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Greenhouse gas reduction potential and cost-effectiveness of economy-wide hydrogen-natural gas blending for energy end uses

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ABSTRACT

North American and European jurisdictions are considering repurposing natural gas infrastructure to deliver a lower carbon blend of natural gas and hydrogen; this paper evaluates the greenhouse gas reduction potential and cost-effectiveness of the repurposing. The analysis uses a bottom-up economy-wide energy-systems model of an emission-intensive jurisdiction, Alberta, Canada, to evaluate 576 long-term scenarios from 2026 to 2050. Many scenarios were included to give the analysis broad international applicability and differ by sector, hydrogen blending intensity, carbon policy, and hydrogen infrastructure development. Twelve hydrogen production technologies are compared in a long-term greenhouse gas and cost analysis, including advanced technologies. Autothermal reforming with carbon capture provides both lower-carbon and lower-cost hydrogen compared to most other technologies in most futures, even with high fugitive natural gas production emissions. Using hydrogen-natural gas blends for end-use energy applications eliminates 1–2% of economy-wide GHG emissions and marginal GHG abatement costs become negative at carbon prices over $300/tonne. The findings are useful for stakeholders expanding the international low-carbon hydrogen economy and governments engaged in formulating decarbonization policies and are considering hydrogen as an option.

1. Introduction

In 2018, the global energy supply was sourced from oil (31%), coal (27%), natural gas (NG) (23%), and the remaining from nuclear, waste, and renewables (19%) [1]. Given that fossil fuels will eventually deplete and that the climate system is warming due to greenhouse (GHG) emissions from the use of fossil fuels, it makes sense to transition away from the use of fossil fuels to avoid severe irreversible impacts to ecosystems [2,3]. Hydrogen can play a significant role in this transition, for instance, by displacing gaseous fossil fuels, since its combustion produces low GHGs. However, hydrogen is not naturally widely available and so, to use it for energy, it must be produced by converting another energy form. Fortunately, low-carbon hydrogen can be produced with renewable electricity and may effectively integrate into renewable electricity systems [4,5]. Although this production method is not currently competitive at an industrial scale, it may be within the next decade [5]. Fossil fuel-based processes using carbon capture and sequestration (CCS) can also provide low-carbon hydrogen; however, there is debate over the efficacy of CCS as the long-term effectiveness of sequestering carbon is still uncertain [6].

Many jurisdictions currently rely on NG in homes, buildings, and industry and have developed robust NG transmission and distribution infrastructure. A transition to low-carbon heating may require eliminating NG. There has been interest across Europe and North America to investigate using NG infrastructure to deliver hydrogen by blending it with NG (also referred to as hythane) [7]. For instance, hydrogen-natural gas blending pilot projects in the United Kingdom

Abbreviations: ATR, autothermal reforming; B, baseline scenario; CAD, Canadian dollar; CAPX, capital cost; CC, carbon capture; CCS, carbon capture and storage; CL-POM, chemical looping partial oxidation of methane; CHOPS, cold heavy oil production with sand; CP, carbon policy; CP0, carbon price policy of $0/t; CP50, carbon price policy of $40/t in 2021 and $50/t from 2022 to 2050; CP170, carbon price policy of $40/t in 2021, $50/t in 2022, and rising linearly to $170/t by 2030, then increase with inflation; CP350, carbon price policy of $40/t in 2021, $50/t in 2022, and rising linearly to $350/t by 2030, then increase with inflation; CRF, capital recovery factor; HDSAM, Argonne National Laboratory's Hydrogen Delivery Scenario Analysis Model; IPCC, Intergovernmental Panel on Climate Change; GERG, Groupe Européen de Recherches Gazières; GHG, greenhouse gas; LEAP, Low Emissions Analysis Platform; NEMO, Next Energy Modelling system for Optimization; NG, natural gas; NGD, natural gas decomposition; NPV, net present value; OPX, operating cost; *S*, scenario; SAGD, steam assisted gravity drainage; SMR, steam methane reforming; SI, supplementary information; UCG, underground coal gasification; UK, United Kingdom; WTC, well-to-combustion.

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Quantities

Variables and parameters

$\%E$	energy share
A	activity
AB_f	Alberta installation factor
$BaseYear$	start year of the analysis timeframe that is used for net present value calculations
cap	capital cost
CP	carbon price
D	pipeline diameter
e	pipeline efficiency
$\dot{E}$	energy flow rate
E_{B_N}	GHG emissions of baseline scenario
E_{eU}	GHG emissions of electricity supply
E_{H_2d}	GHG emissions of hydrogen distribution (as hythane)
E_{H_2t}	GHG emissions of hydrogen transmission
E_{H_2p}	GHG emissions of hydrogen production
E_{HgC}	GHG emissions of hythane gas combustion
E_{NgU}	GHG emissions of natural gas supply
E_S	GHG emissions of alternative scenario
ED	energy demand
ED_{H_2}	energy demand of hydrogen
ED_{NG}	energy demand of natural gas
ED_{H_2t}	demand of hydrogen for transmission
EF_{H_2D}	emission factor for fugitive emission reduction due to hydrogen blending
EF_{H_2t}	emission factor for fugitive emissions from hydrogen transmission
EF_{NgC}	emission factor for natural gas combustion
EF_{NgU}	emission factor for natural gas upstream emissions
EF_x	emission factor for hydrogen production
$EndYear$	final year in analysis timeframe
G	specific gravity
i	interest rate
I	energy intensity
H_b	gas energy content reduction due to hydrogen blending
L	pipeline length
mac	marginal abatement cost
$mNPV$	marginal net present value
m_s	GHG mitigation of alternative scenario
n	lifetime
NPV_{eU}	net present value of electricity production
NPV_{H_2d}	net present value of hydrogen distribution
NPV_{H_2p}	net present value of hydrogen production
NPV_{H_2t}	net present value of hydrogen transmission
NPV_{HgC}	net present value of hythane gas combustion
NPV_{NgC}	net present value of natural gas combustion
NPV_{NgU}	net present value of natural gas supply
op	operating cost
P_b	pipeline reference pressure
P_1	pipeline inlet pressure
P_2	pipeline outlet pressure
Q	flow rate
SC_{Ng}	supply cost of natural gas
t	year
T_b	reference temperature
T_a	average gas temperature
v	volume share
Z_a	compressibility factor

Sets

B_N	baseline scenario
d	end use device
f	fuel
H_2t	hydrogen transmission pipeline
S	alternative scenario
t	time
x	hydrogen production technology

(UK) [8], Germany [9], and Canada [10] began in 2020 and are ongoing. There is also interest in using autothermal reforming (ATR) technology to produce hydrogen since it can enable up to 95% of carbon dioxide emissions to be captured at lower costs than steam methane reforming (SMR, the primary method used to produce hydrogen) [11]. Yet, research is lacking around the GHG reduction potential and cost-effectiveness of hydrogen-NG blending, especially if using advanced technologies such as ATR. This research gap is addressed in this article to guide international decarbonization efforts.

Studies that considered using hydrogen for energy applications, and studies investigating the technical feasibility of hydrogen injection into NG pipelines were identified and reviewed. Several review studies summarize the research on the hydrogen economy. Ten review papers from the past decade were reviewed to identify relevant studies and gauge the state of the art. Dagdougui reviewed methods for modelling hydrogen infrastructure [12]. Bockris reviewed the history of the hydrogen economy concept [13]. Ball and Weeda focussed their review on hydrogen use in the transportation sector [14]. Moliner et al. compared prior hydrogen outlooks with realized real-world information and provided an updated outlook for the roles that hydrogen might play in the coming decades [15]. Abdalla et al. provided a high-level review of hydrogen production, transport, and applications [16]. Hanley et al. reviewed studies and modelling methods in which hydrogen is the focus in low carbon pathways [17]; the marginal abatement costs were also reviewed, and an extremely wide range of result values was found. Quarton and Samsatli reviewed energy system modelling studies, economic assessments, and identified and reviewed over 130 power-to-gas real-world projects, 25 of which included the injection of hydrogen into gas grids [18]. Chapman et al. reviewed case studies in which the penetration of hydrogen into different parts of the economy was assessed and concluded that the expected costs of hydrogen in the future are still a key barrier to wide-scale adoption [19]. Quarton et al. detailed the modelling methods and limitations for conducting scenario analyses on hydrogen pathways and discussed a set of useful best practices [20]. Blanco and Faaij reviewed studies that consider hydrogen storage as part their models and quantified the level of storage needed for different levels of renewable generation [21]. Yue et al. conducted a detailed technical review of state-of-the-art hydrogen technologies and concluded that water resource availability, cost, and performance of hydrogen technologies have not developed enough to enable the wide adoption of hydrogen economies [22].

Most energy systems research on hydrogen systems began within the last two decades, as confirmed by Samsatli and Samsatli [23]. Two modelling approaches have been used that consider the entire hydrogen energy supply system over a multi-year time horizon: hydrogen supply chain models and energy systems models; both have used optimization-based modelling frameworks. Optimization-based models minimize an objective function, typically the system cost, to arrive at a least-cost energy system configuration. This approach enables the modeller to conduct scenario analysis because the system configuration changes depending on the inputs, such as GHG reduction targets, technology availability, or carbon price. These optimization-based energy supply chain models and optimization-based energy system models are the norm for assessing integrated hydrogen systems and comparing long-term hydrogen scenarios. Supply chain models can have fine geographical and temporal resolutions suitable for planning or studying potential physical hydrogen networks. In contrast, energy systems models can offer more comprehensive representations of energy systems and simulate over a longer time horizon leading to insights useful for high level policy making.

For the hydrogen supply chain models, Quarton and Samsatli developed an optimization model of the value chain for hydrogen providing heat in Great Britain [23]. The modelling considered the entire hydrogen value chain and showed that 20% of heat demand might be met by hydrogen in an optimal mix of hydrogen and electricity-based heat; the hydrogen in this study was supplied through electrolysis, and hydrogen storage was key to enabling the 20% share, as, without it, the share of hydrogen-based heat reduced. The authors also investigated repurposing the natural gas grid for hydrogen. Quarton and Samsatli used a smilar model to analyse the hydrogen value chains of wind electrolysis with hydrogen storage and compare them with hydrogen produced through SMR with CCS and hydrogen storage under a decarbonization constraint [24]. The study found the wind-electrolysis-storage pathways optimal under baseline conditions, and the model selected electrolysis for long-term decarbonization over SMR + CCS to meet GHG emission constraints on heat and power. One key factor of these results is that the model uses high natural gas prices (about 9 Canadian dollars (CAD)/GJ in the UK compared to about 2 CAD/GJ in Alberta, Canada). The injection of hydrogen into natural gas networks resulted in additional energy system costs totalling 11–14 pounds per MWh of hydrogen injected. Still, hydrogen was shown to play a key role in achieving a net-zero GHG emission target by increasing system flexibility with hydrogen storage. The study did not consider hydrogen produced from advanced low-carbon natural gas-based technologies, such as ATR-CCS. Quarton and Samsatli further developed their model to examine hydrogen policies to reach net-zero by 2050 [25]. They found that a carbon price of over 300 pounds per tonne in 2050 was needed to achieve a net-zero target. They also found that consumer bills for heat from hydrogen could be 50% greater than if the heat were electric. These modelling approaches are essential for simulating and planning physical hydrogen networks since they consider the spatial and temporal aspects of the system, which is important when considering power-to-gas. Colbertaldo et al. modelled long-term scenarios for Italy considering hydrogen and electricity as an integrated system focusing on power-to-gas [26]. De-León et al. also used a hydrogen supply chain model to analyse scenarios in France [27]. Ogbe et al. modelled power-to-gas-based hydrogen injection into the natural gas pipeline system of Ontario, Canada, using a steady state model [28]; GHG reduction was not covered but was recommended for further research. Quarton et al. also summarized global hydrogen use models and scenarios [20].

For energy system models, McCollum et al. included hydrogen pathways in their optimization-based assessment of deep decarbonization for California [29]. Yang and Ogden took a similar approach, and used a California hydrogen-centred optimization model to study SMR, biomass, underground coal gasification (UCG), and electrolysis pathways [30]. Dodds and McDowall used a UK-based MARKAL model to assess decarbonization pathways comparing injecting bio-methane, injecting hydrogen, or completely converting gas infrastructure to hydrogen [31]. They conclude that converting the grid to hydrogen is the only cost-optimal way to avoid abandoning the infrastructure in favour of other more cost-effective technology routes. Dodds and Demoullin, and Cerniauskas et al. assessed gas network conversion to hydrogen [32,33]. McPherson et al. used a MESSAGE framework to analyse long-term hydrogen scenarios involving a range of energy storage and renewable energy sources [34]. Welder et al. simulated a power-to-gas energy system for Germany [35]. Colbertaldo et al. considered variable hydrogen content in the natural gas grid but focused on assessing the role of gas combined cycle turbines in a future with high shares of renewable electricity [36].

As to the extent that blending hydrogen into natural gas networks is feasible, Abeysekera et al. simulated hydrogen injection up to 20% by volume in a low pressure gas network and concluded that the impacts to pipeline operation can be mitigated by selecting appropriate injection points [37]. Abeysekera et al. also analysed the impact that the injection of 10% hydrogen has on the steady state gas flow parameters in decentralized and centralized injection [38]. Santoli et al. discussed safety and the technical ability of existing equipment to adapt to a blended gas and suggested a limit of 20% for gas distribution grids [39]. Guandalini et al. simulated the variation in energy content of a blended gas considering the variable consumption by residential and industrial users [40]. Ogden et al. concluded that pure natural gas pipeline infrastructure would be needed to use hydrogen at a large scale [41]. Others have also studied the operation of pipelines under blending [18,28,42–44]. Testing shows that appliances should be able to safely handle up to 15% hydrogen blends [45]. HyDeploy examined twelve residential heaters, four furnaces, four boilers, two water heaters, and two unvented space heaters with 5% and 15% hydrogen blends [46]. Their results indicate that 15% hydrogen will not impact the safe operation of any of the devices but will decrease the heat output by 4–5%. In the UK, all appliances sold after 1996 can handle up to 23% hydrogen following Europe's 1990 Gas Appliance Directive [47]. Also in the UK, HyDeploy is running a 16-month pilot at Keele University to examine the long-term impact of 20% hydrogen blending on appliances, and a 10-month pilot plan is underway to blend 20% hydrogen in Winlaton's natural gas network [48,49]. In the European Union, THyGa initiated a study in January 2020 to run experiments on 100 appliances to determine appropriate safety limits [49]. Overall, residential appliances should be able to handle up to 20% hydrogen blends, but it is uncertain if all industrial equipment can handle up to 20%. There are questions about whether device modifications are needed to use hythane in steam generators in the heavy oil sector. Hydrogen has a longer flame length, higher flame temperature, and lower emissivity than natural gas. The higher flame temperatures may increase NOx emissions, while the flame length and emissivity will affect heat transfer within the boiler. However, at hydrogen concentrations below 10%, there are negligible impacts on flame length, temperature, and emissivity. Blending hydrogen with natural gas will affect the burner's fuel-to-air ratio. If 20% hydrogen is used with no adjustments, the boiler efficiency could decrease by as much as 13% [50]. However, if the air-to-fuel ratio is optimized appropriately, a 3% boiler efficiency increase may be feasible. For optimal performance, Leicher et al. recommended installing adequate onsite measurement equipment to automatically adjust the air-to-fuel ratio based on the gas composition [50].

