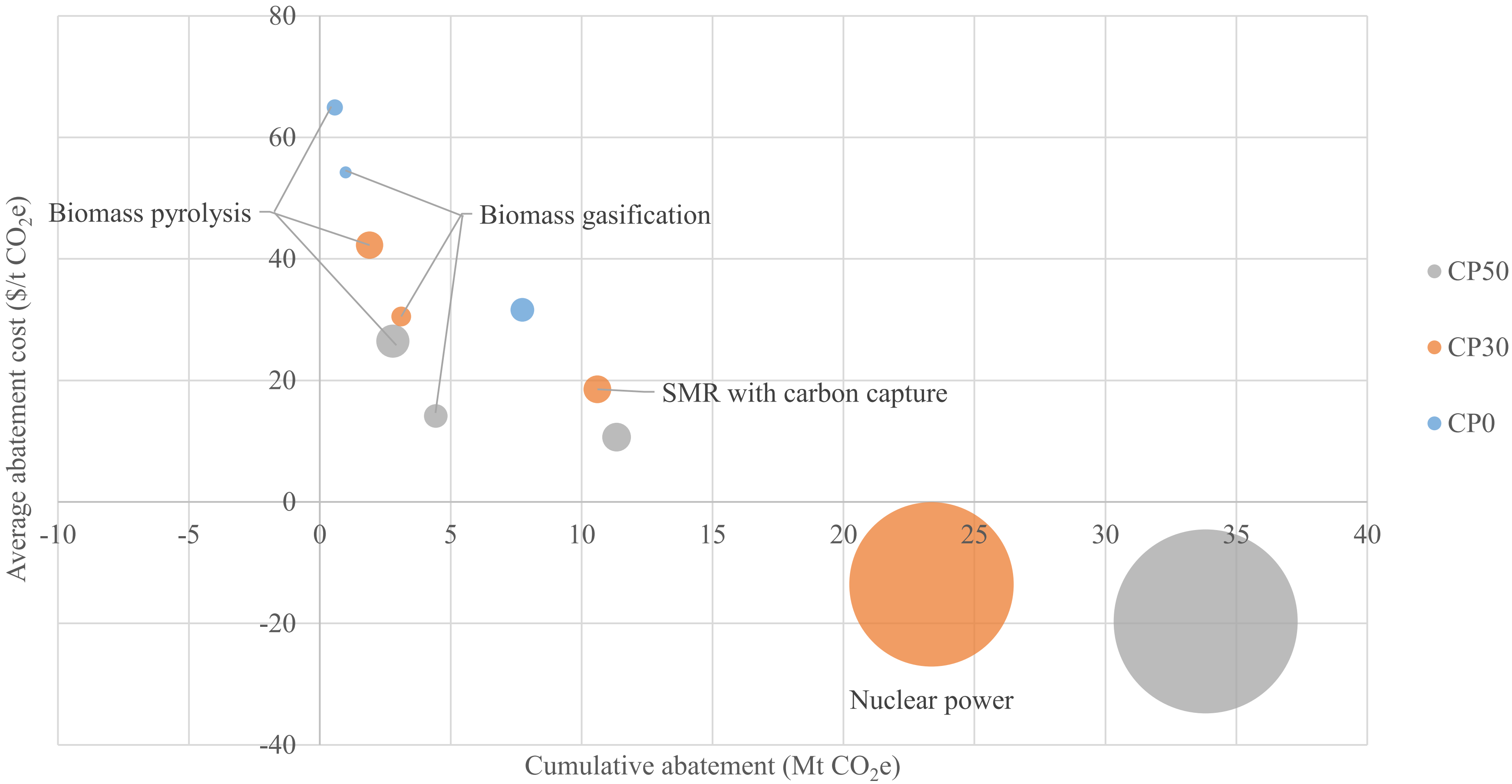

Figure 38: Cumulative 2019-2050 marginal water consumption, cumulative abatement potential, and average abatement cost for select pathways under all carbon prices (excludes hydropower and all cogeneration)

3.3.3 Limitations

This study draws from several GHG abatement and cost modelling efforts. These earlier models use slightly different methods and have different study scopes (e.g., whether emissions reductions are based on grid average emissions factors or the modelling of the electrical grid), and these differences have been reflected in how they are abstracted and included in this study (e.g., estimating water consumption based on grid average water use or the specific generation technologies modelled to increase or decrease in activity). The use of externally developed results has in some places limited the ability to assess apparent inconsistencies in the results of this research, e.g., those presented in section 3.3.2. Another limitation of this study is that each pathway is limited to a single application of the technology in question. For example, the nuclear pathway explored would offset electricity produced by the grid, but other applications could provide process heat or produce hydrogen, thereby offsetting natural gas consumption. This single application feature originates from the scope limitations of previous modelling efforts and thus could not have been overcome in this project alone, but as future modelling work considers the adoption of a wider variety of pathways, future work related to this project can adopt those pathways as well.

The development of water withdrawal and consumption intensities was not part of the scope of this project, and existing sources on the topic are often limited. The quality of the sources varied among the pathways considered, with the set of electricity generation-related intensities typically being of higher quality than those of the emerging technologies, such as the biomass pathways.

Interactions between pathways were typically not accounted for. The hydrogen pathways (other than SMR with carbon capture) were modelled in their underlying work as competing with each other for market shares, and therefore their results are additive. The cogeneration pathways were modelled as occurring distinctly from each other, and thus are not additive. No interactions between the hydrogen and electricity pathways were considered, and no "all pathways" scenario was developed.

3.4 Conclusion

This study assessed several low-carbon pathways proposed for the oilsands under three carbon price scenarios. The water consumption effects of each pathway in four Alberta river basins was estimated. These water consumption results were then integrated with the cost and GHG abatement results to produce a set of integrated environmental impacts associated with each pathway at each carbon price. The water-use impacts of the pathways assessed differed considerably in consumption (i.e., increasing or decreasing), magnitude, river basin location, and sensitivity to the carbon price scenario. The only pathways that showed positive results in terms of GHG abatement, cost, and water consumption were the cogeneration pathways. All others either increased cost or water consumption, each to a different degree.

As more information is developed on emerging low-carbon pathways, better estimates of cost, emissions, and water-use rates will likely be published, and incorporating them in this study would improve it. For the research presented here to more effectively inform water management decisions, additional developments are required. These include formalizing the interactions between pathways, using a sub-annual timestep, developing a more nuanced understanding of how decisions are made in the sector with respect to investment and water use, and incorporating retrofit pathways (rather than those applied only to new production capacity).

4 Conclusion and Recommendations for Future Work

4.1 Conclusion

Long-term water resource planning requires understanding the long-term water demand from various sectors, including oil and gas. A bottom-up model was used to project the water use of the oil and gas sector to 2050 in several scenarios. The model was also used to project the marginal water use associated with several low-carbon pathways to 2050. The projected marginal water use of each pathway was used with GHG abatement potential and marginal cost values of each pathway to generate integrated cost-GHG-water results. The results provide the water withdrawal and consumption of the sector under several future scenarios, as well as the localized impacts of several possible carbon-reducing technologies along with indicators describing the trade-offs between their GHG reduction, cost, and water-use impacts.

4.1.1 Summary of problem context and overall approach

Oil and gas in Canada is an economically important industrial sector, a significant source of national GHG emissions, and a regionally significant water user. Many oil and gas assets have long production lives, and, once completed, projects are typically expected to operate for several decades. The completion of such infrastructure tends to lock in environmental impacts, making the long-term planning of these systems a prudent endeavour. The uncertainty of water availability in a changing climate makes this issue even more important. The research described in this thesis addresses long-term changes in the water demand of the oil and gas sector through two different paradigms. The first is described in Chapter 2, where the water use by the sector is understood as a function of the volume or quantity of production in the sector, and the annual water demand associated with different exogenous production projections is developed and compared between years (e.g., the change in water demand between 2020 and 2050) and scenarios (e.g., the difference in 2050 water demand if prices for oil are high compared to 2050 water demand if prices for oil and gas are low). The second paradigm for understanding changing water use in the oil and gas sector is described in Chapter 3 and assumes that the Alberta's oil sands respond to Canada's industrial policy and GHG emission regulations by including low-carbon technologies in new production capacity. Specific low-carbon technologies are considered and their marginal water use is compared to the standard technologies they are replacing. Together, these two paradigms and the research conducted in each produce valuable insight into several areas of the long-term use of water in the oil and gas sector in Canada.

4.1.2 Summary of Chapter 2's approach, results, novel contributions, and conclusion

The water use of the Canadian oil and gas sector was modelled in the Water Evaluation and Planning (WEAP) environment using a bottom-up activity-intensity water use formulation. Sectoral activity was considered across six subsectors, nineteen river basins, and nine provinces. Water use from 2005 to 2017 was used to validate the model. One of the novel contributions to the WEAP-Canada oil and gas model is the inclusion of non-static water-use intensities used over historic years. The annual water-use intensities of individual subsectors were tracked over the period of 2005 to 2020 where data permits; the results are shown in Figure 39. Most individual subsectors showed a steady decline in water-use intensity over the period of historic data, with occasional outlier years. The natural gas well fracturing water-use intensity in British Columbia did not show a clear trend. The water-use intensities of CSS in Peace River and natural gas well fracturing in Alberta were the only subsectors that showed a clear increase in water use intensity.

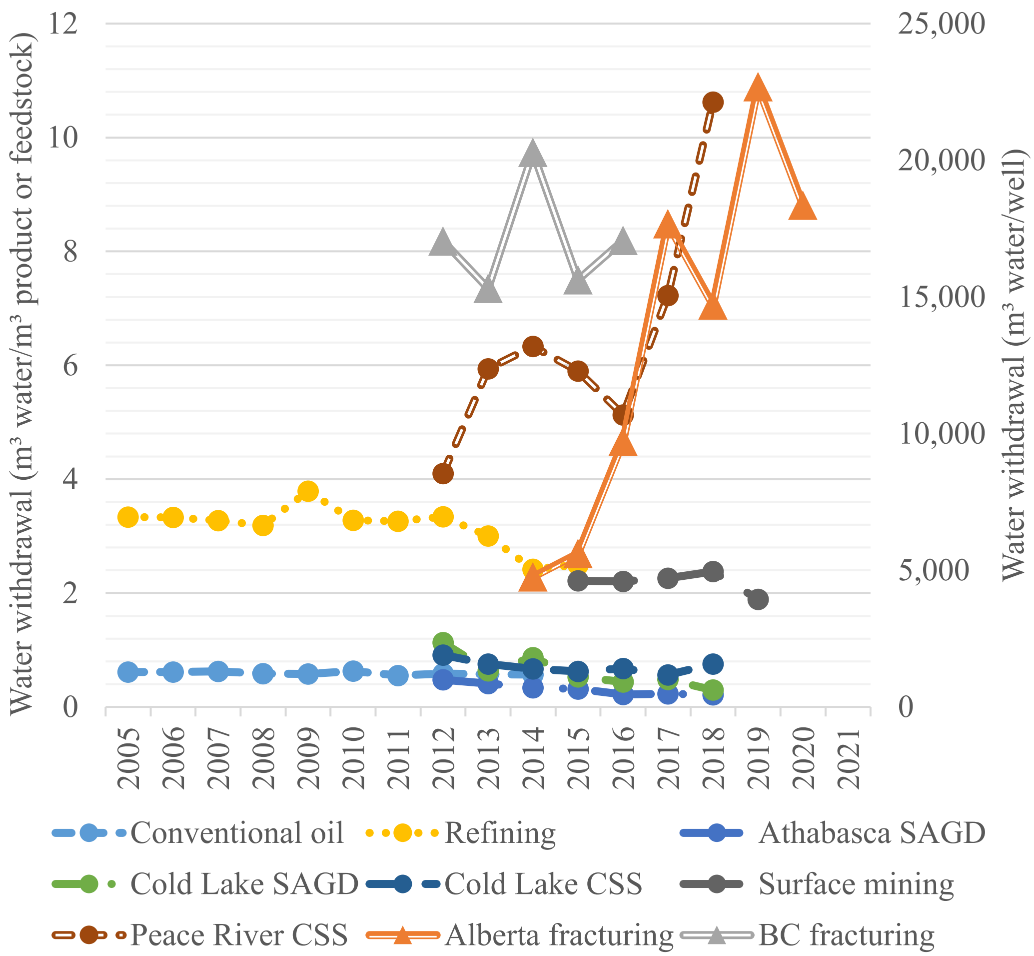

Figure 39: Direct non-saline water withdrawal intensity calculated by year for various energy pathways per cubic metre of product or feedstock (circles, left axis) or per well (triangles, right axis)

Water use from 2020 to 2050 was projected under several exogenous oil and gas production projections. These production projections were adapted from the CER's reference scenario, an evolving climate policies scenario, and low- and high-price oil and gas scenarios. The evolving climate policies scenario considers a future in which Canada continues to adopt climate and energy policy and take GHG emissions reduction actions through to 2050, though not at a pace commensurate with Canada meeting its GHG emissions targets. The low- and high-price scenarios simulate market-based changes to oil and gas production driven by consistent low or high prices for oil and gas products to 2050. The annual water consumption for each subsector (excluding refining) in each province is shown in Figure 40 and includes 2020 consumption in the reference scenario and 2050 consumption in the reference and three alternative production scenarios. A scenario was also constructed that uses the reference oil and gas production projection but projects the water-use intensity trends observed over the historic period to 2050 (not pictured in Figure 40).

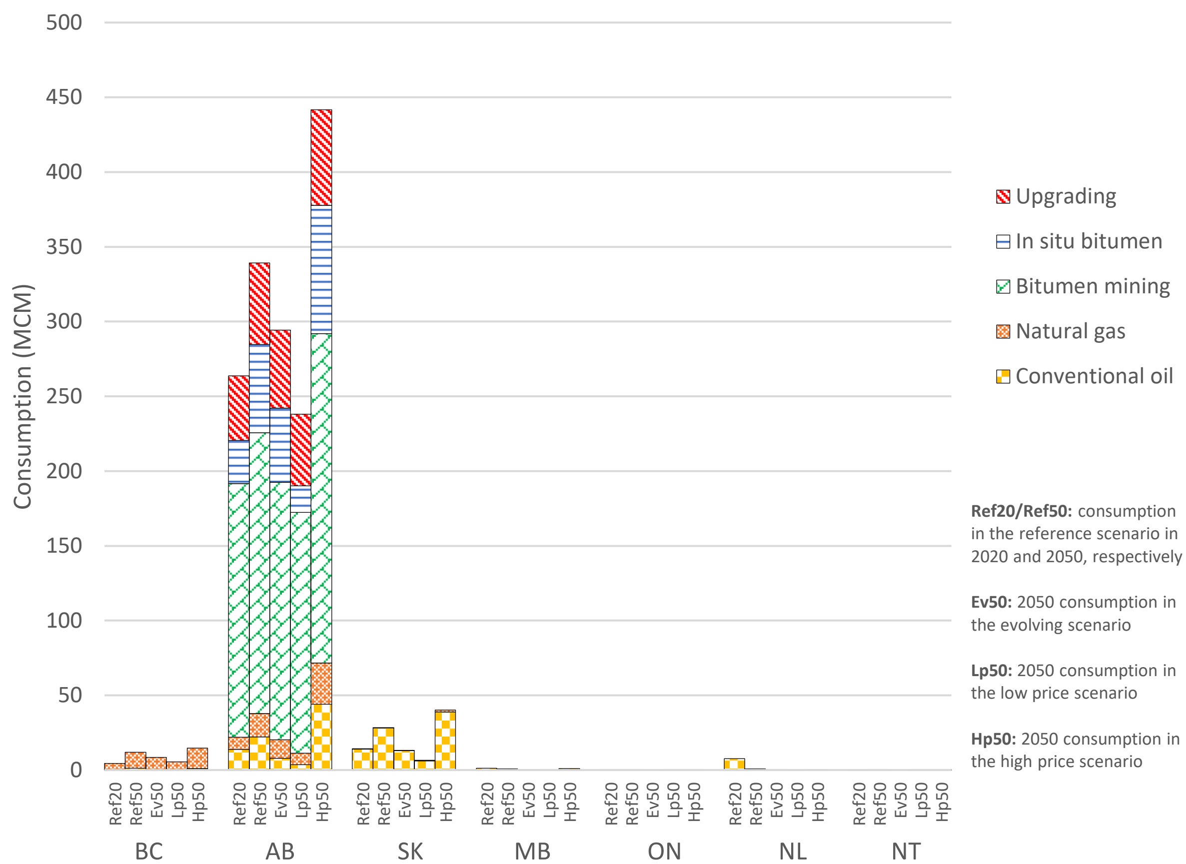

Figure 40: Consumption by province and subsector (excluding refining) in the reference scenario in 2020 and all alternative-production account scenarios in 2050

The policy implications of the water-use projections developed in this research are not clear, as this research was conducted outside policy-making endeavors/exercises. One nonobvious pattern of note is the apparent inertia in the water use of the sector with respect to changing commodity prices. High and low prices are likely to increase or decrease the production of in situ bitumen and conventional oil, which require relatively little water compared to bitumen mining and upgrading, whose activity projections are decidedly less responsive to these price changes. This is important in case there is a low long-term price for oil, which could see much of the existing water demand of the sector remaining in place alongside an economic tightening that could make the adoption of water-efficient technologies such as additional water recovery non-feasible, reducing the sector's ability to respond to climate change-driven water availability uncertainty.

4.1.3 Summary of Chapter 3's approach, results, novel contributions, and conclusion

The marginal water use of several low carbon oil sands pathways was modelled based on previously developed technology penetration and cost/GHG modelling. Ten technology pathways were investigated under three possible carbon price levels. The pathways' water-use intensities were calculated or taken from the literature. The locations of water use of each pathway and the standard pathway being offset were attributed to one of four river basins in Alberta (Athabasca, Bow, North Saskatchewan, and Peace), and their marginal annual water use was calculated. These water consumption results were combined with cost and GHG abatement results to create integrated water consumption-GHG abatement-cost results. Indicators were prepared that estimated the cumulative average marginal water consumption associated with each unit of GHG abatement, as shown for the \$50/tCO$_2$e carbon price in Figure 41. Only the cogeneration-based pathways were found to reduce both GHG emissions and water consumption, and all cogeneration marginal abatement water consumption rates (MAWCRs) were between -2 m^3/tCO$_2$e and -2.5 m^3/tCO$_2$e. The other technologies all increase water consumption, though the MAWCR ranges from 0.52 m^3/tCO$_2$e for SMR with carbon capture to 184 m^3/tCO$_2$e with hydropower electrolysis. Wind power electrolysis does not have previous modelling data from which to estimate the MAWCR using the same methods used for the other pathways, but based on preliminary performance data its MAWCR was estimated to be approximately 2 m^3/tCO$_2$e.

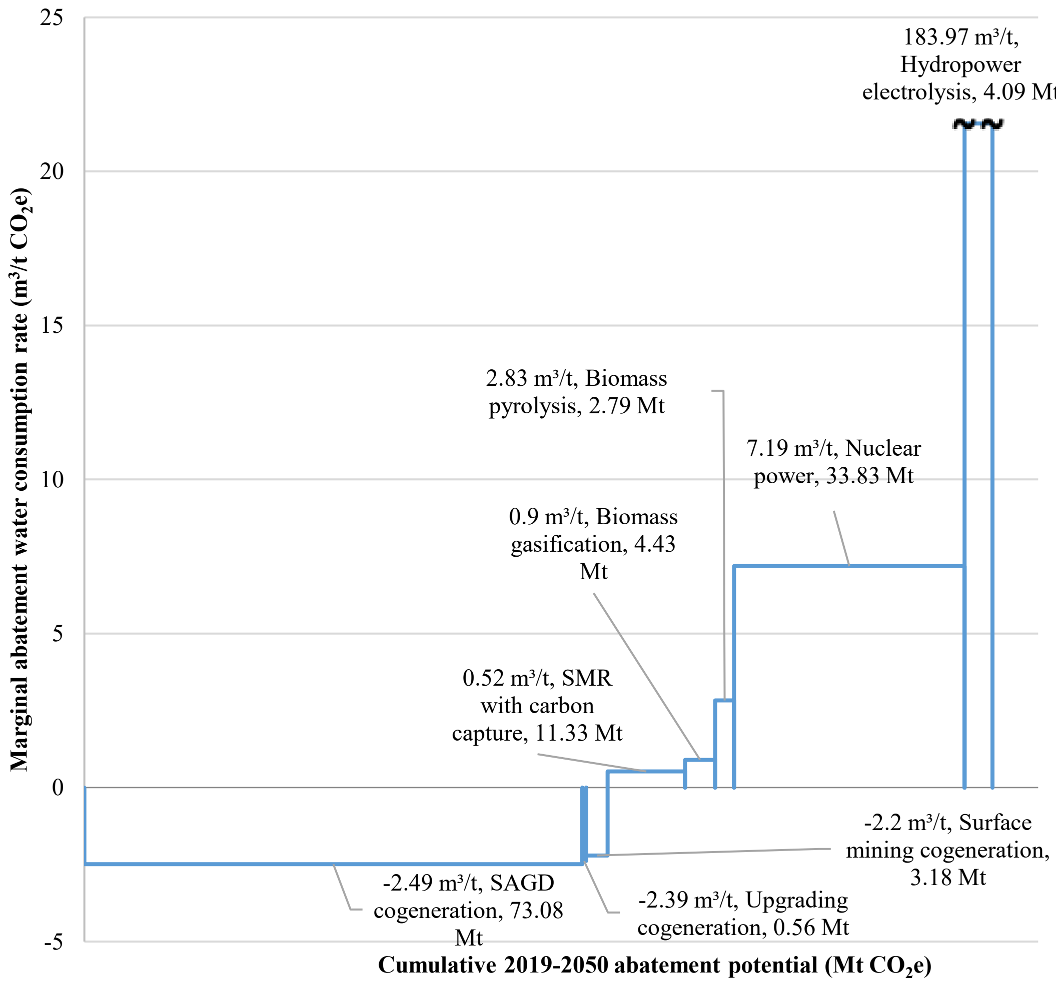

Figure 41: Marginal abatement water consumption curve for pathways with CP50

The total cumulative marginal water consumption, GHG abatement, and cost are shown for the \$50/tCO_2e carbon price in Figure 42. Only cogeneration applied to the surface mining and upgrading subsectors was found to have the ideal characteristics of reducing water consumption, GHG emissions, and cost. All other pathways investigated were found to involve trade-offs with water consumption and/or cost.

