Ministère
de l'Économie,
de l'Innovation
et de l'Énergie
Québec

Bureau du sous-ministre et Secrétariat général

PAR COURRIEL

[redacted]

La présente donne suite à votre demande d'accès à l'information reçue le 11 mai 2023 pour laquelle vous souhaitez obtenir copie des documents suivants :

> *« Toute note, document ou échange concernant les opportunités économiques que représente la filière hydrogène au Québec produit au cours des années 2021, 2022 et 2023 inclusivement. »*

Conformément à l'article 47 de la Loi sur l'accès aux documents des organismes publics et sur la protection des renseignements personnels (chapitre A-2.1) (« la Loi sur l'accès »), nous vous informons que le Ministère de l'Économie, de l'Innovation et de l'Énergie détient des documents quant à l'objet de votre demande. Vous trouverez ci-joints les documents pouvant vous être transmis.

D'autres documents en notre possession ne sont toutefois pas accessibles. Ainsi, nous ne divulguerons pas de documents au stade d'ébauche ou ayant des incidences sur l'économie ou sur des décisions administratives. Nous invoquons à l'appui de notre décision les articles 9, 14, 22 et 34 de la Loi sur l'accès.

De plus, nos recherches ont permis de retracer des documents qui proviennent ou relèvent de la compétence du ministère des Finances. Comme prévu à l'article 48 de la Loi sur l'accès, nous vous fournissons les coordonnées du responsable de l'accès aux documents au sein de cet organisme advenant qu'il vous soit nécessaire de communiquer avec lui :

> David St-Martin
> Directeur général de l'organisation du budget et
> de l'administration et Secrétaire général
> 390, boul. Charest Est, 8e étage
> Québec (QC) G1K 3H4
> Tél. : 418 643-1229
> Téléc. : 418 646-0923
> responsable.acces@finances.gouv.qc.ca

Si vous désirez contester cette décision, il vous est possible de le faire auprès de la Commission de l'accès à l'information. Vous trouverez ci-joint une note explicative concernant l'exercice de ce recours.

Je vous prie de recevoir, [redacted] l'expression de mes sentiments distingués.

Pierre Bouchard
Responsable de l'accès aux documents

710, place D'Youville, 6e étage
Québec (Québec) G1R 4Y4
Téléphone : 418 691-5656
Télécopieur : 418 646-6497

AVIS DE RECOURS

Suite à une décision rendue en vertu de la *Loi sur l'accès aux documents des organismes publics et sur la protection des renseignements personnels.*

RÉVISION

a) Pouvoir
L'article 135 de la loi prévoit qu'une personne, dont la demande écrite a été refusée en tout ou en partie par le responsable de l'accès aux documents ou de la protection des renseignements personnels, peut demander à la Commission d'accès à l'information de réviser cette décision.

La demande de révision doit être faite par écrit; elle peut exposer brièvement les raisons pour lesquelles la décision devrait être révisée (art. 137).

L'adresse de la Commission d'accès à l'information est la suivante :

Québec
525, boulevard René-Lévesque Est, bureau 2.36
Québec (Québec)
G1R 5S9
Téléphone : 418 528-7741
Télécopieur : 418 529-3102

Montréal
500, boulevard René-Lévesque Ouest, bur. 18.200
Montréal (Québec)
H2Z 1W7
Téléphone : 514 873-4016
Télécopieur : 514 844-6170

b) Motifs
Les motifs relatifs à la révision peuvent porter sur la décision, sur le délai de traitement de la demande, sur le mode d'accès à un document ou à un renseignement, sur les frais exigibles ou sur l'application de l'article 9 (notes personnelles inscrites sur un document, esquisses, ébauches, brouillons, notes préparatoires ou autres documents de même nature qui ne sont pas considérés comme des documents d'un organisme public).

c) Délais
Les demandes de révision doivent être adressées à la Commission d'accès à l'information dans les 30 jours suivant la date de la décision ou de l'expiration du délai accordé au responsable pour répondre à une demande (art. 135).

La loi prévoit spécifiquement que la Commission d'accès à l'information peut, pour motif raisonnable, relever le requérant du défaut de respecter le délai de 30 jours (art. 135).

APPEL DEVANT LA COUR DU QUÉBEC

a) Pouvoir
L'article 147 de la loi stipule qu'une personne directement intéressée peut porter la décision de la Commission d'accès à l'information en appel devant trois juges de la Cour provinciale, sur toute question de droit ou de compétence. Cet appel ne peut toutefois être porté qu'avec la permission d'un juge de la Cour provinciale. Ce juge accorde la permission s'il est d'avis qu'il s'agit d'une question qui devrait être examinée en appel.

b) Délais et frais
L'article 149 prévoit que la requête pour permission d'appeler doit être déposée au greffe de la Cour provinciale, à Montréal ou à Québec, dans les 30 jours de la décision, après avis aux parties et à la Commission d'accès à l'information. Les frais de cette demande sont à la discrétion du juge.

c) Procédure
L'appel est formé, selon l'article 150 de la loi, par dépôt auprès de la Commission d'accès à l'information d'un avis à cet effet signifié aux parties dans les 10 jours qui suivent la date de la décision qui l'autorise. Le dépôt de cet avis tient lieu de signification à la Commission d'accès à l'information.

Liste des articles invoqués de la Loi sur l’accès aux documents des organismes publics et sur la protection des renseignements personnels

9. Toute personne qui en fait la demande a droit d’accès aux documents d’un organisme public. Ce droit ne s’étend pas aux notes personnelles inscrites sur un document, ni aux esquisses, ébauches, brouillons, notes préparatoires ou autres documents de même nature.

1982, c. 30, a. 9.

14. Un organisme public ne peut refuser l’accès à un document pour le seul motif que ce document comporte certains renseignements qu’il doit ou peut refuser de communiquer en vertu de la présente loi.

Si une demande porte sur un document comportant de tels renseignements, l’organisme public peut en refuser l’accès si ces renseignements en forment la substance. Dans les autres cas, l’organisme public doit donner accès au document demandé après en avoir extrait uniquement les renseignements auxquels l’accès n’est pas autorisé.

1982, c. 30, a. 14.

22. Un organisme public peut refuser de communiquer un secret industriel qui lui appartient.
Il peut également refuser de communiquer un autre renseignement industriel ou un renseignement financier, commercial, scientifique ou technique lui appartenant et dont la divulgation risquerait vraisemblablement d’entraver une négociation en vue de la conclusion d’un contrat, de causer une perte à l’organisme ou de procurer un avantage appréciable à une autre personne.

Un organisme public constitué à des fins industrielles, commerciales ou de gestion financière peut aussi refuser de communiquer un tel renseignement lorsque sa divulgation risquerait vraisemblablement de nuire de façon substantielle à sa compétitivité ou de révéler un projet d’emprunt, de placement, de gestion de dette ou de gestion de fonds ou une stratégie d’emprunt, de placement, de gestion de dette ou de gestion de fonds.

1982, c. 30, a. 22; 2006, c. 22, a. 11.

34. Un document du bureau d’un membre de l’Assemblée nationale ou un document produit pour le compte de ce membre par les services de l’Assemblée n’est pas accessible à moins que le membre ne le juge opportun.

Il en est de même d’un document du cabinet du président de l’Assemblée, d’un membre de celle-ci visé dans le premier alinéa de l’article 124.1 de la Loi sur l’Assemblée nationale (chapitre A-23.1) ou d’un ministre visé dans l’article 11.5 de la Loi sur l’exécutif (chapitre E-18), ainsi que d’un document du cabinet ou du bureau d’un membre d’un organisme municipal ou scolaire.

1982, c. 30, a. 34; 1982, c. 62, a. 143; 1983, c. 55, a. 132; 1984, c. 47, a. 1.

48. Lorsqu’il est saisi d’une demande qui, à son avis, relève davantage de la compétence d’un autre organisme public ou qui est relative à un document produit par un autre organisme public ou pour son compte, le responsable doit, dans le délai prévu par le premier alinéa de l’article 47, indiquer au requérant le nom de l’organisme compétent et celui du responsable de l’accès aux documents de cet organisme, et lui donner les renseignements prévus par l’article 45 ou par le deuxième alinéa de l’article 46, selon le cas.

Lorsque la demande est écrite, ces indications doivent être communiquées par écrit.

1982, c. 30, a. 48.

Les carrefours d'appui à la transition énergétique : des pistes pour le développement de l'hydrogène vert au Québec

Étude réalisée par l'Institut de l'énergie Trottier pour le Bureau du développement de l'hydrogène vert et des bioénergies du ministère de l'énergie et des ressources naturelles.

Rapport d'analyse

Éloïse Edom
Simon Langlois-Bertrand
Elvire Chloé Agnès Mbog
Normand Mousseau

Octobre 2022

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Éloïse Edom, M. Ing., M. Sc. A.
Simon Langlois-Bertrand, Ph. D.
Elvire Chloé Agnès Mbog, stagiaire
Normand Mousseau, Ph. D.

À propos de l'Institut de l'énergie Trottier (IET)

L'Institut de l'énergie Trottier (IET) a été créé en 2013 grâce à une généreuse donation de la Fondation familiale Trottier. Sa mission consiste à former une nouvelle génération d'ingénieurs et de scientifiques qui comprennent les enjeux énergétiques afin de soutenir la recherche de solutions durables. L'IET vise ainsi à soutenir la transition énergétique qui s'impose en contribuant à la diffusion des connaissances et au dialogue sociétal sur les questions énergétiques.

Ce mandat permet à l'IET de se positionner comme une institution unique dans le secteur de l'énergie au Canada. Basé à Polytechnique Montréal, l'IET rassemble des professeurs-chercheurs de HEC Montréal, de Polytechnique Montréal et de l'Université de Montréal. Cette diversité d'expertises permet de former des équipes de travail transdisciplinaires, une condition essentielle à la compréhension systémique des enjeux énergétiques dans un contexte de lutte aux changements climatiques.

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Twitter : @EnergieTrottier

Remerciements

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Note aux lecteurs

Le contenu de ce rapport n'engage que ses auteurs et d'aucune façon les individus et les organisations qui en ont fait une relecture et fourni des commentaires.

Version 221212

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INSTITUT DE L'ÉNERGIE TROTTIER

1. Introduction

L'hydrogène à faibles émissions de carbone est reconnu comme faisant partie du bouquet de solutions pour atteindre la carboneutralité sur la scène internationale. Toutefois, la création des nouvelles chaînes de valeur de l'hydrogène à faibles émissions de carbone[1] demeure complexe.

L'objectif de ce rapport est de mener une réflexion stratégique pour identifier des orientations pouvant contribuer au déploiement et à la croissance du marché de l'hydrogène au Québec sur un horizon d'une quinzaine d'années. À cette fin, l'étude s'appuie sur une méthodologie en quatre étapes développée par l'Accélérateur de Transition. Ces étapes sont les suivantes : 1) comprendre le fonctionnement du système, 2) élaborer des trajectoires, 3) évaluer et améliorer ces trajectoires et 4) passer à l'action. **Le carrefour d'appui à la transition énergétique** constitue l'un des outils utilisés pour appliquer cette méthodologie. **Il a pour mandat, entre autres, d'apporter son soutien à la mise en œuvre de solutions** en fédérant les acteurs clés et en coordonnant les efforts entrepris (analyses, projets, sources de financement, etc.). **Cette organisation travaille à la création d'une masse critique et à l'atteinte de la viabilité économique** pour un marché émergent sélectionné**.**

Cette démarche vise à ancrer le développement du marché de l'hydrogène dans l'objectif climatique à long terme, soit l'atteinte de la carboneutralité en 2050. Ce rapport s'inscrit dans le cadre de la Stratégie québécoise sur l'hydrogène vert et les bioénergies 2030 (MERN, 2022b). Il s'appuie sur les travaux déjà réalisés et sur diverses consultations avec des acteurs du milieu. **Ce rapport propose les prochaines étapes à entreprendre et constitue un point de départ pour commencer à rassembler les acteurs et déployer les carrefours proposés.**

Le chapitre 2 brosse un portrait des émissions de gaz à effet de serre au Québec et identifie les tendances liées à la décarbonation dans les différents secteurs économiques. Le chapitre 3 présente quelques concepts clés ainsi que les éléments de contexte qui ont été pris en compte pour évaluer diverses orientations possibles pour le déploiement du marché de l'hydrogène au Québec. Le chapitre 4 précise en détail l'orientation axée sur les mines qui est proposée. Le chapitre 5 présente d'autres orientations envisagées. En dernier lieu, après la conclusion, un plan résume les prochaines étapes à suivre.

[1] Dans ce rapport, on se réfère toujours à l'hydrogène à faibles émissions de carbone, à moins d'une indication contraire.

2. La décarbonation des secteurs économiques

2.1. Les émissions de GES du Québec et les cibles de décarbonation

Le Québec a publié en 2006 un premier plan d'action pour lutter contre les changements climatiques. Ce plan couvrait la période 2006-2012 et avait pour objectif une réduction des émissions de gaz à effet de serre (GES) de 6 % par rapport au niveau de 1990 (MELCC, s. d.). Cet objectif a été atteint et même dépassé. Selon les données de l'inventaire québécois des émissions de GES publié en 2020, les émissions ont diminué de 6,8 % par rapport à 2012. Le deuxième plan d'action du Québec couvrait la période 2013-2020 et avait pour objectif une diminution des émissions de 20 % par rapport au niveau de 1990. Les données de 2020 de l'inventaire officiel des GES du Canada indiquent que cet objectif n'a pas été atteint car la réduction totale des émissions en 2020 a été de 12 %, ce qui représente 8 % de moins que l'objectif cible pour 2020. Il faut donc procéder à des changements majeurs pour se réaligner sur une ou des trajectoires menant aux deux prochains objectifs que s'est fixés la province. Le premier changement important est inscrit dans la loi et il consiste à réduire les émissions de 37,5 % en 2030 par rapport au niveau de 1990. Le second changement d'importance annoncé par le gouvernement est l'atteinte de la carboneutralité en 2050 (Figure 1).

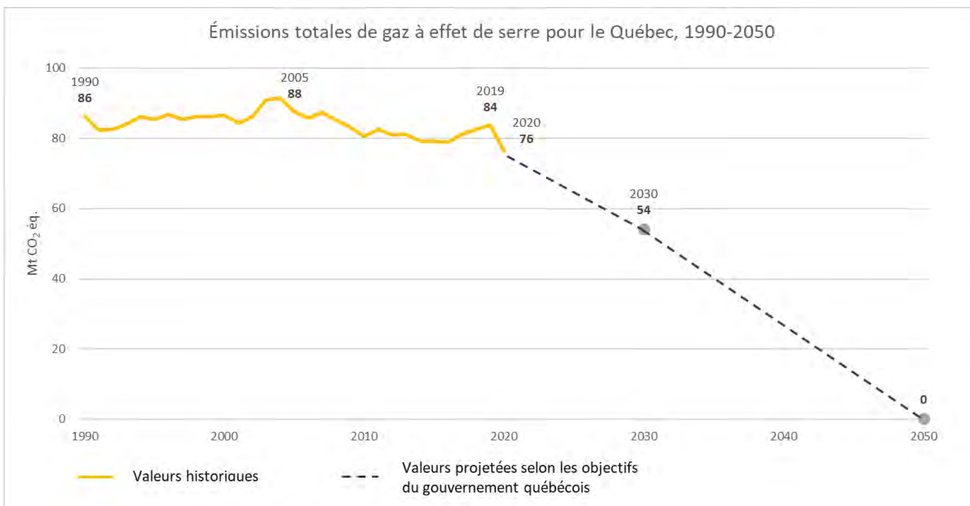

Figure 1 : Les émissions totales de gaz à effet de serre au Québec. 1990-2050
(Tableau A11-11, ECCC, 2021; MELCC, s. d.)

Selon l'étude sur les « Perspectives énergétiques canadiennes 2021 » réalisée par l'Institut de l'énergie Trottier (2021), qui propose une comparaison des scénarios de transformation permettant d'atteindre différents objectifs de réduction des émissions de GES au Canada, l'objectif de la carboneutralité change complètement la donne. En effet, viser la carboneutralité implique des efforts substantiels de réduction des émissions de GES auxquels viendront s'ajouter des solutions de compensation pour les émissions résiduelles incompressibles. Ce nouveau paradigme implique une reconfiguration profonde de notre système énergétique en passant d'un système où les combustibles fossiles occupent une place prépondérante (Figure 2) pour se diriger vers un système où les énergies à faibles émissions seront priorisées (Figure 3). Ce constat est également valide pour l'ensemble de la province de Québec.

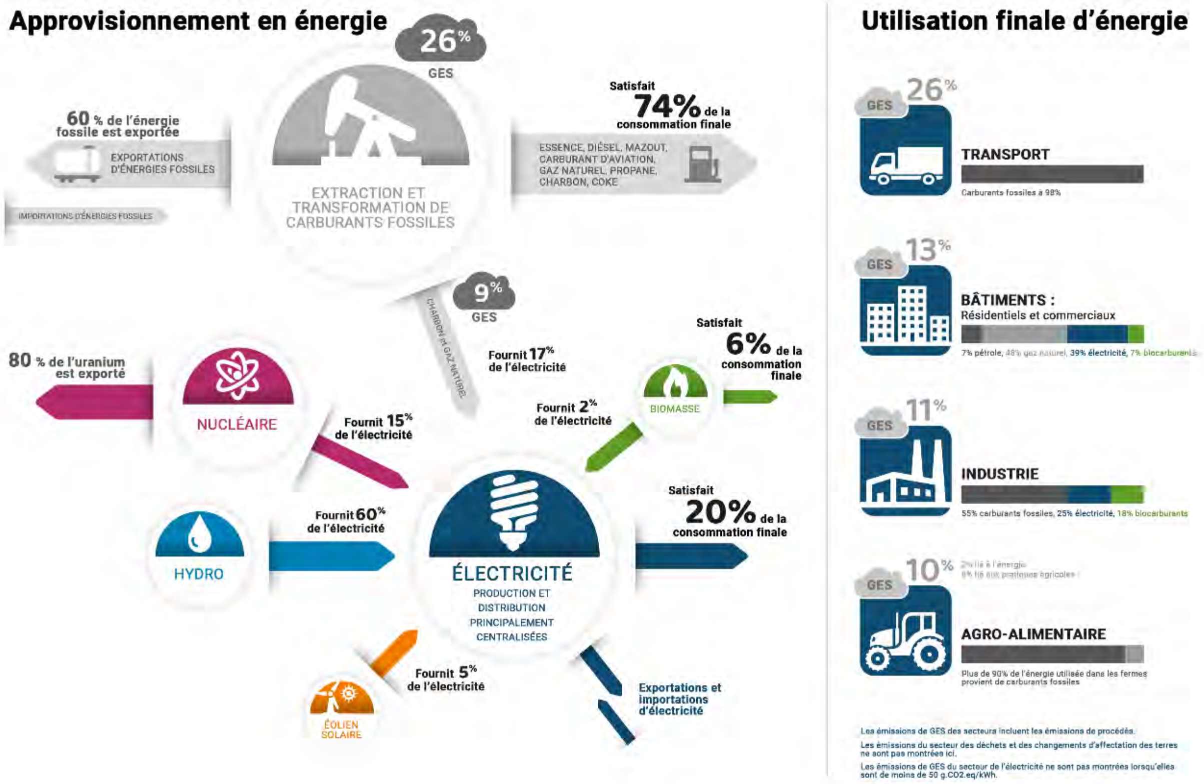

Figure 2 : Schéma du système énergétique canadien
(Traduit de Meadowcroft, 2021)

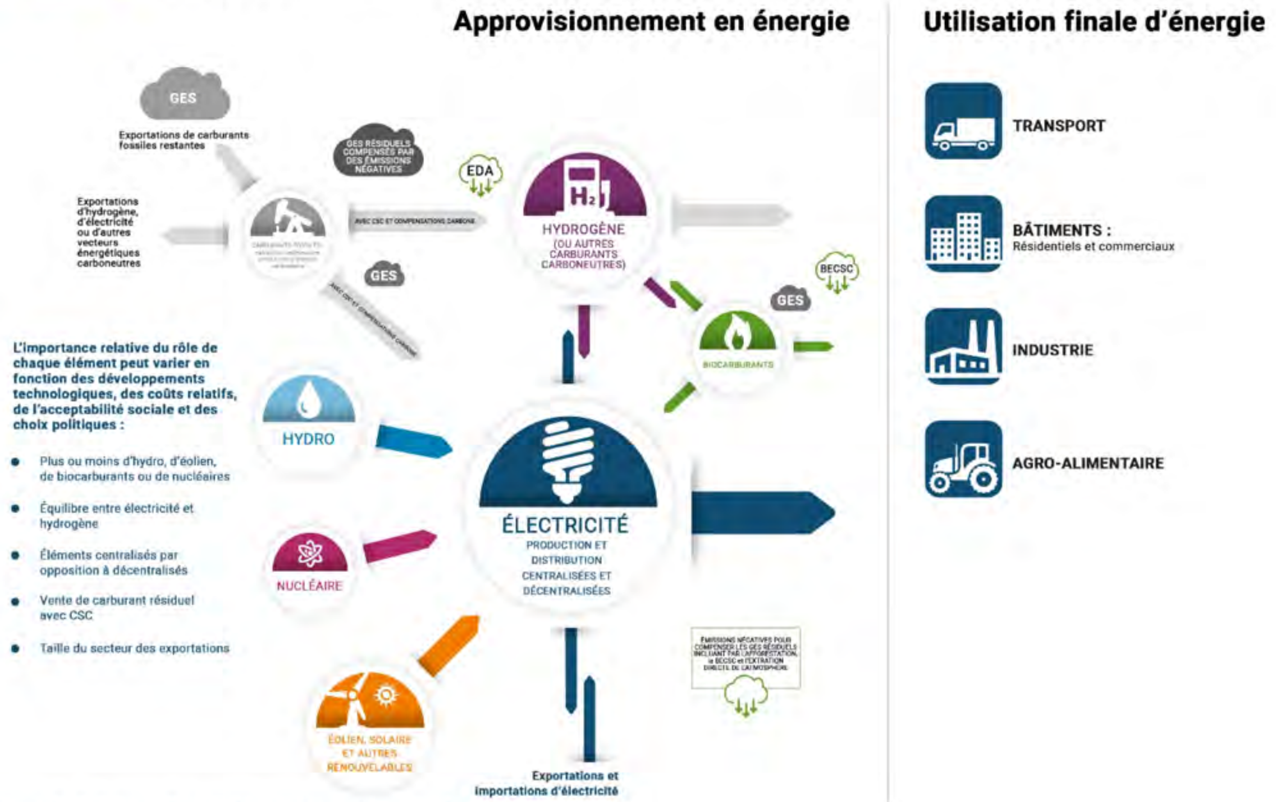

Figure 3 : Schéma d'un système énergétique carboneutre
(Traduit de Meadowcroft, 2021)

Un contexte géographique particulier ainsi que certaines décisions politiques prises dans le passé font que le Québec produit la majeure partie de son électricité à partir de barrages hydroélectriques. Cette situation lui confère une position unique au monde car son électricité est largement décarbonée et les barrages permettent une grande flexibilité d'opération. Ceux-ci offrent notamment la possibilité de procéder à un démarrage rapide des turbines pour répondre à la demande, ou encore la possibilité de stocker de l'énergie. Le Québec doit donc développer des solutions sur mesure pour paver sa voie vers la carboneutralité.

Les trois principaux secteurs à décarboner au Québec sont les secteurs de l'industrie, du transport et du bâtiment, en particulier le chauffage. À ceux-ci s'ajoutent d'autres secteurs, comme l'agriculture et les déchets, qui doivent également être décarbonés.

L'hydrogène à faibles émissions de carbone peut avoir sa place dans les trajectoires qui mèneront le Québec à la carboneutralité. Pour ce faire, il faut aller au-delà d'une approche qui consiste à identifier uniquement les situations où il est techniquement possible d'utiliser cet hydrogène à faibles émissions de carbone. Il est également nécessaire de préciser les utilisations où l'on trouve une valeur ajoutée par rapport à d'autres solutions en termes techniques, environnementaux et socio-économiques. Pour pouvoir répondre aux questions soulevées par la transition énergétique déjà en cours, il faut se doter d'outils pour construire les trajectoires qui nous mèneront vers un avenir souhaitable.

2.2. Les éléments de la méthodologie de l'Accélérateur de transition

Pour accélérer l'atteinte des objectifs de carboneutralité, l'approche dite « traditionnelle » qui vise à réduire de manière incrémentale et à moindre coût les émissions de GES suivant des jalons temporels doit être remplacée par une approche de transition axée sur l'objectif final qui est : la carboneutralité. Selon la définition de l'Accélérateur de transition (Meadowcroft, 2021), une telle approche consiste à accélérer les changements des systèmes ou des secteurs utilisés à grande échelle afin d'atteindre la carboneutralité, mais aussi dans le but de profiter d'autres avantages sociétaux qui ne sont pas

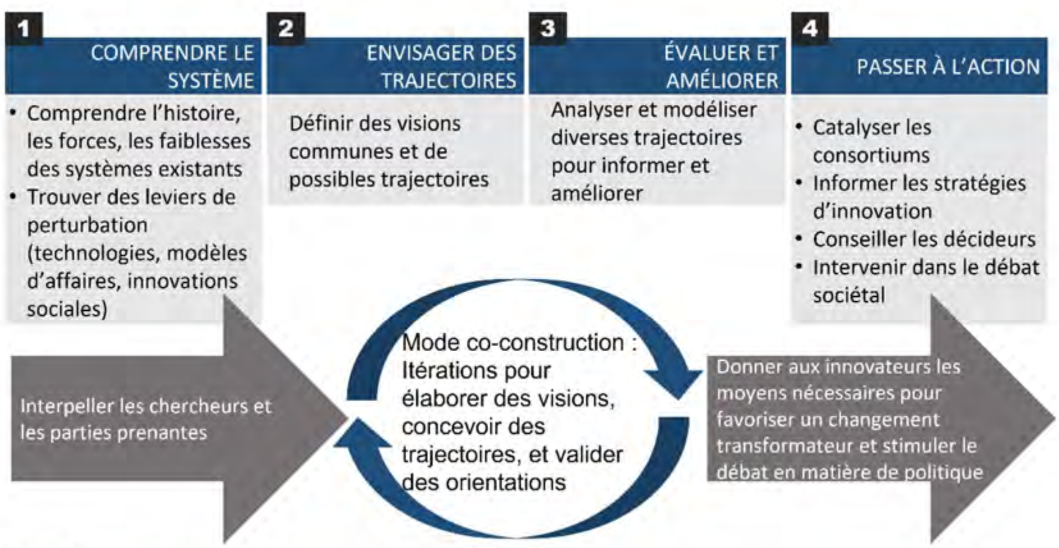

Figure 4 : Méthodologie en 4 étapes de l'Accélérateur de transition
(Meadowcroft et al., 2019)

directement liés au climat. Ainsi, dans le but de développer des trajectoires de décarbonation, l'Accélérateur de transition a développé une méthodologie en quatre étapes (Figure 4).

Cette méthodologie itérative en quatre étapes vise essentiellement à comprendre le fonctionnement des systèmes actuels afin de codévelopper, analyser et faire progresser des trajectoires de transition crédibles, performantes et convaincantes, et cela dans le but d'atteindre des objectifs sociétaux et économiques tels que la cible canadienne de carboneutralité en 2050. Cette approche se caractérise par l'intégration d'analyses critiques quantitatives et qualitatives des dimensions technologiques, sociales, économiques et politiques des trajectoires de transformation. L'accent sera mis sur le passage de l'analyse à l'action, à l'aide de carrefours d'appui à la transition.

Encadré 1 : Les critères d'évaluation des éléments d'une trajectoire

Crédible	
Maturité	C'est le progrès réalisé dans le développement de l'option, soit son évolution depuis le concept de base vers la solution établie. Est-ce une technologie qui a dépassé le stade d'essais en laboratoire? Bénéficie-t-elle d'années d'expérimentation pratique?
Viabilité économique	C'est la compréhension que l'on a actuellement des coûts économiques de l'option par rapport aux alternatives, à l'heure actuelle et dans l'avenir.
Acceptabilité sociale	C'est la probabilité que cette option soit largement acceptée par le public. Y a-t-il des groupes ou des communautés susceptibles de s'opposer de manière active à son déploiement?
Apte	
Adapté aux besoins/objectifs	C'est la capacité d'une option à combler le besoin pour lequel elle est proposée, en se basant sur les performances actuelles et celles anticipées dans l'avenir.
Potentiel de contribution à un avenir carboneutre	C'est le potentiel de contribution de l'option à un avenir carboneutre : (a) en tant que partie de cet avenir, (b) en tant qu'étape nécessaire pour y parvenir ou (c) en tant qu'accélérateur de changement sectoriel. Bien que des technologies et des processus spécifiques dans une société à zéro émissions nettes puissent avoir des émissions de GES résiduelles, les solutions systémiques et sectorielles devraient pouvoir s'approcher le plus possible des émissions nulles afin d'éviter qu'il soit nécessaire de garantir des émissions négatives importantes ailleurs.

Attrayant / Convaincant	
Pour les parties prenantes critiques	C'est l'attrait de l'option pour les groupes ayant le potentiel de faire progresser son développement et sa mise en œuvre. Il peut s'agir d'acteurs des milieux commerciaux, sociétaux, autochtones ou gouvernementaux. Une option pour laquelle il n'y a pas de promoteurs actifs aura du mal à progresser. Les « parties prenantes critiques » peuvent inclure ou non les opérateurs historiques du secteur, le changement pouvant être stimulé par des innovateurs externes.
Coûts et avantages	Ce sont les gains ou les pertes sur le plan sociétal qui ne sont pas liés aux gaz à effet de serre associés au déploiement de cette option, qui peuvent soit encourager ou décourager sa mise en œuvre, et qui ont la possibilité d'entraîner une transformation du système.
Opportunités de développement économique	Ce sont les possibilités économiques pour le Canada dans un monde en voie de décarbonation. L'option peut-elle générer des emplois, créer des marchés, des occasions d'affaires et promouvoir l'avantage comparatif du Canada dans l'avenir?
Prioritaire	
Priorité	C'est la mesure dans laquelle l'option devrait retenir l'attention des décideurs d'aujourd'hui. Ce critère s'appuie sur l'évaluation des huit catégories susmentionnées, en mettant l'accent sur le potentiel stratégique d'accélération du mouvement du système vers le zéro net. Ce que le « statut prioritaire » implique actuellement pour les politiques et les investissements dépend de l'état de développement de l'option, de la phase de transition du secteur et du contexte économique et politique en général. Dans certains cas, l'action doit se concentrer sur l'accélération du déploiement immédiat; dans d'autres, des recherches, des essais ou des expériences supplémentaires peuvent être aujourd'hui nécessaires pour préparer un déploiement à plus grande échelle dans l'avenir.

2.3. Les tendances actuelles de décarbonation dans les secteurs de l'économie québécoise

2.3.1. Les émissions de GES au Québec

Le Québec a établi des cibles de réduction d'émission globale (-37.5% en 2030 par rapport à 1990, puis la carboneutralité en 2050). Pour les atteindre, l'approche sectorielle offre de nombreux avantages. En effet, comme chaque secteur a ses propres caractéristiques et contraintes, une approche par secteur permet d'avoir des problèmes de taille plus abordable à solutionner, ainsi que d'avoir une certaine homogénéité (partage de structures de financement, de technologies, de politiques économiques). D'autre part, une approche sectorielle intégrée permet d'aborder non seulement les changements technologiques nécessaires, mais aussi les changements en termes de modèles d'affaires, d'infrastructures, de marché et d'habitudes sociales. Ces démarches sectorielles doivent toutefois être coordonnées afin de pouvoir maintenir la cohérence et la consistance nécessaires dans les efforts déployés pour atteindre les objectifs globaux.

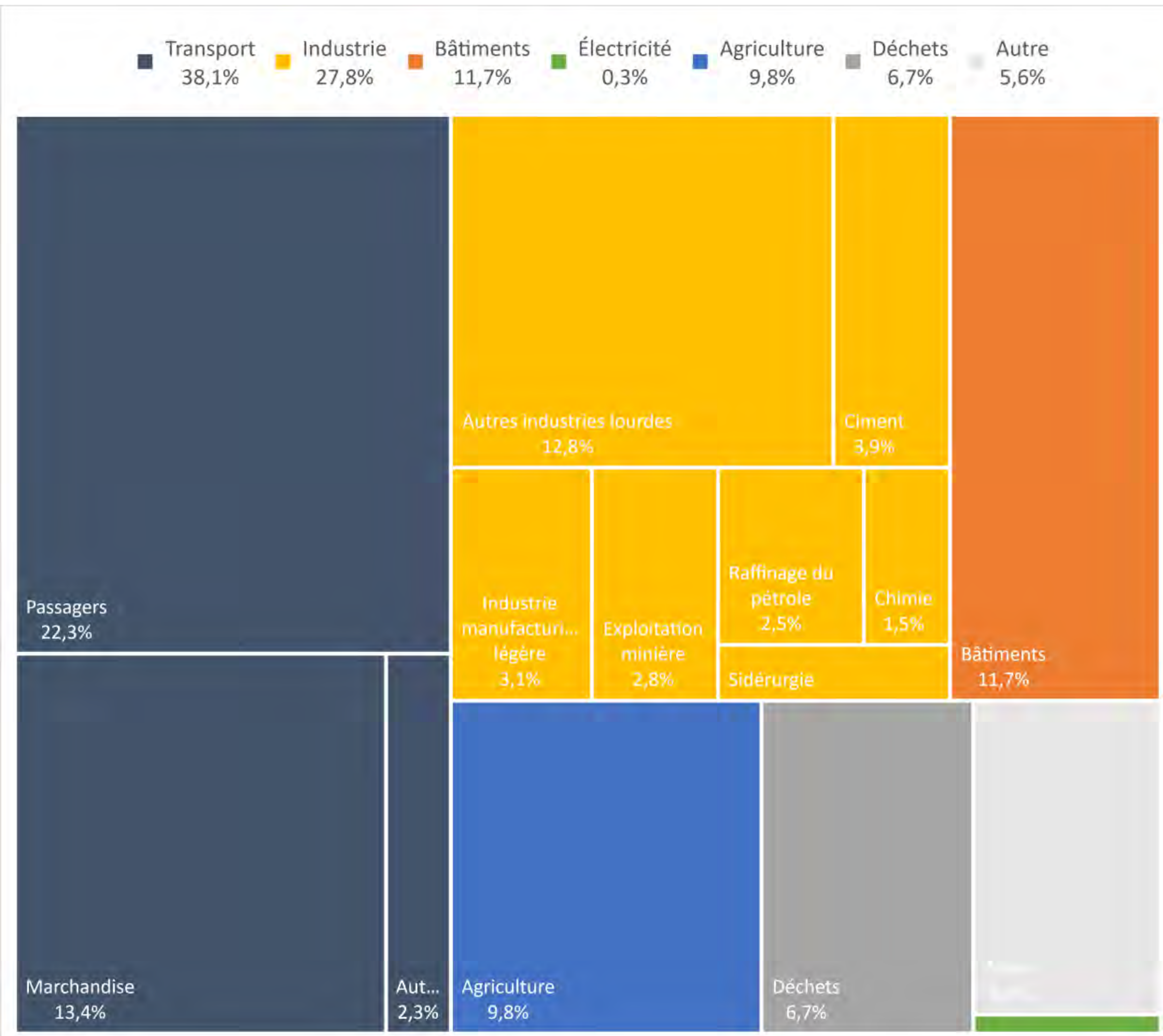

Figure 5 : Les émissions de GES au Québec en 2019, en fonction des secteurs économiques (Total : 84 Mt éq CO_2) (ECCC, 2022)

Notes :

- Émissions de GES selon les secteurs économiques définis par ECCC
- Bâtiments : industrie des services, commercial, institutionnel et résidentiel; comprend la combustion fixe mais aussi l'électricité, les halocarbures et autres produits non énergétiques.
- Autres industries lourdes : Fonte et raffinage (métaux non ferreux, dont aluminium) + pâtes et papiers + chaux et gypse.
- Autre : pétrole et gaz (à l'exception du raffinage de pétrole) + construction + ressources forestières.

2.3.2. Commentaires sur les secteurs et sous-secteurs économiques du Québec

Le choix des secteurs et sous-secteurs qui ont été évalués pour définir l'orientation des carrefours d'hydrogène est basé sur les critères suivants :

- la place de ce secteur dans l'économie actuelle et future;
- le fait que, jusqu'à maintenant, l'électrification directe de ce secteur est difficile;
- le fait que l'hydrogène est déjà utilisé, ou qu'il existe des usages connus dans ce secteur au niveau des procédés ou au niveau énergétique;
- le prix payé par ce secteur pour l'énergie qu'il consomme; et
- le niveau d'émission de GES.

Tableau 1 : Commentaires sur les différents secteurs et sous-secteurs considérés

Bâtiments	**Bâtiments**	Le chauffage des espaces et de l'eau peut être électrifié directement. Les solutions qui semblent faire consensus sont les thermopompes, les réseaux de chaleur et le solaire (passif et actif). Toutefois, l'électrification du chauffage soulève des défis en ce qui concerne la gestion de la demande de pointe.	Pedroli & Mousseau, 2020, 2022; Rosenow, 2022
Industrie	**Ciment**	En 2020, le Québec compte quatre cimenteries qui émettent un peu plus de 3 Mt d'éq. CO_2. Trois d'entre elles sont situées dans la région du Grand Montréal. Celle qui génère le plus d'émissions est la cimenterie de Port-Daniel en Gaspésie. Environ 65 % des émissions de GES proviennent du procédé, le reste découlant de la combustion de combustibles fossiles (charbon, gaz naturel, huile lourde). La principale piste avancée pour réduire les émissions provenant du procédé est l'utilisation du captage et de la séquestration des GES. Des efforts pour décarboner la combustion sont réalisés avec notamment le procédé Synergia de Ciment Québec, ou encore l'utilisation de biomasse comme le prévoit la cimenterie de Port-Daniel. Toutefois, des besoins énergétiques considérables, de l'ordre d'une	Ciment Québec, s. d.; ICI.Radio-Canada, s. d.; Pineau et al., 2019

		tonne de charbon par heure, rendent difficile le remplacement complet des combustibles fossiles.	
	Raffinage du pétrole	Deux raffineries sont en opération au Québec, soit celles des sociétés Énergie Valero à Lévis et Suncor à Montréal. Chacune d'elle émet plus d'un million de tonnes d'éq. CO_2/an. Elles produisent près de 90 % (246,4 t H_2/j) de l'hydrogène au Québec à partir de combustibles fossiles (gaz naturel et naphta lourd).	MELCC, 2021; Whitmore & Pineau, 2022
Industrie	**Chimie**	Deux entreprises de fabrication de produits chimiques génèrent de l'hydrogène en grande quantité comme sous-produit de leurs procédés, soit la société Olin à Bécancour qui utilise un procédé d'électrolyse chlore-soude, et la société Nouryon à Magog qui utilise un procédé de production de chlorate de sodium. Plusieurs industries au Québec consomment de l'hydrogène comme intrant de leur procédé, entre autres pour la production d'engrais, de cosmétiques et de matériel électronique tel que les semi-conducteurs. Il existe plusieurs solutions d'électrification directe pour remplacer la combustion produisant la chaleur nécessaire aux procédés (entre autres la biomasse, les thermopompes et les technologies électrothermiques).	Furszyfer Del Rio et al., 2022; MEI, s. d.; Meillaud, 2020; Pineau et al., 2019; Whitmore & Pineau, 2022; Pyonnier, 2022
	Sidérurgie	En grande partie grâce à son électricité décarbonée et abordable, le Québec compte de nombreux acteurs dans l'industrie de la sidérurgie, dont de grandes entreprises internationales comme les sociétés Arcelor Mittal et Rio Tinto Fer et Titane. La technologie des fours à arcs électriques est celle qui est la plus utilisée dans la province, et aucun haut fourneau n'est en exploitation. L'association canadienne des producteurs d'acier considère l'hydrogène à faibles émissions comme une option potentielle pour la production de chaleur des procédés, ou encore comme agent réducteur dans les procédés.	CSPA & CCRA, 2020
	Autres industries	Les producteurs d'aluminium, qui profitent également des caractéristiques avantageuses de l'électricité	Rio Tinto, 2022

	lourdes (dont la production d'aluminium)	québécoise, sont très présents dans la province. Cette industrie émet entre 5 et 7 Mt d'éq. CO_2. Parmi les efforts de décarbonation menés dans le secteur, citons les sociétés Alcoa et Rio Tinto qui ont développé un procédé d'électrolyse de l'aluminium qui élimine les émissions directes de GES provenant du procédé. Elles ont formé la coentreprise Elysis dont le siège social est situé à Montréal. En ce qui concerne l'industrie des pâtes et papiers, il existe plusieurs solutions d'électrification directe pour remplacer la combustion produisant la chaleur nécessaire aux procédés (entre autres la biomasse, les thermopompes et les technologies électrothermiques).	

Industrie	**Industrie manufacturière légère**	Il existe plusieurs solutions d'électrification directe pour le chauffage des espaces et la production de la chaleur nécessaire aux procédés (entre autres la biomasse, les thermopompes et les technologies électrothermiques). Toutefois, l'électrification de la production de chaleur pose des défis en ce qui concerne la gestion de la demande de pointe.	Pineau et al., 2019
	Exploitation minière	Les émissions générées par l'exploitation minière résultent principalement de la combustion de combustibles fossiles (plus de 80 % des émissions du secteur), en particulier du diésel qui sert à la mobilité de la machinerie et à la production de l'électricité. Au Québec, la chaleur générée sur les sites miniers est généralement produite à partir de mazout ou de coke. Une partie de la machinerie fixe fonctionne déjà à l'électricité, de même qu'une partie de la machinerie mobile (généralement par des systèmes à batterie). Les solutions considérées pour décarboner le secteur comprennent, entre autres, l'électrification, le remplacement des combustibles fossiles par des énergies renouvelables et le stockage de l'énergie pour produire de l'électricité (éolien, solaire, batteries lithium-ion, hydrogène) ainsi que l'automatisation des opérations.	Pineau et al., 2019; Rogers et al., 2019; TUGLIQ Énergies Co., 2016; Zuliani et al., 2021

Les enjeux soulignés dans le tableau ci-dessus concernent surtout les aspects technologiques. Il existe d’autres considérations qui affectent la demande d’énergie, de services et de biens (changements comportementaux, optimisation de la conception des bâtiments, modification des stratégies d’urbanisme, réduction de la production, etc.); cependant, la nature même des secteurs que nous évaluons fait que ces aspects ne sont pas pris en considération dans ce tableau. De même, le secteur des déchets et celui de l’agriculture[2] n’ont pas été évalués dans le cadre de cette étude car, à court et moyen terme, nous considérons qu’ils ne jouent pas un rôle direct significatif dans le développement éventuel d’un marché de l’hydrogène.

L’électricité

Le secteur de l’électricité au Québec est en situation de quasi-monopole avec la société d'État Hydro-Québec en ce qui a trait à la production, au transport et à la distribution d'électricité. Il existe toutefois quelques producteurs indépendants, surtout dans le secteur de l’éolien et les petites centrales hydroélectriques. Certaines communautés éloignées ne sont pas raccordées au réseau électrique d’Hydro-Québec et dépendent principalement de génératrices au diésel. L’électricité produite au Québec est largement décarbonée, mais l’ampleur de la croissance de la demande générée par l’électrification confronte la province à des défis de taille en ce qui concerne ses infrastructures électriques, tant au niveau de la production que du transport et de la distribution. L’électrification risque également d’accentuer les effets des pointes de demande. Plusieurs pistes sont évaluées pour gérer ces pointes de demande, notamment le stockage par batterie, le stockage thermique ou le stockage sous forme d’hydrogène (Edom et al., 2022). L’hydrogène peut aussi être brulé directement dans une chaudière (Pyonnier, 2022).

Le transport routier

Il existe un consensus concernant l’électrification directe des véhicules légers avec l’option des batteries lithium-ion. Cette tendance est moins prononcée pour les parcs de véhicules légers captifs à haute fréquence d’usage et les véhicules lourds (Hunter et al., 2021; IRENA, 2022; Kayser-Bril et al., 2021; Khan et al., 2022).

Bien que le transport lourd soit potentiellement un secteur de demande d’hydrogène, le choix a été fait de ne pas traiter ce secteur dans le présent rapport car nous estimons que ce secteur est moins mature que d’autres secteurs pour la technologie de l'hydrogène à causes des raisons suivantes :

- Il manque beaucoup de données récentes dans ce secteur (profil de déplacement routier, nombre de camions par catégorie, etc.). Les données des études les plus récentes (2019-2021) datent de 2006 (soit de plus de 16 ans) ou au mieux de 2015 (soit près de 7 ans). Les pratiques dans le secteur du transport de marchandises évoluant dans le temps, il est important d'avoir une information reflétant raisonnablement la réalité la plus récente possible. Il faut donc une phase de collection de données. Ce genre de tâches est très chronophage.

[2] Les engrais sont classés dans l’industrie chimique.

- De plus, choisir l'hydrogène pour le transport lourd implique des infrastructures importantes à l'échelle de la province, cela vient avec des risques qui peuvent être atténués et mieux appréhendés si la mobilité à l'hydrogène est testée dans des secteurs ayant un impact plus localisé.
- Plusieurs autres technologies à faibles émissions carbone sont envisagées par le secteur, une analyse comparative de celles-ci dépasserait de loin le mandat accordé ici.
- Le transport lourd est fortement lié au commerce interprovincial et international (USA), il serait toutefois possible de s'attaquer d'abord à certains corridors à l'intérieur de la province. Il faudrait tout de même travailler en collaboration avec les partenaires des autres provinces et des USA pour avoir une stratégie commune et cohérente.

Transport – autres

Les secteurs du transport maritime, ferroviaire et aérien n’ont pas été traités de manière approfondie dans cette étude. Toutefois, l’hydrogène possède le potentiel pour jouer un rôle dans la décarbonation de ces secteurs (IRENA, 2022).

3. Concepts, et contexte de déploiement du marché de l'hydrogène au Québec

3.1. Rappel des objectifs de l'étude

Cette étude vise à **identifier et caractériser des orientations stratégiques** qui permettront le **déploiement et la mise à l'échelle du marché de l'hydrogène au Québec**, tout en restant compatibles avec les cibles de réduction de GES de la province et en particulier celle de la carboneutralité à l'horizon 2050. Les orientations proposées contribueront, sur **un horizon d'une quinzaine d'années**, à **créer une masse critique pour atteindre un marché de l'hydrogène qui soit compétitif du point de vue économique**.

3.2. Concept de carrefour d'appui à la transition énergétique

Un carrefour d'appui à la transition énergétique est une organisation dont le mandat est de susciter et de mener un ensemble de dialogues stratégiques entre plusieurs acteurs intervenant à différentes étapes de la chaîne de valeur d'une technologie. Ce n'est pas une structure matérielle rigide régie par des procédures administratives lourdes. Le carrefour mise plutôt sur une approche agile et flexible capable de s'adapter rapidement aux changements locaux, régionaux, nationaux et même internationaux, ainsi qu'aux conditions particulières, risques et opportunités qui se présentent. Il s'appuie de manière continue sur des analyses multifacettes (techniques, environnementales et des modèles d'affaires, des modèles de financement, des barrières réglementaires et sociales, des chaînes de valeur) pour favoriser le passage à l'action en priorisant l'utilisation des technologies existantes et l'innovation des modèles d'affaires (Edom & Mousseau, 2022).

Un carrefour d'appui à la transition énergétique se définit de la manière suivante :

> *Une organisation agile et flexible qui appuie la reconfiguration de systèmes en vue de la décarbonation de notre société. Pour un marché émergent sélectionné, elle travaille à la création d'une masse critique et à l'atteinte d'un fonctionnement viable économiquement en renforçant les maillons les plus faibles de la chaîne de valeur. À cette fin, elle s'appuie sur les technologies existantes, des analyses multifacettes et divers partenariats avec les secteurs public et privé.*

3.3. Contexte de déploiement du marché de l'hydrogène

3.3.1. Enjeux

En dépit des nombreuses incertitudes entourant le développement du marché de l'hydrogène, certains critères sont privilégiés pour identifier des secteurs ayant un potentiel de demande. Ces critères, qui s'appuient sur plusieurs études (IEA, 2022; IRENA, 2022; Lazard, 2021; Riemer et al., 2022), sont les suivants :

- Viser les secteurs où l'hydrogène apporte le plus de valeur ajoutée;
- Prioriser les usages où il n'existe pas actuellement de solutions alternatives viables;

- Favoriser une consommation locale de l'hydrogène car sa conversion et son transport sont énergivores;
- Prioriser les secteurs où l'hydrogène est déjà utilisé; et
- Viser des usages où la demande peut rapidement contribuer à une mise à l'échelle du marché de l'hydrogène.

L'hydrogène considéré dans cette analyse est surtout l'hydrogène marchand. Toutefois, certaines entreprises industrielles produisent de l'hydrogène qu'elles consomment sur site. Au Québec, par exemple, c'est le cas de la société Arcelor Mittal.

3.3.2. Prix cible de l'hydrogène

À court terme, l'hydrogène a le potentiel d'être un produit compétitif dans l'industrie, en particulier pour les véhicules lourds (mine, construction), comme intrant dans certains procédés industriels et, dans une moindre mesure, comme outil de gestion de la demande de pointe ou encore dans la production de chaleur (Tanguy et al., 2020; Riemer et al., 2022).

