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STANDARDS RESEARCH

Hydrogen Production from Fossil Fuels

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Executive Summary

Hydrogen is globally recognized as a key pathway to achieving a net-zero greenhouse gas (GHG) emissions future by 2050. Canada is well positioned to become a global leader in the transition to hydrogen. Standardizing aspects of hydrogen production from fossil fuels can play an important role in accelerating the implementation of various methods and processes.

This objective of this report is to identify gaps and needs for standardization related to the production of hydrogen from fossil fuels. The research conducted for this report comprised a literature review, gap analysis, and interviews with interested and affected parties from industry and regulatory bodies.

The literature review included hydrogen production methods from fossil fuels, relevant standards, codes, and best practices, and applicable federal, provincial, and territorial regulations and commercial project approval requirements for steam methane reforming (SMR), partial oxidation (POX), autothermal reforming (ATR), and in situ coal gasification (ISCG). Pre-commercial methods of chemical looping combustion (CLC), dry methane reforming (DMR), in situ gasification of heavy oil and bitumen, and methane pyrolysis, were also reviewed.

In Canada, regulated aspects of hydrogen production are usually based on generic requirements for industrial activities, and hydrogen production-specific standards are mostly used at the discretion of the commercial project proponent or owner. Four provinces (Alberta, British Columbia, Québec, and Nova Scotia) have implemented specific hydrogen production project approval mechanisms.

The gap analysis identified several challenges and opportunities for standardization for hydrogen production from fossil fuels in Canada. The report concludes with the following eight recommendations pertaining to standardization for hydrogen production from fossil fuels:

1. Review standards that address safety and processing of fossil fuels for hydrogen production.
2. Reference existing hydrogen production-specific guidance documents in future commercial project regulatory approvals.
3. Establish process performance benchmarks and evaluation methods for large hydrogen production projects in Canada.
4. Develop a new standard providing safety requirements for large scale hydrogen production facilities.
5. Review CSA B149.3 for potential amendment to include use of hydrogen as fuel gas in fired equipment.
6. Take a single approach to GHG emissions quantification for hydrogen production from fossil fuels.
7. Develop a standard for future gas–solid separation technology in methane pyrolysis.
8. Develop standard test methods to evaluate process performance for in situ gasification of heavy oil and bitumen.



"Canada is well positioned to become a global leader in the transition to hydrogen"

1 Introduction

Hydrogen is globally recognized as one of several key pathways to achieving a net-zero greenhouse gas (GHG) emissions future by 2050. Several reports have forecast that both global and Canadian hydrogen production capacity could increase by between five and nine times between 2030 and 2050, resulting in significant reductions in total tonnes of carbon dioxide equivalent (CO_2e) emissions [1], [2]. However, this potential may only be realized economically by making hydrogen cost competitive with incumbent fuels and by reducing lifecycle emissions intensity across the hydrogen value chain. For example, the Transition Accelerator forecasts that beyond 2030, the levelized cost of hydrogen production for water electrolysis and for methane reforming coupled with carbon capture and storage (or sequestration) (CCS) technology could be reduced to 2.38 CAD/kg and 1.32 CAD/kg, respectively [2]. The lifecycle emissions intensity of hydrogen produced by methane reforming processes with CCS, including upstream emissions associated with natural gas production, is currently estimated to be between 2 and 8 $kgCO_2e/kgH_2$ [2], [3]. This is compared to between 1 and 4 $kgCO_2e/kgH_2$ for production from water electrolysis using various low emission power generation methods [2], [3]. For reference, methane emissions to atmosphere are characterized to have a CO_2 equivalent impact of 29.8 $kgCO_2e$ per 1 kg of methane [4]. In 2023, CSA Group published a report that reviewed various policies and lifecycle assessment methods relating to hydrogen supply chains and pathways [5]. Further emissions reductions are possible with technological innovations across the value chain.

Canada is well positioned to become a global leader in the transition to hydrogen, already possessing the following key components of an emerging hydrogen economy:

- Abundant, low-cost fossil fuel and freshwater reserves;
- Low-cost, industrial-scale hydrogen production using SMR;
- Extensive infrastructure for transporting captured CO_2 from fossil fuel-based hydrogen production processes;
- Extensive capacity for underground storage of CO_2 and hydrogen in salt caverns and porous formations; and
- Large regional markets ("hubs") for hydrogen as a fuel and as a feedstock for chemical synthesis, hydrocarbon upgrading, and petrochemical processes.

There is a range of technologies and methodologies to produce hydrogen from fossil fuels, which may use CCS or inherently avoid production of CO_2. While some production methods are well established, various emerging methods have been demonstrated pre-commercially to reduce carbon emissions and increase production efficiency.

Standardizing aspects of hydrogen production from fossil fuels can play a role in accelerating the implementation of various methods and processes by providing:

- Benchmarks and best practices for aspects of hydrogen production that are common to all methods and processes; and
- Guidance to industry and regulators to support continued safety for the protection of people, property, and the environment.

The objective of this report is to identify gaps and needs for standardization related to the production of hydrogen from fossil fuels. The research conducted for this report included a review and analysis of current and emerging hydrogen production methods from fossil fuels as well as existing domestic and foreign regulations, codes, and standards. This was used to identify key gaps, challenges, and opportunities for Canada's oil and gas sector with the goal of standardizing hydrogen production from fossil fuels.

2 Methods

Non-confidential information available in the public domain was collected and summarized through an extensive literature search of academic and industry publications, textbooks, news articles, corporate disclosures and regulatory filings, company websites, market reports, statutes, codes, standards, codes of practice, and guidelines. The literature review covered information relevant to existing commercial and emerging hydrogen production methods from fossil fuels and the current status of the regulatory framework governing these methods.

Interviews were conducted with nine interested and affected parties from industry and regulatory bodies to supplement the literature review and gap analysis, and explored the following questions:

- What aspects of a commercial hydrogen production process using fossil fuels are regulated, and by which regulator(s)?
- What standards are referenced in commercial hydrogen production project regulatory approvals?
- Are commercial project regulatory approvals made publicly available?
- Are there projects or situations where it is not clear who the responsible regulator is or which legislation is applicable?
- What actions or changes are being contemplated to clarify licencing and application approval requirements for hydrogen production processes from fossil fuels?
- What regulatory requirements are your customers asking from you relating to your technology?
- Which standards are applicable to a hydrogen production process using fossil fuels?
- What challenges, if any, have you encountered with applying the available standards?
- What aspects of commercial hydrogen production projects are in "grey" areas where there does not appear to be any regulatory or standards-based guidance?
- What are your suggestions on requirements that should be included in future editions of existing standards (and which) or in the development of new standards?

3 Results

3.1 Review of Hydrogen Production Methods and Canadian Activities

3.1.1 Overview

The commercial production of hydrogen comes from four primary sources: natural gas, oil, coal, and water, which account for 48%, 30%, 18%, and 4% of the world's hydrogen production, respectively [6]. Globally, between 70 and 94 million tonnes of hydrogen are produced every year, with the vast majority produced from fossil fuels [6], [7]. Along with emerging methods, the known hydrogen production processes from fossil fuels include:

- Steam methane reforming (SMR)
- Partial oxidation (POX)

- Autothermal reforming (ATR)
- Chemical looping combustion (CLC)
- Dry methane reforming (DMR)
- In situ bitumen, heavy oil, and coal gasification
- Methane pyrolysis

SMR is the most common production process. Another common method of hydrogen production that does not use fossils fuels as the feedstock is electrolysis of water.

Hydrogen production schemes are often grouped and referred to by colours in descriptions made available to the general public. The colour-based groupings consider the feedstock, emissions intensity and type of energy source, and the ultimate fate of the by-products [5]. Green hydrogen refers to hydrogen produced from water using renewable energy sources. When captured CO_2 from fossil hydrogen is produced from fossil fuels through methane reforming processes that emit CO_2, it is usually referred to as grey hydrogen. Blue hydrogen refers to hydrogen produced from natural gas with associated carbon capture, utilization, and storage (CCUS). Turquoise or teal hydrogen refers to hydrogen produced by methane pyrolysis, which produces solid elemental carbon as a by-product instead of CO_2.

Table 1 summarizes the hydrogen production methods using fossil fuels that are reviewed in detail in sections 3.1.2 through 3.1.8. The table provides key attributes of each process, including feedstock (reactants), target products, by-products, typical production temperature range, estimated technology readiness level (per Innovation, Science and Economic Development Canada definitions [8]), known number of active commercial projects in Canada, and whether the process requires CCUS to lower GHG emissions.

3.1.2 Steam Methane Reforming (SMR)

Steam reforming processes comprise a wide range of reactions in which steam is reacted with a hydrocarbon to produce hydrogen (H_2) and carbon monoxide (CO). The generalized, overall reaction for steam reforming is shown in Equation 1:

Equation 1

$$C_nH_m + nH_2O \rightarrow nCO + (n + ½m)H_2,$$

where n and m denote the hydrocarbon type.

SMR is the most common hydrogen production process, accounting for nearly half of the world's hydrogen supply. It is a process where methane (CH_4) is reacted with steam (H_2O) at high temperatures (700–1100°C), and a nickel-based catalyst is typically used to produce H_2, CO, and CO_2 [9]. It is an energy efficient and inexpensive hydrogen production process [10].

SMR is an endothermic reaction and requires high temperature and pressure to fully convert the reactants. Generalized, stoichiometric SMR reaction pathways are shown in equations 2 and 3. Heat must be provided to drive the reaction to produce hydrogen [9], though a catalyst reduces the required temperature of the process.

Equation 2

$$CH_4 + H_2O \rightarrow CO + 3H_2, \Delta H° = 206 \text{ kJ/mol},$$

Equation 3

$$CO + H_2O \rightarrow CO_2 + H_2, \Delta H° = -41.1 \text{ kJ/mol}.$$

$\Delta H°$ represents enthalpy change, that is, the energy released (positive values) and absorbed (negative values) per 1 mole of product. In practice, there is incomplete conversion of CO to CO_2 in Equation 3, so some CO_2 must be removed and potentially captured from the syngas product.

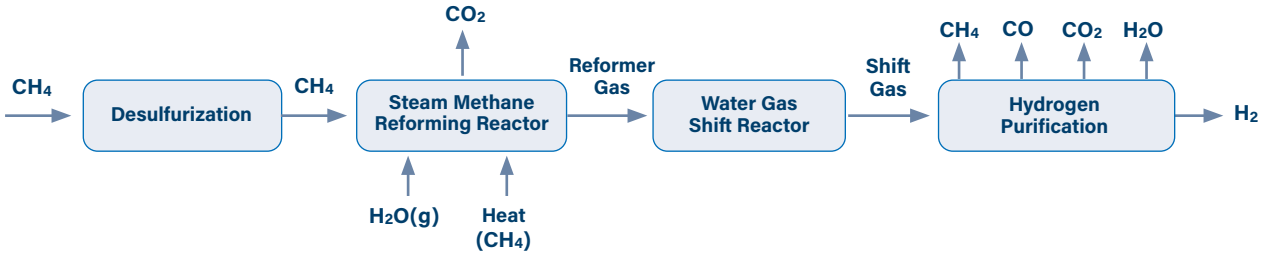
Upon steam reforming (Equation 1), produced syngas (mainly H_2 and CO), as well as unconverted CH_4 and H_2O, and some CO_2, go through a heat recovery and water-gas shift reactor (Equation 2), where additional H_2 is produced from the reaction between the steam and CO, as shown in Figure 1. The gas mixture leaving the shift reactor, mainly comprising H_2 and CO_2 and containing unconverted CH_4, CO, and H_2O, may go through either pressure swing adsorption or CO_2 removal and hydrogen purification to produce virtually pure H_2 [11]. It is possible to increase the energy efficiency of SMR by recycling the gases rejected from

Table 1. Summary of Hydrogen Production Methods Using Fossil Fuels and Their Attributes

Hydrogen Production Method	Feedstock (Reactants)	Target Products	By-products	Typical Processing Temperature Range	Estimated Technology Readiness Level	Number of Active Commercial Projects in Canada	Requires CCUS? (Yes/No)
Steam Methane Reforming (SMR)	CH_4 H_2O (gas)	H_2 $H_2 + CO$	CO_2 CO H_2O (liquid)	700–1100°C	Commercial	At least 11	Yes
Partial Oxidation (POX)	Various hydrocarbons (gas, liquid, solid) O_2 H_2O (gas)	H_2 $H_2 + CO$	CO_2 CO S H_2O (liquid)	600–1500°C	Commercial	0	Yes
Autothermal Reforming (ATR)	CH_4 H_2O (gas) O_2	H_2 $H_2 + CO$	CO_2 CO S H_2O (liquid)	750°C	Commercial	2	Yes
Chemical Looping Combustion (CLC)	Various hydrocarbons (gas, liquid, solid) O_2 H_2O (gas)	H_2 $H_2 + CO$	CO_2 CO H_2O (liquid)	800–1000°C	6–7 (Pre-commercial)	0	Yes
Dry Methane Reforming (DMR)	CH_4 CO_2	$H_2 + CO$	None	650–1000°C	7–9 (Pre-commercial)	0	No
In Situ Gasification	Various hydrocarbons (liquid, solid) O_2 H_2O (gas)	H_2 $H_2 + CO$	CO_2 CO H_2S H_2O (liquid)	700–900°C	Commercial (coal) 7–8 (heavy oil) 2–3 (bitumen)	1 (Pre-commercial)	Yes
Methane Pyrolysis	CH_4	H_2 C (solid)	None	1000–2000°C	9 (Early commercial)	0	No

Note. CH_4 = methane; H_2O (gas) = steam; H_2O (liquid) = water; H_2 = hydrogen; CO_2 = carbon dioxide; CO = carbon monoxide; $H_2 + CO$ = syngas; O_2 = oxygen; H_2S = hydrogen sulfide; C = carbon.

Figure 1. Simplified block diagram of a typical steam methane reforming (SMR) process



the hydrogen purification step (off-gas) to preheat fuel gas and combust it to provide process heat for the reforming reaction [12].

Hydrogen produced via SMR is referred to as grey hydrogen when CO_2 produced by the process is unmitigated and released to the atmosphere. When CCUS is coupled with the process to mitigate CO_2 emissions, the hydrogen produced via SMR is referred to as blue hydrogen. SMR is widely used because it is a convenient and cost-effective method for producing hydrogen from natural gas and has a high hydrogen yield. The conversion efficiency of fuel to hydrogen is 70% to 85% [13].

There were at least 11 commercial SMR operations across Canada at the time of writing this report [14].

3.1.3 Partial Oxidation (POX)

POX is a process in which virtually any hydrocarbon source can be reacted solely with oxygen or air to produce syngas [15], [16], [17], [18], [19], [20], [21]. The process is also commonly known as gasification when dealing with heavier liquid and solid hydrocarbon sources but is referred to simply as POX in this report. The reaction is a sub-stoichiometric (partial) exothermic (heat releasing) oxidation of the hydrocarbon source. The H_2:CO product ratio depends on the hydrocarbon feedstock and decreases as the C:H ratio in the feedstock increases. The overall reaction for a generalized hydrocarbon source in the POX process is [19], [20], [22]:

Equation 4

$$C_nH_m + \frac{n}{2} O_2 \rightarrow nCO + \frac{m}{2} H_2$$

Using methane (natural gas) as an example, the general reaction is [19]:

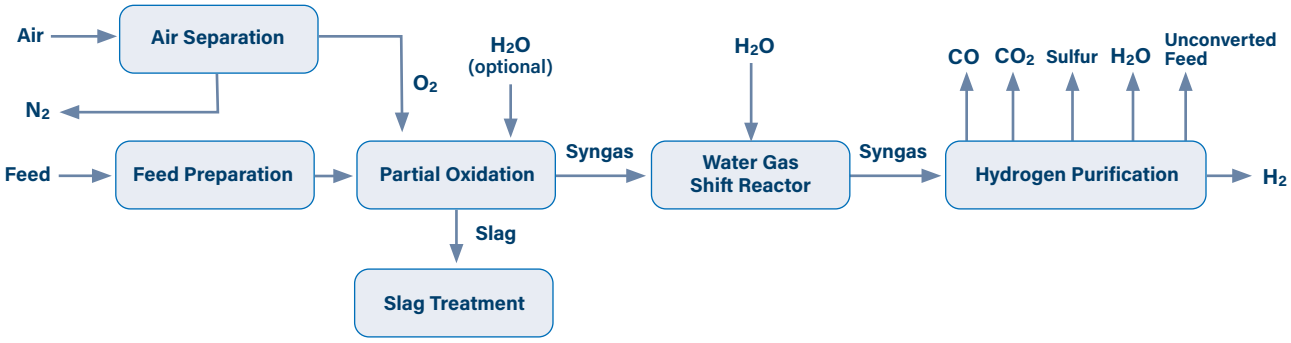
Equation 5

$$CH_4 + \frac{1}{2} O_2 \rightarrow CO + 2H_2, \Delta H = -43.6 kJ/mol$$

Equations 4 and 5 represent an ideal, generalized reaction. In reality, the chemistry is complex and there are many intermediate, simultaneous reactions. If oxidation of the hydrocarbon source is allowed to proceed to fully oxidize the feedstock, CO_2 and H_2O can also be formed in the process, and hydrogen sulfide (H_2S) can be formed if the feedstock contains sulfur.

Figure 2 shows a simplified block diagram of a typical POX process. Either air or purified oxygen is mixed with the hydrocarbon feedstock in the POX reactor [15], [20], [23], [24], [25]. The reaction produces syngas at temperatures in the range of 600°C to 1500°C. Commercial POX processes typically operate at pressures of 2 MPa to 4 MPa [23], [25], [26]. In most commercial POX processes, the syngas in the POX reactor is quenched either directly or indirectly by water. This generates and preheats steam, which can be used in a water-gas shift reaction to increase the H_2:CO ratio. The order of the syngas quenching and shift reaction steps varies in each commercial process. However, in all cases, the produced gas undergoes hydrogen purification and separation to remove CO_2, H_2S, and H_2O, and isolate desired product gases. Typical purification and separation processes used in POX include water scrubbing, amine scrubbing, and pressure swing adsorption [15], [20], [23]–[25].

Figure 2. Simplified block diagram of a typical partial oxidation (POX) process. Adapted from [15], [20], [23]–[25])



When syngas is produced from coal and other high carbon number hydrocarbons by POX alone, without further reforming, the H_2:CO ratio is typically 1:1 or less (compared to 2:1 for POX conversion of methane), which is too low to be suitable for many useful applications. As such, the POX process of coal conversion is often combined with another process (typically steam reforming) to increase the H_2:CO ratio above 2:1 for synthesis of chemicals, such as ammonia and methanol [15]. The addition of steam also helps cool the syngas produced by the exothermic POX reaction.

At the time of writing, there are no known commercial POX operations in Canada using fossil fuel sources. However, from the 1980s to the early 2010s, there were surges in interest and limited pre-commercial activities in above ground coal gasification and integrated gasification combined cycle projects across Canada [24], [27], [28], [29].

3.1.4 Autothermal Reforming (ATR)

ATR is a process used to produce hydrogen from hydrocarbon fuels, such as natural gas/methane (CH_4), propane (C_3H_8), and gasoline. ATR is a combination of steam reforming and POX (described in Section 3.1.3). In ATR, the endothermic steam reforming reaction receives heat from the combined exothermic partial oxidation reaction to promote the production of hydrogen [11]. The reaction requires less external energy input compared to other methods of hydrogen production, such as SMR. A typical ATR operating temperature is 750˚C with a constant heat supply.

The general ATR reaction is:

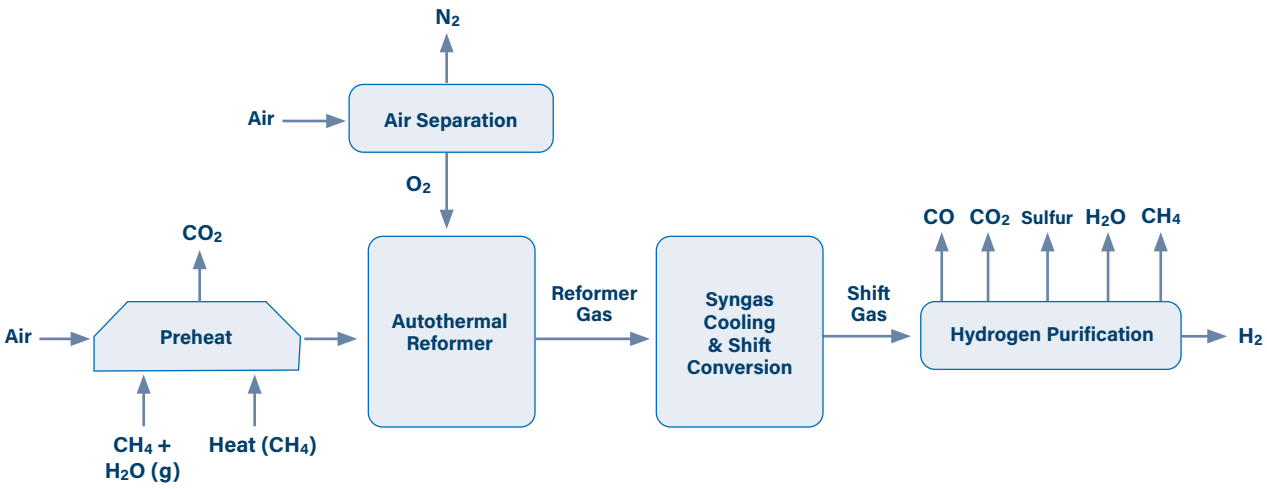
Equation 6

$$4C_nH_m + 2n\ H_2O + n\ O_2 \rightarrow (2m+2n)\ H_2 + 4n\ CO,$$

where *n* and *m* denote the hydrocarbon type. For example, in methane reforming, *n* and *m* are 1 and 4, respectively.