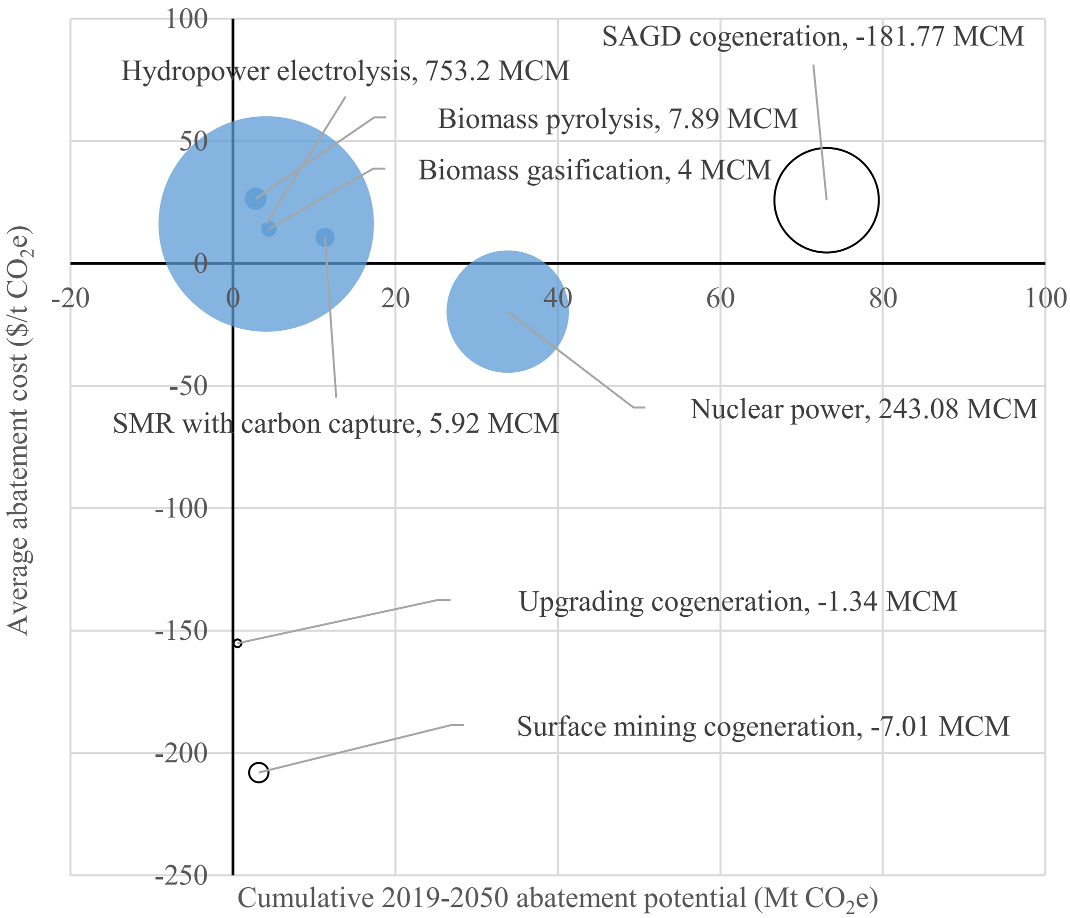

Figure 42: Cumulative 2019-2050 marginal water consumption, cumulative GHG abatement potential, and average abatement cost by pathway in the CP50 scenarios

Based on the explored conditions, it appears that much of the adoption of water-intensive low-carbon technology in the oil sands will increase water consumption in the relatively water abundant regions of the Peace and Athabasca river basins. This may indicate that the adoption of these low-carbon technologies will not immediately be constrained by water availability to nearly the degree they would be if the water-use impacts occurred in the South Saskatchewan River Basin. Additionally, much of the water-use reduction from offset electricity generation in the Alberta electrical grid occurs in the South Saskatchewan River Basin.

Across the technologies adapted in this model, there is significant variability in their water use required per unit of GHG abatement, and therefore further modelling may be required to address larger magnitudes of abatement and the corresponding water-use impacts. The marginal abatement water consumption rate (MAWCR) may be the most relevant concept for industry decision makers, as its results allow the estimation of the water required to meet certain abatement targets. In the current formulation of these indicators, however, the numerical results presented typically do not reflect the perspective of individual industrial actors (e.g., the cogeneration pathways have an apparent water savings alongside GHG abatement, but the water use reduction occurs at the point of the electricity generators throughout the grid that see lower activity, and the actual water consumption at the oil sands site in question would increase because of cogeneration use).

Though integrated GHG-cost-water consumption results have been generated for decarbonization options in other Albertan sectors such as the electricity sector, this is the first time integrated environmental impacts for individual low-carbon pathways have been developed for the oil sands. This work has assessed several approaches for considering different types of pathways, the different ways they cause water-use changes, and how to reconcile these differences to produce results that can be easily compared. The results generated for this thesis can hopefully guide or act as a point of comparison for later works approaching the important topic of the technological options for oil sands decarbonization.

4.2 Recommendations for future work

The research described in this thesis explored water use in the oil and gas sector from the point of view of differing sectoral production outlooks and the integration of specific low-carbon technological options. Through the completion of this research, several topics have been identified that could warrant future work. The purpose of the following recommendations is to communicate areas of limitation that were encountered in the preparation of this thesis research, make suggestions on out-of-scope work that could supplement the approach used in this thesis work and help fulfill these research objectives, and identify aspects of the research conceptualization that warrant later reaffirmation.

Recommendation 1: Gather more historic data on water use in the oil and gas sector, specifically for low-activity provinces and at a watershed level.

The availability of historic water-use data in Canada is irregular, with regions where oil and gas activity is prevalent (such as Alberta or BC) typically having more data available than regions with less activity. Moreover, data is typically aggregated at the provincial level, which introduces the significant challenge of assigning water withdrawals and consumption to rivers or other bodies of water.

Recommendation 2: Determine the specific planning initiatives where the WEAP-Canada oil and gas model is intended to be used and develop the features or capabilities in the model to ensure it is compatible with these initiatives and has sufficiently high subsector and temporal resolution and up-to-date production projections and historic water-use data.

The WEAP-Canada oil and gas model is fundamentally limited in scope, for example, by not including other important water-using sectors such as municipal or agriculture. It cannot directly be used in water resources planning and instead requires a broader planning initiative to which it may have valuable contributions. It may be sensible to consider the specific planning initiative this model is intended for use with. There will likely be specific requirements for this model's outputs to be compatible, and those areas should be built upon before adding other model features.

The WEAP-Canada oil and gas model has several general limitations that could be remedied to make a higher-fidelity model, including an annual timestep, broad categorization of sectoral activities, and the requirement of detailed exogenous production projections. While these limitations are deemed appropriate, building upon the model in these areas may be valuable future work and may be required for use as or with a decision-making tool.

Recommendation 3: Assess the ongoing literature contributions related to low-carbon technologies in the oilsands to identify additional pathways to assess.

The low-carbon pathways explored in this research are limited by the studies this research has built upon. Given the salience of industrial carbon abatement, there may be future investigations of GHG abatement potential in the oil sands, which may open additional pathways to be assessed for water-use impacts. Additional pathways could include novel technologies (such as solvent-aided SAGD), new configurations of explored technologies (such as nuclear-derived steam or other biomass-based pathways), or modelling the adoption of a technology as a retrofit to existing production capacity rather than merely as an inclusion for new capacity.

Recommendation 4: Reassess the energy and environmental policies that are likely to apply to the oil and gas sector, with a focus on the range of plausible carbon prices and GHG emissions limits for the oil sands, and re-model the low-carbon pathways under these new conditions.

As this exploration of low-carbon pathways in the oil sands is based on past research projects, there is a several year lag between the parameters that underly the GHG and cost modelling related to this research and the current outlook of energy and environmental policy in Canada. At the time of the GHG modelling, exploring carbon price points of \$0, \$30, and \$50/tCO_2e seemed reasonably prudent. As policy has evolved since then, it is possible these carbon prices no longer represent a reasonable range of possible future prices and that higher carbon prices should be considered. The modelling was also performed irrespective of national and international GHG emission targets, which could be important considerations for understanding the long-term outlook of the sector and the water-use impacts of its various emissions abatement options.

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5 Appendix A (Chapter 2)

5.1 Input data

The following sections contain tables with additional information and details on the construction of the model and other input data.

Table 23: Conventional oil production by province and year in thousand cubic metres per day [14]

Year	NF	ON	MT	AB	BC	SK	NT
2005	48.5	0.4	2.2	90.8	4.7	66.6	3.0
2006	48.3	0.3	3.4	86.3	4.5	68.1	3.0
2007	58.6	0.3	3.5	83.4	4.1	68.0	2.8
2008	54.6	0.3	3.8	79.9	3.7	69.9	2.6
2009	42.6	0.3	4.1	73.3	3.5	67.4	2.5
2010	43.9	0.2	4.8	73.0	3.5	67.2	2.4
2011	42.1	0.2	6.5	77.9	3.2	68.0	1.7
2012	31.4	0.2	8.1	88.4	3.3	75.0	2.1
2013	36.9	0.2	8.3	92.5	3.1	77.1	1.8
2014	34.3	0.2	7.8	93.7	3.4	88.6	1.8
2015	27.4	0.2	7.3	84.3	3.4	77.3	1.6
2016	33.2	0.2	6.4	70.8	3.7	73.0	1.4
2017	35.1	0.1	6.2	70.9	3.4	77.2	0.1
2018	38.2	0.1	6.7	77.8	3.3	77.8	0.3
2019	43.1	0.1	7.0	77.5	2.6	77.4	1.2
2020	39.8	0.1	6.7	73.8	2.3	73.7	1.3
2021	43.4	0.1	6.0	76.2	2.3	81.1	1.3
2022	46.9	0.2	5.3	74.1	2.4	85.2	1.3
2023	44.3	0.1	4.9	74.2	2.5	90.3	1.2
2024	43.3	0.1	4.7	75.6	2.7	96.7	1.2
2025	45.7	0.1	4.6	77.9	2.9	101.3	1.2
2026	43.2	0.1	4.5	80.5	3.7	105.2	1.1
2027	40.9	0.1	4.5	83.3	4.0	108.8	1.1
2028	33.7	0.1	4.5	85.8	4.2	112.0	1.0
2029	30.2	0.1	4.4	88.2	4.4	115.0	1.0
2030	28.2	0.1	4.4	90.5	4.6	117.9	0.9
2031	28.1	0.1	4.4	92.8	4.8	120.7	0.9
2032	30.7	0.1	4.5	95.0	5.0	123.3	0.9
2033	29.1	0.1	4.5	97.1	5.2	125.9	0.8
2034	26.5	0.1	4.5	99.2	5.4	128.3	0.8
2035	26.3	0.1	4.6	101.1	5.6	130.4	0.8
2036	26.6	0.1	4.6	103.0	5.8	132.2	0.8
2037	26.6	0.1	4.7	104.7	6.0	134.2	0.7
2038	25.4	0.1	4.7	106.4	6.1	135.9	0.7
2039	22.9	0.1	4.7	108.0	6.3	137.6	0.7
2040	20.4	0.1	4.7	109.5	6.4	139.2	0.6
2041	17.7	0.1	4.7	110.9	6.5	140.6	0.6
2042	15.0	0.1	4.8	112.3	6.6	142.0	0.6
2043	12.9	0.1	4.8	113.4	6.7	143.2	0.6
2044	11.5	0.1	4.8	114.4	6.7	144.4	0.5
2045	10.0	0.1	4.7	115.4	6.8	145.4	0.5

2046	8.2	0.1	4.7	116.2	6.8	146.3	0.5
2047	7.2	0.1	4.7	116.8	6.8	147.0	0.5
2048	4.6	0.1	4.7	117.3	6.8	147.6	0.4
2049	3.8	0.1	4.6	117.6	6.8	148.1	0.4
2050	3.7	0.1	4.6	117.7	6.7	148.4	0.4

Table 24: Natural gas wells drilled and fractured by year and province [16]

Year	Drilling only wells			Hydraulic fractured wells		
	AB	BC	SK	AB	BC	SK
2005	7237	458	400	6133	308	1658
2006	8959	696	408	5962	355	1252
2007	11130	763	368	4873	404	1182
2008	8290	691	273	3843	289	986
2009	6165	413	130	3689	321	934
2010	4604	320	157	2719	341	1005
2011	1962	125	15	1598	420	195
2012	2010	58	5	1587	414	67
2013	1018	14	11	797	349	37
2014	430	16	11	797	407	6
2015	494	13	10	1032	495	0
2016	442	15	7	697	471	0
2017	163	2	5	628	300	0
2018	70	5	3	779	557	0
2019	24	2	2	475	252	1
2020	20	2	1	438	232	1
2021	19	2	1	436	232	1
2022	17	2	1	432	230	1
2023	18	2	2	479	293	2
2024	20	2	2	538	396	2
2025	21	2	2	594	570	2
2026	23	2	2	639	668	2
2027	24	3	2	675	513	2
2028	25	3	2	705	530	2
2029	26	3	3	731	545	2
2030	26	3	3	751	803	2
2031	26	3	3	744	765	2
2032	26	3	3	745	625	2
2033	27	3	3	764	600	2
2034	27	3	3	769	604	2
2035	27	3	3	775	608	3
2036	28	3	3	781	593	3
2037	28	3	3	788	597	3
2038	28	3	3	793	600	3
2039	28	3	3	798	603	3
2040	28	3	3	802	605	3
2041	28	3	3	807	607	3
2042	28	3	3	811	609	3
2043	28	3	3	816	611	3
2044	28	3	3	820	613	3

2045	28	3	3	824	615	3
2046	28	3	3	829	617	3
2047	28	3	3	833	619	3
2048	28	3	3	838	621	3
2049	28	3	3	842	623	3
2050	28	3	3	847	625	3

Table 25: Water use for hydraulic fracturing in Alberta and this study's estimates apportioning use to natural gas and oil production

Parameter in column:	CO HMSF wells placed on production	NG HMSF wells placed on production	Total HMSF wells (CO+NG)	Total makeup water (MCM)	Water used for NG fracturing (MCM)	Water used for CO fracturing (MCM)
Source of data or formula if calculated:	AER ST98 Table S4.1	AER ST98 Table S5.1	col1+col2	AER water use report, hydraulic fracturing	(col2/col3)*col4	col4-col5
Column number:	1	2	3	4	5	6
2013 and before	X	X	X	X	X	X
2014	1636	974	2610	10.17	3.79	6.37
2015	739	890	1629	10.59	5.79	4.80
2016	403	649	1052	10.97	6.77	4.20
2017	1049	954	2003	23.31	11.10	12.21
2018	1086	730	1816	28.49	11.45	17.04
2019	788	635	1423	24.14	10.77	13.37
2020 and later	X	X	X	X	X	X

Table 26: Water-use intensity of conventional oil by year, contributions from conventional methods and hydraulic fracturing

Parameter:	Water use - conventional (MCM)	Water use - fracturing (MCM)	Oil produced[5] (MCM/year)	Demand intensity (m^3/m^3)
Source of data:	[71]	Estimated (see text below)	[16]	Calculated (=[col1+col2]/col3)
2005	20.32	0	33.14	0.613
2006	19.35	0	31.51	0.614
2007	18.97	0	30.43	0.623
2008	17.03	0	29.18	0.584
2009	15.48	0	26.75	0.579
2010	15.48	1.27	26.63	0.629
2011	13.16	2.55	28.43	0.553
2012	15.10	3.82	32.28	0.586
2013	14.32	5.10	33.77	0.575
2014	12.97	6.37	34.20	0.566

The AER reports that horizontal drilling and multistage hydraulic fracturing began in 2010 [13]. No water use has been attributed to conventional oil production from fracturing before 2010, with the years 2010 through 2013 assumed to increase linearly from zero to the amount disaggregated from the AER's reported hydraulic fracturing water use in 2014, described in Table 22.

[5] Taken as the sum of light and heavy conventional crude oils

Table 27: Canada-wide refining capacity factor by year [89]

Year	Capacity factor (use)
2005	0.94
2006	0.92
2007	0.95
2008	0.88
2009	0.78
2010	0.84
2011	0.81
2012	0.81
2013	0.86
2014	0.93
2015	0.89
2016	0.82
2017	0.91
2018	0.81
2019 and later	0.86

Table 28: Division of total in situ bitumen production by OSA and method for each year (sources vary; see comments below)

Region:	Alberta (total)			Athabasca		Cold Lake			Peace River	
Type:	SAGD	CSS	Primary	SAGD	Primary	SAGD	CSS	Primary	CSS	Primary
2005 to 2010	43.0%	31.0%	26.0%	41.7%	7.8%	1.3%	30.2%	13.6%	0.8%	4.7%
2011	43.0%	33.0%	24.0%	41.7%	7.2%	1.3%	32.2%	12.5%	0.8%	4.3%
2012	50.0%	25.0%	25.0%	48.5%	6.7%	1.5%	25.5%	12.8%	0.8%	4.3%
2013	50.0%	24.0%	26.0%	51.0%	7.7%	1.6%	22.3%	12.5%	0.5%	4.4%
2014	57.0%	19.0%	24.0%	56.5%	7.8%	1.6%	18.8%	11.1%	0.4%	3.8%
2015	61.0%	20.0%	19.0%	59.3%	6.9%	2.2%	18.9%	9.3%	0.4%	3.0%
2016	69.0%	15.0%	16.0%	64.3%	5.9%	3.0%	16.7%	7.1%	0.4%	2.5%
2017	71.0%	16.0%	13.0%	67.6%	5.4%	2.8%	15.4%	5.6%	0.3%	2.8%
2018	74.0%	14.0%	12.0%	71.1%	4.9%	3.2%	13.6%	5.1%	0.2%	1.9%
2019	74.0%	14.0%	12.0%	70.9%	4.8%	3.1%	13.8%	5.0%	0.2%	2.2%
2020	75.0%	13.0%	12.0%	71.9%	4.8%	3.1%	12.8%	5.0%	0.2%	2.2%
2021	75.0%	13.0%	12.0%	71.9%	4.8%	3.1%	12.8%	5.0%	0.2%	2.2%
2022	74.0%	13.0%	13.0%	70.9%	5.2%	3.1%	12.8%	5.4%	0.2%	2.4%
2023	74.0%	13.0%	13.0%	70.9%	5.2%	3.1%	12.8%	5.4%	0.2%	2.4%
2024	74.0%	13.0%	13.0%	70.9%	5.2%	3.1%	12.8%	5.4%	0.2%	2.4%
2025	74.0%	14.0%	12.0%	70.9%	4.8%	3.1%	13.8%	5.0%	0.2%	2.2%
2026	73.0%	16.0%	11.0%	70.0%	4.4%	3.0%	15.7%	4.6%	0.3%	2.0%
2027	73.0%	16.0%	11.0%	70.0%	4.4%	3.0%	15.7%	4.6%	0.3%	2.0%
2028	73.0%	16.0%	11.0%	70.0%	4.4%	3.0%	15.7%	4.6%	0.3%	2.0%
2029	73.0%	16.0%	11.0%	70.0%	4.4%	3.0%	15.7%	4.6%	0.3%	2.0%
2030	73.0%	17.0%	10.0%	70.0%	4.0%	3.0%	16.7%	4.2%	0.3%	1.9%
2031	72.0%	19.0%	9.0%	69.0%	3.6%	3.0%	18.7%	3.7%	0.3%	1.7%
2032	72.0%	19.0%	9.0%	69.0%	3.6%	3.0%	18.7%	3.7%	0.3%	1.7%
2033	72.0%	19.0%	9.0%	69.0%	3.6%	3.0%	18.7%	3.7%	0.3%	1.7%
2034	72.0%	19.0%	9.0%	69.0%	3.6%	3.0%	18.7%	3.7%	0.3%	1.7%
2035	72.0%	19.0%	9.0%	69.0%	3.6%	3.0%	18.7%	3.7%	0.3%	1.7%
2036	72.0%	19.0%	9.0%	69.0%	3.6%	3.0%	18.7%	3.7%	0.3%	1.7%
2037	72.0%	20.0%	8.0%	69.0%	3.2%	3.0%	19.7%	3.3%	0.3%	1.5%
2038	72.0%	20.0%	8.0%	69.0%	3.2%	3.0%	19.7%	3.3%	0.3%	1.5%
2039	72.0%	20.0%	8.0%	69.0%	3.2%	3.0%	19.7%	3.3%	0.3%	1.5%
2040 to 2050	71.0%	20.0%	9.0%	68.1%	3.6%	2.9%	19.7%	3.7%	0.3%	1.7%

The distribution of production by OSA and in situ type for the years 2012 to 2018 was calculated using data from the Alberta Energy Regulator [92]. The Alberta-wide use of each in situ type was based on work by Davis et al. [95], and from this and the OSA distribution in 2012/2013 and 2017/2018, in situ use in each OSA was estimated for the remaining years (i.e., pre-2012 and post-2018).