To summarize the knowledge gaps found in the reviewed literature, all the studies reviewed have used either renewable energy-based power-to-gas or SMR to produce hydrogen, and much of the focus has been on electrolytic hydrogen along with intermittent wind and hydrogen storage. While these provide highly valuable insights, there is no assessment of blending hydrogen from natural gas via ATR-CCS or other advanced technologies. Also, previous GHG studies on NG-hydrogen blending used only optimization models. There is limited application of other energy system models to determine metrics that may complement the existing metrics by the established literature. There is also limited insight in the literature on economy-wide hydrogen blending in jurisdictions outside the UK, as well as of marginal abatement costs and GHG emission abatement potential across highly fossil-fuel intensive economies, such as Canada. Countries across Europe and North America are exploring blending low-carbon hydrogen into their existing natural gas networks as governments progress towards net-zero emissions. Therefore, the following novel contributions are provided to aid in low-carbon hydrogen policy formation:

- Using low-carbon hydrogen to blend with natural gas for the purpose of reducing an economy's GHG emissions has been a topic of limited study. Only renewable electricity-based electrolysis and SMR-CCS

have been considered to produce low-carbon hydrogen in the existing studies. This paper considers 12 different low-carbon hydrogen production technologies, all of which have different feedstock and fuel requirements, cost, and emissions characteristics, and we compare their effectiveness of reducing GHG emissions if their hydrogen is blended with natural gas.
- A novel method that integrates fundamental process models, fundamental engineering equations, energy and emissions accounting fundamentals, and a systems-based framework is used to model the entire supply chain from hydrogen production to consumption across an entire economy.
- The marginal abatement costs and GHG reduction potential of 576 scenarios are provided, each scenario representing a distinct set of conditions/inputs making the results applicable broadly to many sectors and jurisdictions internationally.

The overall purpose of this research is to determine the GHG emission mitigation potential and cost-effectiveness associated with economy-wide low-carbon hydrogen blending into natural gas-consuming end use energy applications. The specific objectives are:

- Model a suite of low-carbon hydrogen technologies to determine long-term production cost and GHG footprints;
- Develop and evaluate long-term scenarios that consider different end uses, blend rates (1%, 5%, 10%, 15%), distances between hydrogen production and use (central, semi-central, and decentralized), hydrogen production pathways, and carbon reduction policies;
- For each scenario, determine the potential for GHG mitigation and associated costs for low-carbon hydrogen integration through blending with natural gas for energy end use consumption.

Alberta, Canada, a highly emission-intensive region that primarily uses NG for building and industry heating [51], was chosen as the case study region for the analysis. Canada ranks 4th globally in the production of natural gas and Alberta is a western Canadian province that produces 71% of Canada's natural gas (2019 data) [52]. Canada produces 5–6% of global hydrogen, or ~4 million tonnes (Mt) annually, over 60% of which occurs in Alberta mostly due to heavy oil upgrading and ammonia production. SMR is used to produce most of the hydrogen in Alberta. Two large carbon capture and storage projects, the Carbon Trunk Line [53] and Quest [54] are located in Alberta. The Carbon Trunk Line is the world's largest pipeline transporting anthropogenic CO_2 (14.6 Mt per year capacity). Currently, 1.6 million tonnes per year of CO_2 is captured and used, then stored through enhanced oil recovery. The project was designed for the connection of future facilities. The Quest project has a cumulative CO_2 storage capacity of 17 Mt. Alberta has a robustly developed NG industry and low NG prices, as well as experience with carbon capture and storage; the 5-year average (2016–2020) price benchmark for western Canadian NG is $1.89/GJ [55] and the 5-year average (2016–2020) supply cost is $1.67/GJ [56]. The Canadian government has recently released The Hydrogen Strategy for Canada, envisioning a significant scale-up of the current hydrogen economy [57]. To further bolster this, the federal government announced an investment of $1.5 billion in low-carbon and zero-emission fuels and $287 million for a zero-emission vehicles program [58]. Moreover, the provincial Alberta government has indicated an interest in expanding hydrogen production for export and use in energy applications by leveraging existing natural gas production, transmission, and distribution infrastructure and world-class experience with carbon capture and storage [59,60]. Alberta also produces, upgrades, and refines oil sands, which use substantial amounts of natural gas in extraction and upgrading processes. Air Products recently announced a multi-billion dollar plan to build a state-of-the-art net-zero hydrogen production facility in Alberta using autothermal reforming technology with carbon capture and storage [61]. For the above reasons, Alberta is a suitable case study area for this research.

2. Methods and data

2.1. Framework for GHG mitigation scenario analysis of economy-wide hydrogen-NG blending

Fig. 1 illustrates the analysis framework at a high level. This framework captures the system-wide GHG emissions (cradle-to-grave) associated with economy-wide hydrogen-NG blending scenarios. The annual NG demands to 2050 were calculated (process 1) based on economic activity and energy intensity of the modelled end-use devices in each sector. The demands are met by upstream processes (process 2–4). In the baseline (B) scenario, NG demand is met through extraction, processing, and the delivery of the NG to the consumption points (process 2-B). For the hythane scenarios (S), a portion of the NG energy demand is met with hydrogen, blended into NG (process 2-S). For process 2-S, blending hydrogen with NG begins at a relatively small scale in 2026 and is scaled up to the prescribed blend rate by 2030. For example, for a scenario with 15% hythane, blending begins at a rate of 3% hydrogen in 2026 and is scaled up from 3% per year to 15% in 2030.

To supply hydrogen for blending during process 2, pure hydrogen pipelines transport hydrogen from production to the blend point (process 3). A short and a long distance between production and blend point was used to provide a reasonable range of result values, considering that hydrogen production could be centralized or semi-centralized. Existing NG distribution infrastructure is used to supply hythane to end users. This approach does not fix any locations of supply and consumption; however, to determine a reasonable range of distances, example locations can be developed to align with present industrial zones/hydrogen production clusters and possible consumer clusters. For Alberta, the long-distance hydrogen transmission pipeline distance (centralized case) is based on the approximate distance between Alberta's Industrial Heartland of Fort Saskatchewan and Calgary, ~337 km. The short-distance hydrogen transmission pipeline (semi-centralized case) assumes that hydrogen production facilities are located close to the point of use, for example, production in the Industrial Heartland and consumption by industrial facilities nearby or production at Fort Saskatchewan and consumption in Edmonton, Alberta, ~37 km. Hydrogen transmission pipelines are assumed to be newly built to transport hydrogen from the production facility to the blending point. Hydrogen supply could also occur with electrolyzers at the site of consumption (no pipelines) through a decentralized approach; these scenarios are compared to those using NG infrastructure. This analysis provides a comparative assessment of centralized and semi-centralized approaches with a decentralized approach.

Process 4 produces the required hydrogen for transmission to the blend points. Because there are many established and emerging hydrogen production processes, and each production method has unique cost, energy use, and emissions characteristics depending on the jurisdictional energy system, the long-term cost and GHG emission footprints of 12 different pathways were evaluated through a combination of process modelling, techno-economic assessment, and GHG footprint assessment. ATR-CCS, SMR-CCS, and grid-electrolysis were selected to supply hydrogen for the scenarios. For scenarios using NG-based hydrogen, an assumption is made that ATR-CCS will not be commercially available for production until 2030 because of the novelty of the technology application and construction time, so SMR-85%CCS is used for 2026–2030. Other hydrogen production technologies were assessed (summarized in the SI) but were deemed not commercially viable for scale-up and adoption within the assessment timeframe; these include UCG, biomass gasification and pyrolysis-based pathways, solar-based pathways, and nuclear-based pathways.

Table 1 gives the scenario details and naming convention. The time horizon of the present study is 2026–2050; 2026 allows 5 years for the required governance, feasibility studies, infrastructure, and standards to be developed from 2021. This analysis considers system-wide implications, that is, the entire hydrogen supply chain and all connected energy

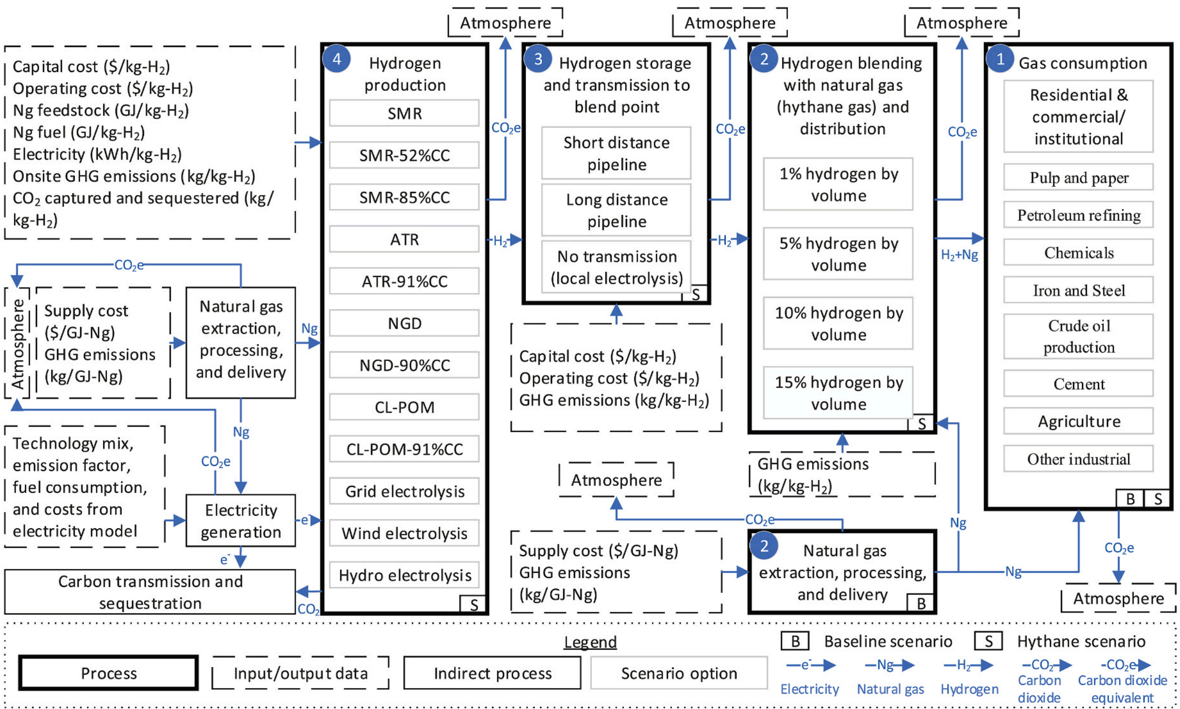


Fig. 1. Developed GHG mitigation analysis framework for economy-wide hydrogen-NG blending.

systems. All energy supply chain systems, both direct and indirect, were modelled from the bottom up using a fundamentals approach. There are separate scenarios for each sector and scenarios combining all sectors (economy-wide scenarios). Sensitivity scenarios were also developed for the economy-wide scenarios, these scenarios are representative of all other scenarios, and the impact of changing key input variables has similar effects at different scales. The variables tested for sensitivity are NG supply cost, NG supply emissions (from production, processing, transmission, and distribution), cost variables of hydrogen production facilities, cost variables of CCS infrastructure, and hydrogen storage costs (on-site and system-wide).

Four long-term carbon policy (CP) environments were designed to cover a wide range of possibilities so that the results remain applicable regardless of policy change. Energy prices and the carbon footprint of the electricity and NG supply endogenously change in the model depending on the carbon price environment. The four carbon policy environments are: CP0: $0/t; CP50: $40/t in 2021 and $50/t from 2022 onward; CP170: $40/t in 2021, $50/t in 2022, and rising linearly to $170/t by 2030; CP350: $40/t in 2021, $50/t in 2022, and rising linearly to $350/t by 2030. Low carbon prices (CP0 and CP50) were considered to cover polices that use a performance benchmark approach where a regulator may not charge, or charge less, for carbon produced from facilities performing better than the benchmark. The carbon price is applied system-wide to any GHG emissions.

2.2. Energy systems model

The model used to conduct the analysis in this study was developed using the Low Emissions Analysis Platform (LEAP) [62]. LEAP is a flexible and transparent accounting-based energy modelling platform with optimization-based electricity system modelling capabilities, making it suitable for this study. An extensive energy model of the jurisdiction of interest (Alberta, Canada) was previously developed and validated by conducting numerous GHG mitigation studies that consider the different sectors across an economy. Model development can be found in previously published studies on energy use [63,64], GHG emissions [51], and scenario analysis for the residential [65], commercial [66], oil sands [67–70], mineral mining [71,72], petroleum refining [73], iron and steel [74], cement [75], chemical [76], electricity [77,78], and agricultural [79] sectors. In this previous research, detailed bottom-up energy demand trees and energy supply processes were designed, modelled, and validated, capturing over 90% of the energy flow in Canada (and Alberta) through a first-principles approach. Energy demands (*EDs*) of an end use (*d*) were calculated with the fuel (*f*) energy intensity (*I*) and activity (*A*) of the end use in Eq. (1); the end uses, energy intensities, and activity are described in detail in the studies referred to above. Section 2.6 describes the considered end uses.

$$ED_{d,t,f} = I_{d,t,f} * A_{d,t} \quad (1)$$

The LEAP-Canada model was adapted for this study. The green modules shown in Fig. 2 were modified to model the hydrogen processes outlined in the analysis framework. The calculation procedures used by the LEAP-Canada model are, in brief: the calculations begin for energy demands, emissions, and costs at a specific energy-consuming process/device (end-user) level and the results are aggregated upwards to attain results at the sector or regional level; the calculated energy demands prompt the energy supply processes to respond and, since the model is systems-based, the integrated nature and feedback loops of energy supply chains are captured in the model design and execution (energy resource extraction - processing - transformation - transmission & distribution - consumption). The Next Energy Modelling system for Optimization (NEMO) [62] was used for electricity system modelling within LEAP-Canada in the present analysis, solved with CPLEX. The detailed calculation procedures for LEAP can be readily found [80]. The model setup for this study uses eight time slices (day and night for each season) for which electricity and NG demand profiles are used. These temporal aspects of the model are relevant for NG demand [81] and electricity load and generation [77]. NG demand impacts hydrogen demand for scenarios and associated upstream processes. Electricity load is annually distributed according to the jurisdiction's electricity load curve. Wind and solar electricity generation also follow domestic temporal availability.

The global model data relevant to this study are in Table 2 and align with the input data requirements given in the analysis framework

Table 1
Hythane scenarios (naming convention: Ω_β_Ψ_ϕ_α).