De manière générale, le coût de l'unité d'énergie peut grandement différer selon le vecteur énergétique utilisé, l'usage qui en est fait, ainsi que l'endroit où cette énergie est consommée. Au Québec en 2021-2022, les consommateurs raccordés au réseau d'Hydro-Québec ont payé leur électricité entre 0,057 $/kWh[3] et 0,142 $/kWh selon la catégorie de client (Hydro-Québec, 2021). Dans les communautés éloignées qui ne sont pas connectées au réseau, comme certaines communautés autochtones ou encore certains sites miniers, le prix du kilowattheure peut atteindre jusqu'à 1,20 $ (TUGLIQ Énergies Co., 2016). La Figure 6 illustre bien cet écart. Elle montre aussi le coût du kilowattheure livré à Hydro-Québec annoncé dans le cas du projet d'Apuiat, soit 0,06 $/kWh (en vert), ainsi que le coût estimé du kilowattheure pour un projet éolien de taille moyenne[4] dans les régions du nord du Québec, soit 0,15 $/kWh (en vert) (ICI.Radio-Canada.ca, 2021; Zuliani et al., 2021).

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[3] Toutes les valeurs monétaires sont en dollars canadiens sauf indication contraire.
[4] Selon Zuliani et al. (2021), un projet éolien de taille moyenne (40 MW) dans les régions éloignées du nord du Canada coûte de deux à trois fois plus cher qu'un projet de grande puissance dans les régions proches des grands centres.

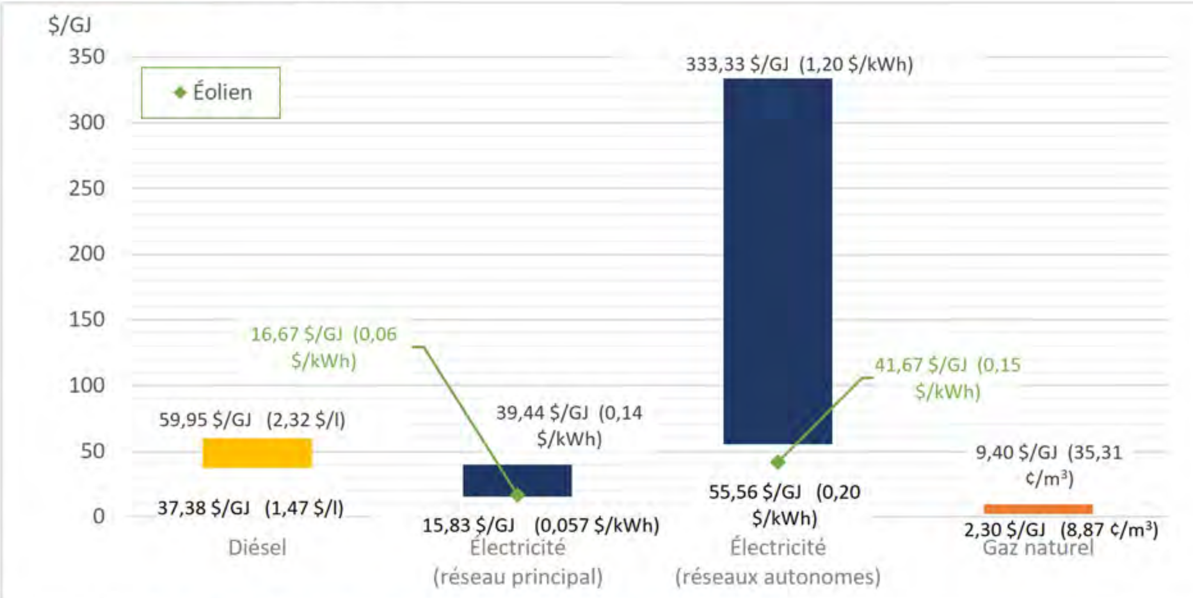

Figure 6 : Le coût du diésel, de l'électricité et du gaz naturel au Québec en 2022

En plus des prix de l'électricité, la Figure 6 présente l'indicateur quotidien du coût d'acquisition (IQCA) minimum et maximum pour le diésel au Québec en 2022 pour les régions de l'Abitibi-Témiscamingue, la Côte-Nord et le Nord-du-Québec (en excluant le Nunavik). L'IQCA a oscillé entre 1,49 $/l et 2,56 $/l en 2022 (Régie de l'énergie du Québec, 2022c). Cet IQCA est défini comme étant une évaluation de ce qu'il en coûte à un détaillant pour acquérir le carburant (Régie de l'énergie du Québec, 2022a). Il comprend le prix minimal à la rampe de chargement (PMRC)[5], le coût minimal de transport du produit entre le point d'approvisionnement et l'essencerie ainsi que les taxes fédérales et provinciales. **Les grands consommateurs de diésel, comme les mines, peuvent négocier de gré à gré des contrats avec les grossistes afin d'obtenir un prix d'achat plus compétitif. Ces prix sont confidentiels et donc inaccessibles au public,** mais ils sont fort probablement plus proches du PMRC que du prix à la pompe (González, 2020).

Depuis 2017, le prix de fourniture du gaz naturel est en deçà de 10 $/GJ (37,9 ¢/m³). À ce prix de fourniture s'ajoutent entre 5 et 7 $/GJ pour prendre en compte les coûts de transport, d'équilibrage, des ajustements liés aux inventaires, de la distribution et des frais liés au SPEDE (Système québécois de plafonnement et d'échange de droits d'émission) (Énergir, s. d.). Le prix du gaz naturel livré est comparable à celui de l'électricité dans le sud du Québec pour les clients industriels et il est nettement inférieur à celui du diésel.

[5] Le PMRC comprend le prix du pétrole brut, la marge de raffinage, la quote-part payable au MERN ainsi que les frais relatifs au SPEDE (Régie de l'énergie du Québec, 2022a).

Selon la Figure 8, et **considérant un prix livré du diésel pour les grands consommateurs qui est compris entre 1,004 $/l et 1,944 $/l[6], l'hydrogène devient compétitif sans subvention pour des prix livrés cibles compris entre 3,63 $/kg et 7,04 $/kg** lorsque que l'on ne tient pas compte de l'efficacité relative[7] des technologies. Par exemple, si on prend en compte cette notion dans le cas de véhicules hors route lourds

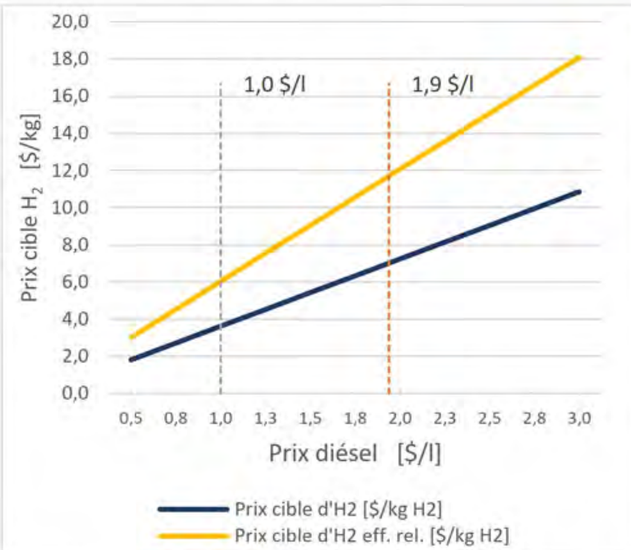

Figure 8 : Le prix cible de l'H_2 basé sur le prix du diésel

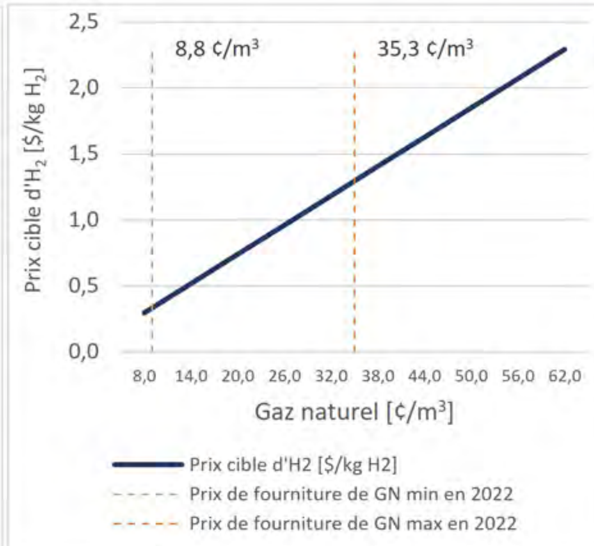

Figure 7 : Le prix cible de l'H_2 basé sur le gaz naturel

(secteur minier) en supposant une efficacité relative de 0,6[8], le prix cible de l'hydrogène se situe entre 6,06 $/kg et 11,73 $/kg. Selon la Figure 7, **pour être compétitif avec les prix du gaz naturel actuels au Québec, l'hydrogène devrait atteindre un prix cible qui se situe environ entre 0,5 $/kg et 1,3 $/kg.**

Avec l'augmentation des frais relatifs au SPEDE qui composent le prix du diésel, comme le montre le Tableau 2, de même que la tendance à la hausse du prix du pétrole observée au port de New York depuis 2016[9], il est probable que le prix du diésel au Québec continuera de croître dans l'avenir en dépit des oscillations du marché.

Tableau 2 : Le prix du carbone et son impact sur le prix du diésel et du gaz naturel
(Lecavalier, 2022; MELCC, 2022)

	2022 QC	2030 QC	2030 CA
Prix du carbone [$/t $_{éq\ CO2}$]	38,3	97	170
Impact sur le prix du diésel [¢/L]	10,7	27,2	47,7
Impact sur le prix du gaz naturel [¢/m^3]	7,3	18,4	32,3

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[6] Ces valeurs sont les PMRC minimums et maximums rapportés par la Régie de l'énergie du Québec entre janvier et août 2022.

[7] L'efficacité relative = efficacité du moteur thermique au diésel/efficacité du moteur électrique alimenté par une pile à combustible.

[8] On suppose ici un rendement de 0,5 pour un véhicule lourd fonctionnant avec une pile à combustible hydrogène, et 0,3 pour un véhicule lourd à moteur diésel à combustion interne (Ballard, 2021).

[9] Note basée sur la figure 16 de González (2020) et sur la Régie de l'énergie du Québec, 2022b.

En résumé, le prix actuel du gaz naturel rend son remplacement par l'hydrogène difficile à court et moyen termes dans la plupart des usages sans recourir à un ensemble de mesures pour soutenir et favoriser ce changement. Il existe déjà de plus en plus d'opportunités pour décarboner certains usages employant du diésel, en particulier dans les régions éloignées où ce carburant peut être très coûteux, notamment en raison du coût du transport. Malgré des prix d'électricité qui sont encore faibles par rapport au prix de l'hydrogène à faibles émissions, celui-ci peut jouer un rôle pour faire face au défi grandissant de la gestion de la demande de pointe auquel sont confrontés les systèmes électriques.

3.3.3. La production d'hydrogène à faible émissions

3.3.3.1. Le reformage de méthane à la vapeur ou le reformage autotherme avec CSC

Actuellement, la technologie la plus utilisée pour la production d'hydrogène à travers le monde est le reformage de méthane à la vapeur (RMV). Comme le montre le Tableau 5 de la section 3.4, en 2021, plus de 95 % de l'hydrogène produit au Québec provient du gaz naturel ou de produits pétroliers (naphta lourd). Les technologies utilisant des énergies fossiles produisent un hydrogène ayant une intensité carbone d'environ 8 à 12 kg d'éq. CO_2 par kg d'H_2 (figure 17, Gouvernement du Canada, 2020; Neisiani et al., 2020).

Certaines provinces, comme l'Alberta, étudient la possibilité de coupler le procédé de reformage de méthane à la vapeur, ou le procédé de reformage autotherme (RA), à un système de captage et séquestration du carbone (CSC) afin de produire un hydrogène à faibles émissions de carbone, soit environ 0,9 à 3,1 kg d'éq. CO_2 par kg d'H_2 à un taux de captage de CO_2 de 90 %. L'hydrogène produit à partir de cet ensemble de technologies (RMV ou RA + CSC) est couramment appelé hydrogène bleu. Son coût de production est grandement influencé par le prix du gaz naturel. Dans l'étude technico-économique portant sur la chaîne de valeur de l'hydrogène pour le transport lourd en Alberta, Khan et al. (2022) calculent les plages de coût de production de l'hydrogène bleu au Canada pour trois horizons temporels. Ces coûts de production varient en fonction de la capacité de production quotidienne d'une centrale (100 à 600 t H_2/j) et du prix du gaz naturel (1 à 17 $/GJ). Le cas de figure étudié est celui d'une production centralisée, et les auteurs supposent un taux de rendement de 8 % sur le coût du capital investi.

En prenant un prix du gaz naturel de 5 $/GJ, ce qui est proche de la valeur médiane du prix du gaz au Québec pour 2021-2022[10], et une production de 100 t H_2/j, le prix de production d'un kilogramme d'hydrogène serait de 2,3 $/kg H_2 (14,3 $/GJ H_2) à court terme et de 2 $/kg H_2 (16,4 $/GJ H_2) en 2030.

La production d'hydrogène à faibles émissions par RMV ou RA + CSC est compétitive en termes de coûts pour une production centralisée. Toutefois, elle présente plusieurs inconvénients :

- Elle nécessite de passer par des étapes de purification, surtout si l'hydrogène est destiné à être utilisé dans une pile à combustible;

[10] 5 $/GJ ≈ 4,64 $/GJ, valeur médiane calculée pour 2021-2022 à partir de l'historique du prix de référence Énergir (Énergir, s. d.).

- Elle n'est pas adaptée à une production décentralisée car les coûts du système de CSC ne sont compétitifs qu'à partir d'environ 1 Mt CO_2 captée par an. Cela implique une production d'hydrogène par RMV ou RA d'au moins 400 t H_2/j;
- La séquestration de carbone nécessite un sous-sol ayant des caractéristiques géologiques spécifiques qu'on ne retrouve pas dans tous les cas; et
- La technologie de CSC présente encore beaucoup d'incertitudes.

Au Québec, le potentiel de stockage géologique est limité (Bédard et al., 2012, 2017; Konstantinovskaya et al., 2011). Il serait donc peut-être judicieux de réserver le CSC aux procédés industriels pour lesquels il n'existe pas actuellement de solutions de décarbonation complètes et déployables, par exemple pour la production de ciment. De plus, le Québec n'étant pas un producteur de gaz naturel, cette production ne présente donc que peu d'attrait pour la province.

Il serait toutefois possible, dans une certaine mesure, d'importer de l'hydrogène bleu des autres provinces. Pour que cette option soit envisageable, il faudrait que le prix de production, de conditionnement (compression et/ou liquéfaction), de transport et de livraison soit compétitif avec le coût de la production locale par électrolyse.

3.3.3.2. L'électrolyse à partir d'électricité à faibles émissions de carbone

Au Québec, l'accent est mis sur la production d'hydrogène à faibles émissions de carbone par électrolyse (MERN, 2022b). En 2021, l'hydrogène produit par électrolyse ou obtenu comme sous-produit d'un autre procédé chimique représente environ 4 % de la production totale du Québec. Il existe plusieurs technologies d'électrolyse, soit :

- L'électrolyse alcaline (EA);
- L'électrolyse à membrane échangeuse de protons (EMEP); et
- L'électrolyse à oxyde solide (EOS).

Les électrolyseurs à oxyde solide n'ont pas atteint un stade de commercialisation comparable à celui des deux autres technologies.

Tableau 3 : Les caractéristiques principales des électrolyseurs à membrane échangeuse de protons (EMEP) et des électrolyseurs alcalins (EA)
(Cummins, 2022; IEA, 2022; IEA, 2019; Langlois-Bertrand et al., 2021; Neisiani et al., 2020)

	EMEP	**EA**
Pression d'opération [bars]	15-30	2-10
Durée de vie du système (an)	10-20	20-30
Efficacité [kWh/kg H_2]	51-55	55-60
Démarrage à froid [min]	<10	>15

Coût actuel [$/kW]	1220-2750	760-2140
Coût à l'horizon 2030 [$/kW]	1070	880
Inconvénients	• Nécessite l'utilisation d'eau d'une grande pureté • Coût d'investissement généralement plus élevé • Durée de vie typiquement plus courte	• Dynamique lente • Plage de fonctionnement plus réduite (de 10 à 110 % de la charge nominale) • Pression de fonctionnement limitée • Électrolyte corrosif
Avantages	• Conception compacte • Produit de l'H_2 d'une très grande pureté (> 99,995 %) • Produit de l'H_2 déjà comprimé réduisant les besoins de compression pour le stockage et le transport • Dynamique rapide • Plage de fonctionnement large (de 0 à 160 % de la charge nominale)	• Technologie bien établie • Coût d'investissement généralement plus faible • Représente 60 % de la capacité de fabrication d'électrolyseurs à travers le monde

La technologie EMEP est considérée comme étant celle qui est la plus apte à fonctionner à partir d'une électricité produite par des énergies renouvelables variables, grâce, entre autres, à sa capacité à démarrer rapidement et à sa large plage de fonctionnement, comme l'indique le Tableau 3. Toutefois, avec une conception des équipements auxiliaires adaptée, les électrolyseurs alcalins peuvent offrir des performances équivalentes (IRENA, 2020).

Le coût de production d'hydrogène par électrolyse dépend de plusieurs facteurs, notamment du coût d'investissement de l'électrolyseur, du prix de l'électricité alimentant le procédé et de l'efficacité de l'électrolyseur. L'amélioration technique et l'augmentation de la production des électrolyseurs contribueront à faire diminuer leur coût d'investissement (IEA, 2019, 2022; IRENA, 2020). **Dans la Figure 9, on note que pour un prix de l'électricité de 6 ¢/kWh (prix d'achat par Hydro-Québec du kilowattheure annoncé pour le projet éolien d'Apuiat dont la mise en service est prévue pour 2024), le coût actualisé estimé de production d'hydrogène en 2022 varie entre 4,1 $/kg H_2 et 6,7 $/kg H_2, selon le facteur de charge de l'électrolyseur, et il peut éventuellement diminuer d'ici 2030, pour se situer entre 3,6 $/kg H_2 et 5,5 $/kg H_2.**

a) **Actuel [$/kg H_2]**

Heure d'opération (millier d'h/an)										
7	2,1	2,6	3,1	3,6	4,1	4,7	5,2	5,7	6,2	6,8
6	2,2	2,8	3,3	3,8	4,3	4,8	5,4	5,9	6,4	6,9
5	2,5	3	3,5	4	4,6	5,1	5,6	6,1	6,6	7,2
4	2,8	3,4	3,9	4,4	4,9	5,4	6	6,5	7	7,5
3	3,4	4	4,5	5	5,5	6	6,6	7,1	7,6	8,1
2	4,6	5,1	5,7	6,2	6,7	7,2	7,7	8,3	8,8	9,3
	20	30	40	50	60	70	80	90	100	110

Prix du MWh d'électricité

b) **2030 [$/kg H_2]**

Heure d'opération (millier d'h/an)										
7	1,7	2,2	2,7	3,2	3,6	4,1	4,6	5,1	5,6	6,1
6	1,8	2,3	2,8	3,3	3,8	4,2	4,7	5,2	5,7	6,2
5	2,0	2,5	3,0	3,4	3,9	4,4	4,9	5,4	5,9	6,3
4	2,3	2,7	3,2	3,7	4,2	4,7	5,2	5,6	6,1	6,6
3	2,7	3,2	3,7	4,1	4,6	5,1	5,6	6,1	6,6	7,0
2	3,6	4,0	4,5	5,0	5,5	6,0	6,4	6,9	7,4	7,9
	20	30	40	50	60	70	80	90	100	110

Prix du MWh d'électricité

◆ Électricité du réseau à 0,0602 $/kWh (tarif grande puissance d'Hydro-Québec) et facteur de charge de 68%

◆ Électricité d'énergie éolienne à 0,06 $/MWh et facteur de charge de 40%

Figure 9 : La variation du prix actualisé de la production d'hydrogène, en $/kg H_2, en fonction du nombre d'heures d'opération et du prix du MWh d'électricité pour un électrolyseur de 4.2 MW de nos jours (a), et en 2030 (b).

(Figure adaptée du rapport de Khan et al. 2022).

Notes :

- Efficacité de l'électrolyseur : 52 kWh/kg H_2
- Le facteur de charge pour l'électricité du réseau, soit 68 %, provient du rapport « The future of hydrogen » (IEA, 2019). Ce facteur se base sur l'existence d'un prix de l'électricité qui varie en fonction de la pointe de demande. Ce mécanisme est peu présent au Québec. Il pourrait donc être raisonnable de supposer un facteur de charge qui soit plus élevé.
- Le facteur de charge pour l'éolien (40 %) provient de l'article de Zuliani et al., 2021.
- Les calculs sont faits pour un CAPEX d'électrolyseur de 1 377 $/kW pour le tableau a, et un CAPEX de 1 071 $/kW pour le tableau b (IEA, 2019).

Avec le prix actuel du kilowattheure au Québec pour les clients industriels connectés au réseau (5.70 ¢/kWh et 7.96 ¢/kWh (Hydro-Québec, 2021)), et les plus récents prix kilowattheure livré de l'éolien au Québec, l'hydrogène pourrait être livré à un prix compétitionnant celui du diésel sous certaines conditions. Parmi elles, deux conditions ont été identifiées :

- l'usage de l'hydrogène dans les régions éloignées où le prix du diésel est élevé;
- la production et l'utilisation localisées pour éviter les coûts de transports (IRENA, 2020).

Avec le prix actuel du kilowattheure au Québec pour les clients industriels connectés au réseau (5,70 ¢/kWh et 7,96 ¢/kWh (Hydro-Québec, 2021)), et les prix les plus récents du kilowattheure livré de l'éolien au Québec, l'hydrogène pourrait être livré à un prix pouvant compétitionner avec celui du diésel sous certaines conditions. Parmi ces conditions, deux ont été identifiées, soit :

- L'utilisation de l'hydrogène dans les régions éloignées où le prix du diésel est élevé; et
- La production et l'utilisation localisées pour éviter les coûts de transport (IRENA, 2020).

À l'horizon 2030, les coûts actualisés de l'éolien devraient continuer à décroître, ce qui augmentera l'attrait de cette énergie pour alimenter la production d'hydrogène (NREL, 2022). Le Tableau 4 résume les coûts projetés de production de l'hydrogène.

Tableau 4 : Les coûts projetés pour la production de l'hydrogène par RMV ou RA + CSC et par électrolyse [$/kg H_2]
(Khan et al., 2022)

	2022	2030	2050	
RMV ou RA + CSC	1,2-4,8	1,0-4,5	1,0-4,4	Prix du gaz naturel variant de 1 à 17 $/GJ Échelle de production variant de 100 à 600 t H2/j
Électrolyse	2,1-9,3	1,7-7,9	1,3-6,5	Prix de l'électricité variant de 20 à 110 $/MWh Heures d'opération de l'électrolyseur variant de 2000 à 7000 h/an

Dans les cas où l'eau nécessaire à l'électrolyse doit être dessalée et/ou transportée, les coûts associés sont faibles, de l'ordre de 0,5 % du coût d'électrolyse pour le dessalement et de 0,07 $/100 km pour le transport (IEA, 2022). Il existe d'autres technologies de production d'hydrogène à faibles émissions de carbone, telles que la pyrolyse de la biomasse. Ces technologies n'ont cependant pas encore atteint le stade de commercialisation à moyenne/grande échelle et ne sont donc pas analysées dans cette étude.

3.3.3.3. L'hydrogène produit à partir de biomasse

Bien que sa part actuelle dans la production mondiale d'hydrogène soit négligeable, la production d'hydrogène à partir de biomasse pourrait être appelée à jouer un rôle important dans les efforts de décarbonation. Par exemple, là où des ressources adéquates se trouvent concentrées, cette production pourrait voir son coût diminuer. En supposant une gestion active de la biomasse assurant son renouvellement rapide, une telle production représenterait également une alternative à faibles émissions par rapport à l'électrolyse qui a été décrite ci-dessus.

On classifie généralement les méthodes utilisées pour une telle production selon deux catégories distinctes, soit les méthodes thermochimiques et les méthodes biochimiques (Neisiani et al., 2020). Dans les méthodes thermochimiques, l'hydrogène est obtenu soit par gazéification ou par pyrolyse de la biomasse solide ou liquide. On forme ainsi un mélange gazier contenant du CO_2 et de l'H_2 qui, par la suite, peut être traité pour isoler l'hydrogène. Lorsque l'on procède par pyrolyse, la biomasse est chauffée rapidement en absence d'air. La ressource est ainsi vaporisée, pour être ensuite condensée en bio-huile. La phase suivante, qui est nécessaire, consiste en une gazéification permettant de produire un gaz de synthèse qui, encore ici, nécessite une étape finale de purification pour en extraire l'hydrogène.

La seconde catégorie, soit celle des méthodes biochimiques, utilise le biogaz issue de la digestion anaérobique de biomasse résiduelle, par exemple des résidus agricoles, des eaux usées industrielles ou provenant de stations d'épuration. Le biogaz ainsi obtenu peut ensuite être purifié pour produire du méthane, lequel peut subir un reformage à la vapeur comme décrit à la section 3.3.3.1.

Pour que la production d'hydrogène à partir de biomasse présente un intérêt dans une perspective de décarbonation, il faut toujours porter une attention particulière à deux aspects. En premier lieu, la disponibilité continue et la qualité de la ressource utilisée demande une gestion attentive du cycle d'approvisionnement de cette production. Par exemple, les ressources en résidus forestiers nécessitent parfois une décontamination (par exemple, le bois peut contenir des impuretés métalliques susceptibles d'endommager les équipements de traitement pour la gazéification). D'autre part, l'approvisionnement de ces ressources doit être coordonné afin de s'assurer de disposer de quantités suffisantes pour permettre une production qui soit rentable. En second lieu, *le CO_2 relâché par le traitement du mélange gazier* annule l'effet de stockage naturel de CO_2 par la biomasse utilisée. Il existe toutefois un potentiel de captage appliqué à ces procédés, ce qui permettrait d'en faire une production à faibles émissions, souvent considérée comme étant négative en termes d'émissions nettes, puisque le CO_2 capté et stocké est retiré de l'atmosphère lors du cycle de vie de la biomasse utilisée (IEA, 2022). Pour qu'elle soit complète, cette comptabilisation demande toutefois de prendre en compte l'impact d'une telle utilisation sur la biomasse existante. Autrement dit, il faut s'assurer de la soutenabilité de la ressource si sa coupe est utilisée pour remplir ces objectifs.

Nonobstant ce potentiel, il n'existe qu'un seul projet en développement au Québec qui utilise la biomasse, soit celui de H2V à Bécancour (voir le Tableau 5), dont la mise en service est prévue pour 2024. Quant au captage des émissions, la première usine de gazéification de biomasse pour la production d'hydrogène avec captage du CO_2 pourrait être achevée en 2025 (IEA, 2022). Actuellement, il y a peu d'informations disponibles concernant les coûts liés à ces projets.

3.3.4. Le transport et le stockage

Dans le cas d'une production à grande échelle qui est centralisée, l'hydrogène doit être transporté jusqu'au lieu de consommation. Dans un tel cas, une chaîne d'approvisionnement générale comprend les étapes suivantes : la production, la préparation (conversion en vecteur liquide comme l'ammoniac, si applicable; purification; compression), le transport ainsi que la station de ravitaillement ou simplement le poste de distribution sur le lieu de consommation.

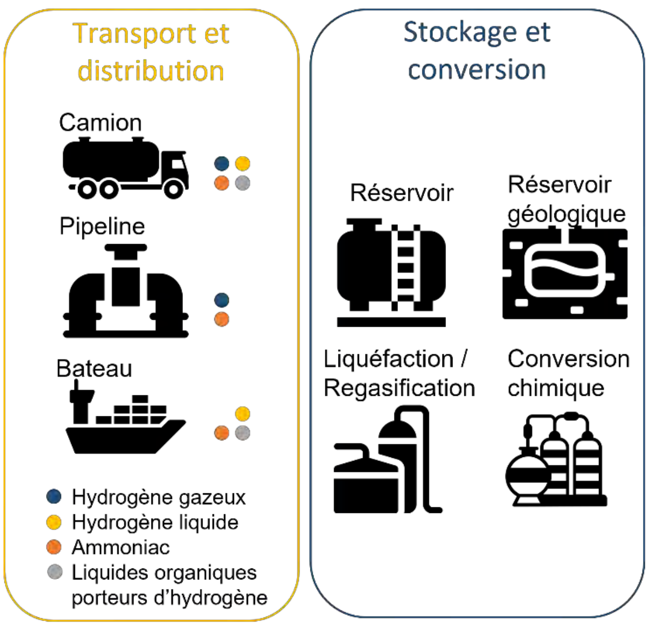

Figure 10 : Les différentes options de transport, distribution, conversion, et stockage de l'hydrogène

Le choix du mode de transport, et les coûts associés, dépendent principalement de la quantité Le choix du mode de transport et les coûts qui y sont associés dépendent surtout de la quantité d'hydrogène qui doit être transportée par jour, ce qui équivaut à la demande quotidienne, la distance parcourue et la pureté requise pour l'hydrogène (IEA, 2019). Toutefois, quelques tendances sont soulignées par l'Agence internationale de l'énergie (IEA, 2019) et Khan et al. (2022). Ces tendances sont les suivantes :

- Actuellement, pour transporter des quantités de tailles faibles ou modestes (< 100 tpj[11]), le transport d'hydrogène gazeux comprimé par camion est l'option la plus intéressante.

[11] tpj : tonnes par jour

- À l'horizon 2030, les gazoducs ou pipelines (pour vecteurs liquides) sont les options de transport les plus compétitives en termes de coûts pour de grandes quantités (≥ 100 tpj) et de longues distances. Au-delà d'une distance de 3 500 km, les vecteurs liquides deviennent l'option la moins chère, et l'option du transport par navire devient compétitive.
- Les chaînes de valeur possibles pour l'hydrogène sont toutes intensives en capital, ce dernier étant dominé par le CAPEX qui peut représenter entre 45 et 65 % du total (l'ordre de grandeur est de plusieurs millions de dollars canadiens).

Dans le cas d'une production décentralisée, le besoin de transport est presque inexistant et, bien souvent, l'hydrogène comprimé ou liquéfié répond aux besoins, ce qui permet d'éviter les coûts de conversion et reconversion en vecteurs liquides tels que l'ammoniac ou les liquides organiques porteurs d'hydrogène (LOPH).

3.4. L'état actuel de la production d'hydrogène au Québec

Plusieurs projets de production d'hydrogène sont actuellement en exploitation ou en développement au Québec (Tableau 5). Comme c'est le cas ailleurs qu'au Québec, la majeure partie de cette production provient du reformage de méthane et de naphta lourd, bien que la mise en service prochaine de plusieurs électrolyseurs soit prévue. Un seul projet de gazéification de biomasse, utilisant des matières résiduelles, est en cours de développement; sa mise en service est prévue pour 2024.

Pour le moment, il faut noter que cette production vise essentiellement des clients locaux. L'absence d'infrastructures de stockage, de transport et de distribution, qui demeurent très coûteuses, fait en sorte qu'il y a très peu de commerce d'hydrogène (autant entre régions qu'à l'international).

Dans sa revue des développements prévus liés à l'hydrogène, et particulièrement en ce qui concerne le commerce international, l'Agence internationale de l'énergie indique que malgré une évolution rapide des chaînes de valeur pour le commerce international, l'immense majorité de la production est toujours planifiée avec des visées locales. On note, entre autres, que l'hydrogène continuera souvent à être produit dans des grappes industrielles, soit près de son lieu d'utilisation (IEA, 2022).

Si des infrastructures de transport et de distribution sont en cours de développement à travers le monde, elles demeurent très coûteuses, quel que soit le mode de transport utilisé (pipeline, navires, etc.). Par conséquent, plusieurs des projets d'exportation sont planifiés comme faisant partie intégrante de carrefours industriels situés à proximité d'installations portuaires. Comme la plupart des pôles d'utilisation industrielle de l'hydrogène au Québec ne présentent pas ces caractéristiques géographiques, il semble difficile d'envisager ce genre de développement pour le Québec. De plus, la mise à niveau des systèmes de distribution gaziers pour l'hydrogène demande des transformations significatives et la gestion de problèmes de sécurité importants.

Tableau 5 : Production d'hydrogène au Québec en 2021
Adapté de (Whitmore & Pineau, 2022)

		Capacité de production [kgH_2/j]	Lieu	Technologie	Intrant ou puissance installée	Commentaires
En exploitation	Station Harnois	200	Québec	Électrolyse	1 MW	Station-service. Alimente 50 véhicules appartenant au gouvernement provincial et à la Ville de Québec.
En exploitation	Air Liquide	8 200	Bécancour	Électrolyse	20 MW	-
En exploitation	Messer Canada (Nouryon)	1 400	Magog	Électrolyse de chlorate de sodium	-	Nouryon produit de l'H_2 gazeux comme sous-produit d'électrolyse dans le procédé de production du chlorate de sodium (désherbant et pyrotechnie) et le vend à Messer qui le purifie et le liquéfie pour la vente. La capacité de production ci-contre correspond à celle de Messer à liquéfier l'H_2 gazeux, or la quantité d'H_2 produit par Nouryon, qui n'est pas connue, est potentiellement plus grande.
En exploitation	Air Liquide (Olin)	2 000	Bécancour	Électrolyse chlore-soude	-	Le volume d'H_2 généré comme sous-produit du procédé de production de chlore et de soude caustique varie. L'H_2 est capté, acheminé et vendu à l'installation d'Air Liquide qui le purifie pour la vente.
En exploitation	Air Liquide	16 000	Bécancour	Reformage du méthane	Gaz naturel	-
En exploitation	Suncor	96 393	Montréal	Reformage du méthane	Gaz naturel	-
En exploitation	Valero	150 000	Lévis	Reformage catalytique	Naphta lourd	Reformage servant à améliorer l'octane du naphta dont la réaction chimique produit de l'H_2
À l'étude / en développement	Éthanol cellulosique Varennes	-	Varennes	Électrolyse	88 MW	Mise en service prévue : fin 2023. L'usine alimentera la future usine de biocarburants Recyclage Carbone Varennes (RCV). Capacité de production potentielle de 34 619 kgH_2/j
À l'étude / en développement	Grenfield Global	-	Varennes	Électrolyse	60 MW	Mise en service prévue : fin 2025. Production d'H_2, méthanol et GNR. Capacité de production potentielle de 26 000 kgH_2/j
À l'étude / en développement	Charbone Corporation	-	Sorel-Tracy	Électrolyse	0.5 MW	Projet en cinq phases, dont la première, de 0,5 MW, permettra de produire 230 kgH_2/j et débutera en avril 2022. Le projet vise un total de 20 MW afin de produire 9 000 kgH_2/j.
À l'étude / en développement	Évolugen-Gazifère	-	Gatineau	Électrolyse	20 MW	Hydrogène pour injection dans le réseau de distribution gazier de Gazifère. Capacité estimée d'environ 425 000 GJ (soit près de 10 000 kg/jour).
À l'étude / en développement	H2V Énergies	-	Bécancour	Gazéification par torche à plasma	Matières résiduelles	Mise en service prévue : 2024. Capacité de production potentielle de 36 986 kgH_2/j. Matière résiduelle : rejets de bois de construction, écorces, plastiques et papiers non recyclables.

4. Une première orientation de carrefour hydrogène : les mines

4.1. Le portrait du secteur des mines au Québec

4.1.1. Les émissions de GES, l'énergie et l'économie

En 2019, le secteur des mines au Canada a consommé environ 1 500 PJ d'énergie et a émis près de 90 Mt d'éq. CO_2. Au Québec, la consommation d'énergie s'est élevée à 43 PJ et les émissions étaient de 2,3 Mt d'éq. CO_2, ce qui représente un peu moins de 3 % des émissions totales du Canada en 2019 (ECCC, 2022).

Le Québec possède une longue histoire d'exploitation minière. En 2019, on recense 26 mines actives, et plus d'une dizaine de projets sont considérés comme étant avancés (Institut de la statistique du Québec, 2021; Table jamésienne de concertation minière, 2020). Les sites miniers se retrouvent dans neuf régions dont les trois principales sont le Nord-du-Québec, l'Abitibi-Témiscamingue et la Côte-Nord. À elles seules, ces trois régions étaient responsables de plus de 75 % de la valeur totale des livraisons minérales du Québec en 2019. Les principaux minerais exploités, en termes de valeur, sont l'or, le minerai de fer et la silice. En 2020, le Québec a produit 31 % de l'or et 56 % du minerai de fer au Canada (Ressources naturelles Canada, 2022). Présentement, il n'existe qu'une seule mine de graphite active au Canada et elle est située au Québec. Toutefois, plusieurs projets sont en cours, dont un qui est en phase de démonstration au Québec et dont l'exploitation commerciale devrait commencer d'ici un à trois ans (Nouveau Monde Graphite, 2022).

Tableau 6 : Les caractéristiques des mines québécoises

Types de mines	Fosse Mine souterraine
Minerais exploités[12]	Argent, cadmium, cobalt, cuivre, diamant, graphite, ilménite, iridium, lithium, matériaux de construction, minerai de fer, nickel, niobium, or, palladium, platine, rhodium, ruthénium, silice, zinc
Régions	Abitibi-Témiscamingue, Capitale-Nationale, Côte-Nord, Gaspésie-Îles-de-la-Madeleine, Laurentides, Mauricie, Nord-du-Québec, Outaouais, Saguenay-Lac-Saint-Jean

[12] Pour une liste plus complète des minerais métalliques et non métalliques exploités, voir *La production minérale au Québec en 2019* (Institut de la statistique du Québec, 2021).

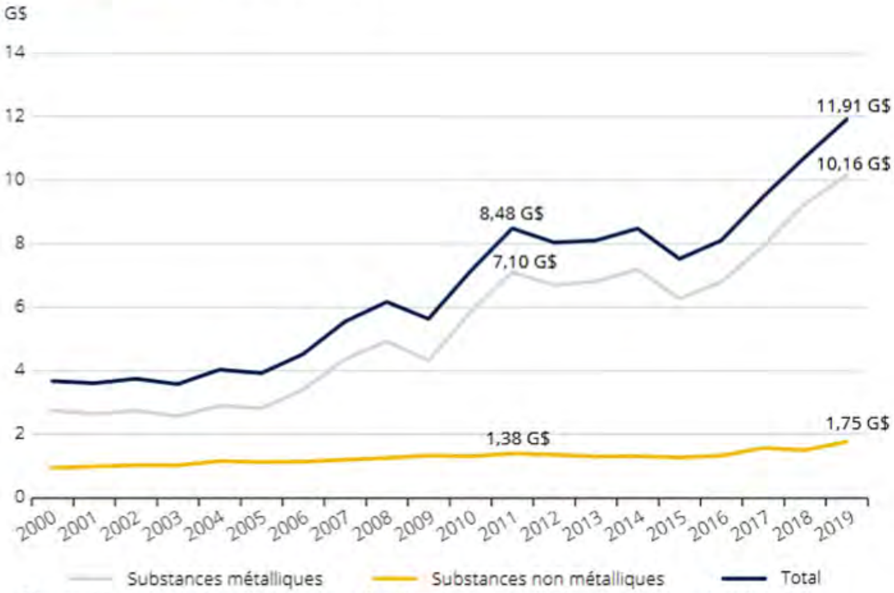

Figure 11 : L'évolution de la valeur des livraisons minérales du Québec 2000-2019
Tiré de (Institut de la statistique du Québec, 2021)

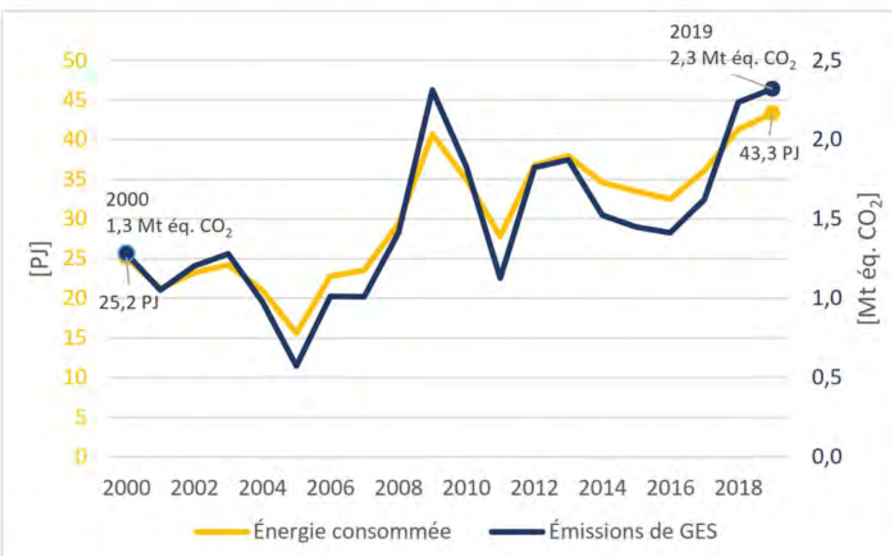

Figure 12 : L'énergie consommée et les émissions de GES du secteur minier au Québec, 2000-2019 (Secteur industriel – Québec, Tableau 12, Ressources naturelles Canada, s. d.)

Les Figure 11 et Figure 12 montrent l'évolution de la valeur de la livraison minérale, de la consommation d'énergie et des émissions de GES du secteur minier au Québec depuis l'année 2000. On remarque d'abord que la valeur des livraisons minérales poursuit une tendance vers la croissance entre 2000 et 2019. Ainsi, la valeur de livraison des substances métalliques a plus que triplé durant cette période, passant d'un peu moins de 3 G$ à environ 10 G$. Cette augmentation de l'extraction et de la production de minerais entraîne également un accroissement de 72 % de l'énergie consommée et de 77 % des émissions de GES; en 2019, cela représentait 43,3 PJ et 2,3 Mt d'éq. CO_2 respectivement. **Les principaux vecteurs énergétiques consommés sont le diésel (32 %), l'électricité (32 %) et le mazout lourd (23 %)**

(Ressources naturelles Canada, s. d.). Le diésel est surtout utilisé pour les équipements mobiles, l'électricité plutôt pour les équipements stationnaires, et en particulier la ventilation dans le cas des mines souterraines, tandis que le mazout lourd sert exclusivement à la production de chaleur pour des procédés comme le bouletage de minerai de fer (Allen, 2021; Katta et al., 2020). La Figure 13 présente un schéma détaillé de la demande énergétique dans une mine pour deux types différents de minerais de fer, soit la magnétite et l'hématite, qui sont les types de minerais les plus présents au Canada. De nos jours, les mines éloignées des réseaux électriques existants produisent généralement leur électricité à partir de génératrices au diésel, ou plus rarement à partir de centrales au gaz naturel. L'énergie est le deuxième plus important poste de dépenses en termes d'opérations après celui de la main-d'œuvre (TUGLIQ Énergies Co., 2016).

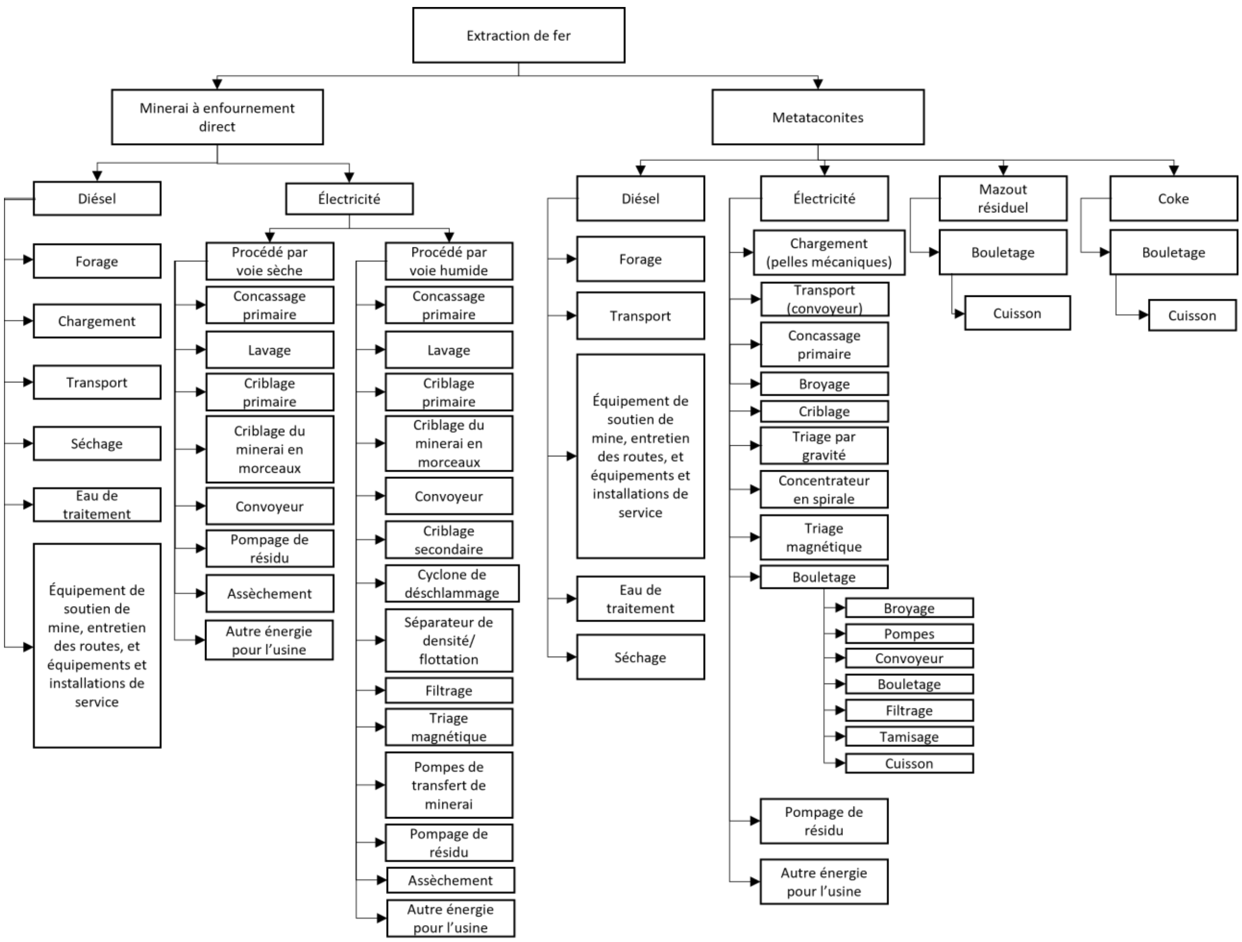

Figure 13 : Schémas des sources de demande énergétique dans une mine de fer
Traduit de Katta et al. (2020)

La consommation d'énergie et les émissions de GES d'une mine dépendent de plusieurs facteurs, en particulier du minerai exploité, du type de mine (fosse ou mine souterraine), mais aussi de la taille de la mine. Par exemple, la consommation moyenne d'énergie d'une mine d'or au Canada en 2016 est de l'ordre de 150 GJ/kg de produit, tandis que celle d'une mine de fer est de 0,7 GJ/t de produit (Katta et al., 2020; Ulrich et al., 2020). La consommation énergétique est nettement plus élevée pour les mines d'or, et ce, pour plusieurs raisons. Tout d'abord, les minerais ayant des teneurs très différentes, l'écart peut être de plusieurs ordres de grandeur; il faut donc extraire plus ou moins de matière pour produire un kilogramme de minerai. Par exemple, l'or a une teneur de l'ordre de 5 ppm (1 000 t de matériau extrait pour produire 5 kg d'or) alors que le minerai de fer a une teneur allant de 15 à plus de 60 % (dans le cas de 50 %, 2 t de matériau extrait pour produire 1 t de minerai de fer). De plus, la très grande majorité des mines d'or sont souterraines et ont donc besoin de grands systèmes de ventilation, ce qui n'est pas le cas des mines de fer qui, au Québec, sont toutes des exploitations à ciel ouvert. Il existe d'autres raisons liées notamment aux procédés d'extraction et de concentration des minerais et à la localisation de la mine. **En termes de GES, les ordres de grandeur des intensités d'émissions sont de 8 620 kg d'éq. CO_2/kg de produit pour les mines d'or, de 33 kg d'éq. CO_2/t de produit pour les mines de fer, et de 380 kg d'éq. CO_2/t de matériau transformé pour le graphite** (Engels et al., 2022; Katta et al., 2020; Ulrich et al., 2022).

Tableau 7 : L'intensité énergétique de quelques minerais dans le contexte canadien
(Allen, 2021; Engels et al., 2022; Katta et al., 2020; Ulrich et al., 2022)

	Total [GJ/t de produit]	**GES [kg éq. CO_2 /t de produit]**
Or - fosse	150 000	8 620 000
Minerai de fer - magnétite + bouletage	0,7	33
Graphite	3,1	380

Le Québec est un grand exportateur de minerai de fer. Une grande partie du minerai exporté est conditionné sous forme de boulettes; ces dernières sont utilisées dans les hauts fourneaux servant à fabriquer de l'acier. Le procédé de bouletage, généralement réalisé sur le site de la mine, est très énergivore à cause des hautes températures des fours de cuisson qui peuvent atteindre jusqu'à 1 350 °C; on parle d'un peu plus de 1 GJ/t produite (Katta et al., 2020; Moraes et al., 2018; Pineau et al., 2019). C'est principalement du mazout lourd qui est utilisé comme combustible, ce qui en fait un procédé à fortes émissions de GES.