Figure 3 shows a simplified block diagram of a typical ATR process. A preheat stage, typically fired by natural gas, increases the temperature of the methane and steam feedstocks prior to delivery to the autothermal reformer reactor. The preheat stage produces CO_2 and other combustion products that can be captured to reduce emissions. An air separation unit delivers pure O_2 to the process, which is combined with the preheated methane and steam in the autothermal reformer reactor. Methane reforming and partial oxidation occur simultaneously in the autothermal reformer to produce syngas (H_2 + CO). In many commercial ATR units, water-gas shift also occurs within the autothermal reformer, but shift reactions can also occur in a separate reactor at lower temperatures. Finally, the produced gas undergoes gas purification and separation, producing hydrogen along with CO_2 and other impurities that can be captured to reduce emissions.

Figure 3. Simplified block diagram of a typical autothermal reforming (ATR) process. Adapted from [30].



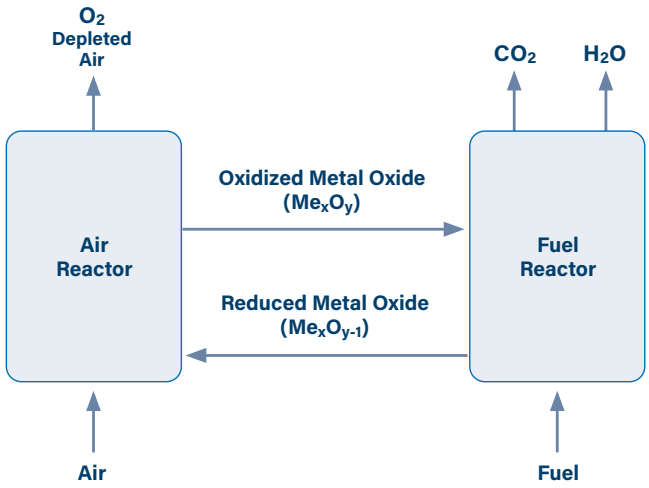
ATR is an attractive option for hydrogen production due to its high hydrogen yields, efficient operation, lower energy inputs, and reduced GHG emissions [30]. Without being coupled with CCUS, ATR can generate lower overall emissions per kilogram of H_2 than SMR because some of the required process heat is provided by partial oxidation in the autothermal reformer, which translates into less combustion of heating fuel in the preheat stage. There is a trade-off in ATR, however, as there can be emissions associated with increased electricity consumption for the air separation unit. When coupled with CCUS, ATR emissions can be further reduced relative to SMR because most of the CO_2 produced in the process occurs in the gas product stream, which is partially isolated and captured inherently during the hydrogen purification step. Since fewer emissions occur at the preheat step in ATR compared to SMR, smaller CO_2 capture units with lower energy inputs and emissions are required.

At the time of writing, three commercial ATR projects have been announced in Canada and are expected to come online in the 2020s [14], [31].

3.1.5 Chemical Looping Combustion (CLC)

CLC is a process based on cyclic oxidation and reduction of solid oxygen carrier particles, such as metal oxide particles, that is viewed as a promising method for hydrogen production using a wide range of potential hydrocarbon fuels [32], [33], [34]. When a reforming process producing hydrogen or syngas is incorporated into a CLC method, the overall process is typically known as chemical looping reforming or chemical looping gasification [34]. The CLC process provides heat from the combustion of a hydrocarbon fuel that can be used for various purposes, including hydrogen production from fossil fuels. Notably, the CLC process for hydrogen production produces higher purity CO_2 than post-combustion flue gas, which significantly reduces the energy and capital inputs required for CCUS in CLC [35]. Various metal oxides, typically iron, nickel, and copper, are used as the solid oxygen carrier in CLC [34]. The solid oxygen carrier particles are transported between, and pass repeatedly through, air and fuel reactors in a circulating loop, as shown in Figure 4.

Figure 4. Simplified block diagram of a typical chemical looping combustion (CLC) process. Adapted from. [32] [33]



Starting at the air reactor shown in Figure 4, air is blown into the air reactor and contacted with the depleted (reduced) metal oxide returning from the fuel reactor. The metal oxide is regenerated by O_2 in the air stream through a metal oxidation reaction. The regenerated (oxidized) oxygen carrier is then transported back to the fuel reactor. Fuel is introduced into the fuel reactor, where it undergoes a combustion reaction with the regenerated oxygen carrier, producing CO_2, H_2O, and heat. Since the CO_2 and H_2O combustion products produced in the fuel reactor are inherently separated from air in the air reactor, the energy and capital intensity required to purify the CO_2 in CLC is significantly lower compared to a CO_2 capture system for typical combustion processes. In a typical combustion process, fuel is oxidized by air and the resulting CO_2 concentration is typically less than 20 mol%. The need for CO_2 capture mainly arises from the need to separate CO_2 from nitrogen (N_2) in the combustion flue gas. In CLC, the air reactor acts as an air separation unit by transferring only O_2 from air to the fuel reactor and rejecting N_2. Thus, the CO_2 produced in the fuel reactor is at a much higher concentration (typically greater than 80 mol%, depending on the fuel) compared to the CO_2 occurring in a typical combustion flue gas. In this way, CLC is described as having an integrated carbon capture process [32]–[34].

There are two general reactions taking place in a typical CLC process [34]. In the air reactor, it is:

Equation 7

$2Me + O_2 \rightarrow 2MeO$

where Me refers to the metal and MeO refers to the metal oxide. In the fuel reactor, it is:

Equation 8

$C_nH_m + (2n + ½m)MeO \rightarrow nCO_2 + ½mH_2O + (2n+½m)Me.$

As an example, if nickel oxide (NiO) is used as the carrier particle for combustion of methane, the reactions in the air and fuel reactors, respectively, are:

Equation 9

$4Ni + 2O_2 \rightarrow 4NiO, \Delta H_{1200°C} = -938.2$ kJ/mol, and

Equation 10

$CH_4 + 4NiO \rightarrow CO_2 + 2H_2O + 4Ni, \Delta H_{1200°C} = 136.5$ kJ/mol[34].

Then the overall general reaction for the entire process is:

Equation 11

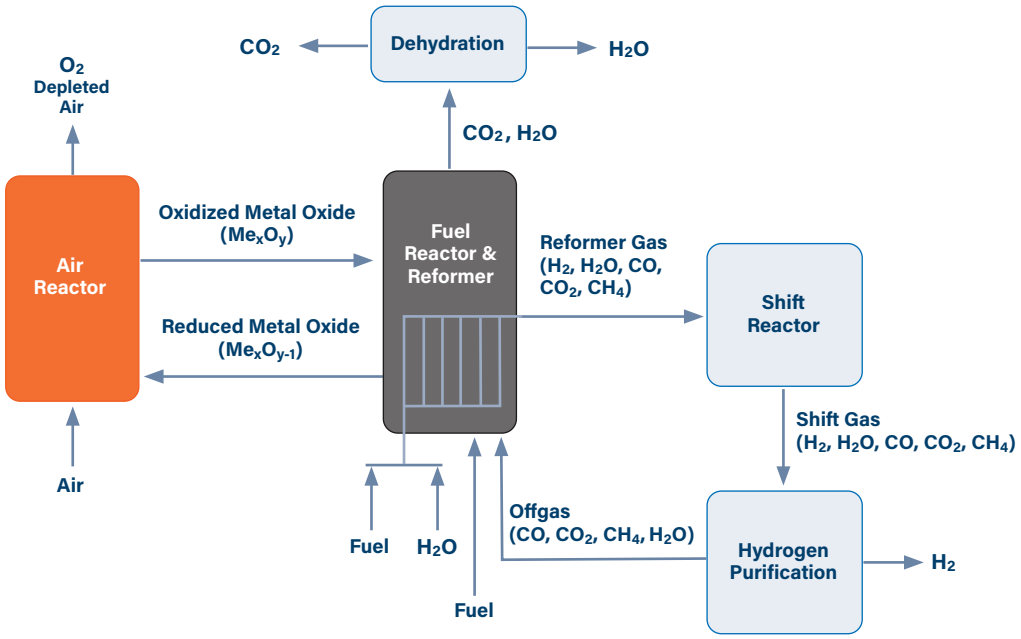
$CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O$, $\Delta H_{1200°C} = -802.7$ kJ/mol.

Figure 5 shows a simplified block diagram for the CLC process configured for hydrogen production [34]. The energy released from fuel combustion in the fuel reactor is used to provide indirect heat for steam reforming. From this point on, the process is essentially the same as steam reforming. Steam and feedstock flow through dedicated tubing within the fuel reactor, which serves as a steam reformer. The steam and fuel react to produce reformer syngas (mostly H_2 + CO) and H_2O, with some CO_2 and unconverted CH_4, which flows to a water-gas shift reactor, in which most of the CO and unreacted fuel reacts with steam to further produce H_2 and CO_2. The gas produced in the water-gas shift reactor is then sent to hydrogen purification units (e.g., pressure swing adsorption) to purify the H_2. The off-gas from the purification process contains CO_2, H_2O, and unconverted CH_4 and CO, which still contain enough heating value to allow them to be recycled back to the fuel reactor and combusted with the primary fuel stream. In this way, the CO and CH_4 are converted to CO_2 and H_2O, and the carbon capture aspect of the CLC process can be preserved. The combustion products from the fuel reactor can be dehydrated to remove water and further purify the CO_2.

The CLC process is still in the pre-commercial stage (estimated technology readiness level 6–7), though several near-commercial pilot scale demonstrations are ongoing globally [36], [37], [38], [39], including the following examples:

- At the Technische Universität Darmstadt in Germany, a 1 MW_{th} thermal CLC pilot plant using calcium and carbonate oxygen carriers has been in operation since 2011, with ongoing research into the use of coal, lignite, and natural gas as fuels in the process [36], [40], [41].
- At the Ohio State University, scale-up of several CLC plants has taken place, ranging in thermal output from 15 kW_{th} to 250 kW_{th}, using coal or methane as fuel, in two basic configurations, either for combustion or gasification (hydrogen production) [42].

Figure 5. Simplified block diagram of a typical chemical looping combustion (CLC) process incorporating steam reforming for hydrogen production. Adapted from [34].



Babcock & Wilcox are developing several commercial CLC process configurations for combustion, CO_2 capture, and hydrogen production, under the trademark BrightLoop™ [39]. The company acquired an exclusive global licence to the CLC technology developed at the Ohio State University in 2021 [43].

At the time of writing this report, no known physical testing of the CLC process is taking place in Canada, and activity related to this process has been limited to modelling and economic studies [44], [45].

3.1.6 Dry Methane Reforming (DMR)

DMR is a process used to transform methane (CH_4) and CO_2 into syngas, which is a valuable building block for a wide range of industrial processes. Specifically, DMR has the potential to reduce the GHG emissions intensity of producing chemicals and fuels that can be synthesized from syngas with a low H_2:CO ratio (e.g., alcohols, lower olefins, dimethyl ether) [46]. DMR technology can be integrated with conventional SMR to reduce the GHG emissions intensity of SMR-based syngas production, and to achieve higher H_2:CO ratios to expand the range of feasible final products (e.g., Fischer–Tropsch fuels, methanol). DMR (either alone or integrated with another methane reforming process) can be considered an alternative to CO_2 capture and sequestration for hydrogen and syngas production from fossil fuels.

The primary DMR reaction can be expressed as:

Equation 12

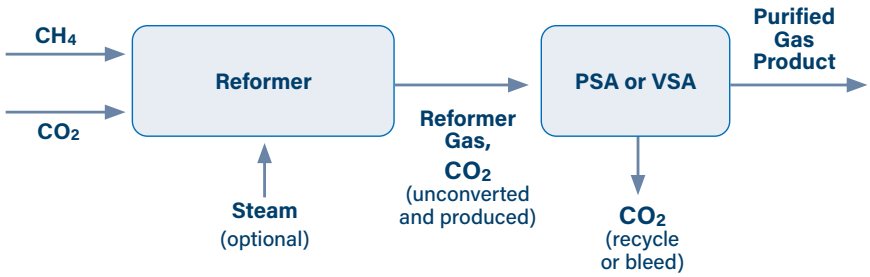
$CH_4 + CO_2 \rightarrow 2CO + 2\ H_2$, $\Delta H° = 247.3$ kJ/mol [46].

DMR is an endothermic process that needs 247.3 kJ/mol to be completed. Each tonne of methane requires 1,124 kWh to produce 1 tonne of syngas [47]. In more complex configurations, steam can be supplied to the reformer reaction, as shown in Figure 6, to promote higher H_2:CO ratios. This differs from SMR as the water-gas shift reaction is suppressed as much as possible in DMR to avoid production of CO_2. Conversion of CO_2 in the DMR reaction is inevitably incomplete, and if the process is supplemented with steam, some CO_2 will be produced in the syngas. Unconverted and produced CO_2 can either be recycled, captured, or vented to the atmosphere.

Figure 6 shows a simplified block diagram of the DMR process. The two main process units are a reformer and hydrogen purification unit (e.g., pressure swing adsorption [PSA] or vacuum swing adsorption [VSA]).

In the mid-2010s, Pioneer Energy were developing a butanol production process using DMR as an intermediate step [48]. BASF and Linde have also partnered on the development and commercialization of a DMR catalyst and process design to produce syngas,

Figure 6. Simplified block diagram of a typical dry methane reforming (DMR) process.



which has reached the commercial demonstration scale [49]. This would place the core DMR process (without downstream conversion to end products) at an estimated technology readiness level of 7 to 9.

3.1.7 In Situ Gasification

In situ gasification comprises methods for producing hydrogen in a geological formation (reservoir) through the gasification of hydrocarbon-rich feedstocks, such as bitumen, heavy oil, or coal. A simplified overview of this hydrogen production method is shown in Figure 7. In this process, the feedstock is partially oxidized in place, usually underground, to produce a mixture of gases that include H_2, CO, and CO_2.

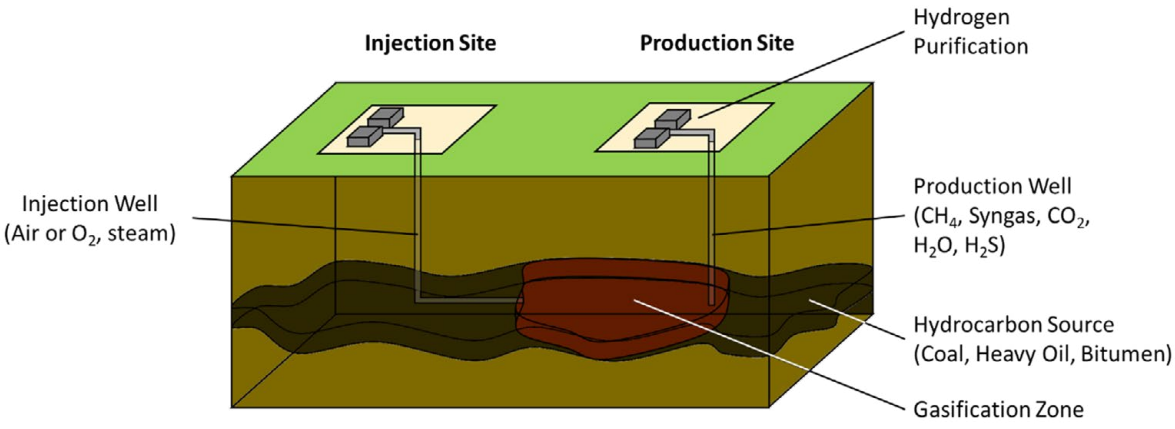
As shown in Figure 7, oxygen or air is injected into the reservoir of fossil fuel to initiate combustion and raise the temperature of the formation sufficiently to enable gasification. In situ gasification constitutes a system of multiple complex reactions with different combinations of series and parallel reactions [50]. Such reactions include pyrolysis, aquathermolysis, water-gas shift, and oxidation mechanisms because of the co-existence of fossil fuels, water, and oxygen in the presence of high temperature and high pressure. Eventually, the reaction gases, CH_4, CO, H_2, CO_2, H_2O, and potentially trace H_2S, surface through a production well and the syngas or hydrogen is separated from other constituents [51].

In situ gasification may require less external energy input than other hydrogen production methods from fossil fuels because the energy needed to raise the formation to gasification temperatures is obtained from partial oxidation of a portion of the hydrocarbon source itself. This method also has the potential for reduced emissions to atmosphere relative to other hydrogen production methods not coupled with CCUS, because acid gases (e.g., H_2S and CO_2) are sequestered to some extent in the reservoir [50].

In situ bitumen and coal gasification have the advantage of reducing the need for mining, which can be cost-intensive and environmentally damaging, and allow for the use of resources that are difficult to extract through conventional mining methods. Additionally, in situ gasification produces valuable syngas or hydrogen, which can be used for power generation and other industrial processes. However, the process also produces carbon dioxide and methane, which could be released to atmosphere if not separated and kept below surface.

In the early 2020s, Proton Technologies Canada operated a pilot demonstration in situ gasification project in an end-of-life heavy oil field near Kerrobert, Saskatchewan [52].

Figure 7. Simplified illustration of in situ gasification.



3.1.8 Methane Pyrolysis

Methane pyrolysis is a process of thermal decomposition of methane in which a hydrocarbon is converted into hydrogen and solid elemental carbon. The general reaction for pyrolysis of any hydrocarbon can be expressed as:

Equation 13

$2C_nH_m \rightarrow 2nC + mH_2$ [11].

For methane, the reaction is:

Equation 14

$CH_4 \rightarrow C + 2H_2$, $\Delta H° = 75.6$ kJ/mol [53].

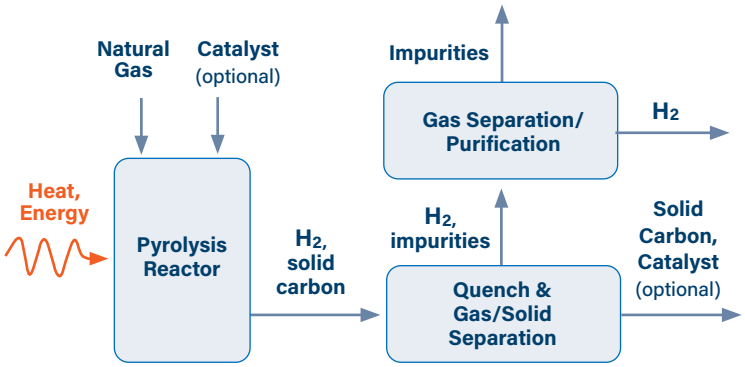
A simplified block diagram of the process is shown in Figure 8. Natural gas (composed primarily of methane) is fed to the pyrolysis reactor, potentially with a catalyst to reduce the reaction energy. Energy is delivered to the pyrolysis reactor to thermally decompose the methane feed into molecular hydrogen gas and solid carbon. The produced hydrogen and solid carbon leave the pyrolysis reactor and are then quenched and separated using cyclones or other gas–solid separation methods. The produced hydrogen may contain impurities that need to be removed in a gas separation–purification step. The elemental solid carbon can take several forms, including amorphous, graphitic, and nanotubes/nanohorns.

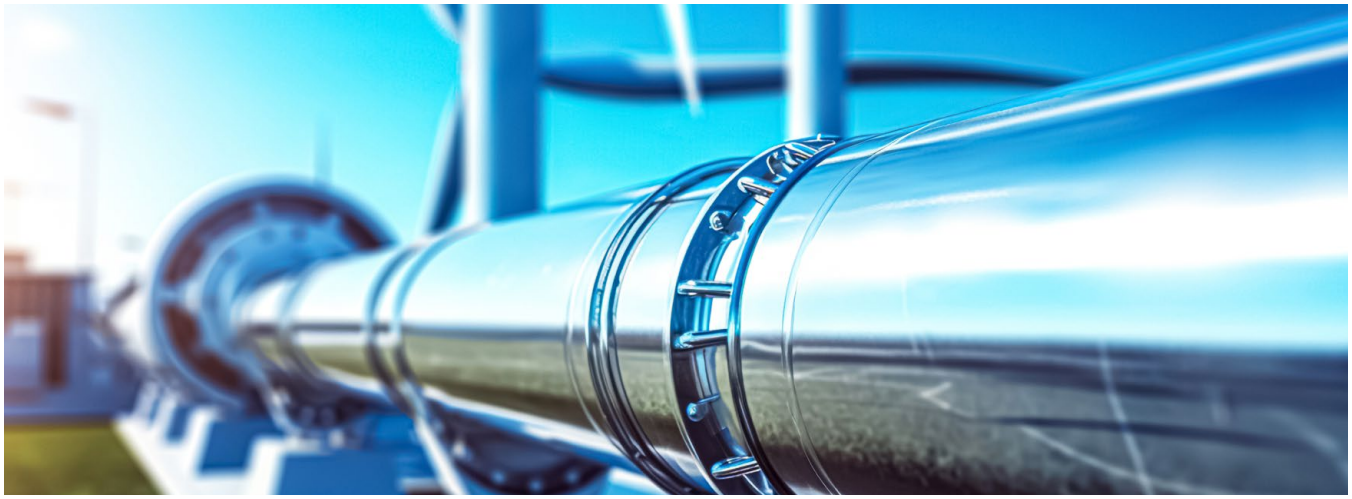
With the increasing concern about CO_2 emissions, the need to implement CCUS for SMR, ATR, and other processes has become a serious challenge affecting process economics. Methane pyrolysis has the potential to circumvent the need for CCUS.