Hythane consumption sector	Sector abbreviation (Ω)	Volume of hydrogen blended with NG (β)	Distance between hydrogen production and blend point (Ψ)	Hydrogen production method (ϕ)[a]	Carbon price (α)	Number of scenarios (total = 420)[d]
Residential and commercial/institutional	ResCom	1% (hyth1) 5% (hyth5) 10% (hyth10) 15% (hyth15)	37 km transmission (37kmTrans) 337 km transmission (337kmTrans)	2026–2030: SMR-85%CCS 2030–2050: ATR-91%CCS	CP0 CP50 CP170 CP350	32
Pulp and paper	PulpPaper	hyth1 hyth5 hyth10 hyth15	37kmTrans 337kmTrans	2026–2030: SMR-85%CCS 2030–2050: ATR-91%CCS	CP0 CP50 CP170 CP350	32
Petroleum refining	PetRef	hyth1 hyth5 hyth10 hyth15	37kmTrans 337kmTrans	2026–2030: SMR-85%CCS 2030–2050: ATR-91%CCS	CP0 CP50 CP170 CP350	32
Chemicals	Chem	hyth1 hyth5 hyth10 hyth15	37kmTrans 337kmTrans	2026–2030: SMR-85%CCS 2030–2050: ATR-91%CCS	CP0 CP50 CP170 CP350	32
Iron and steel	Steel	hyth1 hyth5 hyth10 hyth15	37kmTrans 337kmTrans	2026–2030: SMR-85%CCS 2030–2050: ATR-91%CCS	CP0 CP50 CP170 CP350	32
Crude oil production	OilSands	hyth1 hyth5 hyth10 hyth15	37kmTrans 337kmTrans	2026–2030: SMR-85%CCS 2030–2050: ATR-91%CCS	CP0 CP50 CP170 CP350	32
Oil sands surface mining subsector	OS SM	hyth1 hyth5 hyth10 hyth15	37kmTrans 337kmTrans	2026–2030: SMR-85%CCS 2030–2050: ATR-91%CCS	CP0 CP50 CP170 CP350	32
Oil sands in situ extraction subsector (cyclic steam stimulation [CSS], steam-assisted gravity drainage [SAGD], primary)	OSInSitu	hyth1 hyth5 hyth10 hyth15	37kmTrans 337kmTrans	2026–2030: SMR-85%CCS 2030–2050: ATR-91%CCS	CP0 CP50 CP170 CP350	32
Oil sands in situ extraction subsector – SAGD process	SAGD	hyth1 hyth5 hyth10 hyth15	37kmTrans 337kmTrans	2026–2030: SMR-85%CCS 2030–2050: ATR-91%CCS	CP0 CP50 CP170 CP350	32
Cement	Cement	hyth1 hyth5 hyth10 hyth15	37kmTrans 337kmTrans	2026–2030: SMR-85%CCS 2030–2050: ATR-91%CCS	CP0 CP50 CP170 CP350	32
Agriculture	Ag	hyth1 hyth5 hyth10 hyth15	37kmTrans 337kmTrans	2026–2030: SMR-85%CCS 2030–2050: ATR-91%CCS	CP0 CP50 CP170 CP350	32
Other industrial	OtherInd	hyth1 hyth5 hyth10 hyth15	37kmTrans 337kmTrans	2026–2030: SMR-85%CCS 2030–2050: ATR-91%CCS	CP0 CP50 CP170 CP350	32
All sectors combined[b]	Comb	hyth1 hyth5 hyth10 hyth15	37kmTrans 337kmTrans	2026–2030: SMR-85%CCS 2030–2050: ATR-91%CCS	CP0 CP50 CP170 CP350	32
All sectors combined[b]	Comb	hyth15	0	2026–2050: Decentralized electrolysis (DecentralElect)	CP170 CP350	2
All sectors combined[b]	Comb	hyth15	0	2026–2050: Decentralized electrolysis (DecentralElect_WND)[c]	CP170 CP350	2

a: For scenarios with SMR-85%CCS and ATR-91%CCS, ϕ is omitted from the name. **b**: Residential, commercial, agriculture, construction, pulp and paper, smelting and refining, petroleum refining, chemicals, iron and steel, other manufacturing, mining, cement, resource extraction. **c:** aggressive wind power deployment. **d**: remaining 156 scenarios are given in the sensitivity analysis section, totalling 576 scenarios.

(Fig. 1). These include NG and electricity cost, carbon price, and emission details over the study period. All costs are in 2020 CAD. Retail NG price projections use a 23% percent markup of the supply costs (average markup between 2005 and 2018), derived from the difference between the industrial end use prices [82] and supply costs [56], and include additional costs for carbon charges during NG supply. The table also details the four different carbon policy assumptions used in the modelling. NG extraction, processing, and the delivery emission factor (which includes fugitive venting, flaring, and fugitive emissions) were estimated from the 5-year-average (2015–2019) of GHG emissions from NG production, processing, transmission, distribution [83], marketable NG production [82], and regulated emission reductions [84]. This emission factor is within ranges found in a study by Raj et al. [85]. Retail electricity price projections use a 78% percent markup of the endogenous production costs (average markup between 2015 and 2019), derived from the difference in industrial end use prices [82] and the model's

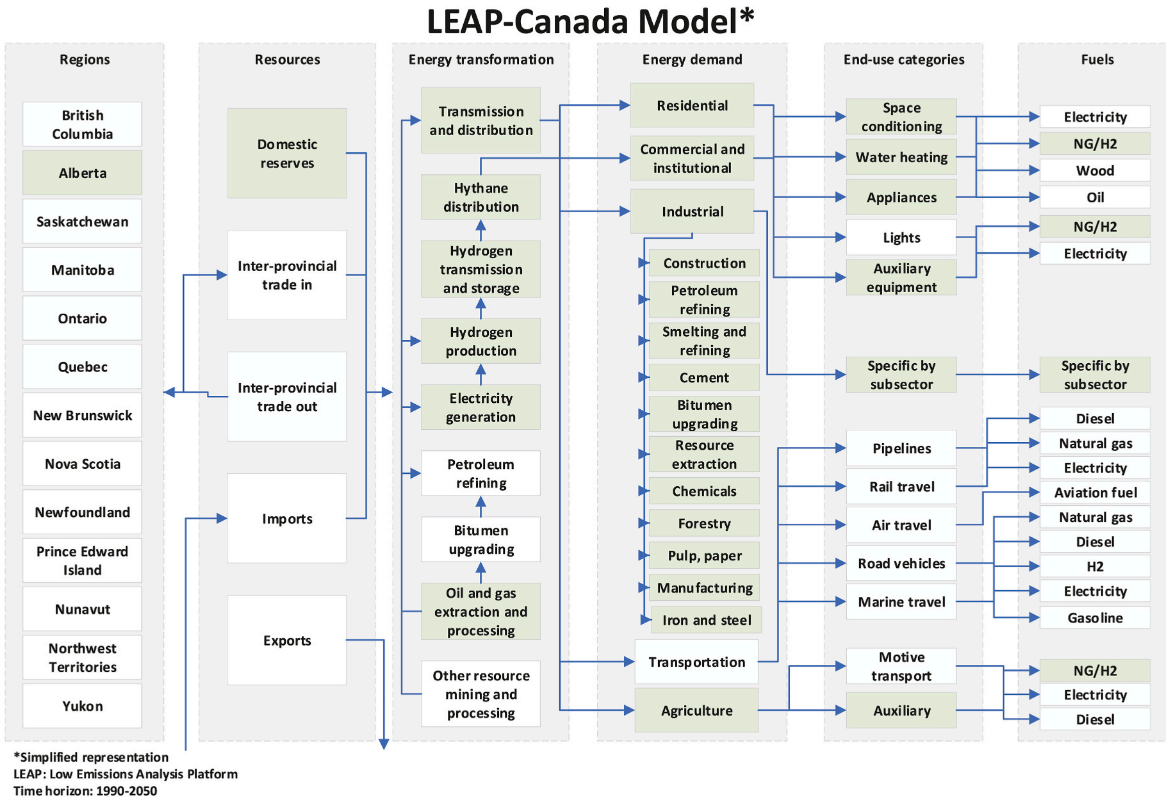


Fig. 2. Modelling framework implemented in the Low Emissions Analysis Platform-Canada (LEAP-Canada) – illustrative block diagram.

endogenous electricity production costs. The electricity emission factors were extracted from the model reference scenarios; these values were calculated endogenously for each scenario. Full details on the electricity modelling data and methods can be found in an earlier study [77], with modifications for the present paper shown in Table 2. Emission factors were applied throughout the model following the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Tier 1 emissions factors programmed into LEAP. A 100-year global warming potential was used to calculate CO_2e values.

2.3. Hydrogen production modelling and assumptions

The data for NG-based hydrogen production pathways were developed from bottom-up process-based models and are described in other research precluding the present paper [11,86]. Carbon capture and storage is considered for all natural gas-based H_2 production pathways. If the hydrogen production method includes CCS, the carbon is assumed to be transported 84 km. While no specific locations of hydrogen production and carbon sequestration are considered, the 84 km distance is the rough distance between Fort Saskatchewan and Thorhild, Alberta, for which detailed CCS techno-economic and life cycle assessment data have been generated [87]. This data was used to estimate the distance between hydrogen production and carbon dioxide sequestration. Table 3 contains the data used to model each NG-based hydrogen production technology; the assumptions and methods for this data are contained in the respective studies [11,86].

The % CC rate given with the production technology names is the amount of facility emissions to which CC is applied. It does not mean ## % of emissions are reduced but that ##% of emissions are subjected to CC. Since CC requires additional energy to run, and CC units do not remove 100% of the carbon emissions, the emission intensity reduction will be less than the CC rate. SMR has two locations where carbon can be captured: from chemical reactions occurring in the reactor and from combustion emissions in the reforming furnace. SMR with 52% CC indicates that CC is used at one location (one capture unit, covering about half the emissions from SMR). Since CC does not remove 100% of the CO_2 in the gas stream and requires energy to run, the overall carbon reductions compared to no CC are lower, ~40%. To capture more carbon emissions from SMR, two CC units are required, one at the reactor and one at the reforming furnace. Using two CC units increases the cost of hydrogen production, but 85–90% capture rates can be achieved, reducing overall emissions by ~78% compared to no CC. ATR emissions mostly occur in the reactor stream, unlike SMR, which has high emissions in both the reactor and furnace streams. Because of this, a capture rate of up to 95% is possible with one CC unit in ATR. Because only one CC unit is required, carbon emissions can be reduced at less cost than SMR (if the carbon charge is above ~\$60/t). Because the CC unit captures up to 95% of emissions from the process stream in ATR, combustion emissions are still generated. Overall, this results in an emissions reduction of less than 95% compared to ATR with no CCS.

Electrolysis-based hydrogen production pathways were also considered. Previous research has assessed wind- and hydro-based electrolysis-based hydrogen production in Alberta as a low-carbon alternative to supply the bitumen upgrading sector with hydrogen [88–90]. The modelling data from these studies were updated and harmonized for the present work. Grid-based electrolysis was also considered in CP170 and CP350 scenarios in which the modelled Alberta electricity grid undergoes an endogenous transition from the currently carbon-intensive grid to a low-carbon grid; Table 2 contains the emission factors of the grid for each baseline scenario. These values consider system reserve margin, load shape, intermittency of renewables, and maximum annual capacity additions; the reader is referred to the source paper [77] for further information on the electricity module.

Table 3 contains the data used to model each electrolysis-based hydrogen production technology; the assumptions and methods for this data are contained in the respective studies [88–90]. Monetary values were updated to be consistent with the present study's data sets.

Table 2
Relevant global model data.

Variable	Carbon policy	2026	2030	2040	2050
Carbon price applied to all emissions (nominal CAD/tonne CO_2e). In all cases, once the target carbon price is reached, it is assumed that the carbon price increases with inflation (constant value in real terms).	CP0	0	0	0	0
	CP50	50	50	50	50
	CP170	110	170	170	170
	CP350	200	350	350	350
Natural gas extraction, processing, transmission, and distribution emission factor (kg-CO_2e/GJ-Ng)	CP0	7.1	7.1	7.1	7.1
	CP50	7.1	7.1	7.1	7.1
	CP170	7.1	4.4	4.4	4.4
	CP350	7.1	2.7	2.7	2.7
Natural gas supply cost (CAD/GJ)	All	2.6	2.9	3.5	3.8
Electricity emission factor (g-CO_2e/kWh) and % renewable generation	CP0	344 (13%)	241 (13%)	227 (17%)	151 (18%)
	CP50	336 (13%)	240 (20%)	64 (75%)	37 (79%)
	CP170	158 (46%)	158 (85%)	38 (88%)	29 (91%)
	CP350	158 (52%)	158 (87%)	26 (91%)	16 (95%)
Electricity cost of production (CAD/GJ)	CP0	12	13	14	14
	CP50	17	17	15	14
	CP170	19	17	15	15
	CP350	23	19	17	16
Natural gas delivered price (CAD/GJ)	CP0	3.2	3.5	4.3	4.6
	CP50	3.6	3.9	4.6	5.0
	CP170	3.9	4.2	4.9	5.3
	CP350	4.3	4.3	5.1	5.4
Electricity delivered price (CAD/GJ)	CP0	23	24	26	27
	CP50	28	27	27	28
	CP170	30	28	28	29
	CP350	34	31	29	29
Wind maximum annual capacity addition (MW)[a]	All	1000	4000	4000	4000
Optimization framework[a]	All	NEMO V1.6			
Optimization solver[a]	All	CPLEX V20.1.0			

a: Electricity module changes from Davis et al. [77].

2.4. Hydrogen transmission modelling and assumptions

For the hydrogen pipelines connecting hydrogen to blend point or point of use, the inlet pressure of the pipeline is at 70 bar (which is the compression pressure at the production facility for hydrogen storage) [87] and the assumed outlet pressure at the blending points is 50 bar. The appropriate diameter (D) of the hydrogen pipeline for the centralized and semi-central delivery approaches was back-calculated from the Panhandle B equation for compressible gas flows in long pipelines (assuming a negligible static head) for a known hydrogen flow rate (Q_{H_2}) as shown in Eq. (2) [91]:

$$D\ (inches) = \sqrt[2.53]{\left[\frac{Q_{H_2}}{737 * \left(\frac{T_b}{P_b}\right)^{1.02} * e * \left(\frac{P_1^2 - P_2^2}{L * Z_a * G^{0.961} * T_a}\right)^{0.51}}\right]} \tag{2}$$

where $D =$ desired pipeline diameter, $Q_{H_2} =$ hydrogen flow rate in the pipeline in standard cubic feet per day (scf/day), $e =$ pipeline efficiency (92%), $G =$ specific gravity of hydrogen (0.07), $L =$ pipeline length adjusted from km to miles, $P_b =$ reference pressure in psi (14.7 psi), $P_1 =$ pipeline inlet pressure adjusted from bar to psi (1015 psi), $P_2 =$ pipeline outlet pressure adjusted from bar to psi (725 psi), $T_b =$ reference temperature in Rankine (530), $T_a =$ average gas temperature in Rankine (537), and $Z_a =$ compressibility factor (1.04).