4.1.2. La main-d'œuvre

Le bassin de main-d'œuvre du secteur minier compte environ 18 000 travailleurs et travailleuses. Près de 50 % des établissements miniers comptent de 50 à 500 employés. Toutefois, deux très grands établissements ont plus de 1 000 employés, soit la mine Mont-Wright (minerai de fer) détenue par la société Arcelor Mittal et la mine Raglan (nickel et cuivre) propriété de la société Glencore Canada (Figure 14). Les trois régions du Québec responsables de 75 % des valeurs de livraison de minerai concentrent près de 60 % des emplois. Selon l'étude « Estimation des besoins de main-d'œuvre du secteur minier au Québec 2019-2023 avec tendances 2028 » réalisée par la Table jamésienne de concertation minière (2020) pour le compte du Comité sectoriel de main-d'œuvre de l'industrie des mines, le nombre d'emplois dans le secteur minier aura tendance à demeurer stable jusqu'en 2028. Toutefois, une forte proportion de la main-d'œuvre devra être renouvelée durant la période 2019-2023 à cause des départs à la retraite et des migrations extrasectorielles.

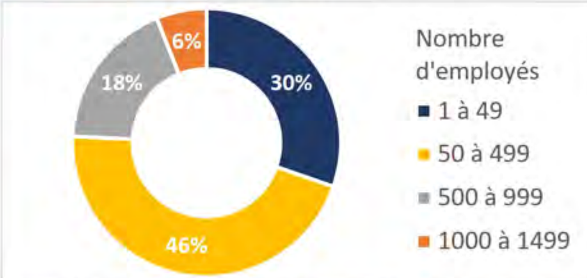

Figure 14 : Répartition des établissements miniers en fonction de leur nombre d'employés. (Institut de la statistique du Québec, 2021)

Note : Cette répartition est basée sur un nombre total de 33 établissements comprenant les fosses, les mines souterraines, les concentrateurs et les usines de bouletage. Les fonderies, les affineries et les usines de transformation de cuivre, chaux, ciment et mica ne sont pas prises en compte.

4.1.3. Les acteurs

Actuellement, les trois plus grands acteurs en termes de taille d'entreprise (établie en fonction du nombre d'employés, mais aussi en termes de valeur de livraison) sont les suivants :

- La société Glencore Canada Corporation avec deux mines situées dans la région du Nord-du-Québec, extrayant du cuivre, du nickel et du zinc;
- La société Arcelor Mittal Exploitation Minière Canada qui détient deux mines de minerai de fer et une usine de bouletage dans la région de la Côte-Nord; et
- La société Mines Agnico Eagle qui exploite quatre mines d'or en Abitibi-Témiscamingue.

Plusieurs minéraux sont appelés à jouer un rôle incontournable pour atteindre l'objectif d'une société faible en carbone, tant à l'échelle du Québec que du monde entier. Parmi ces minéraux figurent notamment le lithium et le graphite (Hund et al., 2020). Les sous-sols du Québec renferment d'importantes réserves de ces minerais. La production de ces minerais est actuellement limitée au Canada, toutefois, plusieurs projets sont présentement actifs. **Au Québec, sept projets sont en cours de réalisation pour l'exploitation du lithium et un pour le graphite** (MERN, 2022a)**.** Les exploitations de lithium ont tendance à être des projets de mines à ciel ouvert, et c'est également le cas pour les exploitations de graphite. Les acteurs pilotant ces projets sont, entre autres, la société Nemaska Lithium, rachetée en 2020 par Investissement Québec et d'autres partenaires, ou encore la société Nouveau Monde Graphite (NMG). Cette dernière a démarré ses activités à une échelle de démonstration en 2018 et poursuit actuellement la mise à l'échelle de ses opérations. Une fois le projet complété, cette mine, située dans la région de Lanaudière au Québec, sera la plus grande mine de graphite naturel d'Amérique du Nord.

La société NMG est un acteur d'intérêt dans le cadre des efforts de décarbonation du Québec, non seulement à cause du minerai que l'entreprise exploite, mais aussi par ses engagements envers le développement durable. Elle a, entre autres, comme objectif d'électrifier entièrement ses activités à la mine et au concentrateur situé à Matawinie. Afin d'atteindre cet objectif, l'entreprise mise sur une connexion au réseau d'Hydro-Québec lui donnant accès à de l'électricité à très faible empreinte carbone, et sur un partenariat avec le manufacturier Caterpillar pour électrifier l'ensemble de ses équipements mobiles d'ici 2028.

Dans une étude sur les engins hybrides et électriques dans le secteur minier au Québec parue en 2022, l'Institut national des mines a fait plusieurs constats**. D'abord, les équipements mobiles des sites miniers, et en particulier ceux des mines à ciel ouvert, sont surtout équipés de moteurs à combustion interne fonctionnant essentiellement au diésel. Toutefois, on note que de plus en plus de manufacturiers offrent davantage de modèles d'engins miniers électriques ou hybrides. On retrouve des engins électriques à batterie, des engins hybrides diésel/électrique fonctionnant avec une caténaire ainsi que des engins hybrides électriques à batteries et piles à combustible hydrogène.** Pour l'instant, l'offre est dominée par la solution électrique à batterie, mieux adaptée aux engins miniers légers. **Dans le cas des engins lourds comme les tombereaux, plusieurs solutions sont encore à l'essai. Les principales contraintes pour ce type d'engin sont : (i) la nécessité d'avoir de la puissance (celle-ci pouvant être supérieure à 1,5 MW), (ii) des conditions d'opération difficiles, et (iii) des temps d'opération élevés (de l'ordre de 20 h d'opération par 24 h).** Au niveau international, plusieurs sociétés testent des solutions de remplacement. Ainsi, la société Boliden, dans sa mine Aitik en Suède, teste des tombereaux hybrides diésel/électrique à caténaires (*Boliden Aitik Mine*, s. d.); de même, la société Anglo American teste à sa mine Mogalakwena en Afrique du Sud un tombereau électrique hybride de 2 MW à batteries et piles à combustible hydrogène (Rébillon, 2022). Les piles à combustible de ce prototype proviennent du spécialiste canadien Ballard. Plus près du Québec, en Ontario, la mine Borden Gold, qui est détenue par la société Newmont Goldcorp et qui est entrée en opération durant le dernier trimestre de 2019, a électrifié l'ensemble de son parc d'engins miniers en utilisant des engins électriques à batterie (Mining Technology, 2020).

D'autres acteurs, comme des fournisseurs de solutions énergétiques par exemple, sont présents au Québec. Que ce soit dans le passé, le présent ou l'avenir, ces acteurs jouent toujours un rôle actif dans le secteur minier et dans d'autres secteurs au Québec. Parmi ceux-ci, on retrouve la société Tugliq Énergie, un producteur d'énergie indépendant qui offre plusieurs types de solutions à faibles émissions pour les milieux isolés. Cette société, en partenariat avec Hatch, a mené un projet de démonstration de réseau intelligent d'électricité renouvelable à la mine Raglan Glencore[13]. Ce réseau a été mis en service en 2014 (TUGLIQ Énergies Co., 2016). Un deuxième projet, sur le même site, a permis d'accroître la puissance installée d'énergie éolienne et de stockage (Tugliq Energie, 2018). Dans cette optique, les offres de service se structurent. Ainsi, la société Charbone Hydrogène (Charbone Hydrogène, s. d.) vise à acquérir, développer, exploiter et optimiser des centrales hydroélectriques de faible et moyenne puissance (0,25 MW à 25 MW) en Amérique du Nord, ainsi que fournir de l'hydrogène à faibles émissions de carbone sur site. Cet hydrogène serait produit par des électrolyseurs alimentés par de l'électricité provenant de sources renouvelables. Les travaux de construction de la première usine de production d'hydrogène de cette entreprise ont débuté à Sorel-Tracy au Québec en juin 2022 et le début de la production est prévu pour le quatrième trimestre de 2022. Charbonne adopte une approche modulaire et extensible en utilisant des solutions conteneurisées.

[13] Voir les annexes pour plus d'information sur le projet d'intégration d'énergie renouvelable à la mine Raglan.

Il existe plusieurs manufacturiers d'équipements miniers mobiles au Canada. Parmi ceux-ci, on retrouve des sociétés comme Komatsu, RDH-Scharf, MacLean Engineering[14] ou encore Cummins[15], qui réalisent des opérations de fabrication, assemblage et distribution en Ontario et parfois ailleurs au pays. D'autre part, des acteurs comme les sociétés Sandvik, Caterpillar, Volvo Construction Equipment, Sany ou Liebherr Canada distribuent leurs produits au Québec et dans d'autres provinces canadiennes.

4.2. Les opportunités et les barrières

Bien que l'atteinte d'une société sobre en carbone soit un objectif primordial, plusieurs autres objectifs peuvent être atteints tout au long des trajectoires empruntées. Dans le cas du secteur minier au Québec, des discussions avec certains acteurs du milieu et une revue de la littérature sur le sujet[16] ont permis d'identifier un ensemble d'opportunités mais aussi de barrières en lien avec la décarbonation du secteur et l'émergence du marché de l'hydrogène.

LES FREINS PERÇUS

- Les acteurs ont une crainte du risque encore marquée par rapport à ces technologies. Cette crainte est surtout due au fait que les efforts de décarbonation des activités d'une mine demandent des investissements considérables dans un contexte où les politiques publiques sont sujettes à changements.
- Les surcoûts engendrés par plusieurs technologies, comme les véhicules miniers à faibles émissions, les piles à combustible ou les électrolyseurs, demeurent élevés.
- Dans le cadre réglementaire actuel, une entreprise qui fournit des efforts pour décarboner ses activités ne bénéficiera pas d'avantages compétitifs sur le marché.
- Certaines caractéristiques, comme la durée de vie restante d'une mine, sa localisation, ou encore une configuration à ciel ouvert, sont perçues comme des freins à l'engagement pour la décarbonation par les acteurs du secteur.
- L'hydrogène, qui est l'une des solutions envisageables pour décarboner les activités minières, est perçu par certains acteurs comme une substance dangereuse à cause de son potentiel d'inflammabilité et d'explosivité. Le risque perçu est accentué dans le cas d'une mine souterraine.
- Il n'existe pas de manufacturiers qui fabriquent des véhicules miniers ou des électrolyseurs au Québec.

[14] Spécialisées, entre autres, dans les équipements miniers mobiles.
[15] Spécialisée, entre autres, dans les moteurs d'équipements mobiles industriels et les générateurs d'électricité industriels.
[16] Les trois principaux rapports qui ont été utilisés pour identifier les éléments du tableau ont : CIRAIG, 2020; Deloitte & Norcat, 2020; Institut national des mines, 2022.

LES OPPORTUNITÉS

- Les véhicules à faibles émissions et l'électricité décarbonée engendrent souvent des coûts d'exploitation inférieurs aux coûts actuels, notamment en réduisant la consommation de diésel, les coûts de maintenance et les dépenses liées aux droits d'émission de carbone.

- Les prix des carburants issus du pétrole sont volatils. Réduire sa dépendance vis-à-vis de ces derniers permet d'accroître la prévisibilité des charges d'exploitation.

- Les moteurs thermiques sont encore largement utilisés dans les parcs mobiles des exploitations minières. Les remplacer par des moteurs à zéro ou faibles émissions permettrait d'améliorer la santé et la sécurité des mines pour les travailleurs.

- Les règlements et normes sont de plus en plus sévères en ce qui concerne les émissions produites par les moteurs thermiques et la qualité de l'air en milieu de travail. Au Canada, depuis 2018, la norme d'émission de groupe 4 s'applique à tous les moteurs diésel hors route[17] (Loi canadienne sur la protection de l'environnement, 2022). À cela s'ajoute au Québec le règlement sur la santé et la sécurité du travail dans les mines (Loi sur la santé et la sécurité du travail, 2022).

- Décarboner l'énergie utilisée dans le secteur minier peut contribuer à rendre les projets plus acceptables pour les communautés (réduction des émissions de particules, réduction des passages de camions pour le transport de carburant, etc.).

- Certaines entreprises qui se positionnent par rapport à des technologies vertes peuvent avoir un intérêt stratégique à décarboner leurs activités.

- Présentement, des efforts sont réalisés à l'échelle de la planète pour décarboner les activités minières (développements par les manufacturiers de machineries à zéro ou faibles émissions, automatisation, optimisation des procédés, nouveaux procédés).

Par ailleurs, le secteur minier est confronté, comme beaucoup d'autres secteurs économiques au Québec, à des enjeux en rapport avec la main-d'œuvre. Une forte proportion de la main-d'œuvre doit être renouvelée à cause des départs à la retraite dans les prochaines années. Cette situation peut être perçue comme un frein dans les efforts de transition, mais peut aussi être vue comme une incitation au

[17] Les normes d'émissions et les procédures d'essai sont basées sur celles de l'*Environmental Protection Agency* (EPA) des États-Unis.

changement, car décarboner les activités minières permet d'offrir un environnement de travail qui est plus sain. Cet argument peut contribuer à faciliter le recrutement de main-d'œuvre.

En dehors des solutions reposant sur l'électricité (batteries, piles à combustible hydrogène ou hybrides), il existe la possibilité d'utiliser des biocarburants. C'est l'option qui engendrerait le moins d'impacts sur les infrastructures existantes, mais elle ne permettrait pas de solutionner les problèmes de pollution de l'air et de pollution sonore, ni les coûts liés à l'approvisionnement pour les régions éloignées. De plus, cet usage de la biomasse peut entrer en conflit avec d'autres usages ayant une plus forte valeur ajoutée, comme la production d'électricité à partir de biomasse avec captage et séquestration des émissions.

4.3. Proposition d'orientation d'un carrefour d'appui à la transition énergétique pour le secteur des mines

La décarbonation des activités minières exigera l'utilisation de plusieurs technologies complémentaires. Les trois groupes d'activités à décarboner sont la production d'énergie, les parcs de véhicules et les procédés. La présente section se concentre sur la décarbonation des deux premiers groupes, soit l'énergie et les véhicules. Plusieurs études évaluent la possibilité de remplacer le diésel utilisé dans des communautés éloignées, en totalité ou en partie, par des énergies renouvelables (éolien et/ou solaire PV), et dans certains cas par de l'hydrogène (Cecilia et al., 2020; Karimi & Kazerani, 2017). D'autres études et projets se concentrent sur le cas particulier du remplacement du diésel, en totalité ou en partie, sur des sites miniers éloignés (Romero et al., 2020; TUGLIQ Énergies Co., 2016; Wallace, 2021; Zuliani et al., 2021).

Le choix de l'orientation axée sur les mines, et en particulier celles situées en régions éloignées, se justifie pour plusieurs raisons, dont les suivantes :

- Le prix du diésel, en particulier dans les régions éloignées non connectées au réseau électrique, est élevé.
- Certains usages sont difficiles à électrifier; c'est le cas des véhicules de grande puissance qui fonctionnent durant de longues heures et qui ont besoin d'être rechargés rapidement. De plus, pour ces véhicules, la possibilité de réduire la fréquence ou le temps de maintenance constitue un avantage.
- Un véhicule de grande puissance consomme une à deux tonnes d'hydrogène par jour, donc un parc de ces véhicules requiert une puissance installée d'électrolyseur de l'ordre de quelques mégawatts.
- Cette orientation offre la possibilité de réaliser un déploiement par phases.
- Cette orientation a le potentiel de contribuer au développement des électrolyseurs, des systèmes de compression et de stockage de l'hydrogène ainsi que des systèmes de ravitaillement (station de distribution). Si la production d'hydrogène repose sur des énergies renouvelables variables, cette orientation peut aussi contribuer à améliorer les solutions d'intégration et de gestion de microréseaux.

4.3.1. Description de l'orientation axée sur les mines

L'orientation proposée consisterait à décarboner la production d'électricité, actuellement produite essentiellement à partir de diésel, en utilisant l'énergie éolienne couplée à des solutions de stockage, dans le cas de mines non connectées au réseau électrique québécois. Cette orientation permettrait également de décarboner les parcs de véhicules hors route en combinant des solutions de véhicules électriques à batterie, à piles à combustible et hybrides. Dans cette orientation, l'hydrogène nécessaire aux véhicules serait produit sur place par électrolyse. Une production locale éviterait les coûts de

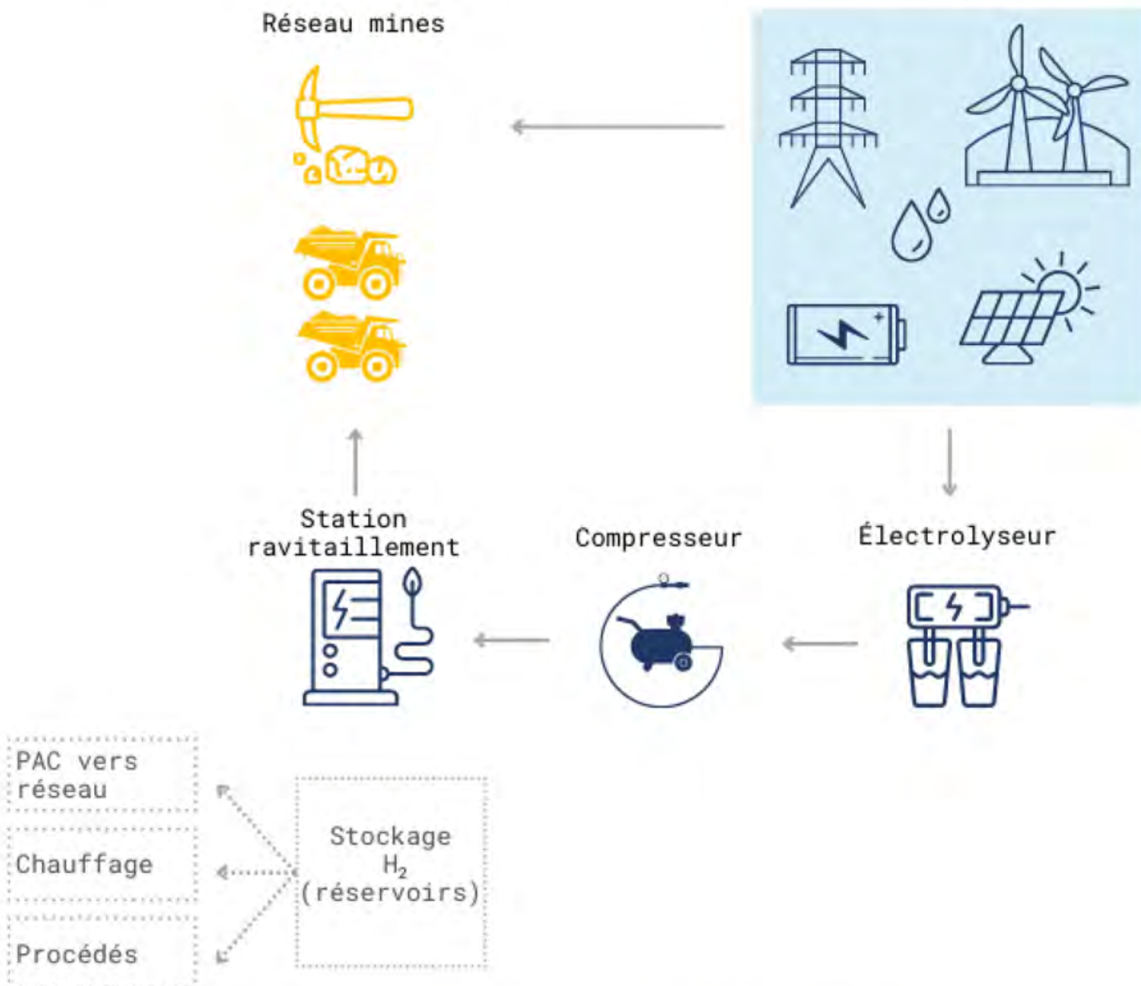

Figure 15 : Schéma d'une mine utilisant de l'hydrogène pour une partie de sa flotte de tombereaux

transport et réduirait les coûts de transformation de l'hydrogène. La Figure 15 illustre schématiquement une mine alimentée par de l'énergie décarbonée et qui utilise de l'hydrogène à faible émission pour une partie de sa flotte de tombereaux.

Les véhicules qui sont considérés pour les options employant de l'hydrogène sont ceux qui nécessitent une grande puissance (1,5 à 3 MW) et sont en opération de 15 à 20 heures par jour, comme les tombereaux de grande capacité par exemple. On suppose que les véhicules nécessitant moins de puissance utiliseront des batteries de type lithium-ion.

Selon la capacité de production, l'hydrogène produit sur place pourrait servir de stockage à long terme pour l'électricité, d'intrant dans certains procédés ou encore pour le chauffage d'appoint de bâtiments (via la récupération de chaleur ou chaudière à l'hydrogène).

4.3.2. La caractérisation de la chaîne d'approvisionnement

La Figure ci-dessous illustre l'écosystème minier décarboné s'appuyant sur l'hydrogène qui est envisagé, et présente certains des acteurs qui en font partie (cette liste n'est pas exhaustive).

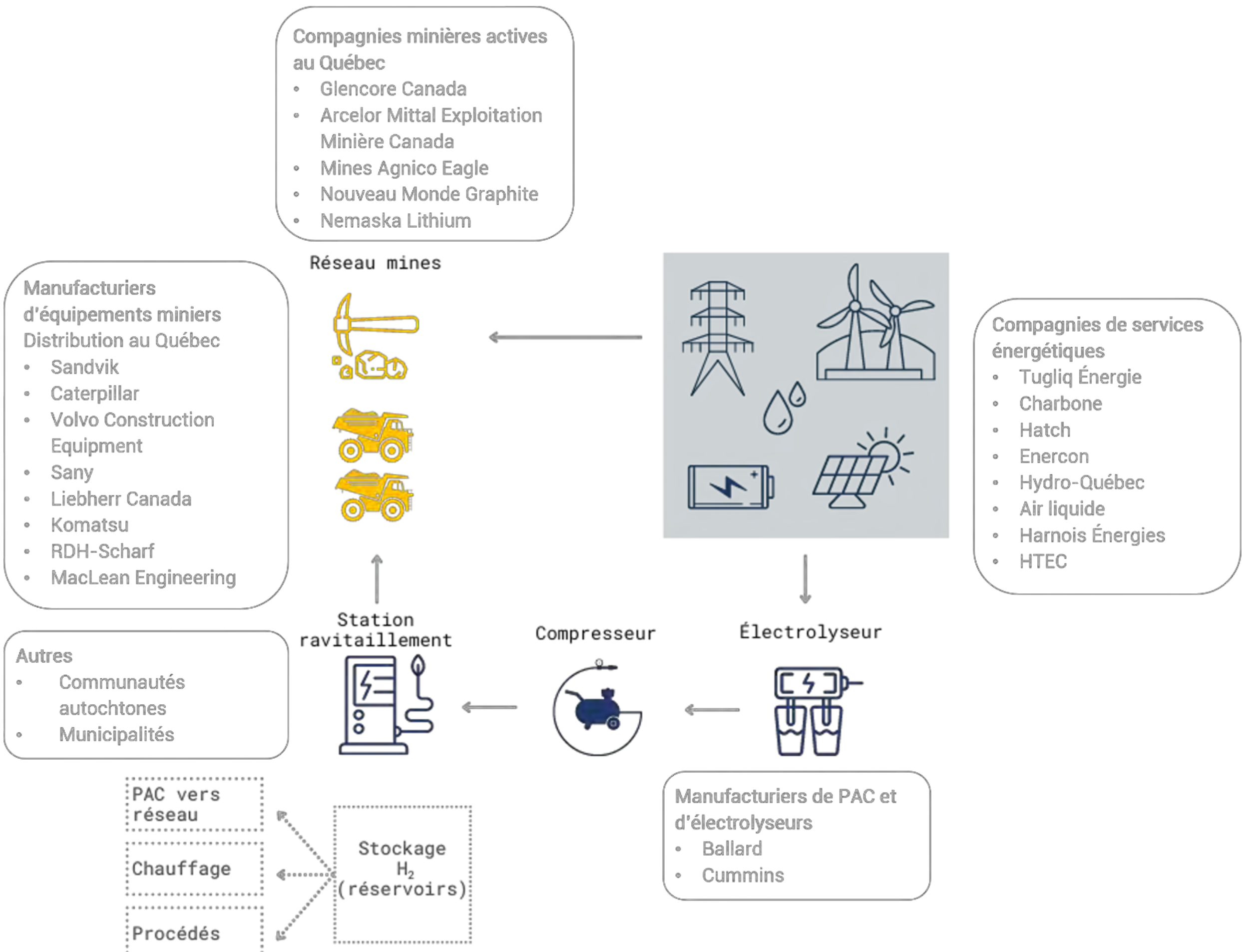

Figure 16 : Schéma de l'écosystème minier dont l'énergie est décarbonée
(Listes des acteurs non exhaustives)

La demande viendrait principalement des compagnies minières qui utiliseraient, dans un premier temps, l'hydrogène pour les tombereaux de grande capacité. Les communautés à proximité pourraient aussi être une source de demande. Pour ces communautés, l'hydrogène pourrait, par exemple, combler une partie des besoins pour le chauffage. Les manufacturiers d'équipements miniers mobiles sont ceux qui fourniraient les technologies consommatrices d'hydrogène, en particulier les tombereaux. Présentement, il n'y a pas de tombereau à piles à combustible à l'hydrogène qui soit commercialisé, il y a toutefois quelques prototypes en cours d'essai. Les entreprises de services énergétiques accompagnent les compagnies minières dans leurs projets énergétiques, elles offrent des services allant de la réalisation d'analyses technico-économiques, jusqu'à la livraison de solutions énergétiques clé en main. Enfin, les manufacturiers d'équipements de production et de conversion d'hydrogène fournissent les technologies et les services permettant une production locale de l'hydrogène, ils peuvent aussi collaborer avec les manufacturiers d'équipements miniers pour le développement de véhicules électriques à piles à combustible. L'annexe III.b fournit des informations supplémentaires sur la chaîne de valeur pour le secteur minier.

Typiquement, un tombereau de grande capacité (290 t de charge utile et plus, appelé camion « ultra class » en anglais) consomme plus d'un million de litres de diésel par an. En 2016, le Canada comptait près de 700 tombereaux (Wallace, 2021). La réduction des émissions de GES que représente la décarbonation de l'ensemble de ces véhicules est de l'ordre de 2 Mt d'éq. CO_2/an. Ce nombre est une borne inférieure, car la production minière et l'énergie consommée par le secteur ont continué de croître et le nombre de tombereaux a donc sûrement augmenté depuis 2016. Le nombre de tombereaux en usage au Québec n'est pas disponible dans la documentation publique. Toutefois, le Québec faisant partie des trois provinces canadiennes ayant les valeurs d'expédition de minerais les plus élevées, il serait raisonnable de supposer qu'une proportion importante des tombereaux en circulation au Canada se trouve au Québec (≈ 1/3). La combustion issue de ces véhicules représente entre 30 et 80 % des émissions produites par une mine (Wallace, 2021).

Tableau 8 : Exemple de caractéristiques de tombereaux
(Caterpillar, s. d.; Stantec, 2019; Wallace, 2021)

Description	**Diésel**	**H_2**
Taille du tombereau (charge utile) [t]	364	364
Puissance brute [kW]	2983	2983
Consommation diésel [L/j] et H_2 [kg/j]	3000-5000	900-1400
CAPEX véhicule (estimé) [M$ CAD]	6,6	8,6

La consommation énergétique d'une mine dépend grandement du type de minerai exploité, de la concentration de ce dernier dans la zone exploitée ainsi que du type de mine. Par exemple, une mine d'or produisant sept tonnes d'or par année consomme environ 1 000 TJ/an, soit 277 800 MWh/an. Cette valeur peut varier selon que la mine est souterraine ou à ciel ouvert. Entre 30 et 60 % de cette énergie est directement utilisée pour la mobilité sur le site minier (Allen, 2021; Katta et al., 2020). Cela équivaut à une consommation se situant entre 7 et 15,2 millions de litres de diésel par année. Dans le cas d'une mine de lithium produisant 7 000 tonnes de concentré par année, l'énergie consommée est plutôt de l'ordre de 100 TJ/an, soit 30 800 MWh. Si on suppose une proportion d'utilisation du diésel pour la mobilité similaire à celle d'une mine d'or, soit entre 30 et 60 %, cela représenterait, en termes de diésel consommé, entre 0,8 et 1,7 million de litres par an. Le tableau ci-dessous montre des ordres de grandeur si une proportion de 15 % du diésel des exemples de mines cités précédemment était remplacée par de l'hydrogène. Ces valeurs ne prennent pas en compte l'efficacité relative des technologies.

Tableau 9 : Ordres de grandeur des variables si 15 % du diésel actuellement consommé était remplacé

	Quantité de diésel annuelle convertie en H_2	Quantité d'H_2	Capacité de production à installer (électrolyseur)	CAPEX électrolyseur
	Ml/an	t/an	MW	M$ CAD
Or	2,3	630	3,7	5,1
Lithium	0,1	36	0,2	0,3

Parmi les critères pouvant favoriser l'adoption de solutions d'énergie et de mobilité à faibles émissions de carbones, on retrouve les suivants :

- La taille de la mine;
- Si la mine est déjà en exploitation ou selon le nombre d'années d'exploitation qu'il lui reste. Car, dans l'un ou l'autre cas, ce critère permet d'optimiser les investissements dans les infrastructures;
- Si la mine est souterraine ou à ciel ouvert. Car dans le cas des fosses, les équipements mobiles qui sont utilisés ont tendance à être de plus grande taille;
- Si la mine est connectée ou non au réseau électrique d'Hydro-Québec; et
- Selon le type de minerai exploité, car certains minerais requièrent davantage de transport par tombereau que d'autres.

5. Autres orientations proposées

5.1. Un carrefour technologique et sectoriel axé sur la chaleur industrielle

L'électrification massive de plusieurs secteurs de l'économie nécessite une réflexion en profondeur sur la gestion de la demande d'électricité en général, et la demande de pointe en particulier. Dans l'industrie ou le bâtiment par exemple, une électrification importante pour arriver à supprimer ou réduire fortement les émissions liées à l'utilisation de carburants fossiles passe par l'utilisation d'électricité pour les principales fonctions en lien avec cette demande, soit la production de chaleur et le chauffage des espaces et de l'eau. Par conséquent, et parallèlement à l'accroissement de la demande totale d'électricité, cette décarbonation par l'électrification suscite des inquiétudes liées à un accroissement du déséquilibre entre la demande de pointe et la demande moyenne ou typique.

Au cours des dernières années, il s'est constitué un important corpus de littérature sur le sujet dans le but de trouver des solutions à ce déséquilibre. Ainsi, plusieurs études explorent et modélisent différentes options de gestion de la demande, particulièrement pour les bâtiments commerciaux ou institutionnels. Des modèles sont utilisés, entre autres, pour évaluer le potentiel d'une optimisation de la demande pour les systèmes de chauffage, la ventilation et la climatisation (CVC). Par exemple, en regroupant les bâtiments par grappes pour permettre la mise en commun des avantages inhérents aux différentes caractéristiques des bâtiments, comme l'inertie thermique ou le type de chauffage à stockage thermique tel que les planchers dits chauffants (Mugnini et al., 2021; Sun et al., 2018). Un autre exemple est l'optimisation des horaires de recharge des véhicules électriques des employés et travailleurs sur leur lieu de travail (Cai & Braun, 2019; Krzywda et al., 2018).

Les services publics d'électricité proposent aussi des options tarifaires pour amenuiser le déséquilibre lié à la demande de pointe. Par exemple, depuis 2019, Hydro-Québec offre une option de gestion de la demande de puissance à ses clients, incluant les abonnés industriels, leur permettant d'obtenir une compensation financière en diminuant leur demande de puissance lors d'événements de pointe.

La littérature scientifique comprend également des études exploratoires sur le potentiel de certaines configurations technologiques pour arriver à mieux gérer cette demande de pointe, entre autres par des transformations technologiques incluant le recours au stockage d'énergie. L'hydrogène est parfois appelé à jouer un rôle dans cette problématique. Par exemple, une contribution étudiée porte sur la possibilité d'utiliser un mélange d'hydrogène et de gaz naturel dans le réseau gazier pour décarboner l'utilisation de gaz naturel dans la production de chaleur (en supposant que la production d'hydrogène soit sans émissions). La portion d'hydrogène qu'il est possible d'introduire dans ce mélange est toutefois limitée sans apporter des transformations majeures aux infrastructures de transport et de distribution du mélange. Cette option est surtout étudiée pour les milieux urbains à forte densité où l'espace se trouve limité pour installer d'autres options technologiques, comme c'est le cas dans certaines villes européennes. De la même façon, une revue récente des études sur le sujet montre de manière non équivoque que l'utilisation de l'hydrogène pour la production de chaleur à faible intensité, comme pour le chauffage des espaces ou les applications de chaleur industrielle à basse température, est presque toujours surpassée par d'autres options technologiques déjà disponibles ou en cours de développement (Rosenow, 2022).

Néanmoins, la réponse aux besoins divers en ce qui concerne la production de chaleur industrielle exigera l'utilisation de plusieurs solutions, puisque les températures à atteindre et les conditions précises des applications varient fortement. D'une part, si certaines de ces solutions sont électriques, les effets potentiels sur la demande de pointe exigeront la réalisation d'une analyse comparative avec d'autres solutions permettant d'alléger cette pression, et l'hydrogène fait partie de ces solutions potentielles. De plus, certains niveaux de chaleur à produire présentent des enjeux techniques importants pour d'éventuelles solutions électriques dans lesquelles l'utilisation de l'hydrogène présente un potentiel intéressant. C'est le cas, par exemple, de la production de ciment ou d'acier, où la chaleur demandée doit atteindre entre 1 000 et 1 600 °C (Pineau et al., 2019; Pyonnier, 2022).

L'hydrogène pourrait ainsi être un complément important à d'autres options technologiques, par exemple, pour faciliter la gestion de la demande de pointe d'électricité. De plus, l'utilisation d'hydrogène pour la production de chaleur industrielle peut être couplée à d'autres sources pour améliorer l'efficacité du procédé. Par exemple, la biomasse peut être utilisée pour atteindre les 250 à 1 000 °C nécessaires à certaines transformations chimiques et, avec l'aide de l'hydrogène, il est possible de réaliser des économies sur la quantité de biomasse nécessaire (Pineau et al., 2019).

Plusieurs éléments sont perçus comme des freins par les acteurs du secteur. Un carrefour axé sur la chaleur industrielle devra s'appuyer, entre autres, sur les opportunités qui s'offriront grâce à la résolution de ces freins.

LES FREINS PERÇUS

- Faible prix du gaz naturel
- Difficulté de répondre au besoin de haute température
- Longue durée de vie des équipements industriels limitant leur renouvellement
- Surcoûts encore élevés des technologies à faibles émissions
- Manque d'incitatifs (réglementation, pratiques du marché)
- Manque de connaissance chez les acteurs des solutions existantes à faibles émissions

Une orientation envisagée est la décarbonation d'une partie de la production de chaleur en industrie qui est actuellement essentiellement produite à partir de carburants fossiles. Cette décarbonation serait réalisée en utilisant des technologies à l'hydrogène en complément à d'autres options de décarbonation, telles que les thermopompes, et ce, particulièrement pour la chaleur à haute intensité. L'hydrogène nécessaire pourrait être produit localement, soit par électrolyse ou par gazéification de la biomasse, selon la composition du parc industriel de la région et de ses ressources en biomasse, afin de réduire les coûts de transport.

5.2. Autres carrefours envisageables

Ce rapport a présenté de manière détaillée une orientation axée sur le secteur des mines, puis de manière plus succincte, celle axée sur la chaleur industrielle. Toutefois, plusieurs autres orientations de carrefours de décarbonation, englobant les solutions basées sur l'hydrogène mais aussi sur l'électrification directe, peuvent être envisagées. Il y a, par exemple, la piste de la gestion de la demande de pointe des bâtiments institutionnels et commerciaux, ou encore l'électrification des parcs captifs de véhicules lourds ou à haute fréquence d'usage ayant besoin de puissance ou de recharge rapide.

5.3. Un carrefour existant : le carrefour hydrogène d'Edmonton

Lancé en 2021, le Carrefour hydrogène d'Edmonton, en Alberta, a été le premier à voir le jour au Canada. Il a pour objectif de développer et de mettre à l'échelle le marché de l'hydrogène à faible intensité de carbone dans la ville d'Edmonton et ses environs. C'est un carrefour hybride alliant des caractéristiques de carrefour technologique, sectoriel et géographique. En plus des comités de direction et de gestion, il est composé de cinq comités d'action axés sur les points suivants :

- L'approvisionnement en hydrogène à faible intensité de carbone;
- L'hydrogène pour la production de chaleur et d'électricité;
- La décarbonation du transport grâce à l'hydrogène
  - des parcs de véhicules municipaux, et
  - des parcs privés de camions lourds; et
- Le développement économique de la région.

Ce dernier comité travaille à l'élaboration et à l'application d'une stratégie visant à exploiter pleinement le potentiel économique de l'hydrogène dans la grande région d'Edmonton (Edom & Mousseau, 2022).

Ce carrefour travaille en collaboration avec le Centre d'excellence pour l'hydrogène qui est piloté par « Alberta Innovates », une agence de recherche et d'innovation. Ce centre d'excellence offre un programme de financement, des installations d'essai ainsi que des forums d'échange qui favorisent la création de partenariats (*Hydrogen Centre of Excellence*, s. d.).

Depuis son lancement, ce sont plus de cent organisations qui ont été mobilisées par le Carrefour. Plus d'une douzaine de webinaires et d'ateliers ont été présentés[18] et plusieurs articles de blogue et analyses technico-économiques[19] ont été publiés afin de diffuser le plus rapidement possible les informations. Par ailleurs, plusieurs projets sont en cours, comme le projet AZETEC[20] portant sur l'essai de camions lourds à pile à combustible à hydrogène.

[18] Edmonton Region Hydrogen HUB - YouTube
[19] https://erh2.ca/news-and-events/
[20] Alberta Zero Emissions Truck Electrification Collaboration (AZETEC) - Emissions Reduction Alberta (eralberta.ca)

6. Conclusion et prochaines étapes

6.1. Conclusion

En conclusion de ce rapport, nous présentons une **analyse s'intéressant aux aspects stratégiques de la décarbonation de notre société**, sur un **horizon d'une quinzaine d'années**, afin d'identifier des **orientations pouvant contribuer au déploiement d'un marché de l'hydrogène compétitif** du point de vue économique et **s'inscrivant dans les efforts de décarbonation** du Québec et du Canada. Deux orientations ont été identifiées et présentées en détail, soit celles axées sur les mines et la chaleur industrielle. Des carrefours d'appui à la transition énergétique peuvent être créés pour enrichir et réaliser les trajectoires proposées.

Les orientations qui ont été présentées dans ce rapport ne sont pas les seules qui soient possibles. Ce document propose une approche reproductible pour d'autres secteurs à décarboner et ayant le potentiel de contribuer au marché de l'hydrogène. **Ce rapport est une ébauche qui pourra servir à rassembler différents acteurs pour encourager la création de carrefours d'appui à la transition énergétique**. Les prochaines étapes présentées dans la section suivante se résument ainsi : d'abord mobiliser les acteurs souhaités, puis réaliser des études technico-économiques détaillées afin de soutenir un ensemble de projets.

6.2. Les prochaines étapes

Les carrefours d'appui à la transition énergétique doivent avoir comme objectif premier la décarbonation des secteurs visés. Dans certains cas, l'hydrogène fait partie des solutions compétitives permettant d'atteindre cet objectif. Dans cette perspective, les carrefours découlant des orientations proposées doivent toujours développer des trajectoires et mener des actions compatibles avec les cibles climatiques à long terme annoncées par les gouvernements provincial et fédéral. Tout au long du développement de trajectoires, il faut éviter de se piéger technologiquement, en optant pour des options menant à des réductions partielles mais ne pouvant déboucher sur les transformations profondes qui sont nécessaires à l'atteinte de la carboneutralité.

Pour la plupart d'entre elles, les étapes décrites ci-dessous peuvent être menées en parallèle. Les partenaires initiaux qui sont ciblés doivent être en mesure de prendre des décisions au sein de leur propre organisation. Les premières implications de ces parties prenantes peuvent être un partage de données, d'expertise, d'installations physiques, de ressources humaines ou encore de financement.

6.2.1. Les étapes à suivre pour l'orientation axée sur les mines

Dans le cadre de l'orientation axée sur les mines, l'usage proposé pour l'hydrogène est complémentaire à d'autres technologies et repose sur l'utilisation d'électricité décarbonée. Dans ce cas, le carrefour proposé pourrait, par exemple, s'appeler : « Carrefour des mines vers la carboneutralité ».

Tableau 10 : Les étapes à suivre pour la mise en place d'un carrefour axé sur le secteur minier

Étape 1	Identifier et mobiliser les partenaires initiaux	Prioriser les consommateurs potentiels directs et indirects d'hydrogène - dans l'industrie : minières et, possiblement, manufacturiers (matériel roulant, piles à combustible) - autres consommateurs : communautés, municipalités (chaleur / électricité), industries locales
Étape 2	Créer le carrefour, et chercher un financement initial	Financement initial pour la création du secrétariat d'intégration, pour la réalisation d'études (dont le rapport de référence), et la préparation de documents de cadrage
Étape 3	Identification et analyses des contraintes	- Contraintes externes (réglementation, accès à l'énergie, etc.) - Contraintes internes (stratégie de décarbonation du secteur, de l'entreprise; objectifs de la maison mère; etc.)
Étape 4	Évaluation des coûts initiaux en fonction des technologies, des risques et des stratégies opérationnelles	Investissement et opération
Étape 5	Développer et renforcer des partenariats	Pour les technologies, l'expertise, le financement
Étape 6	Mise en œuvre des premiers projets	Projets concernant : le matériel roulant, la production d'hydrogène, l'intégration, l'opération, les données

L'étape 1, soit l'identification et la mobilisation des partenaires initiaux, permet d'identifier des acteurs critiques qui sont en mesure de faire bouger les choses et qui possèdent la capacité de collaborer et d'agir pour stimuler la création d'un carrefour. Si une personne travaille à temps plein à la réalisation de cette première étape, il doit être possible de la compléter sur une période d'environ six mois (voir Tableau 11). D'autres étapes peuvent être réalisées en parallèle, au fur et à mesure des échanges avec les partenaires initiaux. La chaîne d'influence à suivre dans le cadre des activités d'un carrefour minier au Québec est présentée à la Figure 17.

Les gouvernements fédéral et provincial peuvent contribuer au financement du carrefour. Les retombées de ce dernier seront d'abord perçues au niveau provincial, mais elles peuvent potentiellement avoir aussi des impacts aux niveaux national et international, suivant les stratégies qui seront adoptées par les sociétés minières internationales.

Tableau 11 : L'échéancier préliminaire pour la création d'un carrefour axé sur le secteur minier

Étapes		Mois									
		3	6	9	12	15	18	21	24	30	36
Étape 1	**Étapes préliminaires**										
	Identification des partenaires initiaux										
Étape 2	Recherche de financement pour le carrefour										
	Création du carrefour										
Étapes 3 & 4	**Définition de la vision/analyse des contraintes**										
	Analyses										
	Analyses des éléments fondamentaux										
	Autres analyses										
	Élaboration des trajectoires										
	Itération 1										
	Itérations suivantes										
Étape 5	**Développement et renforcement des partenariat**										
Étape 6	**Premier projet**										
	Planification et recherche de financement										
	Début du projet										
	Autres projets										

Légende	
Activité définie dans le temps	
Activité récurrente	
Jalon	

La Figure 17 illustre la chaîne d'influence à suivre pour mobiliser les acteurs autour de la cocréation de trajectoires attrayantes, aptes et crédible, et pour mettre en œuvre ces trajectoires. L'accent est d'abord mis sur le côté demande en identifiant des consommateurs potentiels, ici les compagnies minières et les communautés vivant à proximité des sites miniers. Les listes d'acteurs présentées ne sont pas exhaustives.

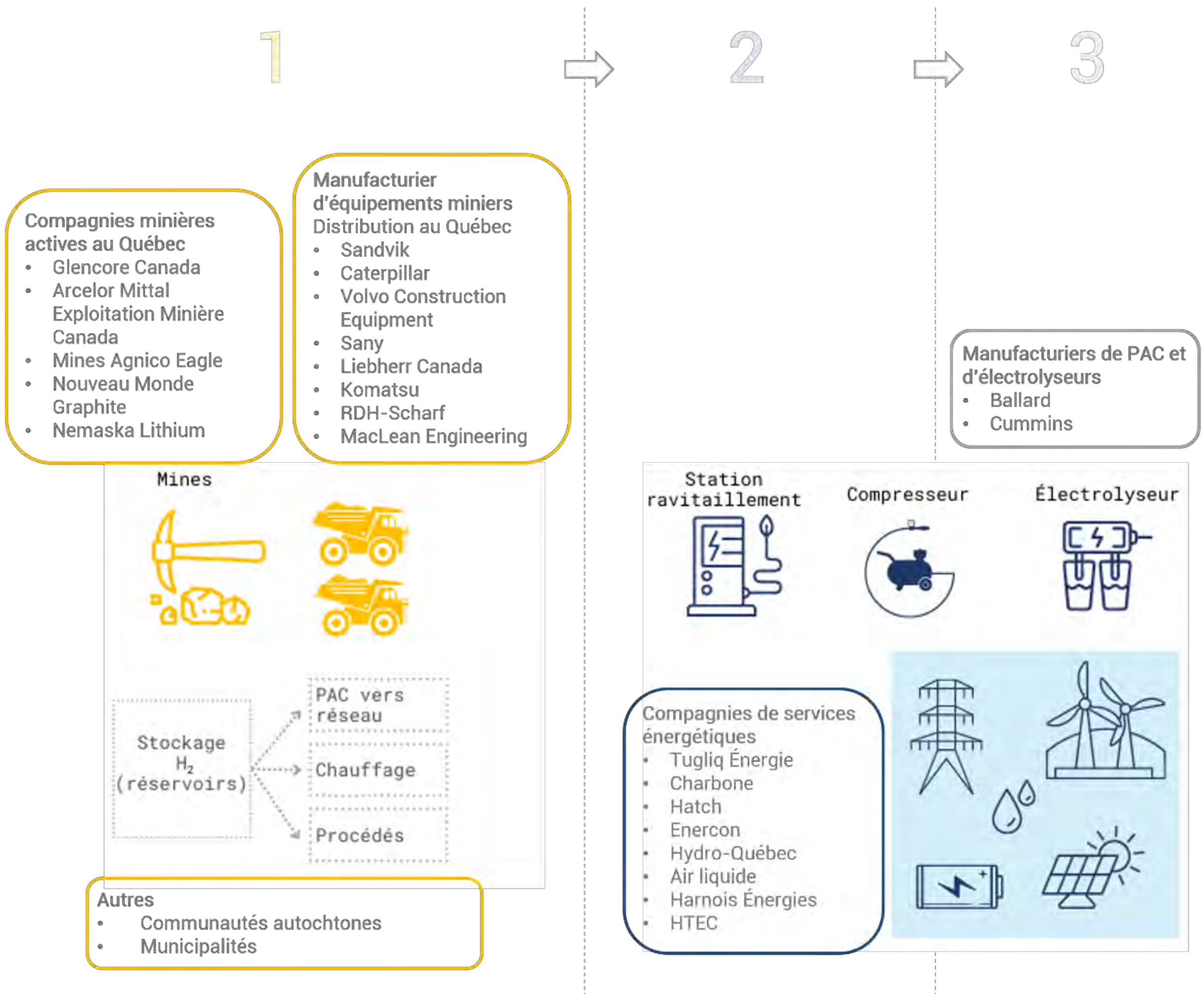

Figure 17 : La chaîne d'influence des acteurs d'un carrefour axé sur le secteur des mines

6.2.2. Étapes pour l'orientation chaleur industrielle

Les étapes à suivre pour le carrefour de décarbonation de la chaleur industrielle sont sensiblement les même que pour le carrefour de décarbonation des mines. Toutefois, le contexte et l'angle d'approche sont différents. Dans le cas de la chaleur industrielle, l'approche vise des zones géographiques regroupant une certaine densité d'industries avec des profils de demande d'électricité présentant une variation quotidienne ou hebdomadaire importante rendant ainsi critique le défi de gestion de la pointe. L'hydrogène pourrait servir à produire de l'électricité pour alimenter les thermopompes industrielles.

Tableau 12 : Étapes pour la mise en place d'un carrefour pour la chaleur industrielle

Étape 1	Identifier et mobiliser les partenaires initiaux	Prioriser les consommateurs - industries présentant une variation de la demande quotidienne ou hebdomadaire importante - industries ayant une complémentarité saisonnière
Étape 2	Créer le carrefour, et chercher un financement initial	Financement initial pour la création d'un secrétariat d'intégration, la réalisation d'études et la préparation de documents de cadrage
Étape 3	Identification et analyses des contraintes	- Contraintes externes (réglementation, accès à l'énergie, etc.) - Contraintes internes (stratégie de décarbonation du secteur, de l'entreprise; etc.)
Étape 4	Évaluation des coûts initiaux en fonction des technologies, des risques et des stratégies opérationnelles	Investissement et opération
Étape 5	Développer et renforcer des partenariats	Pour les technologies, l'expertise, le financement
Étape 6	Mise en œuvre des premiers projets	Projets concernant : la production d'hydrogène, la production d'électricité à partir de piles à combustibles, la production de chaleur à partir de thermopompes, l'intégration, l'opération, les données

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ANNEXES

I. Fiche : Projet de microréseau intégré (éolien et stockage), mine Raglan de Glencore

Localisation : Québec, territoire du Nunavik, région du Nord-du-Québec

Description : Le projet s'est déroulé en deux phases réparties entre 2009 et 2019. Son objectif consistait à tester la faisabilité de la mise en place d'un réseau intelligent basé sur l'énergie éolienne et le stockage dans les conditions climatiques rigoureuses de l'Arctique. Ce projet a permis de démontrer que l'exploitation d'énergie renouvelable et le stockage de cette énergie à l'échelle industrielle et communautaire peut réduire de façon importante les coûts de l'énergie et la consommation du diésel par rapport à la production d'électricité à partir de diésel seulement ou à partir d'autres options de production éolienne-diésel.