Thermodynamically, methane pyrolysis requires much less energy (10.5 kWh/kg H_2) than electrolysis of water (39.7 kWh/kg H_2) [54]. Various energy forms (plasma, electromagnetic, thermal) can be used to achieve reaction temperatures required for methane pyrolysis. Catalysts can be used to increase reaction rates at lower temperatures that would otherwise result in very low conversion of feedstock to products. When plasma is used as the energy source, pyrolyzed methane dissociates to hydrogen and elemental carbon at temperatures between 1,000°C (cold plasma) and 2,000°C (hot plasma). In thermal pyrolysis, methane decomposition occurs at elevated temperatures above 1,000°C without any catalyst. Catalytic pyrolysis facilitates methane decomposition and reduces the required temperature to below 1,000°C.

Because methane pyrolysis is an inexpensive process that does not require CCUS, at the time of writing, there are approximately 40 organizations globally, including some in Canada, working to develop and commercialize this technology [55]. The technology readiness level of the most advanced methane pyrolysis processes is assessed to be 8 or 9 [56].

Figure 8. Simplified block diagram of a typical methane pyrolysis process.





3.2 Standards, Codes, and Best Practices

3.2.1 Standards and Codes

Commercial hydrogen production from fossil fuels has existed since at least the 1930s [57]. Many standards and codes have been developed for hydrogen production from fossil fuels, and they can be grouped into three main categories:

1. Production process operation and safety;
2. Production process performance; and
3. Product specification and testing.

Standards and codes relevant to hydrogen production from fossil fuels are identified, categorized, and discussed in sections 3.2.1.1 through 3.2.1.3.

3.2.1.2 Production Process Operation and Safety

The production, compression, and storage of hydrogen at a production facility poses several safety risks and challenges due to hydrogen's properties and behaviour. Hydrogen has the lowest atomic mass and is the smallest of all elements, and has the smallest possible molecular mass, size, and density as an H_2 molecule [58]. Hydrogen is a gas at standard atmospheric conditions and it is typically compressed to high pressures for storage due to its low energy density by volume. Its small size means hydrogen is prone to leak from process equipment and to slowly diffuse through most materials of construction, but it also rapidly rises in air in the case of leaks [59]. Hydrogen has a wide flammability range in air (4% to 75% by volume), can be ignited easily, and burns with a nearly invisible flame [59]. The combination of its requirement to be stored at high pressure, tendency to leak, ability to induce material failure through hydrogen embrittlement and high temperature hydrogen attack, difficulty to be detected by many types of sensors, flammability, ignitability, and nearly invisible flame make hydrogen a hazardous substance.

Due to the unique hazards of producing and handling hydrogen at a commercial scale, numerous standards have been developed. The ones listed in Table 2 pertain to the following aspects of hydrogen production processes:

- Hydrogen system installation and certification requirements;
- Determination of hazardous area classification;
- System and subsystem safety (for all production methods);
- Fire prevention, detection, suppression, and response (for all production methods);
- Hydrogen venting (for all production methods);
- Requirements and safety of pressure swing adsorbers (for all production methods using them); and
- Design and operation best practices and safety of steam methane reformers (for SMRs only).

Proper material selection is critical in the design and operation of hydrogen production systems, and several guidance documents exist to aid material selection for hydrogen service. However, this topic is outside the scope of this report.

Table 2. Summary of Hydrogen Production Process Operation and Safety Guidance Documents

Organization	Document Designation	Document Title	Applicable Production Methods	Production Process Aspects Addressed	Reference
American Institute of Aeronautics and Astronautics (AIAA)	ANSI/AIAA G-095A	Guide to Safety of Hydrogen and Hydrogen Systems	All	System-wide	[60]
American Society of Mechanical Engineers (ASME)	ASME B31.12	Hydrogen Piping and Pipelines	All	System-wide construction and safety	[61]
Bureau de normalisation du Québec (BNQ)	CAN/BNQ 1784-000	Canadian Hydrogen Installation Code	Reforming (non-specific)	System-wide safety	[62]
Compressed Gas Association (CGA)	CGA G-5.5	Standard for Hydrogen Vent Systems	All	H_2 venting	[63]
CGA	CGA H-10	Combustion Safety for Steam Reformer Operation	SMR	Combustion safety	[64]
CGA	CGA H-11	Safe Startup and Shutdown Practices for Steam Reformers	SMR	Operational safety	[65]
CGA	CGA H-12	Mechanical Integrity of Syngas Outlet Systems	All methods producing syngas	Syngas production	[66]
CGA	CGA H-13	Hydrogen Pressure Swing Adsorber (PSA) Mechanical Integrity Requirements	All methods using PSA	H_2 purification	[67]
CGA	CGA H-14	HP Plant Gas Leak Detection and Response Practices	All methods producing syngas	System-wide safety	[68]
CGA	CGA H-15	Safe Catalyst Handling in HP Plants	All methods producing syngas	H_2 production	[69]
CGA	CGA P-89	Prevention of Plant Instrument and Utility Gas System Cross Contamination	All	System-wide safety	[70]
Canadian Standards Association (CSA)	CSA B149.3	Code for the Field Approval of Fuel-Burning Appliances and Equipment	All methods using fuel-burning equipment	Fired heater safety	[71]
CSA	CSA/ANSI FC 5	Hydrogen Generators Using Fuel Processing Technologies — Part 1: Safety	All	System-wide safety	[72]
CSA	CSA Z767	Process Safety Management	All	System-wide safety	[73]
International Organization for Standardization (ISO)	ISO/TR 15916	Basic Considerations for the Safety of Hydrogen Systems	All	System-wide safety	[74]
ISO	ISO/TS 19883	Safety of Pressure Swing Adsorption Systems for Hydrogen Separation and Purification	All	H_2 purification	[75]
ISO	ISO 26142	Hydrogen Detection Apparatus — Stationary Applications	All	Localized H_2 detection and safety	[76]
National Fire Protection Association (NFPA)	NFPA 2	Hydrogen Technologies Code	All	System-wide fire prevention	[77]

3.2.1.2 Production Process Performance

Two standard test methods that relate to hydrogen production process performance are discussed below.

ASTM D3908 describes a standard test method to evaluate the hydrogen chemisorption of supported platinum catalysts used occasionally in hydrogen production [78]. ASTM has published dozens of additional standard test methods for catalysts that may potentially be applicable to the determination of physical–chemical and physical–mechanical properties of catalysts used in hydrogen production [79].

ISO 16110-2 provides a comprehensive framework for evaluating the performance of hydrogen generators (small scale hydrogen production from fossil fuel with a capacity less than 400 m^3/h at 0°C and 101.325 kPa) [80]. The framework describes how to define a test boundary for the production process, relevant test conditions, how to develop a test plan and operating procedure, how to calculate relevant process parameters, and requirements for test reports. Relevant process performance parameters include electrical power input, material and energy balances, and overall efficiency.

3.2.1.3 Product Specification and Testing

Each end use of hydrogen (e.g., transportation fuel, chemical feedstock, heat, power) has unique product purity requirements that affect the hydrogen production process configuration (particularly in gas purification steps) required to produce different product grades.

CGA G-5.3 [81], ISO 14687 [82], and SAE J2719 [83] outline the quality and purity requirements of hydrogen for various end uses. The specifications are intended for commodity hydrogen product sampling downstream of a production facility (e.g., in a transmission pipeline or at a fuel station dispenser) but are also relevant for hydrogen production quality assurance. CGA G-5.3 applies to the hydrogen product from a production facility through to delivery just upstream of a dispensing facility, and specifies composition requirements for several commodity hydrogen grades for gaseous and liquid hydrogen fuel, including for use in fuel cells [81]. The characteristics for each grade are defined in terms of minimum volume hydrogen content and maximum allowable volume content of various impurities (Ar, CO_2, CO, He, N_2, O2, CH_4, H_2O, and particulates). ISO 14687 and SAE J2719 apply to hydrogen fuel delivered to vehicles at a dispensing facility. ISO 14687 specifies composition requirements for hydrogen used in all applications, including proton exchange membrane (PEM) fuel cells in road vehicles and PEM fuel cells in stationary applications [77]. SAE J2719 specifies composition requirements only for PEM fuel cell vehicle applications. ISO 14687 lists minimum hydrogen quality requirements, as described in CGA G-5.3, as well as total sulfur compounds, formaldehyde, formic acid, ammonia, and halogenated compounds for several different grades. However, the ISO and CGA requirements are not aligned in relation to the grade definitions and specifications differ significantly for several impurities. Moreover, the CGA specifications cover a wider range of applications than the ISO and SAE specifications with less focus on PEM fuel cell applications. In comparison to ISO 14687 requirements for hydrogen used in PEM fuel cell vehicles, SAE J2719 also lists limits for Na+ and K+ ions within the water impurity limits.

Numerous standardized methods for measuring impurities in commodity hydrogen exist and include the highly sensitive cavity ring-down laser absorption spectroscopy described in ASTM D7941/D7941M [84], particulate gravimetric concentration determination by ASTM D7651 [86], and microscopy visualization by ASTM D7634 [85], gaseous contaminants quantification by gas chromatography per ASTM D7649 [86] and ASTM D7892 [87], and by infrared spectroscopy per ASTM D7653 [88], and hydrocarbon gas chromatography quantification by ASTM D7675 [88] and ASTM UOP899 [89]. Concerns have been raised that available test methods cannot quantify total halogenated compounds as specified in ISO 14687, and some of the recommended modifications to the standard include listing specific halogenated compounds that can be measured individually, identifying and measuring proxy compounds that can be measured easily and can represent hydrogen produced from different sources, and defining unique specifications for hydrogen produced from different feedstocks (e.g., hydrocarbons vs. water vs. chloralkali compounds) [90].

3.2.2 Best Practices

Several best practice guides have been developed for specific hydrogen production methods from fossil fuels, or for generic or common aspects of all production processes. This section summarizes published best practices for hydrogen production from fossil fuels.

Comprehensive lists of international regulations, standards, codes, and best practices applicable to hydrogen production using fossil fuels are available in the National Renewable Energy Laboratory's (NREL) Hydrogen Technologies Safety Guide and the Pacific Northwest National Laboratory's H_2 Tools [91], [92]. These guides describe general safety issues, applicable regulations in the United States (US), relevant international codes and standards, and material and component selection for hydrogen technologies. H_2 Tools also describes considerations and solutions for hydrogen system safety, design, components, operating procedures, and maintenance and inspection. Hydrogen's two greatest safety hazards are its wide flammability range in air and its ease of ignition. This has wide ranging impacts on hydrogen production process design and operation to mitigate and eliminate ignition sources, detect hydrogen leaks, provide adequate ventilation, and store produced hydrogen safely. H_2 Tools describes best practices for all of these aspects.

The National Research Council (NRC) has published a review and gap analysis of codes and standards relating to all hydrogen value chain segments (production to end use) that includes worldwide codes and standards [93]. The codes and standards documented in the NRC report that apply to hydrogen production from fossil fuels are discussed in sections 3.2.1.1 through 3.2.1.3 of this report, along with the aspects of hydrogen production they address.

The National Energy Technology Laboratory (NETL) has published guidelines for the design of modular POX (gasification) systems (see Section 3.1.3) [94]. The NETL handbook provides guidance on permitting requirements and applicable regulations in the US, along with design guidelines on all aspects of a modular POX system, including the POX reactor, feedstock handling and pretreatment, oxygen supply, syngas purification and cleanup, power generation and electrical grid connection, syngas conversion to liquid fuels and chemicals, by-product environmental treatment, CCUS, and ancillary systems.

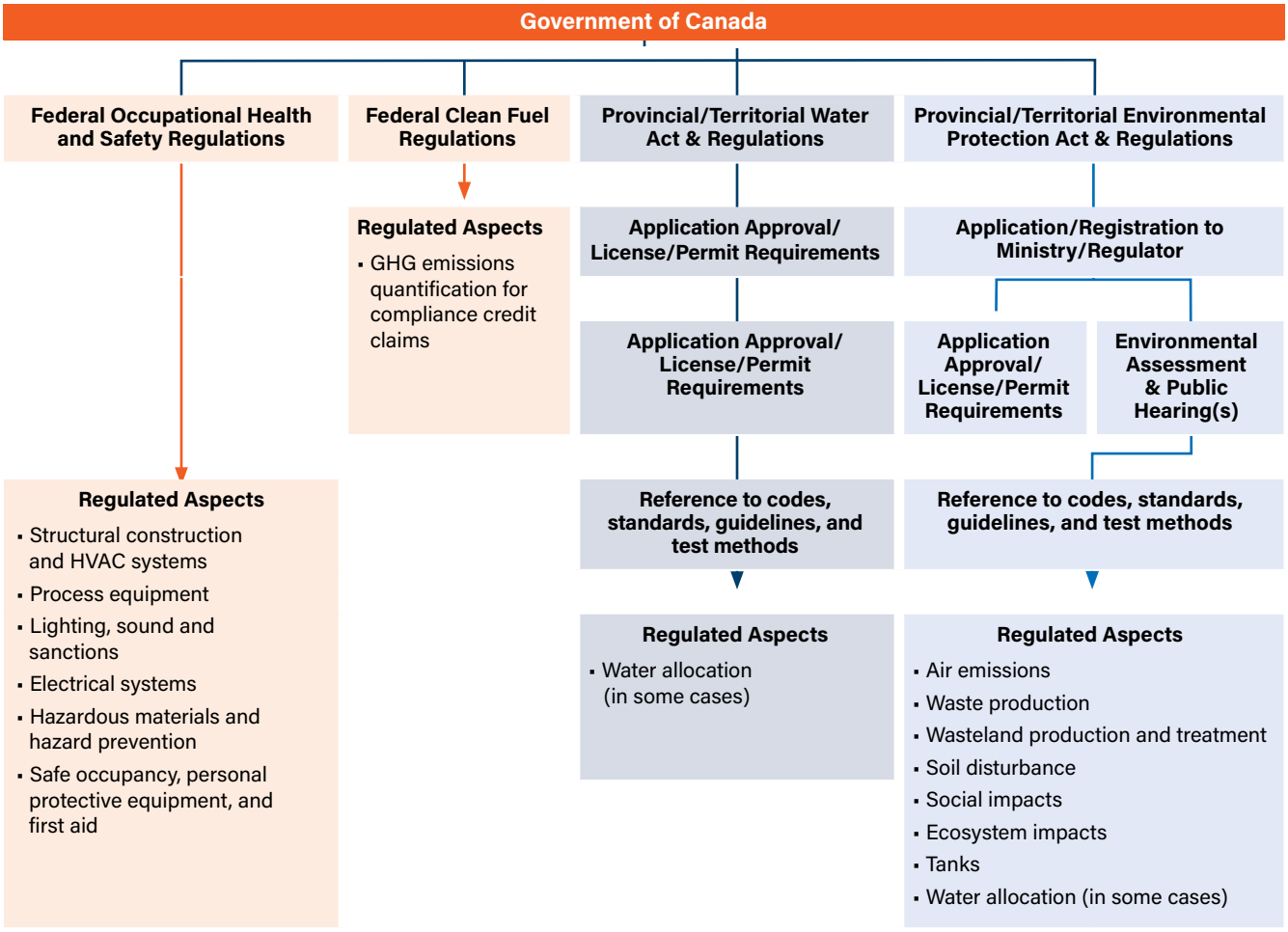
Finally, the Lawrence Livermore National Laboratory (LLNL) has published a comprehensive best practices guide for in situ coal gasification (ISCG; see Section 3.1.7) as a method of hydrogen production [95]. This guide discusses ISCG and its history, along with process details, environmental management, US regulatory framework, risk management, carbon management, best practices, and technology gaps and recommendations. Best practices for ISCG relating to long term operation; well design, construction, and operation; site closure and abandonment; groundwater protection; and ground subsidence management are relevant to all types of in situ gasification schemes for different hydrocarbon plays, including ongoing or future Canadian projects. The LLNL best practices should be considered in revised regulations and should form the basis for standardization relating to all in situ gasification processes.

3.3 Regulations

3.3.1 Introduction

Current provincial regulatory regimes in Canada do not specifically address hydrogen production processes [96]. However, there are federal, provincial, and territorial regulatory mechanisms for generic industrial activities that apply to aspects of hydrogen production. These mechanisms include requirements for structural construction, heating, ventilation, and air conditioning (HVAC) systems, process equipment, lighting, sound, sanitation, electrical systems, storage and handling of hazardous materials, hazard prevention, safe occupancy, personal protective equipment, first aid, chemical facilities, water use, wastewater treatment and production, emissions, soil disturbance, social and ecosystem impacts, and CCUS. Historically, SMR plants, which represent the leading method for producing hydrogen both globally and in Canada, have been integrated into larger industrial operations with the produced hydrogen used as a feedstock for chemical synthesis processes. Examples include bitumen upgrading, oil refining, petrochemical

Figure 9. Overview of regulation of commercial hydrogen projects in Canada.



manufacturing, and ammonia production [2]. The larger industrial process in which SMR is integrated typically falls within the jurisdiction of specific regulators in each province or territory, and in those cases the required licencing is sometimes apparent.

With the emergence of standalone hydrogen production and hydrogen use cases other than industrial chemical synthesis (e.g., heat, power, transportation fuel, energy storage), there may be ambiguity and potential gaps in existing regulatory regimes regarding project approval requirements and applicable authorities. As such, this section reviews existing regulatory frameworks at the federal and provincial levels in Canada, and summarizes approval processes for hydrogen production facilities. The review considers air, land, water usage, facilities, environmental assessment, and the applicable regulators in each Canadian jurisdiction for a hydrogen production facility.

3.3.2 Overview of Canadian Federal, Provincial, and Territorial Regulatory Framework

Figure 9 shows an overview of commercial hydrogen project regulations in Canada. Regulation is divided among federal, provincial, and territorial authorities. The federal Clean Fuel Regulations [97] and Canada Occupational Health and Safety Regulations [98] are discussed in Section 3.3.3.

All provinces and territories have environmental and water acts and regulations, which cite codes, standards, guidelines, and standard test methods that are used to demonstrate hydrogen production compliance. A summary of the provincial regulatory framework and project approvals are discussed in Section 3.3.4. Specific details on hydrogen production regulations by province and territory are reviewed in Appendix A.

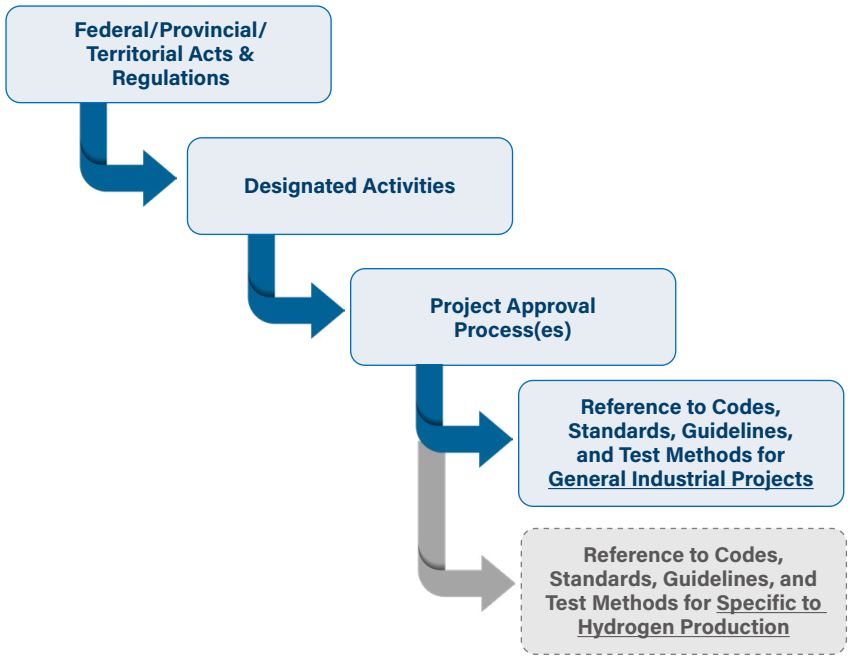
Figure 10 illustrates the existing regulatory framework for commercial hydrogen production project approvals in Canada. Hydrogen production falls under designated activities specified in acts and regulations in some provinces. Designated activities have defined project approval processes in which reference to codes, standards, guidelines, and standard test methods is made for generic industrial projects. There is currently no reference to guidance documents specific to hydrogen production in project approvals available in the public domain. Many details of how hydrogen is produced in commercial projects (e.g., production process design and operating conditions) are not specified, and existing guidance documents (e.g., those reviewed in Section 3.2) are almost entirely used at the discretion of project proponents or owners. One exception to this is a reference to CAN/BNQ 1784-000, *Canadian Hydrogen Installation Code*, which has been adopted in gas safety regulations in British Columbia, Newfoundland and Labrador, Ontario, Québec, and Saskatchewan.

3.3.3 Federal Regulatory Framework, Codes, and Standards

The guidance documents specific to hydrogen production from fossil fuels reviewed in Section 3.2.1 are not presently cited in any Canadian federal regulations.