Table 29: Production of surface-mined bitumen by year in 1000 m^3/day [16]

Year	Mined bitumen
2005	99.6
2006	120.9
2007	124.7
2008	114.7
2009	131.2
2010	136.2
2011	141.9
2012	148.2
2013	155.2
2014	152.7
2015	184.7
2016	182.8
2017	202.8
2018	236.7
2019	255.2
2020	230.7
2021	256.0
2022	261.1
2023	262.0
2024	262.7
2025	264.8
2026	266.3
2027	268.5
2028	272.0
2029	274.0
2030	274.0
2031	274.0
2032	274.0
2033	274.0
2034	274.0
2035	274.0
2036	274.0
2037	274.0
2038	274.0
2039	273.3
2040	272.1
2041	270.8
2042	270.1
2043	269.3
2044	267.7
2045	265.6
2046	263.5
2047	261.5

2048	259.5
2049	257.6
2050	255.7

Table 30: Upgrading activity by volume of SCO and Sturgeon Refinery activity (MCM/year)

Year	Upgraded bitumen [16]	Sturgeon Refinery capacity (5 years assumed between refinery expansion phases)	Sturgeon Refinery activity (Calculated based on refinery use)
2005	30.30	0.00	0.00
2006	35.92	0.00	0.00
2007	37.85	0.00	0.00
2008	35.99	0.00	0.00
2009	41.93	0.00	0.00
2010	40.77	0.00	0.00
2011	47.02	0.00	0.00
2012	47.42	0.00	0.00
2013	48.46	0.00	0.00
2014	48.89	0.00	0.00
2015	49.35	0.00	0.00
2016	54.07	0.00	0.00
2017	59.78	0.00	0.00
2018	63.33	0.00	0.00
2019	66.01	0.00	0.00
2020	61.89	2.90	2.50
2021	69.31	2.90	2.50
2022	69.32	2.90	2.50
2023	69.32	2.90	2.50
2024	69.71	2.90	2.50
2025	71.21	5.80	5.00
2026	72.09	5.80	5.00
2027	72.37	5.80	5.00
2028	72.86	5.80	5.00
2029	72.94	5.80	5.00
2030	72.27	8.70	7.50
2031	74.35	8.70	7.50
2032	75.72	8.70	7.50
2033	75.84	8.70	7.50
2034	75.84	8.70	7.50
2035	75.84	8.70	7.50
2036	75.84	8.70	7.50
2037	75.84	8.70	7.50
2038	75.84	8.70	7.50
2039	75.84	8.70	7.50
2040	75.84	8.70	7.50
2041	75.64	8.70	7.50
2042	75.43	8.70	7.50

2043	75.23	8.70	7.50
2044	75.02	8.70	7.50
2045	74.82	8.70	7.50
2046	74.62	8.70	7.50
2047	74.42	8.70	7.50
2048	74.22	8.70	7.50
2049	74.02	8.70	7.50
2050	73.82	8.70	7.50

Table 31: Decreasing water-use intensity equations, minimums, 2050 results, and context

Product (unit)	Most recent calculated withdrawal and year of data (m^3 water/unit)	Projection formula (m^3 water/unit)	Minimum withdrawal (m^3 water/unit)	2050 withdrawal (m^3 water/unit)
Conventional oil (m^3 oil)	0.57 (2014)	0.6236*EXP(-0.01*(YYYY-2014))	0.46	0.46
Refining (m^3 feedstock)	2.50 (2015)	3.6965*EXP(-0.028*(YYYY-2014))	0.98	1.02
Athabasca SAGD (m^3 bitumen)	0.22 (2018)	1.4257*EXP(-0.141*(YYYY-2014))	0.15	0.15
Cold Lake SAGD (m^3 bitumen)	0.30 (2018)	4.5023*EXP(-0.187*(YYYY-2014))	0.15	0.15
Cold Lake CSS (m^3 bitumen)	0.75 (2018)	1.104*EXP(-0.041*(YYYY-2014))	0.35	0.35
Surface mining (m^3 bitumen)	1.89 (2019)	2.9825*EXP(-0.024*(YYYY-2014))	1.20	1.20

5.2 Supplementary Results

Table 32: In situ water use components and calculated indicators

Year	Total water (m^3)	Recycled water (m^3)	Hydrocarbon production (BOE)	Total water use/hydrocarbon production (m^3/BOE)	Recycled water %
Source:	[121]	[121]	[121]	Calculated	Calculated
2016	216,085,934	184,468,129	476,584,594	0.453	85%
2017	243,506,395	210,841,746	546,315,718	0.446	87%
2018	258,028,708	222,350,045	563,292,134	0.458	86%
2019	255,989,824	222,966,036	557,846,645	0.459	87%
2020	249,216,105	219,483,084	549,698,956	0.453	88%

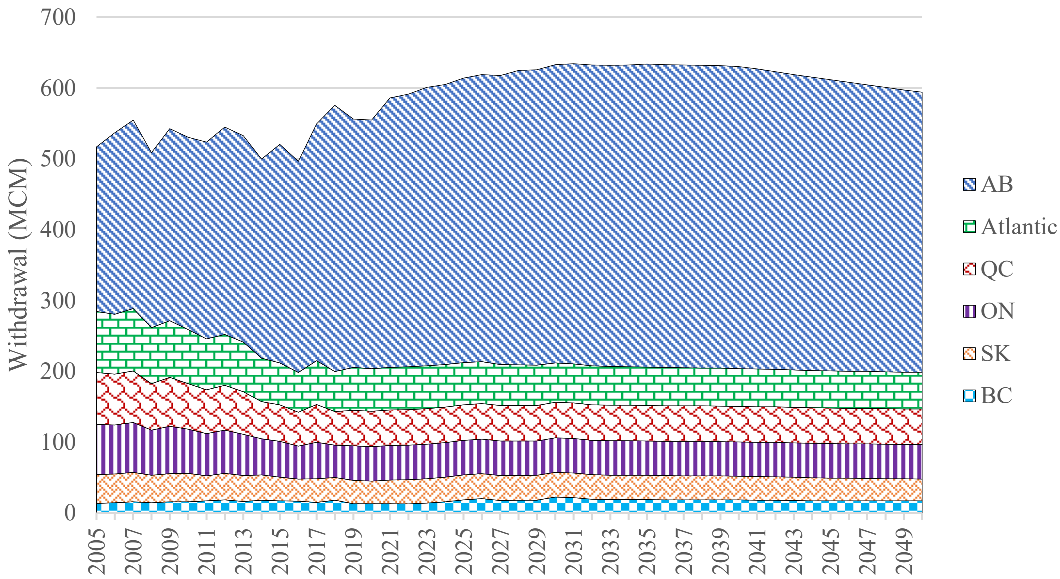

Figure 43: National yearly oil and gas water use by province, reference scenario (Manitoba not shown given its negligible water use)

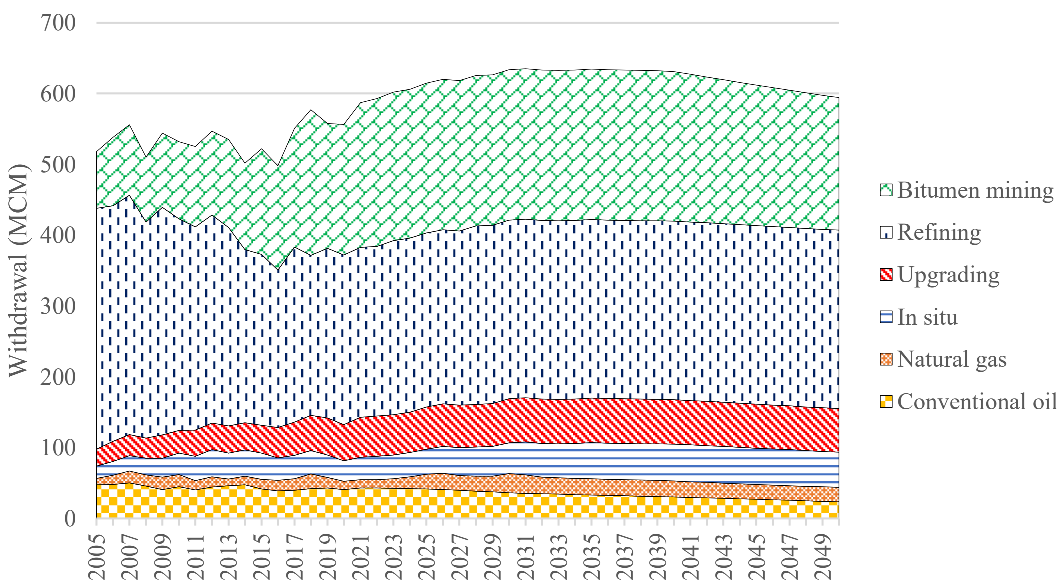

Figure 44: National yearly oil and gas water use by subsector, reference scenario

Table 33: Water withdrawal (and consumption) by province and river in MCM for select years in the reference scenario

Region	2005	2010	2015	2020	2025	2030	2040	2050
AB	**232 (141)**	**272 (187)**	**308 (236)**	**351 (271)**	**406 (317)**	**438 (342)**	**455 (358)**	**443 (348)**
Athabasca	110 (100)	152 (139)	199 (183)	240 (219)	277 (253)	288 (264)	292 (268)	278 (255)
Bow	9 (9)	10 (10)	8 (7)	8 (8)	10 (10)	12 (12)	14 (14)	15 (14)
Cold Lake	10 (10)	17 (17)	15 (15)	11 (11)	15 (15)	21 (21)	27 (27)	28 (28)
North Saskatchewan	93 (12)	81 (11)	74 (20)	82 (23)	92 (27)	102 (31)	104 (32)	104 (33)
Oldman	0 (0)	1 (1)	0 (0)	0 (0)	1 (1)	1 (1)	1 (1)	1 (1)
Peace	6 (6)	7 (7)	7 (7)	6 (6)	7 (7)	9 (8)	11 (10)	11 (11)
South Saskatchewan	4 (4)	4 (4)	4 (4)	4 (4)	4 (4)	5 (5)	6 (6)	6 (6)
BC	**14 (2)**	**16 (6)**	**17 (9)**	**13 (5)**	**19 (11)**	**23 (15)**	**20 (12)**	**20 (13)**
Fraser	12 (1)	11 (1)	10 (2)	9 (1)	10 (2)	10 (3)	10 (2)	10 (2)
Liard	0 (0)	0 (0)	1 (1)	0 (0)	1 (1)	1 (1)	1 (1)	1 (1)
Peace	1 (1)	4 (4)	7 (7)	4 (4)	8 (8)	12 (12)	9 (9)	10 (10)
MT	**0 (0)**	**1 (1)**	**2 (1)**	**1 (1)**	**1 (1)**	**1 (1)**	**1 (1)**	**1 (1)**
Assiniboine	0 (0)	1 (1)	2 (1)	1 (1)	1 (1)	1 (1)	1 (1)	1 (1)
NB	**55 (3)**	**48 (2)**	**39 (4)**	**37 (4)**	**37 (4)**	**37 (4)**	**37 (4)**	**37 (4)**
Saint John	55 (3)	48 (2)	39 (4)	37 (4)	37 (4)	37 (4)	37 (4)	37 (4)
NF	**32 (11)**	**28 (10)**	**21 (7)**	**23 (9)**	**24 (10)**	**20 (7)**	**19 (5)**	**15 (2)**
Offshore	32 (11)	28 (10)	21 (7)	23 (9)	24 (10)	20 (7)	19 (5)	15 (2)
NW	**1 (1)**	**1 (1)**	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**
Mackenzie	1 (1)	1 (1)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
ON	**71 (4)**	**62 (3)**	**50 (6)**	**49 (5)**	**49 (5)**	**49 (5)**	**49 (5)**	**49 (5)**
Lake Erie	21 (1)	18 (1)	15 (2)	14 (2)	14 (2)	14 (2)	14 (2)	14 (2)
Saint Claire	50 (3)	44 (2)	36 (4)	35 (4)	35 (4)	35 (4)	35 (4)	35 (4)
QC	**73 (4)**	**64 (3)**	**52 (6)**	**50 (5)**	**50 (5)**	**50 (5)**	**50 (5)**	**50 (5)**
Saint Lawrence	73 (4)	64 (3)	52 (6)	50 (5)	50 (5)	50 (5)	50 (5)	50 (5)
SK	**41 (16)**	**40 (18)**	**33 (17)**	**32 (16)**	**38 (21)**	**41 (24)**	**46 (28)**	**48 (30)**
North Saskatchewan	5 (4)	5 (5)	5 (4)	5 (4)	6 (6)	7 (7)	9 (8)	9 (9)
Qu'Appelle	25 (1)	22 (1)	17 (2)	17 (2)	17 (2)	17 (2)	17 (2)	17 (2)
Souris	6 (5)	6 (5)	6 (6)	6 (5)	8 (7)	9 (9)	11 (10)	12 (11)
South Saskatchewan	6 (5)	8 (7)	5 (5)	5 (4)	7 (6)	8 (7)	9 (8)	10 (9)
Grand Total	**518 (182)**	**532 (231)**	**522 (286)**	**557 (317)**	**624 (375)**	**660 (404)**	**676 (420)**	**664 (409)**

Table 34: Water withdrawal (and consumption) in each subsector in each province in MCM for select years in the reference scenario

Subset	2005	2010	2015	2020	2025	2030	2040	2050
AB	**232 (141)**	**272 (187)**	**308 (236)**	**351 (271)**	**406 (317)**	**438 (342)**	**455 (358)**	**443 (348)**
BM	80 (73)	109 (100)	149 (137)	184 (170)	212 (195)	219 (201)	217 (200)	204 (188)
CO	20 (19)	17 (15)	17 (16)	15 (14)	16 (15)	19 (17)	22 (21)	24 (22)
IS	18 (18)	30 (30)	37 (37)	29 (29)	38 (38)	47 (47)	58 (58)	59 (59)
NG	7 (7)	10 (10)	6 (6)	8 (8)	11 (11)	14 (14)	15 (15)	16 (16)
Re	84 (4)	74 (4)	60 (7)	64 (7)	70 (8)	76 (8)	76 (8)	76 (8)
Up	24 (20)	32 (27)	39 (33)	51 (43)	60 (51)	63 (54)	66 (56)	64 (55)
BC	**14 (2)**	**16 (6)**	**17 (9)**	**13 (5)**	**19 (11)**	**23 (15)**	**20 (12)**	**20 (13)**
CO	1 (1)	1 (1)	1 (1)	0 (0)	1 (1)	1 (1)	1 (1)	1 (1)
NG	0 (0)	4 (4)	8 (8)	4 (4)	10 (10)	14 (14)	10 (10)	11 (11)
Re	12 (1)	11 (1)	9 (1)	8 (1)	8 (1)	8 (1)	8 (1)	8 (1)
MT	**0 (0)**	**1 (1)**	**2 (1)**	**1 (1)**	**1 (1)**	**1 (1)**	**1 (1)**	**1 (1)**
CO	0 (0)	1 (1)	2 (1)	1 (1)	1 (1)	1 (1)	1 (1)	1 (1)
NB	**55 (3)**	**48 (2)**	**39 (4)**	**37 (4)**	**37 (4)**	**37 (4)**	**37 (4)**	**37 (4)**
Re	55 (3)	48 (2)	39 (4)	37 (4)	37 (4)	37 (4)	37 (4)	37 (4)
NF	**32 (11)**	**28 (10)**	**21 (7)**	**23 (9)**	**24 (10)**	**20 (7)**	**19 (5)**	**15 (2)**
CO	11 (10)	10 (9)	6 (5)	8 (8)	9 (9)	6 (5)	4 (4)	1 (1)
Re	21 (1)	18 (1)	15 (2)	14 (2)	14 (2)	14 (2)	14 (2)	14 (2)
NW	**1 (1)**	**1 (1)**	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**
CO	1 (1)	1 (1)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
ON	**71 (4)**	**62 (3)**	**50 (6)**	**49 (5)**	**49 (5)**	**49 (5)**	**49 (5)**	**49 (5)**
CO	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
Re	71 (4)	62 (3)	50 (5)	49 (5)	49 (5)	49 (5)	49 (5)	49 (5)
QC	**73 (4)**	**64 (3)**	**52 (6)**	**50 (5)**	**50 (5)**	**50 (5)**	**50 (5)**	**50 (5)**
Re	73 (4)	64 (3)	52 (6)	50 (5)	50 (5)	50 (5)	50 (5)	50 (5)
SK	**41 (16)**	**40 (18)**	**33 (17)**	**32 (16)**	**38 (21)**	**41 (24)**	**46 (28)**	**48 (30)**
CO	15 (14)	15 (14)	16 (15)	15 (14)	21 (19)	24 (22)	29 (26)	31 (28)
NG	1 (1)	3 (3)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
Re	25 (1)	22 (1)	17 (2)	17 (2)	17 (2)	17 (2)	17 (2)	17 (2)
Grand Total	**518 (182)**	**532 (231)**	**522 (286)**	**557 (317)**	**624 (375)**	**660 (404)**	**676 (420)**	**664 (409)**

Table 35: Water withdrawal (and consumption) in each province by subsector in MCM for select years in the reference scenario

Subset	2005	2010	2015	2020	2025	2030	2040	2050
BM	**80 (73)**	**109 (100)**	**149 (137)**	**184 (170)**	**212 (195)**	**219 (201)**	**217 (200)**	**204 (188)**
AB	80 (73)	109 (100)	149 (137)	184 (170)	212 (195)	219 (201)	217 (200)	204 (188)
CO	**48 (44)**	**45 (41)**	**42 (38)**	**41 (38)**	**48 (44)**	**51 (47)**	**58 (53)**	**58 (53)**
AB	20 (19)	17 (15)	17 (16)	15 (14)	16 (15)	19 (17)	22 (21)	24 (22)
BC	1 (1)	1 (1)	1 (1)	0 (0)	1 (1)	1 (1)	1 (1)	1 (1)
MT	0 (0)	1 (1)	2 (1)	1 (1)	1 (1)	1 (1)	1 (1)	1 (1)
NF	11 (10)	10 (9)	6 (5)	8 (8)	9 (9)	6 (5)	4 (4)	1 (1)
NW	1 (1)	1 (1)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
ON	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
SK	15 (14)	15 (14)	16 (15)	15 (14)	21 (19)	24 (22)	29 (26)	31 (28)
IS	**18 (18)**	**30 (30)**	**37 (37)**	**29 (29)**	**38 (38)**	**47 (47)**	**58 (58)**	**59 (59)**
AB	18 (18)	30 (30)	37 (37)	29 (29)	38 (38)	47 (47)	58 (58)	59 (59)
NG	**8 (8)**	**17 (17)**	**14 (14)**	**12 (12)**	**21 (21)**	**28 (28)**	**25 (25)**	**26 (26)**
AB	7 (7)	10 (10)	6 (6)	8 (8)	11 (11)	14 (14)	15 (15)	16 (16)
BC	0 (0)	4 (4)	8 (8)	4 (4)	10 (10)	14 (14)	10 (10)	11 (11)
SK	1 (1)	3 (3)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
Re	**340 (18)**	**299 (14)**	**241 (26)**	**240 (26)**	**246 (27)**	**252 (27)**	**252 (27)**	**252 (27)**
AB	84 (4)	74 (4)	60 (7)	64 (7)	70 (8)	76 (8)	76 (8)	76 (8)
BC	12 (1)	11 (1)	9 (1)	8 (1)	8 (1)	8 (1)	8 (1)	8 (1)
NB	55 (3)	48 (2)	39 (4)	37 (4)	37 (4)	37 (4)	37 (4)	37 (4)
NF	21 (1)	18 (1)	15 (2)	14 (2)	14 (2)	14 (2)	14 (2)	14 (2)
ON	71 (4)	62 (3)	50 (5)	49 (5)	49 (5)	49 (5)	49 (5)	49 (5)
QC	73 (4)	64 (3)	52 (6)	50 (5)	50 (5)	50 (5)	50 (5)	50 (5)
SK	25 (1)	22 (1)	17 (2)	17 (2)	17 (2)	17 (2)	17 (2)	17 (2)
Up	**24 (20)**	**32 (27)**	**39 (33)**	**51 (43)**	**60 (51)**	**63 (54)**	**66 (56)**	**64 (55)**
AB	24 (20)	32 (27)	39 (33)	51 (43)	60 (51)	63 (54)	66 (56)	64 (55)
Grand Total	**518 (182)**	**532 (231)**	**522 (286)**	**557 (317)**	**624 (375)**	**660 (404)**	**676 (420)**	**664 (409)**

Table 36: Water withdrawal (and consumption) by subsector in MCM for select years

Subsector	Scenario	2005	2010	2015	2020	2025	2030	2040	2050
Conventional oil	Ref	48 (44)	45 (41)	42 (38)	41 (38)	48 (44)	51 (47)	58 (53)	58 (53)
	Ev					42 (38)	36 (33)	30 (28)	23 (22)
	Lp					34 (32)	26 (24)	17 (16)	11 (10)
	Hp					61 (56)	74 (68)	86 (79)	93 (85)
Natural gas	Ref	8 (8)	17 (17)	14 (14)	12 (12)	21 (21)	28 (28)	25 (25)	26 (26)
	Ev					20 (20)	27 (27)	22 (22)	21 (21)
	Lp					16 (16)	16 (16)	13 (13)	13 (13)
	Hp					26 (26)	31 (31)	36 (36)	43 (43)
Bitumen mining	Ref	80 (73)	109 (100)	149 (137)	184 (170)	212 (195)	219 (201)	217 (200)	204 (188)
	Ev					212 (195)	212 (195)	211 (194)	187 (172)
	Lp					204 (188)	201 (185)	188 (173)	175 (161)
	Hp					225 (207)	237 (218)	239 (220)	239 (220)
In situ	Ref	18 (18)	30 (30)	37 (37)	29 (29)	38 (38)	47 (47)	58 (58)	59 (59)
	Ev					35 (35)	44 (44)	52 (52)	50 (50)
	Lp					36 (36)	36 (36)	29 (29)	18 (18)
	Hp					52 (52)	64 (64)	77 (77)	86 (86)
Upgrading	Ref					60 (51)	63 (54)	66 (56)	64 (55)
	Ev					60 (51)	62 (53)	63 (53)	61 (52)
	Lp					57 (48)	59 (50)	58 (49)	56 (48)
	Hp					67 (57)	74 (63)	75 (64)	75 (64)

6 Appendix B (Chapter 3)

6.1 Input data

6.1.1 Basic electricity account parameters

Table 37: Water withdrawal and consumption intensities of individual technologies [114, 118, 119]

Generation technology - cooling technology	Withdrawal intensity (m^3/MWh)	Consumption intensity (m^3/MWh)
Coal supercritical - CP	1.6	0.88
Coal supercritical - WCT	2.19	1.61
Coal subcritical - OT	116.48	1.24
Coal subcritical - CP	2.33	1.95
Coal subcritical - WCT	2.31	2.01
Natural gas simple - DC	0.38	0.09
Natural gas combined - WCT	0.96	0.63
Natural gas cogeneration - WCT	0.58	0.28
Biomass industrial - WCT/DC	0.32	0.16
Hydroelectric - N/A	5.4	5.4
Wind - N/A	0.006	0.005
Solar - N/A	0.02	0.02
Oil combustion - DC	0.38	0.09
Coal-to-gas converted - WCT	0.96	0.63

Table 38: Cooling technology utilization [122]

Fuel and cooling technology	Alberta
Coal	
Coal subcritical	
Cooling pond	49.3%
Once through	12.9%
WCT	37.8%
Coal supercritical	
Cooling pond	50.2%
WCT	49.8%
Natural gas	
Cogeneration	
WCT	100.0%
Combined cycle	
WCT	100.0%

Table 39: Electricity generation assets in Alberta with greater than 50 MW capacity classified by fuel, type, capacity, and river basin (manually compiled)

Facility	Main fuel	Capacity (MW)	River basin to apply to	Type	Cooling tech
Shepard (EGC1)	Natural gas	860	S. Sask.	NGCC	WCT
Syncrude #1 (SCL1)	Natural gas	510	Athabasca	Cogen	WCT
Joffre #1 (JOF1)	Natural gas	474	S. Sask.	Cogen	WCT
Firebag (SCR6)	Natural gas	473	Athabasca	Cogen	WCT
Genesee 3	Coal	466	N. Sask.	Coal supercritical	Cooling pond
Keephills 3	Coal	463	N. Sask.	Coal supercritical	WCT
Sundance 4	Coal	406	N. Sask.	Coal subcritical	WCT
Sundance 5	Coal	406	N. Sask.	Coal subcritical	WCT
Sundance 6	Coal	401	N. Sask.	Coal subcritical	Cooling pond
Genesee 1	Coal	400	N. Sask.	Coal subcritical	Cooling pond
Genesis 2	Coal	400	N. Sask.	Coal subcritical	Cooling pond
Sheerness 1	Coal	400	S. Sask.	Coal subcritical	Cooling pond
Keephills 1	Coal	395	N. Sask.	Coal subcritical	WCT
Keephills 2	Coal	395	N. Sask.	Coal subcritical	WCT
Sheerness 2	Coal	390	S. Sask.	Coal subcritical	Cooling pond
Battle River 5	Coal	385	N. Sask.	Coal subcritical	OT
Poplar Creek (SCR5)	Natural gas	376	Athabasca	Cogen	WCT
Sundance 3	Coal	368	N. Sask.	Coal subcritical	Cooling pond
Brazeau Hydro (BRA)	Hydro	350	N. Sask.	Reservoir	N/A
Dow Hydrocarbon (DOWG)	Natural gas	326	N. Sask.	Cogen	WCT
Bow River Hydro (BOW1)	Hydro	320	S. Sask.	Reservoir	N/A
ENMAX Calgary Energy Centre (CAL1)	Natural gas	320	S. Sask.	NGCC	WCT
Sundance 1	Coal	280	N. Sask.	Coal subcritical	Cooling pond
Sundance 2	Coal	280	N. Sask.	Coal subcritical	WCT
Syncrude Mildred	Natural gas	270	Athabasca	Cogen	WCT
Nexen Inc #2 (NX02)	Natural gas	220	Athabasca	Cogen	WCT
Medicine Hat #1 (CMH1)	Natural gas	210	S. Sask.	NGCC	WCT
MacKay River (MKRC)	Natural gas	207	Athabasca	Cogen	WCT
CNRL Horizon (CNR5)	Natural gas	203	Athabasca	Cogen	WCT
Muskeg River (MKR1)	Natural gas	202	Athabasca	Cogen	WCT
MEG1 Christina Lake	Natural gas	202	Athabasca	Cogen	WCT