Phase 1	**Phase 2**

Équipements :
• Turbine éolienne de 3 MW
• Système de stockage :
  ○ volant à inertie, 200 kW / 1.5 kWh
  ○ batteries lithium ion, 200 kW / 250 kWh
  ○ boucle à hydrogène, 200 kW / 4 MWh
Mise en service : 2014
	Équipements :
	• Turbine éolienne de 3 MW
	• Système de stockage :
	  ○ Batteries lithium ion, 3 MW / 1 MWh
	Mise en service : 2019

Pour plus de détails : Raglan I - Microréseau hybride éolien / batteries - Tugliq Energie	Pour plus de détails : Raglan II - Commande renouvelée d'une éolienne de 3MW - Tugliq Energie

Résultats globaux :

- Intégration d'énergie provenant de source renouvelable et équivalant à 40 % de la puissance installée alimentée au diésel;
- Réduction de la consommation de diésel de 4,2 millions de litres par an;
- Réduction des GES, plus de 20 000 t cumulées en 2019;
- Réduction des risques de déversement de produits pétroliers grâce à la réduction des quantités de diésel transportées;
- Réduction des effets économiques des mécanismes de tarification du carbone sur les acteurs industriels;
- Établissement de références en termes de technologies, mais aussi en ce qui concerne les modèles d'exploitation et de partenariats;
- Développement de connaissances utiles pour l'élaboration de règlements soutenant la décarbonation de l'énergie consommée dans les mines canadiennes;
- Identification des options de stockage compétitives;
- Expérimentation d'une boucle à hydrogène pour le stockage amenant à la conclusion que l'hydrogène serait possiblement plus pertinent pour la mobilité sur le site minier.

Pour plus d’information, consulter le rapport « *Projet-pilote de démonstration de réseau intelligent d’électricité renouvelable à la mine RAGLAN Glencore* (GC 128296)» (TUGLIQ Énergies Co., 2016).

II. Solutions technologiques

a. Électricité : Approvisionnement et stockage

Approvisionnement en électricité		Stockage d'électricité	
Réseau d'Hydro-Québec	Mature	Batteries lithium-ion	Émergent / Mature
Parc éolien	Mature	Volants d'inertie	Mature
Parc solaire photovoltaïque	Émergent / Mature	Boucle hydrogène (électrolyseur, réservoirs, PAC)	Émergent
Petit ou microréacteur nucléaire modulaire	En développement		

b. Les véhicules hors-route

Le tableau ci-dessous analyse un ensemble de technologies existantes pour les véhicules hors route (VHR), tels que les engins miniers, en utilisant une méthodologie développée par J. Meadowcroft (2021). Cette analyse se base sur les critères présentés dans l'*Encadré 1* de ce document. Deux autres technologies s'ajoutent à celles présentées dans le tableau :

- Les systèmes à caténaires qui peuvent être couplés à des véhicules électriques et des véhicules hybrides (diésel- électrique). Les véhicules hybrides diésel-électrique ont un faible potentiel pour contribuer à l'atteinte de la carboneutralité car, bien qu'ils réduisent de manière importante les émissions de GES, ils ne les éliminent pas complètement.
- L'automatisation des véhicules qui peut s'appliquer en combinaison avec toutes les autres technologies présentées.

Ce tableau peut être mis à jour périodiquement afin de servir d'outil d'aide à la décision.

La légende pour la colonne « Priorité » est la suivante:

Satisfait les critères
Satisfait potentiellement l'ensemble des critères
Satisfait partiellement les critères
Ne satisfait pas les critères

	Crédible			Apte		Attrayant/Convaincant			Priorité
	Maturité	**Viabilité économique**	**Acceptabilité sociale**	**Adapté aux besoins/objectifs**	**Potentiel de contribution à un avenir carboneutre**	**Pour les principales parties prenantes**	**Coûts et avantages**	**Opportunités de développement économique**	
Pile à combustible à hydrogène									
VPACH	Pile à combustible mature mais application pour les VHR en cours d'émergence. H_2 par électrolyse : disponible mais performances encore à améliorer. Infrastructure d'approvisionnement très peu déployée.	Coût des véhicules encore très élevé par rapport aux modèles « classiques ». Transport d'H_2 encore très cher. Actuellement, la production à partir de méthane est moins chère que l'électrolyse ou la production à partir de biomasse.	Préoccupations concernant la sécurité autour de l'H_2.	Oui, bonne performance (couple élevé)	Oui, si l'H_2 est produit par électrolyse à partir d'électricité décarbonée ou à partir de biomasse.	Suscite l'intérêt de certains acteurs (minières, équipementiers).	Bon couple, moins de maintenance, pas de pollution de l'air, réduction du bruit. Préoccupation sur la possibilité de recycler les piles à combustible. Peut jouer un rôle important dans une économie de l'hydrogène (PACH, électrolyseur).	Potentiel de développement d'une filière de fabrication de piles à combustible pour la mobilité; de fabrication d'électrolyseurs; de production d'H_2 par électrolyse ou à partir de biomasse.	Moyen/Élevé A le potentiel de prendre part à un avenir carboneutre
Électrique									
À batterie lithium-ion	En cours d'émergence. La technologie de batterie doit encore être améliorée pour répondre pleinement aux besoins spécifiques des différents secteurs (mine, construction, foresterie).	Coût des véhicules encore élevé par rapport aux véhicules diésel, mais coûts d'exploitation plus faibles (maintenance et énergie).	Préoccupations sur l'impact de la production et la gestion de fin de vie des batteries.	Oui, bonne performance (couple élevé). Toutefois, il reste des défis à relever; entre autres, le rapport autonomie, encombrement et masse des batteries.	Oui, si l'électricité de recharge est décarbonée, et si la chaîne d'approvisionnement l'est aussi, sans oublier la gestion de fin de vie des équipements.	Suscite l'intérêt de certains acteurs (minières, équipementiers).	Bon couple, moins de maintenance, pas de pollution de l'air, réduction du bruit.	Opportunités d'emploi en recherche, conception, assemblage et maintenance.	Élevée A le potentiel de prendre part à un avenir carboneutre

	Crédible			Apte		Attrayant/Convaincant			Priorité
	Maturité	Viabilité économique	Acceptabilité sociale	Adapté aux besoins/objectifs	Potentiel de contribution à un avenir carboneutre	Pour les principales parties prenantes	Coûts et avantages	Opportunités de développement économique	
Biodiésel									
Biodiésel	Mature	Actuellement plus cher que le diésel principalement à cause de la nature de la source d'approvisionnement (matière agricole et/ou matière résiduelle) nécessitant du transport, de la manutention et des traitements.	Pas de préoccupations identifiées pour le moment.	Oui, performances similaires aux véhicules diésel.	Possible mais la disponibilité de la matière première est limitée et potentiellement en compétition avec d'autres usages (émissions négatives - BECSC).	Suscite l'intérêt de certains acteurs (surtout du côté production).	Peut utiliser les infrastructures existantes (stockage, transport, distribution). Ne répond pas aux problèmes de pollution de l'air et sonore. A un impact négatif sur l'utilisation des sols.	Peut ouvrir de nouveaux marchés pour la biomasse et les matières résiduelles.	Faible/Moyen Ne contribue que partiellement à la transition. Contribue à la pollution de l'air.
Hydrogène									
Moteur à combustion à hydrogène	Encore à l'étape de R&D.		Préoccupations concernant la sécurité autour de l'H_2.		Pas d'émission de CO_2 ou CO, mais des émissions d'oxydes d'azote (Nox).	Encore à l'étape de R&D.			Faible

	Crédible			Apte		Attrayant/Convaincant			Priorité
	Maturité	Viabilité économique	Acceptabilité sociale	Adapté aux besoins/objectifs	Potentiel de contribution à un avenir carboneutre	Pour les principales parties prenantes	Coûts et avantages	Opportunités de développement économique	
Gaz naturel (GN)									
GN compressé ou liquéfié	Mature	Le gaz naturel est globalement peu cher, toutefois son prix est très variable.	Socialement encore acceptable, mais c'est un combustible fossile.	Faibles performances.	Réduction des GES par rapport au diésel (17 % à 30 %), mais n'est pas compatible avec la carboneutralité.	Suscite l'intérêt de certains acteurs (fournisseurs de gaz).	Peut utiliser les infrastructures de GN existantes, et est compatible avec les moteurs thermiques existants.	Peut contribuer à court terme à l'expansion du marché du GN.	Nulle Émissions incompatibles avec un avenir carboneutre
GN renouvelable	Production existante, en cours d'expansion. Usage limité pour les VHR.	Peut-être viable, mais est encore beaucoup plus cher que le GN (2 à 6 fois plus cher).	Pas de préoccupations identifiées pour le moment.	Faibles performances.	Possible mais la disponibilité de la matière première est limitée et localisée. Potentiellement en compétition avec d'autres usages (émissions négatives - BECSC).	Suscite l'intérêt de certains acteurs (fournisseurs de biomasse).	Peut utiliser les infrastructures de GN existantes, et est compatible avec les moteurs thermiques existants.	Peut offrir des opportunités de développement localisées.	Faible

GN synthétique	Encore à l'étape de R&D.	Coûts de production présentement très élevés.	Pas de préoccupations identifiées pour le moment; toutefois si le CO_2 utilisé est transporté par pipeline, peut être source de préoccupations à cause des risques de fuites.	Faibles performances.	A du potentiel mais dépend fortement de l'évolution des technologies de production décarbonée d'H_2 et des sources de CO_2 (DAC, CUC). Potentiellement en compétition avec d'autres usages (émissions négatives - BECSC).	Encore à l'étape de R&D	Peut utiliser les infrastructures de GN existantes, et est compatible avec les moteurs thermiques existants.	Pas claires pour le moment.	Faible Technologie encore très immature

III. Les acteurs

a. Les acteurs rencontrés

Nom	Entité	Poste	Adresse courriel	Rencontré.e.s le
Simon Barnabé	UQTR, IRH	Directeur assistant	simon.barnabe@uqtr.ca	21-03-2022
Oumarou Savadogo	Polytechnique Montréal	Professeur	oumarou.savadogo@polymtl.ca	30-03-2022
Junior Lagrandeur	Université de Sherbrooke	Post Doctorant	Junior.Lagrandeur@USherbrooke.ca	20-04-2022
Daniel Charrette	Charbone	Chef de l'exploitation	dc@charbone.com	23-05-2022
Sid Zerbo	Charbone	Chef de l'ingénierie	sz@charbone.com	23-05-2022
Cédrick Lalaizon	Propulsion Québec	Directeur Innovation et expérimentation	sarah.houde@propulsionquebec.com cedrick.lalaizon@propulsionquebec.com	21-06-2022
Alex Champagne-Gélinas	Innovéé	Conseiller en intelligence sectorielle	agelinas@innovee.quebec	21-06-2022
Nicolas Seguin	Raglan / TUGLIQ Énergie	VP Développement, Projets et Opérations	Nseguin@TUGLIQ.com	29-06-2022
Martine Paradis	Nouveau Monde Graphite	VP Ingénierie, environnement et projet Matawinie	mparadis@nouveaumonde.ca	Par courriel uniquement
Julie Paquet	Nouveau Monde Graphite	VP Communications & Stratégie ESG	jpaquet@nmg.com	05-07-2022
Dinara Millington	Accélérateur de transition	Responsable des régions de l'ouest	dmillington@transitionaccelerator.ca	15-07-2022

b. La cartographie des chaînes de valeur

Le secteur minier

Tableau 13 : La Cartographie à haut niveau de la chaîne de valeur du secteur minier
(Les listes d'acteurs ci-dessous ne sont pas exhaustives)

PRODUCTION		DISTRIBUTION		CONSOMMATION	
Manufacturiers d'équipement de production et conditionnement	Services énergétiques / Ptoduction	Stockage	Stations de ravitaillement	Manufacturiers d'équipements miniers*	Secteur d'utilisation: Mines
Cummins	Tugliq Énergie	Change Energy Services	Harnois Énergies	Sandvik	Glencore Canada
Ballard Power Systems	Charbone		HTEC	Caterpillar	Arcelor Mittal Exploitation Minière Canada
Siemens Canada	Hatch			Volvo Construction Equipment	Mines Agnico Eagle
Next Hydrogen	Enercon			Sany	Nouveau Monde Graphite
Sim Composites	Hydro-Québec			Liebherr Canada	Nemaska Lithium
Xebec (ACS)	Air liquide Canada			Komatsu	
	Harnois Énergies			RDH-Scharf	
	HTEC			MacLean Engineering	
	Xebec (HyGear)				
➢ Maillon le plus mature, mais peu d'acteurs basés au Québec ➢ **Reconfiguration**	➢ Plusieurs acteurs ayant des activités au Québec ➢ **Diffusion**	➢ Peu d'acteurs présent ➢ **Diffusion**	➢ Quelques acteurs présents ➢ **Diffusion**	➢ Essentiellement de la distribution, peu d'activité de production ou d'assemblage au Québec ➢ **Émergence**	➢ Plusieurs grands acteurs potentiels au Québec ➢ **Diffusion**

Note : *La dernière ligne du tableau ci-dessus indique en gras l'état de maturité le plus avancé parmi les acteurs de chaque maillon.*

Légende

QC				
Reste du Canada				
	Reconfiguration Cet acteur joue un rôle établi dans l'économie des technologies et des services directement liés à l'hydrogène.	**Diffusion** Cet acteur joue un rôle dans l'économie des technologies et des services directement liés à l'hydrogène, ou à des solutions complémentaires à l'hydrogène.	**Émergence** Cet acteur peut jouer un rôle potentiel et il manifeste publiquement son intérêt pour des technologies et des services liés à l'hydrogène.	**Non connu** Cet acteur peut jouer un rôle potentiel mais son intérêt pour des technologies et des services liés à l'hydrogène n'est pas connu.

Commentaires sur la chaîne de valeur du secteur minier

- La cartographie de la chaîne de valeur du secteur des mines ci-dessus est organisée selon l’approche classique allant de la production à la consommation. Toutefois, si on applique plutôt la méthodologie des carrefours d’appui à la transition énergétique, l’accent est d’abord mis sur les acteurs du côté de la demande plutôt que de la production.
- En plus des utilisateurs principaux comme les compagnies minières, d’autres acteurs, comme les communautés autochtones, ou les municipalités, peuvent bénéficier de la production d’électricité à partir énergie renouvelable et de la production d’hydrogène à faibles émissions. La première étape d’un carrefour pour le secteur minier viserait donc à mobiliser les compagnies minières, les manufacturiers d’équipements miniers mobiles, et les communautés à proximité des sites pour valider la possibilité de bâtir une demande.
- Glencore Canada a réalisé plusieurs projets pilotes à sa mine Raglan pour tester des solutions permettant de décarboner l’énergie qui y est consommée, en particulier la consommation de diésel. Les options testées sont, entre autres, des éoliennes, du stockage par batterie, et une boucle hydrogène (électrolyseur, stockage dans des réservoirs, piles à combustible). La minière Nouveau Monde Graphite, développe ses activités pour atteindre une production de matériel d’anode actif à faibles émissions de carbone. Elle est donc à la recherche de solutions à faibles émissions de carbone pour ses équipements mobiles, ainsi que le reste de ses activités.
- De nombreux manufacturiers d’équipements miniers mobiles distribuent leurs produits au Québec, toutefois il n’y a que peu d’activités de fabrication ou d’assemblage de ce type d’équipement dans la province. On retrouve plus de ces activités dans la province voisine de l’Ontario. Plusieurs manufacturiers et compagnies minières testent des solutions (véhicule électrique à batteries, véhicule électrique hybride à batteries et à piles à combustible, véhicule hybride diesel et électrique à caténaires) pour décarboner les tombereaux de grande capacité.

- La trajectoire proposée pour le secteur minier est caractérisée par un déploiement localisé des infrastructures de production et de consommation, les enjeux liés au transport de l'hydrogène sont donc en grande partie écartés.
- La production d'hydrogène est gérée par la compagnie minière ou par une compagnie de service énergétique. Selon leur taille et leur emplacement chaque mine ou petit groupe de mines aura ses propres infrastructures. Chaque mine a besoin d'un certain niveau de personnalisation de la solution déployée à cause des caractéristiques propres à chacune.

Le secteur du transport de marchandise

Tableau 14 : La cartographie à haut niveau de la chaîne de valeur du secteur du transport de marchandise
(Les listes d'acteurs ci-dessous ne sont pas exhaustives)

PRODUCTION		DISTRIBUTION			CONSOMMATION	
Manufacturiers d'équipement de production et conditionnement	Production	Stockage	Distribution / Transport	Services énergétiques	Manufacturiers d'équipements	Secteur d'utilisation: Transport lourd
Sim Composites	Air liquide Canada (Olin et autres)	Change energy Services	Harnois Énergies	Air liquide Canada	Caterpillar	TFI International
Xebec	Charbone	Intragaz	HTEC	Harnois Énergies	Volvo Trucks	Canadian National Transportation
Cummins	Harnois Énergies			HTEC	Dana	CAT / Canadian Amerincan Trans.
Ballard Power Systems	Messer (Nouryon)			Hatch	Kenworth (Paccar)	Robert
Siemens Canada	Evolugen-Gazifère			Hydro-Québec	Peterbilt (Paccar)	
Next Hydrogen	Air products			Stantec	Cummins	
	HyGear (Xebec)				Ballard Power Systems	

Commentaires sur la chaîne de valeur du secteur du transport de marchandise

- La cartographie de la chaîne de valeur du secteur du transport lourd ci-dessus suit l'organisation classique allant de la production vers la demande.
- Dans le cas du transport lourd (marchandises), le déploiement doit se faire à l'échelle de la province, ou du moins le long de certains axes routiers. Les stations de ravitaillement doivent

être positionnées stratégiquement et adopter un format similaire afin d'offrir un service consistant aux camionneurs. L'hydrogène peut être produit sur le site de la station de ravitaillement ou être livré à partir d'un centre de production centralisé.

- Ballard et Dana sont des partenaires dans le projet AZETEC en Alberta qui vise à tester deux camions lourds de transport de marchandise fonctionnant avec des piles à combustible. Par ailleurs, Ballard a fourni les piles à combustible qui équipent le tombereau hybride mis à l'essai par la minière Anglo American en Afrique du Sud.

- Les principaux rapports utilisés pour la compléter sont :
  - Hoornweg, D., Wotten, D., Kauling, D., Jianu, O., & Armouldi, E. (2021). Hydrogen : An Overview – Eastern Canada. Transition Accelerator Reports, 3(3), 1-120.
  - Whitmore, J., & Pineau, P.-O. (2022). État de l'énergie au Québec—Édition 2022. Chaire de gestion du secteur de l'énergie, HEC Montréal.

Commentaires généraux sur les chaînes de valeur de l'hydrogène au Québec

- Les maillons des chaînes de valeurs qui diffèrent le plus selon le secteur d'utilisation visé sont
  - Le maillon concernant les manufacturiers d'équipements du côté de la demande,
  - Les maillon production et transport/distribution car les acteurs de ce maillon ne sont pas les mêmes selon que la production soit centralisée ou pas.
- D'autres maillons regroupent sensiblement les mêmes acteurs quelle que soit la filière, notamment le maillon des manufacturiers d'équipement de production d'hydrogène.
- Au Québec, plusieurs établissements universitaires mènent des activités de recherche liées à l'hydrogène, notamment l'université du Québec à Trois-Rivières au sein de son Institut de recherche sur l'hydrogène, et Polytechnique Montréal.

De: Payeur, Mathieu (SITE)
Envoyé: 19 juin 2022 20:48
À: Chabot, Étienne (SITE); Poulin, Julie (SITE); Lalancette, Nadia (SITE); Lamonde, Bernard (SITE)
Cc: Deschênes, Dominique (SITE); Fournier, Michel (SITE); Côté, Jenny (SITE); Gagnon, Stéphan (SITE); Bigouret, Alex (SITE); Comazzi, Sébastien (SITE); Martin, Cynthia (SITE)
Objet: Etude de l'IDQ sur l'électricité verte

Énergie et Ressources naturelles
Québec

Bonjour,

Voir la publication de l'Institut du Quebec sur les perspective économique lié aux choix d'utilisation de l'électricité du Quebec en comparaison avec l'exportation.

On y compare l'option de l'exportation des electrons avec l'utilisation dans le secteur des centres de données, les alumineries, les serres et l'hydrogène.

On y retrouve aussi certains éléments quant aux contributions potentielles en GES, notamment en lien avec l'approche biénergies (@bernard).

Résumé:
https://www.newswire.ca/fr/news-releases/l-electricite-verte-un-levier-de-creation-de-richesse-ecoresponsable-pour-le-quebec-822585878.html

Page:
https://institutduquebec.ca/le-contexte-energetique-mondial-evoluera-de-facon-marquee-dans-les-annees-a-venir-tant-en-raison-des-transformations-structurelles-des-economies-renforcees-par-la-pandemie-de-covid-19-que-des-objec/

Rapport court (16 pages) et version longue (116 pages) disponibles.

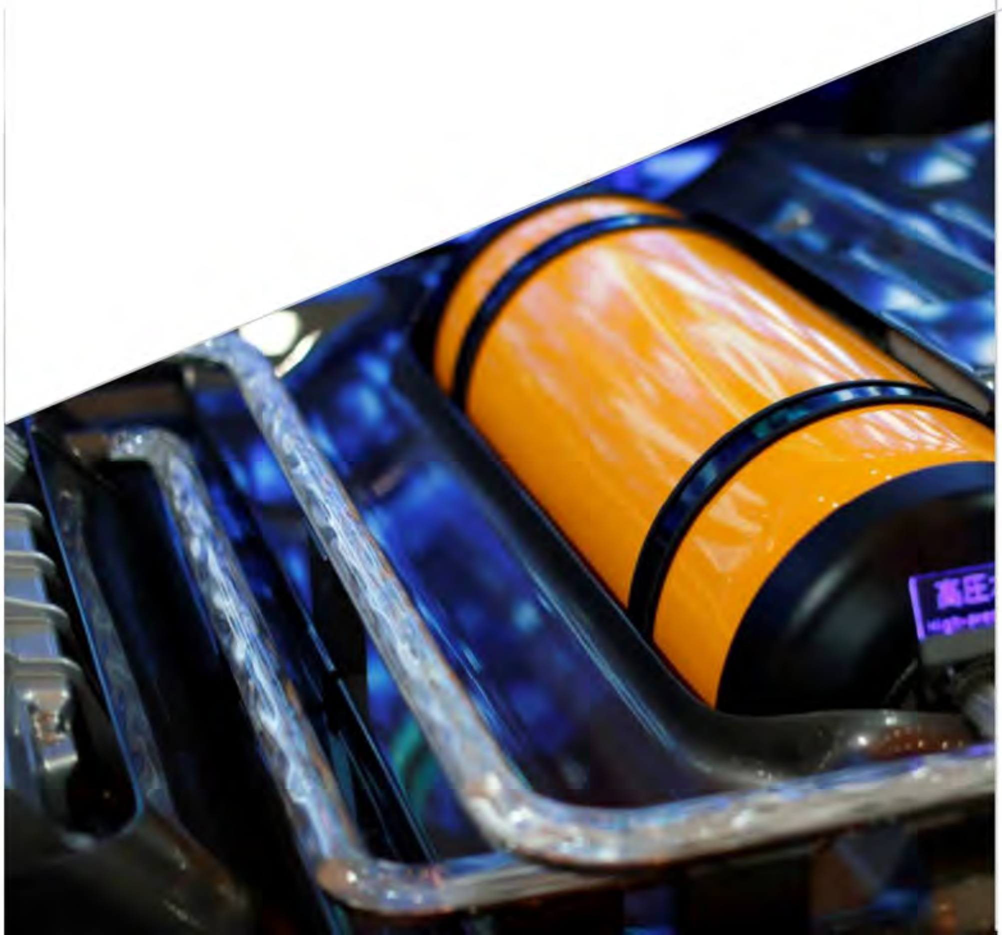
Merci @Stephan pour le post sur Linked in! N'hésites pas à faire circuler à l'interne aussi, pour eviter qu'on echappe des rapports comme celui ci!

Salutations,
Mathieu

Hydrogen Economy Outlook

Key messages

March 30, 2020



Contents

On April 23, BNEF made two changes to this report. This version corrects a rounding error in the cost range of renewable hydrogen displayed on page 2 and updates Figure 12 to exclude some countries.

Key messages

Hydrogen is a clean-burning molecule that could become a zero-carbon substitute for fossil fuels in hard-to-abate sectors of the economy. The cost of producing hydrogen from renewables is primed to fall, but demand needs to be created to drive down costs, and a wide range of delivery infrastructure needs to be built. That won't happen without new government targets and subsidies. These are the key messages of BNEF's *Hydrogen Economy Outlook*, which provides a global, independent analysis and outlook for a hydrogen economy.

A full copy of the Hydrogen Economy Outlook is available for BNEF clients (web | terminal). It draws together analysis and key findings from 12 studies published in 2019 and 2020 from BNEF's Hydrogen Special Project. The full suite of BNEF research on hydrogen is also available for clients on the **hydrogen theme page (web | terminal)**.

Figure 1: Summary of the economics of a hydrogen economy

Scaling-up hydrogen

Requires	Which should drive the delivered cost of clean hydrogen down to	Delivered costs could fall further to	Which would make clean hydrogen
$150 billion	**$15/MMBtu**	**$7.4/MMBtu**	**competitive**
of cumulative subsidies to 2030	in many parts of the world by 2030	by 2050	with current natural gas prices in China, India, Brazil and Germany

Enables

Making green steel with a	Clean dispatchable power with a	Green ammonia with a	Fuel cell powered trucks to compete by
$50/tCO2	**$32/tCO2**	**$78/tCO2**	**2031-34**
price on coking coal	price on natural gas	price on natural gas	with diesel internal combustion engines

Abatement

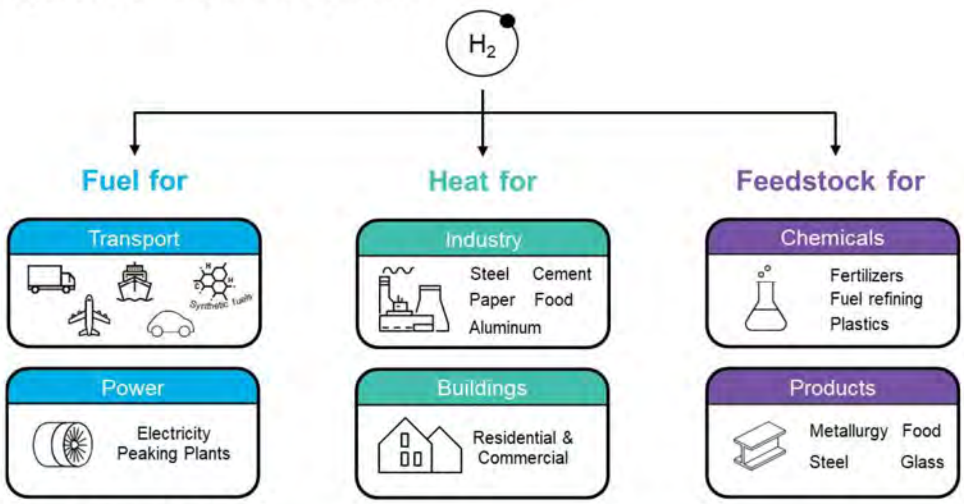
Of up to	Reduction of up to 20% of global emissions for	However the signs of scale-up are	Investors should keep watch for
one-third	**under $100/tCO2**	**not yet there**	**seven signposts**
of global emissions from fossil fuels and industry	using hydrogen at $7.4MMBtu	as policy support is insufficient	to determine whether a hydrogen economy is emerging

Source: BloombergNEF. Note: Clean hydrogen refers to both renewable and low-carbon hydrogen (from fossil-fuels with CCS). Abatement cost with hydrogen at $1/kg (7.5/MMBtu). Currency is US dollars.

Meeting climate targets is likely to require a clean molecule

Renewable electricity can help reduce emissions in road transport, low-temperature industrial processes and in heating buildings. However, fossil fuels have a significant advantage in applications that require high energy density, industrial processes that rely on carbon as a reactant, or where demand is seasonal. To fully decarbonize the world economy, it's likely a clean molecule will be needed and hydrogen is well placed to play this role (Figure 2). It is versatile, reactive, storable, transportable, clean burning, and can be produced with low or zero emissions.

Figure 2: The many uses of hydrogen

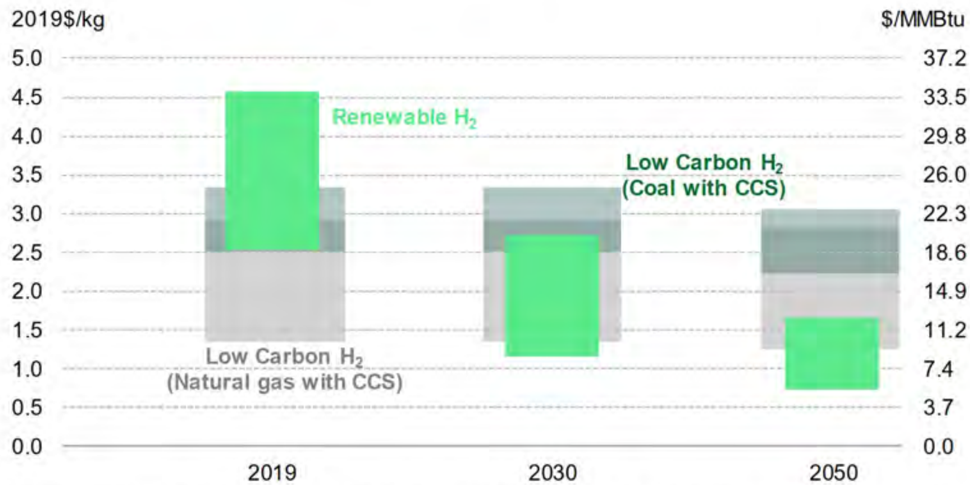


Source: BloombergNEF

Renewable hydrogen is currently expensive, but costs are coming down

In 2018, over 99% of hydrogen was made using fossil fuels, but hydrogen can also be produced cleanly using renewable electricity to split water in an electrolyzer. With the cost of wind and solar continuing to fall, the question is whether the cost for electrolyzers and renewable hydrogen can follow. While they are still expensive in Western markets, there are encouraging signs. The cost of alkaline electrolyzers made in North America and Europe fell 40% between 2014 and 2019, and Chinese made systems are already up to 80% cheaper than those made in the west. If electrolyzer manufacturing can scale up, and costs continue to fall, then our calculations suggest renewable hydrogen could be produced for $0.7 to $1.6/kg in most parts of the world before 2050. This is equivalent to gas priced at $6-12/MMBtu, making it competitive with current natural gas prices in Brazil, China, India, Germany and Scandinavia on an energy-equivalent basis, and cheaper than producing hydrogen from natural gas or coal with carbon capture and storage (Figure 3).

Figure 3: Forecast global range of levelized cost of hydrogen production from large projects



Source: BloombergNEF. Note renewable hydrogen costs based on large projects with optimistic projections for capex. Natural gas prices range from $1.1-10.3/MMBtu, coal from $30-116/t.

Transporting and storing hydrogen needs massive infrastructure investment

Hydrogen's low density makes it considerably harder to store than fossil fuels. If hydrogen were to replace natural gas in the global economy today, 3-4 times more storage infrastructure would need to be built, at a cost of $637 billion by 2050 to provide the same level of energy security. Storing hydrogen in large quantities will be one of the most significant challenges for a future hydrogen economy. Low cost, large-scale options like salt caverns are geographically limited, and the cost of using alternative liquid storage technologies is often greater than the cost of producing hydrogen in the first place (Table 1).

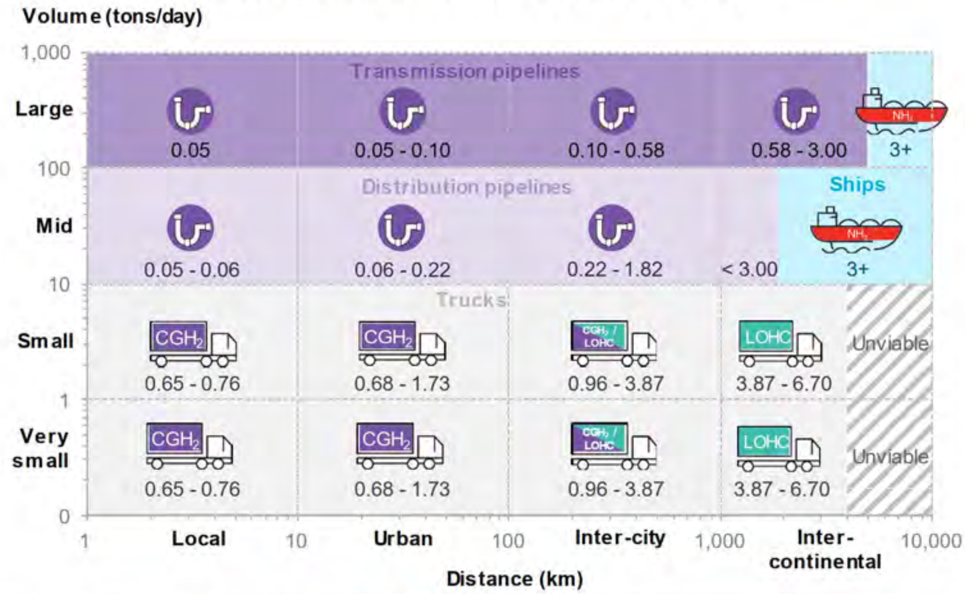
Table 1: Hydrogen storage options

	Gaseous state				Liquid state			Solid state
	Salt caverns	Depleted gas fields	Rock caverns	Pressurized containers	Liquid hydrogen	Ammonia	LOHCs	Metal hydrides
Main usage (volume and cycling)	Large volumes, months-weeks	Large volumes, seasonal	Medium volumes, months-weeks	Small volumes, daily	Small - medium volumes, days-weeks	Large volumes, months-weeks	Large volumes, months-weeks	Small volumes, days-weeks
Benchmark LCOS ($/kg)[1]	$0.23	$1.90	$0.71	$0.19	$4.57	$2.83	$4.50	Not evaluated
Possible future LCOS[1]	$0.11	$1.07	$0.23	$0.17	$0.95	$0.87	$1.86	Not evaluated
Geographical availability	Limited	Limited	Limited	Not limited	Not limited	Not limited	Not limited	Not limited

Source: BloombergNEF. Note: [1] Benchmark levelized cost of storage (LCOS) at the highest reasonable cycling rate (see detailed research for details). LOHC – liquid organic hydrogen carrier.

Low density also makes hydrogen expensive to transport via road or ship. However, hydrogen flows nearly three times faster than methane through pipes, making this a cost-effective option for large-scale transport (Figure 4). But for hydrogen to become as ubiquitous as natural gas, a huge, coordinated program of infrastructure upgrades and construction would be needed, as hydrogen is often incompatible with existing pipes and systems.

Figure 4: H_2 transport costs based on distance and volume, \$/kg, 2019



Legend: Compressed H_2 Liquid H_2 Ammonia Liquid Organic Hydrogen Carriers

Source: BloombergNEF. Note: figures include the cost of movement, compression and associated storage (20% assumed for pipelines in a salt cavern). Ammonia assumed unsuitable at small scale due to its toxicity. While LOHC is cheaper than LH_2 for long distance trucking, it is less likely to be used than the more commercially developed LH_2.

A scaled-up industry could deliver hydrogen for a benchmark cost of \$2/kg in 2030 and \$1/kg in 2050 in many parts of the world

Hydrogen is likely to be most competitive in large-scale local supply chains. Clusters of industrial customers could be supplied by dedicated pipeline networks containing a portfolio of wind- and solar-powered electrolyzers, and a large-scale geological storage facility to smooth and buffer supply. Our analysis suggests that a delivered cost of green hydrogen of around \$2/kg (\$15/MMBtu) in 2030 and \$1/kg (\$7.4/MMBtu) in 2050 in China, India and Western Europe is achievable. Costs could be 20-25% lower in countries with the best renewable and hydrogen storage resources, such as the U.S., Brazil, Australia, Scandinavia and the Middle East. However, cost would be up to 50-70% higher in places like Japan and Korea that have weaker renewable resources and unfavorable geology for storage (Figure 5 and Figure 6).

Figure 5: Estimated delivered hydrogen costs to large-scale industrial users, 2030

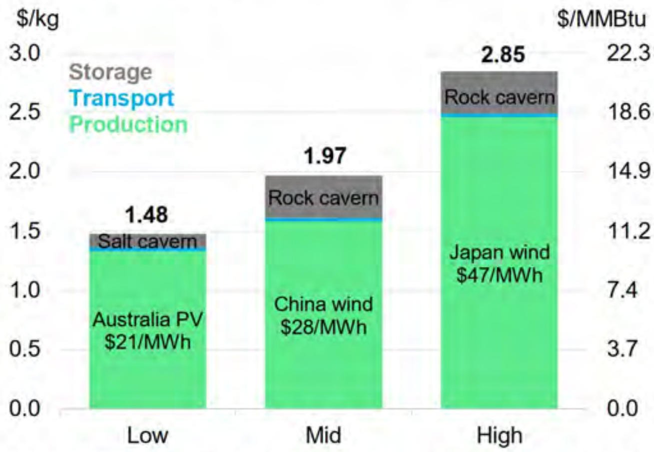
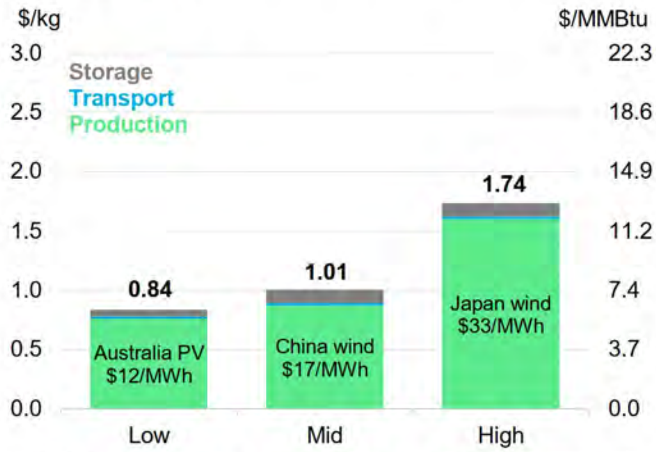


Figure 6: Estimated delivered hydrogen costs to large industrial users, 2050



Source: BloombergNEF. Note: Power costs depicted are the LCOE used for electrolysis, and are lower than the BNEF's standard LCOE projections in 2050 due to savings from integrated design of the electrolyzer and generator, and anticipated additional learning from increased renewable deployment for hydrogen production. Production costs are based on a large-scale alkaline electrolyzer with capex of $135/kW in 2030 and $98/kW in 2050. Storage costs assume 50% of total hydrogen demand passes through storage. Transport costs are for a 50km transmission pipeline movement. Compression and conversion costs are included in storage. Low estimate assumes a salt cavern, mid and high estimate a rock cavern for both 2030 and 2050.

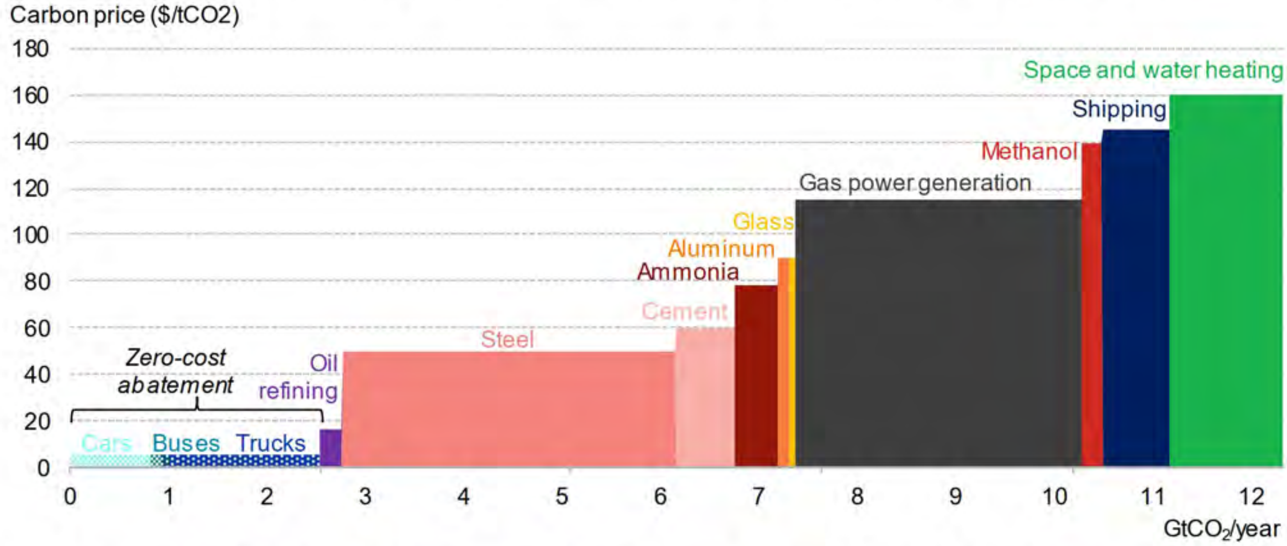
Policy is critical

Reaching a delivered hydrogen cost of $1/kg will require massive scale-up in demand as well as cost declines in transport and storage technologies. And while hydrogen is a hot topic right now, there is little government policy currently in place to help this happen. Policy measures are generally focused on expensive road transport applications, and programs are poorly funded. The more promising use cases in industry are only funded with one-off grants for demonstration projects. For the industry to scale up, demand needs to be supported with comprehensive policy coordinated across government, and the roll-out of around $150 billion of cumulative subsidies to 2030.

…and so is carbon pricing

Even at $1/kg, carbon prices or equivalent measures that place a value on emission reductions are still likely to be needed for hydrogen to compete with cheap fossil fuels in hard-to-abate sectors. This is because hydrogen must be manufactured, whereas natural gas, coal and oil need only to be extracted, so it is likely always to be a more expensive form of energy. Hydrogen's lower energy density also makes it more expensive to handle. But if the required policy is in place, up to 34% of greenhouse gas emissions from fossil fuels and industry could be abated using hydrogen – 20% for less than $100/tCO2 (Figure 7).

Figure 7: Marginal abatement cost curve from using $1/kg hydrogen for emission reductions, by sector in 2050



Source: BloombergNEF. Note: sectoral emissions based on 2018 figures, abatement costs for renewable hydrogen delivered at $1/kg to large users, $4/kg to road vehicles. *Aluminum emissions for alumina production and aluminum recycling only. Cement emissions for process heat only. Refinery emissions from hydrogen production only. Road transport and heating demand emissions are for the segment that is unlikely to be met by electrification only, assumed to be 50% of space and water heating, 25% of light-duty vehicles, 50% of medium-duty trucks, 30% of buses and 75% of heavy-duty trucks.*

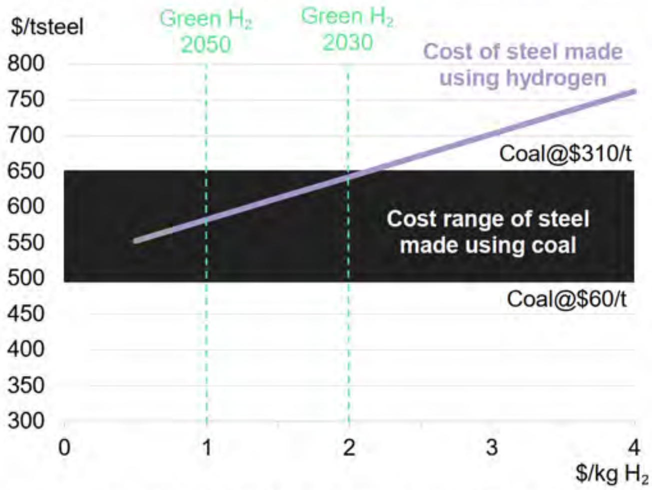
Hydrogen is a promising emissions reduction pathway for the hard-to-abate industry sectors

The strongest use cases for hydrogen are the manufacturing processes that require the physical and chemical properties of molecule fuels in order to work. Hydrogen can enable a switch away from fossil fuels in many of these applications at surprisingly low carbon prices. For example, at $1/kg, a carbon price of $50/tCO2 would be enough to switch to renewable hydrogen in steel making (Figure 8), $60/tCO2 to use renewable hydrogen for heat in cement production, $78/tCO2 for ammonia synthesis, and $90/tCO2 for aluminum and glass manufacturing.

But its role in transport should be focused on trucks and ships

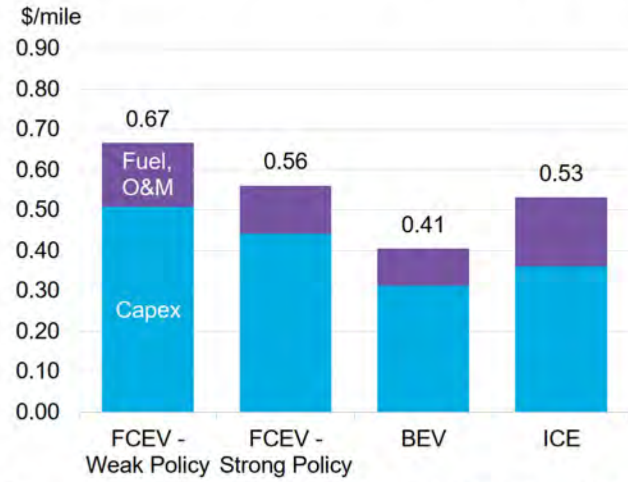
Hydrogen can play a valuable role decarbonizing long-haul, heavy-payload trucks. These could be cheaper to run using hydrogen fuel cells than diesel engines by 2031. But the bulk of the car, bus and light-truck market looks set to adopt battery electric drive trains, which are a cheaper solution than fuel cells (Figure 9). In our view, the fuel cell vehicle industry will also be the most expensive sector to scale up, requiring $105 billion in subsidies to 2030. For ships, green ammonia from hydrogen is a promising option, and could be competitive with heavy fuel oil with a carbon price of $145/tCO2 in 2050.

Figure 8: Levelized cost of steel: hydrogen versus coal



Source: BloombergNEF. Note: levelized costs do not include carbon prices.

Figure 9: Total cost of ownership of SUVs in the U.S., 2030

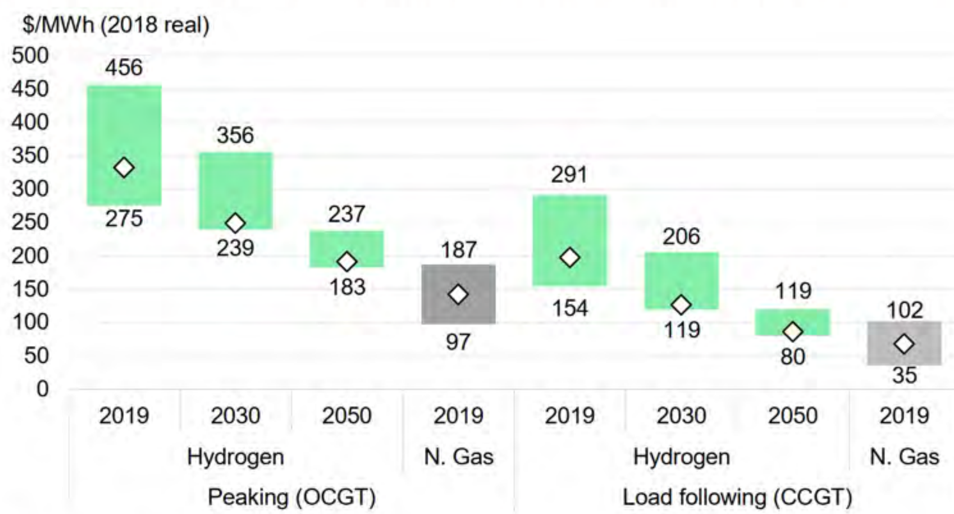


Source: BloombergNEF. Note: FCEV – fuel cell electric vehicle, BEV – battery electric vehicle, ICE – internal combustion engine.

A hydrogen supply chain could deliver carbon-free dispatchable power

With large-scale geological storage in place, hydrogen could be produced from renewable power that would otherwise be curtailed, stored and transported back to a generator at a cost of $8-14/MMBtu by 2050 in most locations. If gas turbines are hydrogen-ready, a carbon price of $32/tCO2 would be enough to drive fuel switching from natural gas to hydrogen, and generate clean, dispatchable power at a competitive price (Figure 10). Producing hydrogen from excess renewable electricity would reduce waste and help to deliver a zero-emissions electricity system.