The Clean Fuel Regulations [97], under the Canadian Environmental Protection Act [99], limit the carbon intensity of designated liquid fuels. The regulations also create a compliance credits system for the production of low carbon intensity, non-designated fuels that have lower carbon intensities than prescribed benchmarks. Hydrogen is treated as a potential low carbon intensity fuel in the regulations when its carbon intensity is below the specified benchmarks for liquid fuels. ISO 14040, 14044, 14064-2, and 14064-3 are cited in the regulations and are the basis for conducting lifecycle assessments, quantifying emissions reductions, and verifying and validating GHG statements [100], [101], [102], [103]. These regulations and the cited ISO

Figure 10. Framework for regulatory commercial hydrogen project approvals in Canada.



standards will have a significant impact on hydrogen production processes from fossil fuels in terms of emissions quantification and ability to qualify for incentives for implementation of CCUS technologies.

The Canada Occupational Health and Safety Regulations [98] and the Oil and Gas Occupational Safety and Health Regulations, under the Canada Labour Code [104], regulate many aspects relevant to chemical manufacturing processes (including hydrogen production from fossil fuels) and reference several supporting codes and standards. It should be noted that neither set of regulations explicitly mention hydrogen production from fossil fuels, but they do provide requirements for hydrogen production and storage through the regulation of dangerous goods and processing of oil and gas.

CAN/BNQ 1784-000 [62] appears to be the only Canadian code specific to hydrogen production from fossil fuels that is referenced in provincial gas safety regulations. CAN/BNQ 1784-000 provides safety requirements for hydrogen generation equipment installation, training, area classification, and protection of equipment from physical damage. In addition, the code specifically requires that "reformers" comply with CSA/ANSI FC 5 [105]. Although CSA/ANSI FC 5 provides definitions for autothermal reforming, steam reforming, and catalytic partial oxidation, which could be inferred as reformers, there is no formal definition of reformer in CAN/BNQ 1784-000. This leaves the term reformer open to interpretation as to whether other hydrogen production methods not defined or identified in CSA/ANSI FC 5, such as DMR and methane pyrolysis, would fall under CAN/BNQ 1784-000.

No other Canadian codes and standards specific to hydrogen production from fossil fuels were identified in the research conducted for this report other than the codes, standards, and standard test methods referenced in the Canada Occupational Health and Safety Regulations relevant to all chemical manufacturing processes.

3.3.4 Provincial and Territorial Regulatory Framework

Regulation of many relevant aspects of hydrogen production from fossil fuels is within provincial constitutional jurisdiction or is delegated to territorial governments. Requirements for licences, permits, authorizations, and approvals for activities, facilities, developments, construction, operation, undertakings, and water use and diversion are typically under the jurisdiction of the provinces and territories. Requirements for waste production and by-products are typically stipulated in environment acts, regulations, and project approvals.

A handover can occur between regulators and even between jurisdictions at the production facility gate, depending on how the produced hydrogen is transported and its destination. Historically, hydrogen has typically been used at the same industrial facility in which it was produced. In these cases, the production, storage, transport, and use activities fall under the same project approval by a single regulator. Outside the production gate, the Canada Energy Regulator may have jurisdiction if the product hydrogen is exported (regardless of transport mode) or is transported via interprovincial pipeline or by rail [106]. However, this is unclear and may present a novel situation because interprovincial hydrogen pipelines and hydrogen exports are not known to exist at the time of writing this report. As discussed with interviewees, if product hydrogen is transported via intraprovincial pipeline, there may be a handover between provincial regulators if the regulator having authority over the pipeline (e.g., Alberta Energy Regulator) is different than the regulator having authority over the hydrogen production facility (e.g., Alberta Environment and Protected Areas).

Guidance documents relevant to hydrogen production from fossil fuels reviewed in Section 3.2.1 are not presently cited in any provincial regulations, licences, permits, authorizations, or approvals available in the public domain.

Figure 11 shows existing provincial and territorial commercial hydrogen production project approval mechanisms. At the time of writing, these mechanisms exist only in Alberta, British Columbia (starting in 2023), Québec, and Nova Scotia. Alberta has the most comprehensive designated activities for hydrogen production projects and associated commercial project approval mechanisms.

Figure 11. Summary of provincial and territorial commercial hydrogen production project approval mechanisms.



Alberta

Environmental Protection & Enhancement ct (EPEA) Hydrogen-Related Designated Activities

Alberta Energy Regulator (AER) Jurisdiction

- Oil sands processing plant

Alberta Environment and Protected Areas (AEP) Jurisdiction

- Chemical manufacturing plant
- Syngas plant (non-gaseous or biomass fueled)
- Part of an oil refinery, sour gas processing plant, sweet gas processing plant, power plant, or fertilizer manufacturing plant

Coal Conservation Act Designated Activities

Alberta Energy Regulator (AER) Jurisdiction

- In situ coal gasification scheme

British Columbia

Energy Statues Amendment Act (ESAA) & Energy Resource Activities Act (ERAA)

- Coming into force 2023
- Creates the BC Energy Regulator (BCER)
- Explicitly includes hydrogen production
- "One-window" approach for all project applications and requirements through BCER

Québec

Regulation respecting mandatory reporting of certain emissions of contaminants into the atmosphere specifically requires the following from hydrogen production projects:

- GHG emission reporting
- Sampling, analysis, and measurement
- Methods for estimating missing data

Nova Scotia

Environment Act (NSEA)

- Hydrogen production is an explicitly regulated "undertaking"

A detailed review of relevant legislation, regulators, regulations, recent hydrogen production project approvals, cited directives, codes, methods, standard methods, and project approval and licencing processes and requirements in all Canadian provinces and territories is provided in Appendix A.

3.3.5 Municipal Regulatory Framework

Municipal zoning and permitting processes cover many important aspects of developing a commercial hydrogen production project using fossil fuels. Each municipality has unique permitting requirements and processes. For example, in the City of Edmonton, development of new commercial buildings follows this high level process: pre-application meeting with city staff (optional), applying for a development permit, applying for a building permit, construction, and inspections [107]. Development permits in Edmonton consider the following aspects of a project: site plan, floor plan for buildings, elevation drawings, fire safety plan, landscaping plan, certificate of title for real estate, and other legal documents, including covenants, rights-of-way, easements, and caveats [107]. Building permits in Edmonton include the following requirements: revised site plan, survey plan, building plans, documents demonstrating compliance with building construction and energy efficiency codes, professional schedules,

geotechnical report, and fire safety documents [107]. Trades permits and a sign permit would also be required for a hypothetical hydrogen production project from fossil fuels in Edmonton.

Several interested and affected parties interviewed for this report indicated that most of the effort and documentation required to obtain regulatory approvals to develop a commercial hydrogen production project from fossil fuels in Canada occur during municipal permitting processes.

3.4 Standardization and Regulatory Gap Analysis

3.4.1 Hydrogen Production Standardization

As the use of hydrogen in fuel cells and combustion devices for transportation and power generation in Canada becomes more widespread, product purity specification will become increasingly important. Some end use devices of hydrogen have very stringent purity requirements for proper functioning and life span (e.g., PEM fuel cells). Hydrogen fuel specification may help ensure product quality and protect consumers. It is unknown to what extent current hydrogen produced from fossil fuels in Canada meets the ISO 14687 [82] requirements for use in vehicular and stationary applications, and the SAE J2719 [83] specifications for PEM fuel cell applications. Federal and provincial legislation do not currently require hydrogen fuel specification analysis. Key future requirements may likely include lab accreditation and specification test methods, such as the ASTM and ISO methods reviewed in Section 3.2.1.3.

ISO 16110-2 provides a comprehensive framework for evaluating the performance of small scale hydrogen generators producing less than 400 Nm^3/h [80]. There does not appear to be any national or international standardization or guidance with regard to hydrogen production process performance and efficiency above 400 Nm^3/h. For context, large scale industrial operations typically produce more than 100,000 Nm^3/h [108]. Key process performance benchmarks that could be standardized or captured as best practices to support deployment of hydrogen production processes include procedures and methods to determine:

- Feedstock conversion rate;
- Product yield;
- Mass and energy balances;
- Process energy efficiency; and
- Process emissions intensity.

The NRC gap analysis referenced in Section 3.2.2 identified several international ISO, SAE, and IEC standards for conducting risk assessments and analysis that could be cited in project approvals and be used in commercial facility design [93]. The NRC report also recommends that CAN/BNQ 1784-000 should be referenced in provincial and territorial commercial project regulations, but highlights the following gaps in CAN/BNQ 1784-000 relating to hydrogen production from fossil fuels:

- The 33.5 kg H_2/h production limit is too low for actual commercial product offerings that would otherwise align with the intended applications of the code (small scale, decentralized, modular production units for non-industrial settings).
- The code does not apply to larger centralized facilities with production rates greater than 33.5 kg H_2/h.
- The language used in the code compels the project proponent to certify process equipment to various standards through third party testing, which can be cost prohibitive for pre-commercial technology developers.
- The code refers to IEC 60079-10-1 [109] for determining electrical area classification, which could result in unsafe installations as the classification determination is sensitive to assumptions used in the method.

In addition to these gaps, CAN/BNQ 1784-000 applies only to reformers in relation to hydrogen production from fossil fuels, and the term reformer is not defined in the standard itself. Although the term “hydrogen generating equipment” is defined and appears to include virtually any conceivable production method, specific requirements for hydrogen generating equipment are provided only for electrolyzers and reformers. Without more precise definitions or explicit inclusion of other



"Although the term "hydrogen generating equipment" is defined and appears to include virtually any conceivable production method, specific requirements for hydrogen generating equipment are provided only for electrolyzers and reformers."

methods, it is unclear which hydrogen production methods from fossil fuels are included in the code's scope under the term reformer.

Because several hydrogen production methods from fossil fuels reviewed in Section 3.1 are pre-commercial, there are currently no best practices available for CLC, DMR, in situ gasification for heavy oil and bitumen, or methane pyrolysis. Technology developers for these production methods have conducted research or piloted different process configurations in recent years that will inform the final design and configuration of future commercial units [39][49][52][55]. Based on the operational experience that will be generated by these pre-commercial activities, there will be an opportunity to compile collective learnings into best practices that could cover topics such as process design, reference to standards for common components (e.g., process equipment, safety systems, gas purification), and process performance benchmarks and evaluation.

Canada's Clean Fuel Regulations [97] reference ISO 14064-2 and 14064-3 for project level GHG emissions quantification in support of carbon credit claims. However, not all Canadian provinces have finalized their emissions offset programs (e.g., Manitoba, Saskatchewan) and have thus not yet adopted ISO 14064-2 and 14064-3. In the CSA Group research report that examined details of GHG emissions quantification, reporting, and labelling of hydrogen product, one of the interviewed interested and affected parties raised the challenge of aligning piping design requirements from different standards when hydrogen is used as fuel gas in a hydrogen production process [5]. Specifically, there is concern that the design requirements for flanges at transitions between hydrogen process piping (e.g., per ASME B31.12) and fuel gas train piping (e.g., per CSA B149.3) are incompatible. Furthermore, CSA B149.3 is specific to propane and natural gas service and there may be a gap in its applicability to the use of hydrogen as fuel gas in fired equipment.

The same interested and affected party also indicated that when existing guidance for materials selection in hydrogen service (e.g., ASME B31.12) is used to design a hydrogen production facility using fossil fuels, prescriptive requirements limit the process design to a range of operating conditions in which material performance is well understood [5]. This interested and affected party claimed that a knowledge gap on materials performance outside demonstrated ranges limits hydrogen production processes to operate at conditions that would allow for higher temperatures and pressures. Further research into the conditions of safe operation ranges is required for amendments to current standards.

3.4.2 Production Method-Specific Considerations

The documents listed in Section 3.2.1 outline codes, standards, guidelines, and test methods relevant to a generic hydrogen production process using fossil fuels. The guidance provided in these documents would apply to all of the production methods discussed in Section 3.1. Two CGA standards, CGA H-10 and CGA H-11, pertain specifically to the operation of steam methane reformers [64], [65]. However, there are additional considerations specific to other hydrogen production methods from fossil fuels where standardization and best practices are currently lacking.

A small number of DMR processes are approaching commercial scale. The core DMR process producing syngas can be considered a platform technology from which a variety of final products can be produced. This technology's greatest challenge is its economic feasibility because syngas can be produced at a much lower cost using SMR. There do not appear to be any standardization gaps for the DMR process other than those noted in Section 3.4.1, which apply to all hydrogen production methods from fossil fuels, particularly around process performance benchmarks that could support business case development for DMR.

In situ gasification of heavy oil and bitumen are currently at low to medium technology readiness levels. More research is needed to overcome the following technical and commercialization challenges: understanding fundamental reaction pathways and kinetics, identification of production loss mechanisms (e.g., undesirable reactions, reservoir leak off, well integrity, surface leaks) in specific formations and fields, and measurement and quantification of production losses in the field. With more operational experience and process performance data, process benchmarks and best practices could then be developed.

3.4.3 Regulatory Project Approval Considerations

Table 3 highlights the apparent gaps in regulatory commercial hydrogen production project approval mechanisms and requirements at the federal level and in each province and territory. The findings discussed in Section 3.3.4 highlighted that all Canadian provinces and territories do have, or appear to have, hydrogen production project approval mechanisms in place through existing acts, regulations, and directives. Project approval mechanisms in all jurisdictions regulate the following project aspects: water allocation, waste and wastewater, emissions, soil impacts, tanks, noise, ecosystem impacts, and social impacts (see Appendix A for details per jurisdiction). Hydrogen production facilities using fossil fuels as a feedstock are known to exist in Alberta [110] and assumed to exist in British Columbia, New Brunswick, Ontario, Québec, and Saskatchewan. However, at the time of writing, Alberta, Nova Scotia, and British Columbia are the only jurisdictions that have established approval mechanisms for hydrogen production projects that are either explicitly mentioned in legislation or based on published precedents and defined designated activities. Regulators also indicated that hydrogen production project approval processes in jurisdictions with unidentified processes would need to be revisited to align with current acts and regulations.

In 2022, British Columbia's Energy Statutes Amendment Act amended the Oil and Gas Activities Act and renamed it the Energy Resource Activities Act (ERAA) [111]. The ERAA came into force in 2023 and has new definitions that explicitly mention hydrogen production from fossil fuels. Project approvals in British Columbia are now regulated primarily by the British Columbia Energy Regulator (BCER) with support from other provincial government ministries and authorities as needed [112]. The project approval process and requirements appear to be clearly defined but remain to be tested under the new legislation. In Québec, emissions from hydrogen production projects are explicitly regulated, but project approval requirements are unclear. In all other provinces and territories, project approval mechanisms appear to exist but examples of project approvals are not available in the public domain. Hydrogen production project applications have either not been submitted in those jurisdictions (no precedents) or previous project applications and approvals are not publicly available.

Appendix A outlines requirements for potential hydrogen production project applications and approvals in Canadian provinces and territories.

Table 3. Gaps in Acts and Regulations Applicable to Commercial Hydrogen Production Project Approval Mechanisms

Guidance / Oversight	CAN	AB	BC	MB	NL	NB	NS	NT	NU	ON	PEI	QC	SK	YT
Clean / Renewable Fuel Regulations	✓	✓	✓	✓	X	X	X	X	X	✓	X	X	✓	X
Environmental Protection Act and Regulations	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Water Act and Regulations	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Generic Project Approval Mechanisms	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Hydrogen Production Recognized as Designated Activity in Acts and Regulations or by Precedent	✓	✓	✓	X	X	X	✓	X	X	X	X	✓	X	X
Hydrogen Production Project Approval Mechanisms	X	✓	✓	?	?	?	✓	?	?	✓	?	?	✓	?
Hydrogen Production-Specific Regulated Aspects	✓	X	✓	X	✓	X	X	X	X	✓	X	✓	✓	X

Explicit references to hydrogen production in oil and gas, environmental, and water resources acts and associated regulations are currently absent in most provinces and territories.

At the time of writing, Alberta has the most hydrogen production project approvals accessible in the public domain. There is a lack of published project approval requirements in all other provinces and territories. Alberta's detailed list of designated activities provides guidance when hydrogen production is integrated into larger industrial projects for specified end uses or for standalone hydrogen production with no specified end use. Standalone hydrogen production appears to be classified uniformly as a chemical manufacturing plant under the jurisdiction of Alberta Environment and Protected Areas (AEP). However, as noted in Appendix A (Section A.1.3), this framework may be ambiguous regarding the applicable regulator in unique scenarios where several designated activities occur simultaneously within a large industrial project. For example, the Air Products 2014 AEP approval for construction, operation, and reclamation of the Scotford Chemical (Hydrogen) Manufacturing Plant at the Shell Canada Scotford Complex [112] demonstrates the potential ambiguity regarding the applicable regulator. In this case, the produced hydrogen is intended for bitumen upgrading, oil refining to liquid fuels, and chemical manufacturing. Bitumen upgrading could be interpreted as an activity of an oil sands processing plant under the Alberta Energy Regulator's jurisdiction, similar to other manufacturers of hydrogen for bitumen upgrading. However, the entire project was classified as an activity of a chemical manufacturing plant under the purview of AEP. Potential reasons and considerations for this decision are discussed in Section A.1.3.

The hydrogen production project approvals available in the public domain in Alberta demonstrate the requirements for certain aspects of a project, including emissions to air, waste production, wastewater production and treatment, soil disturbance, aboveground tanks, water allocations, and social and ecosystem impacts. However, these requirements are generic and applicable to many industrial activities. They are not specific to aspects of the hydrogen production process itself, including process design, safety, operation, and performance. The international guidance documents reviewed in Section 3.2.1

address many specific needs for hydrogen production, including facility-wide and localized safety measures, hydrogen purification, storage, and venting, and best practices for SMR and syngas production. Furthermore, project approvals in Alberta do not have specific risk management or system management requirements aside from ISO/IEC 17025 [113] quality and technical operations requirements for lab sample testing accreditation.

3.5 Standardization Recommendations for Hydrogen Production Using Fossil Fuels

Sections 3.2 and 3.3 highlighted a comprehensive framework of codes, standards, standard test methods, best practices, and regulations relating to systems and subsystems of hydrogen production using fossil fuels. Many existing requirements derive from regulations and standards that apply broadly to hazardous gas and chemical manufacturing. The NRC gap analysis reviewed applicable codes and standards in extensive detail [93]. The recommendations presented in this section are aimed specifically at supporting safe commercial deployment of hydrogen production methods using fossil fuels.

> **Recommendation 1:** Review Standards that Address Safety and Processing of Fossil Fuels for Hydrogen Production

Several existing system and subsystem standards common to all hydrogen production methods using fossil fuels were reviewed in Section 3.2.1.1. It is recommended that the owners of future Canadian hydrogen production projects using fossil fuels review and consider using the following standards to accelerate deployment of hydrogen production technologies:

- ANSI/AIAA G-095A, *Guide to Safety of Hydrogen and Hydrogen Systems* [60];
- CGA G-5.5, *Standard for Hydrogen Vent Systems* [63];
- CGA H-13, *Hydrogen Pressure Swing Adsorber (PSA) Mechanical Integrity Requirements* [67];
- CGA P-89, *Prevention of Plant Instrument and Utility Gas System Cross Contamination* [70];
- CSA/ANSI FC 5, *Hydrogen Generators Using Fuel Processing Technologies — Part 1: Safety* [105];
- ISO/TS 19883, *Safety of Pressure Swing Adsorption Systems for Hydrogen Separation and Purification* [75];
- ISO 26142, *Hydrogen Detection Apparatus — Stationary Applications* [76]; and
- NFPA 2, *Hydrogen Technologies Code* [77].

Use of these standards will help pre-commercial development of new hydrogen production technologies and small scale process prototypes take advantage of established design standards for system-wide safety, hydrogen purification, and storage systems, which are common to all hydrogen production methods using fossil fuels. The primary intent of Recommendation 1 is to raise awareness among hydrogen production technology developers about existing safety standards that can be incorporated into detailed engineering designs as processes are scaled up. The secondary intent of Recommendation 1 is to reduce the cost and time to commercial deployment and to help ensure safe and reliable operations.

As part of this recommendation, experience from the use of these standards should be gathered to enable interested and affected parties and standards development organizations to evaluate the need for amendments to existing standards or creation of new standards focused on hydrogen production from fossil fuels. In particular, there are several hydrogen production safety standards that should be reviewed and considered for harmonization in a single standard. ANSI/AIAA G-095A and NFPA 2 have several overlapping sections regarding hydrogen production system safety, including requirements for overall system safety and emergency plans, piping, venting, storage, and fire and explosion control and protection. ISO 26142 also overlaps with ANSI/AIAA G-095A and NFPA 2 on hydrogen detection. Beyond this, CGA H-13 and ISO/TS 19883 have similar scopes in terms of design requirements and construction material considerations for pressure swing adsorber units used in hydrogen purification.

Recommendation 2: Reference Existing Hydrogen Production-Specific Guidance Documents in Future Commercial Project Regulatory Approvals

As noted in Section 3.3, many aspects of hydrogen production are currently unregulated. One exception is the requirement for reformers producing less than 33.5 kg H_2/h to comply with CSA/ANSI FC 5 in several provinces that have adopted CAN/BNQ 1784-000 [62]. Otherwise, existing guidance documents may be used by commercial project proponents at their discretion. Most commercial hydrogen production using fossil fuels in Canada is currently done by corporations with decades of design and operational experience. However, with several emerging hydrogen production methods using fossil fuels, regulating and standardizing some essential subsystems (e.g., venting, gas purification) may help ensure safe deployment.

It is recommended that regulators evaluating commercial hydrogen production project applications reference existing hydrogen production-specific codes, standards, and best practices. The most relevant guidance documents identified in this report that could be referenced by regulators in commercial project approvals are the same as those listed in Recommendation 1. These documents are assessed as being most relevant because they are applicable to all hydrogen production methods using fossil fuels. Recommendation 2 is intended to help ensure safe and reliable operations. This would also enable project proponents to use the same or similar commercially available technologies designed to those standards in many jurisdictions.