Facility	Main fuel	Capacity (MW)	River basin to apply to	Type	Cooling tech
(MEG1)					
Fort Hills (FH1)	Natural gas	199	Athabasca	Cogen	WCT
Nabiye (IOR2)	Natural gas	195	Athabasca	Cogen	WCT
ATCO Scotford Upgrader (APS1)	Natural gas	195	N. Sask.	Cogen	WCT
Mahkeses (IOR1)	Natural gas	180	Athabasca	Cogen	WCT
Battle River 4	Coal	155	N. Sask.	Coal subcritical	OT
Battle River 3	Coal	149	N. Sask.	Coal subcritical	OT
H.R. Milner	Coal	144	Peace	Coal subcritical	WCT
APF Athabasca (AFG1)	Biomass	131	Athabasca	Biomass	WCT/DC hybrid
Nexen Inc #1 (NX01)	Natural gas	120	S. Sask.	NGCC	WCT
Cavalier (EC01)	Natural gas	120	S. Sask.	NGCC	WCT
bighorn Hydro (BIG)	Hydro	120	N. Sask.	Reservoir	N/A
Northern Prairie Power Project (NPP1)	Natural gas	105	Peace	Simple	N/A
Clover Bar #2 (ENC2)	Natural gas	101	N. Sask.	Simple	N/A
Clover Bar #3 (ENC3)	Natural gas	101	N. Sask.	Simple	N/A
Christina Lake (CL01)	Natural gas	100	Athabasca	Cogen	WCT
Primrose #1 (PR1)	Natural gas	100	Athabasca	Cogen	WCT
Foster Creek (EC04)	Natural gas	98	Athabasca	Cogen	WCT
Air Liquide Scotford #1 (ALS1)	Natural gas	96	N. Sask.	Cogen	WCT
Carseland Cogen (TC01)	Natural gas	95	S. Sask.	Cogen	WCT
Redwater Cogen (TC02)	Natural gas	92	N. Sask.	Cogen	WCT
Kearl (IOR3)	Natural gas	84	Athabasca	Cogen	WCT
Fort Nelson (FNG1)	Natural gas	73	Peace	NGCC	WCT
Bear Creek 1 (BCRK)	Natural gas	64	Peace	Cogen	WCT
B Newsprint (ANC1)	Natural gas	63	Athabasca	Simple	N/A
DAI1 Daishowa (DAI1)	Biomass	52	Peace	Biomass	WCT/DC hybrid
Base Plant (SCR1)	Natural gas	50	Athabasca	Cogen	WCT
Weldwood #1 (WWD1)	Biomass	50	Athabasca	Biomass	WCT/DC hybrid
Rainbow #5 (RB5)	Natural gas	50	Peace	Simple	N/A
Valley View 1 (VVW1)	Natural gas	50	Peace	Simple	N/A
Valley View 2 (VVW2)	Natural gas	50	Peace	Simple	N/A

6.1.2 *Nuclear electricity pathway specific input data*

Table 40: Baseline electricity generation in TWh by technology and calculated average grid withdrawal and consumption by year, used in the nuclear electricity pathway

Year	Coal supercritical	Coal subcritical	Existing natural gas simple	Existing natural gas combined	New natural gas combined	Natural gas cogeneration	Biomass industrial	Hydroelectric	Wind	Solar	Nuclear	Oil combustion	Coal-to-gas conv.	Total	Grid average withdrawal (m^3/MWh)	Grid average consumption (m^3/MWh)
2018	6.92	38.64	0.27	7.61	0.00	22.87	2.12	6.11	4.63	0.05	0.00	0.00	0.00	89.22	8.12	1.41
2019	6.92	24.07	6.55	12.25	5.61	23.97	2.17	4.26	6.56	0.05	0.00	0.00	0.00	92.41	5.19	1.04
2020	6.92	22.49	0.02	12.25	11.21	24.38	2.17	4.39	9.85	0.09	0.00	0.00	0.00	93.77	4.87	1.03
2021	6.92	13.98	0.00	12.25	16.82	24.67	2.17	4.39	13.15	0.09	0.00	0.00	0.00	94.43	3.36	0.89
2022	6.92	8.51	0.00	12.25	19.62	24.90	2.17	4.39	16.44	0.09	0.00	0.00	0.00	95.30	2.39	0.80
2023	5.45	2.50	0.00	12.25	19.62	30.06	2.17	4.39	19.74	0.09	0.00	0.00	0.00	96.28	1.30	0.67
2024	4.33	1.30	0.32	12.17	19.62	30.06	2.17	4.39	23.03	0.09	0.00	0.00	0.00	97.49	1.06	0.62
2025	3.45	0.70	0.10	12.25	19.05	30.57	2.17	4.17	26.33	0.09	0.00	0.00	0.00	98.89	0.91	0.58
2026	3.58	0.67	0.27	12.25	19.15	31.13	2.17	4.17	26.63	0.09	0.00	0.00	0.00	100.12	0.90	0.57
2027	3.79	0.52	0.71	12.25	19.36	31.41	2.17	4.17	26.63	0.09	0.00	0.00	0.00	101.10	0.87	0.57
2028	3.96	0.30	1.12	12.25	19.43	31.69	2.17	4.17	26.63	0.09	0.00	0.00	0.00	101.82	0.84	0.56
2029	4.08	0.00	1.57	12.25	19.47	32.38	2.17	4.17	26.63	0.10	0.00	0.00	0.00	102.81	0.79	0.56
2030	0.00	0.00	2.69	12.25	21.12	33.07	2.17	4.17	28.03	0.10	0.00	0.00	0.40	103.99	0.73	0.52
2031	0.00	0.00	2.98	12.25	21.40	33.42	2.17	4.17	28.03	0.10	0.00	0.00	0.70	105.22	0.73	0.52
2032	0.00	0.00	2.34	12.25	23.40	33.52	2.17	4.17	28.03	0.10	0.00	0.00	0.18	106.16	0.74	0.52
2033	0.00	0.00	2.47	12.25	23.69	33.66	2.17	4.17	28.03	0.10	0.00	0.00	0.42	106.97	0.74	0.52
2034	0.00	0.00	1.82	12.25	25.25	33.73	2.17	4.17	28.03	0.10	0.00	0.00	0.08	107.59	0.74	0.52
2035	0.00	0.00	0.15	12.25	27.35	34.02	2.17	4.17	28.03	0.10	0.00	0.00	0.00	108.24	0.75	0.53
2036	0.00	0.00	0.00	10.57	29.48	34.35	2.17	4.17	28.02	0.10	0.00	0.00	0.00	108.86	0.75	0.53
2037	0.00	0.00	0.00	8.33	32.22	34.48	2.17	4.17	28.01	0.10	0.00	0.00	0.00	109.49	0.75	0.53
2038	0.00	0.00	0.00	8.33	32.82	34.52	2.17	4.17	28.01	0.10	0.00	0.00	0.00	110.12	0.75	0.53
2039	0.00	0.00	0.00	8.33	33.36	34.59	2.17	4.17	28.00	0.10	0.00	0.00	0.00	110.72	0.75	0.53
2040	0.00	0.00	0.00	7.81	34.50	34.59	2.17	4.17	27.99	0.10	0.00	0.00	0.00	111.34	0.76	0.53
2041	0.00	0.00	0.00	7.81	35.05	34.59	2.17	4.17	28.04	0.10	0.00	0.00	0.00	111.93	0.76	0.53
2042	0.00	0.00	0.00	7.81	35.65	34.59	2.17	4.17	28.03	0.10	0.00	0.00	0.00	112.53	0.76	0.53
2043	0.00	0.00	0.00	7.81	36.22	34.59	2.17	4.17	28.02	0.13	0.00	0.00	0.00	113.12	0.76	0.53
2044	0.00	0.00	0.00	7.81	36.76	34.59	2.17	4.17	28.02	0.18	0.00	0.00	0.00	113.71	0.76	0.53
2045	0.00	0.00	0.00	7.81	36.96	34.59	2.17	4.56	28.01	0.18	0.00	0.00	0.00	114.29	0.77	0.55
2046	0.00	0.00	0.00	7.81	37.53	34.59	2.17	4.56	28.01	0.18	0.00	0.00	0.00	114.86	0.78	0.55
2047	0.00	0.00	0.00	6.03	39.85	34.59	2.17	4.56	28.01	0.18	0.00	0.00	0.00	115.39	0.78	0.55
2048	0.00	0.00	0.00	6.03	40.45	34.59	2.17	4.56	28.01	0.18	0.00	0.00	0.00	115.99	0.78	0.55
2049	0.00	0.00	0.00	6.03	40.93	34.59	2.17	4.56	28.01	0.21	0.00	0.00	0.00	116.50	0.78	0.55
2050	0.00	0.00	0.00	0.00	46.92	34.59	2.17	5.15	28.01	0.21	0.00	0.00	0.00	117.05	0.80	0.58

6.1.3 Cogeneration electricity pathway specific input data

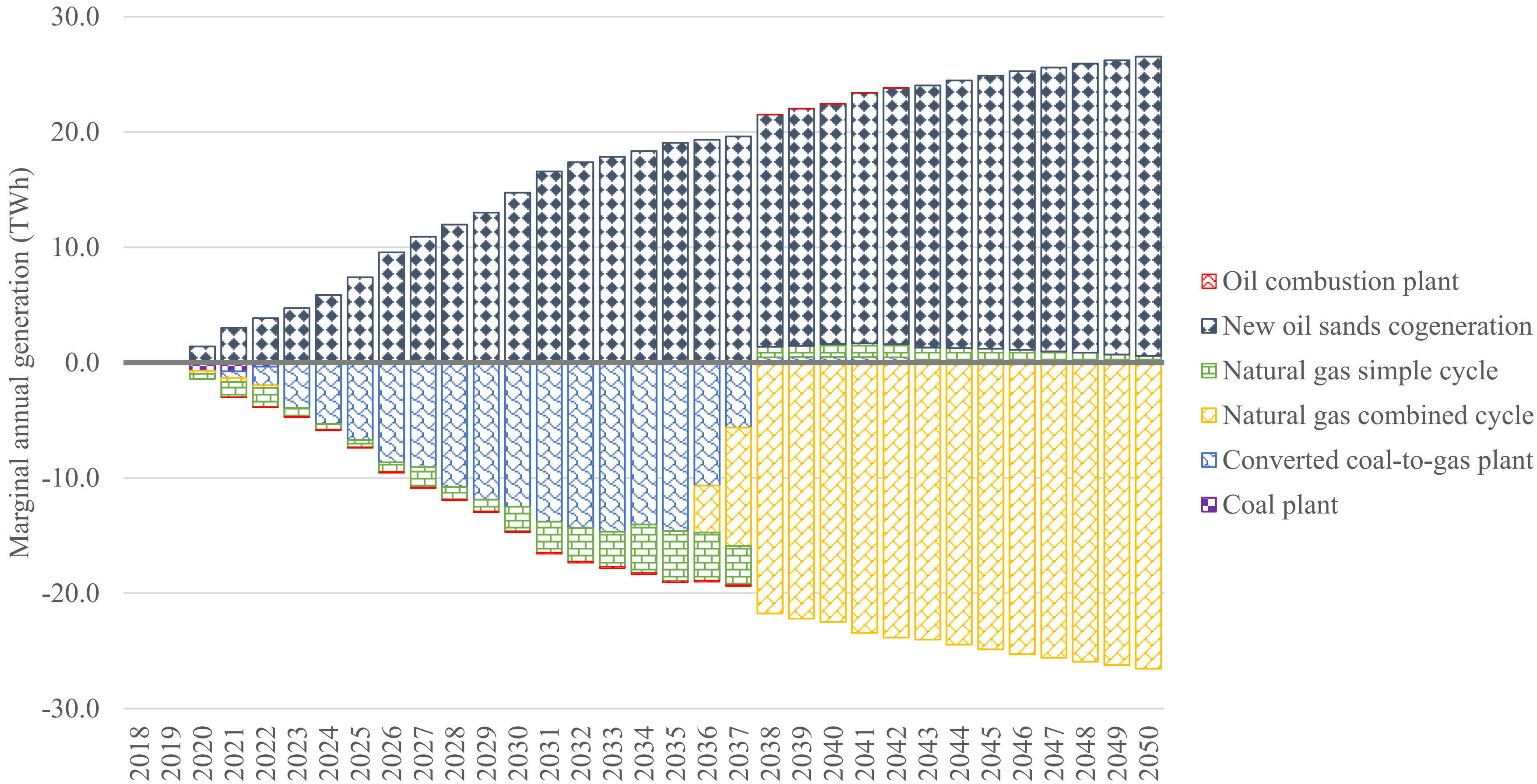

Figure 45: Marginal annual Alberta electrical grid-wide generation by technology in the SAGD-cogeneration-CP0 scenario [60]

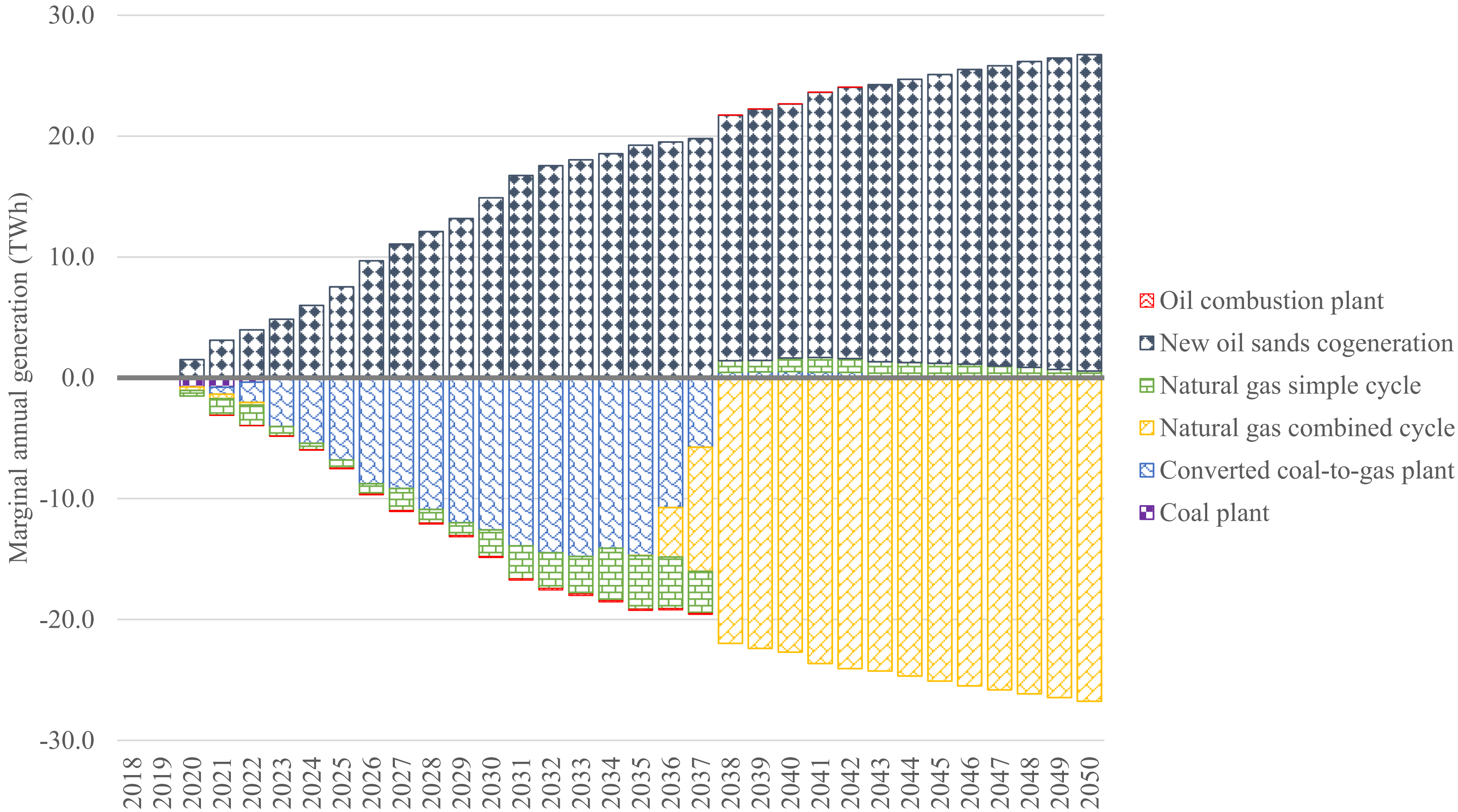

Figure 46: Marginal annual Alberta electrical grid-wide generation by technology in the SAGD-cogeneration-CP30 scenario [60]

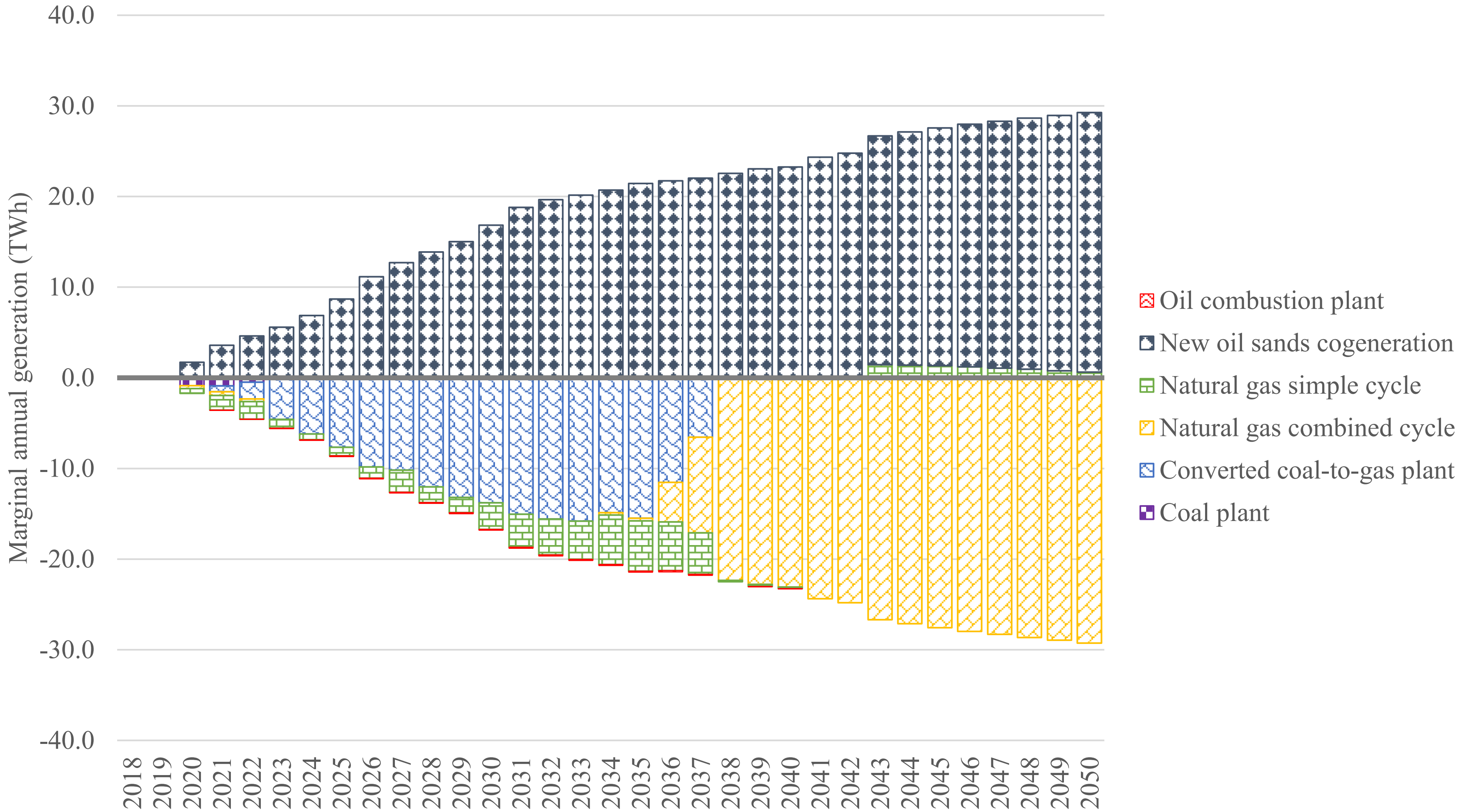

Figure 47: Marginal annual Alberta electrical grid-wide generation by technology in the SAGD-cogeneration-CP50 scenario [60]

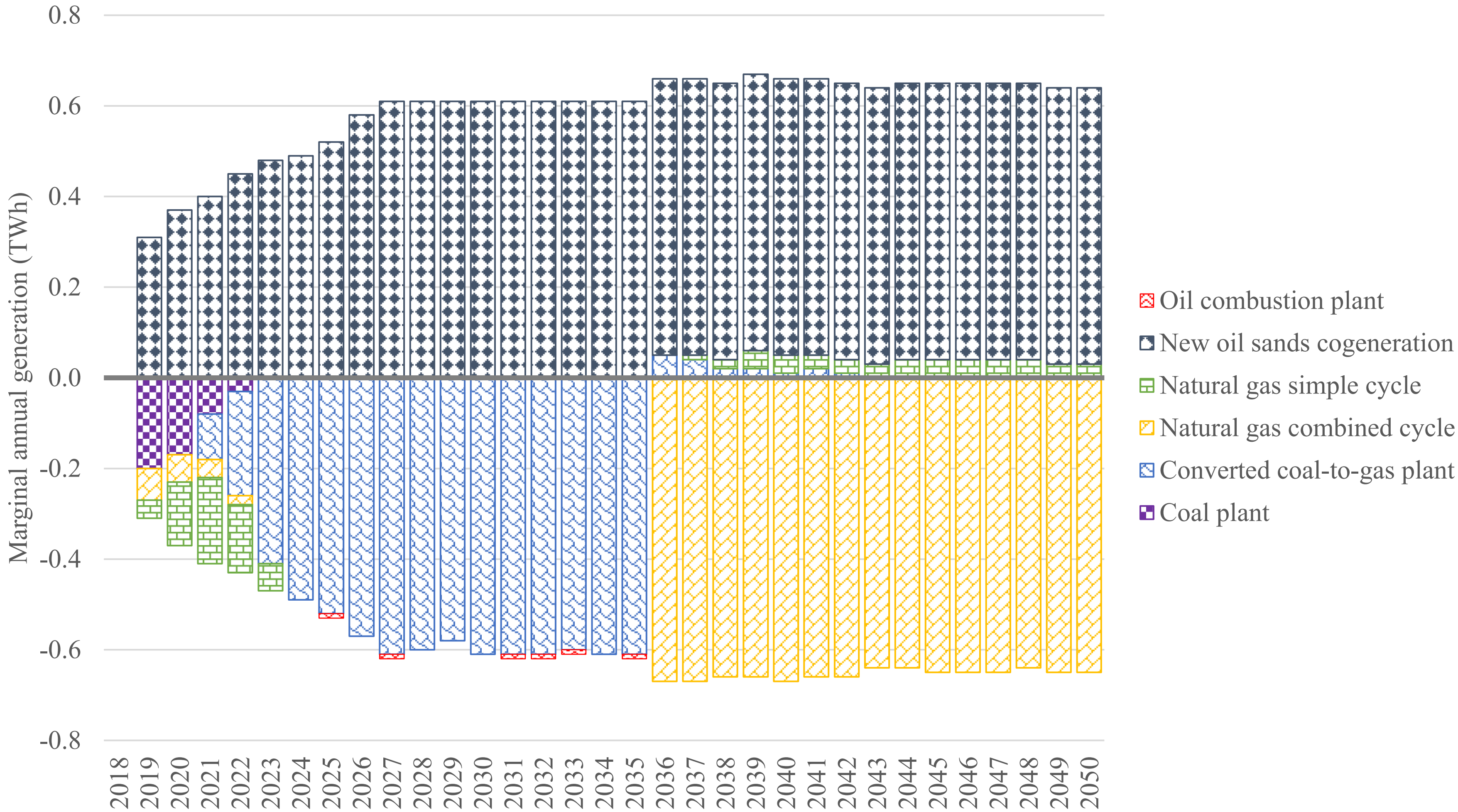

Figure 48: Marginal annual Alberta electrical grid-wide generation by technology in the surface mining-cogeneration-CP0 scenario [60]