Figure 10: Levelized cost of electricity of hydrogen-fuelled turbine power plants

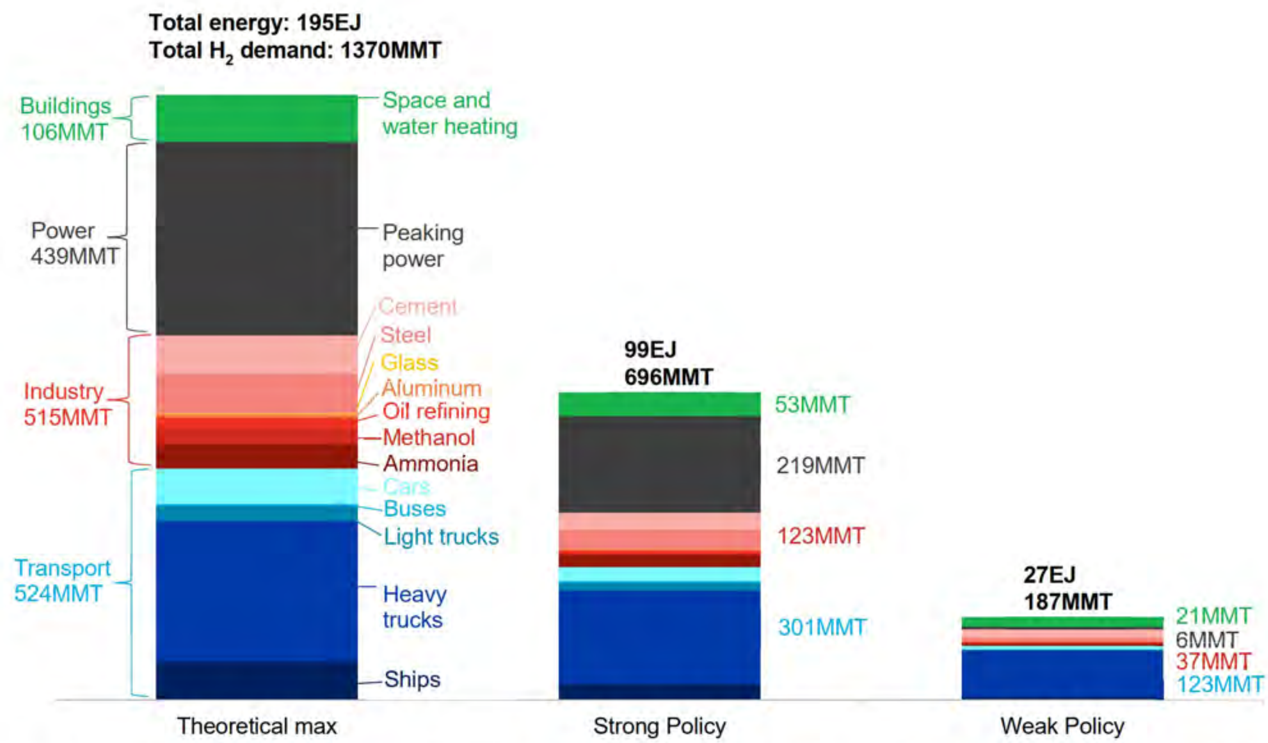


Source: BloombergNEF Note: 'N. Gas' is natural gas. Natural gas LCOEs vary with fuel price: $2 (low) to $7 (mid) and $12/MMBtu (high) and do not include a carbon price.

Hydrogen could meet up to 24% of the world's energy needs by 2050

If supportive but piecemeal policy is in place, we estimate that 187 million metric tons (MMT) of hydrogen could be in use by 2050, enough to meet 7% of projected final energy needs in a scenario where global warming is limited to 1.5 degrees. If strong and comprehensive policy is in force, 696MMT of hydrogen could be used, enough to meet 24% of final energy in a 1.5 degree scenario. This would require over $11 trillion of investment in production, storage and transport infrastructure. Annual sales of hydrogen would be $700 billion, with billions more also spent on end use equipment. If all the unlikely-to-electrify sectors in the economy used hydrogen, demand could be as high as 1,370MMT by 2050 (Figure 11).

Figure 11: Potential demand for hydrogen in different scenarios, 2050

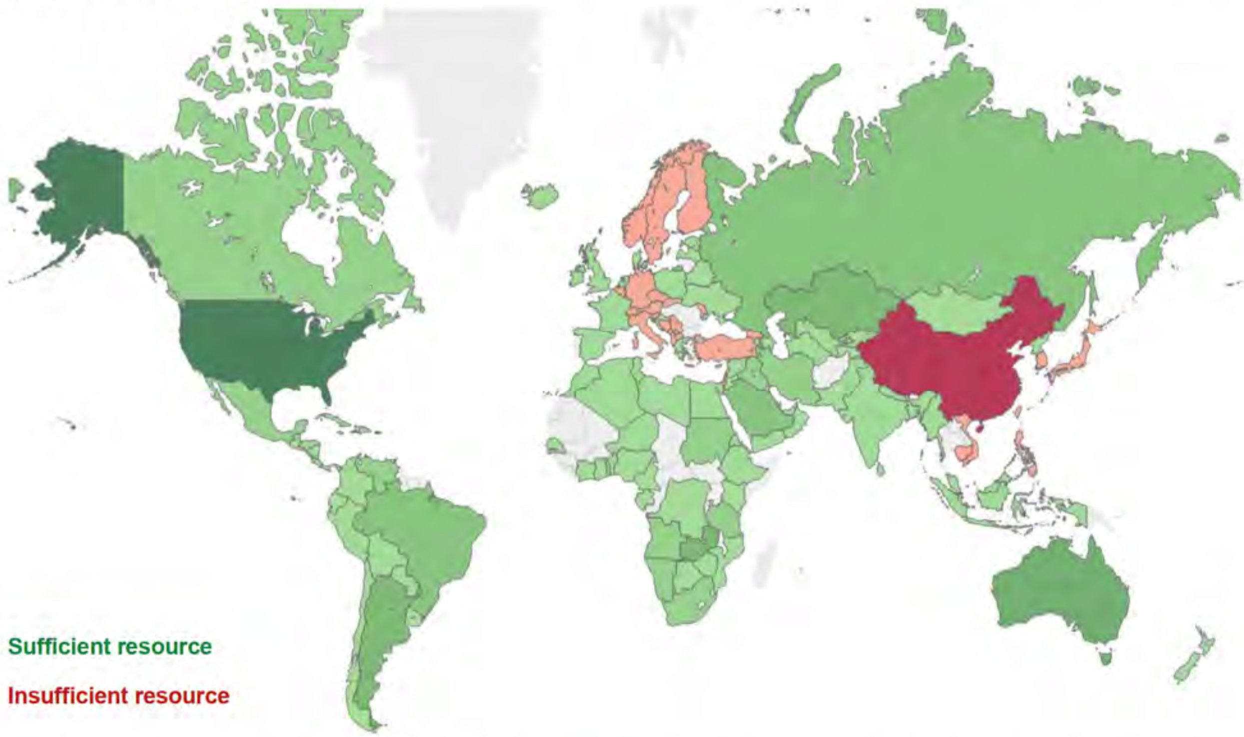


Source: BloombergNEF. Note: Aluminum demand is for alumina production and aluminum recycling only. Cement demand is for process heat only. Oil refining demand is for hydrogen use only. Road transport and heating demand that is unlikely to be met by electrification only: assumed to be 50% of space and water heating, 25% of light-duty vehicles, 50% of medium-duty trucks, 30% of buses and 75% of heavy-duty trucks.

Producing hydrogen at the scales required will, however, be challenging

Meeting 24% of energy demand with hydrogen in a 1.5 degree scenario will require massive amounts of additional renewable electricity generation. In this scenario, around 31,320TWh of electricity would be needed to power electrolyzers – more than is currently produced worldwide from all sources. Add to this the projected needs of the power sector – where renewables are also likely to expand massively if deep emission targets are to be met – and total renewable energy generation excluding hydro would need to top 60,000TWh, compared to under 3,000TWh today. China, much of Europe, Japan, Korea and South East Asia may not have enough suitable land to generate the renewable power required (Figure 12). As a result, trade in hydrogen would be necessary. Although more expensive, hydrogen production from fossil fuels with CCS may still need to play a significant role, particularly in countries like China and Germany that could be short on land for renewables but are well-endowed with gas and coal.

Figure 12: Indicative estimate of the ability for major countries to generate 50% of electricity and 100% of hydrogen from wind and PV in a 1.5 degree scenario



*Source: BloombergNEF, Baruch-Mordo et. al, 2019. Note: **Green** = Country has sufficient estimated solar and wind resources and **Red** = Country has insufficient resources to generate 50% of electricity and 100% of hydrogen by 2050. The methodology used to estimate potential renewable generation is conservative, and may underrepresent achievable generation in specific locations. In some countries the estimate for potential generation is below current levels. These countries are not given a sufficiency rating.*

The signs of scale-up are not yet there, but investors should keep watch for seven signposts

Hydrogen has experienced a hype cycle before, and right now, there is still insufficient policy to support investment and to scale up a clean hydrogen industry. But with a growing number of countries getting serious about decarbonization, this could change. Investors should watch out for the following key events to help determine whether a hydrogen economy is emerging: 1) net-zero climate targets are legislated, 2) standards governing hydrogen use are harmonized and regulatory barriers removed, 3) targets with investment mechanisms are introduced, 4) stringent heavy transport emission standards are set, 5) mandates and markets for low-emission products are formed, 6) industrial decarbonization policies and incentives are put in place and 7) hydrogen-ready equipment becomes commonplace (Table 2).

Table 2: Seven signposts of scale-up toward a hydrogen economy

Event	Effect
1) Net-zero climate targets are legislated	Makes it clear that the hard-to-abate sectors will need to decarbonize
2) Standards governing hydrogen use are harmonized and regulatory barriers removed	Clears or minimizes obstructions to hydrogen projects
3) Targets with investment mechanisms are introduced	Provides a revenue stream for producers, increases competition, builds capacity and experience, and gives equipment manufacturers confidence to invest in plant
4) Stringent heavy transport emissions standards are set	Provides an incentive for manufactures to produce, and users to buy, fuel cell trucks and ammonia-powered ships
5) Mandates and markets for low-emission products are formed	Provides an incentive for manufacturers to produce low-emission goods (e.g. steel, cement, fertilizers, plastics) that will often require the use of hydrogen
6) Industrial decarbonization policies and incentives are put in place	Helps to coordinate infrastructure investment and scale efficient use of hydrogen. Provides incentives for hydrogen use
7) Hydrogen-ready equipment becomes commonplace	Enables and reduces the cost of fuel switching to hydrogen

Source: BloombergNEF

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GREEN HYDROGEN FOR INDUSTRY

A GUIDE TO **POLICY MAKING**

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ABOUT IRENA

The International Renewable Energy Agency (IRENA) serves as the principal platform for international co-operation, a centre of excellence, a repository of policy, technology, resource and financial knowledge, and a driver of action on the ground to advance the transformation of the global energy system. An intergovernmental organisation established in 2011, IRENA promotes the widespread adoption and sustainable use of all forms of renewable energy, including bioenergy, geothermal, hydropower, ocean, solar and wind energy, in the pursuit of sustainable development, energy access, energy security and low-carbon economic growth and prosperity.

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IRENA
International Renewable Energy Agency

GREEN HYDROGEN FOR INDUSTRY

A GUIDE TO **POLICY MAKING**

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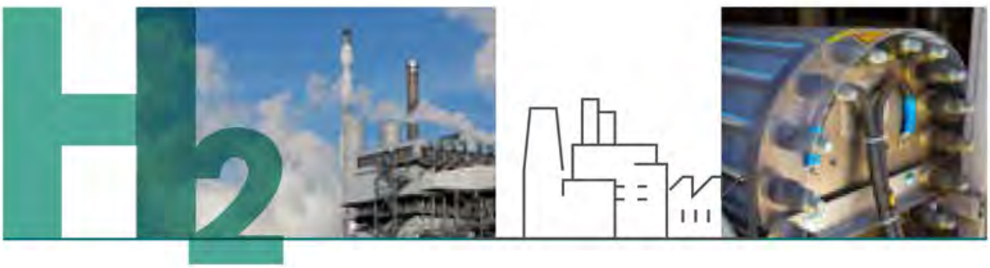

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ABBREVIATIONS

BCA	Border carbon adjustment
BECCS	Bioenergy with carbon capture and storage
BF	Blast furnace
BF-BOF	Blast furnace-basic oxygen furnace
CCfD	Carbon contract for difference
CCS	Carbon capture and storage
CCUS	Carbon capture utilisation and storage
CO_2	Carbon dioxide
COP	Coefficient of performance
DAC	Direct air capture
DRI	Direct reduction of iron
EAF	Electric arc furnace
ETS	Emissions trading system
EV	Electric vehicle
FCEV	Fuel cell electric vehicle
FIP	Feed-in premium
FIT	Feed-in tariff
GHG	Greenhouse gas
H_2	Hydrogen
NO_x	Nitrogen oxide
OBPS	Output-based pricing system
PtH	Power-to-heat
PV	Photovoltaic
SMR	Steam methane reforming
SPP	Sustainable public procurement
WTO	World Trade Organization

UNITS OF MEASURE

EJ	Exajoule
GJ	Gigajoule
Gt	Gigatonne
GW	Gigawatt
kg	Kilogram
kW	Kilowatt
kWh	Kilowatt hour
m^3	Cubic metre
Mt	Megatonne
MW	Megawatt
MWh	Megawatt hour
PWh	Petawatt hour
t	Tonne
TWh	Terawatt hour
yr	Year

GREEN HYDROGEN FOR INDUSTRY

A GUIDE TO **POLICY MAKING**

H_2

INTRODUCTION

ABOUT THIS REPORT

Green hydrogen[1] is benefiting from a new wave of interest due to its potential to make a significant contribution to meeting climate goals and advancing the energy transition. In response, IRENA has been analysing options for the production and consumption of green hydrogen, along with devising policies to support and accelerate its commercialisation and wide adoption (see Box i.1).

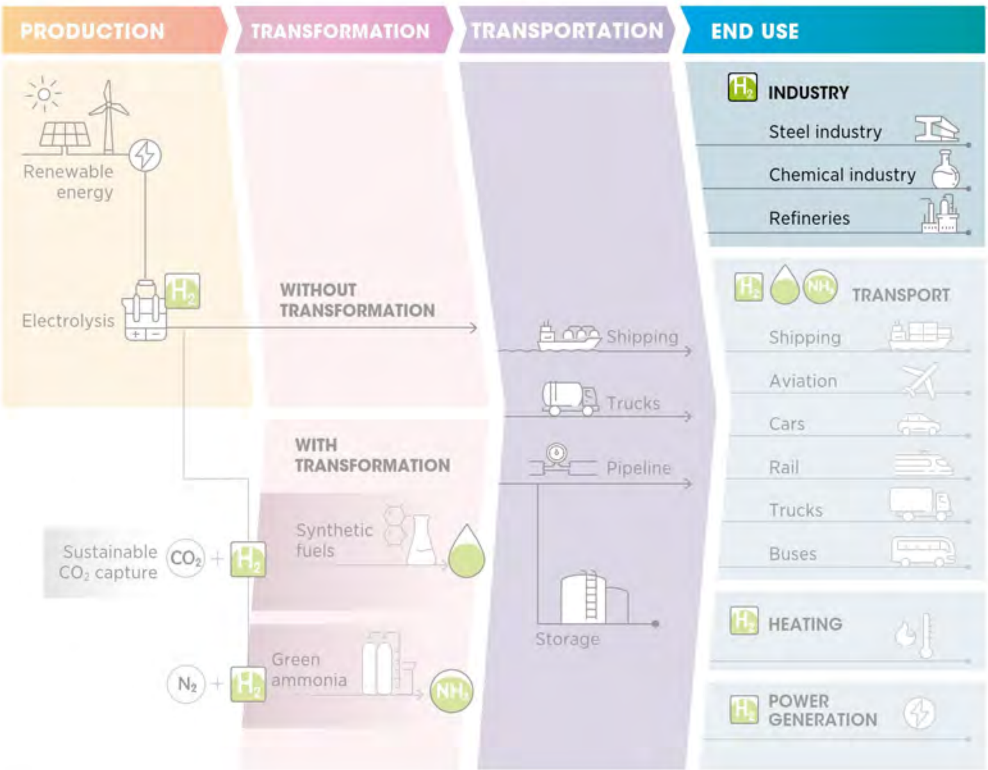
In 2020 IRENA published an initial report focusing on green hydrogen policies: *Green hydrogen: A guide to policy making* (IRENA, 2020a). It outlines the main barriers to the uptake of green hydrogen and the key pillars for effective policy making. It also creates a framework for discussion about green hydrogen policy making.

The green hydrogen value chain, from production to consumption, consists of multiple elements that are interlinked with the broader energy sector. Each of these element can face specific barriers and challenges. IRENA, therefore, conceived a series of reports focusing on these challenges and the options to overcome them. The IRENA report, *Green hydrogen supply: A guide to policy making*, examines the policy options to support the production of green hydrogen by water electrolysis, its transport, and the options for storage (IRENA, 2021a).

The present report explores the challenges that green hydrogen faces in the industrial sector and the policy options available to policy makers to address these challenges.

1 Green hydrogen is hydrogen produced from renewable energy. Since the most established technology options for producing green hydrogen is water electrolysis fuelled by renewable electricity, it will be the focus of this report.

Figure i.1 Green hydrogen value chain and the focus of this report



Sources: IRENA (2020a)

Box i.1 IRENA's work on green hydrogen and hard-to-abate sectors

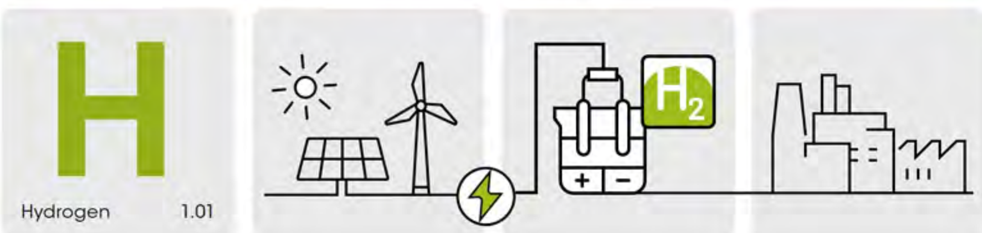
This report is part of IRENA's ongoing programme of work to provide its member countries and the broader community with expert analytical insights into the potential options, the enabling conditions and the policies that could deliver the deep decarbonisation of economies. IRENA's World Energy Transitions Outlook provides a detailed roadmap for emission reductions on a pathway consistent with a 1.5°C goal, alongside assessments of the socio-economic implications (IRENA, 2021b). Building on this, IRENA is analysing specific facets of that pathway, including the policy and financial frameworks needed.

Recent IRENA publications on green hydrogen include:

- Hydrogen from renewable power (2018)
- Hydrogen: A renewable energy perspective (2019)
- Reaching zero with renewables (2020) and its supporting briefs on industry and transport
- Green hydrogen: A guide to policy making (2020)
- Green hydrogen cost reduction: Scaling up electrolysers to meet the 1.5°C climate goal (2020)
- Renewable energy policies in a time of transition: Heating and cooling (2020)
- Green hydrogen supply: A guide to policy making (2021)
- Enabling Measures Roadmap for Green Hydrogen (2021), with the World Economic Forum.
- Geopolitics of the Energy Transformation: The Hydrogen Factor (2022)

These reports complement IRENA's work on renewables-based electrification, biofuels and synthetic fuels and all the options for specific hard-to-abate sectors.

This analytical work is supported by IRENA's initiatives to convene experts and stakeholders, including IRENA Innovation Weeks, IRENA Policy Days and Policy Talks, and the IRENA Collaborative Framework on Green Hydrogen. These initiatives bring together a broad range of member countries and other stakeholders to exchange knowledge and experience.



HARD-TO-ABATE SECTORS AND GREEN HYDROGEN

Energy-intensive industries producing basic materials, such as iron and steel and chemicals, are responsible for a large share of greenhouse gas (GHG) emissions. The iron and steel and chemical sectors alone emitted about 8% and 5% respectively of the 36.9 Gt of global energy- and process-related GHG emissions in 2017 (IRENA, 2020b).

The emissions from these energy-intensive industries have increased steadily with the growing global demand for materials, driven in turn by increased global wealth and urban populations, and associated infrastructure development (Lamb *et al.*, 2021). Reversing this trend and aligning the industrial emissions trajectory with the goals of mitigating the climate crisis is an urgent and challenging task.

Material industries are an integral part of our society; the related policies and social institutions co-evolved with them, often aiming to keep them competitive in a global market. As a result, these industries have become highly efficient but fossil-fuel dependent in their production systems, resulting in "carbon lock-in" (Åhman, 2020). In the iron and steel industry, for example, 40% of the 21 EJ consumed in 2019 came from coal, 33% from fossil gases and 20% from electricity (IEA, 2021a). In addition, demand for basic materials is expected to continue increasing, driven by economic growth and the infrastructure needs of a net zero future.

It has become common to list the iron and steel and chemical industries among the "hard-to-abate" sectors. This is because of their process energy needs and emissions, for which the abatement challenges are many, including the current material use model (with limited recovery after use), the fact that the thermodynamic efficiency of core processes has been maximised without an increase in GHG efficiencies, and the low technology maturity of the electric alternatives (Bataille, 2020).

As its production has become cheaper, with great promise of further cost reduction (IRENA, 2020c), green hydrogen has emerged as a shared decarbonisation solution for some hard-to-abate processes. However, a transition away from fossil fuels is a gradual process, and various policies and measures will be needed along the way (IRENA, 2021b; Rissman *et al.*, 2020).

Policy makers, when supporting the energy transition, have various solutions they can use, with green hydrogen being one of them alongside electrification, energy efficiency, greater material efficiency, a circular economy approach, higher energy efficiency and carbon capture measures. These solutions are not in competition with each other. Instead, they can complement each other when proactive policy making is in place. Still, policy makers need to set priorities and carefully assess the extent of the solutions available. When developing supportive policies, they should consider the relative costs and advantages of green hydrogen compared with other decarbonisation options for certain end uses, especially in view of the ongoing advancement of competing technologies.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PRIORITY SETTING IN GREEN HYDROGEN POLICY MAKING

Technically, hydrogen can be used in many different sectors, as shown in Figure i.1. However, despite hydrogen's great potential, it must be kept in mind that its production, transport and conversion all require energy, as well as significant investment (IRENA, 2021a, 2020c). As a result, its extensive use may not be in line with the requirements of a decarbonised world, where energy consumption and capacity deployment will have to be carefully managed. In particular, the production of green hydrogen requires dedicated renewable energy that could be used for other end uses. Indeed, indiscriminate use of hydrogen could then slow down the energy transition. This calls for priority setting in policy making.[2]

Priority setting for green hydrogen strategy relies on assessing different factors (IRENA, forthcoming). Some of these factors can be similar between different countries globally, while others are country- or region-specific.

Among the global factors are the **technological readiness of the decarbonisation solutions** and **the potential size of local hydrogen demand**.

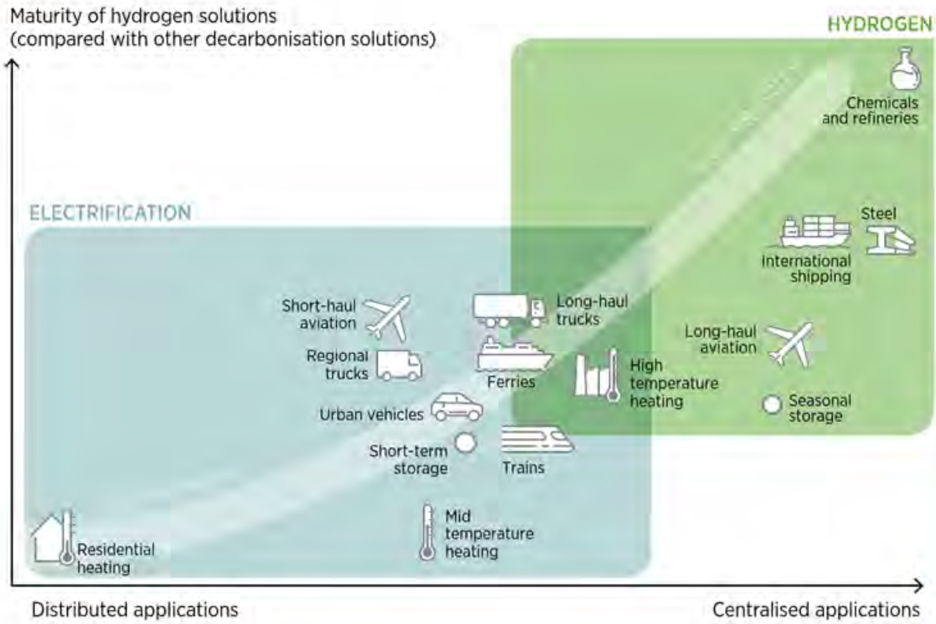
Technological readiness of the decarbonisation solutions: Alternatives to green hydrogen, competing as decarbonisation options, are already available for many end uses. For example, heat pumps and direct use of renewable energy are options for residential heating that have been commercially available for decades. In many other cases, alternatives to hydrogen such as fuels for long-haul aviation (*e.g.* biojet fuels) have not yet been demonstrated at a large scale for commercial use. Finally, there are no alternatives to the use of hydrogen for feedstock.

Potential size of local hydrogen demand: Large demand centres can kickstart economies of scale in green hydrogen, making the shift even more cost-effective compared to distributed or new applications. For example, 475 t per day of green hydrogen could be used to power a single ammonia plant with a production capacity of 1 Mt of green ammonia a year, or to meet the demand for refuelling around 6 700 trucks a day (Siemens *et al.*, 2020; Transport & Environment, 2020). Using the hydrogen to make ammonia would avoid the high infrastructure costs of building the refuelling infrastructure. In general, higher, continuous and long-term demand enables hydrogen production to expand, further reducing costs and enabling even greater use. For this reason, "hydrogen valleys" are an option to kickstart regional hydrogen demand (Section 2.2).

These two factors are plotted in Figure i.2. Industrial uses of hydrogen are among the highest priority end use, as alternatives are still missing in the foreseeable future and demand from these facilities can be large enough to allow economies of scale in production and infrastructure, making the shift to green hydrogen even more cost-effective in these applications. High-grade heat is placed in the medium-priority area, where both electrification and green hydrogen can be used. A range of options to produce high-temperature heat via electricity (with resistance, infrared, induction, microwave and plasma heating) can be more energy-efficient than the burning of green hydrogen (Agora Energiewende and AFRY, 2021; Friedmann, Fan and Tang, 2019; Madeddu *et al.*, 2020).

2 Priority setting is one of the policy pillars listed in IRENA (2020a). The other three are guarantees of origin, national hydrogen strategy, governance system and enabling policies.

Figure i.2 Green hydrogen policy priority

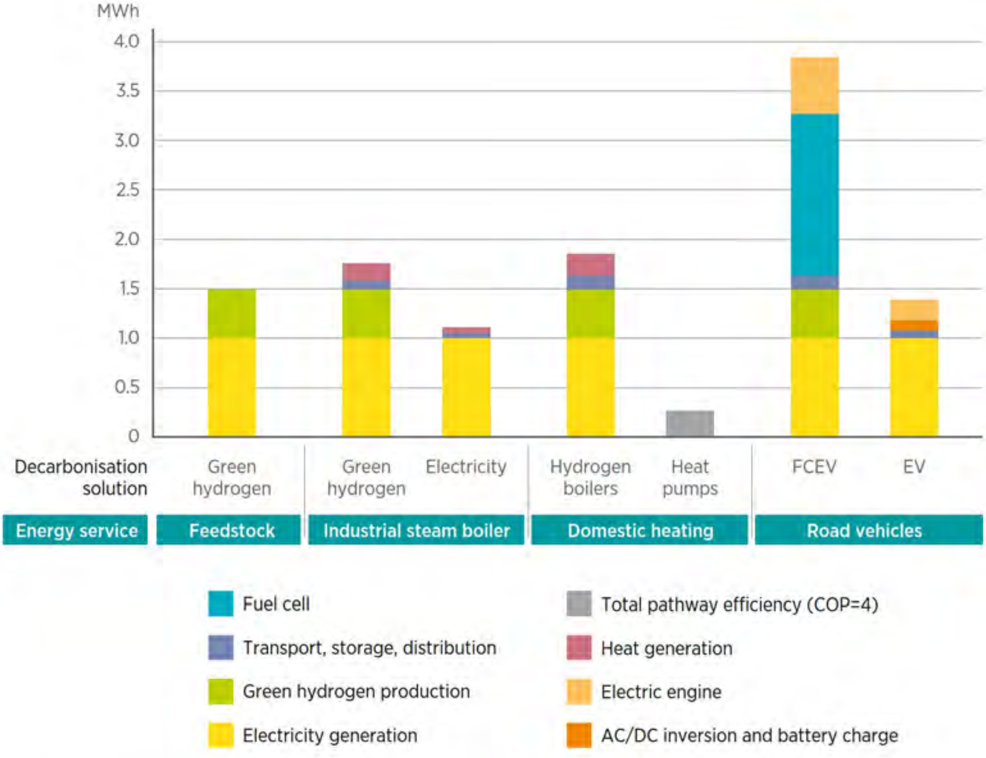


Source: IRENA analysis based on Agora Energiewende (2021a); Belmans and Vingerhoets (2020); Liebreich (2021); IEA (2021b); Natuur & Milieu (2021); Ueckerdt et al. (2021).

Note: On the x-axis the end uses are placed according to the estimated average daily hydrogen demand for industry, refuelling stations and combustion devices, with a power relationship. On the y-axis the end uses are placed according to the differences between the technological readiness levels of hydrogen-based vs electricity-based solutions.

To complement the assessment, when electricity-based alternatives are available the electrical efficiency pathway metric can be used to assess how much more electricity the use of hydrogen would entail compared to direct electrification. This can inform policy makers on the estimated additional power capacity needed to power a certain sector with green hydrogen (examples are in Figure i.3). Furthermore, in considering this aspect, industrial applications have a better outlook than distributed applications. Green hydrogen could still be a preferred option in industrial heat applications, notwithstanding the higher power capacity needed, because of other considerations (*e.g.* energy density, cost, technology maturity and existing assets).

Figure i.3 Estimation of renewable electricity generation needed for 1 MWh by energy services and by transformation passage



Notes: COP = coefficient of performance; EV = electric vehicle; FCEV = fuel cell electric vehicle.

However, energy and industrial sector conditions differ greatly between countries. These different conditions can pivot the priority setting. Country conditions that may change the priority setting can be the maturity level of its industrial sectors, its current level of economic competitiveness, the age of its industrial assets, the presence of a large specific sub-sector (for example, ferries in archipelagic countries), wider political objectives and the potential socio-economic effects, such as job creation and air pollution.

THE EXPERIENCE IN THE POWER SECTOR

Policy making for the energy transition in the industrial sector can look to the cumulated experience of the power sector, where many policies have successfully enabled once niche technologies to become the default option for investors. At the same time, the sectors' different nature should be remembered.

In particular, the energy transition in the power sector has been initiated by new actors participating in the power sector with new technologies, like solar photovoltaic (PV) and wind energy. Electricity is largely produced within the same country it is consumed; import and export are limited by interconnections, mostly under long-term contracts, and electricity is only exchanged with neighbouring countries. Finally, in the power system the participation of smaller actors with limited production, down to self-consumers, is possible.

In the industrial sector it is anticipated that change will be driven by established players with current fossil fuel-dependent facilities being converted to renewable energy. While new players may appear with decarbonised processes, this is unlikely to occur to the extent of replacing current players. Steel and chemicals are widely traded across borders and across long distances, exposing these sectors to global competition. Finally, industrial applications are large and do not have the modular nature of power plants.

Policy makers can devise new policies to support green hydrogen and the energy transition in the hard to abate sectors and can do so through a careful assessment of the experiences in the renewable energy sector as well as by considering the distinctive nature of the industrial sector.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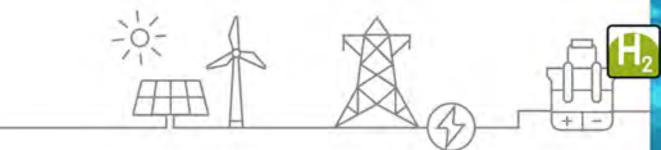

1 POTENTIAL GREEN HYDROGEN USES IN INDUSTRY AND RELATED BARRIERS

1.1. CURRENT STATUS AND POTENTIAL USES

Current hydrogen supply for industrial uses can be separated into three distinct pathways: captive, merchant and by-product hydrogen (Connelly, Elgowainy and Ruth, 2019):

- Captive hydrogen is produced by the consumer for internal use and is the most common method for large hydrogen consumers.
- Merchant hydrogen is generated in an external production facility and delivered to large-scale and retail hydrogen consumers.
- By-product hydrogen is produced in another process where it is not the primary product; it can be consumed as captive hydrogen or sold as merchant hydrogen.

In Europe captive hydrogen production is the most common option, comprising around two-thirds of all hydrogen production (FCHO, 2020).

Hydrogen is currently used in oil refineries to remove impurities and upgrade heavy oil fractions (see Box 1.1), as a feedstock for chemical production (such as ammonia and methanol), and as a reducing agent[3] in iron making. Industry demand for hydrogen was 87.1 Mt in 2020 (Figure 1.1).

The following sections briefly present how hydrogen has or can have a role in the chemicals and steel sectors, focusing on the main applications for the foreseeable future; since a sharp reduction in fossil fuel use is needed to achieve the 1.5°C target, this report does not focus on the decarbonisation of hydrogen production in oil refineries (see Box 1.1).

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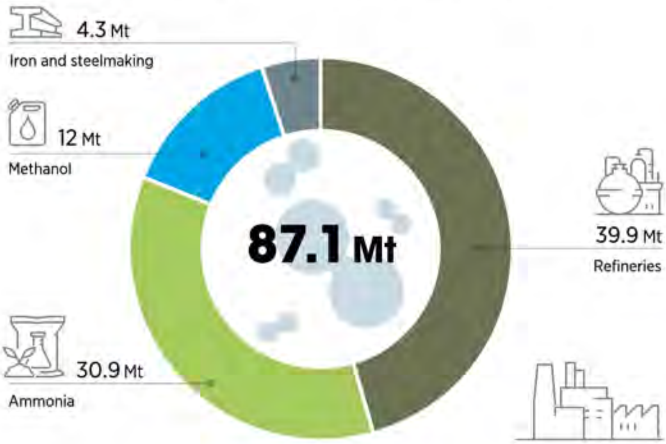
3 Reduction is the necessary process of removing oxygen from iron ore to create iron.

Figure 1.1 Pure hydrogen demand in industry, global, 2020



Box 1.1 Hydrogen in oil refineries

In oil refineries, almost 40 Mt of hydrogen produced in 2020 was used in two processes: hydrocracking and hydrotreating.

Hydrocracking is the process of converting heavy and low-quality gas oil into more valuable fuels such as diesel, gasoline and jet fuel in the presence of hydrogen and a catalyst. Hydrocrackers are used in refineries to maximise diesel production while reducing residual fuel oil.

Hydrotreating is the process of mixing hydrogen (and a metal catalyst) with fossil gas or refined petroleum products (*e.g.* gasoline, jet fuel, diesel) to remove sulphur and other contaminants.

Hydrogen is produced as a by-product in oil refineries, for example in catalytic naphtha reforming. However, by-product hydrogen is not sufficient to cover the hydrogen demand of larger refineries, so around two-thirds of demand is supplied through captive and merchant hydrogen. Refineries' hydrogen demand has grown substantially in the last few decades. Hydrogen production can represent a sizeable amount of the total CO_2 emissions of a refinery, at around 15% in the United States and Europe (Pilorgé *et al.*, 2020; Soler, 2019).

When forecasting future trends for hydrogen demand in oil refineries, it is essential to note that global production from refineries is expected to decrease due to the replacement of fossil fuels in the global economy. According to IRENA's 1.5°C Scenario, the primary energy supply from oil will need to fall from 140 EJ in 2018 to 14 EJ in 2050 (IRENA, 2021b).

1.1.1 Chemical industry

In the chemical industry, hydrogen is used to produce ammonia, methanol and other chemicals. Since hydrogen is already an essential component of these chemicals, the integration of green hydrogen requires limited modification, based only on changing the process for obtaining hydrogen from fossil fuels reforming or gasification to water electrolysis.

Ammonia

Ammonia is produced from hydrogen and nitrogen. It is the second most widely produced chemical commodity by volume, with global production of more than 183 Mt in 2020 (Hatfield, 2020). Fertiliser manufacturers are responsible for using more than 85% of global ammonia production, making the agricultural sector the most significant ammonia consumer (Brightling, 2018). Global population growth is set to increase the demand for fertiliser; this, combined with the prospective use of ammonia in international shipping and power generation, is foreseen to increase the demand for ammonia to almost 600 Mt by 2050, of which around 55% can be produced with green hydrogen (IRENA, 2021b; Saygin and Gielen, 2021).

Ammonia production plants typically use hydrogen from steam methane reforming (SMR). This process alone is associated with 90% of the CO_2 emissions related to ammonia production (The Royal Society, 2020).

Green hydrogen is the solution to deeply decarbonising the production of ammonia. Since there are energy requirements associated with the remaining ammonia production processes, they must also be powered by renewable energy for all ammonia to be truly zero carbon.

Methanol

Methanol is a versatile molecule used to synthesise heavier alcohols, gasoline and many other complex chemicals. The synthesis of chemicals accounted for more than 60% of global methanol production in 2019. It can be used in internal combustion engines as an alternative to conventional transport fuels, where it can function as a stand-alone product or be converted to other chemicals that can be blended with gasoline. In 2019 the use of methanol as a fuel represented about 31% of global methanol production (IRENA and the Methanol Institute, 2021).

Methanol production through the conventional route entails the transformation of fossil gas or coal into synthetic gas (syngas), a mixture of hydrogen and carbon monoxide, and then the conversion of syngas into methanol.

Global production of methanol reached around 98 Mt in 2019 and has more than doubled in a decade. Virtually all of the carbon needed came from fossil fuel resources (fossil gas and coal), with less than 0.2 Mt produced using biomass (IRENA and the Methanol Institute, 2021). Methanol consumption is forecast to grow in a net zero world; production could reach 401 Mt per year by 2050, of which around 73% can be produced with green hydrogen (IRENA, 2021b; Saygin and Gielen, 2021).

Green hydrogen can be used to replace coal and fossil gas to produce green methanol.[4] However, to be "green", the carbon content of the methanol molecule must be obtained sustainably from bioenergy with carbon capture and storage (BECCS) or captured from the atmosphere with direct air capture (DAC) technologies.

4 Where methanol is produced with green hydrogen, it is sometimes called e-methanol to distinguish it from biomethanol (methanol produced from biomass).

1.1.2 Steel production

Steel has been produced for millennia. In 2020 steel production reached 1.878 billion tonnes, with China accounting for over half of global production. Thanks to its wide range of applications and its versatility, steel is the basis for a variety of industries. In 2019, 52% of steel was used in buildings and infrastructure and 17% in transport applications (worldsteel, 2021).

Nowadays, it is produced mainly in two ways: the **blast furnace-basic oxygen furnace (BF-BOF)** route to produce primary steel (from iron ore) and the **electric arc furnace (EAF)** to produce secondary steel (from scrap).

The BF-BOF is the leading production method, with a share of 71% of global steel production, mostly in Asia (Fan and Friedman, 2021). It is composed of the blast furnace (BF), where iron ore is reduced to cast iron using coke, and the basic oxygen furnace, where the hot metal is converted into steel. The BF-BOF route is the more energy intensive, with one tonne of crude steel consuming 21.4 GJ of final energy on average (BNEF, 2021).

An EAF produces secondary steel by melting steel scrap with the heat generated by an electric arc, using additives to adjust the chemical composition of the steel. This production method is used for 24% of steel production, but the availability of recycled steel limits its market share. Steel scrap availability is typically limited by the long lifespan of steel products, such as bridges and buildings (BNEF, 2021; Fan and Friedmann, 2021; IRENA, 2020b).

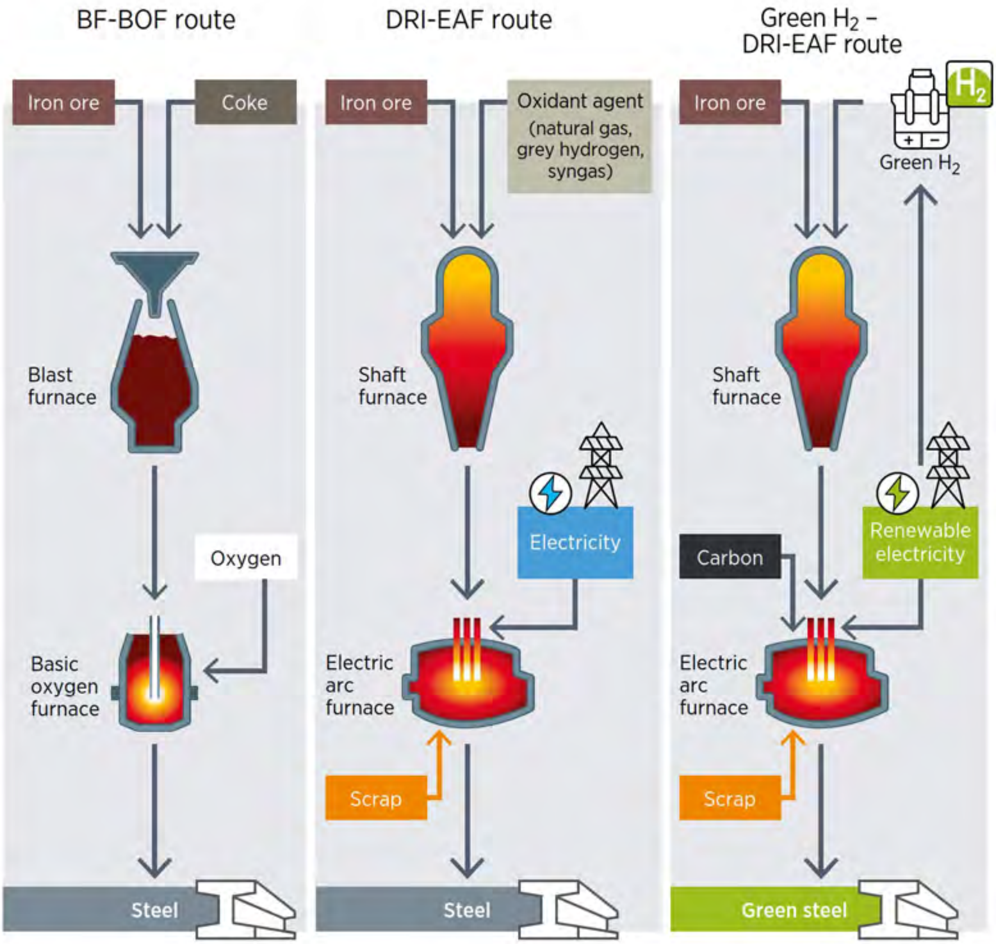
In the absence of steel scrap, the **direct reduction of iron (DRI)** can be used to feed the EAF. DRI is the group of processes for making iron from iron ore, typically using a syngas. No BF is needed to produce primary steel with this method. It is more energy-efficient than the BF-BOF, with 17.1 GJ consumed per tonne of steel. The DRI-EAF method is used for 5% of current steel production and consumed around 4.3 Mt of hydrogen in 2020 (BNEF, 2021; Fan and Friedmann, 2021).

The BF-BOF route is the more carbon-intensive steelmaking process, with emissions reaching 1.7-2.2 t CO_2/t_{steel} (Agora Energiewende, 2020; BNEF, 2021; Fan and Friedmann, 2021). Most of the emissions are from the BF process and the production of coking coal, which is used as a source of heat and a reducing agent for iron. Hydrogen can be used in the BF as a reducing agent, decreasing the amount of coking coal required. However, hydrogen cannot fully replace coking coal. In fact, green hydrogen injection into a BF can only reduce emissions by about 21% (Yilmaz, Wendelstorf and Turek, 2017). Therefore, decreasing the BF-BOF emissions to net zero levels will require the deployment of carbon capture and storage (CCS) technologies. Applying CCS to iron and steelmaking, however, has significant uncertainty surrounding its costs, applicability and carbon offset credibility; as carbon capture will be partial, steelmakers will need to buy carbon offsets if an emissions cap towards net zero is implemented in the local jurisdiction.

While different players around the world are considering the use of hydrogen in DRI-EAF processes (see Box 1.3), there has been no announcements to use CCS in steel production. The only carbon capture utilisation and storage (CCUS) unit in the steelmaking sector is capturing the flue gas from a DRI-EAF plant in the United Arab Emirates, and injecting the CO_2 for enhanced oil recovery in nearby oil fields. The capture capacity is 0.8 Mt CO_2/yr (Agora Energiewende, 2021b). Pilot and demonstration CCS projects in the steelmaking sector have also been commissioned and are operational in Belgium, France, Japan and Sweden, for a total estimated of 0.022 Mt CO_2/yr (BNEF, 2022).

While hydrogen is only an auxiliary reducing agent in a BF, it can be the primary reducing agent in the DRI process. However, a carbon source is still required to produce steel from the EAF. Biogenic carbon sources may be used in lieu of fossil fuels, but the presence of carbon means that emissions cannot be entirely avoided – although they can be reduced sizeably, down to 0.025 t CO_2/t_{steel}. The process still requires iron ore pellets, whose production can cause significant emissions (Berger, 2020; BNEF, 2021; Fuel Cells and Hydrogen 2 Joint Undertaking, 2019).

Figure 1.2 Main steel production pathways

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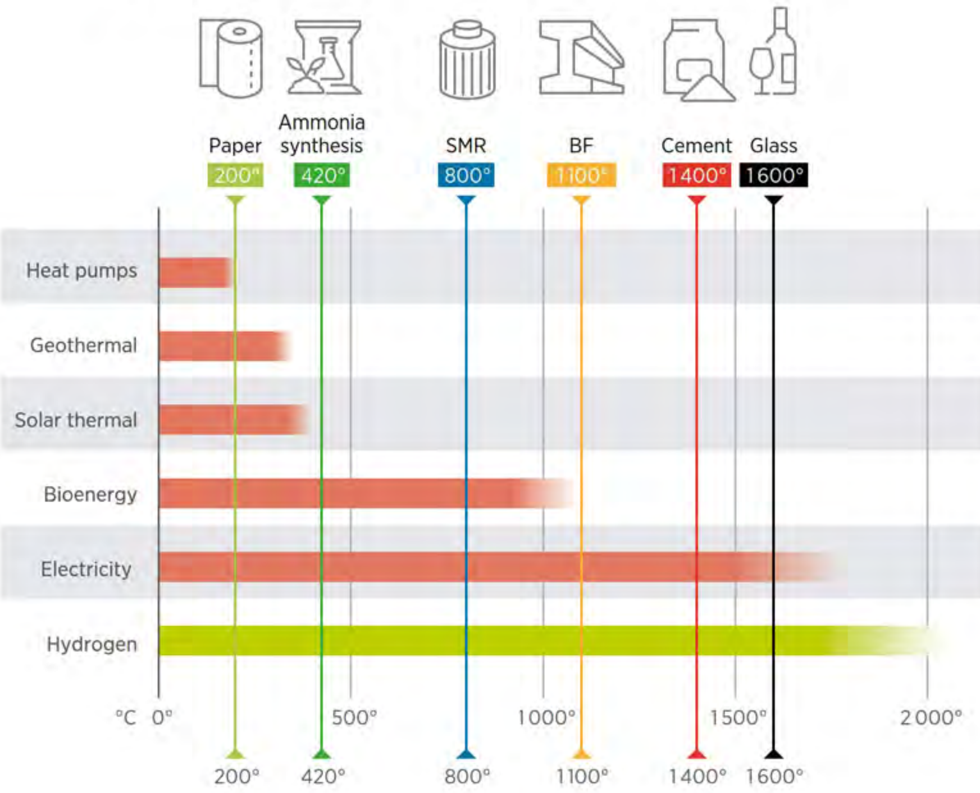
The consumption of green hydrogen in the steel industry is currently limited to demonstration projects. Similar to the chemical industry case, hydrogen consumption would be at sufficient scale to justify the co-location of electrolysers and steelmaking plants without the need for infrastructure to transport hydrogen.

1.1.3 High-temperature heat

Industries need heat for various processes. Industrial heat can be classified as high, medium or low, with high-temperature heat above 400°C, medium-temperature heat between 100°C and 400°C, and low-temperature heat below 100°C. Many decarbonised solutions exist to produce low- and medium-temperature heat without resorting to hydrogen (IRENA, IEA and REN21, 2020). Hydrogen combustion produces high-grade heat that meets almost all heavy industrial applications (Figure 1.3).

Figure 1.3 Working temperatures for selected renewable heat technologies and temperature requirement of selected industries



Sources: Adapted from Friedmann, Fan and Tang (2019); IRENA, IEA and REN21 (2020).

More than 85% of industrial heat is consumed in iron and steel, chemicals and cement. Around 95% of the high-temperature heat is currently provided by the combustion of fossil fuels or combustible by-products (IEA, 2019). Small amounts of biomass are used in specific sectors, such as in the pulp and paper industry.

Electricity can also be used for high temperature heat, generating heat via resistance, infrared, induction, microwave and plasma heating (Agora Energiewende and AFRY, 2021; Madeddu *et al.*, 2020). The advantages of electrical heating include its capacity for precise temperature regulation and lower maintenance costs. Given that the performance factor[5] of high-temperature heat from electric heating is at the very least comparable to burning hydrogen from electrolysis (0.5-0.9 for electrical heating vs 0.55-0.8 for hydrogen burners), power-to-heat technologies should be considered as the first choice, before green hydrogen.