The installed capital cost of the pipelines was determined using Eqs. (2) and (3) from Yang and Ogden [92] and Olateju and Kumar [87]. The installed capital cost depends on the pipeline diameter obtained in Eq. (3). Because of higher-than-average construction costs in Alberta, the installation factor, AB_f, was increased by 15% to a factor of 1.65, as specified by Olateju et al. [87]. The hydrogen pipeline cost obtained in this study was benchmarked against an alternative hydrogen pipeline capital cost estimation model developed by Di Lullo et al. [93]. The difference in the estimated pipeline capital cost between the approach adopted in this paper and by Di Lullo et al. [93] is less than 10%, suggesting a sufficient convergence. The capital cost is further amortized over the lifetime (n) at an interest rate (i) with the capital recovery factor (CRF) formula shown in Eq. (4). The operating cost ($/year) is 5% of the installed capital cost. Table 4 provides a data summary of the hydrogen pipeline cost estimation.

$$Pipeline\ installed\ capital\ cost = AB_f * 3092.6 * D^2 * L \tag{3}$$

$$CRF = \frac{i*(1+i)^n}{(1+i)^n - 1} \tag{4}$$

2.5. Hydrogen storage modelling and assumptions

Long-term hydrogen storage is needed for seasonal variations in demand and to ensure that shortages do not occur from plant outages. Using Argonne National Laboratory's Hydrogen Delivery Scenario Analysis Model (HDSAM) [94], in calculating hydrogen storage costs, it is assumed that underground salt caverns are used. The model's labour cost was increased by 15% to account for higher labour costs in Alberta; the NG, hydrogen, and electricity prices were also modified with Alberta-specific data. Taxes were not included, as with the other analyses conducted in this study. Also, aligning with the HDSAM, the minimum and maximum storage pressures are 20 and 125 atm, respectively.

The model assumes a single cavern is used; in some cases, several smaller caverns may be used, increasing overall costs. Typical cavern working capacities vary from 1,900 to 4,800 tonnes of hydrogen storage, corresponding to 210 and 535 tonnes/day hydrogen production. While there will be some hydrogen storage at the production facilities, it may be limited to smaller-scale above-ground steel tanks, costing between $135 and $345/kg H_2 [95]. Conversely, long-term hydrogen storage would likely use underground salt caverns with costs of $2 to $13/kg H_2.

There is sufficient capacity expected for hydrogen storage using salt caverns, particularly in the sedimentary basins in Alberta [96]. Deep saline aquifers were discovered in the basins suited and favourable for underground hydrogen storage [97]. Alberta also has an abundance of depleted hydrocarbon deposits suitable for gas storage [98].

The resulting levelized storage cost ranges from the HDSAM are between $0.056 and $0.077/kg H_2, depending on cavern size. The cavern costs are responsible for 53% of the total cost and the compressors for the remaining 47%. The hydrogen production rate is between 210 and 535 tonnes/day to maintain the assumed storage pressures, and several production facilities may share the same storage cavern. With these factors, an average modelled cost of $0.068/kg-$H_2$ was used.

The HDSAM assumes 10-day hydrogen storage to account for plant outages as well as a 10% increase in consumption during the summer and a 10% decrease during the winter to calculate storage capacity. The model also assumes that hydrogen is used only for transportation, not home heating; thus, summer demand is higher. In Alberta, winters are cold, and hydrogen demand may be higher in the winter if hydrogen is used for space heating. It is assumed that these factors will not significantly impact the annual average storage cost used in the analysis.

2.6. Gas distribution and consumption modelling and assumptions

Four NG-hydrogen blend rates were considered for each sector: 1%, 5%, 10%, and 15% hydrogen by volume. The upper bound of 15% was chosen since it is not expected to cause any issues with end-use equipment or distribution pipelines, as found by the literature reviewed (see

Table 3
Input data for hydrogen production technologies.

Hydrogen production technology	SMR	SMR-52%CCS	SMR-85%CCS	ATR	ATR-91% CCS	NGD	NGD-90%CCS	CL-POM	CL-POM-91%CCS	HYDRO-ELEC.	WIND-FARM-ELEC.	GRID ELEC.
First available operational year	2026	2026	2026	2030	2030	2030	2030	2030	2030	2026	2026	2026
Hydrogen production capacity (thousand tonnes H_2 per year)	199	199	199	199	199	199	199	199	199	54	54	54
CO_2 capture CAPX (million $)	–	74	247	–	100	–	123	–	49	–	–	–
CO_2 pipeline CAPX (million $)	–	113	166	–	131	–	36	–	122	–	–	–
CO_2 pipeline distance (km)	–	84	84	–	84	–	84	–	84	–	–	–
CO_2 storage CAPX ($)	= CO_2 pipeline CAPX ($)											
Production plant CAPX (million $)	397	395	402	723	807	774	798	1877	1877	1948	1416	437
Interest rate for capital amortization	10%	10%	10%	10%	10%	15%	15%	15%	15%	12%	12%	12%
CO_2 capture OPX ($/yr)	= 4% of CO_2 capture CAPX ($)											
CO_2 pipeline OPX ($/yr)	= 4% of CO_2 pipeline CAPX ($)											
CO_2 storage OPX ($/yr)	= 4% of CO_2 storage CAPX ($)											
Labor/admin annual OPX (million $/yr)	2.16	3.21	4.33	6.41	6.41	2.52	5.04	2.16	2.48	Included in total OPX		
Production plant equipment OPX (million $/yr)	= 4% of Production plant CAPX ($)									Included in total OPX		
CAPX/OPX cost reductions (% reduction 2026–2050)	–	–	–	–	–	–	–	–	–	12%	12%	12%
Capacity utilization	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
Carbon capture rate	0%	52%	85%	0%	91%	0%	90%	0%	91%	–	–	–
Plant life (years)	25	25	25	25	25	25	20	25	25	40	20	20
NG feedstock consumption (GJ/kg-H_2)	0.122	0.12	0.12	0.15	0.15	0.18	0.18	0.14	0.14	0.00	0.00	0.00
NG energy consumption (GJ/kg-H_2)	0.064	0.10	0.13	0.00	0.00002	0.03	0.04	0.00	0.00	0.00	0.00	0.00
Electricity consumption (kWh/kg-H_2)	0.96	1.32	4.42	2.35	3.59	2.23	3.19	1.16	1.78	54.52	54.52	55.08
Onsite emission factor (no electricity grid emissions) (kg-CO_2e/kg- H_2)	9.17	5.52	1.98	8.39	0.62	1.84	0.90	7.40	0.67	–	–	–

Table 4
Hydrogen pipeline data.

Hydrogen pipeline	37 km	337 km
Installed capital cost ($/GJ-$H_2$)	0.99	19.31
Operating cost ($/GJ-$H_2$)	0.05	0.97
Interest rate (i) for capital amortization	10%	10%
Lifetime	40 years	40 years
Maximum availability	90%	90%
Losses	0.1%	0.1%
Fugitive emissions	40.5 g-CO_2e/GJ-H_2	44 g-CO_2e/GJ-H_2

the introduction); going to 20% is expected to be sufficient for residential appliances, but it is uncertain if all commercial and industrial equipment can handle 20%. Furthermore, the Canadian Standards Association [45] conducted research to study gas appliance performance using up to 15% fraction blends (input rate, ignition and burner operating characteristics, combustion products properties, and gas leakage), and a technical report by NREL concluded that a max hydrogen fraction of 15% should be considered because beyond 15% there are higher chances of performance impacts, required modifications, and additional costs. Modifying end-use equipment is out of scope as the purpose of this study is to evaluate the potential for GHG mitigation without modifying end use equipment.

For each gas blend, the energy fraction of NG ($\%E_{NG}$) and hydrogen ($\%E_{H2}$) were calculated with Eq. (5) and Eq. (6), respectively,

$$\%E_{NG} = -1.691845*(v_{H2}^{6}) + 3.590022*(v_{H2}^{5}) - 3.346555*(v_{H2}^{4}) + 1.224916*(v_{H2}^{3}) - 0.487049*(v_{H2}^{2}) - 0.288505*v_{H2} + 0.999647 \quad (5)$$

$$\%E_{H2} = 1 - \%E_{NG} \quad (6)$$

where v_{H2} is the volume fraction of hydrogen in hythane (%vol.). This correlation was fit to data generated from the NGTL + H2 model [7] using the Groupe Européen de Recherches Gazières (GERG) equation of state [99]. Table 5 gives the hydrogen energy fractions. The blend levels were assumed constant throughout downstream distribution grids, flow rates were assumed constant, and the cost of blending was assumed negligible. Fugitive losses at the distribution stage were considered. The hydrogen mass fugitive rate was estimated to be three times larger than the fugitive methane rate; however, the fugitive emission rate was lower for hythane because hydrogen has a lower GWP (4.8) than methane (30). The calculations used can be found in Di Lullo et al. [7]. The change in emissions was then allocated to hydrogen using an emission factor (EF) (Eq. (7)) [7]. The GHG emissions associated with the distribution of the blended product were considered since the global warming potential of the fugitive gas would be reduced due to the displacement of NG with hydrogen [7]. The natural gas energy content used was 37.3 MJ/sm^3.

Table 5
Hythane distribution and consumption input data.

Variable	Hydrogen by volume blend			
	1%	5%	10%	15%
H_2 energy fraction ($\%E_{H2}$)	0.33%	1.6%	3.3%	5.2%
Distribution fugitive emissions reduction (g-CO_2e/GJ-H_2)	408	305	312	319
Hydrogen losses during distribution	0.023%	0.023%	0.022%	0.021%

$$EF_{H2} = \frac{EF_{Hythane} - EF_{NG}*\%E_{NG}}{\%E_{H2}} \tag{7}$$

The consumption of the blended gas was modelled by modifying the LEAP-Canada model with the data in Table 5. Natural gas energy content reductions were applied to the end-use energy intensities of consumption points given in Table 6, and hydrogen energy was incorporated to make up the balance. Prior studies for each sector are given in the first column of Table 6; these studies provide detailed methods of the demand tree and energy data, emissions data, and activity data development for the model. As a general note, improvements in energy efficiency continue at realized/expected trends; projections of population, GDP, and natural resource production for 2021 to 2050 were used [82]. For the crude oil production sectors, produced gas and still gas were accounted for in the modelling and were not considered for blending; likewise, NG used as feedstock (chemical and oil upgrading/refining sectors) was not considered for blending. The full data set used for the hythane-consuming sectors has approximately 600,000 data points.

2.7. Calculation of system-wide GHG mitigation

The GHG mitigation of an alternative scenario (m_s) was calculated from the total emissions between 2021 (t = *baseYear*) and 2050 (*endYear*) from the baseline scenario (E_{B_N}) minus the total emissions between 2021 and 2050 from an alternative scenario (E_S). Given in Eq. (8) to Eq. (15), B_N is the baseline scenario (there are 4 baseline scenarios, one for each carbon price: CP0, CP50, CP170, CP350). Emission factors *(EF)* for natural gas upstream (extraction, processing, and delivery [*NgU*]), natural gas combustion (*NgC*) emissions, energy demand of natural gas (*ED_{NG}*), and energy demand of hydrogen (EDH_2) are used to calculate the total emissions in a given year (t). H_gC is hythane gas combustion, H_2t and H_2d are hydrogen transmission and distribution, respectively, H_2p is hydrogen production, and eU is the electricity upstream module. H_b is the gas energy content reduction due to hydrogen blending, EF_{H_2D} is the fugitive emission reduction due to blending, and x is the hydrogen production technology.

$$m_s = E_{B_N} - E_S \tag{8}$$

$$E_{B_N} = \sum_{t=baseYear}^{endYear} (EF_{NgC}*ED_{NG,t,B_N}) + (EF_{NgU}*ED_{NG,t,B_N}) \tag{9}$$

$$E_S = \sum_{t=baseYear}^{endYear} (E_{HgC,t,S} + E_{H_2d,t,S} + E_{H_2p,t,S} + E_{eU,t,S} + E_{NgU,t,S}) \tag{10}$$

$$E_{HgC,S} = \sum_{t=baseYear}^{endYear} (EF_{NgC}*ED_{NG,t,S}*[1 - H_{b,S}]) \tag{11}$$

$$E_{H_2d,S} = \sum_{t=baseYear}^{endYear} (ED_{H_2,t,S}*[-EF_{H_2D,S}]) \tag{12}$$

$$E_{H_2t,S} = \sum_{t=baseYear}^{endYear} (ED_{H_2t,t,S}*EF_{H_2t,S}) \tag{13}$$

$$E_{H_2p,S} = \sum_{t=baseYear}^{endYear} (EF_x*ED_{H_2,t,S}) \tag{14}$$

$$E_{NgU,S} = \sum_{t=baseYear}^{endYear} (EF_{NgU}*ED_{NG,t,S}) \tag{15}$$

2.8. Calculation of system-wide marginal abatement costs

Eq. (16) gives the marginal abatement cost of a scenario (mac_s), calculated from the marginal net present value of a scenario ($mNPV_s$) divided by the GHG mitigation of the scenario (m_s), which are both

Table 6
Modelled hythane consumers.

Sector	Subsectors	Consumption points	Energy intensity (energy use/ activity)
Residential [65]	Single detached, single attached, apartment, mobile home	Space heating, water heating, clothes drying, ranges	MJ/household
Commercial and institutional [66]	Wholesale trade, retail trade, transportation and warehousing, information and cultural industries, offices, educational services, health care and social assistance, arts and entertainment and recreation, accommodation and food services	Space heating, space cooling, water heating, auxiliary equipment	MJ/m^2 of floor space
	Other services		
Pulp and paper [100]	Kraft pulp mills	Digestor, oxygen delignification, bleaching, pulp machine, black liquor evaporators, power plant, kiln and recausticizing,	MJ/tonne of production
	Thermomechanical pulp mills	Pulp dryer	
	Newspaper mills	Stock preparation, forming pressing operations, drying and finishing	
Petroleum refining [73]	Conventional crude oil	Process heat/steam production, catalytic reforming	MJ/barrel of crude refined
	Synthetic crude oil		
Chemicals [76]	Ammonia	Process heat/steam generation	MJ/tonne of production
	Ethylene		
Iron and Steel [74]	Integrated plant	Blast furnace, basic oxygen furnace, casting, forming and finishing	MJ/tonne of production
	Electric arc furnace plant	Electric arc furnace, forming and finishing	
Crude oil production [67–70]	Bitumen upgrading	Hydroconversion/hydrocracking, hydroconversion/ hydrotreatment, hydroconversion/sulfur plant, coking/crude distillation, coking/vacuum distillation, coking/coker, coking/ hydrotreatment, coking/sulfur plant	MJ/barrel of crude produced
	Surface mining of bitumen, in situ bitumen extraction (CSS, SAGD, Primary and EOR)	Process heat/steam generation	
Cement [75]	Dry processing	Clinker production	MJ/tonne of production
Agriculture [79]	Crops, livestock, other	Irrigation, heat, other	MJ/activity unit
Other industrial	Construction	Natural gas use (general)	MJ/gross domestic product
	Smelting and refining		
	Other manufacturing		
	Other mining		

found from the difference between the scenario and baseline values (Eq. (17) and Eq. (18)). The $mNPV_s$ is calculated from the net present value from 2021 to 2050 in an alternative scenario (NPV_S) minus the net present value between 2021 and 2050 from the baseline scenario (NPV_B), given in Eq. (19) to Eq. (26). CP is the carbon price, i is the discount rate, SC is the supply cost, cap_p is the capital cost of hydrogen pipeline capacity, H_2t is the hydrogen transmission pipeline (either short or long), p is hydrogen production, L is the lifetime, x is the production technology, and op is the non-fuel non-carbon operating cost. While the total costs in all scenarios encompass the entire energy system model, only the modules indicated in the equations are relevant to the results presented in this paper as the other module data and results remain static across scenarios.