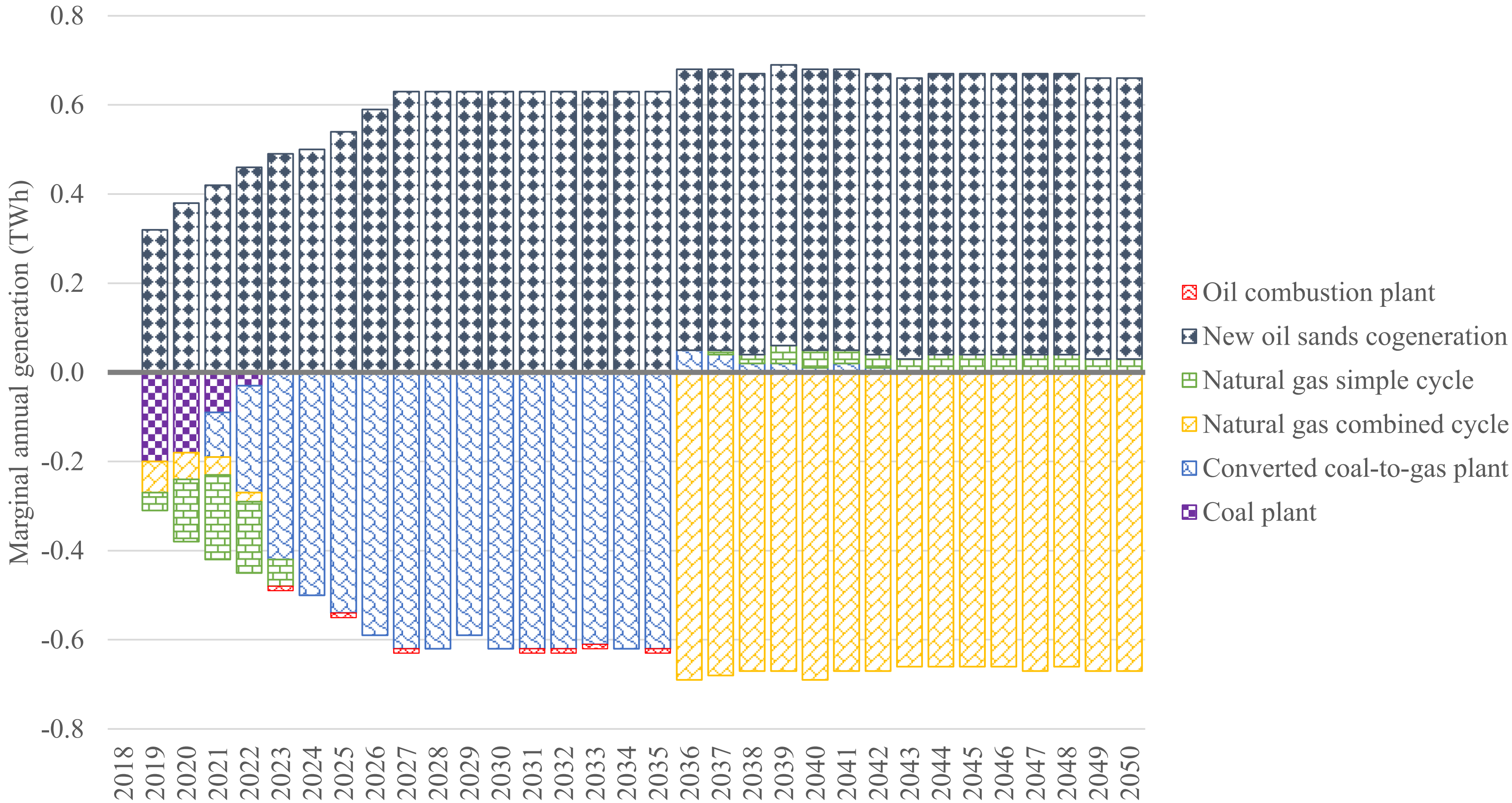

Figure 49: Marginal annual Alberta electrical grid-wide generation by technology in the surface mining-cogeneration-CP30 scenario [60]

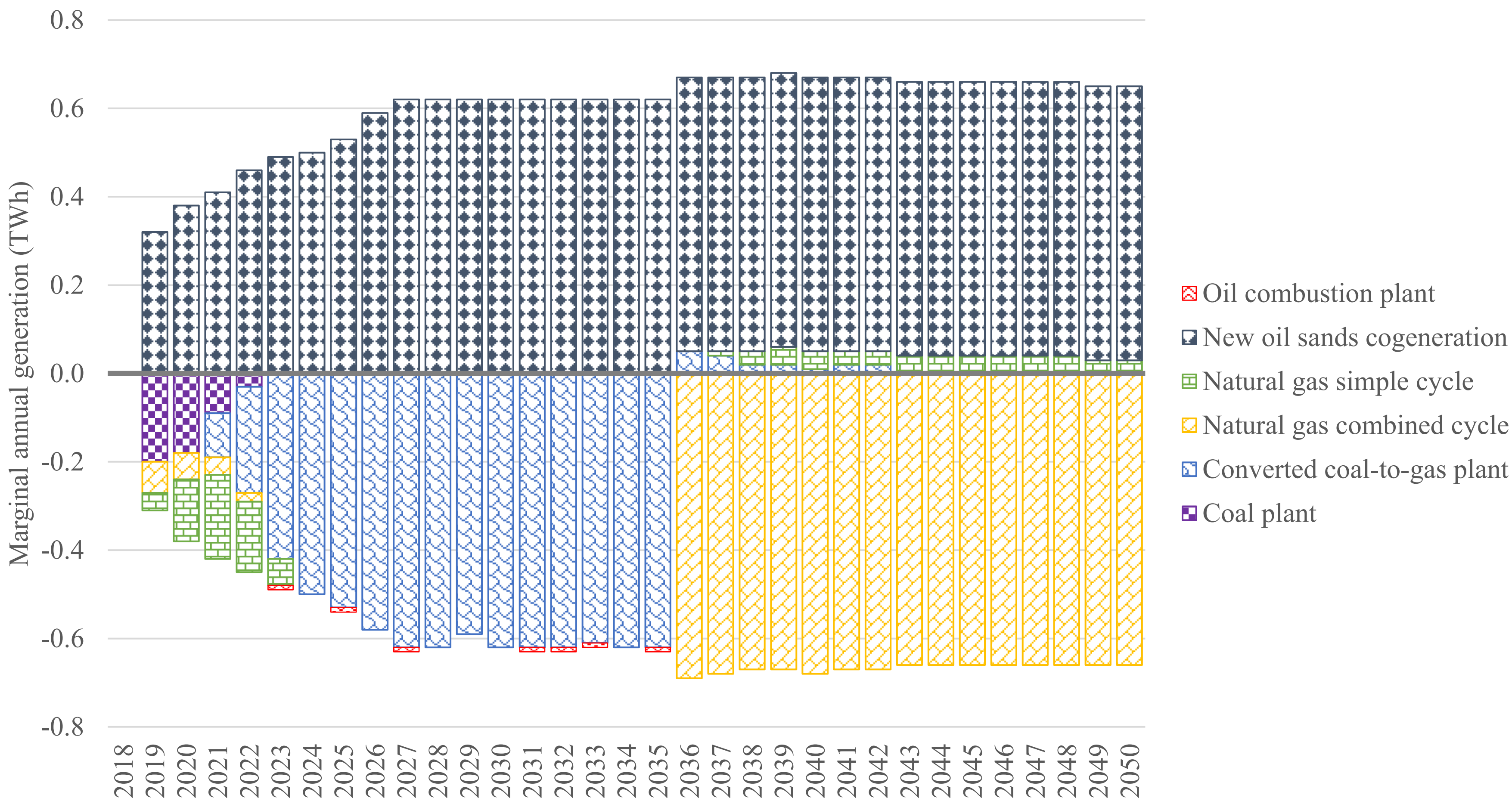

Figure 50: Marginal annual Alberta electrical grid-wide generation by technology in the surface mining-cogeneration-CP50 scenario [60]

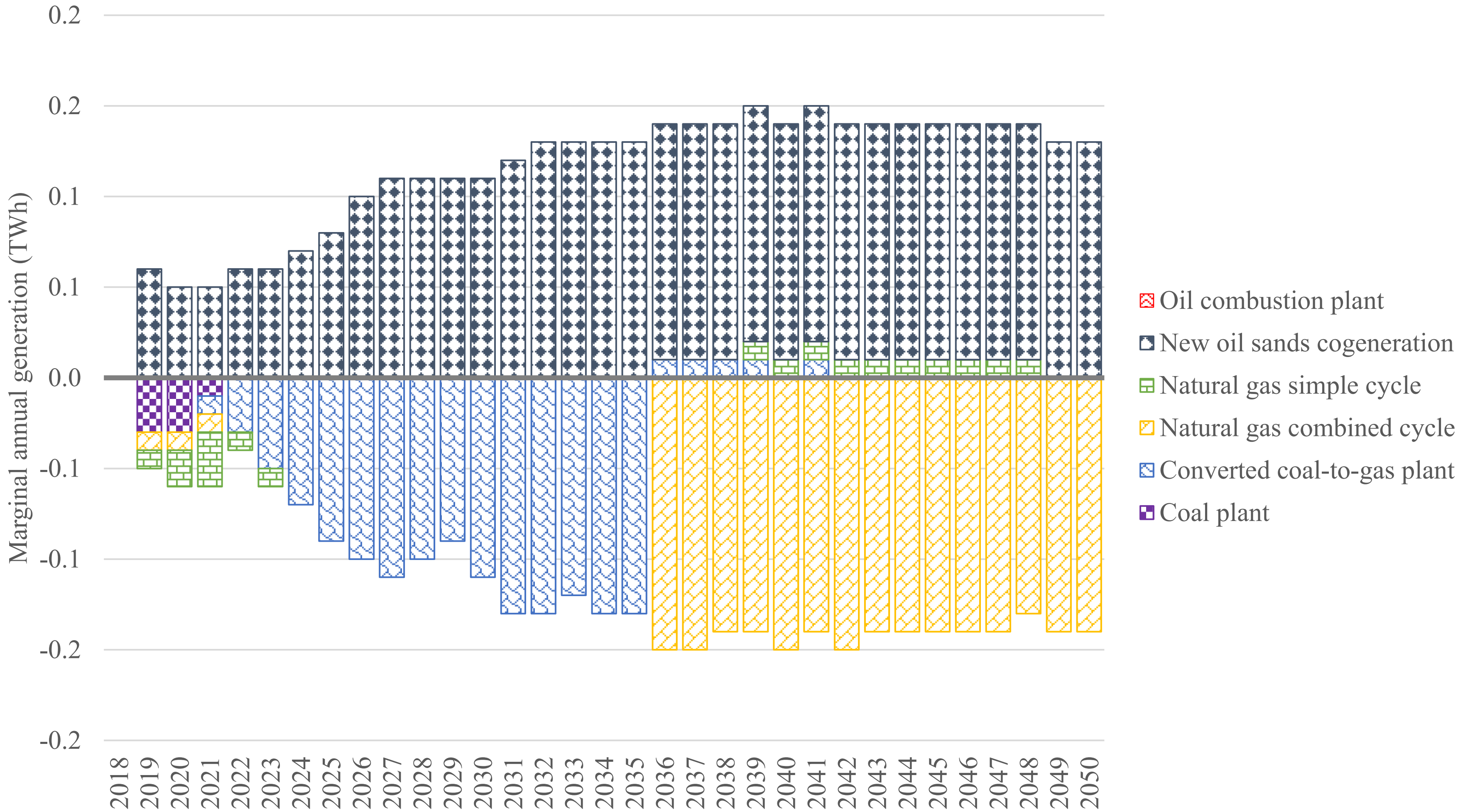

Figure 51: Marginal annual Alberta electrical grid-wide generation by technology in the upgrading-cogeneration-CP0 scenario [60]

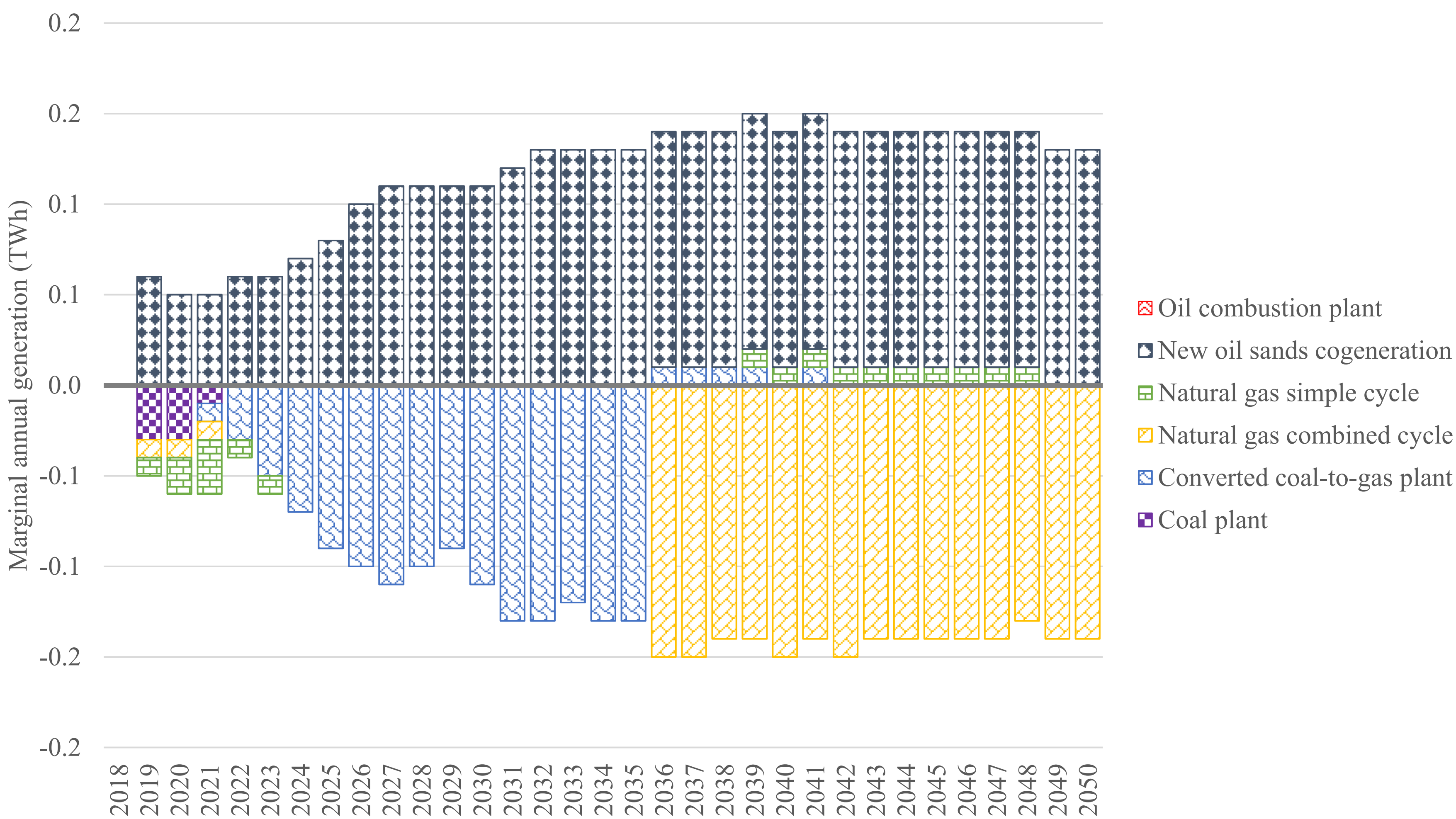

Figure 52: Marginal annual Alberta electrical grid-wide generation by technology in the upgrading-cogeneration-CP30 scenario [60]

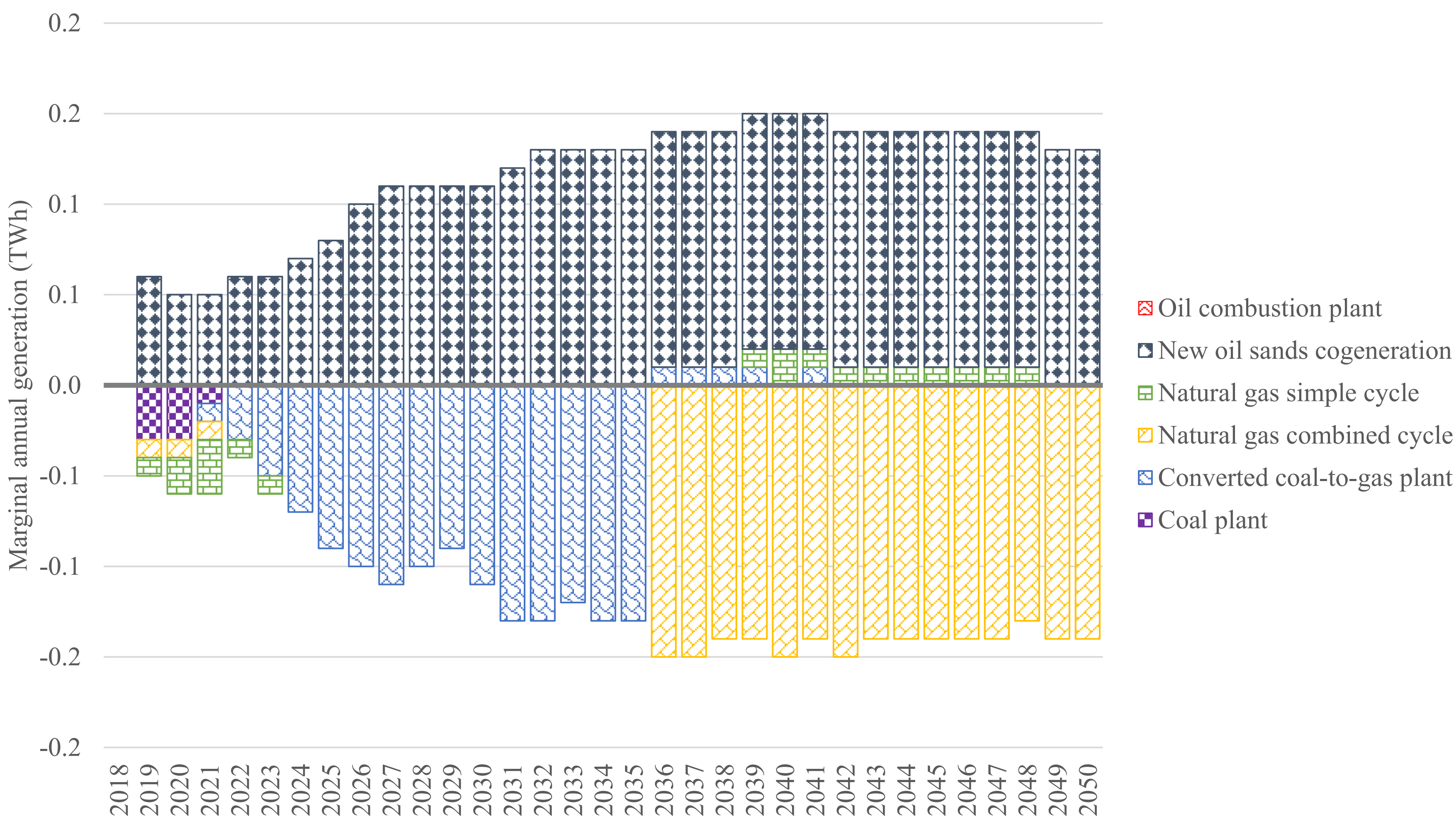

Figure 53: Marginal annual Alberta electrical grid-wide generation by technology in the upgrading-cogeneration-CP50 scenario [60]

6.2 *Supplementary Results*

6.2.1 *Marginal annual water use of electrical generation technologies due to cogeneration and carbon price scenarios by year*