Recommendation 3: Establish Process Performance Benchmarks and Evaluation Methods for Large Hydrogen Production Projects in Canada

There are currently no widely accepted methods to evaluate hydrogen production performance at large commercial scale. ISO 16110-2 provides a suitable framework for process benchmarking and evaluation but only applies to hydrogen production rates below 400 Nm^3/h per hydrogen generator [80], while large commercial facilities based on SMR can have individual reformers that produce more than 100,000 Nm^3/h. Developing standard test methods for all production rates will help production process performance to be quantified on energy efficiency, pollutant emissions to air, and process GHG emissions intensity. These methods will be useful both during technology development and for large commercial projects by providing standardized input data for technoeconomic analysis and to assess commercial feasibility. This will assist technology developers, project developers, investors, technology adopters, and regulators. The determination of GHG emissions associated with hydrogen production is addressed specifically in ISO/TS 19870 [114].

Recommendation 4: Develop a New Standard Providing Safety Requirements for Large Scale Hydrogen Production Facilities

As noted in Section 3.4.1 and in the NRC gap analysis, CAN/BNQ 1784-000 [62] provides equipment installation requirements for small scale, decentralized hydrogen generating equipment producing less than 33.5 kg H_2/h. Development of a standard similar to ANSI/AIAA G-095A and NFPA 2, incorporating installation requirements, is recommended for large scale hydrogen production facilities producing more than 33.5 kg H_2/h. The NRC report made a similar recommendation relating to requirements for large scale hydrogen production facilities [93].

Furthermore, it is recommended that the new standard:

- Includes requirements for other surface facilities-based production processes from fossil fuels that are recently commercialized or approaching commercial scale (e.g., methane pyrolysis and CLC); and
- Increases the limit of applicability to include hydrogen production at any scale. The NRC report suggested a limit of applicability of 100 kg H_2/h to align with commercial product offerings (e.g., on-site power generation and fuel stations). However, it is recommended to consider increasing the limit of applicability by several orders of magnitude to include large scale, centralized commercial production.

Recommendation 5: Review CSA B149.3 for Potential Amendment to Include Use of Hydrogen as Fuel Gas in Fired Equipment

Hydrogen production processes using fossil fuels typically use natural gas-fired heaters to provide energy to the process. As companies consider using hydrogen as fuel gas to reduce process GHG emissions in hydrogen production, there is a need to review whether CSA B149.3 [71] can be amended to apply to hydrogen-fired equipment. CSA B149.3 is currently specific to propane and natural gas-fired equipment.

Recommendation 6: Take a Single Approach to GHG Emissions Quantification for Hydrogen Production from Fossil Fuels

Following from Recommendation 3, it is recommended that all Canadian jurisdictions use one standard for determining GHG emissions quantification for hydrogen production from fossil fuels. Presently, Canada's Clean Fuel Regulations [97] reference the ISO 14064-2 and 14064-3 for GHG emissions quantification. However, not all Canadian provinces have implemented emission offset programs and thus have not yet adopted the ISO 14064-2 and 14064-3 for emissions quantification protocol development. It would be beneficial to project developers for all Canadian jurisdictions to follow the same approach so they do not have to create different emissions quantification protocols in various provinces and territories for the same scope and type of project.

Recommendation 7: Develop a Standard for Future Gas–Solid Separation Technology in Methane Pyrolysis

Further technology development on gas–solid separation in methane pyrolysis is needed to support all technology developers by improving hydrogen product quality and solid carbon product recovery, and by preventing emissions of carbon nanoparticles in future commercial projects. It is recommended that standards development organizations maintain awareness of the technology readiness of these processes.

Recommendation 8: Develop Standard Test Methods to Evaluate Process Performance for In Situ Gasification of Heavy Oil and Bitumen

The best practices for ISCG published by the LLNL provide comprehensive guidance on the design and operation of ISCG facilities [95]. These best practices, along with many existing provincial directives for oil and gas production, are expected to provide comprehensive guidance for in situ gasification projects for various hydrocarbon sources. However, the ISCG best practices do not refer to standard test methods for evaluating process performance for heavy oil and bitumen feedstocks or for determining subsurface production losses. It is recommended that research and technology organizations and technology developers collaborate in developing standard test methods at various scales to evaluate process performance. However, more research is needed to understand bench versus field scale to overcome the following technical and commercialization challenges: understanding fundamental reaction pathways and kinetics, identification of production loss mechanisms (e.g., undesirable reactions, reservoir leak off, well integrity, surface leaks) in specific formations and fields, and measurement and quantification of production losses in the field.

4 Conclusions

The review of standards, codes, and best practices conducted for this report identified three main categories pertaining to hydrogen production from fossil fuels:

1. Production process operation and safety;
2. Production process performance; and
3. Product specification and testing.

Process operation and safety standards for hydrogen production from fossil fuels are comprehensive and several overlapping safety standards were identified. One standard was identified for evaluating process performance but it only applied to small, decentralized hydrogen generating equipment producing less than

400 Nm^3/h. Three hydrogen product specifications and several supporting standard test methods were identified that cover a wide range of hydrogen product applications.

Regulation of commercial hydrogen production projects in Canada is divided among federal, provincial, and territorial authorities. Every Canadian jurisdiction appears to have commercial project approval mechanisms, typically enabled through each province or territory's environment act and regulations. There are several regulated aspects of generic industrial activities that apply to hydrogen production from fossil fuels. In Canada, how hydrogen is produced and the use of production-specific standards are at the discretion of the commercial project proponent or owner, with the exception of CAN/BNQ 1784-000, which has been adopted in gas safety regulations in several provinces.

The gap analysis identified several challenges and opportunities for standardization for hydrogen production from fossil fuels in Canada. Most importantly, for large scale, centralized hydrogen production projects, hydrogen production safety standards are not referenced by regulations. There are also apparent gaps in process performance evaluation and GHG emissions quantification (though this gap is expected to be mostly or partially closed by ISO/DTS 19870). For pre-commercial hydrogen production methods, there is an opportunity to develop best practices for process design, operational knowledge, and experience, and to develop test methods to evaluate process performance. Technology and project developers interviewed for this report indicated that there is a general lack of clarity around hydrogen production project regulatory approval requirements in most provinces and territories. In some cases, technology or project developers are unsure of who is the relevant regulator in a given province or territory.

To address the challenges and opportunities identified in the gap analysis, the following eight recommendations were proposed for standardization for hydrogen production from fossil fuels:

1. Review standards that address safety and processing of fossil fuels for hydrogen production.
2. Reference existing hydrogen production-specific guidance documents in future commercial project regulatory approvals.
3. Establish process performance benchmarks and evaluation methods for large hydrogen production projects in Canada.
4. Develop a new standard providing safety requirements for large scale hydrogen production facilities.
5. Review CSA B149.3 for potential amendment to include use of hydrogen as fuel gas in fired equipment.
6. Take a single approach to GHG emissions quantification for hydrogen production from fossil fuels.
7. Develop a standard for future gas–solid separation technology in methane pyrolysis.
8. Develop standard test methods to evaluate process performance for in situ gasification of heavy oil and bitumen.

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Appendix A– Detailed Provincial and Territorial Regulatory Review

Appendix A provides a detailed regulatory review of legislation, regulators, recent commercial hydrogen production project approvals, cited directives, codes, methods, and standard methods, and project approval and licencing processes and requirements in all Canadian provinces and territories.

A.1 Alberta

In 2021, Osler published a comprehensive overview of regulatory considerations for hydrogen production from fossil fuels in Alberta [96].

A.1.1 Legislation and Regulators

Alberta's Environmental Protection and Enhancement Act (EPEA) [115], Oil and Gas Conservation Act (OGCA) [116], Coal Conservation Act [117], Water Act [118], and their associated regulations apply or may apply to hydrogen production activities in the province.

Regarding hydrogen production facilities, under the EPEA, the Ministry of Environment and Protected Areas (AEP) is responsible and grants approvals for chemical manufacturing plants, syngas plants, and integrated processes of oil refineries, sour gas processing plants, sweet gas processing plants, power plants, and fertilizer manufacturing plants [96]. The Ministry of Energy, through the Alberta Energy Regulator (AER), is responsible and grants approvals for oil sands processing plants and bitumen upgraders under the EPEA, and some gas processing plants under the OGCA [96].

There is a lack of clarity as to whether the EPEA or OGCA (and by extension which regulator) regulates approval of a standalone hydrogen production facility, because this activity could be considered either a chemical manufacturing plant, a syngas plant, or a gas processing plant in the case of natural gas. However, there are several precedents in which AEP has regulated standalone hydrogen production applications treated as chemical manufacturing plants, even when the hydrogen production activity is integrated within a bitumen upgrader, such as at the Shell Canada Scotford Upgrader [112], [119], [120]. It could be argued that AER could have been the regulator if the hydrogen plant was considered part of the bitumen upgrader. This ambiguity is discussed in Section A.1.3 and a suggested interpretation is provided.

Regarding water use, hydrogen production project developers must receive a licence from AEP under the Water Act to divert fresh water if it is required in their process [96]. For example, a water diversion licence was issued for Air Products' Fort Saskatchewan Hydrogen Facility [121].

The Coal Conservation Act specifically defines the terms "in situ coal gasification" and "in situ coal scheme" for the in situ production of hydrogen from underground coal seams [117]. The AER is responsible for the Coal Conservation Act and has jurisdiction over a "facility [...] that is connected to or associated with the recovery, development, production, handling, processing, treatment or disposal of synthetic coal gas."

A.1.2 Regulations

Several regulations associated with the legislation listed in Section A.1.1, that are applicable to hydrogen production, are in force.

Hydrogen production plants are often treated as chemical manufacturing plants, which are designated activities under the EPEA's Activities Designation Regulation [122]. Syngas plants producing hydrogen and carbon monoxide are also explicitly defined and recognized in this regulation. However, the definition excludes the following activities, which are designated elsewhere in the regulation: oil refineries, sour gas processing plants, sweet gas processing plants, power plants, fertilizer manufacturing plants, and chemical manufacturing plants. The definition of syngas in the Activities Designation Regulation only includes production from non-gaseous fuel or biomass and therefore appears to exclude processes using natural gas as feedstock.

High level descriptions of the requirements and procedure for approvals and registrations for various types of projects, including hydrogen production plants, under the EPEA are provided in the Approvals and Registrations Procedure Regulation [123]. Under the EPEA, hydrogen production project proponents may also be required to conduct an environmental assessment with conditions specified at the discretion of the director [96]. Hydrogen production is not explicitly mentioned in the EPEA's Environmental Assessment (Mandatory and Exempted Activities) Regulation [124]. However, the director has provided guidance on required environmental monitoring and reporting requirements in recent project approvals [112], [119], [120].

Under the Coal Conservation Act, Alberta's Coal Conservation Rules provide guidance on the requirements for ISCG schemes [125]. These requirements include:

- Applications and approvals;
- Submission of information, data, and materials;
- Records and reports;
- Regulator register of in situ schemes and designation of coal seams;
- Measurements; and
- Performance bonds, security, and fees.

A.1.3 Recent Hydrogen Production Approvals

Air Products received AEP approvals in 2014, 2016, and 2022 for the construction, operation and reclamation of three chemical manufacturing plants producing hydrogen: Scotford Chemical (Hydrogen) Manufacturing Plant, Edmonton Hydrogen Plant, and Edmonton 3 Hydrogen Plant [112], [119], [120]. Two of the project applications involved SMR processes and one involved ATR.

Examples of existing hydrogen production plants from fossil fuels that were explicitly mentioned in recent AER approvals for oil sands processing plants include Suncor Energy's Oil Sands Processing Plant and Mine [126] and Syncrude Canada Limited's Mildred Lake Oil Sands Processing Plant and Mine [127]. Hydrogen production at the Shell Canada, Syncrude, and Suncor oil sands processing facilities are all intended for bitumen upgrading, but the applications were processed by different regulators. The ambiguity as to whether AEP or AER is the relevant regulator for bitumen upgraders can be explained by observing that Shell Canada's Scotford Complex also includes an oil refinery and chemical manufacturing plants [128], which are within the jurisdiction of AEP. Potential reasons and considerations for classification of the project as a chemical manufacturing plant include:

- All project applications relating to the Scotford Complex may have been consolidated within AEP's jurisdiction to expedite and streamline approvals within a single regulator's purview;
- Assignment to AEP may relate to the ultimate activities of the overall Scotford Complex project (oil refining and chemicals manufacturing);
- The project is not located within designated oil sands geographical regions under AER jurisdiction; and
- The applicant was Air Products, who is neither owner nor operator of the Scotford Complex, in which case the hydrogen plant could be considered a standalone chemical manufacturing plant.

A.1.4 Cited Directives, Codes, Methods, and Standard Methods

Table A-1 summarizes the relevant guidance documents that were cited in the recent hydrogen production project approvals using fossil fuel feedstock described in Section A.1.3 [112], [119], [120], [126], [127]. The table indicates which aspect of the project the cited guidance document pertains to, along with a brief description of the requirements or guidance provided by the document.

Table A-1. Summary of Guidance Documents Cited in Recent Hydrogen Production Project Approvals in Alberta

Relevant Part(s) of the Hydrogen Production Project	Guidance Document(s)	Requirements/Guidance
Sample analysis	ISO/IEC 17025, General Requirements for the Competence of Testing and Calibration Laboratories [113]	Samples taken as directed in the project approval must be analyzed in a laboratory accredited to ISO/IEC 17025.
Gas vent and flare stacks	Alberta Stack Sampling Code [129]	Provides methods for measuring the emissions of air pollutants from stationary sources.
	Methods Manual for Chemical Analysis of Atmospheric Pollutants [130]	Per title.
	Air Monitoring Directive [131]	Sets out requirements for monitoring and reporting air quality.
	Continuous Emission Monitoring System (CEMS) Code [132]	"Establish requirements for the installation, certification, operation and maintenance of CEMS in Alberta; Ensure consistent and effective measurement, recording, and standardized reporting of specified emissions and other parameters; Establish requirements for the quality assurance and quality control of continuous emission monitoring systems and data; Establish requirements for alternative and replacement monitoring systems; and Provide guidance for meeting CEMS requirements."
	Electronic Reporting of CEMS Information User Manual [133]	"Procedures to successfully create, upload, verify, and submit the monthly CEM data to the Regulator (AEP and AER)."

Relevant Part(s) of the Hydrogen Production Project	Guidance Document(s)	Requirements/Guidance
Industrial wastewater, runoff, groundwater, and domestic wastewater	Standard Methods for the Examination of Water and Wastewater [134]	Methods to test for pollutants and contaminants in process-affected water streams and water bodies affected by the overall project.
Soil disturbance	Soil Monitoring Directive [135]	"Identify sources of substance releases from approved plants in Alberta before they result in significant contamination to the soil resource; Ensure timely actions are taken to eliminate or control the sources of soil contamination and prevent or reduce the risk of contaminant transfer from impacted soils to other environmental media (air or water) or potential receptors; and Ensure timely assessment, management and reporting of all contaminated areas associated with approved plants and reduce the environmental impact associated with industry approvals in Alberta."
	Soil Quality Criteria Relative to Disturbance and Reclamation [136]	Assist land reclamation activities by specifying soil quality criteria in specific regions of Alberta.
	Directive for Monitoring the Impact of Sulphur Dust on Soils [137]	"Soil monitoring and mitigation activities that may be required when sulphur manufacturing, processing or storage facilities in Alberta have the potential to release sulphur dust to soils."
Waste production	Test Methods for Evaluating Solid Waste: Physical/Chemical Methods Compendium, SW-846 [138]	Per title.
	Methods Manual for Chemical Analysis of Water and Wastes [139]	Per title.
	Toxicity Characteristic Leaching Procedure, Method 1311 [140]	"Determine the mobility of both organic and inorganic analytes present in liquid, solid, and multiphasic wastes."
Tanks	Guidelines for Secondary Containment for Above Ground Storage Tanks [141]	Dyke and dyked area requirements surrounding above ground tanks.
	Environmental Guidelines for Controlling Emissions of Volatile Organic Compounds from Aboveground Storage Tanks, PN 1180 (reference not found)	Unknown.

A.1.5 Approval and Licencing Processes and Requirements

Figure A-1 illustrates the approval process and requirements for hydrogen production project scenarios regulated by AEP. The main requirements are approval of an application for construction, operation, and reclamation of designated activities under the EPEA (which may also require an environmental assessment), and a licence to divert water under the Water Act. As noted in Section A.1.1, AEP regulates hydrogen production processes in the following scenarios: chemical manufacturing plant, syngas plant, and integrated processes of oil refineries, sour gas processing plants, sweet gas processing plants, power plants, and fertilizer manufacturing plants.

Figure A-2 illustrates defined and potential approval processes and requirements for hydrogen production project scenarios regulated by AER. As noted in Section A.1.1, AER regulates hydrogen production processes in oil sands processing plants, gas processing plants, and ISCG schemes. The main requirements for an oil sands processing plant are approval of an application for construction, operation, and reclamation of designated activities under the EPEA (which may also require an environmental assessment), and a licence to divert water under the Water Act. An ISCG scheme, which includes processing facilities, also requires approval of an application under the Coal Conservation Act. There is no precedent as to whether a hydrogen production process could be considered a gas processing plant under the OGCA. However, this scenario is conceivable if future hydrogen production plants were to be added to existing natural gas processing plants for direct access to hydrogen–natural gas blending gates. This hypothetical scenario is indicated with a dashed line in Figure A-2, in which an existing requirement could be an application for a new gas processing plant or an amendment to an existing gas processing plant under the Oil and Gas Conservation Rules associated with the OGCA [142].

Figure A-1. Flowchart for hydrogen production project approval and licencing requirements in Alberta regulated by AEP.

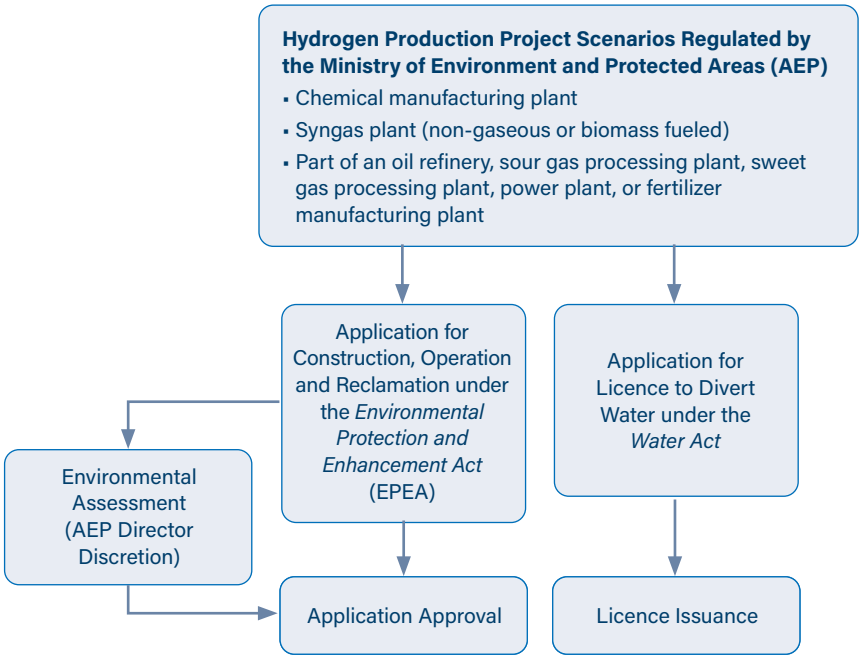
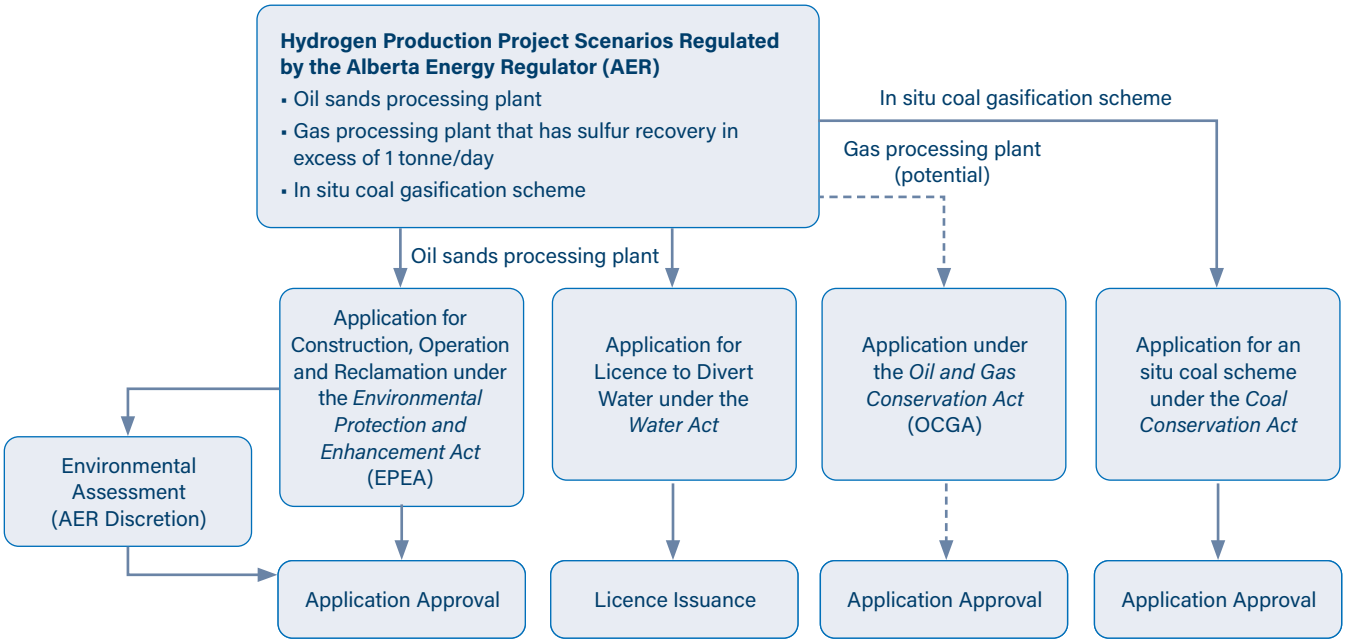


Figure A-2. Flowchart for hydrogen production project approval and licencing requirements regulated by AER.