$$mac_S = \frac{mNPV_S}{m_S} \tag{16}$$

$$mNPV_S = NPV_S - NPV_{B_N} \tag{17}$$

$$NPV_{B_N} = NPV_{NgC,B_N} + NPV_{NgU,B_N} \tag{18}$$

$$NPV_{NgC,B_N} = \sum_{t=baseYear}^{endYear} \frac{CP_{t,B_N} * EF_{NgC} * ED_{NG,B_N}}{(1+i)^{t-baseYear}} \tag{19}$$

$$NPV_{NgU,B_N} = \sum_{t=baseYear}^{endYear} \frac{(CP_{t,B_N} * [EF_{NgU} * ED_{NG,t,B_N}]) + (SC_{Ng,t} * ED_{NG,t,B_N})}{(1+i)^{t-baseYear}} \tag{20}$$

$$NPV_S = NPV_{HgC,S} + NPV_{H_2d,S} + NPV_{H_2t,S} + NPV_{H_2p,S} + NPV_{eU,S} + NPV_{NgU,S} \tag{21}$$

$$NPV_{HgC,S} = \sum_{t=baseYear}^{endYear} \frac{CP_{t,S} * EF_{NgC} * ED_{NG,t,S} * (1 - H_{b,S})}{(1+i)^{t-baseYear}} \tag{22}$$

$$NPV_{H_2d,S} = \sum_{t=baseYear}^{endYear} \frac{CP_{t,S} * ED_{H_2,t,S} * (-EF_{H_2D,S})}{(1+i)^{t-baseYear}} \tag{23}$$

$$NPV_{H_2t,S} = \sum_{t=BaseYear}^{EndYear} \frac{\left[\left(cap_{H_2t,S} * \frac{i}{1-(1+i)^{n_{H_2t}}} + op_{H_2t,S}\right) * ED_{H_2t,S}\right] + \left(CP_{t,S} * ED_{H_2t,t,S} * EF_{H_2t,S}\right)}{(1+i)^{t-baseYear}} \tag{24}$$

$$NPV_{H_2p,S} = \sum_{t=BaseYear}^{EndYear} \frac{\left(cap_{x,t,S} * \frac{i}{1-[1+i]^{n_x}} + op_{x,t,S} + [CP_{t,S} * EF_x]\right) * ED_{H_2,t,S}}{(1+i)^{t-baseYear}} \tag{25}$$

$$NPV_{NgU,S} = \sum_{t=baseYear}^{endYear} \frac{(CP_{t,S} * [EF_{NgU} * ED_{NG,t,S}]) + (SC_{Ng,t} * ED_{NG,t,S})}{(1+i)^{t-baseYear}} \tag{26}$$

3. Results and discussion

3.1. Comparison of 12 low-carbon hydrogen production technologies to 2050: production cost and GHG footprint

The annual cost of production and GHG footprints (includes full natural gas and electricity supply chain emissions) are given in Fig. 3 and Fig. 4, respectively. Many variables influence these characteristics over the long term, such as feedstock and fuel prices, emissions factors and carbon pricing, capital and operating cost declines, and technology commercialization. These variables are considered for each technology for each year in the study. It should be noted that these are the raw production costs in 2021 CAD, so they do not consider a rate of return as in the case of supply costs. The selling price of hydrogen may be higher than the values provided in Fig. 3. Also, the cost components for the natural gas-based pathways assumed to be commercially scaled by 2030 are ideal costs based on process modelling. In practice, higher initial costs may result from the novelty of the technology deployed for large-scale hydrogen production.

Analysis of the cost of hydrogen production yielded ATR-91%CCS as the lowest production cost after the carbon price reaches \$50–60/t (depending on the natural gas price). This is important as many governments, including Canada, plan to increase the carbon price to around \$170/t by 2030 [101]. Electrolysis-based technologies are considerably more costly than the natural gas-based pathways using CCS. Grid-based electrolysis hydrogen production costs fall within the ranges given by Guerra et al. [102].

Wind and hydro-based electrolysis have the lowest GHG footprints. The grid-based electrolysis GHG footprint is high due to the mostly natural gas-based electricity grid of the modelled jurisdiction. The grid-based electrolysis GHG footprint reduces over time in the CP170 and CP350 scenarios, reaching close to zero after 2047 and 2041, respectively. Of the natural gas-based technologies, chemical looping with partial oxidization of methane (CL-POM) with 91%CCS has the lowest emissions factor in most years under all carbon prices, and ATR-91%CCS is only slightly higher, followed by natural gas decomposition (NGD) technologies. If the sources of electricity supply are decarbonized, the emissions footprints of CL-POM-91%CCS and ATR-91%CCS are indistinguishable. Included in Fig. 4 is a natural gas emission line, which is the equivalent emission intensity of using natural gas; using hydrogen produced from the technologies with emission footprints above this line to replace natural gas would result in more emissions considering the system-wide scope. There are inflections in the emission intensities under CP50 assumptions due to relatively more emission-intensive marginal electricity generation technology mixes across the 2040–2050 timeline.

Analysing the cost of production and the carbon footprints, ATR-91% CCS has both low production costs and a low carbon footprint compared to other hydrogen production technologies. Because of this, ATR-91% CCS is the chosen hydrogen production technology for the hythane scenarios since it is likely to be the primary hydrogen supply technology in the long term, given the expectations for an increasing carbon price. Since it is assumed that ATR will not be commercially built at large scale until 2030, SMR-85%CCS is used to supply hydrogen until 2030 since it is the only technology available during the immediate period to provide GHG reduction, as shown in Fig. 4 below the natural gas emission cut-off lines. Since the costs of SMR-85%CCS are higher than ATR-91%CCS, this could also serve as a proxy for the increased costs that may occur due to the novelty of using ATR-91%CCS for large-scale hydrogen production.

3.2. System-wide cost and GHG emission impacts

The results for GHG mitigation and system-wide cost impacts for the 15% hythane scenario with centralized H_2 production (Comb_hyth15_337kmTrans_CP170) are shown in Fig. 5A and C. This is given as a representative scenario to show the relative scale of mitigation across the economic sectors and to compare the scale of the emission reduction offset due to emissions associated with hydrogen supply. The year 2050 is shown in Fig. 5 however, the proportions of the stack do not vary to

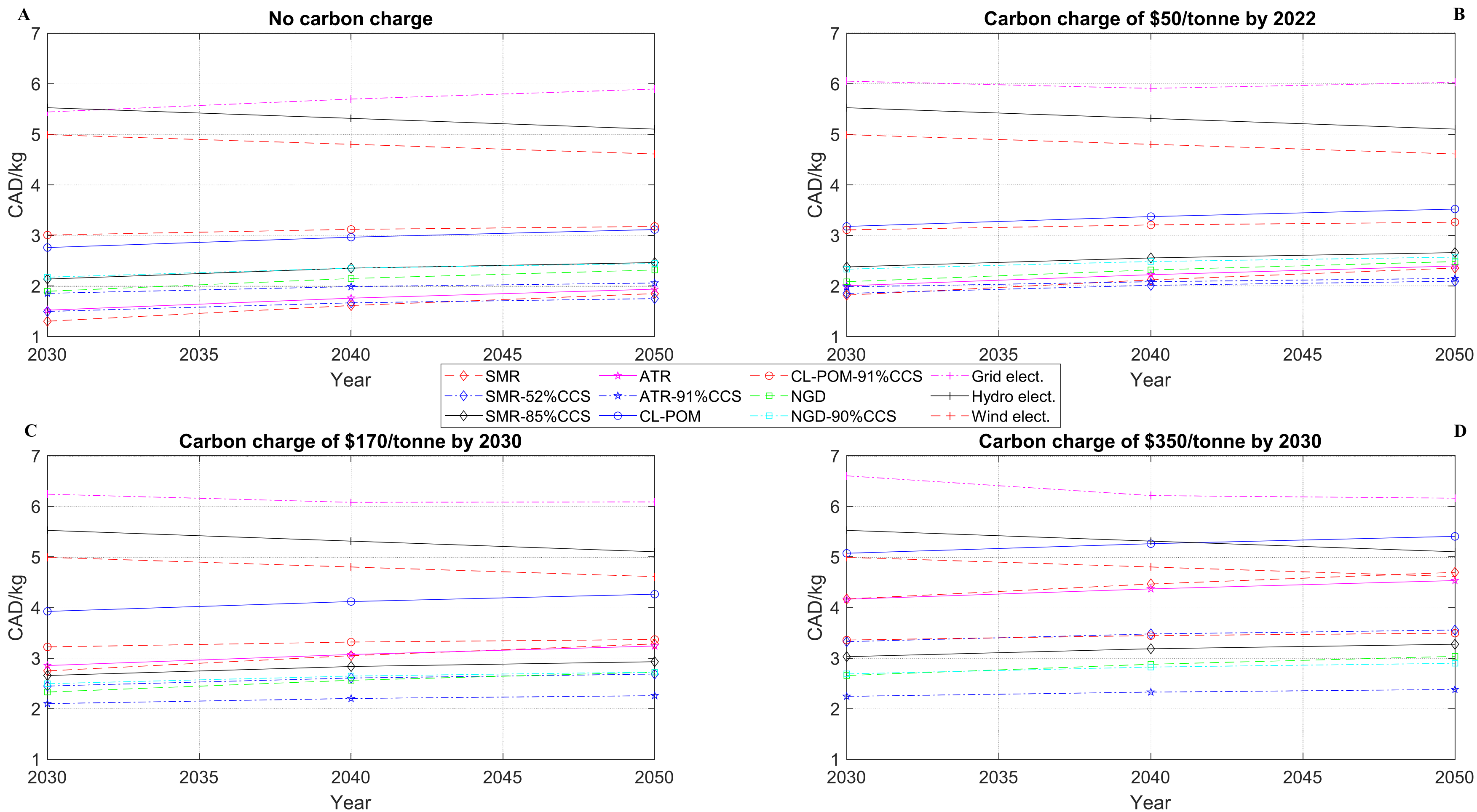


Fig. 3. Annual costs of hydrogen production at different carbon prices (panel 3A: no carbon charge; panel 3B: \$50 per tonne CO_2e; panel 3C: \$170 per tonne CO_2e; panel 3D: \$350 per tonne CO_2e).

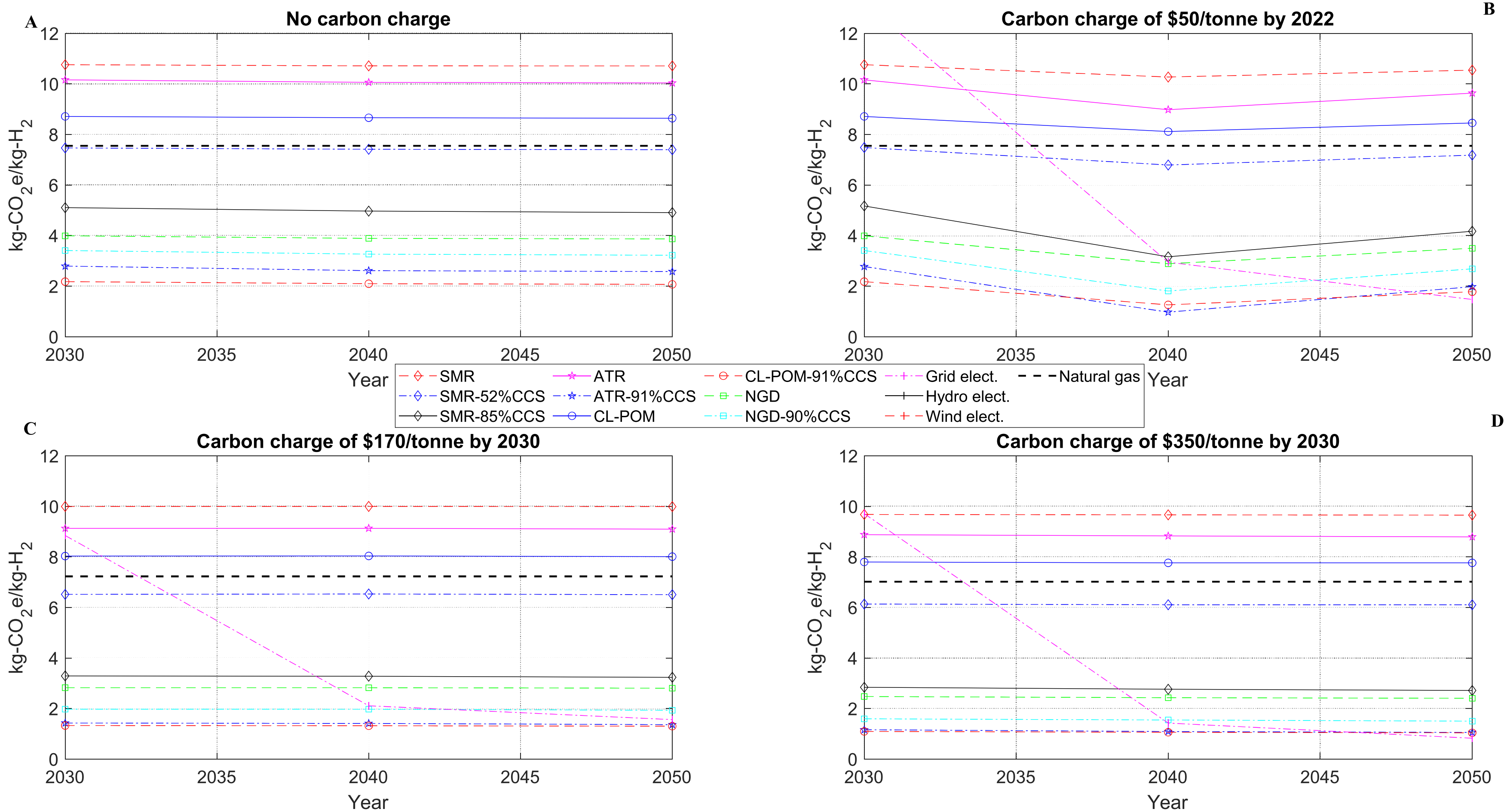


Fig. 4. Annual GHG emission footprint of hydrogen production technologies at different carbon prices (panel 4A: no carbon charge; panel 4B: $50 per tonne CO_2e; panel 4C: $170 per tonne CO_2e; panel 4D: $350 per tonne CO_2e).