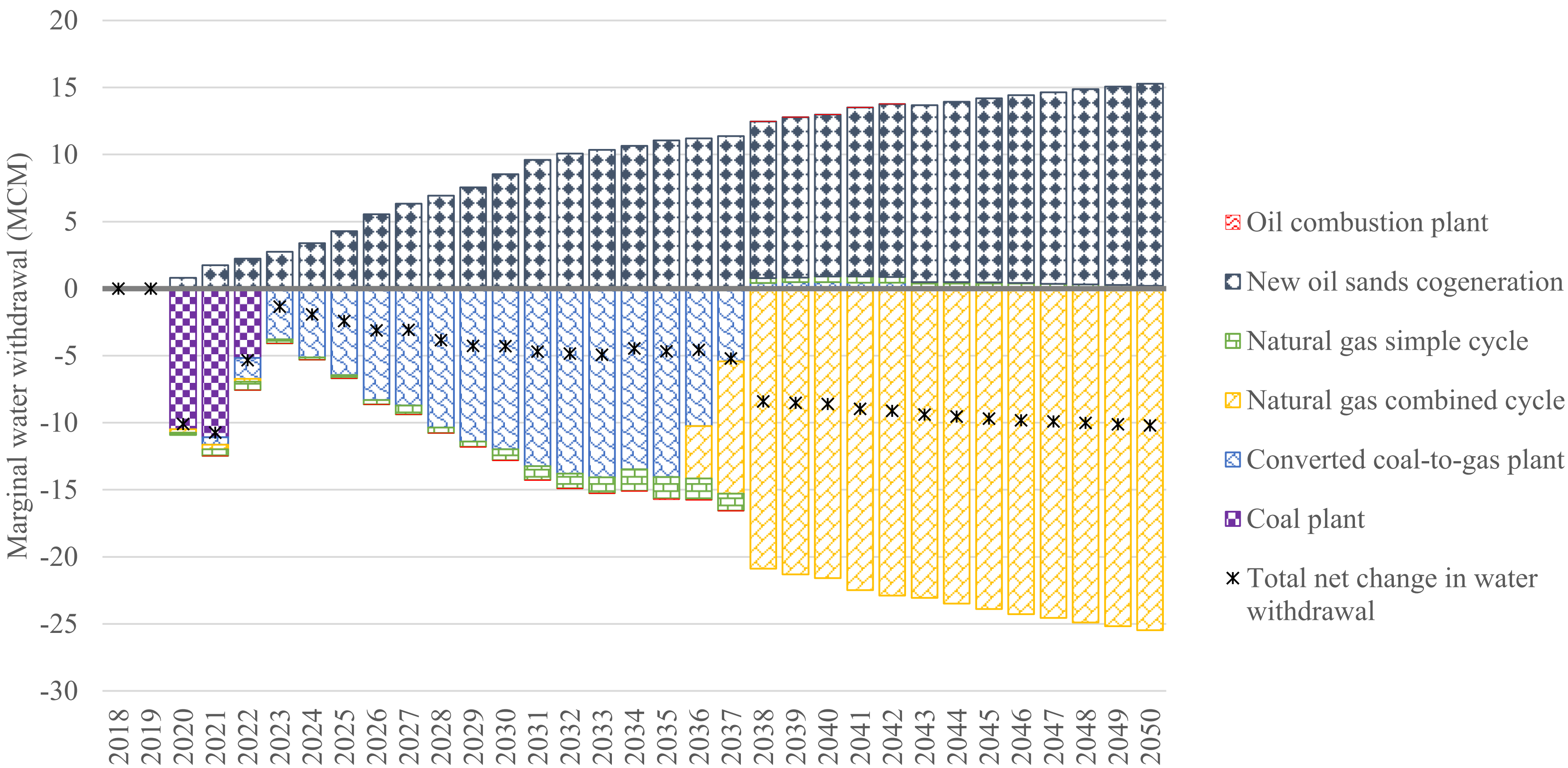

Figure 54: Marginal annual Alberta electrical grid-wide water withdrawal by generation technology in the SAGD-cogeneration-CP0 scenario

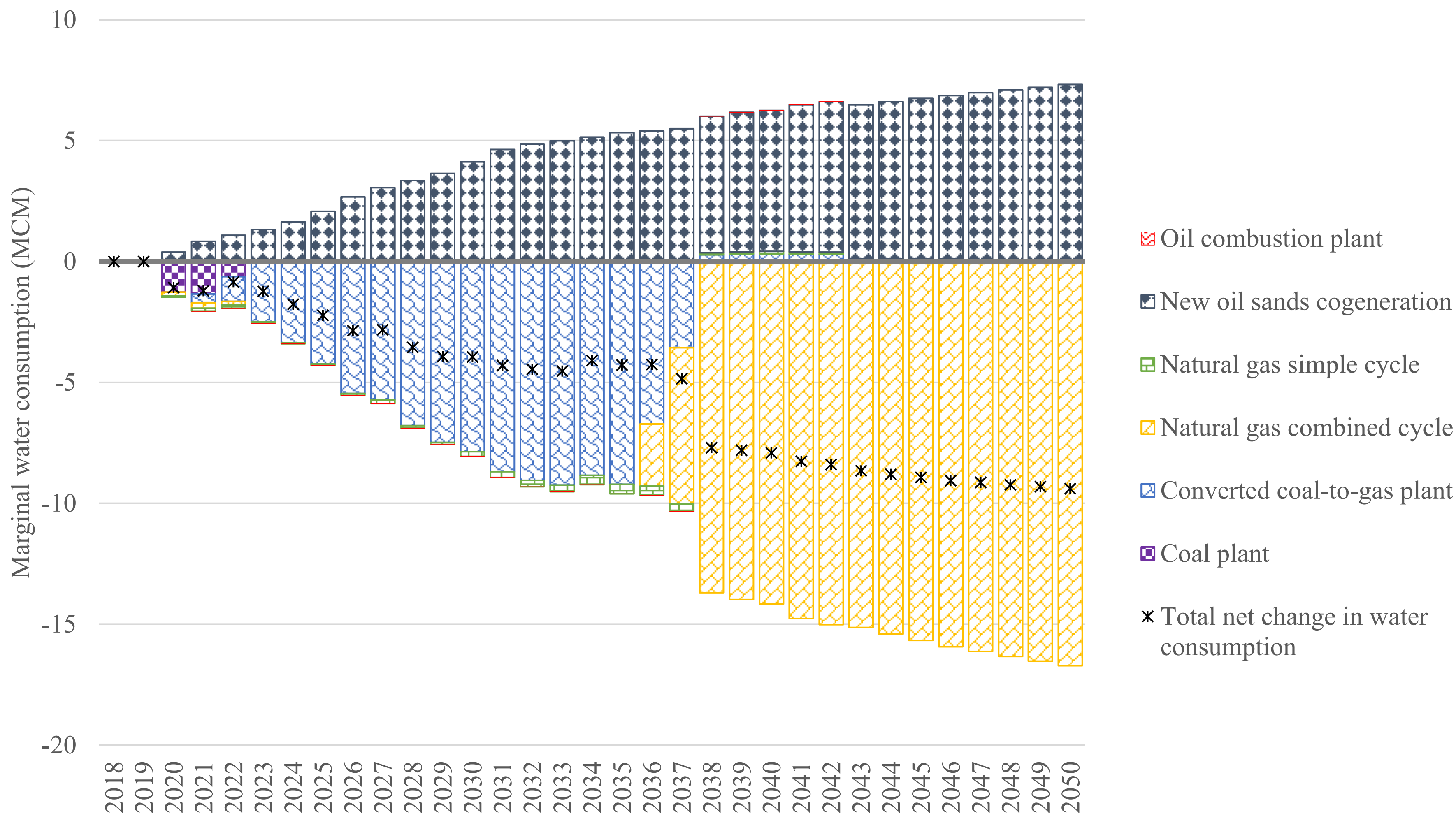

Figure 55: Marginal annual Alberta electrical grid-wide water consumption by generation technology in the SAGD-cogeneration-CP0 scenario

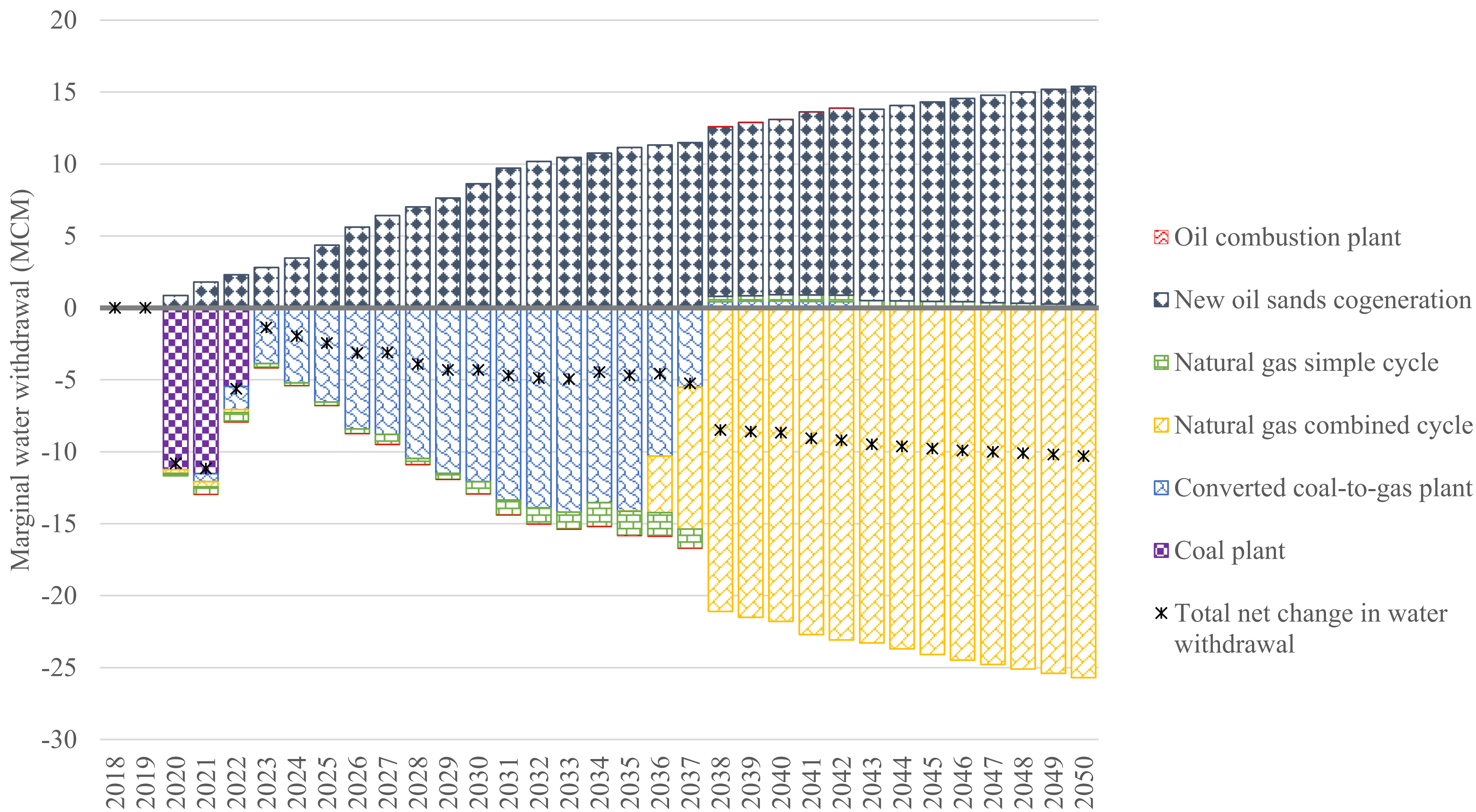

Figure 56: Marginal annual Alberta electrical grid-wide water withdrawal by generation technology in the SAGD-cogeneration-CP30 scenario

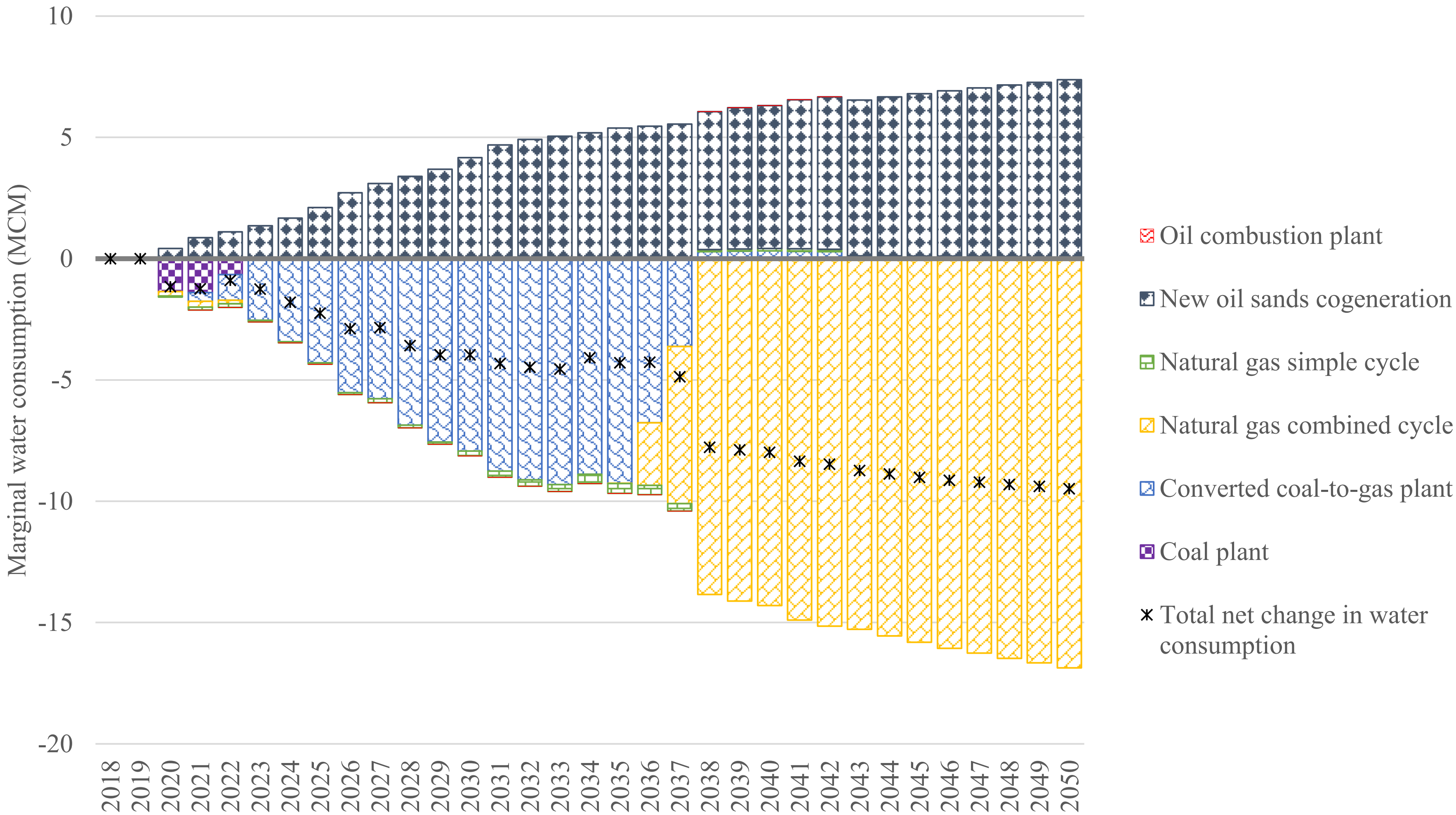

Figure 57: Marginal annual Alberta electrical grid-wide water consumption by generation technology in the SAGD-cogeneration-CP30 scenario

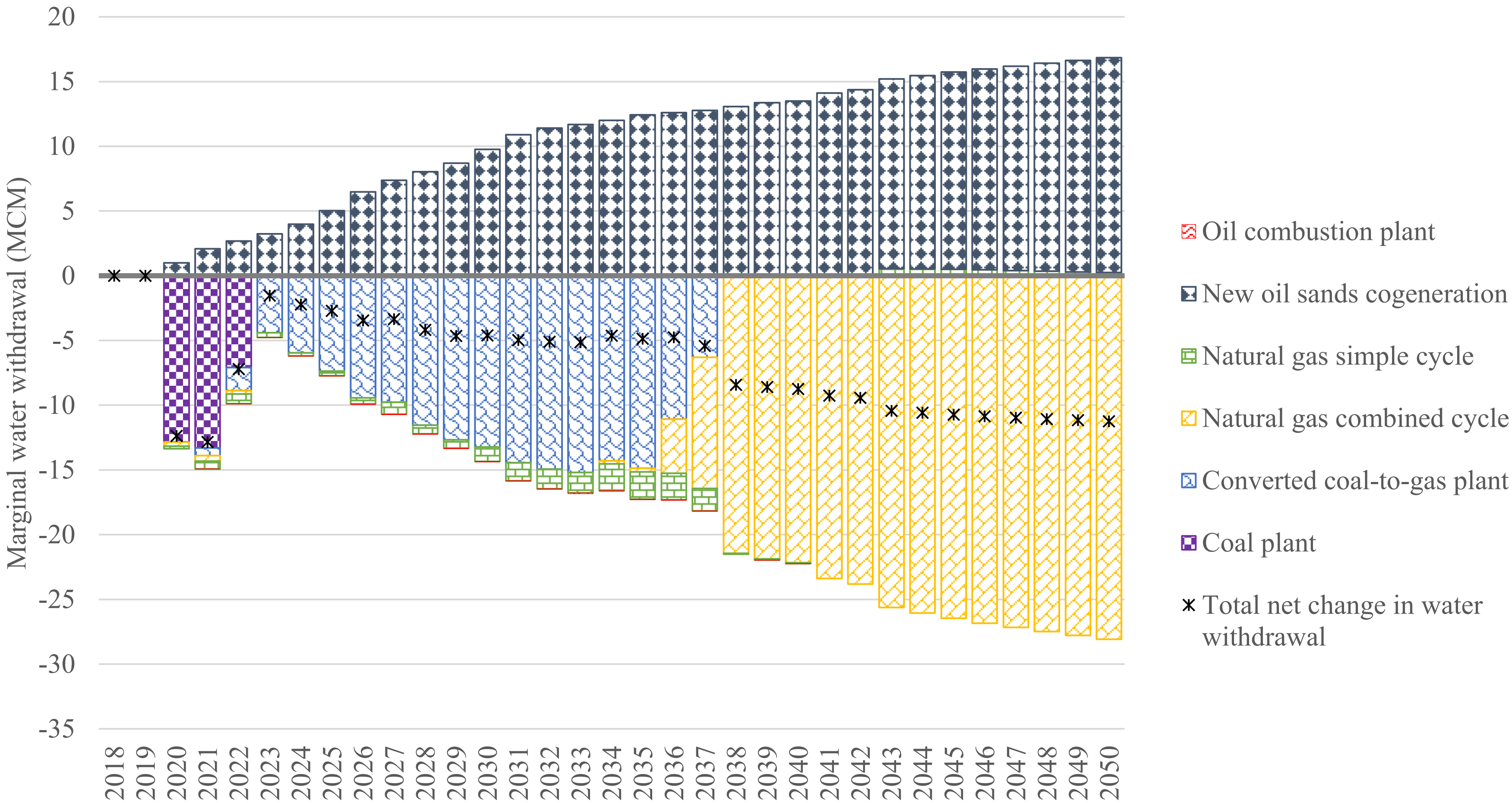

Figure 58: Marginal annual Alberta electrical grid-wide water withdrawal by generation technology in the SAGD-cogeneration-CP50 scenario

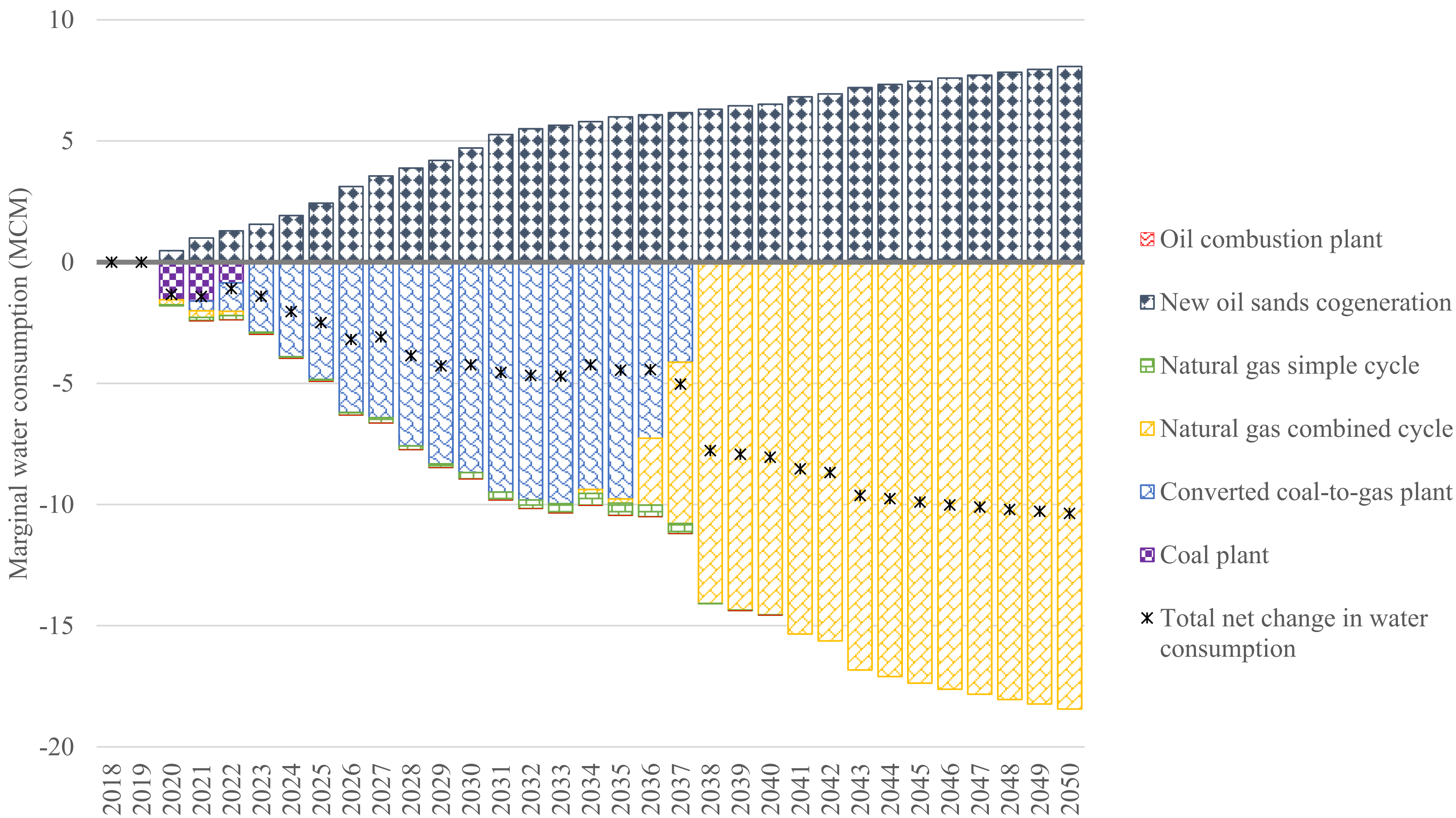

Figure 59: Marginal annual Alberta electrical grid-wide water consumption by generation technology in the SAGD-cogeneration-CP50 scenario