However, the electrification of high-grade heating entails redesigning industrial equipment and, therefore, capital expenditure. Industrial operators may thus prefer less invasive options, such as hydrogen, that involve minimal redesign; substantially modifying existing processes may be considered less viable without financial support (Friedman, Fan and Kang, 2020).

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5 *Expressed as kWh heat output per kWh electricity input.*

1.2. BARRIERS

This section presents the main barriers to the consumption of green hydrogen for the production of green materials and goods.[6] These include the cost barrier, technical barriers, the lack of a real market for green products, policy uncertainties and the carbon leakage risk.

This section does not assess the main barriers to the production and transportation of green hydrogen itself, such as the high cost of production, sustainability issues, unsuitable power system structures and the lack of technical and commercial standards. These aspects are covered in the previous guide entitled Green hydrogen supply: A guide to policy making (IRENA, 2021a).

1.2.1 Cost of green materials and investments

Green production processes for materials cost more than the default fossil fuel-based mature processes (see Box 1.2).

Steel and chemicals industries are very capital intensive with low profit margins, depending to the cost of raw materials and the economic growth. Economies of scale and low raw material and energy prices are crucial to profitability. As long as green products compete against established higher-carbon – but lower-cost – options, they will struggle to charge prices that recover their production costs while remaining competitive against their grey counterparts, also because the product is perceived and buyers focus primarily on final price.

However, the issue is not only the higher cost of the final product. When processes are changed, companies experiment with different technologies which can cost billions of US dollars. Without support schemes or a clear demand for green materials or goods, the investment could be too great for a single firm (Gross, 2021).

It should be noted that basic materials are further processed downstream, so the cost impact on end-product prices is expected to be low. For instance, a 20-30% higher steel cost translates into a 0.5% increase in the cost of a car (Bataille *et al.*, 2018; Material Economics, 2019).

1.2.2 Technical barriers

As hydrogen molecules are the same independent of the production route, processes that use hydrogen produced from fossil fuels can use green hydrogen without technical challenges if the flow remains unchanged.

However, in the petrochemical and chemical sector the SMR processes used to produce grey hydrogen[7] also work as a heat sink, increasing the overall efficiency of the process. Electrolysis is not a heat sink and thus it cannot use waste heat from other processes, potentially reducing the overall efficiency.

Without storage, green hydrogen from variable renewable energy will similarly have a variable production pattern. Industrial processes have limited experience with continuous load adjustment for supply variation. So hydrogen storage could ensure a steady supply, working as a buffer for the electrolysers, but also increasing the overall green hydrogen costs. Assuming 30 years of useful life, pressurised tanks add costs of USD 0.2-0.85/kg (BNEF, 2019; IRENA, 2021a). The processes themselves could become more flexible to cope with solar and wind variability. For example, the ammonia production process can become more flexible by adopting different types of machinery or operating at different pressures (Armijo and Philibert, 2020).

6 *Across this report, "green materials" refers to steel, ammonia and methanol produced using green hydrogen. "Green goods" refers to goods (cars, fertilisers, etc.) produced using green materials. "Green products" refers to both when appropriate.*

7 *Grey hydrogen is produced with fossil fuels, from methane using SMR or coal gasification.*

Box 1.2 Costs of green hydrogen and materials

Green hydrogen and green products share the barrier of cost with other energy transition-related technologies. The cost barrier has always been higher at the inception of a new technology and gradually decreased as experience and economies of scale are accumulated for a given technology. After high initial costs, solar PV and wind energy are now cheaper than the operational costs of existing coal-fired generators (IRENA, 2021c). These costs do not take into account the externalities related to the consumption of fossil fuels, which would reduce the cost gap and ultimately make green solutions always more attractive than traditional approaches.

Green hydrogen is currently more expensive than grey hydrogen. IRENA estimates that current green hydrogen costs are in the range of USD 4-6/kg, compared with USD 1-2/kg for grey hydrogen (IRENA, 2020c). The use of green hydrogen therefore increases the cost of the goods produced with such a carrier. Many first movers in green hydrogen solutions present the cost gap as the main obstacle (IRENA Coalition for Action, 2021).

Estimates indicate that while grey ammonia costs stood in the range of USD 250-450/t in the past decade, **green ammonia** can be two to three times more expensive. However, it is estimated that green hydrogen technology can cover this gap by 2030 as the cost of electrolysers and renewable electricity declines, even with dedicated ammonia synthesis facilities. According to estimates, green ammonia may be produced term at a competitive cost of between USD 500/t and USD 625/t in areas heavily endowed with renewable resources by fine-tuning the size of hydrogen storage and synthesis equipment, and taking advantage of resource complementarity (Armijo and Philibert, 2020; Fasihi *et al.*, 2021; IRENA and AEA, forthcoming; Saygin and Gielen, 2021; Valentini, 2020).

The cost of producing grey methanol is in the range of USD 100-400/t. The current production cost of **green methanol** is estimated to be USD 800-1600/t assuming the CO_2 is sourced from BECCS at a cost of USD 10-50/t. If the CO_2 is obtained by DAC, where costs are currently USD 300-600/t, green methanol production costs would be USD 1200-2400/t. With anticipated decreases in renewable power prices, the cost of green methanol is expected to decrease to levels between USD 250-630/t by 2050 (IRENA and The Methanol Institute, 2021).

Green steel investment and operating costs are in the order of 30-50% higher compared to the principal route, including the electrolyser. Energy consumption for green steel is around 15% lower, but the electricity for electrolysis is much more expensive than coal, which costs around USD 10/MWh (IRENA, 2021a). Market prices for steel fluctuate; during 2015-2020 average prices were in the range of USD 400-600/t, while during the 2021 global supply chain crisis they achieved USD 800/t. Early assessments of the production price of full-scale hydrogen-based direct reduction indicate a 20-30% higher cost with the price of electricity below USD 60/MWh (Koch Blank, 2019; Rissman, 2020; OECD, 2021; Vogl, Åhman and Nilsson, 2018).

The conversion cost of equipment to produce **high-temperature heat** from green hydrogen depends on the existing equipment and its size. It has been estimated that the conversion cost ranges from USD 52/kW (steam boilers in the chemical industry) to around USD 100/kW (for example, for paper drying) in the United Kingdom of Great Britain and Northern Ireland (UK) context (Hy4Heat, 2019).

For hydrogen to replace fossil fuels in certain processes, such as in steelmaking, a complete change of technology will be necessary. Shifts in technology are not unprecedented. For example, in the 1950s open-hearth furnaces were the dominant technology in US steelmaking (producing up to 90% of US steel), but were completely phased out in 50 years by EAF and BOF technology (Manning and Fruehan, 2001). However, the energy transition will require a more rapid and global phase-out of current technologies.

Critical challenges to using hydrogen for high-temperature heat include changes in heat transfer characteristics and flue gas composition, including higher nitrogen oxide (NOx) emissions. Furthermore, fossil gas equipment must be modified to operate on hydrogen because of different combustion characteristics. As of today, hydrogen uses in industry for high-temperature heat are still at the prototype stage for some technologies like steam boilers.

For methanol to be carbon neutral and sustainable, the CO_2 has to be from BECCS or DAC technologies. Sequestration of carbon from biomass can already be applied today. DAC, although promising, is still at the early stages of development (IRENA and The Methanol Institute, 2021).

Finally, a large amount of electricity would be needed to satisfy the demand for green hydrogen in industry. If green hydrogen provided 16.8 EJ to chemicals and steel only by 2050, this would require total electricity of almost 6.81 PWh/yr (IRENA, 2021b).[8] For comparison, this is close to the world's entire renewable electricity production in 2020 (7 PWh). The issue, however, is not the total electricity needed, since the global renewable resource potential is in orders of magnitude higher than hydrogen demand, but whether the annual pace of development of renewable electricity will be fast enough to meet the needs of both end-use electrification and the development of a global supply chain in green hydrogen (IRENA, 2020a, 2021b).

1.2.3 Lack of value recognition and low demand

The current production and use of sustainable materials and plans for green materials are driven mainly by climate ambition or speculation on their demand rather than immediate economic gain. While stakeholders may believe that economic gain will happen in the future, currently an established means of placing a monetary value on the benefits of green goods does not exist. Indeed, there is no widespread compensation for the higher costs that green goods entail, nor are there adequate economic barriers to non-climate-friendly solutions.

While interest in the idea of green materials and goods is growing, little to no actual demand exists. Despite increased public concern about climate change, the "intention-action" gap in purchases exists and resists (Joshi and Rahman, 2015; Song *et al.*, 2019); public-sector procurement rules may focus more on corruption avoidance and cost reduction, leaving environmental concerns aside.

The lack of demand is accompanied by a substantial lack of production and infrastructure (IRENA, 2020a), creating the so-called **chicken and egg problem** of green hydrogen: green hydrogen solutions are cost-prohibitive today, but without demand, investment remains too risky for wide-scale production that could reduce costs. Without a change in this dynamic, costs will remain too high to kickstart actual large-scale demand for green hydrogen.

Despite the absence of incentives for green products in industry and the lack of market demand for these products, progressive private-sector entities have been making decarbonisation efforts (Box 1.3 presents some prominent examples). Their approach is to build electrolysers within the facility using the energy carrier or creating "hydrogen valleys", meaning regions where centralised hydrogen production serves multiple industries. These cluster enough demand to achieve economies of scale, leading to lower costs and justifying common infrastructure development.

8 Assuming an overall production and transport efficiency of 68% by 2050.

Box 1.3 Industrial companies with hydrogen-related decarbonisation targets selected examples

HYBRIT (Hydrogen Breakthrough Ironmaking Technology) is a consortium formed in April 2016 by three Swedish companies: the steelmaker SSAB, the iron ore mining company LKAB and the energy company Vattenfall. The consortium's goal is to transition to fossil-free iron and steel production in the Swedish and Finnish markets by 2035. The objective is to have a complete low-carbon process across the entire value chain, from the mine to finished steel. LKAB, the largest iron ore producer in Europe, will be replacing coal with green hydrogen for the DRI process, while SSAB will convert to EAFs. Vattenfall will provide the fossil-free electricity required for both processes and develop the technology for large-scale underground hydrogen storage. In June 2021 HYBRIT successfully completed the test production of sponge iron. The first steel made with HYBRIT technology was rolled by SSAB in July. The partners aim to demonstrate the technology on an industrial scale as early as 2026 (Arens and Vogl, 2019; HYBRIT, 2021; Vattenfall, 2021).

Voestalpine is an Austrian steel-based technology and capital goods company. The company's stated goal is to achieve carbon-neutral steel production by 2050. Its strategy is based on achieving a 30% reduction in emissions by 2030 through the gradual phase-out of coal-based steel production to production based on fossil gas and renewable electricity, increasing the share of green hydrogen, and delivering carbon-neutral steel by 2050. In 2019 Voestalpine and five other companies in the EU flagship project H2FUTURE developed a large polymer electrolyte membrane electrolyser pilot facility, located at Voestalpine's steel plant in Linz, Austria. The plant has run successful trials and can produce around 100 kg of green hydrogen per hour (Arens and Vogl, 2019; Voestalpine, 2021).

HBIS Group, also known as Hesteel Group, is one of the largest steel producers in China and the third-largest globally. In March 2021 the company announced its Low Carbon Green Development Action Plan, detailing its carbon reduction ambitions. According to the plan, HBIS aims to be carbon neutral by 2050. To achieve its target, HBIS Group has set the short-term targets of reaching a peak in emissions by 2022, then cutting emissions by 10% and 30% by 2025 and 2030, respectively. The company's plan for decarbonisation is separated into two phases. In the first phase, which is scheduled to begin in late 2021, the company will produce blue hydrogen to feed the process of producing 600 000 t of iron per year, reducing emissions by at least 40%. The second phase foresees the use of green hydrogen (Steelguru, 2021).

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Fertiberia is a Spanish chemical manufacturing company and one of the largest producers of fertilisers and ammonia in the European Union. In 2020 the company signed an agreement with the Spanish electric utility company Iberdrola to install 800 MW of green hydrogen production capacity over the next seven years, equivalent to 20% of Spain's target of 4 GW of electrolyser capacity by 2030. The agreement entails a combined investment of EUR 1.8 billion and is predicted to create 4 000 jobs. The first of their four planned hydrogen plants comprises a 100 MW solar PV system, a 20 MWh lithium-ion battery system and a 20 MW electrolyser. The hydrogen produced from the first plant will be used at Fertiberia's green ammonia plant in Puertollano, Spain. The first molecules of green hydrogen were produced in December 2021 (Iberdrola, 2020).

The **Westküste 100** project is a cross-industry consortium made up of multiple entities, including EDF Germany, Holcim Germany, OGE, Ørsted, Raffinerie Heide, Stadtwerke Heide, Thyssenkrupp Industrial Solutions, Thüga, the Region Heide development agency and the Westküste University of Applied Science. The project aims to create an industrial-scale regional hydrogen economy on the west coast of Schleswig-Holstein, Germany, integrating regional industries' needs while demonstrating green hydrogen's potential. Initially, a 30 MW electrolyser powered by an offshore wind farm is to be installed at Heide Refinery. Building on the experience from the initial 30 MW electrolyser, the consortium plans to scale up hydrogen production capacity to 700 MW. The hydrogen produced is to be combined with the CO_2 captured from a cement plant, to produce methanol (Westküste100, 2021).

The HYBRIT, Fertiberia and Westküste 100 examples are featured as case studies in the IRENA Coalition for Action report, "Decarbonising end-use sectors: Practical insights on green hydrogen" (2021).

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1.2.4 Lack of sufficient policy ambition

Significant investment in green hydrogen technologies and infrastructure will be more complex without clear, binding policy commitments. Regardless of the policy mechanism, stable and long-term frameworks are necessary to realise the potential of green hydrogen (IRENA, IEA and REN21, 2020).

When implementing policies that will translate climate commitment into reality, the risk is the adoption of sub-optimal policies. The short timeframes of the energy transition imply that a technological change must happen as soon as possible. However, decarbonisation policies often promote a gradual pathway for each sector (for example, gradual use of renewable-based solutions or energy efficiency measures).

The goal of reaching zero emissions requires a very different mindset compared to an objective of gradually reducing emissions and, in some cases, progressing with the "gradual reduction" mindset risks locking in emissions.

The "gradual reduction" mindset, in fact, enables a market for less carbon-intensive but still fossil fuel-based solutions. Blue hydrogen with partial CCUS could be an example, and electrolytic hydrogen fuelled by fossil-based electricity could offer a lifeline for fossil fuels. These solutions create additional transitional barriers, as adopters of the more efficient (but still fossil fuel-based) solutions aim to complete their investments' lifetime instead of changing technology as new, more restrictive policies are adopted. This situation will require additional actions to eliminate the remaining emissions when more ambitious climate change objectives are later adopted, creating additional government expenditure and stranded assets that pile up as the infrastructure of the fossil fuel era.

Investment decisions in industry have a long-term impact due to the high capital costs and long useful life of industrial assets. These investment decisions are also urgent: 71% of blast furnaces will need major refurbishment before 2030, and the remainder will need it before 2040 (Agora Energiewende, 2021b). The average lifetime of chemical plants is around 30 years; the average ammonia plant is 15 years old, and the oldest are located in Europe and Asia (IEA, 2020). Therefore, only one investment cycle exists before 2050, and new low-carbon technologies must be the next recipient of investment to avoid carbon lock-in within the limited timeframe to avoid climate catastrophe.

A step change, whilst expensive, may be the only option for specific industries to achieve a net zero emission system. For hard-to-abate industries, the technological shift must also be timed with the deployment of the renewable power needed to produce green hydrogen. This would reduce the risk of locking in emissions in the power sector.

The size of these challenges led some governments in Glasgow to sign the Glasgow Breakthroughs, which cover steel and hydrogen among other sectors (Box 1.4).

Box 1.4 The Glasgow Breakthroughs

To better frame the action needed to reduce emissions, the UN High Level Climate Champions presented the 2030 Breakthroughs at COP26 in Glasgow in November 2021. These are time-based sectoral objectives across the energy sector that provide a path to reducing emissions. The Glasgow Breakthroughs were presented as five government-backed targets for 2030 for strategic sectors. Steel and hydrogen are among them: for steel, the target is "to make near-zero emission steel the preferred choice in global markets, with efficient use and near-zero emission steel production established and growing in every region by 2030". For hydrogen, "to make affordable, renewable and low-carbon hydrogen globally available by 2030" (UNFCCC, 2021). This initiative aims to mobilise governments to co operate in establishing demonstration projects and collaborate in addressing the main challenges faced by these sectors.

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GREEN HYDROGEN

1.2.5 Carbon leakage risk

"Carbon leakage" describes the situation where, due to higher costs incurred to comply with climate policies, companies relocate facilities to jurisdictions with laxer emission constraints, possibly leading to an increase in total emissions. Explicit carbon pricing or mandates targeting industry can cause carbon leakage, but other policies may also indirectly hamper a company's business case (*e.g.* increased energy costs due to renewable energy surcharges) (Cosbey *et al.*, 2019; Marcu *et al.*, 2013).

Carbon leakage can become a barrier to the use of green hydrogen if businesses decide to relocate to jurisdictions where its use is not necessary, decreasing global demand. Moreover, producers who decide to comply with climate requirements may face competition from producers that prefer to move their operations to countries with lax climate policies.

Carbon leakage also becomes a barrier to green hydrogen when, to avoid leakage effects, governments implement measures to reduce the impact of climate change policies on heavy industry, such as technology-specific free allocation of emission allowances, shielding them from the burden of a step change that could require the use of green hydrogen.

2 POLICIES TO PROMOTE GREEN HYDROGEN IN INDUSTRY

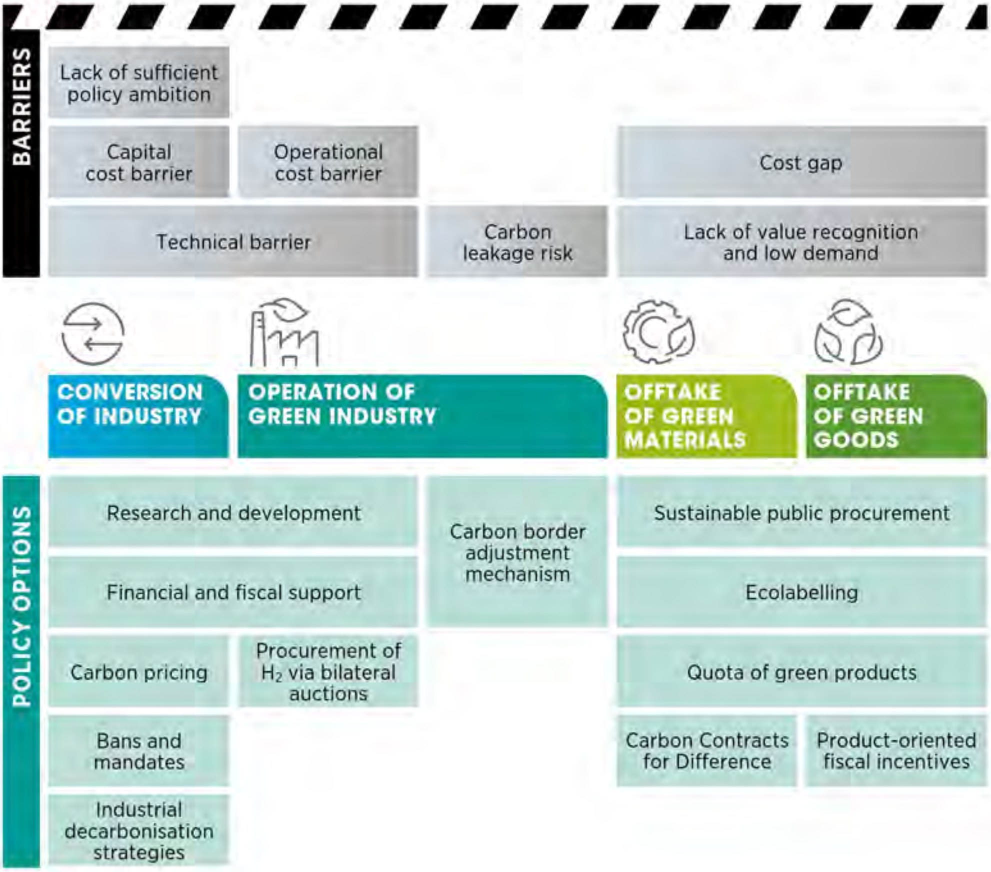
The energy transition calls for the phase-out of fossil fuel-based technologies used to produce basic materials and the adoption of low-carbon technologies. As the previous section has shown, there are multiple barriers to overcome and individual investors, when they are not required to do so, have no clear incentive to deploy green technologies, in particular where these technologies are not competitive with incumbent processes. Some investors may see a long-term advantage in becoming first movers, but even in these cases deep decarbonisation of the processes may be hard to achieve without a change in the enabling environment.

The fossil fuel dependency of the hard-to-abate sectors can be unlocked by concerted effort and a long-term vision. This unlocking will require changes to many aspects of traditional industrial policy making, which evolved in most of the world with the prime objective of keeping the industrial sector local and competitive.

Creating new policies and regulations to decarbonise industry will have to face the national role played by industry, particularly heavy industry. Industrial policies aiming to reinvigorate developed countries' industries resurfaced in response to the 2008 financial crisis, reintroducing policies supporting local industry in contrast with the previous decades' pro-globalisation policy trend. At the same time, for developing countries, industrialization is a way to promote development, create higher domestic value-added, and create higher-value jobs (Åhman, 2020).

For the world to achieve net zero carbon emissions by 2050, investment in green materials and progress along the learning curve must start as soon as possible. New measures will be required to overcome the policy and cost barriers that impede the conversion of traditional material industries, support the creation of a green materials and a green goods market, and overcome carbon leakage (Figure 2.1).

Figure 2.1 Barriers and policies to support green hydrogen uptake in the industrial sector



Policy makers, historically, have heavily influenced the course of industrial activity. Government actions have routinely improved workers' conditions and reduced environmental impacts, and affected other aspects of industrial life. Government actions have included imposing environmental limits on or changes to production processes that would not otherwise have been taken into consideration, support for change, and requests to modify production processes and goods themselves to achieve national objectives.

However, so far industry has been largely shielded from climate policy, which has resulted in GHG emissions remaining high. In particular, the hard-to-abate sectors have been entirely or partially spared from climate policy making due to their dependency on fossil fuels and national importance. This will need to change if green hydrogen's potential is to be realised.

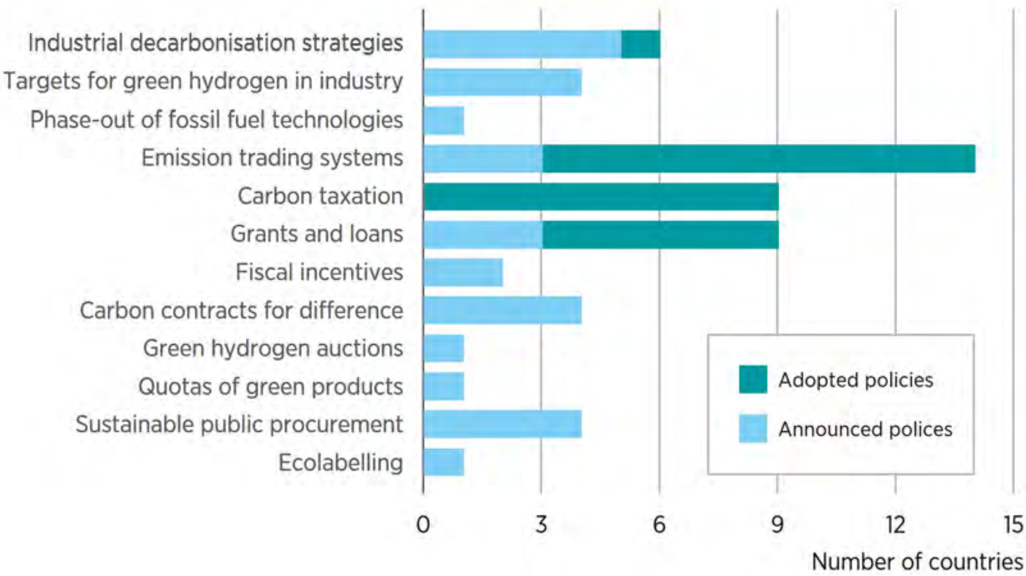
Governments have begun to recognise the need for greater intervention in industrial policy making as the need to find a feasible solutions for hard-to-abate sectors in the next decade has become increasingly apparent.

In fact, when published national hydrogen strategies describe actions to support green hydrogen, they also presents the options governments are considering to support industrial decarbonisation (as well as hydrogen use in other sectors), complementing measures announced in other policy documents and policies already adopted (IRENA, forthcoming) (Figure 2.2).

In particular, countries with a focus on importing green hydrogen have an interest in creating a demand for it, and for this reason have announced more policies to support its use in the industrial sector. One example is the German hydrogen strategy, which includes various measures targeting the industrial sector (Box 2.1). The principal instrument already used that can support green hydrogen for industry are carbon pricing mechanisms, already adopted in many countries (Section 2.4) and support systems in the form of grants, in particular for pilot projects (Section 2.5.1).

This chapter presents the options to support green hydrogen in the industrial sectors. Chapter 3 then provides a roadmap of actions to support the movement of green hydrogen in industry from niche to mainstream.

Figure 2.2 Green hydrogen industrial policies by status, selected countries, 2022



Source: World Bank (2022) and IRENA

Note: Policy announcements are extracted from the published hydrogen strategies and announcements of Canada, Chile, Colombia, France, Germany, Hungary, Japan, Luxembourg, the Netherlands, Norway, Paraguay, Portugal, Republic of Korea, Spain and the United Kingdom. Information in this figure is as accurate as possible at the time of writing; however, more policies may have been announced or adopted.

Box 2.1 German hydrogen strategy

The German hydrogen strategy supports two green hydrogen phases and aims to kick-start a hydrogen market in the country. The first phase (until 2023) lays the foundations for a domestic market for green hydrogen, which will enable growth in subsequent phases. The second phase (from 2024) envisages the consolidation of the domestic market and the development of European and international markets.

On the supply side, the strategy focuses on the production of green hydrogen. However, it suggests that by linking the national market to the European and international markets, there could be some use of imported blue hydrogen or other low-carbon alternatives. On the demand side, the strategy focuses on applications where green hydrogen is the least in need of economic support, or where there are limited choices for decarbonisation (*i.e.* the hard-to-abate sectors). These include refineries, steel production, the chemical industry, aviation and shipping.

In the industrial sector, the strategy is based on replacing grey hydrogen with green hydrogen in the chemical industry and substituting blast furnaces for iron reduction with hydrogen DRI in the steel industry. To promote hydrogen in industrial processes, the government will provide investment grants and launch a carbon contracts for difference (CCfD) programme, which is mainly aimed at the steel and chemical industries. The German government is considering establishing a demand quota for materials such as green steel to increase the demand for industrial products manufactured using green hydrogen and other low-emission processes. The strategy recognises that facilitating this increased demand would require the creation of an ecolabel to differentiate sustainable products.

The strategy is implemented through a committee of state secretaries supported by a national hydrogen council (with 25 representatives from business, science and civil society). A hydrogen co ordination centre monitors progress. There will be annual reports with performance indicators and a main report every three years to re-evaluate the overall strategy and adjust targets depending on market developments.

To pursue its strategy, Germany allocated USD 10 billion to create a demand-driven market for hydrogen (as part of the USD 156 billion stimulus package for economic recovery from the COVID-19 crisis), plus USD 2.4 billion dedicated to partnerships with countries where hydrogen can be produced.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Sources: BMWi (2020a); Reuters (2020).

2.1. GREEN (HYDROGEN) INDUSTRIAL POLICIES

Industrial policy can be defined as the variety of policy interventions aimed at guiding and controlling the structural transformation process of an economy (Bianchi and Labory, 2006).

Industrial policy became less popular in countries where neoliberalism emerged as a dominant theory. It was seen as an inefficient government practice to control the private sector (Johnstone *et al.*, 2021). However, the need for an economic recovery after the 2008 financial crisis enabled a 'renaissance' of industrial policy making in many parts of the world, including in regions where a that embraced the idea of a minimal role of the state in the market (Ahman, 2020; Alami and Dixon, 2019; Ciurak, 2011; Johnstone *et al.*, 2021).

In this renaissance of industrial policy, the latter been seen and used as also a way to achieve a number of societal objectives, including the need to move towards low-carbon and a resource efficiency to address the urgent necessity to accelerate the energy transition, *i.e.* "Green industrial policy" (Johnstone *et al.*, 2021).

Green industrial policy intervention is also required in achieving decarbonisation in the hard-to-abate sectors, in order to enable for a change that cannot otherwise happen at the scale and speed needed to avoid the climate crisis.

The focus of this report is green hydrogen industrial policy. The green hydrogen industrial sector is still at the "infant" one, still not competitive with grey hydrogen, and therefore, as for many infant industries, is a good candidate for industrial policy making.

Industrial policies can take many forms; they can actively force the hand of industrial stakeholders to change the status quo, make the fossil fuel solution unattractive for investors, or vice versa, provide support policies to green hydrogen to attract investment. Supportpolicies in particular have been widely used in the energy sector to support the deployment of renewable electricity through support schemes, and these can offer many lessons for green hydrogen. (IRENA, IEA and REN21, 2018).

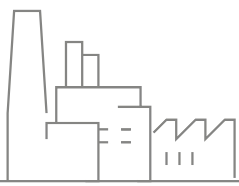
Designing green hydrogen industrial policies may involve the following:

- **Industrial decarbonisation strategies.** Policy makers should ensure the adoption of policies occurs in a way which takes into account national circumstances, clearly signalling to stakeholders the forthcoming changes, and considering the broad impact of a policy. This can be achieved through proactive planning, as presented in Section 2.2.
- **Regulatory action that mandates a change.** Introducing punitive measures such as fines or confiscation of property in case of non-compliance. Technological mandates and forced green hydrogen quotas can direct the industrial sector to reduce or eliminate the use of carbon-intensive practices. Options are presented in Section 2.3.
- **Internalisation of climate change externalities** makes the use of carbon-intensive technologies less financially sustainable in the long term. This can be achieved, for example, by creating a carbon pricing instrument that will enable green hydrogen technologies to become more financially attractive. There is no strict obligation in this second case, but the cost of the carbon-intensive technologies may become unbearable. These options are assessed in Section 2.4.
- The idea behind mandates and carbon pricing is that operators comply following a cost-benefit assessment where green hydrogen becomes more attractive. Stricter penalties lead to faster compliance and a diminishing role for fossil fuels as the expected costs of consuming the latter rises. However, these policies may increase the risk of carbon leakage or loss of competitiveness leading to lower economic activity. Therefore, specific **carbon leakage policies** may be needed to avoid such a situation (see "In focus" section).

- **Financial and fiscal support** to help first movers overcome high investment costs and bridge the cost gap between green hydrogen and mature fossil fuel technologies. Options are presented in Section 2.5.
- **Creating demand for green materials and goods.** An anchor demand for green products can push entrepreneurs to change their processes to meet this demand and gain first advantage as it increases. Policies to nudge businesses and consumers towards more sustainable patterns of consumption are presented in Section 2.6.
- **Research and Development (R&D) support**. Public R&D funding can pivot research activities to encourage technology development that will benefit national industry. The status of R&D funding for green hydrogen industry is presented in Section 2.7

2.2. INDUSTRIAL DECARBONISATION STRATEGIES

The energy transition creates challenges for the industrial sector, increasing costs and potentially placing the national industry at a disadvantage compared to competitors elsewhere in the world where decarbonisation is less of an immediate priority. Policy makers can introduce an **industrial decarbonisation strategy** to understand and present the size of these challenges while proposing ways to address them. This requires drawing up a plan to decarbonise the industrial sector, reflecting the nuances of the country's industrial sectors and taking into consideration actions to keep them internationally competitive.



To establish an industrial decarbonisation strategy, governments will need data on current country emissions. Facility-level data may be missing **Mandatory GHG reporting programmes** impose a requirement on industries to provide credible information about their GHG emissions and their sources, enabling the establishment of a solid foundation to support mitigation policies. These programmes allow governments to understand their emissions-related risks and opportunities, assisting them in creating dedicated decarbonisation policies.

Mandatory and standardised reporting brings consistency and allows policy makers to track their progress and support those industries that are improving their carbon footprint. Mandatory GHG emission reporting is now widespread in the Global North (Singh and Bacher, 2015).

Tailored sub-sector planning is essential because of industrial equipment's capital-intensive and long-lasting nature and the fact that specific industries have strict feedstock specifications.

To achieve net zero targets, gradual or moderate changes, such as in fuel efficiency standards, are unlikely to be enough. Decarbonisation strategies should aim at a step change in technology that reduces the risk of locking in emissions and of stranded fossil fuel assets in the future. A planned step change will help bring in the processes needed for deep decarbonisation and align the actions of investors and businesses with the interests of the public. Both electrification and green hydrogen technologies would benefit from such step change planning, to avoid companies investing in short-sighted efforts that are not helpful in achieving carbon neutrality by 2050 (IRENA, 2020b; Agora Energiewende, 2020).

Given the urgency of the energy transition, specific deadlines for the decarbonisation of all end-use sectors are necessary for the coming years. Adopting an industrial decarbonisation strategy can mark these deadlines in the calendars of industrial stakeholders, informing them years in advance about when the new emission limits will kick in and when a new supporting policy will be in place. The drafting and updating of industrial strategies can also allow bilateral information exchange to take place.

An industrial decarbonisation strategy should inform and be informed by the national hydrogen strategy, if in place or under development, providing a harmonious plan for both. It should also be the opportunity to identify no-regret options for industrial uses of hydrogen, prioritising actions in those sectors and avoiding the identification of hydrogen as a complete substitute for fossil fuels (IRENA, 2020a). Industrial decarbonisation strategies should assess current hydrogen demand, potential additional hydrogen uses, high-temperature industrial heat demand suitable for hydrogen use, and opportunities to co-locate hydrogen production and use across different industries (IRENA, 2020a; IRENA, IEA and REN21, 2020), identifying potential **hydrogen valleys** in their jurisdictions.

A hydrogen valley is a geographical area where several hydrogen users or potential users are present and can be combined to create a local system that covers the entire value chain from production, storage and distribution to final use. Industries already tend to be co-located within industrial clusters (*e.g.* ports) or regions, making it possible to combine various uses to benefit hydrogen production by achieving more significant economies of scale.

Hydrogen valleys present an opportunity to create a large, stable and long-term source of demand that can be used as an anchor for future hydrogen producers. Hydrogen valleys have the potential to reduce electrolyser project risk, as a variety of off-takers for green hydrogen production can be identified upfront. The synergies in such clusters help create a virtuous circle between supply and demand, where large-scale production decreases costs, encouraging further demand within the same area. Co-location also reduces the immediate need for long-haul transport infrastructure, while potentially taking advantage of existing infrastructure for the transport of green hydrogen (*e.g.* pipelines and shipping). Finally, even small-scale hydrogen valley projects can shed more light on the feasibility of a hydrogen economy encompassing various industries at the same time.

To assist the creation of a hydrogen valley, policy makers can identify target industrial clusters where green hydrogen supply and demand can be co-located. After identifying the area, policy makers can bring together key industry players to co-develop a local plan for the hydrogen valley. This would be the opportunity to assess the whole range of appropriate technologies for decarbonisation, including electrification, system efficiency and circularity (IRENA and WEF, 2021).

Hydrogen valleys should be seen as a means to achieving national objectives, so the targets for the region and sectors involved should be in line with national net zero goals.

Finally, such strategies are an opportunity to set targets for green products, planning the phase-out of technologies (see Section 2.3), introducing government public procurement targets, announcing funds (Section 2.5.1) and introducing other policies, such as those presented in this report. The United Kingdom has published its Industrial Decarbonisation Strategy (Box 2.2), which includes a staged approach similar to the one presented in Chapter 3.

Box 2.2 UK Industrial Decarbonisation Strategy

In March 2021, before the publication of a hydrogen strategy, the United Kingdom released its Industrial Decarbonisation Strategy, which covers the full range of domestic industry sectors, with a view to aligning them with its ambitious target of reaching net zero emissions by 2050. According to the strategy, to keep the United Kingdom in line with its nationally determined contribution under the Paris Agreement, emissions from industry must fall by around two-thirds by 2035 and at least 90% by 2050, compared with 2018 levels.

To remain on track, the strategy lays out the following milestones: 3 Mt CO_2 of industrial emissions captured through CCUS each year by 2030, four major industrial clusters linked up to the necessary CCUS and hydrogen infrastructure by 2030, and a minimum of 20 TWh of fossil fuel use replaced with low-carbon alternatives in 2030.

To overcome the range of barriers faced by industry along the way, the strategy recognises that government efforts will be imperative, and a shift in the policy landscape must take place. The strategy identifies the following policy principles, which will serve as the basis of government action:

- Government intervention should be technology-neutral and focus on addressing market failures or barriers to decarbonisation.
- Government should mitigate the risks of carbon leakage.
- Government should play a key role in delivering large infrastructure projects for critical technologies where cost or risk is too high for the private sector.
- Government should intervene to deliver specific strategic outcomes in line with broader green growth priorities.

It should be noted that the strategy does not make a difference between blue[9] and green hydrogen, combining them under the "low-carbon hydrogen" name as in the subsequent UK Hydrogen Strategy. Low-carbon hydrogen is earmarked to assume a central role. According to the strategy scenarios, low-carbon hydrogen consumption in the industrial sector alone will be 10-16 TWh per year by 2030 and 24-86 TWh per year by 2050. For comparison, the United Kingdom produced around 23 TWh of grey hydrogen in 2019 (or 700 000 t). The oil refining and chemical sectors are considered important drivers of the transition to low-carbon hydrogen.

The strategy recognises that it is critical to solve the chicken and egg problem. It aims to solve it by promoting fuel switching to hydrogen in industrial sites parallel to ramping up hydrogen production. Opportunities for hydrogen are identified in heat production for chemicals, oil refineries and the paper industry. Possible conversion of furnaces in the steel industry is earmarked from 2035.

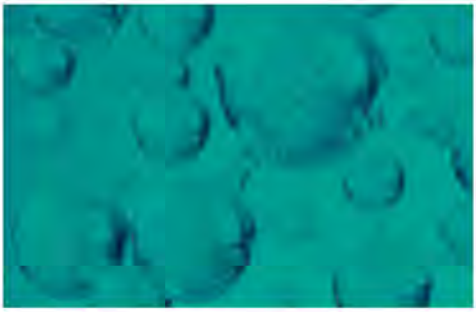
The UK government will look to develop business models and fuel standards to cover the cost gap between hydrogen and fossil fuels. Hydrogen projects can also access government co-investment through the USD 425 million Industrial Energy Transformation Fund, USD 230 million Industrial Decarbonisation Challenge and the USD 13.5 million Green Distilleries Fund. Additionally, the government has confirmed that a USD 324 million Net Zero Hydrogen Fund will be created to provide capital co-investment for early hydrogen production projects.

Source: Lambert and Schulte, 2021; UK Government, 2021a, 2021b

9 Blue hydrogen has the same production processes of grey hydrogen coupled with CCS.

2.3. TECHNOLOGICAL MANDATES

While some industrial players may be proactive in decarbonising their processes (see Box 1.3), this may not be the case for all. If left unchecked, the industrial sector may keep its status quo, avoiding addressing its global responsibility toward climate change. Policy makers can change the prevalent practice with "stick" policies imposing a change that may not happen on its own. These policies can be accompanied by carrots (see Sections 2.5 and 2.6) to financially and politically assist such change.



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2.3.1 Bans and mandated phase-outs of fossil fuel technologies

Mandated fossil fuel bans and phase-outs set a deadline for the commissioning of new fossil fuel-based technologies and the operation of existing assets.

Bans on fossil fuel technologies are not a novelty and have been adopted in the power sector (particularly for coal plants). Similarly, mandates to push a new energy carrier are not uncommon in the power and transport sector (*e.g.* green certificates and biofuel mandates).

Industrial assets can have decades-long lifetimes: if these assets are installed today, their useful lifetime would exceed the 2050 deadline, making their premature retirement economically unattractive (Agora Energiewende and Wuppertal Institut, 2019).

The adoption of bans and phase-out mandates would make it possible for green solutions to be adopted in the soonest industry investment cycle, avoiding a lengthy carbon lock-in. Regarding the steel industry, blast furnaces can use hydrogen, but ultimately they cannot operate purely on hydrogen since the furnace design needs coke. To achieve full decarbonisation, therefore, a phase-out of blast furnaces will be needed, to be substituted with DRI.

The phase-out of technologies could happen automatically if a country or region has already adopted plans and policies to decarbonise the whole energy sector.

To accelerate the switch, policy makers could announce, and later enforce, bans on specific technologies to avoid the creation of early stranded assets and inform industry and academia of the need to adopt low-carbon technologies by a specific year. Similarly, the early phase-out of existing fossil fuel technologies could be announced, and later enforced. This may require sectoral industrial decarbonisation strategies (see Section 2.2) that include all decarbonisation options for hard-to-abate sectors. It would present the opportunity to bring together key industry players and policy makers to co-develop a phase-out strategy, which could be assisted by dedicated funds and tax rebates (Section 2.4.2) (IRENA and WEF, 2021).

2.3.2 Targets and binding green hydrogen quotas

Targets for green hydrogen can be introduced specifying a set share of overall gas consumption to be from renewable gases. These targets can focus on the industrial use of hydrogen (or solely on grey hydrogen, which is used mostly in industry) to provide an indicative level of future green hydrogen consumption and, therefore, of future procurement needs. This is the case proposed in the Spanish hydrogen strategy, in which the government included a 25% minimum contribution of green hydrogen to the total hydrogen consumed in 2030 by all industries, both as a feedstock and as an energy carrier. The equivalent of 25% of current hydrogen consumption in Spain is about 125 000 t per year.

The European Commission "Fit for 55" proposal package includes targets that would give a significant boost to the development of green hydrogen in industry. The target is to have a 50% green share in total hydrogen consumption by industry – or around 5 Mt – by 2030.

Binding quotas move the implementation of targets a step ahead, imposing an obligation on selected industries to reach a share of green hydrogen in their total amount of hydrogen or total gas demand.

Virtual blending could complement this approach, *e.g.* by buying certificates for the equivalent consumption of green hydrogen while not necessarily carrying out the physical use (IRENA, 2021a). This idea is already used in green certificate systems for renewable electricity and could be explored for green hydrogen. This would require a robust certification system, along with a central repository to allow the trading of certificates (Agora Energiewende, 2021c; IRENA, 2021a).

The growing demand created by a quota system would reduce investment risk and financing costs for green hydrogen facilities, facilitating investment in electrolysis while at the same time putting all the industrial companies within the jurisdiction under the same obligation and similar additional costs.

A binding quota with a certificate system can only be adopted at the beginning of the transition, as in the long term net zero emission systems will need all users to achieve physical reductions in their emissions. Setting targets and quotas at an achievable level in the short term requires robust and comprehensive national and regional assessments of hydrogen production capacity and the competitiveness of the domestic industry.

2.4. CARBON PRICING

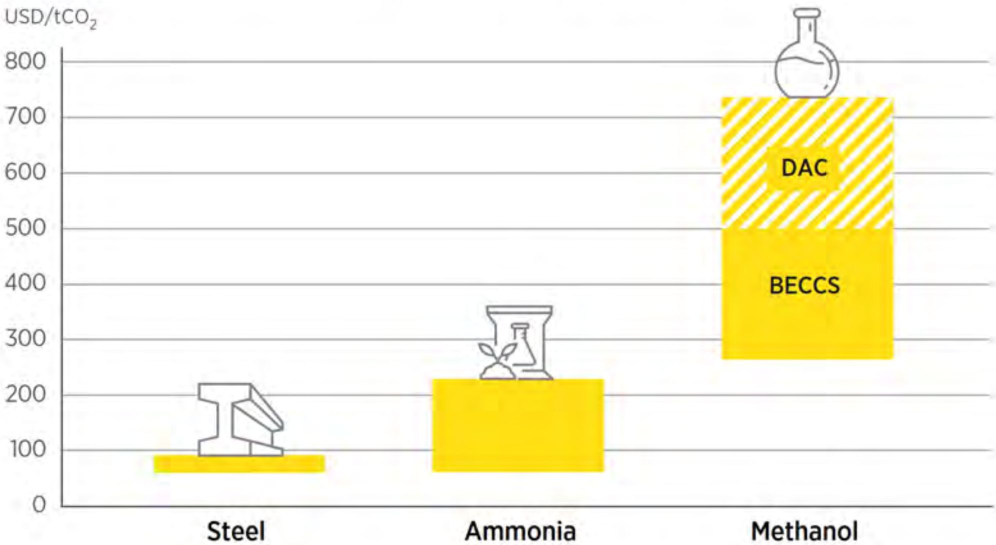
Green hydrogen will bring major GHG emission reductions to industry. However, in many cases this benefit is not reflected in commodity output prices, reducing the economic incentive to produce green products. By internalising the carbon externalities in the form of either an emissions trading system (ETS) or a carbon tax, policy makers can assist in valuing this benefit, closing the economic gap with fossil fuel pathways.

Investment in low-carbon technological innovations, including green hydrogen, can be stimulated by carbon pricing. But to support green hydrogen investment, carbon pricing would need to cover the cost gap between green and grey materials (Figure 2.3).

If carbon pricing does not achieve such levels, supplementary policies such as those presented in other sections (Sections 2.5 and 2.6) will be needed to make green hydrogen technologies economically viable. The alternative of waiting until carbon prices reach high enough levels may result in capital turnover that is too slow, which will not achieve the energy transition in the industrial sector within the 2050 deadline.

An ETS and carbon taxes, presented below, do provide important signals to the market to decarbonise processes. In 2021 these initiatives are estimated to have already covered 11.65 Gt CO_2-eq, representing 21.5% of global GHG emissions (World Bank, 2022).

Figure 2.3 Estimated carbon prices needed to cover the cost gap between green and grey materials



Notes: Estimated costs of green steel production (between USD 650 and 715/t) are compared to a grey steel cost of USD 550/t. Avoided CO_2 emissions/per tonne of steel are assumed as 1.87 t. Estimated costs of green ammonia production (between USD 500/t and USD 900/t) are compared to a grey ammonia cost of USD 350/t. Avoided CO_2 emissions/per tonne of ammonia are assumed as 2.4 t. Estimated costs of green methanol production (between USD 800/t and USD 1200/t with BECCS and between USD 1200/t and USD 1600/t with DAC) are compared to a grey methanol cost of USD 350/t. Avoided CO_2 emissions per tonne of methanol are assumed as 1.7 t (see Box 1.2).

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Moreover, they generate significant revenue flows that can be used to boost investment in renewable energy and energy efficiency, to align infrastructure and the general economy better with climate goals, or be deployed in support of a fair transition strategy. Revenues from the policy can also be earmarked to support technology demonstrations and close the economic gap for the first few plants using green hydrogen.

2.4.1 Emissions trading systems

An ETS is a market-based approach that aims to provide incentives to reduce emissions. Different systems exist worldwide (in California, the European Union, New Zealand and the Republic of Korea, for example), with different design elements and various degrees of success. China introduced its own nationwide ETS in 2021 (ICAP, 2021a).

An ETS with a cap-and-trade system requires a public body to set an emissions cap for the emitters in one or more sectors, which become obliged parties. Obliged parties must at the end of a period hold allowances in an amount equal to their emissions; if they emit more than allowed, they have to buy allowances from other obliged parties that had total emissions below the cap. This creates an incentive to reduce emissions while making polluters pay. The cap ensures that allowances have a value. The number of allowances should be reduced over time so that total emissions fall. The obliged parties may receive from the same body a limited number of allowances to emit a specific amount of emissions for free ("free allowances") (See "In focus" section). In the European Union, manufacturing industry received 80% of its allowances for free in 2013; these then decreased gradually, down to 30% in 2020. The amount not covered by free allowances, in the European Union, can be bought on national auctions or from secondary markets. Allowance prices, based on actual and projected emissions, depend on general economy activity. In early 2020 many ETSs experienced a sharp price reduction during the onset of the pandemic, due to falling emissions from COVID-19 related restrictions. Prices had recovered by the second half of 2020. Following the economic recovery, EU ETS prices kept increasing, reaching USD 100/t CO_2 in December 2021 and February 2022 , to decrease by 30% in early March 2022 (ICAP, 2021a, Ember, 2022) (Figure 2.4).

An output-based standard disengages the ETS price from the general economy. The principle is similar to the cap-and-trade design, but it does not involve an absolute cap. Instead, the limit

Figure 2.4 Carbon allowance price in the European Union, 2008-2020

Source: ICAP (2021b), Ember (2022).

is put at facility level and based on its output (*e.g.* the amount of ammonia produced). As such, it is not affected by economic downturns and does not penalise industry in case of economy growth. The output-based standard then sets a performance standard for different industrial activities. Facilities that produce more emissions than the sectorial standard have to compensate for the excess.

An example of an industrial output-based standard is the output-based pricing system (OBPS) introduced by the federal government of Canada. This system determines the facilities whose emissions are in excess of the standard, which must then compensate for the excess. Facilities whose emissions are below the standard receive surplus credits, which may be sold or kept for a later date. Facilities can also comply by paying the carbon price. The OBPS includes steelmakers, chemical plants and refineries (ICAP, 2021b; Turcotte, Gorski and Riehl, 2019).