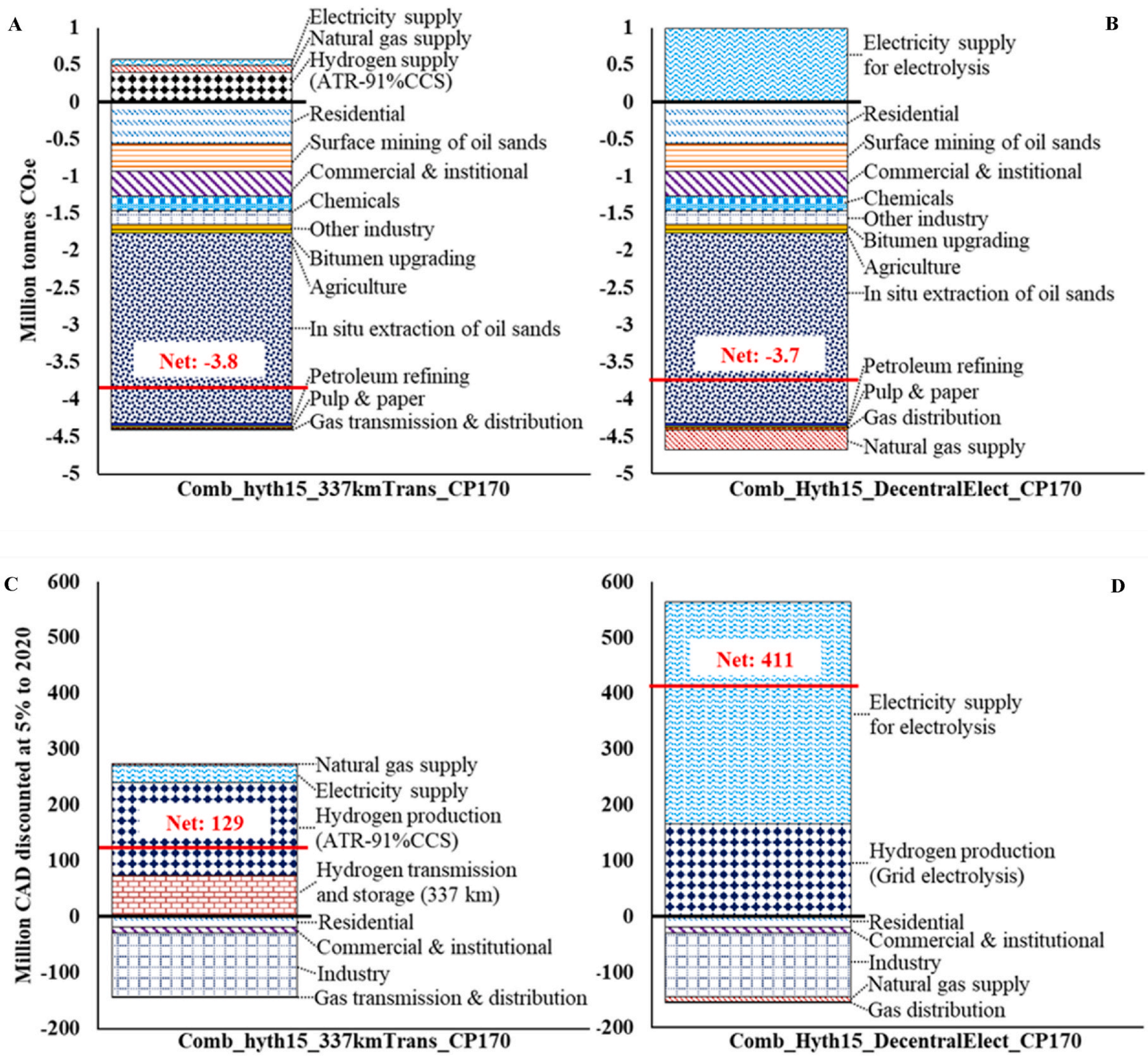


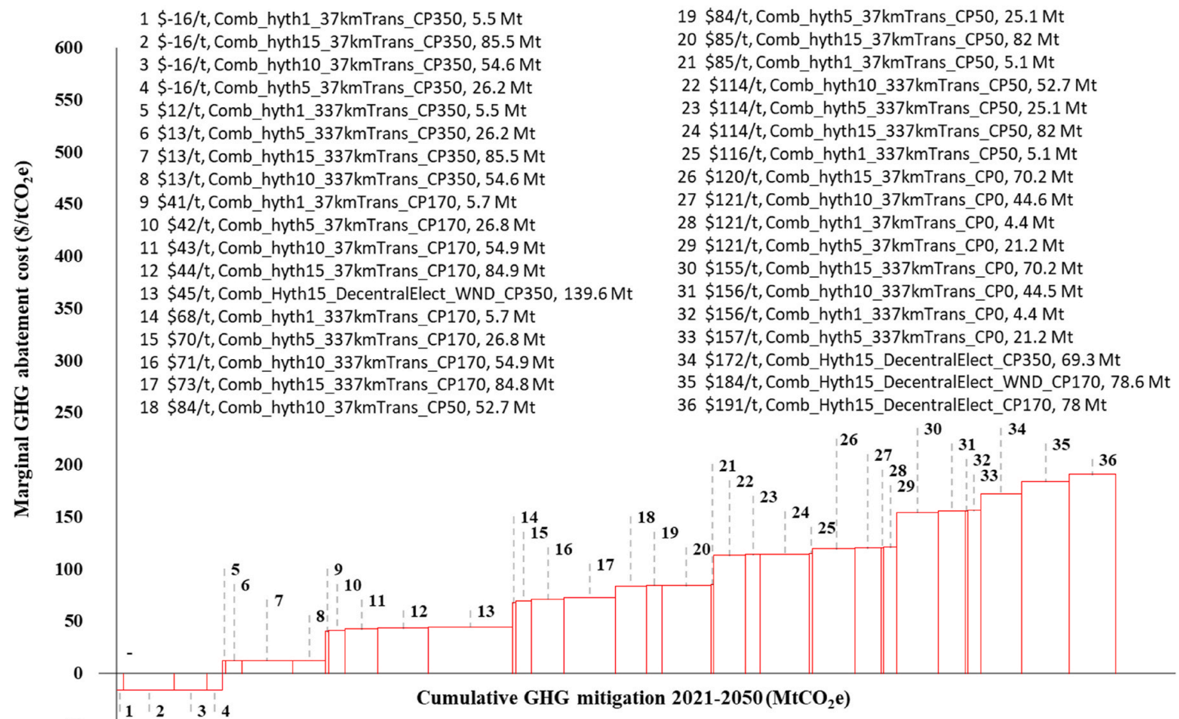
Fig. 5. Economy-wide use of hythane (15% hydrogen by volume) in Alberta in the year 2050; system-wide GHG emission (panel 5A and 5B) and cost (panel 5C and 5D) impacts for centralized NG-based (panel 5A and 5C) and decentralized grid electrolysis (panel 5B and 5D) hydrogen.

any notable degree from year to year, though electricity generation and NG upstream emissions do change slightly, as their carbon footprints decrease over time and with increasing carbon price. The system-wide annual average mitigation is 3.5 Mt/yr of CO_2e over 24 years (from 2026 to 2050) and 3.8 Mt/yr in the year 2050. The end-use sectors' GHG reductions amount to 4.4 Mt; 78% of this occurs in the industrial sector and 20% in the residential and commercial sectors combined. The Alberta oil sands make up 87% of the industrial GHG reductions and 69% of the total end-use sector reductions.

The positive costs shown in Fig. 5C and D are due to hydrogen production and transmission costs, while the negative costs are a result of reduced carbon costs compared to the baseline. The largest components of costs are the capital and operating costs (includes fixed, variable, and carbon costs) of hydrogen production. The net NG and electricity supply costs are also shown; the costs are the marginal system-wide costs of supplying these fuels to produce hydrogen. NG supply costs are small since the NG used in the ATR process offsets the NG savings in the end-use sectors. Hydrogen transmission and storage for the centralized approach are also shown in Fig. 5; the semi-centralized scenario reduces this cost by 82% (reducing the average hydrogen transmission distance from 337 km to 37 km).

Oil sands extraction was found to have the largest potential for GHG mitigation. The greatest GHG mitigation potential among the hythane scenarios in the oil sands was found in SAGD oil sands extraction. Using 15% hythane for oil sands SAGD heat generation amounts to a production of 251 and 277 thousand tonnes of hydrogen in 2030 and 2050, respectively, and 38–42 PJ of incremental NG would be required. This translates to 29–35 Mt of GHG reductions system wide between 2026 and 2050, or an annual average of 1.2–1.5 Mt.

The system-wide GHG and cost impacts of decentralized electrolysis in the year 2050 are shown in Fig. 5B and D. There is 1 Mt of GHG emissions associated with using electrolysis in 2050; the grid mix in the CP170 scenario is 91% renewable. The net annual GHG mitigation potential is slightly lower for scenarios using electrolysis than for scenarios using ATR-91%CCS under CP170; for the CP350 electrolysis scenario with aggressive wind deployment (Comb_Hyth15_DecentralElect_WND_CP350), there is a 1.6× higher GHG reduction compared to the equivalent ATR-91%CCS scenario (Comb_Hyth15_Ψ_CP350). The largest component of the system-cost changes is in the building and operating of electricity generators to supply the electrolyzers with electricity. It should be noted that firming capacity is added to the system to maintain planning reserve margins of 15%, which take the form of mostly simple cycle NG and some hydropower. Water costs are included in the hydrogen production block. Capital and operating cost declines of 12% were considered for electrolysis between 2026 and 2050 as the baseline. A 24% cost reduction was also tested, which brought the



Notes
Discount rate for NPV calculation = 5%. The scenario mitigation results are non-additive (each scenario is mutually exclusive).
Hydrogen production with SMR85%CC up to 2030 and ATR91%CC 2030-2050 (except for decentralElect scenarios).

Fig. 6. Marginal GHG abatement cost curve for economy-wide hythane use scenarios.

costs closer to the costs of the ATR-91%CCS scenarios. Equivalent ATR-91%CCS scenarios still lowered marginal abatement costs by 58–67% of the Comb_Hyth15_DecentralElect_WND_α scenarios; using 2.5× more upstream NG emissions reduced the gap to 25–39%. These impacts can be seen in the section on sensitivity analysis. Note that electrolysis scenarios assessed here do not consider integration with stand-alone renewable electricity systems or storage systems, which have been shown to reduce system costs [103,104].

3.3. Marginal abatement costs

The marginal abatement cost curve is provided in Fig. 6. The figure is read by considering each box as a scenario. The width of the box is proportional to the GHG reduction associated with the scenario cumulatively from 2021 to 2050, and the height of the box gives the marginal abatement cost (NPV discounted to 2020 at a 5% discount rate divided by cumulative GHG mitigation). Scenarios on the lower left have more favourable GHG abatement costs; scenarios with wider boxes have more GHG reduction potential. The presentation of scenarios in the marginal abatement cost curves should not be mistaken for a ranking of scenarios, which, as validly pointed out by Taylor [105], can be questionable when negative marginal abatement costs are included on the curve. The cost curves in this study are used to present the results, not to rank options for GHG abatement.

The cost curve illustrates how using hythane in the end-use energy sectors becomes a more cost-effective GHG mitigation strategy as carbon price increases. More GHG mitigation is attained with higher carbon prices because the electricity and NG supply segments of the hydrogen supply chain are further decarbonized (Table 2). For electricity, higher carbon pricing results in higher NG-based electricity costs causing more renewable power deployment instead of NG. For NG supply, a more aggressive fugitive methane reduction policy is assumed to reduce upstream NG emissions up to what is technically possible. The maximum potential for GHG mitigation considering all end-use energy processes that can use hythane in Alberta is 85–140 Mt from 2026 to 2050, equalling average annual mitigation of 4–6 Mt CO_2e, or ~1–2% of Alberta's 2019 GHG emissions. Of the four carbon pricing assumptions used, only the highest ($350/t by 2030) resulted in decreased energy system costs. Further analysis gives a break-even carbon price between $300 and 400/t (nominal by 2030), depending on the length of the hydrogen transmission pipeline. This means that, at carbon prices below the break-even point, there is a net increase in energy-system costs from implementing hythane, and those costs may be passed on to the consumer of the gas and result in higher energy costs compared to using pure NG; this is after considering the carbon cost reductions from hydrogen displacing NG.

The effect of carbon price and hydrogen transmission distances can be seen in the cost curve. Shorter distance hydrogen transmission pipelines (37 km) reduce the abatement cost by $27–35/t compared to long-distance (337 km) hydrogen pipelines. Increasing carbon costs from $0 to $350/tonne reduces the marginal abatement costs by $136–144/t depending on the hydrogen transmission distance. Note that the marginal abatement cost results are found from the difference in the net present values (marginal costs) of the hythane and reference scenarios over the cumulative GHG emissions reduced, and the different CP assumptions are applied to both the reference scenario and the hydrogen scenarios for each CP.

3.4. Uncertainty in upstream/fugitive emissions associated with NG

The emissions associated with producing and transporting NG have recently been an area of contention as current national inventory methods may lead to GHG underreporting. For instance, recent studies have suggested that current methane emissions have been underestimated, such as the baseline developed as part of the National Inventory Report submitted to the IPCC (Canada's inventory reports give a fugitive emissions rate of ~0.71% of natural gas production) or GREET (fugitive emissions rate of 1.1% of natural gas production) [106]. Chan et al. [107], Mackay et al. [108], and Tyner and Johnson [109] suggest methane emissions are 1.5, 1.9, and 2.2× higher than Canadian National

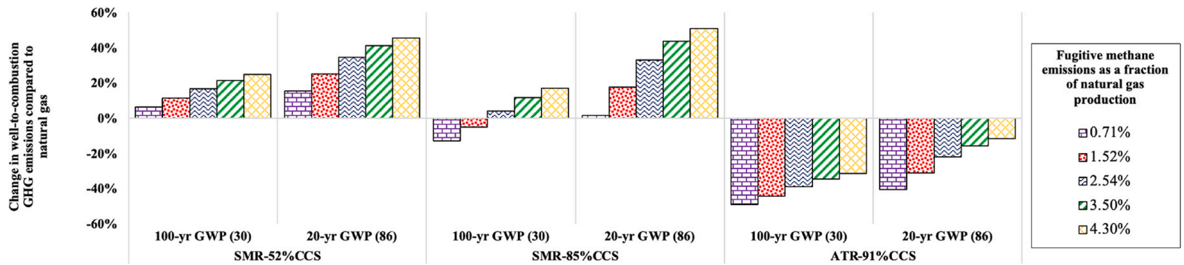


Fig. 7. Analysis of upstream/fugitive emissions associated with NG emissions. The figure shows hydrogen well-to-combustion emissions relative to NG; the main analysis used 0.71% and a 100-yr GWP (30).

Inventory Report estimates, respectively. Alvarez et al. suggest that methane fugitives in the US are 1.6× higher than the Environmental Protection Agency estimates [110]. Howarth and Jacobson have suggested that low-carbon hydrogen from NG sources is overall more emissions-intensive than directly using NG [111]; this possibility is investigated in the present analysis.