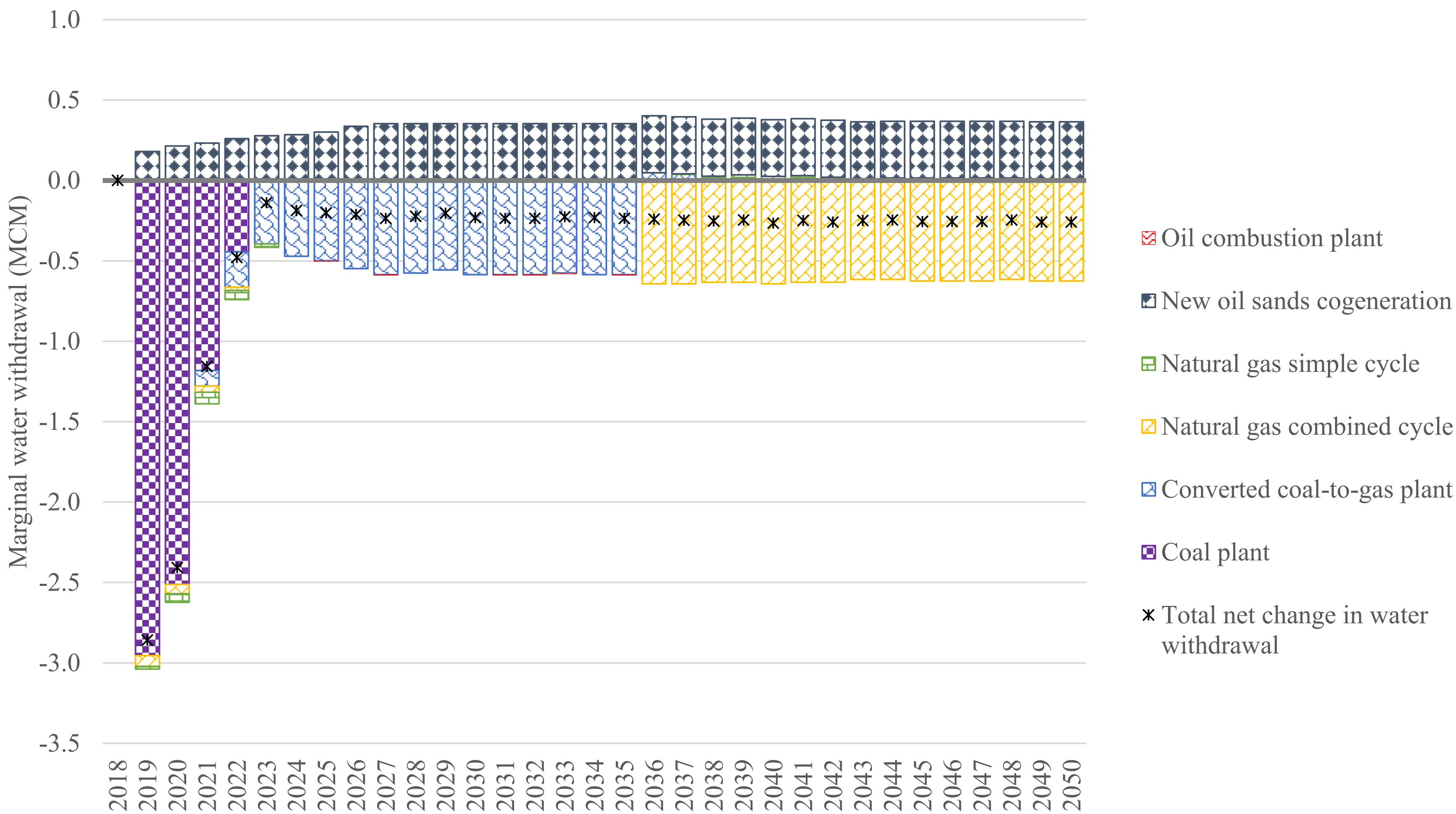

Figure 60: Marginal annual Alberta electrical grid-wide water withdrawal by generation technology in the surface mining-cogeneration-CP0 scenario

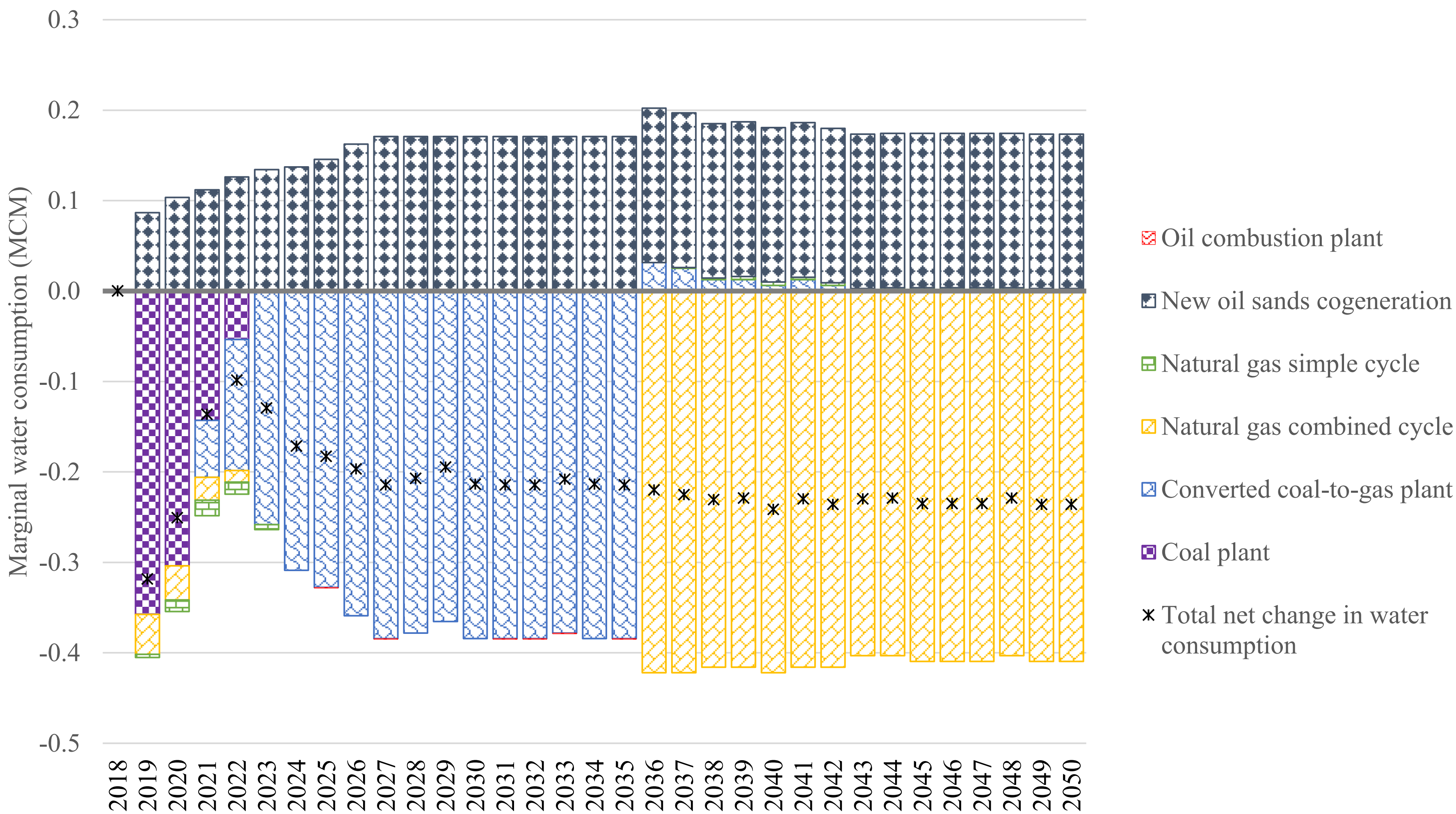

Figure 61: Marginal annual Alberta electrical grid-wide water consumption by generation technology in the surface mining-cogeneration-CP0 scenario

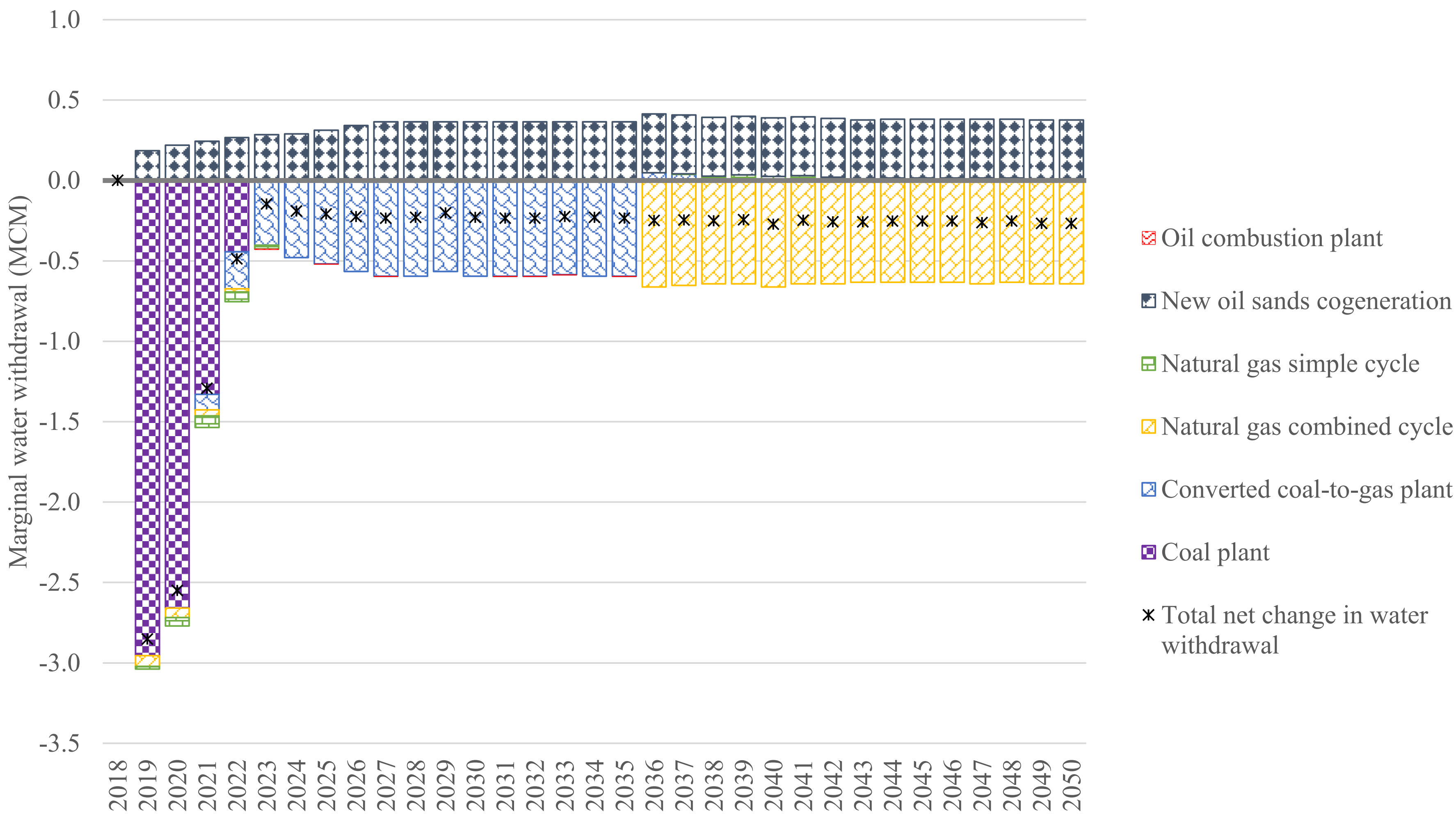

Figure 62: Marginal annual Alberta electrical grid-wide water withdrawal by generation technology in the surface mining-cogeneration-CP30 scenario

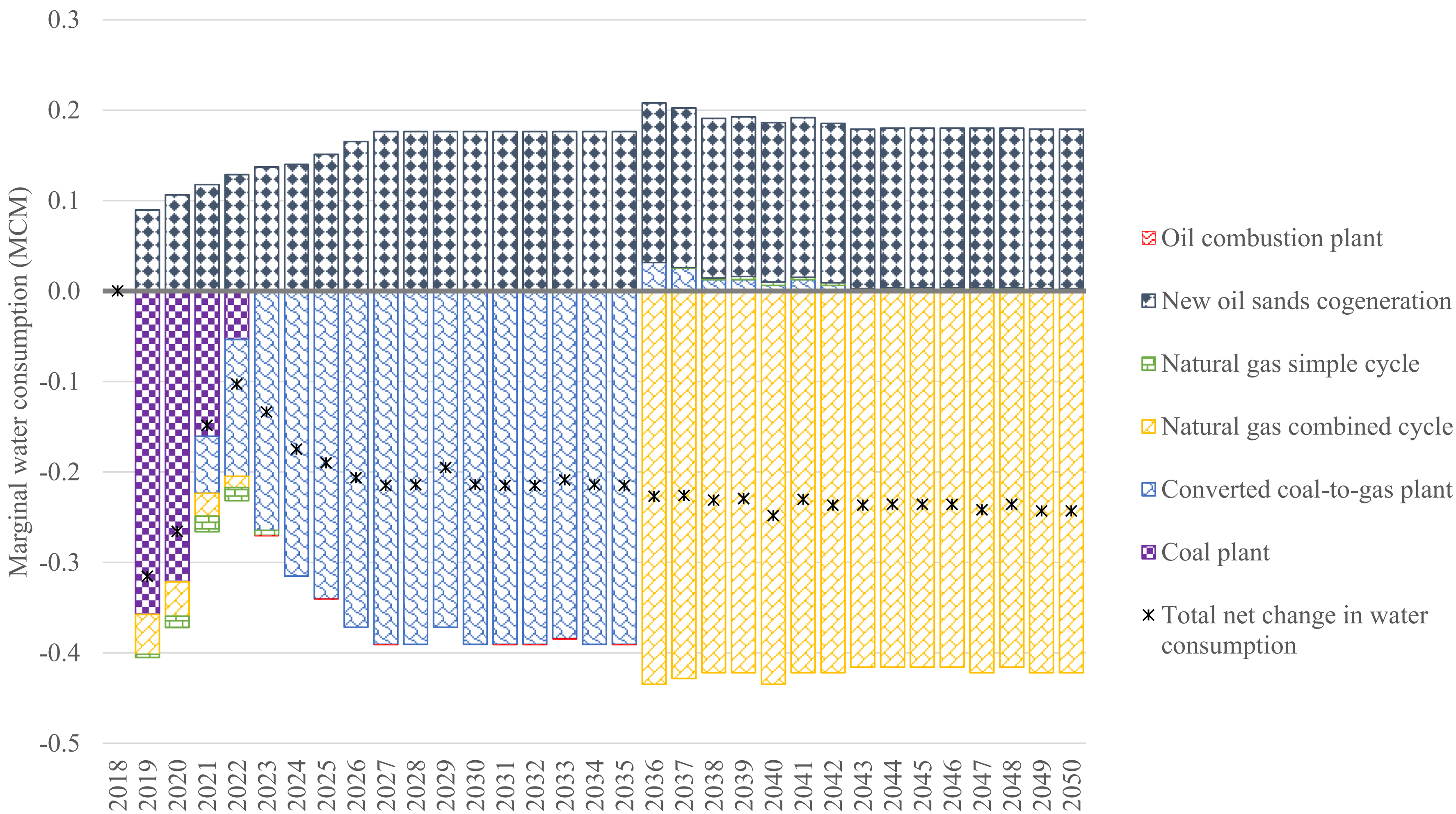

Figure 63: Marginal annual Alberta electrical grid-wide water consumption by generation technology in the surface mining-cogeneration-CP30 scenario

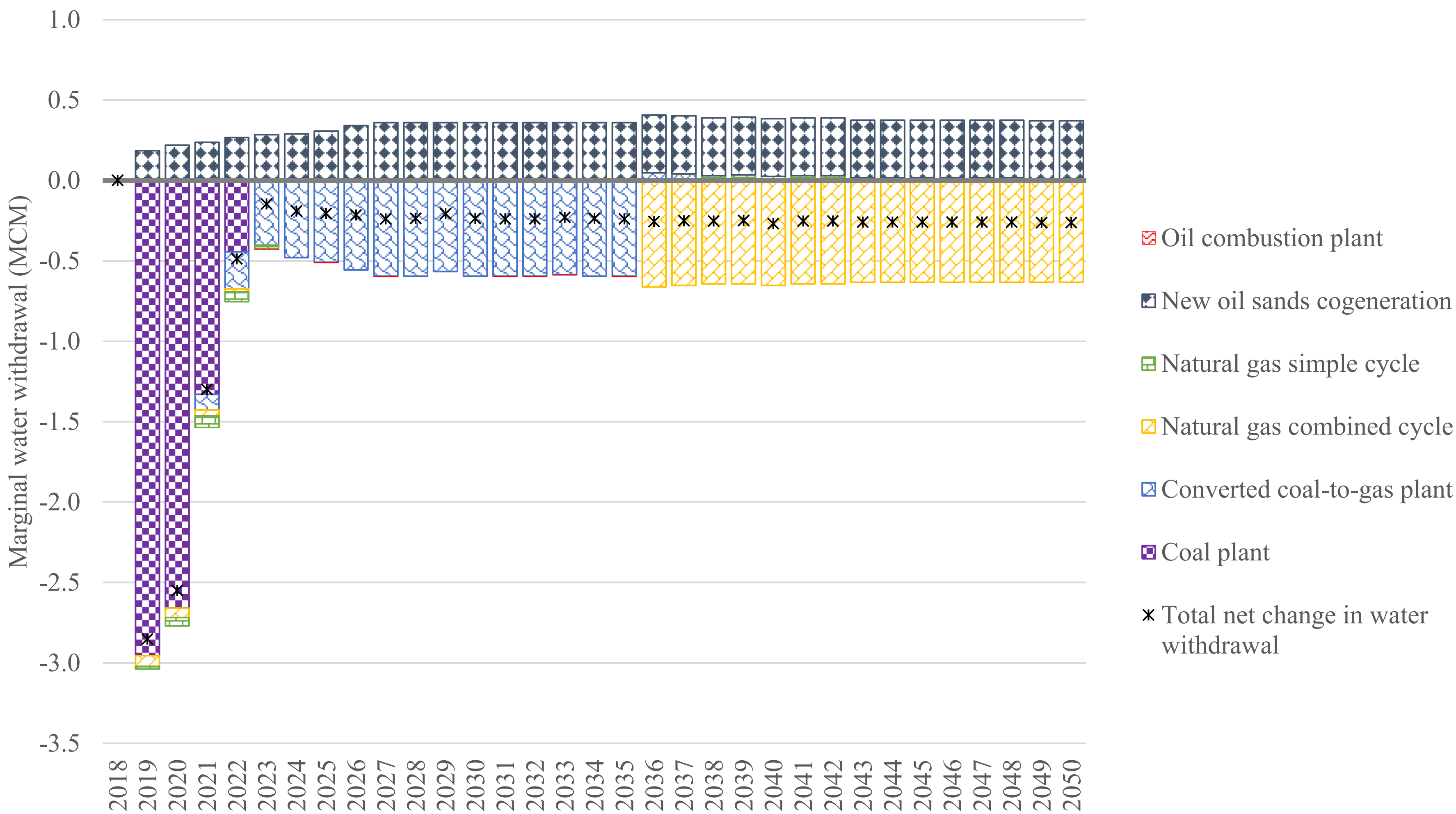

Figure 64: Marginal annual Alberta electrical grid-wide water withdrawal by generation technology in the surface mining-cogeneration-CP50 scenario

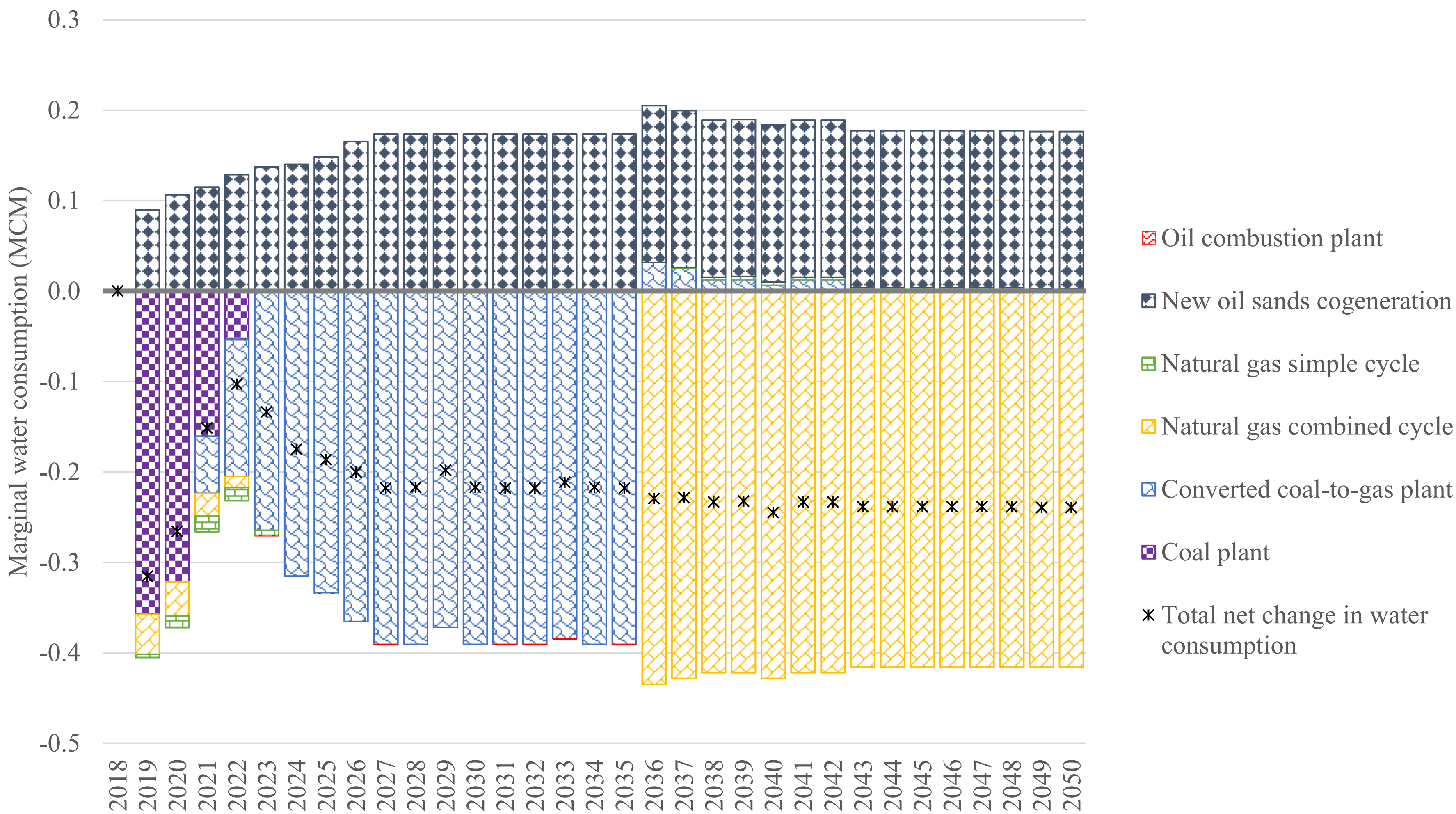

Figure 65: Marginal annual Alberta electrical grid-wide water consumption by generation technology in the surface mining-cogeneration-CP50 scenario