The terms and conditions attached to previous approvals granted under the EPEA were similar and detailed in nature, regardless of whether the regulator granting approval was AEP or AER, and covered the following:

- Reporting;
- Record keeping;
- Analytical, construction, and operational requirements for air, industrial wastewater, industrial runoff, groundwater, domestic wastewater, soil conservation and management, waste management, monitoring and reporting, and accreditation of test labs;
- Above ground storage tanks; and
- Decommissioning and land reclamation.

The terms and conditions attached to EPEA approvals are not specific to hydrogen production but cite many directives, codes, standards, test methods, procedures, and guidelines providing limits and guidance on various aspects of the project in general. Table A-2 summarizes the guidance documents cited in the Air Products project approvals [112], [119], [120]. It should be noted that the approvals and cited guidance documents only relate to the potential environmental impacts of the projects. They do not regulate or standardize the actual hydrogen production processes used in the projects, nor do they refer to construction codes and standards for the plant process units and equipment. The issue of construction codes and standards are outside the scope of this report.

Table A-2. Summary of Guidance Documents Cited in Air Products Hydrogen Production Project Approvals in Alberta

Project Consideration	Guidance Document	Authority
Air	Alberta Stack Sampling Code [129]	Government of Alberta
	Methods Manual for Chemical Analysis of Atmospheric Pollutants [130]	Government of Alberta
	Air Monitoring Directive [131]	Government of Alberta
	CEMS Code [132]	Government of Alberta
Industrial Wastewater, Industrial Runoff, Groundwater, and Domestic Wastewater	Standard Methods for the Examination of Water and Wastewater [134]	American Public Health Association; American Water Works Association; Water Environment Federation
Soil	Soil Monitoring Directive [135]	Government of Alberta
	Soil Quality Criteria Relative to Disturbance and Reclamation [136]	Government of Alberta
	Directive for Monitoring the Impact of Sulphur Dust on Soils [137]	Government of Alberta
Waste	Test Methods for Evaluating Solid Waste: Physical/ Chemical Methods Compendium [138]	US Environmental Protection Agency (EPA)
	Methods Manual for Chemical Analysis of Water and Wastes [139]	Government of Alberta
	Toxicity Characteristic Leaching Procedure, Method 1311 [140]	US EPA
	Standard Methods for the Examination of Water and Wastewater [134]	American Public Health Association; American Water Works Association; Water Environment Federation

A.2 British Columbia

An overview of the regulatory considerations for hydrogen production from fossil fuels in British Columbia (BC) is provided in [96].

A.2.1 Legislation and Regulators

BC's Energy Statutes Amendment Act (ESAA) [110], Water Sustainability Act (WSA) [143], and Environmental Assessment Act (BCEAA) [144] will or may apply to hydrogen production from fossil fuels in the province. New regulatory requirements came into force in 2023 through the ESAA, which repealed the Oil and Gas Activities Act (OGAA) and replaced it with the Energy Resource Activities Act (ERAA) [145]. The ESAA also expanded responsibilities to explicitly include hydrogen production [146].

The OGAA and its associated regulations did not list requirements specific to hydrogen production in BC. However, hydrogen production from natural gas or petroleum could be considered an "oil and gas activity" under the Act

and be subject to permit requirements [96], [145]. The BC Energy Regulator (BCER) (formerly the BC Oil and Gas Commission) was responsible for issuing permits to prescribed applicants under the OGAA. With the ESAA coming into force in 2023 with specific reference to hydrogen production, BCER has explicit and sole responsibility for hydrogen production processes from natural gas and petroleum in BC [145], [146]. An interview conducted prior to the ESAA coming into force indicated that the regulator may take a lead role in hydrogen production project approvals, but that there will likely be interagency coordination and collaboration on issues such as water use and process equipment certification.

Regarding water use, BC's WSA does not specifically refer to hydrogen production or list hydrogen production as a "water use purpose" [96], [143]. Furthermore, hydrogen production does not appear to fit within the definition of an "oil and gas purpose," which is defined as "the use of water in the development of petroleum or natural gas wells or the production of petroleum or natural gas resources." In spite of this, it is expected that hydrogen production project proponents will likely require a licence to divert and beneficially use water [96]. Licences are issued by the comptroller, water managers, or engineers designated within the WSA [143] or by BCER [147].

Environmental assessments in BC are regulated by the BCEAA [144], which does not specifically reference hydrogen production projects. Environmental assessments are needed for "reviewable projects" as defined in the BCEAA and in the Reviewable Projects Regulation [148]. Reviewable projects are ones that are described in the regulation, based on effects thresholds, or designated to be reviewable by the responsible minister [96].

A.2.2 Regulations

The Oil and Gas Processing Facility Regulation (OGPFR) under the OGAA contained definitions for a "gas processing plant" and "processing facility" that pertain to the extraction of gases and liquids from natural gas, manufacturing plants "designed to convert natural gas into other organic compounds," and petroleum refineries [149]. Although a hydrogen production plant could be interpreted as a processing facility, it is not explicitly specified in the regulation. The OGPFR outlines requirements for a processing facility, including project application, reports, engagement with Indigenous nations, design and construction, operation, suspension of operations and decommissioning, records, and management systems.

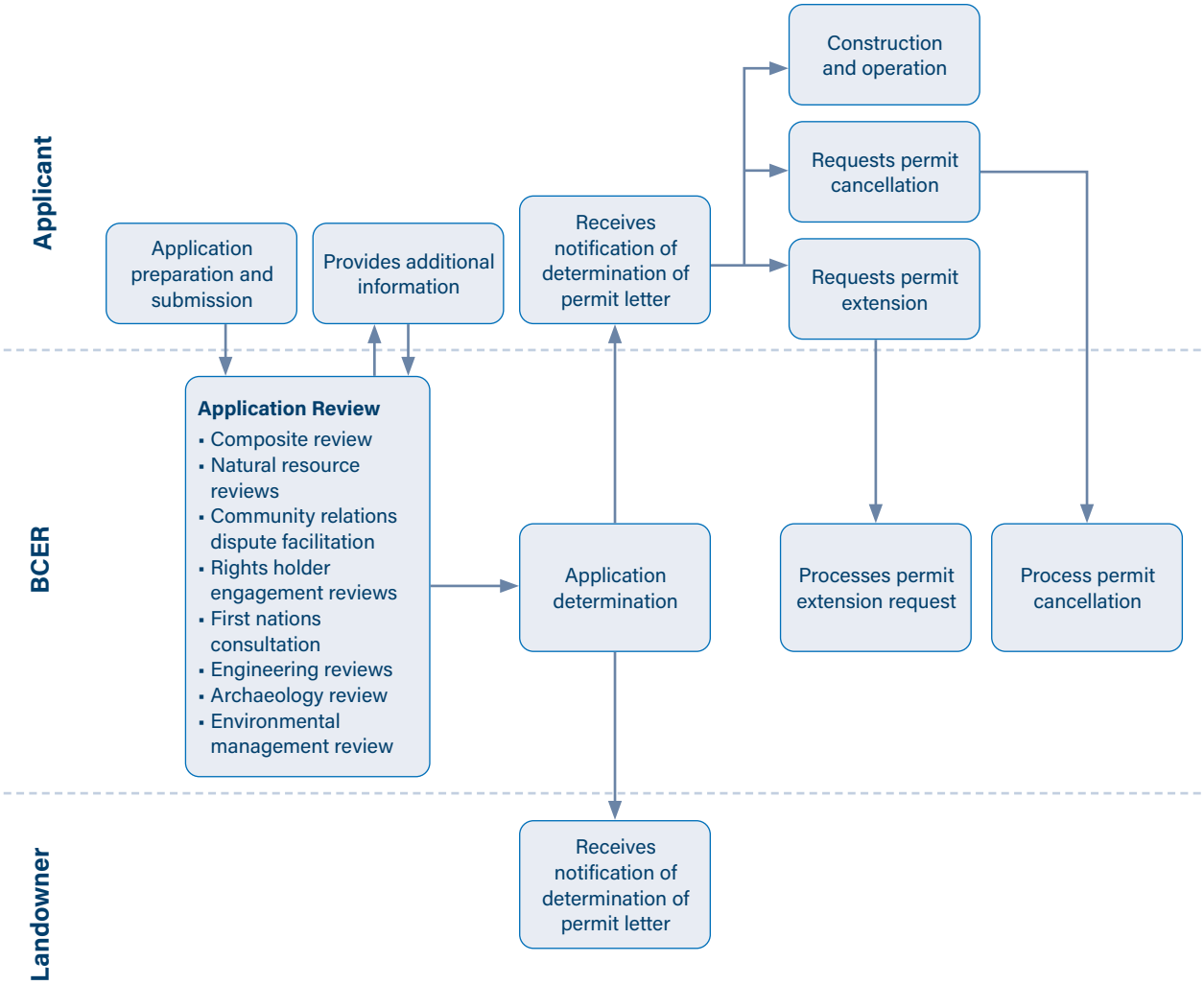
The Requirements for Consultation and Notification Regulation under the OGAA specified the circumstances and conditions for consultation or notification with interested and affected parties on proposed oil and gas activities [150]. The need to consult or notify is part of the activity pre-application process [145], [149], [150]. However, it is unclear whether hydrogen production would necessitate consultation or notification. Before issuing a permit for an oil and gas activity, the BCER considers the application, written submissions from interested and affected parties engaged during consultation and notification, and the government's environmental objectives under the Environmental Protection and Management Regulation [151].

The Water Sustainability Regulation under the WSA designates 20 different "industrial water use purposes" for water diversion and use, but hydrogen production does not appear to fit within any of the designated purposes [152]. While the "processing and manufacturing" designated purpose is the most suitable candidate, in practice, the definition is specific and refers to "diversion and use of water for the operation of a sawmill, shipyard, factory or other manufacturing facility or for the operation of a wharf, and includes the use of water in a gravel washing plant or the use in an industrial context of water to prevent a fire."

A.2.3 Recent Hydrogen Production Approvals

No recent hydrogen production approvals in BC were discovered in the research conducted for this report.

Figure A-3. BC oil and gas activity application review and determination process. Adapted from [147].



A.2.4 Approval and Licencing Processes and Requirements

Figure A-3 provides an overview of the application review and determination process for oil and gas activities regulated by BCER [147]. The applicant prepares and submits an application to BCER, who reviews the application and may request additional information. BCER then makes a decision on the application and notifies both the applicant and the landowner. If a permit is issued, the applicant can either proceed to construction and operation, request the permit be cancelled prior to the start of construction, or request a permit extension. BCER processes the permit cancellation or extension request. The requirements for a water diversion or use licence, consultation and notification, and environmental assessment are described in Section A.2.2.

As noted in previous sections, the historical process under the BC OGCA did not envision or explicitly reference hydrogen production. However, under the new ESAA, it is possible that the process shown in Figure A-3 will be expanded to include hydrogen production projects, or a new review and approval process will be implemented.

A.3 Manitoba

A.3.1 Legislation and Regulators

Manitoba's Oil and Gas Act (MBOGA) [153], Water Rights Act (MBWRA) [154], Environment Act (MBEA) [155], and their associated regulations may apply to hydrogen production activities in the province. As with many Canadian provinces and territories, hydrogen production from fossil fuels is not specifically mentioned in the legislation and regulations.

The MBOGA defines a "gas plant" as "a system or arrangement of pressure vessels, piping and other equipment designed to process gas from a well or battery" [153]. The term "gas plant" may encompass hydrogen production from fossil fuels in Manitoba. The minister of the Department of Natural Resources and Northern Development may issue gas plant permits under the MBOGA.

The MBWRA describes a licencing system for water use, diversion, and works. The minister or appointed director of the Department of Environment and Climate Change issues water allocation licences in Manitoba under the MBWRA [154]. Licences are required for "industrial purposes" that use "water obtained from a source other than a municipal or community water distribution system, for the operation of an industrial plant producing goods or services other than primary agricultural products." Hydrogen production processes obtaining their own water sources may likely be treated as industrial purposes and would therefore require a water use, diversion, and works licence. The minister may attach additional terms and conditions to the licence beyond what is prescribed in the regulations.

The minister or appointed director of the Department of Environment and Climate Change issues licences for proposals on various types of "development" projects, industries, operations, or activities under the MBEA [155]. The term "development" in the MBEA has a wide scope that is intended to capture any possible detrimental environmental impacts or harm to natural resources. Three classes of development are described in the MBEA relating to the nature of the perceived environmental impact:

- Class 1 development: release of pollutants.
- Class 2 development: unrelated to pollution or in addition to pollution.
- Class 3 development: exceptional project due to the magnitude or number of environmental issues.

The director determines the form of the assessment required for proposals. The minister or director can commission a public hearing in parallel with, or subsequent to, the assessment, before deciding on licence issuance. The main consideration for hydrogen production processes from fossil fuels in this scheme would likely be the release of CO_2 and H_2S to atmosphere, if any, associated with the production method.

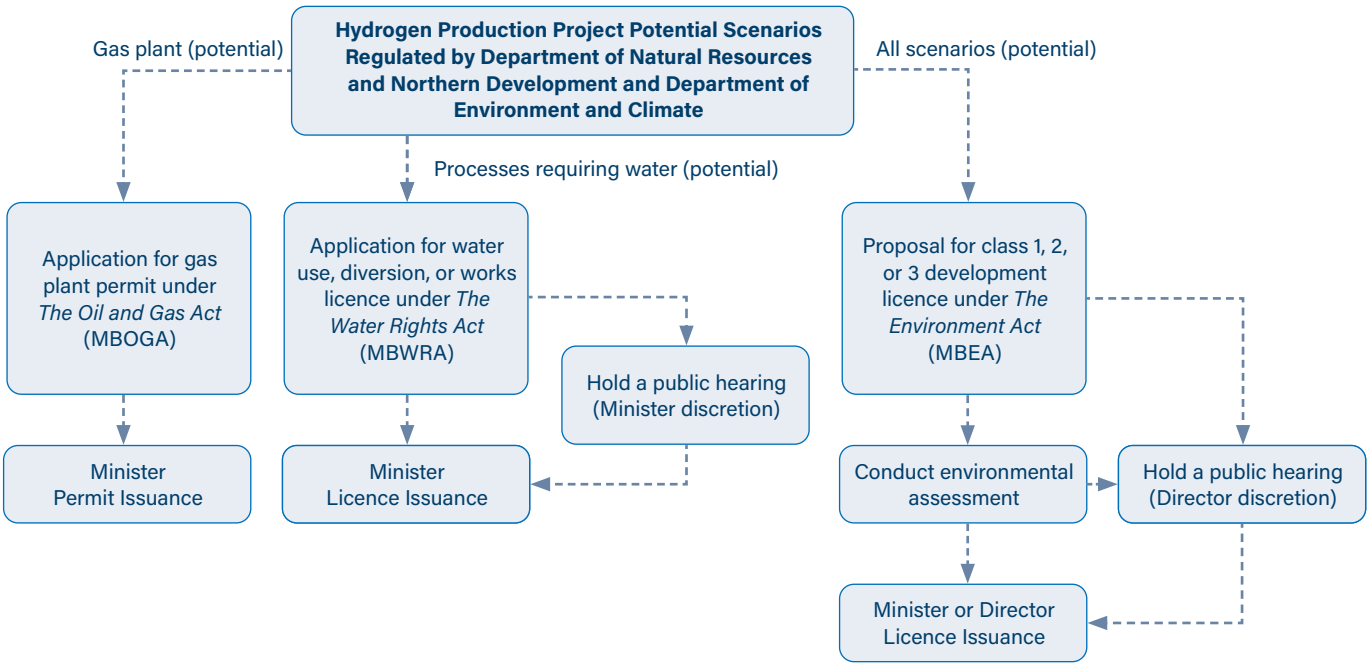
A.3.2 Regulations

The Water Rights Regulation under the MBWRA provides additional details and requirements for water allocation licence applications in Manitoba that are likely relevant to hydrogen production processes from fossil fuels requiring water [156].

The following regulations under the MBEA are also likely relevant to development proposals for hydrogen production methods from fossil fuels:

- Classes of Development Regulation [157];
- Environmental Assessment Hearing Costs Recovery Regulation [158];
- Joint Environmental Assessment Regulation [159]; and
- Licensing Procedures Regulation [160].

Figure A-4. Flowchart for potential hydrogen production project approval, licencing, and permitting requirements in Manitoba.



A.3.3 Recent Hydrogen Production Approvals

No recent hydrogen production approvals in Manitoba were discovered in the research conducted for this report.

A.3.4 Approval and Licencing Processes and Requirements

Figure A-4 illustrates the potential approval, licencing, and permitting processes and requirements for hydrogen production project scenarios in Manitoba. The potential requirements are regulated by the Department of Natural Resources and Northern Development and the Department of Environment and Climate Change.

A.4 Newfoundland and Labrador

A.4.1 Legislation and Regulators

Newfoundland and Labrador's Petroleum and Natural Gas Act (NLPNGA) [161], Water Resources Act (NLWRA) [162], Environmental Protection Act (NLEPA) [163], and their associated regulations may apply to hydrogen production from fossil fuels in the province. As with many Canadian provinces and territories, hydrogen production is not specifically mentioned in the legislation and regulations.

The NLPNGA defines "gas" as "natural gas and includes substances, other than oil, that are produced in association with natural gas," and includes gas within the definition of "petroleum" [161]. These terms could be interpreted to include hydrogen production from fossil fuels. The Department of Industry, Energy and Technology issues licences and permits to explore, develop, or produce petroleum as defined in the NLPNGA [164].

The Water Resources Management Division issues water diversion and use licences in Newfoundland and Labrador under the NLWRA [165]. Although hydrogen production is not specifically mentioned in the NLWRA or associated regulations, it is expected that a hydrogen production process from fossil fuels requiring water would need to apply for a water rights licence.

Approval for an undertaking under the NLEPA must be obtained from the Environmental Assessment Division [166]. The term "undertaking" in the NLEPA refers to "an enterprise, activity, project, structure, work or proposal [...] that may, in the opinion of the minister, have a significant environmental effect" [163]. An undertaking would almost certainly include hydrogen production projects from fossil fuels. The requirements for an undertaking proposal include notification and registration of the undertaking, and may also include:

- An environmental assessment;
- And environmental preview report;
- And environmental impact statement;
- A public consultation; and
- A public hearing.

A.4.2 Regulations

Newfoundland and Labrador's Petroleum Regulations provide additional licencing and permitting requirements for petroleum operations under the NLPNGA [167]. The term "petroleum operations" is defined as "any work or survey conducted for the purpose of petroleum exploration, development or production," which could be interpreted to include hydrogen production from fossil fuels. The regulation may require a project proponent to conduct a public hearing or briefing at the minister's discretion.

The Environmental Assessment Regulations outline a procedure and provide additional details and requirements for environmental assessments, preview reports, impact statements, and public consultations and hearings for undertaking applications under the NLPNGA [168].

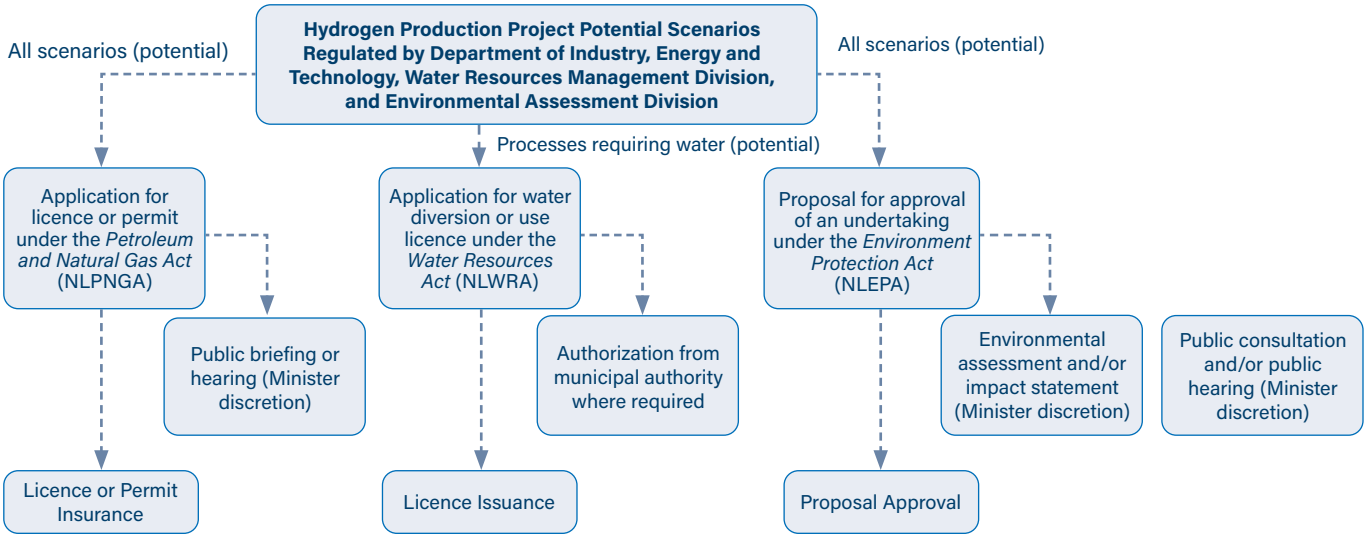
A.4.3 Recent Hydrogen Production Approvals

No recent hydrogen production approvals in Newfoundland and Labrador were discovered in the research conducted for this report.