The well-to-combustion (WTC) emissions of low-carbon hydrogen from different sources considered in this study were compared to NG, as shown in Fig. 7A; the NG upstream emission factor used for this figure is 2.34 kg CO_2/GJ of NG and 0.29 kg CH_4/GJ of NG. Assuming GWPs of 30 (100 years) and 86 (20 years), new upstream CO_2e were calculated for NG and then used to update the hydrogen emission factor. The baseline data used in this study gives a fugitive NG emission rate of 0.71% of natural gas production; the highest fugitive rates in Fig. 7 were based on the extreme end found in Howarth and Jacobson [111]. Using hydrogen from SMR with 52% CCS increases emissions compared to using NG directly. SMR with 85% CCS reduces WTC emissions at baseline and increases emissions at the higher fugitive NG rates, even more than for 52% carbon capture due to the natural gas required to run the additional carbon capture unit. ATR with 91% CCS reduces emissions compared to NG for all fugitive rates and for both 20-year and 100-year GWPs.

It is also important to note that while methane emissions may have been underestimated in the past, they have also been in a downward trend (9% reduction from 2014 to 2019) in Canada [83]. It has been found that after venting regulations in Alberta were implemented in 2017, methane emissions in Peace River decreased by 65% (2016 vs. 2018) [108]. Alberta regulations that went into effect in 2020 aim to reduce methane fugitives by 45% by 2025 [84]. Fugitive methane emission studies may also report oil and gas emissions together. Mackay et al. found that fugitive emissions are 3.6× higher at oil sites than at gas sites [108]. Lloydminster, which is dominated by cold heavy oil production with sand (CHOPS), had the highest emission intensity; CHOPS typically has higher rates of routine venting [108]. At oil sites where methane is considered a by-product, it is more likely to be vented, as recovery is uneconomical. These results emphasize the need to reduce uncertainty in upstream NG emissions and consider this uncertainty in GHG mitigation assessments.

3.5. Sensitivity analysis

Table 7 gives the parameters used for sensitivity analysis. The low natural gas supply cost is based on the last five years of historical data (2016–2020). The high natural gas supply cost is ~54% higher than baseline values (nears historical high since the year 2000). The natural gas extraction, processing, transmission, and distribution emission factor is based on data in the Canadian National Inventory Reports submitted to the IPCC. However, as discussed earlier, there has been aerial evidence that the inventory data methods are underestimating leakage rates, particularly from tanks and gathering compressors; 2.5× baseline values were used to cover this uncertainty. Hydrogen production capital and non-energy operating costs are also considered because of the novelty of using an ATR process; large-scale hydrogen production in Alberta using ATR may result in higher initial costs. Lower costs could be the result of brownfield projects. An arbitrary range of ± 25% is used to cover a wide range and also applied to electrolysis costs. The same range is considered for CCS costs, as there is less experience due to the small number of commercial projects. The learning rate for electrolysis costs is increased by 2; while costs are expected to come down in general, the location and speed of cost reductions are uncertain. Hydrogen production plant lifetime assumptions are also tested by extending the lifetime to 40 years. Hydrogen storage is also investigated by varying the cost

Table 7
Sensitivity analysis input parameters.

Variable	Sensitivity case	Carbon policy (α)	Hydrogen production method (ϕ)	2026	2030	2035	2040	2045	2050
Natural gas supply cost (CAD/GJ)	Low	All	All	1.67	1.67	1.67	1.67	1.67	1.67
	High	All	All	4.2	4.85	5.43	5.87	6.11	6.32
Natural gas extraction, processing, transmission, distribution emission factor (kg-CO_2e/GJ-Ng)	High (2.5× baseline)	CP0	All	17.8	17.8	17.8	17.8	17.8	17.8
		CP50	All	17.8	17.8	17.8	17.8	17.8	17.8
		CP170	All	17.8	11.1	11.1	11.1	11.1	11.1
		CP350	All	17.8	6.7	6.7	6.7	6.7	6.7
Hydrogen production capital and non-energy operating cost	Low	All	All	0.75 x baseline					
	High	All	All	1.25 x baseline					
CCS capital and non-energy operating cost	Low	All	ATR-91%CCS	0.75 x baseline					
	High	All	ATR-91%CCS	1.25 x baseline					
Electrolysis learning rate	Low	All	Grid electrolysis	Baseline					
	High	All	Grid electrolysis	2 x baseline					
Plant lifetime	High	All	All	40 years					
Large-scale hydrogen storage	Low	All	ATR-91%CCS	0.5 x baseline					
	High	All	ATR-91%CCS	1.5 x baseline					
Onsite hydrogen storage	Include instead of large-scale system storage	All	ATR-91%CCS	Storage capacity: 304 tonnes Capital cost: $366,660,971 Operating cost: 4% of capital cost					

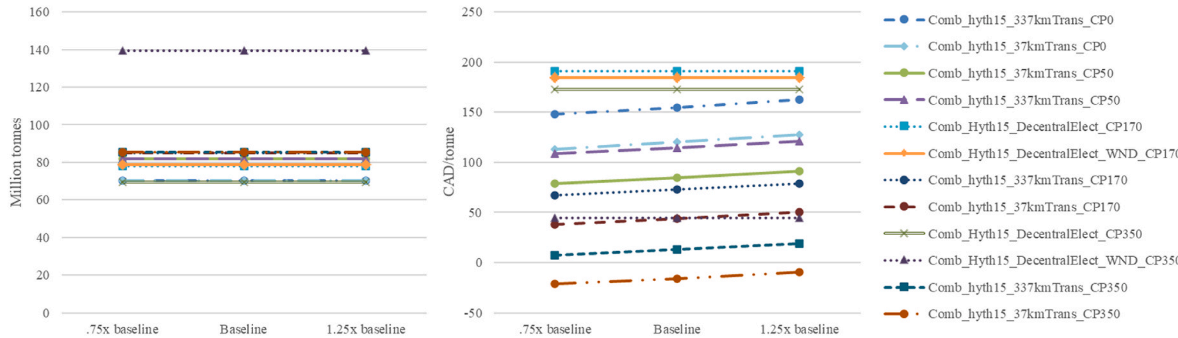


Fig. 8. Sensitivity of GHG mitigation and MAC to CCS capital and non-energy operating costs.

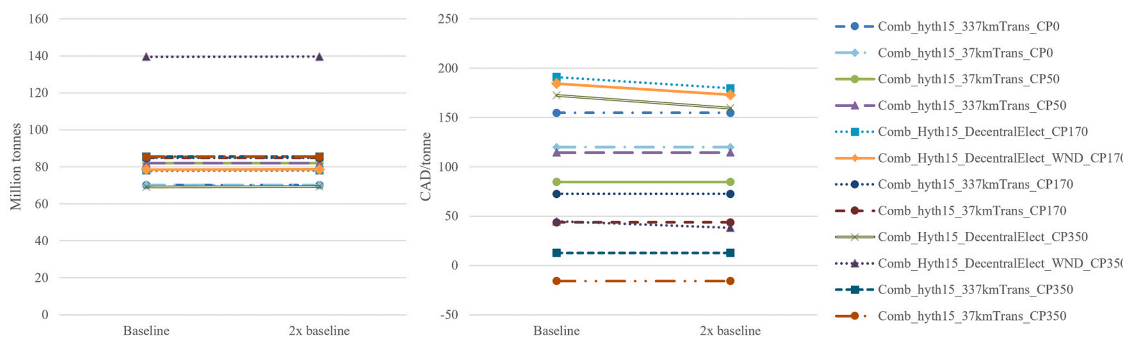


Fig. 9. Sensitivity of GHG mitigation and MAC to electrolysis learning rate.

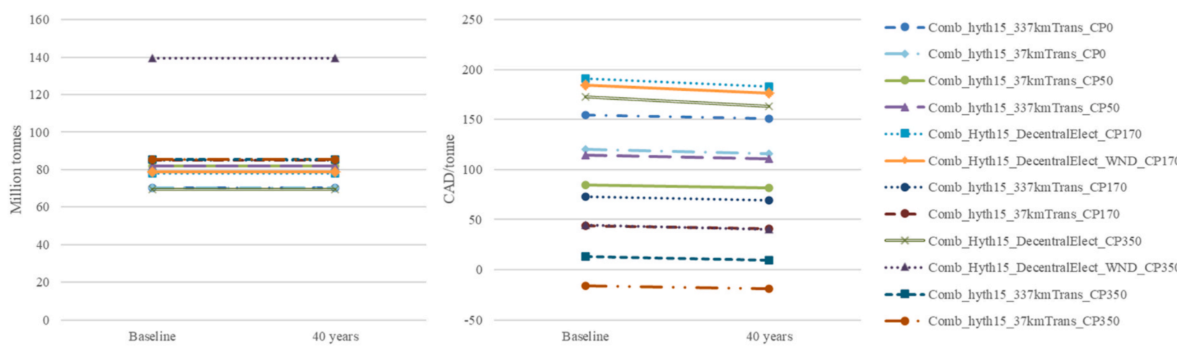


Fig. 10. Sensitivity of GHG mitigation and MAC to plant lifetime.

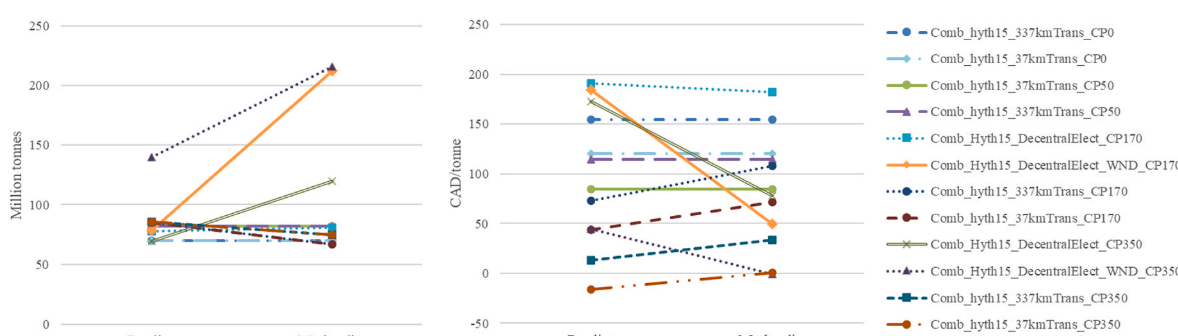


Fig. 11. Sensitivity of GHG mitigation and MAC to natural gas supply emission intensity.

assumptions for large-scale system-wide storage and by using half-day on-site storage at the centralized and semi-centralized hydrogen production facilities.

Fig. 8 to Fig. 15 show the results of the sensitivity analysis. Of the variables tested, CCS costs (see Fig. 8), system wide (see Fig. 15) and on-site H_2 storage costs (see Fig. 13), electrolysis learning rate Fig. 9), and H_2 plant lifetime (see Fig. 10) and costs (see Fig. 14) only impact the marginal abatement cost of scenarios (GHG mitigation potential does

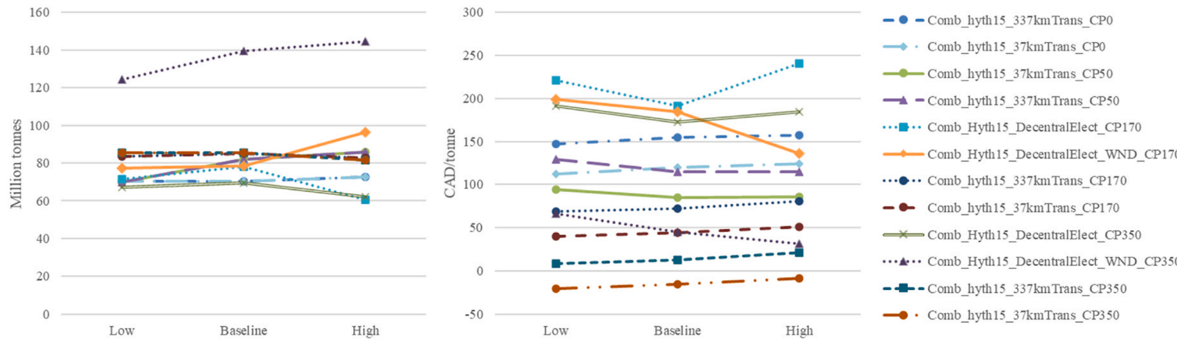


Fig. 12. Sensitivity of GHG mitigation and MAC to natural gas supply cost.

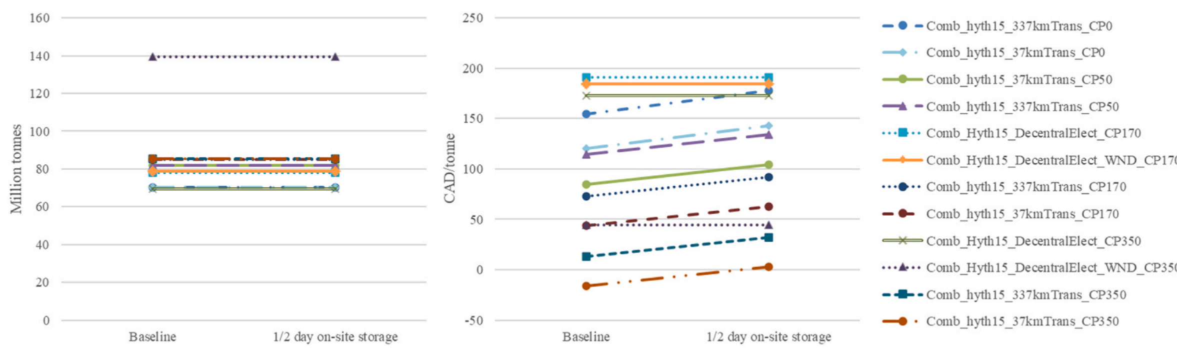


Fig. 13. Sensitivity of GHG mitigation and MAC to including ½ day on-site H_2 storage at SMR & ATR production facilities.

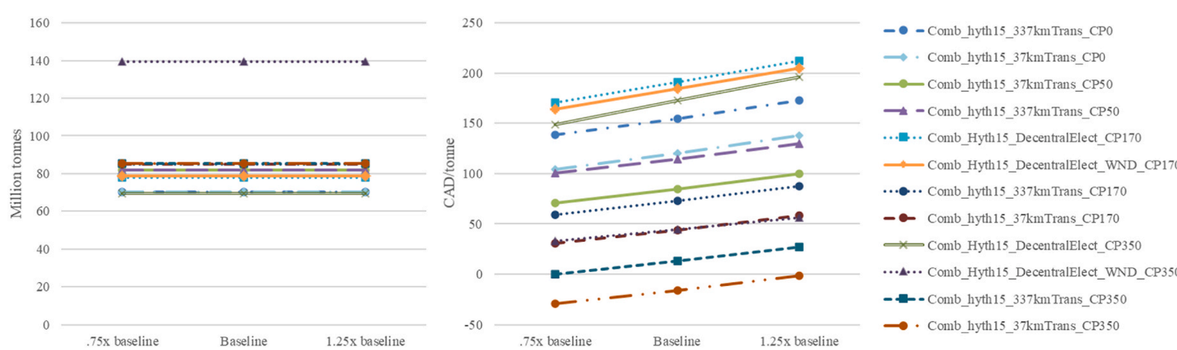


Fig. 14. Sensitivity of GHG mitigation and MAC to H_2 plant capital and non-energy operating costs.