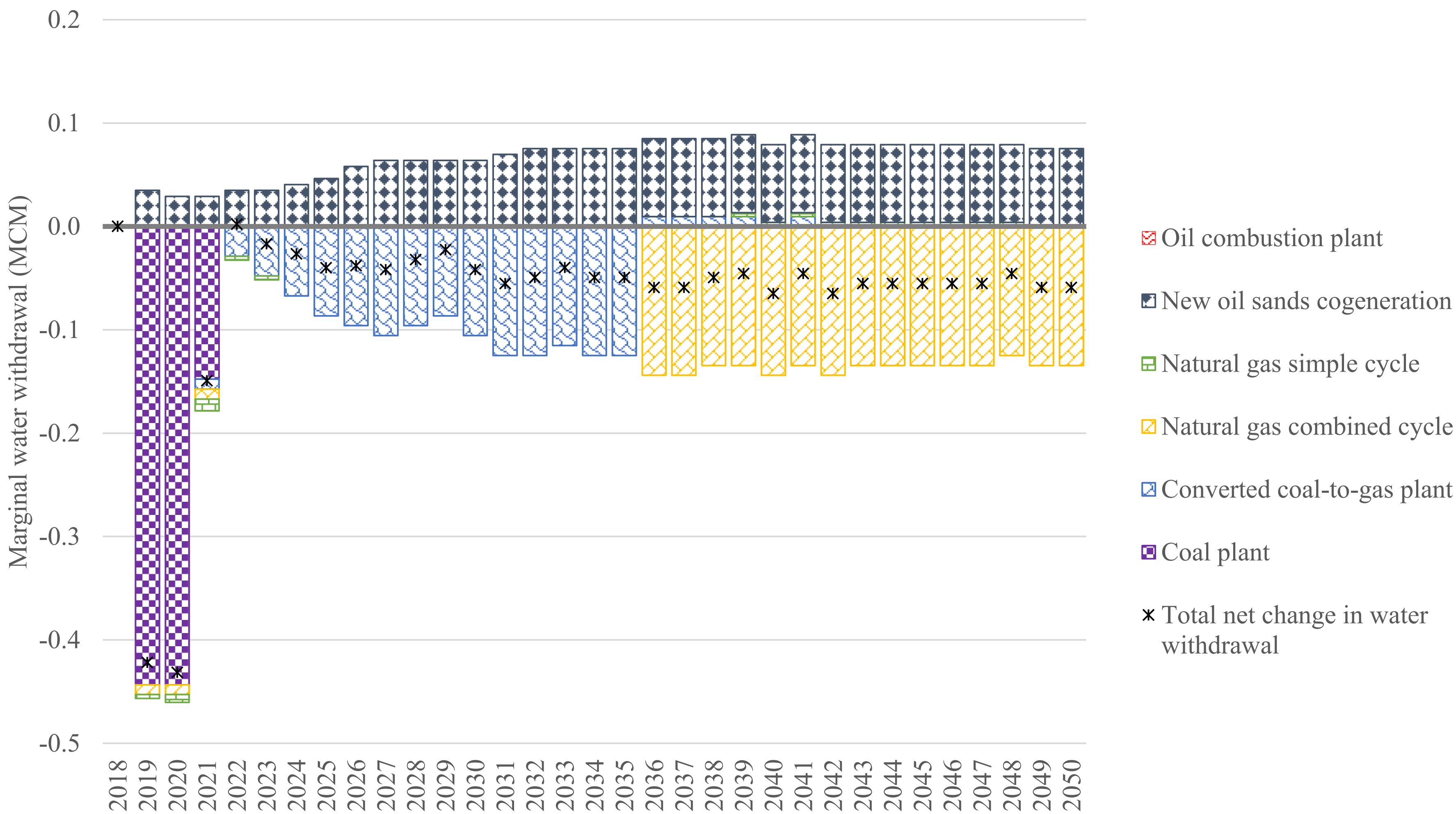

Figure 66: Marginal annual Alberta electrical grid-wide water withdrawal by generation technology in the upgrading-cogeneration-CP0 scenario

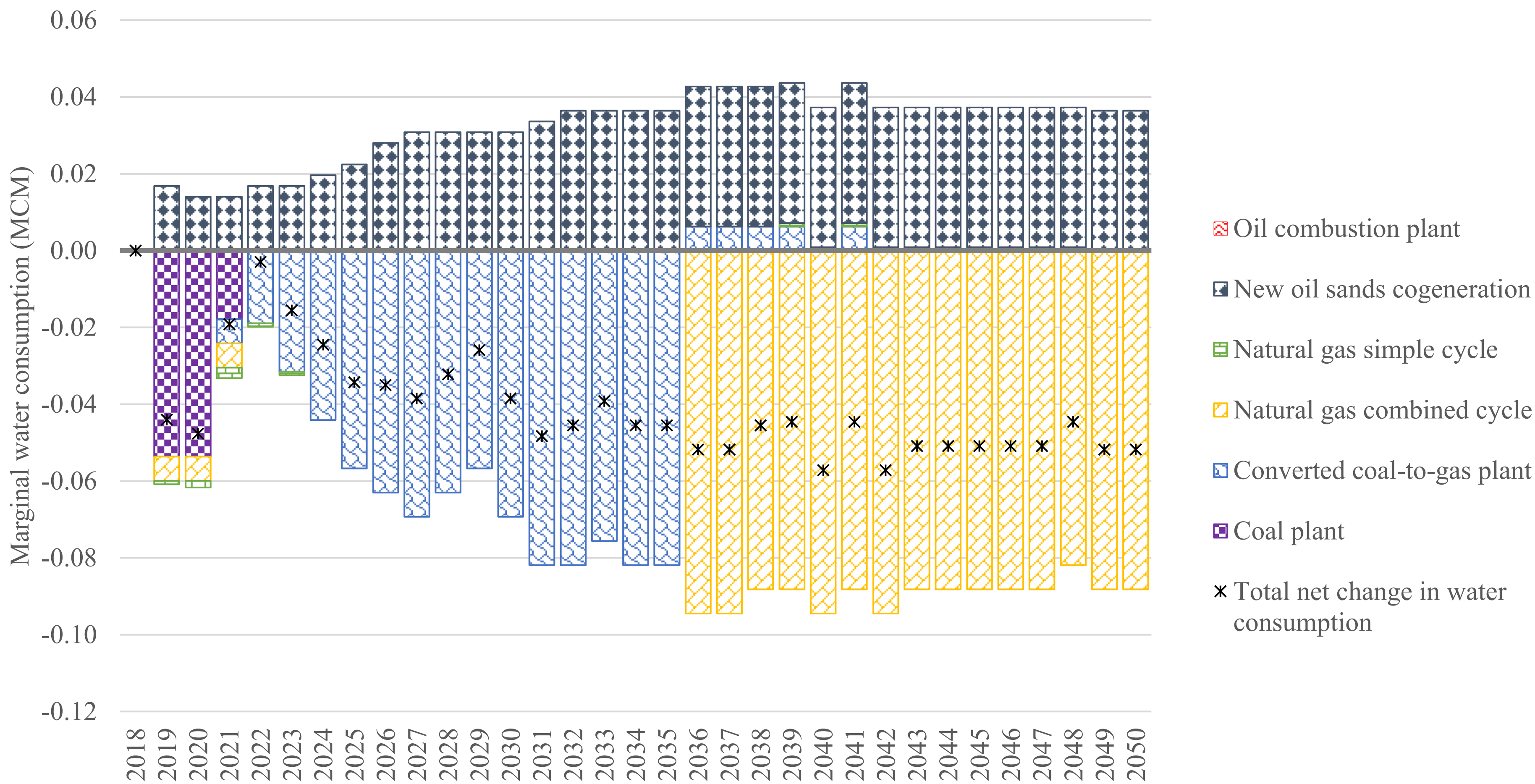

Figure 67: Marginal annual Alberta electrical grid-wide water consumption by generation technology in the upgrading-cogeneration-CP0 scenario

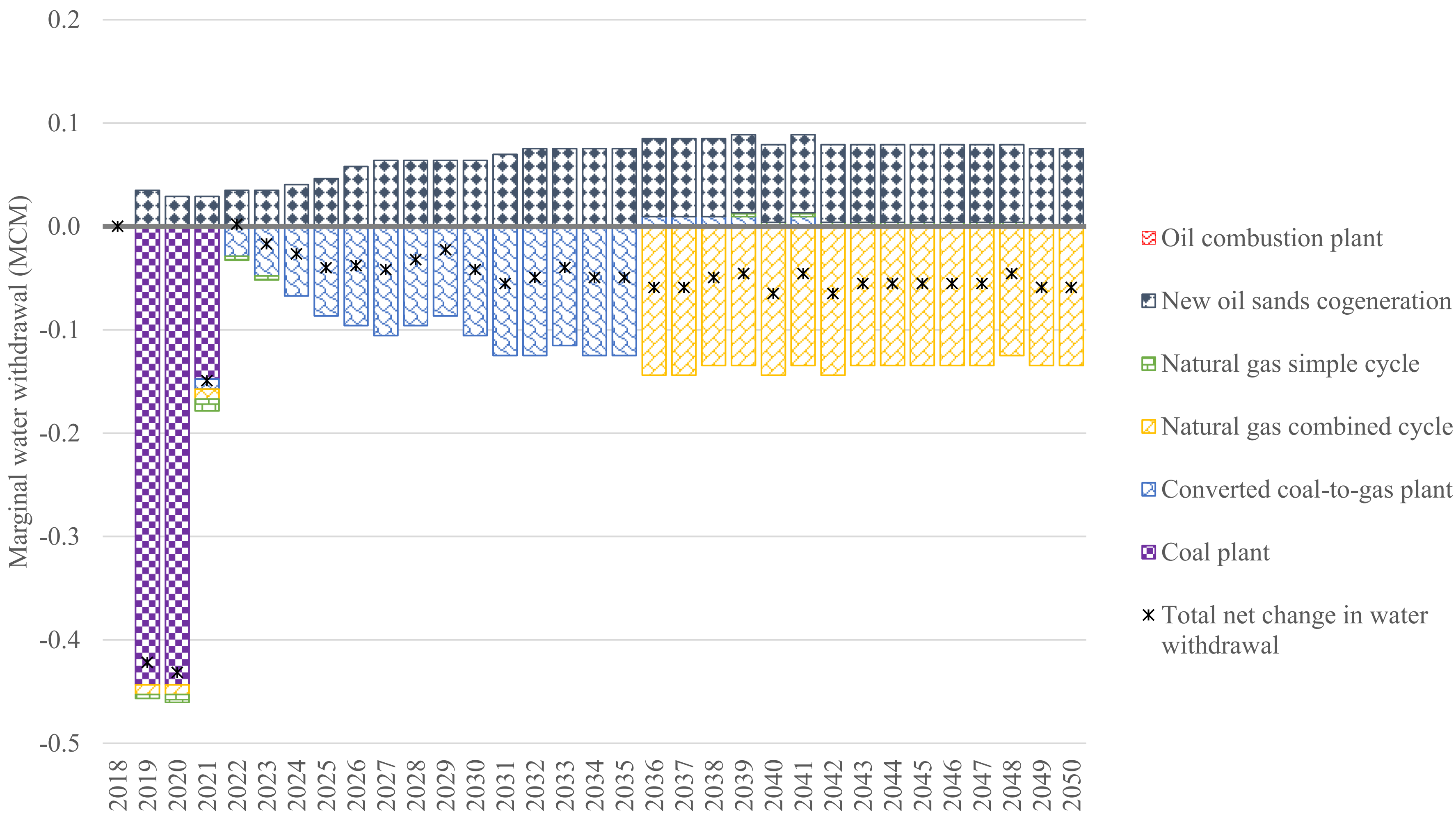

Figure 68: Marginal annual Alberta electrical grid-wide water withdrawal by generation technology in the upgrading-cogeneration-CP30 scenario

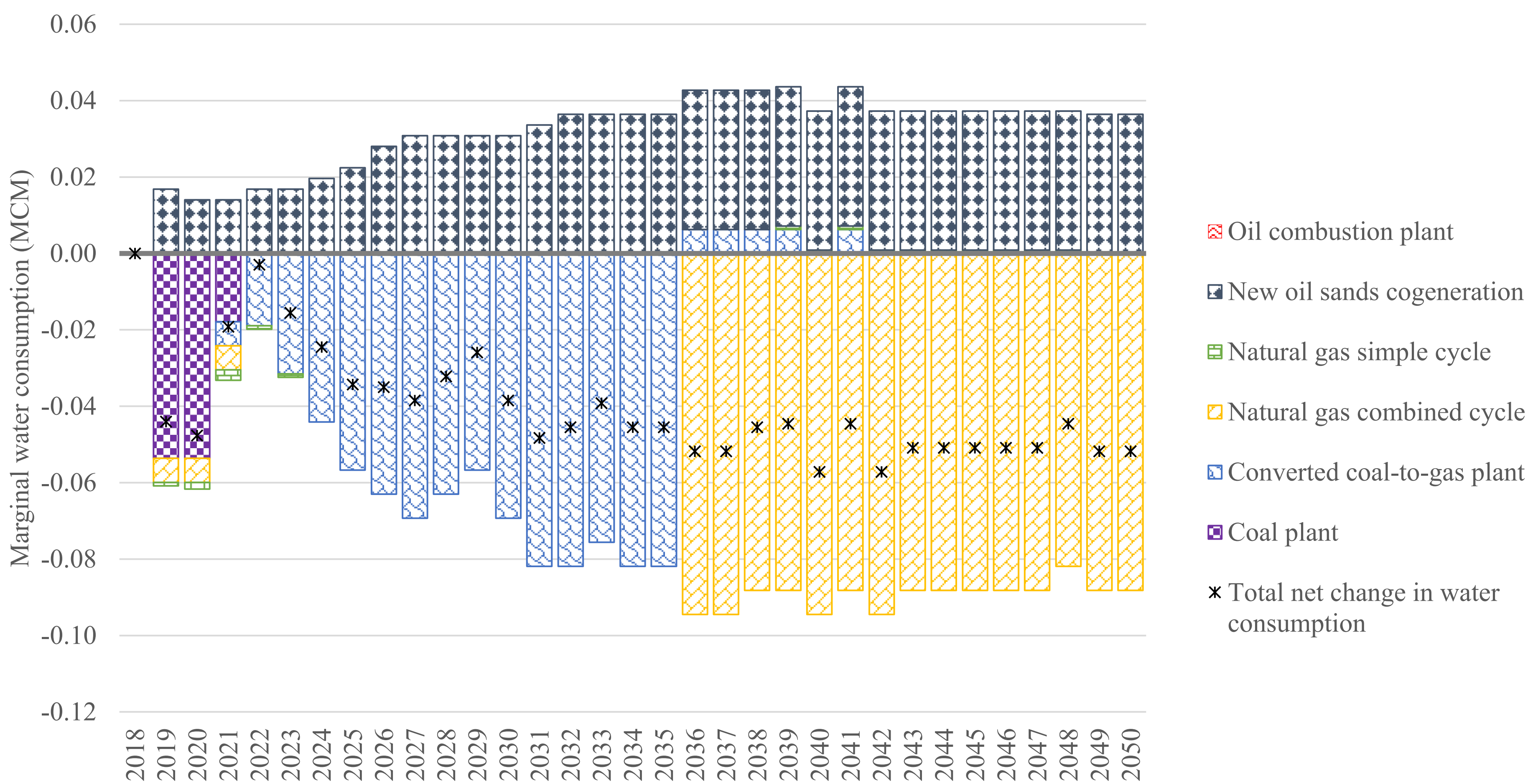

Figure 69: Marginal annual Alberta electrical grid-wide water consumption by generation technology in the upgrading-cogeneration-CP30 scenario

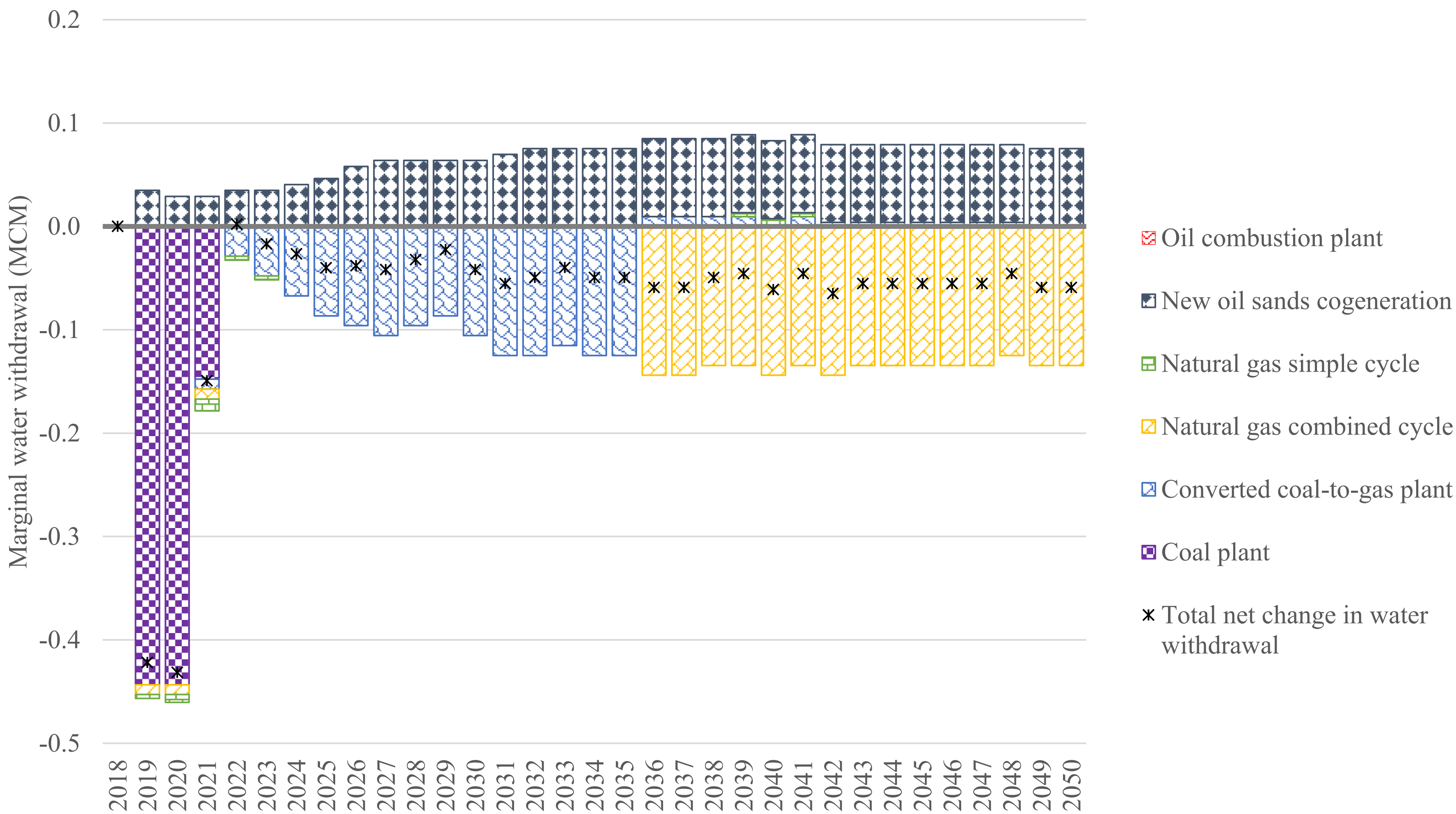

Figure 70: Marginal annual Alberta electrical grid-wide water withdrawal by generation technology in the upgrading-cogeneration-CP50 scenario

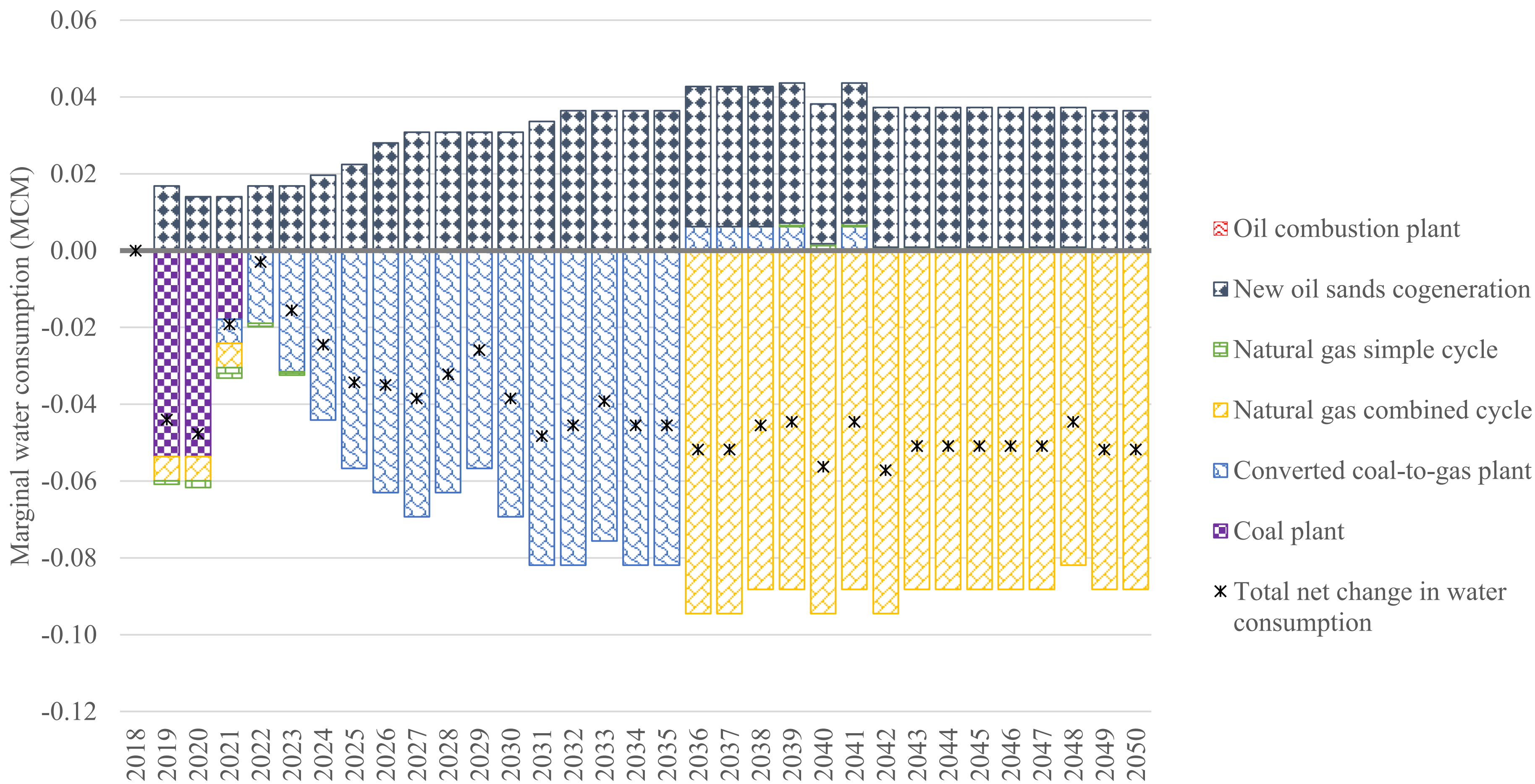

Figure 71: Marginal annual Alberta electrical grid-wide water consumption by generation technology in the upgrading-cogeneration-CP50 scenario