Investments in green hydrogen technologies require a high, long-term and predictable allowance price, in the absence of other measures to support the technological change. High allowance prices may also trigger the purchase of merchant green hydrogen, as green hydrogen would be cheaper than its counterpart. But in this case prices also need to be constantly and predictably at remunerative levels. Manufacturers should be exposed to their carbon costs as much as possible and in an expedited way, or the incentive to switch processes to reduce carbon may fall beyond the 2050 deadline.

2.4.2 Carbon taxation

Carbon taxation is the fiscal measure used in various jurisdictions to capture the estimated external costs of GHG emissions of selected emitters. Carbon taxes are now adopted in 27 countries, covering around 5% of global emissions (World Bank, 2022).

Carbon taxation, is a source of revenue for governments and has also the advantage of providing more certainty on the final revenue compared to the ETS, as the carbon pricing is administratively set and issued to a selected range of emitters. Moreover, carbon taxes can be easier to adopt than ETS systems, since they can be implemented via existing taxation systems, such as levies or other excise taxes on fuels.

Carbon taxation may take different forms depending on the targeted sector. In particular, performance standards can be considered a form of carbon taxation in industry. Under this policy, an emissions reduction trajectory is set for each industry, together with an economic penalty for any CO_2 emissions above the target.

Performance standards can be imposed on industries currently consuming grey hydrogen, requiring them to start decarbonising their hydrogen consumption. This may create a market for green hydrogen if the carbon price imposed is above the cost gap between grey and green hydrogen. This option also provides better certainty of price compared to the allowance trading, where the price is defined according to the supply of and demand for allowances. It is also a more transparent scheme in which citizens (who will be the final payers of the cost increase in the final good) can be aware of the reason for these higher costs and how this extra expenditure is used.

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IN FOCUS: ADDRESSING CARBON LEAKAGE

As climate policies started being implemented, countries around the world also began considering measures to avoid carbon leakage. For example, under the EU ETS industrial installations considered to be at high risk of carbon leakage receive special treatment to support their competitiveness. The European Commission defines sectors at high risk of carbon leakage as those where production costs are seen to increase by 5% due to the direct or indirect effects of climate policies and the sector's trade intensity with non-EU countries (imports and exports) is above 10%. This section presents policies in place or planned to avoid or minimise the risk of carbon leakage.

Free allowances and exemptions under an ETS

Under an ETS, the most common policy mechanism that policy makers have used to address leakage to date is through the provision of free allowances.

The allocation of free allowances can follow three methodologies: grandfathering, output-based allocation and fixed sector allocation (PMR, 2015):

- **Grandfathering** is the allocation of free allowances to specific firms based on their historical emissions. The allocation does not vary with annual changes in output and only changes when the policy is reviewed. This is usually applied in the early stages, with a move towards output-based or fixed sector benchmarks following later. Grandfathered emitters still have the incentive to produce fewer emissions than historically, but have no immediate constraints. In the first phase of the EU ETS, free allowances were allocated almost exclusively through grandfathering (ICAP, 2021a).
- **Output-based allocations** are mechanisms through which firms receive allowances based on their recent production levels. If production increases, the next round of free allocations will also increase, and if production declines, allowances will be removed. Since allowance allocation adapts to the output, this kind of free allowance allocation can act as a subsidy and encourage additional production at the margin. This methodology also provides firms with an incentive to reduce emissions by improving emissions performance, rather than reducing production. The New Zealand ETS provides output-based allocations to industries considered emissions intensive and trade exposed (Ecofiscal, 2017; ICAP, 2021a).
- **Fixed sector allocations** are distributed according to evaluation of sector-wide benchmarks developed for each product, based on the best-performing installations producing that product. All installations in a given sector receive the same allocation of free allowances per unit of activity. Under this methodology, allocations are independent of the technology or fuel used and the size of the installation. In the third phase of the EU ETS, this benchmarking approach was used based on the best-performing 10% of installations producing a given product (European Commission, 2020; ICAP, 2021a).

Among the various solutions to prevent carbon leakage, the more immediate one is fully or partially **exempting** some sectors from the ETS. This solution may be used for cases where a policy application might be difficult or too expensive. In particular, small enterprises and strategic sectors may benefit from exemptions.

With carbon prices at around USD 100/t, green hydrogen could already become competitive with fossil fuels in EU industry, for example in the steel sector. However, manufacturing industry, such as steelmaking and oil refining, has been shielded from climate policies, and these free allowances and exemptions have the effect of the removal of industry accountability towards climate change in favour of competitiveness.

Border carbon adjustments

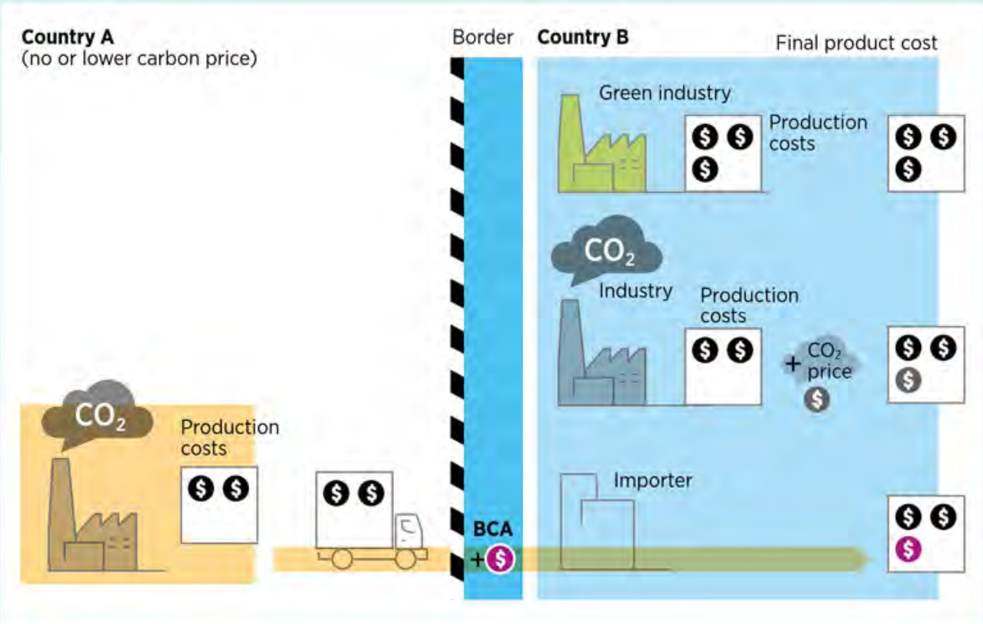
Border carbon adjustments (BCAs) are alternative systems to avoid carbon leakage but that still expose local industry to the carbon costs. BCA are import taxes that account for the difference in carbon pricing policies between countries. The objective is to make polluters, even outside the importing jurisdiction, pay the same (or a similar) carbon price paid by local industry, discouraging carbon leakage and levelling the playing field between industry regardless of the local carbon policy (Figure 2.5). A BCA on incoming products means domestic producers will not be at competitive disadvantage compared to their foreign counterparts.

BCAs have been widely discussed in academic and policy circles for two decades, and there is now a rich literature analysing how they can be designed to overcome the significant legal, technical and political challenges. However, there is so far limited experience of BCA implementation (Cosbey *et al.*, 2019; OECD, 2020).

Although broader coverage has been advocated, in practice, most BCA proposals have focused on energy-intensive sectors, which may be at risk of carbon leakage. The carbon leakage protection of a BCA is expected to vary from sector to sector, depending on characteristics such as the commercial balance of a specific product (Fischer and Fox, 2012).

Some of the issues to consider in the policy design of a BCA are how to determine the CO_2 emissions associated with imported products, ensuring fair competition, the sectors covered and the treatment of exported goods.

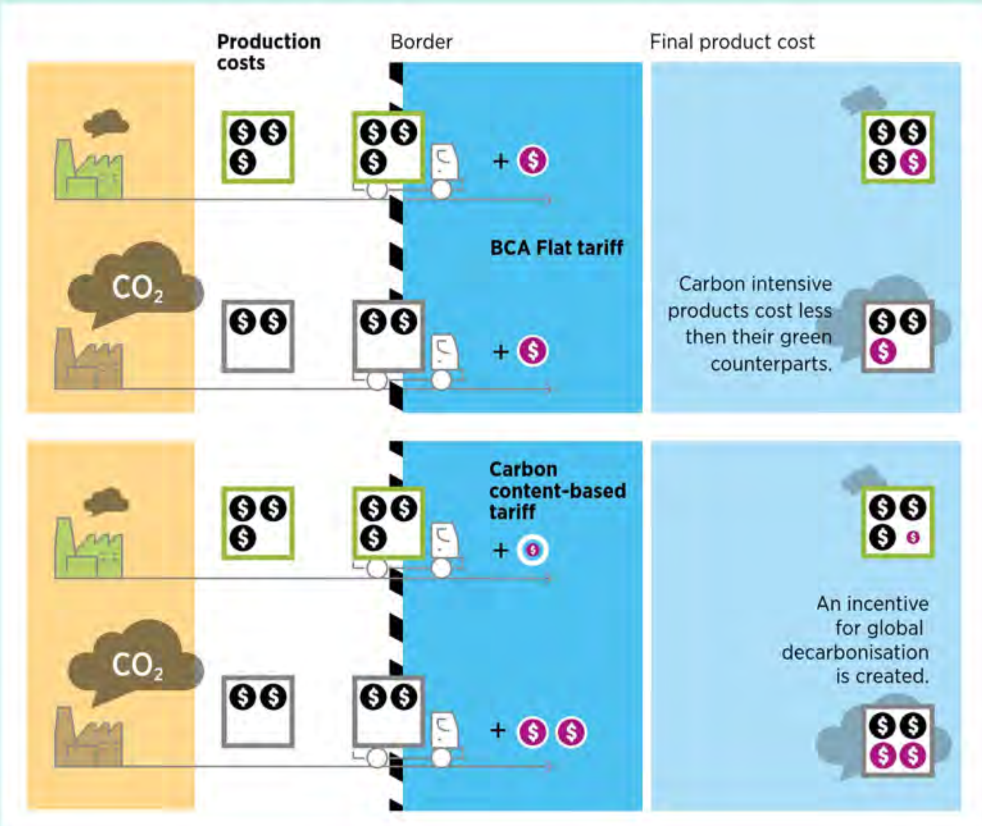
Figure 2.5 Schematic of a BCA



A BCA tariff can be "flat" – meaning it would be the same for a given imported good[10] – or it can be based on the actual carbon content – meaning the tariff would consider the actual emissions in the life cycle of the specific good. The application of a carbon content-based tariff at the border may have important implications for green hydrogen-based products, as shown in Figure 2.6. A flat tariff would naturally benefit the more cost-competitive solution, regardless of the process used and the emissions incurred. An imported product produced with green hydrogen could not compete within the region that has a flat BCA tariff. By contrast, a carbon content-based tariff would be lower for green products and higher for blue or grey products, incentivising carbon reduction during manufacture (Euractiv, 2020).

An important challenge for a BCA is the fact that, as a border tax, it should be compliant with the World Trade Organization (WTO) General Agreement on Tariffs and Trade (GATT). Generally speaking, the GATT mandates that any imported goods taxation

Figure 2.6 Flat vs carbon content BCA tariffs



10 A flat tariff can still differentiate between countries' carbon intensity.

cannot result in treatment that is less favourable than the treatment of comparable goods produced domestically. However, WTO case law suggests that a BCA would be allowed if it were based on the carbon content of a product rather than on the goods' country of origin; moreover, the GATT exempts certain cases from obligations where they are based on environmental protection (Acworth, Kardish and Kellner, 2020; Cosbey *et al.*, 2019).

Policy makers will also need to determine whether the scheme adjusts for domestic exports, meaning a carbon cost rebate for exported products to level the playing field in countries with more relaxed carbon policies. However, domestic export rebates reduce abatement incentives in the more export-oriented industries, shielding domestic production from actual carbon costs. Export rebates also put the entire concept of a BCA at risk, since its reason for existing is to push to reduce emissions that have a global effect (Acworth, Kardish and Kellner, 2020; Cosbey *et al.*, 2019; Mehling *et al.*, 2019; PMR, 2015).[11]

A further issue is the different impacts carbon prices and BCAs have on domestic and importing companies. National carbon costs are applied to the entire domestic production, while any BCA would likely apply only to the quantity that foreign producers export to the country with a BCA, hence having the possibility of absorbing such costs throughout their entire production. In other words, a local steelmaker with total production of 5 Mt of grey steel and an average carbon cost of USD 25/t_{steel} pays USD 125 million; at the same time, a similarly sized foreign producer exporting only 50 000 t would face costs of only USD 125 000, which are much easier to absorb, thus making the BCA ineffective.

To avoid such dynamics, BCAs could be adopted by multiple countries (as in the recent EU proposal), co operating to enlarge their market share sufficient to make the extra cost harder to absorb. This co operation is important: BCAs may be seen as a confrontational measure, but it can also offer significant incentives to bring about a common and shared system of climate change mitigation. BCAs would leverage current heterogeneous emissions performance among industries, pushing for a race to the top to decarbonise beyond national borders.

The first carbon content trade agreement was announced in November 2021 when the United States and the European Union agreed to modulate their tariffs on steel and aluminium based on the carbon content of the commodities.

This new arrangement (which will be negotiated over a three-year period) aims to give preference to the trade in low-carbon commodities. It will require a shared methodology for counting carbon content. Lower tariffs will translate into lower costs for consumers, but also in higher costs for high-carbon-content steel from Asia, where most of the coal-fired blast furnaces are located. The European Union and the United States will encourage other jurisdictions to participate in this agreement (White House, 2021a, European Commission, 2021a).

Conclusion

Carbon leakage raises both environmental and socio-economic concerns, putting global decarbonisation efforts at risk. Fundamentally, policies to combat carbon leakage are a method of correcting the asymmetric climate policies of different countries. In order to truly address the issue of carbon leakage, countries could employ a multilateral approach and come to a consensus on the dangers of climate change. A lack of agreement between countries on the associated impacts of increased emissions will only further increase the divide on policies and targets. This divide is what creates the foundation for carbon leakage to take place, as some countries may not enact climate policies, notwithstanding the daunting challenge of climate change. Harmonised global climate policies will ease both addressing carbon leakage and reducing global emissions, creating a demand for decarbonisation solutions at global scale.

Support systems, like those presented in Sections 2.5 and 2.6, can be considered as implicit measures against carbon leakage, providing local industries with a market for green products and the capital to decarbonise their processes.

11 Moreover, it may be more difficult to prove a BCA to be an environmental exception to the GATT if exported goods are not subject to the environmental charge.

2.5. FINANCIAL AND FISCAL SUPPORT

Currently, green hydrogen is more than twice as expensive as grey hydrogen and green materials face similar or higher premiums. A simple way to support green hydrogen technologies is to provide financial assistance, lowering the high cost barriers to entry. In the early stages, grants and loans can help the first movers cover the high investment costs of the newer technologies. As the market matures, the nature of the financial assistance provided can evolve from direct financial assistance to tax incentives and other kinds of subsidies.

2.5.1 Grants and loans

Funds for green hydrogen projects may be needed at the various project stages, from pre-feasibility studies to commissioning the final facility. Financial assistance can be applied to any industrial decarbonisation solution. Policy makers may need to support all the possible technologies, including those at their inception with great promise, such as green hydrogen technologies, to avoid dedicating funds only to more mature solutions, such as energy efficiency measures, leaving green hydrogen solutions without the needed initial support.

Supporting local industry with grants, convertible loans and similar financing mechanisms is not a novel concept. This kind of financial assistance can be used to reduce the invested costs and the necessary financing. It therefore can and should be used for the conversion of fossil-based processes to climate-neutral solutions (for example, the early phase-out and conversion of BF-BOF). These instruments should be adopted at the inception of an industry's decarbonisation efforts, to assist first movers and to keep the impact on government budgets low. Industrial decarbonisation strategies (see Section 2.2) can inform the nature of the financial assistance and the burden on government budgets. For jurisdictions with an ETS or a carbon tax, part of their revenues could be invested back in low-carbon technologies for industry.

Funds for decarbonisation of the industrial sector are already present in various jurisdictions, and can benefit the hydrogen industry too:

- The **European Union** has established the Innovation Fund for the commercial demonstration of innovative low-carbon technologies. The fund may increase to EUR 20 billion over the ten-year period to 2030 (for all sectors of the energy system), depending on carbon allowance pricing. Large and small hydrogen-based projects can apply for the fund. The HYBRIT project (see Box 1.3) has been pre-selected for a grant.

- The HYBRIT project also benefited from a grant from the **Swedish** Energy Agency, equal to SEK 528 million (USD 57 million), in support of the construction of two pilot plants, covering around 37% of the expected costs. This marked the largest single grant in the history of the agency.

- The Energy and Climate Fund in **Germany** includes EUR 45 million for the transition of the steel, cement and chemical industries, while the 2020 budget set aside EUR 445 million (by 2024) for the use of green hydrogen in the industrial sector. The federal government also plans to close the economic gap for hydrogen through the Industrial Decarbonisation Fund for CO_2 mitigation and use in basic industries. The economic stimulus in response to the COVID-19 crisis includes EUR 7 billion for the hydrogen sector, with support for the shift of industrial processes (Box 2.3) (BMU, 2020; BMWi, 2020a, 2020b; Wehrmann and Wettengel, 2020).

In jurisdictions where the push for the energy transition is strong, there is the possibility that green hydrogen investors may find themselves with multiple possible financing streams and public funds. Applying for them may create a bureaucratic barrier, requiring multiple grant requests that call for a large number of documents to be presented. Creating **a one-stop shop for finance** can be a solution to reduce the burden, connecting stakeholders with funding sources for green hydrogen projects, while allocating funds more efficiently (IRENA and WEF, 2021).

2.5.2 Tax rebates

A tax rebate represents another method of supporting green hydrogen projects. The intention is to promote carbon emission reductions by reducing the overall tax liability faced by industrial firms if they invest in carbon-neutral processes, such as green hydrogen consumption. For industries that buy hydrogen from merchant producers, rebates may be used to support the purchase of green hydrogen. The tax rebate can be determined by CO_2 reduction per unit of output or the adoption of specific new processes that the government wants to support.

Carbon tax rebates are also used to address the risk of carbon leakage, without reducing incentives to cut emissions. In this instance, carbon tax rebates may aim to avoid an industrial firm's overall tax liability increasing if certain conditions are met, for example specific activities to decarbonise processes (*e.g.* the installation of an in-situ electrolyser). In this way, carbon pricing would effectively support the decarbonisation of the same taxed industry, allocating the budget to decarbonisation projects.

Although not related to carbon emissions or green hydrogen, the Swedish tax on NO_x emissions provides an interesting example of a tax rebate that actively supported environmentally friendly activities. In 1988 the Swedish government placed NO_X emission limits on combustion plants through a permitting system. After realising that NO_X emission limits were not sufficient to reduce emission rates, in 1990 Sweden set a tax rate of SEK 40/kg of NO_x emitted from any combustion plant producing at least 50 MWh per year. A refund mechanism was placed in the design of the tax, returning all of the revenues generated (except for a small amount to recover administration costs) to the plants covered by the tax. The tax revenues were returned to the plants in proportion to the amount of energy they produced. In effect, this meant that plants with low rates of emissions per unit of energy produced received a subsidy and those with high rates were the net payers of the tax (Braathen, 2012).

2.5.3 Carbon contracts for difference

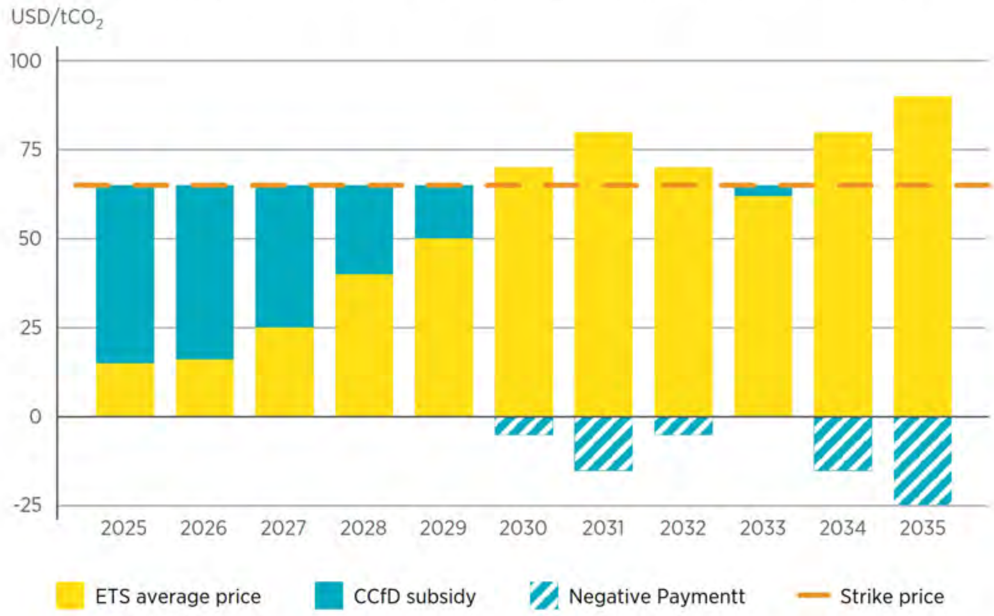
A solution that has worked in recent decades and which is still one of the most widely adopted solutions to accelerate the energy transition is the creation of a premium for each unit of the energy. They are usually called feed-in tariffs (FITs) or feed-in premiums (FIPs). Tariffs and premiums have been introduced in various jurisdictions either administratively or competitively (with auctions).

These systems have been recognised as successful for electricity production and are being considered for green hydrogen too (IRENA, 2021a), but there is a growing consensus around the fact that they could be applied to green materials too, through the use of carbon contracts for difference (CCfDs) that can complement ETS systems.

These CCfDs would be contract between governments and projects that produce materials with reduced carbon intensity. A CCfD would guarantee a fixed "strike price" for tonnes of CO_2 avoided for a predetermined number of years. If at the end of a certain period (*e.g.* a year) the average annual ETS price has been below the strike price, the industrial producer will receive, for each tonne of CO_2 avoided, the difference between the two values.

Figure 2.7 represents how it could work.

Figure 2.7 Relationship between average ETS price and CCfD subsidy at strike price of USD 65/tCO_2



CCfDs would help to ensure that low-CO_2 industry is be in place without needing to wait until a combination of economic conditions is present to justify the investment (*e.g.* high ETS prices, BCA). CCfDs would cover a proportion of the cost difference between a conventional and a low-carbon product. More crucially, they would stabilise revenue streams by removing the risk of CO_2 price volatility for project investors. As a result, they could considerably increase the economic feasibility and bankability of projects, as seen by the outcomes of renewable energy auctions throughout the world. Because of the enhanced certainty of pay-offs, projects can increase the proportion of debt in overall project financing compared to equity. Debt is less expensive, which lowers the cost of capital and, as a result, the breakeven carbon price (Agora Energiewende, 2020, 2021c; IRENA, 2019; McWilliams and Zachmann, 2021). Even if green hydrogen is bought from a merchant producer, a CCfD will increase the maximum price the industrial player can negotiate to buy green hydrogen, allowing green hydrogen merchant producers to compete in markets they would have been otherwise excluded from.

In order to set up a CCfD scheme, policy makers could identify a target industry for a CCfD pilot scheme, where a suitable CO_2 pricing mechanism or ETS is already in place. The design of the CCfD would benefit from the engagement of industry stakeholders and leveraging best practice from renewable electricity contract for difference schemes and floating FIPs. The programme could be then scaled up in line with a national hydrogen or industrial decarbonisation strategy (IRENA and WEF, 2021).

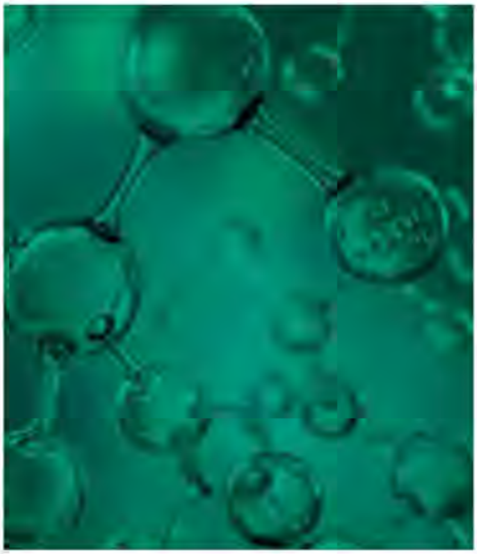
It should be noted that CCfDs would not be expected to have a large impact on government budgets. This is because CCfDs with high strike prices would only be available to kickstart commercial projects, followed by lower strike prices as the processes mature, to be eventually phased out when the technology becomes widespread and the market for green products established. Moreover, the government would not pay the full strike price of the CCfD. Rather, it would pay only the difference between the strike price and the actual observed ETS allowance price. Thus, if the carbon price steadily rises over time, the net annual cost would fall and eventually become negative. Estimates indicate that CCfD prices in Europe may be in the order of a few million euros per country to decarbonise 10% of the hard-to-abate sectors (Sartor and Bataille, 2019; Agora Energiewende, 2020).

Even more ambitious plans would not be too expensive: to convert 33% of German and 50% of EU primary steel production to green hydrogen processes, estimates foresee the annual funding requirements in the range of USD 1.2-3.1 billion for Germany and USD 4.7-11.8 billion for the European Union with the current free allocation regime (Agora Energiewende, 2021c). Funds for the CCfD programme may come from the carbon pricing mechanism or from product-related economic instruments (see Sections 2.2 and 2.4)

When preparing CCfDs, policy makers will have to consider a variety of design elements, in part similar to those typical of renewable energy auctions (IRENA, 2019), in part novel. Important design elements will be the treatment of negative prices, the length of the contracts, the price setting and the eligible technologies

If the average ETS price is above the strike price, then the difference would be negative (as in Figure 2.7): in these cases the government could receive the difference in return for the CO_2 price risk. Another option would be to require no payment in the case of negative difference; this could support initial projects, increasing their total returns from the measure (McWilliams and Zachmann, 2021).

The length of a CCfD contract is another important feature. In any case, CCfDs will need to cover sufficiently long periods to compensate for upfront capital investment. For example, the German environment ministry plans to sign CCfDs with a ten-year period (BMU, 2021). Adjustment could be made to extend the contract in cases of financial crises or any other event that may disrupt or halt production for a period of time.



CCfD strike prices could be administratively or competitively set. In other words, the level could be set in advance to attract investment with a secure income per unit of production on a first-come, first-served basis, or it could be decided via an auction to select the most competitive price (and be less burdensome on government budgets). If administratively set, it could decrease over time to promote incentives for technological improvement and to follow technological development. If competitively set, participants could bid their proposed strike prices for a total amount of avoided emissions, and the auctioneer (a public body) could select the projects that would achieve the largest emission cuts with the least budget burden for the government.

It should be noted that a CCfD scheme may also support partial decarbonisation solutions based on the avoided emissions. Governments supporting total decarbonisation of the industry will then have to consider what projects to actually fund to avoid the "gradual shift" risk mentioned in Section 1.2.4. The same CCfD scheme could support, for example, one green hydrogen project or two blue hydrogen projects with 50% CCS rates. A whitelist of eligible technologies, including direct electrification and green hydrogen, could be a solution to guarantee long-lasting and effective decarbonisation and reduced total costs.

2.5.4 Procurement of green hydrogen via bilateral auctions

Without sufficient demand for green hydrogen, producers lack the incentive to deploy it at a large enough scale to reduce the cost, leaving green hydrogen at a cost that cannot generate demand, creating the chicken and egg problem (see Section 1.2.3).

A centralised auction scheme to ensure hydrogen offtake and consumption, with the cost differential paid by a public body, can help solve this issue. A public body would act as central auctioneer and would sign long-term purchase agreements with electrolysers and sale agreements with industrial players.

Through such a mechanism, green hydrogen and its derivative products could be purchased using a double auction scheme. The lowest purchase agreements and the highest sale agreements resulting from the auctions would be awarded the contract, while too high purchase offers and too low sale offers will be rejected (Figure 2.8). The public body would then cover the price difference. Moreover, it can determine a floor price below which the green hydrogen sale is not considered, and a ceiling price above which purchase is not considered.

The physical trade may be arranged by the parties or remain virtual, with the industrial players winning the auction buying only certificates and being able to claim the green nature of their production. Depending on auction design, a captive green hydrogen producer may sign both contracts, basically receiving a premium for their green hydrogen self-production.

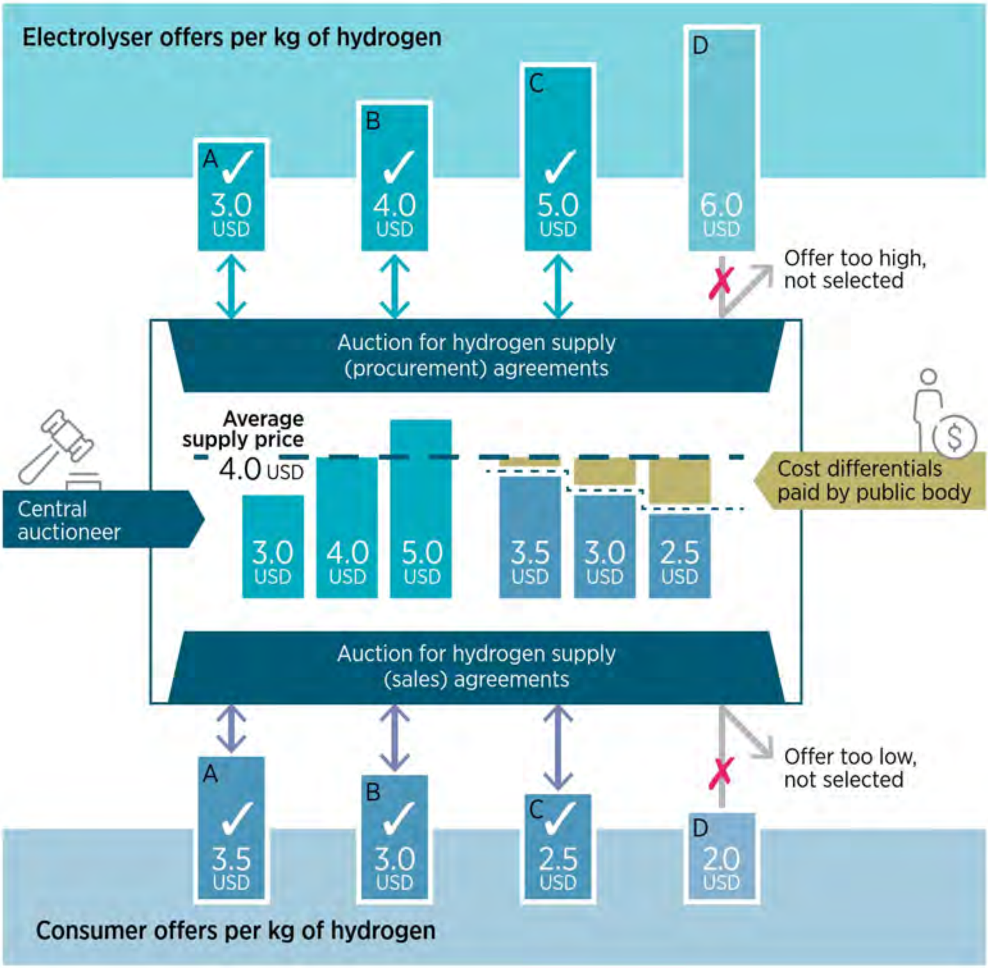
A competition-based mechanism such as an auction could prove instrumental in kick-starting the use of green hydrogen in industry. If auctions are successful in reducing the cost of green hydrogen, as has been done for solar PV and wind energy (IRENA, 2019), this would significantly improve green hydrogen's business case in various industries. Indeed, achieving cost parity with carbon-intensive forms of hydrogen is pivotal for the future prospects of green hydrogen in industry.

This kind of scheme is currently being designed in Germany under the H2Global funding programme. H2Global is an auction scheme to procure green hydrogen for German industry; it aims to procure green hydrogen from all across the globe. Germany has already signed many memorandums of understanding with other countries to plan future imports of hydrogen (IRENA, 2021a; 2022).

The H2Global programme established an intermediary body called the Hydrogen Intermediary Network Company (HINT.CO) to sign long-term agreements. HINT.CO is supported with EUR 900 million of funding to temporarily compensate the difference between the hydrogen purchase agreements and sale agreements.

The programme expects that future adjustments to the regulatory framework will increase industrial off-takers' willingness to pay for green hydrogen and the sale agreement price will rise over time. This will gradually reduce the need for HINT.CO to compensate for the price differential until a point is reached where the demand and supply prices are in line with each other. At that point, the role of the intermediary would end.

Figure 2.8 Bilateral auction system schematic



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2.6. CREATING THE MARKET FOR GREEN PRODUCTS

Although there is a growing interest in the production of green hydrogen, the demand for goods manufactured using green materials is lagging, as they are more expensive than their grey counterparts., Governments have a variety of actions that they can take to generate sufficient demand and create a market for green products, such as sustainable public procurement and quotas. These measures will require ecolabelling, meaning a scheme to measure, validate and trace the carbon content of the green materials or goods.

2.6.1 Quotas of green products

In order to create a minimum anchor demand for green materials, governments can introduce increasing demand quotas for green materials. This quota would create the basis of a market that does not currently exist.

Large consumers of basic materials (*e.g.* carmakers) would be requested to prove the purchase of a minimum amount of green materials, or pay a fine. Those producers who exceed their quota may sell their excess to non-compliant producers in the form of certificates, similarly to green certificate schemes in the power system. It is essential to remember that allowing the quota to be met through certificates might not align with a long-term net zero emissions system, *i.e.* the real consumption of green materials is the ultimate guarantee and economic signal to ensure that the system efficiently progresses towards net zero (as it also is for determining the scale of production capacity, logistics, infrastructure etc.). In this sense, the certificates and their corresponding surrendering rules could be designed to fulfil such goal, thus cancelling the risk of locking in emissions and future stranded assets.

From experience with green certificate schemes, it is possible to identify two main policy design elements that may allow the policy to succeed:

- The level of ambition for the target. If the target is set too high or the increase too steep, national supply might be below the quota requirement, resulting in high compliance costs and a detrimental effect on profitability. If the target is too lenient, it might not spur the necessary demand to kickstart the growth in production that would result in large cost decreases. Quotas should follow and anticipate green hydrogen production capacity, taking into consideration other concurrent hydrogen uses.
- The level of the fine. The fine itself sets the cap on the cost of the low-carbon material. A low fine may encourage the obliged party not to comply. An excessively high fine may conversely result in a detrimental effect on profitability, with carbon leakage risks.

An example of this policy measure is envisaged in the German Hydrogen Strategy, including definitions and criteria, and will be subject to further evaluation (BMWi, 2020b). The German strategy recognises the necessity of a verification and labelling system able to guarantee the sustainability of the goods (see Section 2.4.4).

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2.6.2 Sustainable public procurement

Public procurement refers to the process by which public authorities, such as government departments or local authorities, procure, purchase and acquire work, goods or services from companies.

UNEP's definition of sustainable public procurement (SPP) is:

> ***"A process whereby public organisations meet their needs for goods, services, works and utilities in a way that achieves value for money on a whole life-cycle basis in terms of generating benefits not only to the organisation, but also to society and the economy, whilst significantly reducing negative impacts on the environment."***

Public procurement accounted for 12% of GDP in OECD countries and up to 30% in developing economies in 2017. Over 250 000 public authorities in the European Union spend around USD 2.4 trillion per year (around 14% of EU GDP) on the purchase of services, works and supplies (European Commission, 2021b; UNEP, 2017).

National laws regulate public authorities' and utility operators' procurement activities, which are usually based on tenders. While regulations are mostly designed to avoid corruption, they can be redesigned to include elements of social and environmental sustainability.

UN Sustainable Development Goal 12.7 calls for national SPP plans, promoting public procurement practices that are sustainable, in accordance with national policies and priorities.

SPP can represent an initial and stable demand driver for green goods and materials, as governments often have high purchasing power and capital available to promote the uptake of green products. SPP may have a larger impact on the creation of a green steel market than for other materials like ammonia, as steel is used in buildings, bridges, railways and transport fleets (*e.g.* buses) (worldsteel, 2021).

Direct and indirect government purchases of steel may be small. AISI (the American Iron and Steel Institute) estimates that government purchases account for 3.3% of total steel use in the United States (Krupnick, 2020). Notwithstanding the small size of the market, through the incentives provided, the examples set and the learning by doing, such programmes might move the industry. A specific procurement of green steel could, for instance, be incorporate in auctions for wind farms (see Box 2.3).

Examples of SPP adoption are already widespread, with at least 41 countries implementing it (UNEP, 2017). The Buy Clean California Act is a recent example. It imposes a maximum acceptable global warming potential (GWP) limit on selected construction materials. It targets, among other materials, carbon emissions associated with the production of structural steel and concrete reinforcing steel, with a maximum GWP between 1.49 and 0.89 Mt CO_2-eq/ Mt_{steel}. From 2024, and every three years thereafter, the maximum acceptable GWP will be reviewed for each material, and the limit may be adjusted downward to reflect industry improvements. The GWP of a material is stated on an environmental product declaration, an independently verified and registered ecolabel that reports a product's environmental impact over its life cycle.

During COP26, the governments of Canada, Germany, India and the United Kingdom, some of the world's largest steel and concrete buyers, pledged to buy low-carbon construction material when available. The objective of the initiative is to make investors confident in the existence of a market for their products. The countries will also aim to track and report on the carbon content of public construction by 2025. The countries aim to achieve net zero public-sector buildings by 2050, with interim targets to be defined at the time of the writing (UNIDO, 2021).

In December 2021 an executive order was signed in the United States that directs the federal government to use its scale and procurement power to support the growth of clean technology industries, with the aim of achieving net zero emissions from federal procurement by 2050. The federal government aims to launch a "buy clean" initiative for low-carbon materials and prioritise the purchase of sustainable products (White House, 2021b).

Box 2.3 Procurement of green steel through auctions for renewable energy

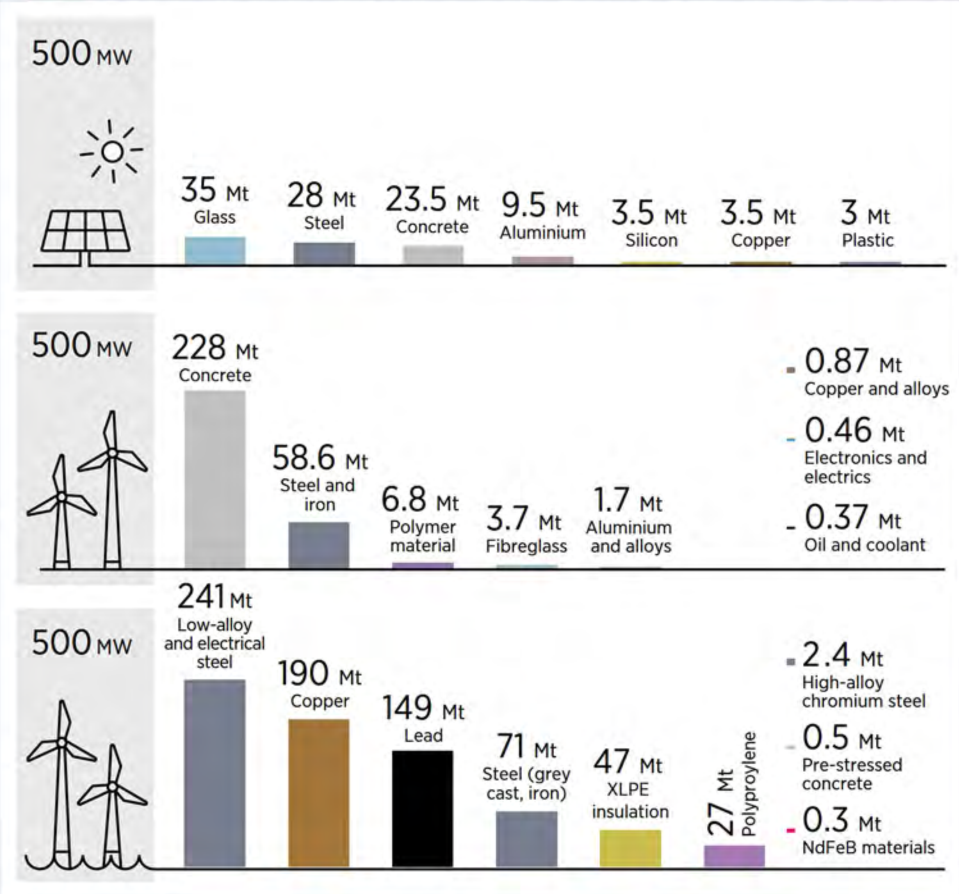
Iron and steel are essential materials for the manufacture of important components used in the development of all renewable energy plants (Figure 2.9). According to IRENA's latest projections in the World Energy Transitions Outlook: 1.5°C Pathway report, to limit global warming to 1.5°C by 2050, renewable power capacity will have to increase over tenfold from around 2800 GW in 2020 to more than 27700 GW in 2050. The lion's share of this increase will be provided by variable renewable technologies, namely solar PV, and onshore and offshore wind. Based on IRENA's scenario, solar PV capacity will reach over 14000 GW and wind capacity (both onshore and offshore) will reach over 8100 GW.

Renewable energy auctions will be instrumental in reaching these ambitious targets. Auctions have become an increasingly popular way of procuring renewable electricity, with over 100 countries having conducted at least one auction. The ability of auctions to determine the lowest market prices has been a major motivation for their adoption worldwide. However, price discovery is not the only benefit of conducting renewable energy auctions; the flexibility in their design allows them to be tailored to country-specific conditions and to achieve objectives such as timely project completion, system integration and socio-economic development.

One of the main objectives that countries seek to address during the design of their auctions is that of fostering local development through, for example, winner selection criteria or local content requirements. Such requirements can be featured as part of qualification requirements, restricting participation to developers who comply with a minimum threshold of local content. This is typically represented as a minimum percentage of the total project costs to be spent on domestic products and services. By incentivising or mandating developers to source a proportion of their materials and equipment locally, auctions can help develop local industries and supply chains in the renewable energy sector and beyond. Such auction design elements have already been introduced in auctions conducted in Brazil (whereby wind project developers can benefit from concessional financing from the local development bank only if a certain percentage of local content is met), Morocco and South Africa where local content was introduced both as qualification requirement and as winner selection criteria. Although such design elements can increase the energy price, at least in the short term, they create local value for the economy, support innovation and further enhance energy autonomy and security.

To ensure that renewable energy projects are developed in the most sustainable manner possible, policy makers may consider the introduction of auction design elements, either in the form of incentives (*e.g.* through winner selection) or requirements on "green content" that support the use of green practices and materials, such as green steel. Although such design elements may result in higher prices, they can help achieve the objective of greening the renewable energy sector, and contribute to developing the sector for green materials and processes. More precisely, if auctions include a criterion incentivising or requiring a certain amount of the steel procured for a plant to be manufactured using net zero processes, either locally or internationally, this could substantially increase the market for green hydrogen-based materials and accelerate the proliferation of green hydrogen.

Figure 2.9 Material required to build a 500 MW solar plant, onshore wind plant or offshore wind plant



Note: values are intended for 500 solar PV systems of 1 MW size, ten onshore wind farms of 50 MW and an offshore wind farm of 500 MW

Note: XLPE = cross-linked polyethylene.

Sources: IRENA (2017a, 2017b, 2018, 2019, 2021b).

2.6.3 Product-related economic instruments

Product-related economic instruments, such as tax differentiation and capital allowances, are measures that governments can adopt to nudge consumers and businesses toward less damaging forms of consumption.

Tax differentiation is a type of tax design in which the rates on goods are adjusted to reflect a government goal. If producers do not pass the tax on to customers in the form of increased pricing, the tax's impact will be seen in lower profitability, which will push enterprises to move toward producing less taxed alternatives.

Consumers will be incentivised to switch to alternatives if the tax is passed onto them in the form of increased product costs. Taxes affecting less than 10% of the selling price of items are unlikely to cause major behavioural changes in consumer purchasing or company production choices (OECD, 2014).

Tax differentiation should be designed to ensure that the difference in taxation is proportionate to the scale of climate impact involved, and in order to have this kind of data, an ecolabel may be necessary.

Tax differentiation can have a particular impact on recurrent purchases (*e.g.* cleaning products), as opposed to one-off purchases where many factors impact the final decision. For non-recurrent purchases, such as cars and new buildings, tax relief can be adopted to encourage consumers to invest in more expensive green goods. Under such a scheme, the expense incurred in buying a green product can be partially or totally deducted from corporate or income taxes.

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Currently, no scheme specifically targets green materials or goods (as intended in this report), focusing more on the energy efficiency of appliances and cars. Policy makers could consider them once the green products are commercially viable to facilitate their market entrance.

All UK businesses that pay corporation or income taxes can benefit from an enhanced capital allowance, which provides 100% tax relief on any investment in new or unused energy-saving equipment in the same tax year as the purchase is made. Therefore, a business paying corporation tax at 30% will receive GBP 0.30 tax relief for every GBP 1 invested in energy-saving equipment.

2.6.4 Ecolabelling

Materials and goods produced in a sustainable manner are typically indistinguishable from their counterparts. For this reason, many different systems collect data and track products to inform the public of the quality and sustainability of production in a process known as ecolabelling.

Many ecolabels exist for various goods (paper, food, etc.). Ecolabelling is intended to provide a mechanism for conveying information to consumers on products that meet environmental standards, and to manufacturers or retailers on targets for reducing environmental impact. Ecolabels are instrumental in creating a market that values sustainability, with this value translating into justifiable higher prices and improved economics for sustainable producers. However, voluntary ecolabels may have a limited impact on the market, struggling to be noticed by environmentally conscious and environmentally unaware consumers alike (Song *et al.*, 2019).

In order to identify the environmental impacts, a system of traceability is needed, *i.e.* a system to follow each part of the supply chain and quantify the impact of each process. Traceability systems vary widely and are designed to be fit for purpose. They could be paper-based with a limited level of detail, or could adopt more advanced solutions to have more granular visibility over all the materials and processes. Recently, the use of the Internet of things and blockchain has been proposed to assist data gathering (ISEAL, 2016; Balzarova and Cohen, 2020).

As many of the best GHG abatement opportunities are in materials such as steel, which are rarely purchased by consumers directly, ecolabels would be primarily aimed at public bodies that purchase these materials in large quantities or that support them. The presence of ecolabels is a necessary condition to either impose the use of green materials or simply to guarantee their provenance for SPP (Agora Energiewende, 2021c; Rissman *et al.*, 2020).

Ecolabelling can be a private sector-led initiative or a public-sector initiative, such as the Ecoleaf programme in Japan (see Box 2.4)

Ecolabelling chemicals may be more difficult because the supply chain is more complicated, with more intermediary steps, but digitisation is changing industrial production processes and producing data that allow plant management to determine energy use, emissions and abatement opportunities (Rissman *et al.*, 2020).

Box 2.4 Ecoleaf

The Ecoleaf environmental label is an ecolabel supported by the Japanese government. The programme was fully implemented in 2002 as a way of promoting an eco-conscious lifestyle among the Japanese populace through the proliferation of environmentally friendly goods and services.

Ecoleaf quantitatively shows environmental information for a wide range of products, including food, clothing and office supplies, but also construction products and steel.

The system follows all the stages of the products life cycle, from the extraction of resources to discarding or recycling. It aims to facilitate the comparison of products' environmental impacts and promotes transparent communication between a business and its stakeholders. Each product category under the Ecoleaf label contains a set of unified criteria known as the product category rules, which determine data acquisition methods, life-cycle assessment calculation methods and label content.

As an example, an environmental declaration for a steel plant under the Ecoleaf certification provides information on its global warming impact, resource consumption, environmental effects (acidification, land use, etc.) and the amount of recycled materials and renewable energy used by the process.

Source: Ecoleaf (2021).

2.7. RESEARCH AND DEVELOPMENT

While governments can incentivise or mandate industry to decarbonise their processes, continued Research and Development (R&D) to make green hydrogen products competitive with incumbent technologies will increase the effectiveness of the supporting policies and, ultimately, make them less necessary.

R&D programmes, sponsored by government, can accelerate innovation. Governments have traditionally had a central role in setting the research agenda through dedicated funds, grants, tax incentives for private industry, concessional loans and equity in start-ups. Moreover, patents in green hydrogen technology can increase the competitiveness of local industry and allow it to become a leader in the nascent sector.

Policy makers can set R&D goals in their hydrogen strategies: while most refer to the reduction of green hydrogen costs, they can also introduce goals to measure the impact of R&D for manufacturers. These can include CO_2 emission reductions from new processes or the number of key technologies ready for large-scale use.

Hydrogen serving industrial users must be produced on a large scale and delivered with a certain regularity. Industrial processes need stability of supply, so storage (batteries or hydrogen storage) becomes necessary to cope with the variability of wind and solar PV generation, increasing costs. For the adoption of green hydrogen in the steel industry, it will be necessary to replace BF-BOF with DRI-EAF fuelled by hydrogen. While a prototype is already in place (see Box 1.3), replicability of the process in different contexts is still to be assessed. The physical aspects of the hydrogen-driven reduction process vary depending on parameters such as the operating temperature, type of metal oxide and grain size. These aspects still have to be deeply researched for the several metal oxides used in the production of steel.