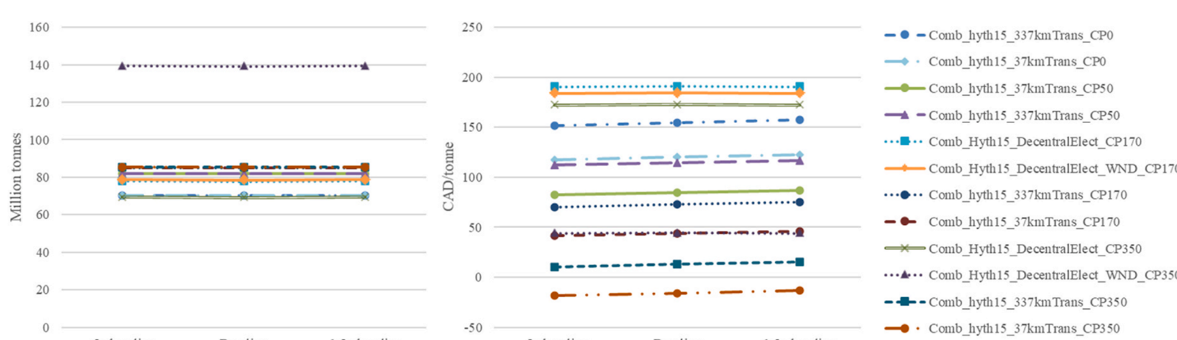


Fig. 15. Sensitivity of GHG mitigation and MAC to system-wide storage cost.

not change). Only the natural gas supply emission intensity (see Fig. 11) and cost (Fig. 12) have an impact on mitigation results. The mitigation results are impacted when the natural gas supply emission intensity is increased 2.5× the baseline values. The scenarios using natural gas-based hydrogen production experience a 5–12% decrease in GHG mitigation as the overall emission savings are reduced because of the higher emissions during natural gas production. An increase in GHG mitigation is seen in the electrolysis scenarios with aggressive wind deployment.

For higher upstream NG emissions, the results for scenarios using ATR-CCS are not largely affected; however, the decentralized electrolysis scenarios become significantly more effective at reducing GHG emissions and, thus, also significantly more cost-effective. A varied natural gas supply cost reduces GHG mitigation up to 5% for natural gas-based hydrogen scenarios due to a slightly different evolution of the electricity generation system; electrolysis-based scenarios show ±2–22% GHG mitigation as significantly more electricity is needed. Marginal abatement costs are more sensitive ($23–52/t change) to natural gas supply emission intensity, natural gas supply cost, hydrogen plant costs, and onsite hydrogen storage implementation. Marginal abatement costs are less sensitive ($3–13/t change) to CCS costs, system-wide hydrogen storage costs, and the electrolysis learning rate.) (see

3.6. Policy implications and limitations

3.6.1. Policy implications

An outcome of this analysis is finding where hythane fits into broader decarbonization efforts for consideration during GHG reduction policy development. To do this, the results of this analysis were compared to the results of other energy system GHG reduction studies that used similar methods. Previous work evaluated 34 residential [65] and 23 commercial [66] energy efficiency-based GHG reduction scenarios using similar modelling methods. In these studies, investment costs, operating costs, and discount rates were considered as in the present study. The earlier studies found that 80% of the mitigation potential in the residential sector [65] and 65% of the mitigation potential in the commercial sector resulted in negative marginal abatement costs [66]. The residential and commercial results do not include any carbon credits. Therefore, compared to energy efficiency opportunities in the residential and commercial sectors, hythane generally has higher abatement costs and similar annual GHG mitigation potential (~1–2% of present-day emissions).

GHG reductions scenario analyses in the electricity generation sector that used similar modelling methods [77] were also compared. Fifteen feasible electricity generation scenarios were identified that produced lower energy system costs compared to baseline and considering a $30/t carbon price. The associated annual average GHG mitigation for these scenarios range from 4.5 to 8.4 Mt CO_2e [77]; contrast this to 4–6 Mt CO_2e annual average mitigation for hythane scenarios where energy system costs are not reduced until there is a >$300 carbon price, which shows that hythane is relatively more costly and has lower GHG reduction potential compared to GHG reduction options available in the electricity sector.

The crude oil production (oil sands scenarios) results were compared with a separate analysis of integrating existing hydrogen production with CCS in the petroleum industry. Janzen et al. determined the marginal abatement cost of converting existing SMR plants in crude bitumen upgraders to SMR-CCS [70]. To compare those results with the present study's, Janzen et al.'s model was updated and harmonized with this study's analysis framework. The resulting cost curve is given in Fig. 16; the results only consider upgraders that are not already using CCS. Retrofitting these SMR facilities by 2025 with 52% and 85% CCS gives average mitigation of 6 and 11 Mt of CO_2e per year between 2025 and 2050, respectively (input data provided in Table 3). This is higher than the hythane scenarios, which ranged from ~4 to 6 Mt. The marginal GHG abatement costs for the oil sands upgrading SMR retrofit with CCS for the CP170 and CP350 have a negative value, indicating a net cost benefit associated with the scenarios at lower carbon prices compared to the hythane scenarios. Compared to the hythane scenarios, the scenarios with CCS additions to existing hydrogen production show higher GHG mitigation potential at lower costs. This implies that using CCS to decarbonize existing hydrogen production facilities should be considered prior to greenfield hydrogen if the goal is cost-effective GHG reductions.

It is also important to note that using natural gas-based low-carbon hydrogen to replace natural gas results in a net increase in natural gas use. For instance, by 2050, hythane use in Alberta's residential and commercial sectors could necessitate 133 thousand tonnes of hydrogen, resulting in incremental natural gas demand of 20 PJ for the least-cost hydrogen production pathway. Similarly, the usage of hythane for oil sands SAGD heat generation corresponds to 277 thousand tonnes of hydrogen production by 2050 and an incremental natural demand of more than 42 PJ. The incremental natural gas demand for hythane blending is low in the context of the region's natural gas production environment; however, if reducing reliance on fossil fuels is a policy goal, this may not be a justified GHG mitigation strategy.

The scenarios examined in this work offer policymakers useful and timely information, applicable across jurisdictions globally contemplating hydrogen blending options to reduce emissions, with a few caveats. The policy implications are expected to be similar across jurisdictions where natural gas is widely used. Some differences may be in the price of natural gas, which is higher in most other parts of the world, so higher natural gas costs were considered in the sensitivity analysis. Alberta's economy is highly reliant on natural gas; the residential, commercial/institutional, and industrial sector natural gas consumption makes up 80%, 67%, and 62% of total energy consumed, respectively. Other countries may use less natural gas and so overall economy-wide GHG mitigation would be lower. The outcome of requiring a $300-$400/t carbon price to avoid raising system costs aligns with a study by Quarton and Samsatli that showed that high rates of hydrogen injection with NG are generally not cost effective for

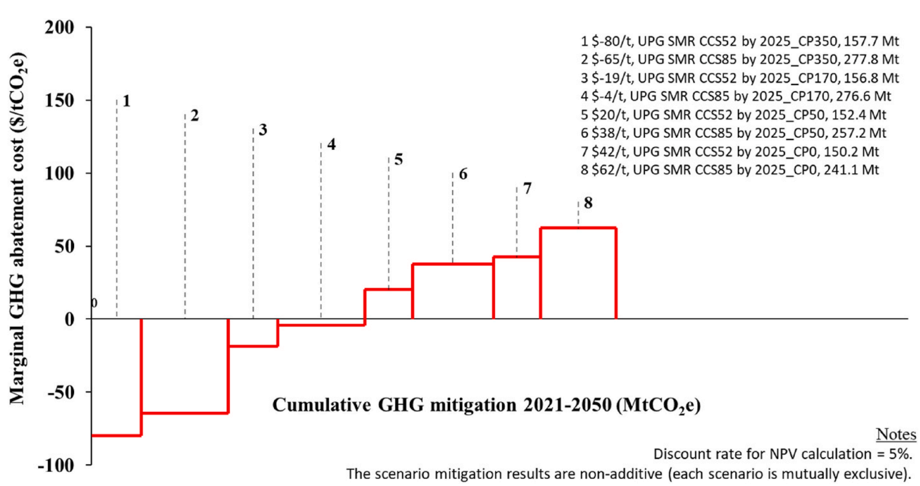


Fig. 16. Marginal GHG emission abatement cost curve for crude bitumen upgrading SMR retrofit with 52% and 85% carbon capture.

consumers in the UK [18]. In another study, Quarton and Samsatli found that consumer heating bills would increase compared to using non-hydrogen pathways because of the relative costs of producing hydrogen for energy use compared to other energy options [25]. This aligns with the results of the present analysis. All monetary result values presented are in 2020 CAD; at the time of this writing, multiply by 0.78 to convert to United States dollar (USD) and by 0.76 to convert to Euros (EUR).

3.6.2. Technical limitations of hythane

Energy shortages may occur due to the volumetric energy content reduction of a hydrogen-blended gas compared to pure natural gas: As the percent of blended hydrogen increases, the energy content of the gas (GJ/m^3) reduces. Depending on the application/device using the gas, this might affect its performance. Blending 15% hydrogen would result in a 10% decrease in energy capacity if the volumetric flow rate remains constant. Unlike high-pressure transmission lines, the lower pressure (69 kPa) distribution lines can increase their volumetric flow rate by 6% while keeping the overall pressure drops unchanged. This results in only a 5% decrease in the energy flow rate instead of 10% for 25 mm and 150 mm mid-pressure natural gas delivery lines. The distribution system relies primarily on pressure regulating valves to control flow and drop the pressure as gas moves from mid-pressure mains to lower pressure delivery lines. It should be noted that this only applies to the distribution system when pressure-reducing valves are used instead of compressors. For distribution and transmission pipelines that require compressors, the flow rate cannot be increased without increasing compressor power. Thus, for some end-use devices, i.e., in industry or in commercial/institutional applications that currently use natural gas and run for 24 h per day, switching to hythane could create a shortage of energy for that application unless modifications are made. The way around this is to increase the flow rate of the gas or modify the pipelines to supply a greater volume of gas, both of which come with additional costs. For the present study, the common assumption taken for all scenarios is that the volume flow rate of current pipelines stays fixed, and no downstream equipment would face an energy shortage. This would need to be confirmed on a case-by-case basis.

While not considered in this analysis, consumers downstream of a blend point may require (or desire) pure natural gas. These customers must either accommodate the blend, which could require capital investment or re-separate the natural gas from the hythane mix in the distribution pipelines, incurring additional system costs and reduced operational efficiencies. It was assumed for this study that all consumers using natural gas for energy end use can use the blended gas and the amount of natural gas used for feedstock is simply omitted from the analysis. Having customers that do not agree to a blend may limit the acceptability of wide-scale blending, and blending may only be feasible for specific distribution networks.

Using electrolysis requires water availability and could become an issue that constrains adoption depending on where plants are located. For example, Southern Alberta has the highest solar and wind energy resource potential and also the lowest water resource availability. The analysis does not consider spatial aspects; a separate analysis is recommended to understand these.

Spatial and high-resolution temporal aspects, which can be seen as a limitation of the study in the context of planning a physical hydrogen network, were not considered. This work is meant to determine the GHG mitigation effectiveness (cost and scale) of different blends across an economy using ATR-CCS as the primary hydrogen producer over the long term. Developing a hydrogen supply chain model of a physical hydrogen network, including power-to-gas, is also recommended for further planning and design, as well as validation of the results of this analysis.

3.6.3. Social/economic limitations of hythane

Large-scale infrastructure modifications may be required to solve the energy shortage issue and/or to transfer the hydrogen from the production location to the blend point. If natural gas-based hydrogen is used, large-scale capital-intensive infrastructure would be required to transport and store the carbon dioxide produced.

Alberta's retail natural gas costs over the past five years have been ~ $2–4/GJ natural gas. The supply costs of hydrogen, as modelled in this study, amount to ~$13/GJ hydrogen. The price of heating for the average customer will increase as the hydrogen portion in the hythane mix increases unless the carbon price is significantly high ($300–400/t); this may create a challenge for social acceptance of hythane.

Power-to-gas should also be explored through a decentralized approach to provide pure hydrogen supply (or for onsite hythane mixing) to large commercial and industrial consumers capable of installing electrolyzer systems, thus eliminating the added system cost of upstream hydrogen blending and downstream separation of natural gas for pure natural gas-dependent consumers. Further research is required to assess the value, limitations, and supporting mechanisms of integrating electrolytic hydrogen produced from curtailed renewable energy into the power sector (through centralized or decentralized modes) under varying unit commitment and uncertainty constraints of natural gas-based generators.

Linepack flexibility of the gas grid is also not considered in the present analysis since the distribution grids are assumed to operate at relatively low pressure, and hydrogen production is steady state with ATR instead of variable output renewables. The impact of linepack can be significant at higher pressures for regional grids and may be beneficial to consider for power-to-gas applications where storage through linepack can improve economics [112].

4. Conclusions

This paper evaluated 576 scenarios for the years 2026–2050 to determine the GHG mitigation potential and cost effectiveness of blending hydrogen with natural gas for end-use energy consumption across an economy. A range of hydrogen production technologies, natural gas-hydrogen blend rates, infrastructure strategies, and carbon policies was considered. A systems-based modelling approach using data based on engineering fundamentals analysis (bottom up) was applied.

The GHG mitigation potential was found to be low, about 1–2% of the economy's present-day emissions (Alberta, Canada); this considers autothermal reforming with 91% carbon capture and sequestration or electrolysis. Considering the uncertain variables, the total GHG reduction potential increases to about 5% at most. The extreme high end of fugitive methane emission uncertainty (2.5× time baseline) and both 20- and 100-year global warming potentials was tested; the conclusions of the analysis hold true (GHG reductions occur) if autothermal reforming with 91% carbon capture is used to produce hydrogen.

The cost effectiveness of GHG mitigation was also found to be low. Total net energy system costs increase unless the GHG emission reduction credit is $300–400/tonne. Compared to other GHG reduction options, energy efficiency, renewable electricity, and adding carbon capture to existing hydrogen production facilities should be supported first, since these are more cost effective (considering up to the year 2050) and provide deeper emission reductions. However, given the need to establish low-carbon hydrogen economies for long-term sustainability, blending hydrogen into natural gas networks offers a near-term opportunity for capacity building and technology learning. The associated costs could be low enough to justify hydrogen-natural gas blending since economies will benefit from the infrastructure scale-up through job creation, attracting investment, and technology export. While not considered here, these factors will need to be weighed by decision-makers, and the costs to be passed on to consumers should be determined.

Author contributions

M.D. and A.K. designed the research. A.O. and G.D.L. contributed to the study design. M.D. and A.K. conceptualized and built the LEAP-Canada model, processed the data, conducted the model runs, and analysed the results. A.O., G.D.L., and T.G. did the pipeline modelling and generated input data for the LEAP-Canada model. A.O. reviewed all hydrogen production methods and harmonized the associated data. M. D. led the writing of the manuscript, with contributions from A.O., G.D. L., and A.K. A.K was also responsible for the supervision, investigation, visualization, project administration, resources and funding acquisition.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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Appendix A. Supplementary data

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