A.4.4 Approval and Licencing Processes and Requirements

Figure A-5 illustrates the potential approval, licencing, and permitting processes and requirements for hydrogen production project scenarios in Newfoundland and Labrador. The potential requirements are regulated by the Department of Industry, Energy and Technology, the Water Resources Management Division, and the Environmental Assessment Division.

Figure A-5. Flowchart for potential hydrogen production project approval, licencing, and permitting requirements in Newfoundland and Labrador.



A.5 New Brunswick

A.5.1 Legislation and Regulators

New Brunswick's Clean Environment Act (NBCEA) [169] and its associated regulations may apply to hydrogen production from fossil fuels in the province. The NBCEA is a comprehensive legislation regulating undertakings affecting the environment, water usage, and environmental assessment requirements in the province.

Approval for an undertaking under the NBCEA must be obtained from the Department of Environment and Local Government. The term "undertaking" in the NBCEA refers to "an enterprise, activity, project structure, work or program that may, in the opinion of the Lieutenant Governor in Council, result in a significant environmental impact." Hydrogen production is not explicitly designated in the regulations but could likely be considered an undertaking based on the regulations discussed in Section A.5.2. The requirements for an undertaking application include notification and registration of the undertaking, and may also include:

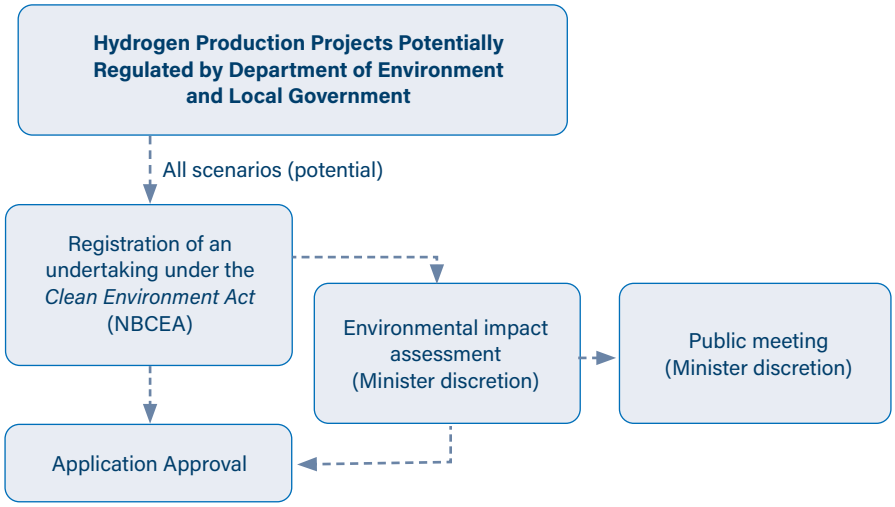
- An environmental impact assessment;
- And environmental impact assessment report; and
- A public meeting.

A.5.2 Regulations

The Environmental Impact Assessment Regulation [170] specifies the process and requirements for approval of registration of an undertaking under the NBCEA. Hydrogen production from fossil fuels could likely be considered an undertaking interpreted as "commercial extraction or processing of combustible energy-yielding materials, except fuelwood."

Hydrogen production from fossil fuels may also be subject to the Air Quality Regulation (e.g., CO, H_2S, and particulate emissions) [171].

Figure A-6. Flowchart for potential hydrogen production project approval requirements in New Brunswick.



A.5.3 Recent Hydrogen Production Approvals

No recent approvals for hydrogen production from fossil fuels in New Brunswick were discovered in the research conducted for this report.

A.5.4 Approval Process

Figure A-6 illustrates the potential approval process for hydrogen production projects in New Brunswick based on the NBCEA and associated regulations.

A.6 Northwest Territories

A.6.1 Legislation and Regulators

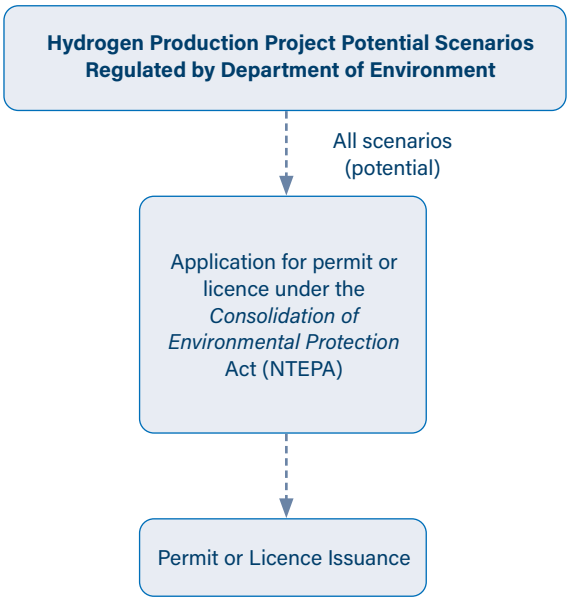
The Northwest Territories' Oil and Gas Operations Act (NTOGOA) [172], Environmental Protection Act (NTEPA) [173], Waters Act (NTWA) [174], and their associated regulations may apply to hydrogen production from fossil fuels in the territory. As with many Canadian provinces and territories, hydrogen production is not specifically mentioned in the legislation and regulations.

The NTOGOA defines "gas" as "natural gas and includes all substances, other than oil, that are produced in association with natural gas." Although this is understood to be intended for production of hydrocarbons to surface, it could also be interpreted to include hydrogen production from fossil fuels. The NTOGOA requires an operating licence and work or activity authorization. The Office of the Regulator of Oil and Gas Operations issues licences for oil and gas activities [175].

Various regional and watershed boards issue water licences in the territory under the NTWA [175]. Although hydrogen production is not mentioned in the NTWA or associated regulations, it can be expected that a hydrogen production process from fossil fuels requiring water would need to apply for a water licence. A public hearing may be required in some instances.

A permit or licence for an activity under the NTEPA must be obtained from the Department of Environment and Natural Resources. The NTEPA provides no guidance with respect to designated activities.

Figure A-7. Flowchart for potential hydrogen production project approval, licencing, and permitting requirements in Northwest Territories.



A.6.2 Regulations

There appear to be no regulations relevant to hydrogen production from fossil fuels in the Northwest Territories.

A.6.3 Recent Hydrogen Production Approvals

No recent approvals for hydrogen production from fossil fuels in the Northwest Territories were discovered in the research conducted for this report.

A.6.4 Approval and Licencing Processes and Requirements

Figure A-7 illustrates the potential approval, licencing, and permitting processes and requirements for hydrogen production project scenarios in the Northwest Territories.

A.7 Nova Scotia

A.7.1 Legislation and Regulators

Nova Scotia's Environment Act (NSEA) and its associated regulations specifically apply to hydrogen production from fossil fuels in the province [176]. The NSEA is a comprehensive legislation regulating undertakings affecting the environment, water usage, and environmental assessment requirements.

Approval for an undertaking under the NSEA must be obtained from the Inspection, Compliance, and Enforcement division [177]. The term "undertaking" in the NSEA refers to "an enterprise, activity, project, structure, work or proposal that, in the opinion of the Minister, causes or may cause an adverse effect or an environmental effect"

[176]. Hydrogen production is designated in the regulations as an activity requiring registration and a specified environmental assessment process. The requirements for an undertaking application include notification and registration of the undertaking, and may also include:

- An environmental assessment;
- A focus report; and
- A public hearing or review.

A.7.2 Regulations and Requirements

The Activities Designation Regulations [178] under the NSEA specifically designate hydrogen production as a chemical manufacturing plant. This designation is categorized as an activity that requires ministerial approval. The type of approval required for this activity is specified by the Approval and Notification Procedures Regulations [179].

The Environmental Assessment Regulations under the NSEA specifically designate a hydrogen facility as a Class I undertaking [180]. The required environmental assessment process for Class I undertakings includes registration, and may include:

- A focus report;
- Terms of reference;
- An environmental assessment report;
- Alternate dispute resolution; and
- A referral to a review panel.

The Environmental Assessment Regulations describe these potential components of the process in more detail, and the Environmental Assessment Review Panel Regulations describe the requirements for a review panel of an environmental assessment [181].

Hydrogen qualifies as a Class 2 dangerous good in the Dangerous Goods Management Regulations [182] by reference to the federal Transportation of Dangerous Goods Regulations [183]. Nova Scotia's Dangerous Goods Management Regulations prescribe storage requirements, contingency plans, and inventory keeping.

Hydrogen production from fossil fuels may also be subject to the Air Quality Regulations (e.g., CO, H_2S, and particulate emissions) [184].

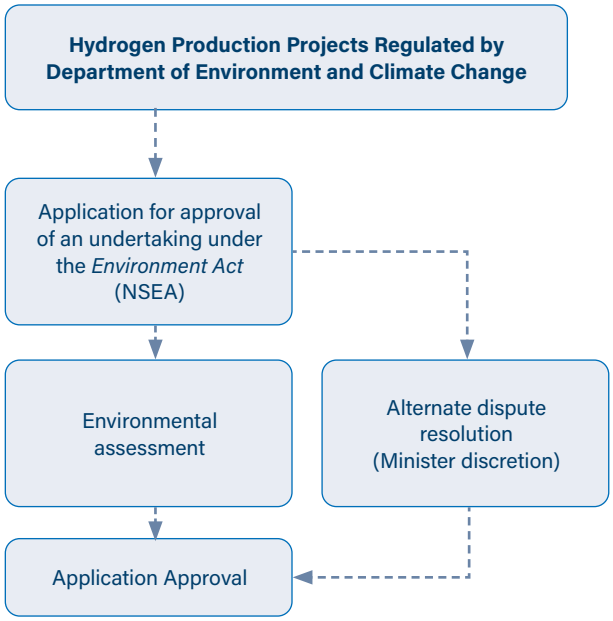
A.7.3 Recent Hydrogen Production Approvals

No recent approvals for hydrogen production from fossil fuels in Nova Scotia were discovered in the research conducted for this report.

A.7.4 Application Approval Process

Figure A-8 illustrates the approval process for hydrogen production projects in Nova Scotia based on the NSEA and associated regulations. The approval process requirements are described in Section A.7.2.

Figure A-8. Flowchart for hydrogen production project approval requirements in Nova Scotia.



A.8 Nunavut

A.8.1 Legislation and Regulators

Nunavut's Consolidation of Environmental Protection Act (NUEPA) [185] appears to be the only legislation that may apply to hydrogen production from fossil fuels in the territory. As with many Canadian provinces and territories, hydrogen production is not specifically mentioned in the legislation and regulations. A permit or licence for an activity under NUEPA must be obtained from the Department of Environment, but the Act provides no guidance with respect to designated activities.

A.8.2 Regulations

There appear to be no regulations relevant to hydrogen production from fossil fuels in Nunavut.

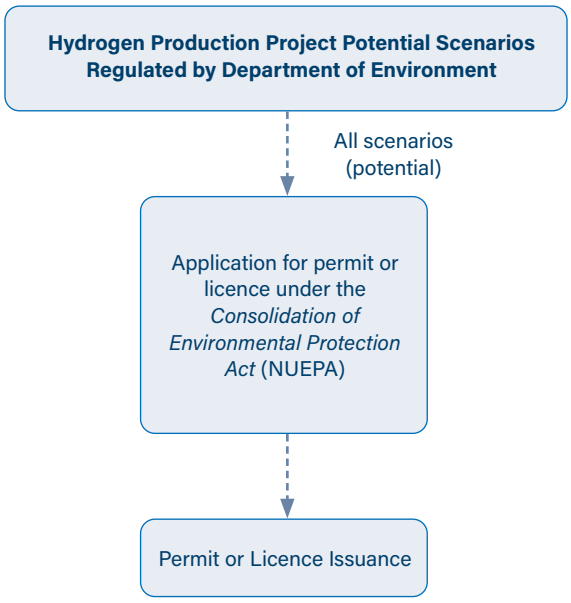
A.8.3 Recent Hydrogen Production Approvals

No recent approvals for hydrogen production from fossil fuels in Nunavut were discovered in the research conducted for this report.

A.8.4 Approval and Licencing Processes and Requirements

Figure A-9 shows the potential approval, licencing, and permitting processes and requirements for hydrogen production project scenarios in Nunavut.

Figure A-9. Flowchart for potential hydrogen production project licencing and permitting requirements in Nunavut.



A.9 Ontario

A.9.1 Legislation and Regulators

Ontario's Oil, Gas and Salt Resources Act (OGSRA) [186], Ontario Water Resources Act (OWRA) [187], and Environmental Protection Act (EPA) [188], and their associated regulations may apply to hydrogen production activities in the province. As with many Canadian provinces and territories, hydrogen production from fossil fuels is not specifically mentioned in the legislation and regulations.

The OGSRA defines a "facility" as "any work used to store, process or transport any substance produced from or injected into a well" [186], and may encompass hydrogen production from fossil fuels. The Ontario Energy Board (OEB) or responsible minister grants oil and gas facility licences under the OGSRA. However, interviewees indicated that hydrogen production from fossil fuels falls under the authority of the Ministry of the Environment.

Directors appointed by the Minister of the Environment issue water taking permits in Ontario under the OWRA [187]. Permits are required for "persons" (i.e., facility developers/owners) taking more than 50,000 litres of water per day and not qualifying for exceptions under the OWRA. This would likely impact hydrogen production processes based on the scale of a proposed project. The director may require permit applicants to undertake tests or studies, have tests or studies certified by a qualified individual, or conduct consultations.

Directors appointed by the Minister of the Environment also approve environmental compliance applications for plants or production processes in Ontario under the EPA [188]. The director may require applicants to submit "plans, specifications, technical reports or other information and to carry out and report on any tests or experiments" related to the application, and to conduct consultations. Hydrogen production processes from fossil fuels, though not explicitly mentioned in the EPA, may be considered plants or production processes.

A.9.2 Regulations

The Water Taking and Transfer regulation supplements the OWRA by providing additional details for issuing water taking permit applications that may be relevant to hydrogen production from fossil fuels [189].

There are several regulations under the EPA that may be relevant to environmental compliance applications for hydrogen production from fossil fuels. These regulations and their potential impacts are summarized in Table A-3.

Regulation under the EPA	Potential Impact on Hydrogen Production from Fossil Fuels
Registrations under Part II.2 of the Act – Activities Requiring Assessment of Air Emissions [190]	An assessment of air emissions may be required for an environmental compliance application for hydrogen production process that emits anything to the natural environment other than water.
Alternative Low-Carbon Fuels [191]	Provides additional conditions for an environmental compliance application if hydrogen produced from fossil fuels is considered an alternative low carbon fuel.
Applications for Environmental Compliance Approvals [192]	Provides general requirements for all environmental compliance applications.

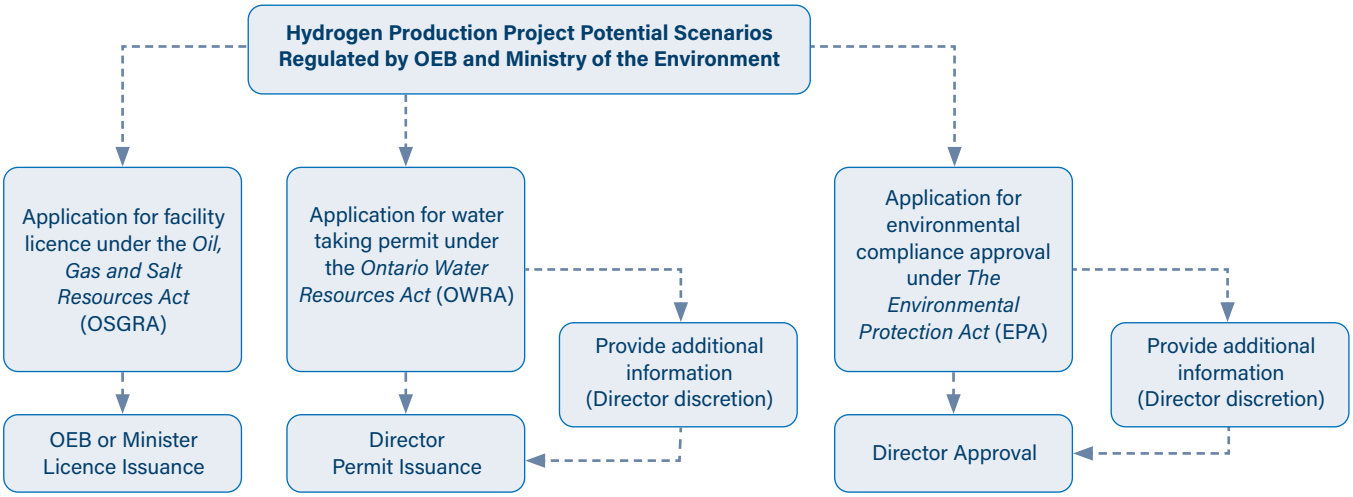
A.9.3 Recent Hydrogen Production Approvals

No public disclosures of hydrogen production approvals in Ontario were discovered in the research conducted for this report, though the existence of hydrogen plants at various refineries and fertilizer manufacturing facilities in Ontario is known.

A.9.4 Approval and Licencing Processes and Requirements

Figure A-10 illustrates the potential approval, licencing, and permitting processes and requirements for hydrogen production project scenarios in Ontario. The potential requirements are managed by the OEB and Ministry of the Environment. As mentioned, the Ministry of the Environment appears to be the primary regulator for hydrogen production projects in Ontario based on a conducted interview. The water taking permit requirements appear to be based mainly on the volume of water used in the process.

Figure A-10. Flowchart for potential hydrogen production project approval, licencing, and permitting requirements in Ontario.



A.10 Prince Edward Island

A.10.1 Legislation and Regulators

Prince Edward Island's Environmental Protection Act (PEIEPA) [193], Water Act (PEIWA) [194], and their associated regulations may apply to hydrogen production from fossil fuels in the province. As with many Canadian provinces and territories, hydrogen production is not specifically mentioned in the legislation and regulations.

Approval for an undertaking under the PEIEPA must be obtained from the Department of Environment, Energy and Climate Action. The term "undertaking" in the PEIEPA refers to any construction, industry, operation, or other project that will or may have negative environmental impacts. Hydrogen production is not explicitly designated but could likely be considered an undertaking. The requirements for an undertaking proposal may include:

- An environmental impact assessment and statement; and
- Notifying the public of the proposal and allowing for comment.

A.10.2 Regulations

The Water Withdrawal Regulations [195] require a "person" (i.e., the facility developer/owner) to apply for a water withdrawal permit if the rate of withdrawal is more than 25 cubic metres per day. Commercial scale hydrogen production processes using water typically require hundreds or thousands of cubic metres of water per day, so the need for a permit would apply. The applicant may be required to complete tests, collect data, obtain information, or submit a drought contingency plan at the discretion of the minister.

Hydrogen production from fossil fuels may also be subject to the Air Quality Regulations (PEI Reg EC377/92) (e.g., CO, H_2S, and particulate emissions) [196].

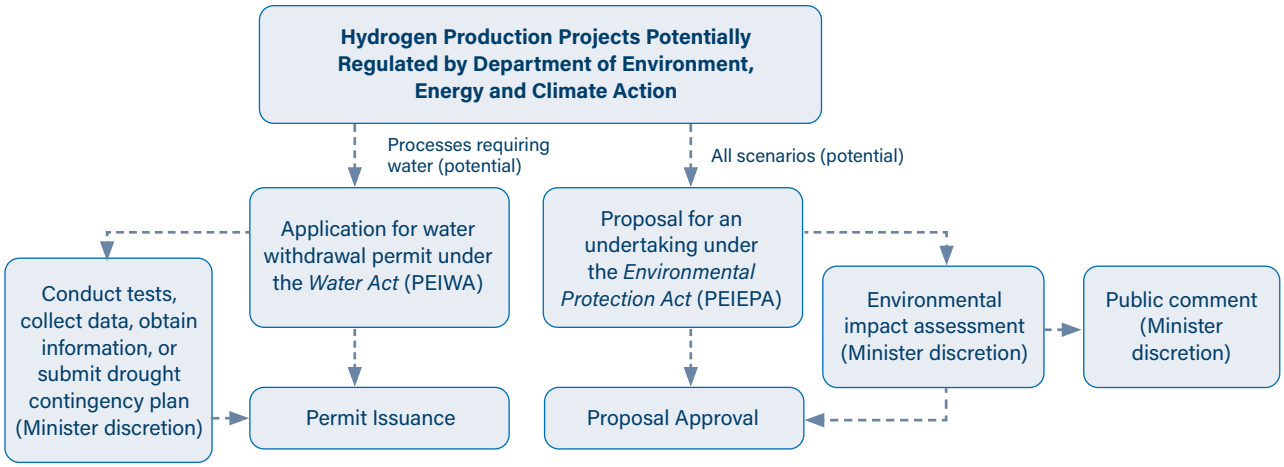
A.10.3 Recent Hydrogen Production Approvals

No recent approvals for hydrogen production from fossil fuels in Prince Edward Island were discovered in the research conducted for this report.

A.10.4 Approval Process

Figure A-11 shows the potential approval process for hydrogen production projects in Prince Edward Island.

Figure A-11. Flowchart for potential hydrogen production project approval requirements in Prince Edward Island.



A.11 Québec

A.11.1 Legislation and Regulators

Québec's Environment Quality Act (EQA) appears to be a comprehensive legislation regulating industrial facilities affecting the environment, water usage, and environmental assessment requirements in the province, which may apply to hydrogen production from fossil fuels [197]. Requirements for hydrogen production are specifically mentioned in the Regulation Respecting Mandatory Reporting of Certain Emissions of Contaminants into the Atmosphere, and are discussed further in Section A.11.2 [198].

The EQA requires a project proponent to obtain one or more authorizations from the Minister of the Environment, the Fight Against Climate Change, Wildlife and Parks. Authorization is required for the following activities that would likely be relevant to a hydrogen production plant using fossil fuels:

- Operation of an industrial establishment (e.g., the hydrogen production plant);
- Withdrawal of water including related works (e.g., for SMR and ATR);
- Management of hazardous materials (e.g., H_2 and H_2S);
- Installation and operation of equipment designed to prevent, abate, or stop the release of contaminants into the atmosphere (e.g., acid gas removal and flaring); and
- Operation of a residual materials elimination or reclamation facility (e.g., acid gas removal and flaring).

A single ministerial authorization may be the only requirement for all of these listed activities. However, the EQA refers specifically to a hazardous materials authorization elsewhere, which may be an additional requirement.

The EQA also provides extensive details regarding the requirements for an application for authorization. It is beyond the scope of this report to list all the details relevant to a hydrogen production project.

A.11.2 Regulations

The Regulation Respecting Mandatory Reporting of Certain Emissions of Contaminants into the Atmosphere lists the following requirements for all hydrogen production processes [198]:

- GHG emission reporting;
- Sampling, analysis, and measurement; and
- Methods for estimating missing data.

In addition, the following regulations under the EQA may apply to hydrogen production from fossil fuel projects:

- Regulation Respecting Private Waterworks and Sewer Services (e.g., firewater) [199];
- Clean Air Regulation (e.g., CH_4, CO, and H_2S emissions) [200];
- Regulation Respecting the Declaration of Water Withdrawals (e.g., for SMR or ATR) [201];
- Regulation Respecting the Regulatory Scheme Applying to Activities on the Basis of Their Environmental Impact (e.g., for project environmental impact assessments) [202];
- Regulation Respecting the Environmental Impact Assessment and Review of Certain Projects (e.g., H_2 production in refineries, plants that synthesize energy-producing gas, and chemical plants whose output is greater than 50,000 tonnes/year) [203];
- Regulation Respecting the Operation of Industrial Establishments (e.g., H_2 production in an iron or steel mill) [204];
- Regulation Respecting Hazardous Materials (e.g., H_2 production and handling) [205];
- Water Withdrawal and Protection Regulation (e.g., for SMR or ATR) [206]; and
- Regulation Respecting the Quality of the Atmosphere (e.g., for potential particulate matter emissions from methane pyrolysis) [207].

A.11.3 Cited Standards

The requirements for sampling, analysis, and measurement of hydrogen production in Québec's Regulation Respecting Mandatory Reporting of Certain Emissions of Contaminants into the Atmosphere cite the following standards [198]:

For solid feedstocks:

- ASTM D2013/D2013M, *Standard Practice for Preparing Coal Samples for Analysis*;
- ASTM D2234/D2234M, *Standard Practice for Collection of a Gross Sample of Coal*;
- ASTM D3176, *Standard Practice for Ultimate Analysis of Coal and Coke*;
- ASTM D6609, *Standard Guide for Part-Stream Sampling of Coal*;
- ASTM D6883, *Standard Practice for Manual Sampling of Stationary Coal from Railroad Cars, Barges, Trucks, or Stockpiles*; and
- ASTM D7430, *Standard Practice for Mechanical Sampling of Coal*.

For liquid feedstocks:

- ASTM D2597, *Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography*;
- ASTM D4057, *Standard Practice for Manual Sampling of Petroleum and Petroleum Products*;
- ASTM D4177, *Standard Practice for Automatic Sampling of Petroleum and Petroleum Products*;
- ISO 3170, *Petroleum Liquids — Manual Sampling*; and
- ISO 3171, *Petroleum liquids — Automatic Pipeline Sampling*.

For gaseous feedstocks:

- ASTM UOP539, *Refinery Gas Analysis by Gas Chromatography*; and
- GPA 2261, *Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography*.

A.11.4 Recent Hydrogen Production Approvals

No public disclosures of hydrogen production authorizations in Québec were discovered in the research conducted for this report, though the existence of hydrogen plants at refineries in Québec is known.

A.11.5 Authorization Review and Approval Process and Requirements

Fallon et al. [208] have published a brief overview of the authorization review and approval process and requirements in Québec.

Figure A-12 illustrates the potential approval, licencing, and permitting processes and requirements for hydrogen production project scenarios in Québec. The potential requirements are fairly straightforward in terms of a single ministerial authorization under the EQA. However, as noted in sections A.11.1 and A.11.2, the requirements for authorization are extremely detailed and many regulations may apply.

A.12 Saskatchewan

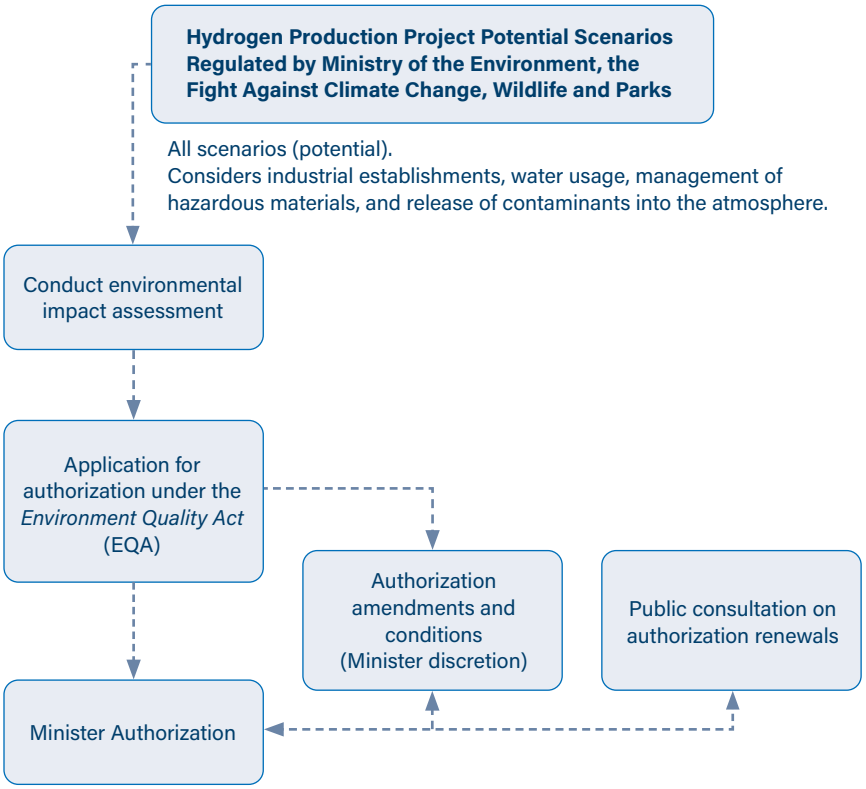
An overview of the regulatory considerations for hydrogen production from fossil fuels in Saskatchewan is provided in [96].

A.12.1 Legislation and Regulators

Saskatchewan's Oil and Gas Conservation Act (SKOGCA) [209], Water Security Agency Act (WSAA) [210], Environmental Management and Protection Act [211], and their associated regulations may apply to hydrogen production from fossil fuels in the province. As with many Canadian provinces and territories, hydrogen production is not specifically mentioned in the legislation and regulations.

The SKOGCA defines "non-oil-and-gas substance" as "any substance, other than oil and gas waste, from a prescribed industry," and "product" as a "commodity made from oil and gas" including "by-products derived from oil or gas" [96], [212]. These terms could be interpreted to include hydrogen production from fossil fuels. The Ministry of Energy and Resources issues licences to construct and operate oil and gas facilities [213], and an interview with staff from the Ministry of Energy and Resources confirmed that it is the relevant regulator for subsurface hydrogen production projects.

Figure A-12. Flowchart for potential hydrogen production project authorization requirements in Québec.



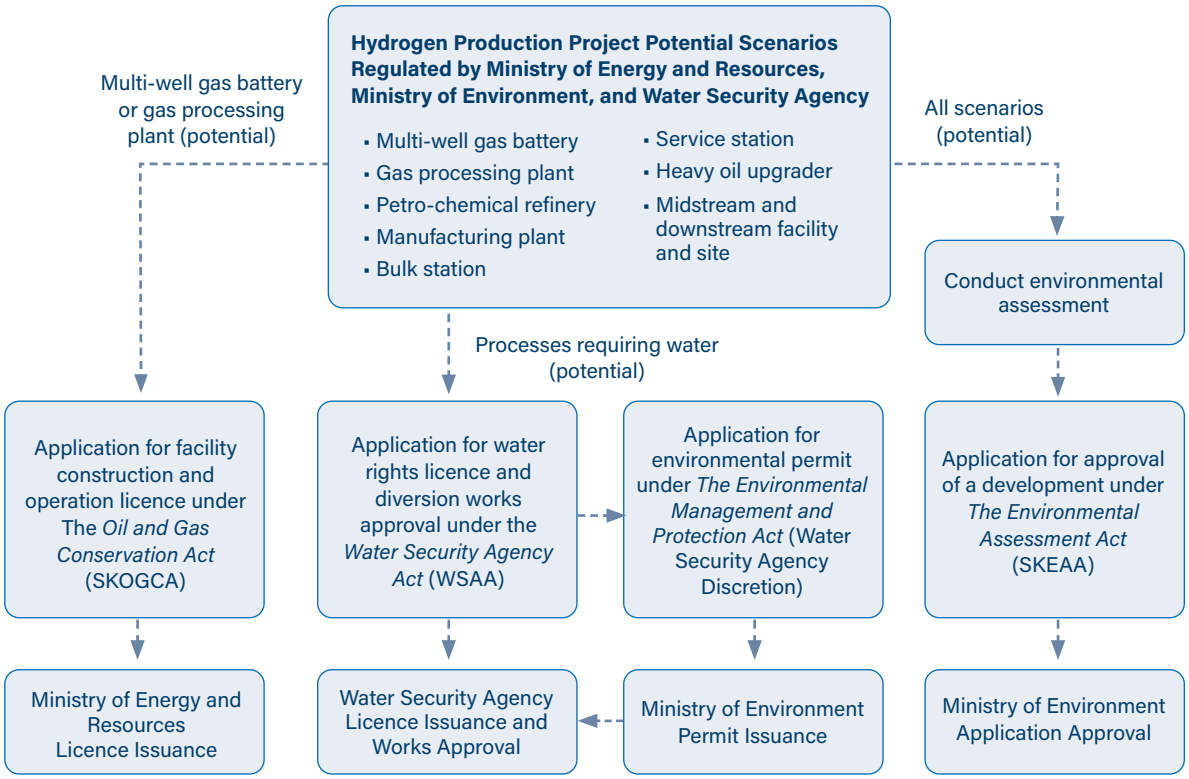
The Water Security Agency issues water rights licences in Saskatchewan and must give approval for construction and operation of water works under the WSAA [96], [210], [214]. Although hydrogen production is not mentioned in the WSAA or its associated regulations, it is expected that a hydrogen production process from fossil fuels requiring water would need to apply for a water rights licence and potentially for an approval for the diversion works [96]. This process would also initiate a public notification period [96]. Furthermore, the Water Security Agency has authority to refer an application to the minister responsible for the Environmental Management and Protection Act, which could result in the project proponent needing to apply for an environmental permit [96], [211].

Approval for a development under the Environmental Assessment Act (SKEAA) must be obtained from the Ministry of Environment [96], [215]. An interview confirmed that it is the relevant regulator for surface-based hydrogen production projects. The term "development" in the SKEAA has extensive scope and includes the following relevant meanings [215], which may almost certainly include hydrogen production projects from fossil fuels (though hydrogen is not explicitly mentioned):

- Substantially use any provincial resource;
- Cause the emission of any pollutants or create by-products;
- Involve a new technology concerned with resource use; and
- Necessitate a further development which is likely to have a significant impact on the environment.

Under this interpretation of a hydrogen production project as a development under SKEAA, the project proponent would need to conduct an environmental assessment.

Figure A-13. Flowchart for potential hydrogen production project approval, licencing, and permitting requirements in Saskatchewan.



A.12.2 Regulations

In Saskatchewan's Oil and Gas Conservation Regulations (SKOGCR), a "facility" is defined as "any building, structure, installation, equipment or appurtenance that is connected to or associated with the [...] production, [...] processing, [...] of oil, gas, water, products or other substances" [212]. A "person" (i.e., the facility developer/owner) must be issued a licence or exemption for a facility [96]. Although a hydrogen production plant could be interpreted as a facility, it is not explicitly specified in the regulation.

Saskatchewan's Directive PNG001: Facility Licence Requirements outlines requirements for a facility licencing document, including a process flow diagram, equipment spacing diagram, site survey, Directive S-20 documentation, air dispersion model, exemption requests, a waste processing facility application, a gas processing plant application for gas processing plants, and other general requirements [216]. Hydrogen production is not specifically mentioned in Directive PNG001, and therefore the need to apply for a facility licence for a hydrogen production plant under the directive could likely be context dependent and open to interpretation. A multi-well gas battery and gas processing plant each require a licence. Refineries, manufacturing plants, service stations, bulk stations, heavy oil upgraders, and all midstream and downstream facilities and sites are exempt from facility licencing requirements. Hydrogen production from fossil fuels could conceivably be implemented in all of these listed facilities.

A.12.3 Recent Hydrogen Production Approvals

Proton Technologies Canada operates a pilot demonstration in situ gasification project in an end-of-life heavy oil field near Kerrobert, Saskatchewan [52]. However, public disclosure on the application, approvals, licencing, and permitting for this project was not found during the research conducted for this report.

A.12.4 Approval and Licencing Processes and Requirements

Figure A-13 shows the potential approval, licencing, and permitting processes and requirements for hydrogen production project scenarios in Saskatchewan. The potential requirements and processes are relatively complex, as they are regulated by three ministries and agencies and appear to be highly context dependent.

A.13 Yukon

A.13.1 Legislation and Regulators

Yukon's Oil and Gas Act (YOGA) [217], Environment Act (YEA) [218], Waters Act (YWA) [219], and their associated regulations may apply to hydrogen production from fossil fuels in the province. As with many Canadian provinces and territories, hydrogen production is not specifically mentioned in the legislation and regulations.

The YOGA defines the following terms, which could be interpreted to include hydrogen production from gaseous or liquid fossil fuels:

- Gas: "natural gas and includes all substances, other than oil, that are produced in association with natural gas"; and
- Gas processing plant: "a plant [...] for the extraction from raw gas [...] of hydrogen sulphide, helium, ethane, natural gas liquids or other substances."

The YOGA requires a licence for the export of any products obtained by processing oil or gas associated with an "oil and gas activity," which includes gas processing plants. These requirements could be interpreted to include hydrogen production from fossil fuels. The Geothermal and Petroleum Resources Branch of the Department of Energy, Mines, and Resources issues licences for oil and gas activities [220].

The Yukon Water Board issues water licences in the territory under the YWA [221]. Although hydrogen production is not mentioned in the YWA or its associated regulations, it is expected that a hydrogen production process from fossil fuels requiring water would need to apply for a water licence. A public hearing may be required in some cases.

A permit for a development under the YEA must be obtained from the Department of Environment. The term "development" in the YEA means "any human project, industry, undertaking, enterprise or operation," which would almost certainly include hydrogen production projects from fossil fuels (though hydrogen is not explicitly mentioned). Under this interpretation of a hydrogen production project, the project proponent may need to conduct an assessment if the project is prescribed by regulation to be a "major development."

A.13.2 Regulations

The Gas Processing Plant Regulation [222] under the YOGA specifies detailed requirements for a processing plant licence application and construction and operation of a processing plant. The licence application requirements include: a management system, safety program, environmental protection program, a program for non-destructive examination of welded joints, quality control and quality assurance program, description of the processing facilities and control system, and information regarding venting and flaring. The regulation also specifies construction and operation requirements, including the explicit need for approval prior to start of operation.

The Waters Regulation [223] under the YWA prescribes the requirements for an undertaking involving the handling or storage of petroleum products, which may likely apply to hydrogen production processes from fossil fuels requiring water. The requirements include a plan for safe handling, storage, and disposal, and a contingency plan for containment and spill cleanup.

The Air Emissions Regulations [224] under the YEA may likely apply to hydrogen production from fossil fuels and may require an additional permit in addition to a development permit.

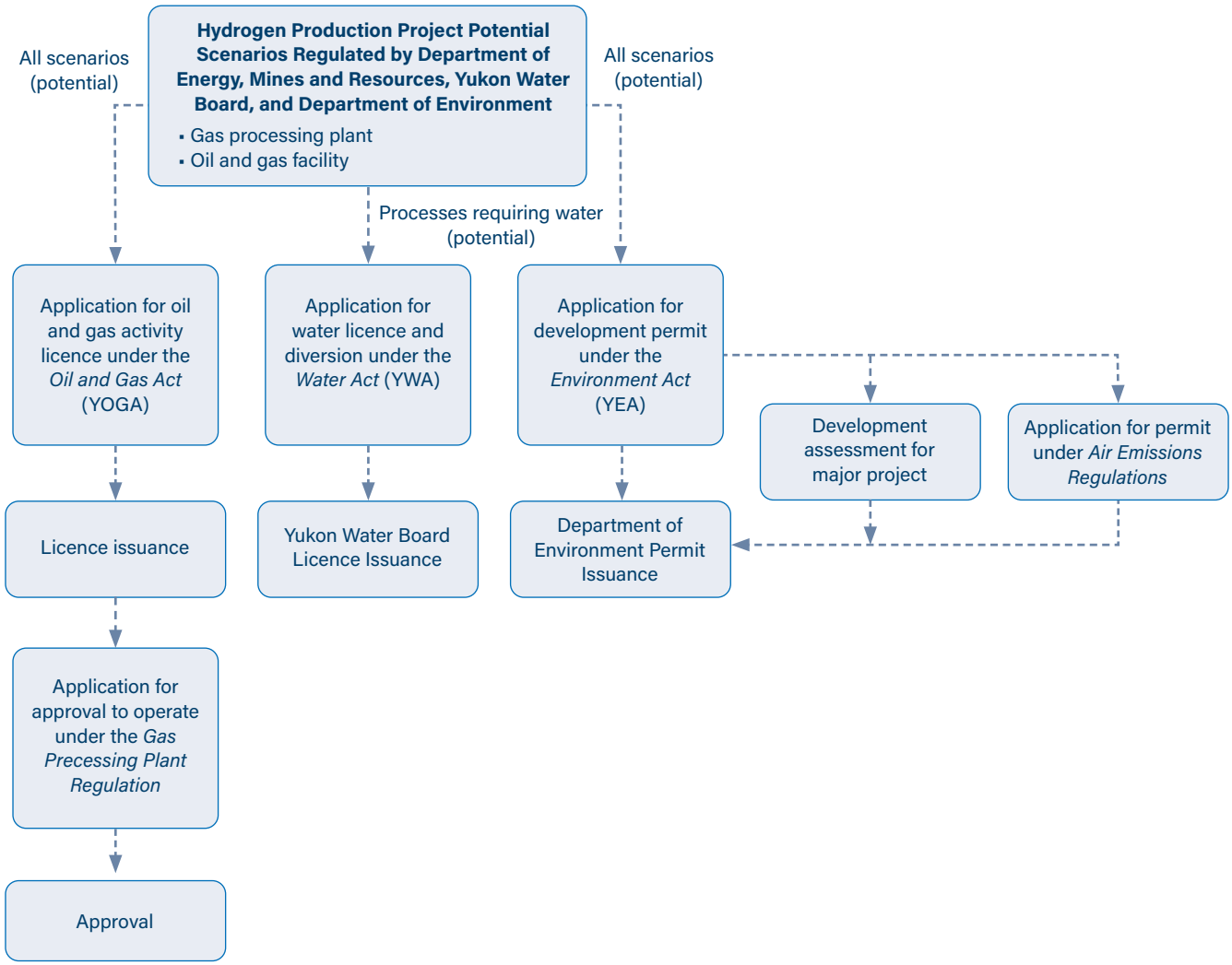
A.13.3 Recent Hydrogen Production Approvals

No recent approvals for hydrogen production from fossil fuels in Yukon were discovered in the research conducted for this report.

A.13.4 Approval and Licencing Processes and Requirements

Figure A-14 illustrates the potential approval, licencing, and permitting processes and requirements for hydrogen production project scenarios in Yukon. The potential requirements and processes are relatively complex, as they are regulated by three ministries and agencies.

Figure A-14. Flowchart for potential hydrogen production project approval, licencing, and permitting requirements in Yukon.



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