Research into decarbonising ammonia production is focused on increasing the operational flexibility of the synthesis unit to cope with the variability of supply and on new processes that could succeed the Haber Bosch process. These include the electrochemical, plasma-chemical, thermochemical and photochemical generation of ammonia. All these routes, however, are still at their inception, with very low technology readiness levels.

Methanol production needs to identify a sustainable and low-cost carbon source. Further research is needed on various integrated pathways. This issue is shared with other synthetic fuels. Possible solutions include DAC or the use of waste biomass (*e.g.* sewage gas), unrecyclable waste (*e.g.* plastics), or by-products of cement production (CO_2 production is unavoidable when calcinating limestone). Another research pathway includes the co-electrolysis of CO_2 and water, which could lead to higher process efficiencies.

Governments around the world are already supporting the use of green hydrogen for industry through R&D programmes:

- A variety of funding programmes are being launched in Germany. These include the Use of Hydrogen in Industrial Production programme, amounting to EUR 15 million in 2020 and with a commitment amounting to EUR 430 million by 2024 (BMWI, 2020b).
- The US Department of Energy awarded around USD 8 million for HySteel, a programme to improve hydrogen-based steelmaking (Fuel Cells Bulletin, 2020).
- Australia is looking forward to becoming a major exporter of green hydrogen and green ammonia. The Australian Renewable Energy Agency has allocated USD 40 million (AUD 55 million) for R&D and demonstration of green hydrogen and ammonia projects and has supported various feasibility studies for ammonia (ARENA, 2020).

3 THE WAY FORWARD

As seen in the previous chapter, policy makers have various options to support green hydrogen for the decarbonisation of hard-to-abate sectors. They can push for a change with strategies and specific bans and mandates or incentivise the industry to decarbonise by making it pay for its emissions. In these cases, carbon leakage policies may be needed to avoid a situation where businesses transfer production to other countries with more lenient emission constraints. Alternatively, policy makers can support industry with direct support schemes or indirectly by creating a market for green materials and goods.

It is likely that a mix of these policies will be needed to both support and push the necessary change. Certain policies are suitable for kick-starting the change, informing developers of what is expected to happen and supporting R&D, while others will be needed later as the system makes progress. The "policy stage" concept, introduced in IRENA (2020a) has been created to help policy makers understand when a policy could be introduced, according to the status of the country's hydrogen sector.

For the industrial sector, the stages are described as:

STAGE ONE DEMONSTRATION AND GOVERNANCE.

At this stage the profitability gap is the widest, requiring the largest economic incentives. Compensation for the higher investment can be directed through grants or loans that attract private capital. Strategies and targets are set to inform stakeholders about the decarbonisation of the industrial sector. Green steel, ammonia and methanol are not yet valued for their lower GHG emissions, so a system is needed to track the upstream emissions and create a differentiated market that values these properties. Carbon pricing policies are introduced. Given the international market for materials from energy-intensive industries, global co ordination and co operation are even more critical than for other hydrogen applications. CCfDs can be introduced to support the uptake of green materials. Ecolabels should be defined to allow SPP and other policies in the later stages. SPP rules can be put in place to create demand promptly once green materials and goods are available.

STAGE TWO ACHIEVING COMMERCIAL SCALE.

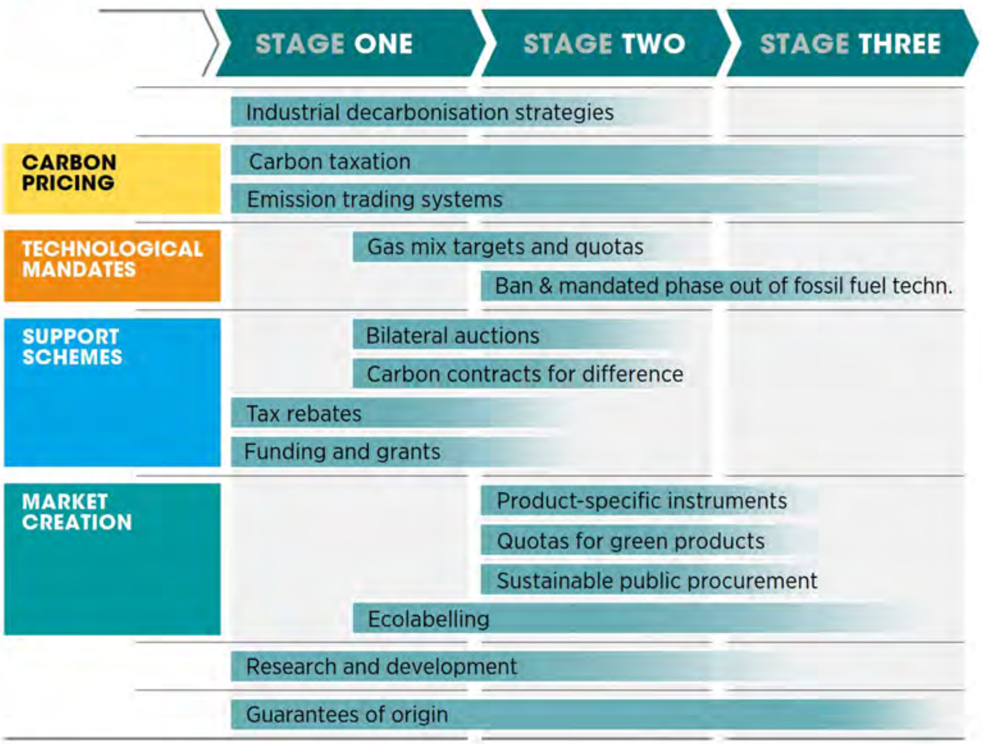
At this stage the first green products are being produced. Green hydrogen progressively replaces grey hydrogen, in particular if green gas targets are in place. Policies in place need to create a market for green product, such as SPP and quotas. Green products can be supported with specific product-related economic instruments.

STAGE THREE ON THE PATH TO FULL DECARBONISATION.

Green hydrogen has become widespread across the energy system and costs have greatly reduced. Policies supporting green hydrogen or green products are no longer necessary, as the economic gap has been closed. The role of policy makers is to ensure the progressive phase-out of the final fossil fuel technologies while maintaining all the instruments that allow clear and comparable information on both the materials and the goods, and to prevent carbon leakage vis-à-vis regions not making comparable decarbonisation efforts.

Figure 3.1 shows the range of policies explored in this report across the three stages, proving a roadmap for said policies. The bars indicate when a policy should be in place; in order to be ready, however, actions for its implementation will have to be enacted beforehand.

Figure 3.1 Roadmap of policies to promote hydrogen use in industry across three stages of deployment



CONCLUSIONS

There is growing global awareness of the effects of climate change. As a result, many governments have adopted suites of policies to start decarbonising the energy sector, the main source of GHG emissions. Policies have been so far mostly focused on the power sector.

The next challenge for policy makers will be to focus on the whole energy system, which includes the manufacturing facilities producing basic materials such as steel, chemicals and refined fossil fuels. Global emissions from these industries have been increasing, notwithstanding the ever-decreasing costs for renewable energy, in contrast to the commitments made in Paris to limit global warming and the IPCC recommendations.

One challenge in these industries is the fossil fuel dependency of their processes, causing them to fall under the umbrella of hard-to-abate sectors. As renewable energy technology has evolved, however, solutions for these industries have emerged; among them, green hydrogen is one of the more prominent, and is shared between industries.

Moving toward green hydrogen-based heavy industries would require a major technological shift in their core industrial processes. Historically, such shifts have occurred because of major economic gains enabled by technological innovation. There is no time to wait for green hydrogen technology to become cost-competitive with current technologies, due to the urgency of taking climate action and the fact that hard-to-abate sectors are only one investment cycle away from 2050. The change must be led by policy makers who, through policies and regulation, can accelerate the change and drive investments in this direction.

While the challenge is daunting and pressing, there are signs that this transition is achievable. Technological solutions exist, several initiatives are currently ongoing with pilot trials, and growing numbers of countries are planning policies to support the adoption of green hydrogen by industry.

Industrial policy will be needed to overcome the barriers presented in this report, to support early movers and to make sure that the innovation brought by green hydrogen will become the default option to decarbonise material manufacturing.

This report has laid out a list of proposals for policies that would support in different ways the uptake of green hydrogen in the industrial sector. Some of these policies are already in place in parts of the world, while others are being considered and suggested. Not all these policies will be needed in all jurisdictions at the same time, but it is likely that a combination of policies – both mandating or pushing for change and supporting the same – will be necessary across the globe. Only mandating change, without support, may meet organised resistance from industry, and carbon pricing may not achieve the level and stability needed to push for decarbonisation. At the same time, only supporting green basic materials and goods – without an overall decarbonisation roadmap – risks being ineffective in the long term.

The policies presented, along with the roadmap in Figure 3.1, are not meant to be a to-do list. Rather, this guide aims to provide a comprehensive overview of the options for policy makers, to present the tools already available to facilitate the discourse around these options and accelerate their adoption.

Industrial assets have a long lifetime and industries are deeply interlinked with society, creating jobs and wealth for the hosting countries. As the 2050 deadline approaches, any further delay will complicate their transition. These factors, together with the urgency dictated by the climate change crisis, call for immediate appropriate action by policy makers, who are urged to act now to secure the industrial energy transition.

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Techno-economic assessment of low-carbon hydrogen export from Western Canada to Eastern Canada, the USA, the Asia-Pacific, and Europe

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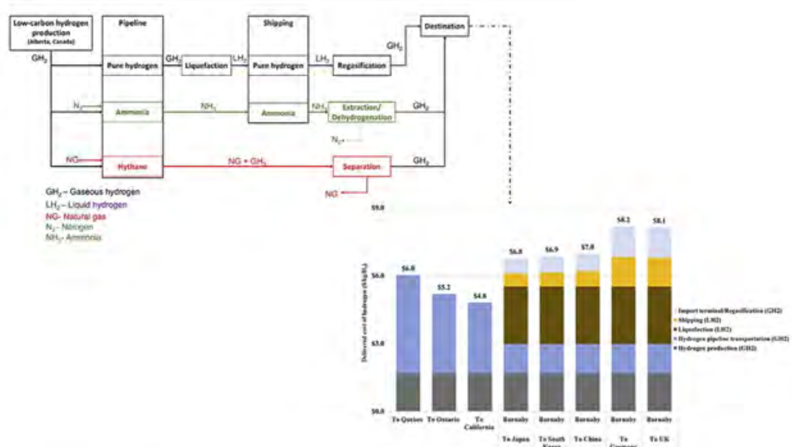
HIGHLIGHTS

- The supply chain cost of H_2 export from Alberta to viable destinations is assessed.
- Exporting H_2 to the USA with new long-distance hydrogen pipelines costs 4.81/kg.
- Exporting hythane to the USA can reduce H_2 delivered cost to \$4.03/kg.
- Exporting H_2 to Asia-Pacific and Europe costs \$6.65/kg and \$8.18/kg, respectively.
- Exporting ammonia can reduce the overseas H_2 delivered cost by over 25%.

GRAPHICAL ABSTRACT



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ABSTRACT

The use of low-carbon hydrogen is being considered to help decarbonize several jurisdictions around the world. There may be opportunities for energy-exporting countries to supply energy-importing countries with a secure source of low-carbon hydrogen. The study objective is to assess the delivered cost of gaseous hydrogen export from Canada (a fossil-resource rich country) to the Asia-Pacific, Europe, and inland destinations in North America. There is a data gap on the feasibility of inter-continental export of hydrogen from an energy-producing jurisdiction to energy-consuming jurisdictions. This study is aimed at addressing this gap and includes an assessment of opportunities across the Pacific Ocean and the Atlantic Ocean, based on fundamental engineering-based models. Techno-economics were used to determine the delivered cost of hydrogen to these destinations. The modelling considers energy, material, and capacity-sizing requirements for a five-stage supply chain comprising hydrogen production with carbon capture and storage,

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Canada
Asia-Pacific
Europe

hydrogen pipeline transportation, liquefaction, shipping, and regasification at the destinations. The results show that the delivered cost of hydrogen to inland destinations in North America is between CAD$4.81/kg and CAD$6.03/kg, to the Asia-Pacific from CAD$6.65/kg to CAD$6.99/kg, and at least CAD$8.14/kg for exports to Europe. Delivering hydrogen by blending in existing long-distance natural gas pipelines reduced the delivered cost to inland destinations by 17%. Exporting ammonia to the Asia-Pacific provides cost savings of 28% compared to shipping liquified hydrogen. The developed information may be helpful to policymakers in government and the industry in making informed decisions about international trade of low-carbon hydrogen in both energy-exporting and energy-importing jurisdictions, globally.

Nomenclature

$ –	2020 Canadian dollar (CAD)
$/kg H_2	2020 Canadian dollar per kilogram of hydrogen
APERC	Asia Pacific Energy Research Center
ATR –	Autothermal reforming
BC –	British Columbia
CAPEX –	Capital cost
CC –	Carbon capture
CCS –	Carbon capture and sequestration
CO_2 –	Carbon dioxide
GHG	Greenhouse gas
H_2 –	Hydrogen
kg	Kilogram
kW	Kilowatt
LNG	Liquified natural gas
Mt –	Million tonnes
MW	Megawatt
NG –	Natural gas
NH_3 –	Ammonia
°C –	Degree Celsius
OPEX –	Operating cost
PSA	Pressure swing absorption
SMR –	Steam methane reforming
TEA	Techno-economic analysis
UK –	United Kingdom
USA	United States of America

Introduction

There is a global urgency to transition towards low-carbon energy to reduce anthropogenic greenhouse gas (GHG) emissions and mitigate the negative impacts of climate change. Hydrogen is a gaseous energy carrier with the potential to support the broad multi-sectoral transition to a low-carbon economy, especially for difficult-to-decarbonize industries [1,2]. Hydrogen has the advantage of not emitting carbon at the end-use point of combustion, can be stored for long periods, and can be transported in existing natural gas (NG) pipeline infrastructures at low concentrations or through dedicated hydrogen pipelines [3,4]. It is projected that the global hydrogen demand will increase nearly 10-fold by 2050 (reaching 78 exajoules or 650 million tonnes/yr) due to its use as a chemical feedstock and as a low-carbon energy source for transportation, building heat, and power generation; this could create a hydrogen economy with ~US$2.50 trillion in revenue per year by 2050 [1].

Canada is a top ten global hydrogen producer, supplying four million tonnes (Mt) of hydrogen per year (5% of global production) [5,6]. NG is a primary feedstock for hydrogen production, so Canada is well positioned to become a leading exporter of hydrogen given the abundance of Canadian NG reserves (73 trillion cubic feet) [7]. Low-carbon hydrogen comprises blue hydrogen (produced from NG-based processes that reduce carbon dioxide [CO_2] emissions by using capture and sequestration [CCS]) and green hydrogen (produced from renewable energy-powered electrolysis of water) [8]. Building on its ambitious climate goal of net-zero GHG emissions by 2050, the Canadian government released a hydrogen strategy that describes plans for a national hydrogen economy and to become a leader in the international trade of low-carbon hydrogen [9]. Global growth of low-carbon hydrogen demand creates an opportunity for Alberta, a Western Canadian province, one of the world's lowest-cost producers of NG [10]. Alberta is also positioned to use its experience in NG extraction and transmission, hydrogen production, and CO_2 capture and sequestration to achieve economies of scale to support low carbon hydrogen production and export. The Alberta Carbon Trunk Line and the Quest carbon capture and storage facility, for instance, have a cumulative transportation capacity of approximately 42 Mt of CO_2 per year [11,12]. The Government of Alberta recently developed their *Hydrogen Roadmap* and *Natural Gas Vision and Strategy* that targets hydrogen export opportunities in Canada, the United States of America (USA), and other parts of the world by 2040 [13,14]. The roadmap and strategy provide a foundation for the province to lead in the production, use, and export of low-carbon hydrogen by leveraging the abundant NG resources and existing technological knowledge in the province [14].

Despite policy support for hydrogen deployment, the trade of hydrogen is an emerging market, and many aspects of participation are unknown. For instance, large-scale capital for infrastructure development is needed to support a hydrogen trading market and the cost-competitiveness of exported hydrogen compared to the prospective importer's domestic production costs need to be addressed before determining the immediate-term viability of hydrogen trade. A few studies have analyzed the cost implications of overseas delivery of hydrogen from one jurisdiction to another. Alberto Boretti assessed hydrogen production from excess wind and solar generation in Australia for export to Japan or Korea [15]. A primary outcome of the study was that electrolytic hydrogen produced in Australia, if exported overseas, would likely be uncompetitive with international low-carbon NG-based processes like steam methane reforming integrated with carbon capture and sequestration (SMR-CCS). Furthermore, the author focused only on the hydrogen production stage and neglected other supply chain stages such as hydrogen transportation, liquefaction, and storage to support the delivery of the produced energy carrier. Watanabe et al. [16] and Heuser et al. [17] estimated the cost of transporting hydrogen from wind-powered-electrolysis in Argentina to Japan. Although the research considered all relevant supply chain stages (analogous to exporting liquified natural gas [LNG]), the authors did not account for the effect of changing the shipping routes and travel distance on the hydrogen boil-off rate, or the associated delivered cost of hydrogen. The boil-off rate is the amount of liquid hydrogen that evaporates per day from the storage vessel when it is transported over a long distance [18]. The cumulative losses due to boil-off during transport reduce the overall economic competitveness of hydrogen delivered to the destination [18]. In addition, the shipping method adopted did not account for the impact of the fuel cost, port fees, and ship hiring cost on the overall specific cost of shipping. Kamiya et al. considered exporting hydrogen from Australia to Japan using lignite-based gasification for hydrogen production [19]. Although the relative annual quantity of hydrogen that can be exported using this production method is high, the process is too GHG emission-intensive to be classified as low-carbon hydrogen technology [17]. A study conducted by the Asia Pacific Energy Research Center (APERC) on the potential of importing low-carbon hydrogen to Japan from Asia-Pacific Economic Cooperation countries, including Canada, included all the supply chain stages [20]. However, the hydrogen pipeline transportation cost analysis did not consider the potential for cost reduction by blending hydrogen with NG (hythane) at acceptable blending limits within existing long-distance NG pipelines [4]. Hythane transport helps to minimize the construction of new inland hydrogen pipelines. In its report on the future of hydrogen, the International Energy Agency (IEA) provided cost implications of hydrogen exports from Saudi Arabia and Australia to Asia [21]. But, similar to the APERC study [20], the IEA did not consider reducing the overall delivery cost by decreasing the number of compression stations associated with inland hydrogen pipeline transportation with larger diameter pipelines. Nor did the study investigate the potential for lower-cost inland hydrogen pipeline transportation as hythane. The study also did not include the competitiveness of hydrogen exports from low-cost production locations in North America to Europe or Asia.

The literature on the hydrogen supply chain has several knowledge gaps. Most studies focus only on hydrogen production and neglect key supply chain stages. The effect of shipping routes and distance to the destination on the overall hydrogen supply cost has not been considered. The potential impact of blending hydrogen with NG has not been widely explored. Furthermore, the studies reviewed above used different study scopes and boundaries to assess the techno-economics of low-cost hydrogen exports from one region via inland or overseas but did not provide a single cohesive framework to analyze low-carbon hydrogen exports from cheaper production locations in North America, such as Canada to the rest of the world. To the best of our knowledge, no study has explored the cost reduction potential with hythane (at 15% hydrogen, 85% NG by-volume blends) in the hydrogen export supply chain, especially for inland export of hydrogen over long distances. Our study aims to fill these gaps.

The study objective is to provide a comprehensive framework to analyze the supply chain cost of low-carbon hydrogen exports from energy-exporting jurisdictions, such as Alberta, to destinations in North America, the Asia-Pacific, and Europe. The following unique contributions are made to achieve the objective:

- Creation of a data-intensive framework to determine energy demand, material sizing, and capacity requirements for each stage of the hydrogen export supply chain (large-scale hydrogen production through low-carbon NG-based pathways, hydrogen pipeline transportation, liquefaction, shipping, and regasification for overseas delivery);
- Assessment of costs for each stage of the hydrogen export supply chain and the delivered cost of hydrogen to the destinations;
- Comparison of hydrogen delivered costs with domestic hydrogen supply costs in the export destinations;
- Evaluation of measures to improve the cost-competitiveness of hydrogen exports (hythane delivery, larger diameter pipelines, and adopting ammonia as the primary carrier to eliminate the hydrogen liquefaction cost for overseas shipping).

The research outcomes are also relevant to jurisdictions importing low-carbon hydrogen. Alberta has the potential to supply low-carbon hydrogen internationally to key energy importers; however, delivery is contingent on the policies and commitment to grow a hydrogen economy to reduce the delivered cost.

In the next section, we describe the methods, which include the assessment framework and supply chain modelling. The Results and discussion provides analysis of each hydrogen supply chain stage and summarizes the limitations of the study findings. The results include the total supply chain hydrogen export (delivered) cost, the cost-competitiveness of the delivered hydrogen in the destination countries, and the cost-reduction measures on the hydrogen

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delivered cost. Conclusions provides the main insights from the analysis and highlights the possible areas of future work.

Methods

To explain our methods, we split this section into three parts. The first part introduces the export destinations considered for low-carbon hydrogen delivery from Alberta, Canada. The second presents the assessment framework and the third describes each supply chain stage and how the techno-economic assessment (TEA) is conducted for each stage. The analysis adopted in this paper can be replicated for other jurisdictions beyond the export-import case studies selected below.

Export-import destination case studies

Three jurisdictional categories were considered as export destinations for Alberta-produced low-carbon hydrogen (from Fort Saskatchewan, Fig. 1a): inland Canada delivery to other provinces, inland export to the state of California in the USA, and overseas exports to Japan, South Korea, and China in the Asia-Pacific, and Germany and the UK in Europe (map shown in Fig. 1b-d). For export within North America, we considered pipeline transportation to two Canadian provinces, Ontario and Quebec, and California, USA (Fig. 1b). Inland pipeline transport for overseas shipping is to various ports in British Columbia (BC), the most western province in Canada: the ports of Vancouver (Burnaby), Kitimat, and Prince Rupert (map shown in Fig. 1c-d). Table 1 gives a brief description of the case studies, and the subsequent subsections discuss the details of each case.

Alberta hydrogen export within Northern America

Canada is making progress to integrate low-carbon hydrogen into the energy, industrial, and transportation sectors. In 2019, the federal government announced a \$130 million budget under a zero-emissions vehicle (ZEV) program to support infrastructure development and incentivize ZEV adoption [23]. Hydrogen is acknowledged to play a role in the transition to a low-carbon economy in several provinces, including Québec [24,25], BC [23,26], and Ontario [27]. Thus, Alberta's low-carbon hydrogen has a potential market in several provinces in Canada.

The demand for hydrogen in the USA is forecast to be 22–40 Mt/year [29], and the transportation sector, among the major end-users, represents ~32.5% of potential applications in that country [29]. California established a zero-emission vehicle policy that mandates all new passenger cars and heavy-duty vehicles be zero emissions by 2035 [30]. The shift to low-carbon alternatives (such as hydrogen) for transportation and industrial application in states like California could create a long-term export market opportunity for low-carbon hydrogen produced in Alberta and transported via new hydrogen-only pipelines or existing NG pipelines (via blending hydrogen at suitable volumes with NG) to the USA. In 2019, 68.09 billion cubic metres of NG were exported to the USA (with about 50% supplied to the US west coast, including California) from western Canada through long-distance gas pipelines [31,32]. There has been a constant decline in natural gas exports to the USA from western Canada (with about a 20% drop over the past ten years [33]), primarily driven by the growth in US-based domestic production and also energy sector decarbonization efforts. Thus, leveraging the existing NG supply chain, such as the pipeline network to support hydrogen exports, could be viable in the long term; though, contingent on the growth of the hydrogen economy in states across the USA, especially California.

Alberta hydrogen export to Asia-Pacific

The Asia-Pacific China, Japan, and South Korea are potential markets. Japan plans to cut its GHG emissions by 80% by 2050, and low-carbon hydrogen could play a pivotal role in achieving this objective [34,35]. Japan will demand about 272,155 tonnes (~0.30 Mt) hydrogen per year by 2030, mainly from overseas imports [36,37], the Japanese government has shown a commitment to developing the requisite supporting infrastructure to foster hydrogen imports. The South Korean government announced a hydrogen economy roadmap to produce 6.20 million fuel cell electric vehicles and 1200 refilling stations by 2040. It also set a target of 15 gigawatts capacity of fuel cells in power generation and 2.1 gigawatts in residential and buildings [38]. South Korea is committed to exploring international hydrogen supply chains to further the scalability of hydrogen use domestically, providing an opportunity for the export of cost-competitive low-carbon hydrogen from Canada. China is the world's largest producer of hydrogen (coal gasification is the main production pathway in the country), responsible for 18% of global production [39]. Although China's ability to scale domestic hydrogen production might seemingly limit international trade into the country, overseas imports of cost-competitive low-carbon hydrogen could be required for hydrogen-powered electricity generation, and this represents an opportunity for Alberta, providing its hydrogen is cost-competitive [20].

Alberta hydrogen export to Europe

There might be future low-carbon hydrogen market opportunities in European markets across Germany and the UK. Germany recently announced plans to spend \$13.70 billion to stimulate the domestic hydrogen economy and foster international hydrogen trade partnerships to meet a demand of 90–120 TWh (or 2.7 to 3.60 million tonnes) by 2030 [40]. The domestic market meets less than 20% of the forecasted demand, hence more than 80% needs to be imported from other markets [40]. Low-carbon hydrogen from Alberta could serve the German market in the short to medium term. The UK requires around 270 TWh of low-carbon hydrogen to achieve its net-zero target [41]. However, it is challenging to produce hydrogen at the required scale in the short term, and this provides an opportunity for Alberta if the supply is cost-competitive.

Assessment framework for hydrogen export supply chains

Four hydrogen delivery pathways are considered: pure hydrogen (path 1-inland and 2-overseas), inland hythane (path 3), and overseas ammonia (path 4). Path 2 is made up of five supply chain stages that include gaseous hydrogen

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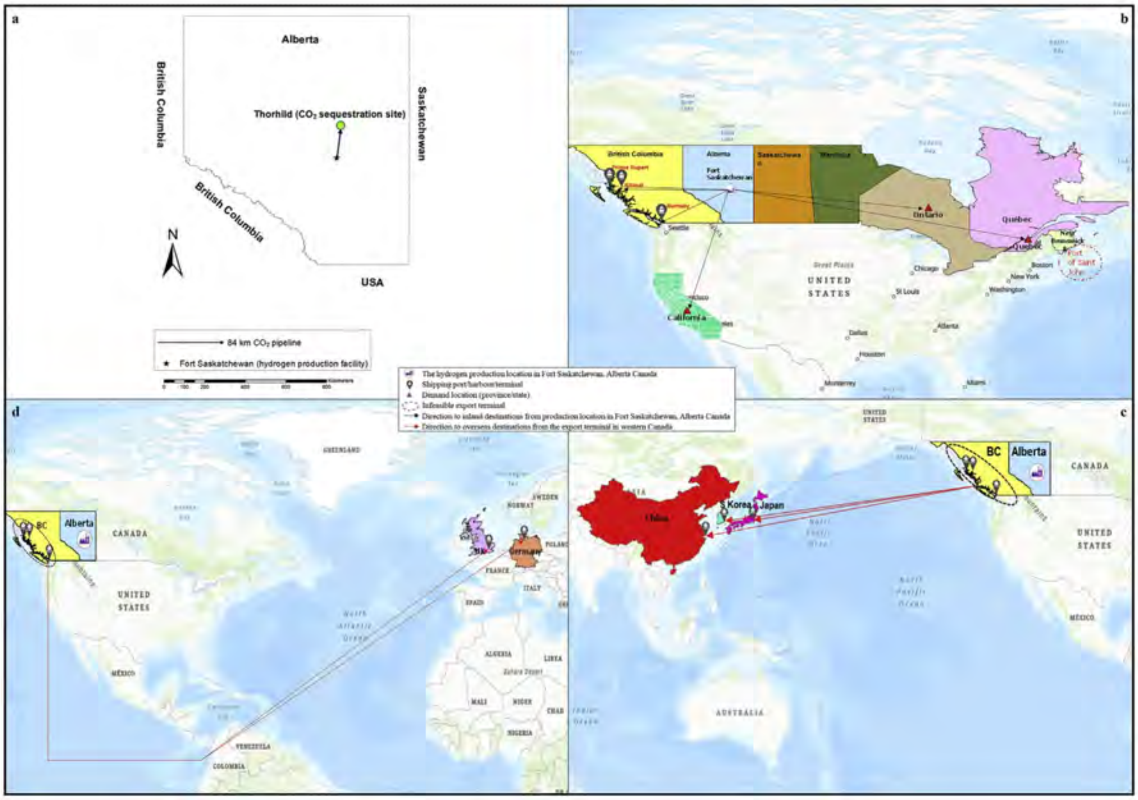

Fig. 1 – Spatial representations of (a) low-carbon hydrogen production and CO_2 sequestration locations at Fort Saskatchewan and Thorhild, Alberta, respectively; (b) inland hydrogen destinations (Quebec, Ontario, California USA, and export terminals in British Columbia), Port Saint John in New Brunswick, a major port in eastern Canada, is considered an infeasible export terminal due to its distance from Alberta relative to closer ports in British Columbia, as the pipeline costs associated with using Port Saint John cause the delivered costs overseas to be uneconomical; (c) overseas export destinations/terminals in Asia-Pacific countries (from the left, Port of Shanghai China, Port of Busan South Korea, and Port of Tokyo Japan); (d) European countries (from the right, Port of Hamburg Germany, and Port of London United Kingdom). ***Maps are developed using ArcMap and ArcGis Pro in WGS 1984 projection*** **[22].**

production, pipeline transportation, liquefaction, shipping, and regasification (Fig. 2a). Path 1 and path 3 are applicable for inland hydrogen exports within Eastern Canada and California, and path 2 and path 4 are applied for overseas hydrogen exports to the Asia-Pacific and Europe. Fig. 2b gives the system boundary for hydrogen delivery to each destination. We did not consider the distribution of hydrogen for possible uses at the destinations since the spatial arrangement of the distribution network and the uses of hydrogen will widely vary. The key outputs are the delivered costs of hydrogen ($/kg) to the respective destinations. The framework can also be used to analyze low-carbon hydrogen exports from other similar export countries to comparable jurisdictions globally where international hydrogen trade is supported with appropriate adjustments to techno-economic data on the hydrogen production method, type of carrier for hydrogen delivery, and the transport pathway.

The delivered hydrogen cost to an export destination was found by adding the specific costs at each stage of the export supply chain. We define the specific cost for each supply chain stage as the ratio of the annualized total cost to the quantity of hydrogen processed. For inland destinations, such as exports to Eastern Canada and the USA, the delivered cost is the sum of the specific costs of low-carbon hydrogen production in Alberta and inland pipeline transportation; the transport cost represents the specific cost of hydrogen or hythane delivery via inland pipeline transportation. For the overseas exports, the delivered cost includes the specific costs of hydrogen production in Alberta, inland pipeline transportation of compressed-gaseous hydrogen from Alberta to the shipping port (export terminal) in BC, hydrogen liquefaction at the export terminal in BC, liquified hydrogen shipping from the selected export terminals in BC to the receiving import terminal in the destination country, and hydrogen regasification at the destination country (from the liquified state adopted for shipping). The costs associated with the inland distribution of hydrogen to end users in the destination countries were ignored, assuming that the distribution costs are equal for both imported and domestically produced hydrogen.

Data and TEA modelling of supply chain stages

The descriptions and techno-economic assessment (TEA) of each supply chain stage are provided in this section. The TEA

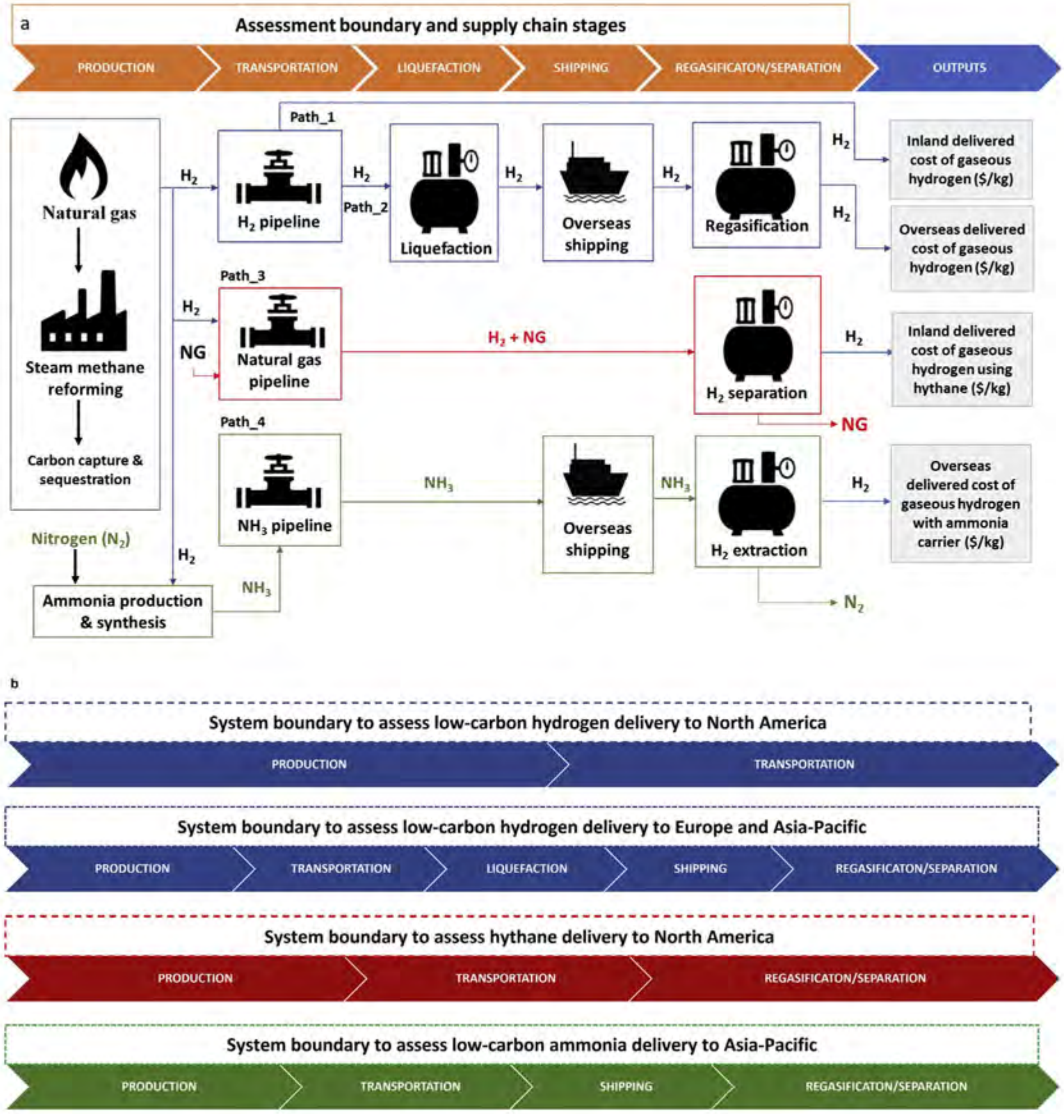

Fig. 2 – Overview of (a) assessment framework and overall system supply chain stages; (b) system boundary considered to each destination.

models were developed to examine the specific costs of delivering hydrogen from a production point in its constituent form to a particular destination. Detailed TEAs of the liquefaction, shipping, and regasification stages were done in this research. The TEAs of the hydrogen production and inland pipeline transportation (including hythane and ammonia transport) stages were conducted in previous works by Okunlola et al. [10] and Di Lullo et al. [42], respectively. All monetary values are in 2020 Canadian dollars ($) except where otherwise stated. The Alberta reference price for NG was considered to be $1.96/GJ (2016–20 price averages) and electricity price was $16.14/GJ (2016–20 price averages) [43].

Hydrogen production

Low-carbon hydrogen production in Alberta, Canada. The choice of the hydrogen production pathway for the large-scale production of hydrogen to support exports depends on feedstock availability and the technology readiness level (TRL). These factors guarantee the viability of long-term adoption. For Alberta, SMR-CCS provides an immediate pathway for large-scale hydrogen production [44–48], although other NG-based hydrogen production processes such as autothermal reforming with CCS (ATR-CCS) may emerge as viable in the near term. With ATR-CCS, higher carbon capture rates can be achieved at production costs comparable with SMR-CCS [49]. We focus primarily on SMR-CCS because the TRL (9) is higher than ATR-CCS's and it is immediately scalable [49,50]. The primary feedstock for the SMR-CCS is NG, and it is readily available in Alberta, posing little or no resource potential challenge to long-term hydrogen production.

The process flow for SMR-CCS is described in Fig. 3. NG is fed into a reformer where hydrogen-rich syngas containing carbon monoxide (CO) and hydrogen is produced from NG reacting with steam (in the presence of a catalyst) at high temperatures and pressure. CO from the cooled syngas is further converted into CO_2 and more hydrogen via water-gas-shift (WGS) reaction in the shift reactor through the addition of high-temperature steam. The CO_2 produced is then

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separated from hydrogen in an amine CO_2 removal unit and pure hydrogen is obtained for further compression, storage and transportation. CO_2 emissions are produced from both the reaction process itself and the combustion of fuel to supply heat for the process. About half of the emissions produced in an SMR facility (52% in our modelling) occur at the reactor stage; adding carbon capture (CC) to this stream reduces the SMR emissions intensity by 40% [10,47,51]. A second CC unit can be used at the reformer to cover 85% of SMR emissions; this reduces the SMR emission intensity by 78% [10,49]. CO_2 emissions from the syngas purification unit are compressed and transported to a geological cavern for sequestration. Note that without the introduction of CCS, syngas from the WGS reaction is directly sent to the syngas purification/pressure swing adsorption (PSA) unit after cooling, and the CO_2 emissions are emitted to the atmosphere.

For the TEA, data for SMR-CCS is provided from earlier modelling [10,49]. The SMR-CCS plant is assumed to be sited in Fort Saskatchewan, Alberta, and the captured CO_2 is transported and stored at a sequestration site in Thorhild, Alberta, about 84 km away from the production facility (see Fig. 1a) [47]. Onsite hydrogen storage is for two days' worth of the production capacity to minimize any risk contingency during inland transport [22]. The hydrogen production capacity of the SMR-CCS plant is 607 tonnes/day (or 221,555 tonnes per year) based on the typical size of an existing SMR plant in Alberta.

A detailed data-intensive process model was built in Aspen Plus [52] and the factorial method was used for the capital cost estimations [10,49]. The factorial method involves determining the cost of each piece of equipment and then multiplying it by the appropriate cost factors [53]. The cost factors used to determine the capital cost of the SMR-CCS facility are provided in Supplementary Information (SI)-Table A1. The lifetime of the plant is 25 years, and the interest rate is 10%. Table 2 gives a breakdown of the cost of hydrogen production from SMR-CCS at different CC levels. The table shows that SMR-CCS at 52% CC ($1.69/kg H_2) provides the lowest cost low-carbon hydrogen production option in the province, although with a higher GHG emission footprint than SMR-CCS with an 85% carbon capture rate; life cycle CO_2 emissions reduction from SMR-CCS at 85% CC can be 19% lower than SMR-CCS at 52% CC [10]. The delivered cost of hydrogen in this work is based on the lower specific hydrogen production cost of SMR-CCS at 52% CC. The effect of a higher specific production cost of hydrogen for SMR-CCS at 85% CC on the cost-competitiveness of delivered hydrogen is discussed in the results. Results considering ATR-CCS is also provided since future carbon intensity standards may be too stringent for SMR-CCS to be considered a low-carbon hydrogen produciton technology.

Ammonia production. Ammonia with approximately 18% hydrogen by mass [54] was chosen as an alternative carrier for overseas hydrogen transport and delivery to mitigate the low infrastructure readiness levels of hydrogen shipping [55]. Ammonia can be produced on a large scale and is flexible and attractive as a hydrogen carrier, despite its low hydrogen purity [56,57]. For this study, ammonia is produced and synthesized through the conventional Haber-Bosch process. In the Haber-Bosch process, hydrogen is reacted with nitrogen at an inlet temperature of up to 500 °C and pressure of over 140 bar in the presence of an iron oxide catalyst [54]. Following this reaction, the produced ammonia is stored on site and eventually transported in a dedicated ammonia pipeline. The GHG emissions of the Haber-Bosch process are primarily impacted by the footprint of the hydrogen production pathway [55]. The ammonia production plant is assumed to be located with the SMR-CCS facility at Fort Saskatchewan, Alberta, where the Haber-Bosch process receives the required low-carbon hydrogen feedstock. Ammonia production cost data for the TEA was obtained from an earlier study [21] and is $1.36/kg H_2 after adjusting to 2020 CAD.

Hydrogen transportation

Inland gaseous hydrogen pipeline. To transport a large amount of pure gaseous hydrogen over long distances on land, pressurized pipelines are often considered the preferred mode because their cost per unit of hydrogen transported is low and they have minimal energy losses [58]. We assume low-carbon hydrogen produced from an SMR-CCS facility is transported

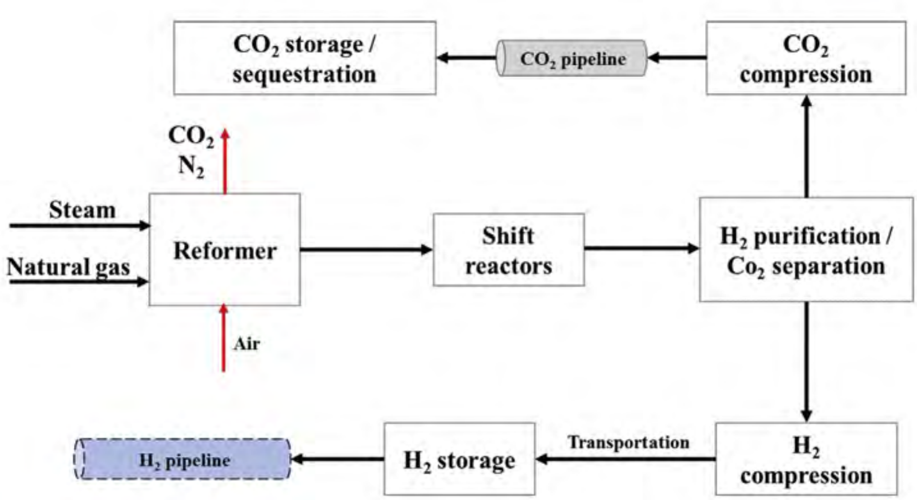

Fig. 3 Flow chart of the hydrogen production process with SMR-CCS (with 52% CC).

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Table 1 – Description of the case studies assessed in this study.

Inland destination	Carrier chosen	Pipeline distance from Alberta	Comments
Quebec (to the city-gate[a])	• Gaseous hydrogen	4050 km	Hydrogen is already acknowledged to play a role in long-term decarbonization plans in Ontario, California, and Quebec. New inland hydrogen pipelines are assessed for large-volume gaseous hydrogen delivery from Alberta to the respective city-gates. Hythane is assessed for Ontario and California because there are existing inland NG transmission pipelines from Alberta to enable hythane transport to the respective interconnection points. Hythane is not assessed for Quebec because the NG pipeline route has multiple interconnection points that may dilute the hydrogen blend to the province.
California (to the city-gate[a])	• Gaseous hydrogen • Hythane	2885 km	
Ontario (to the city-gate[a])	• Gaseous hydrogen • Hythane	3300 km	
Manitoba	• Hythane	1000 km	Manitoba is chosen for hythane delivery because there is an existing NG transmission pipeline from Alberta for hythane transport to the interconnection point in Manitoba.
BC (Burnaby Port)	• Gaseous hydrogen • Ammonia	1180 km	Gaseous hydrogen is transported by pipeline from Alberta to the inland ports before liquefaction for shipping overseas. Shipping ports in BC are chosen for liquefied hydrogen exports to overseas destinations. Ammonia is transported by pipeline to the export terminals in BC for overseas exports.
BC (Kitimat Port)	• Gaseous hydrogen • Ammonia	1213 km	
BC (Prince Rupert Port)	• Gaseous hydrogen • Ammonia	1305 km	
Overseas destination	**Carrier**	**Shipping distance from BC**	**Comments**
Japan	• Liquefied hydrogen[b] • Ammonia	7108–7912 km	The shipping distances to the overseas destinations vary because of differences in the navigation routes from the originating ports in BC. Ammonia is assessed as an alternative hydrogen carrier for shipping to Japan.
South Korea	• Liquefied hydrogen[b]	7771–8562 km	
China	• Liquefied hydrogen[b]	8664–9464 km	
Germany	• Liquefied hydrogen[b]	16,879 km	
UK	• Liquefied hydrogen[b]	16,335 km	

[a] City-gate refers to the point at the entrance of the destination province/state for connecting the transmission pipeline to the distribution pipeline network.
[b] Liquefied hydrogen delivered to the overseas destination is regasified on arrival.

by pipeline to the final destination (in the case of inland delivery) or the liquefaction site (in the case of overseas shipping). Inland pipeline transport is capital intensive; hence, large volumes of hydrogen need to be transported to justify transportation through this mode. The maximum daily output from the hydrogen production plant determines the flowrate and capacity of the pipeline [48], and thus, influencing the chosen pipeline diameter and compressor spacing along the pipeline route. For the TEA, the specific costs of inland pipeline transportation of hydrogen to the selected destinations were calculated from the capital and the annual operating costs of the hydrogen pipeline infrastructure, modelled by Di Lullo et al. [42] using a TEA-enhanced version of the FUNdamental ENgineering PrinciplEs-based ModeL for Natural Gas Transmission Lines (FUNNEL-NGTL)+H_2 model [4]. The FUNNEL-NGTL + H_2 model is a bottom-up model that uses fundamental engineering calculations to predict the pipeline's energy needs based on flow rate, diameter, gas composition, compressor station spacing, and maximum permitted operating pressure [42]. The capital cost of the pipeline infrastructure consists primarily of the hydrogen pipeline and the compression stations. For a flow rate of 607 tonnes of hydrogen per day (i.e., output from the SMR-CCS plant), the total pipeline capital cost was minimized by adjusting the number of compressor stations and pipeline diameter for the given pipeline length.

The capital cost of the pipeline and compressor was determined using Eq. 1-Eq. 3. The compressor cost was calculated using the factorial method [53]. The lifetime of the pipeline and compressor infrastructure is 40 and 10 years, respectively, and an interest rate of 10% was assumed [47]. Twelve-inch internal diameter pipelines are initially assumed and 18, 40, and 47 booster compression stations were chosen based on design criteria for the pipeline route to the export terminals in BC, California, and Ontario/Quebec, respectively (Table 3). The annual operating cost of the

Table 2 – SMR-CCS hydrogen production costs at varying CC rates from Ref. [10].

Parameter	SMR-CCS at 52% CC	SMR-CCS at 85% CC
Capital costs ($ million)	1063	1347
Total operating costs ($ million/year)	167	254
Hydrogen cost ($/kg H_2)	1.69	2.34

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pipelines is 1.5% of the pipeline capital cost and the operating cost of the compressors is a combination of the electricity cost to power the motors, the maintenance, and labour costs [53]. The labour cost factors for the compression station are provided in SI-Table A2.

$$C_P = \left(\left[1,171 \times \left(\frac{D}{25.4}\right)^2 + \left(15,251 \times \frac{D}{25.4}\right) + 329,705\right] \times L + 767,845\right) \times AF \quad (1)$$

$$C_{CC} = (C_{PEC}\,[1 + C_{IF} + OSBL + D\&E + Cont]) \times AF \quad (2)$$

$$C_{PEC} = 30,746 \times P^{0.6089} \quad (3)$$

Cp, derived from Parker [59], represents the capital cost for a hydrogen pipeline in \$, *D* is the pipeline internal diameter adjusted to metres, *L* is the length of the pipeline in km, and *AF* is Alberta's installation factor (1.15), which is 15% higher than the North American average [47]. In Parker [59], the hydrogen pipeline material cost is 50% higher than NG pipelines to account for the extra material requirements to prevent corrosion and embrittlement of the pipeline: the labour cost is also increased by 25%. For the compressor stations, C_{PEC} is the purchase cost of the compressor in \$ and *P* represents the rated power of the compressor motor in kW. C_{CC} is the overall capital cost of the compressor, which comprises the material and labour installation factors (C_{IF}), the off-site infrastructure costs represented by the outside battery limits factor (*OSBL*), the design and engineering cost factor (*D&E*), and the contingency charge factor (*Cont*) equal to 1.385, 0.3, 0.3, and 0.1, respectively [53]. Table 4 provides the capital and annual operating costs of gaseous hydrogen pipeline transport from the production facility in Alberta to the inland delivery locations in Canada and the USA. The hydrogen pipeline model in this study was benchmarked against an alternative cost estimation model developed by Olateju et al. [47] for shorter-distance pipelines (37km/337 km) without added compression due to free-flow of the carrier along the pipeline route, based on methodologies in Yang and Ogden [60]. The additional compression cost in the approach adopted in this paper increased pipeline capital cost estimates by 10% compared to the benchmark model from Olateju et al. [47], which did not account for it.

Hythane pipeline transport. An alternative approach for inland long-distance transport of gaseous hydrogen is to blend it at a low concentration in existing NG export pipelines. This approach could lower the initial capital costs of building new gaseous hydrogen pipelines to inland destinations in North America. A maximum blending limit of 15% hydrogen and 85% NG by volume is considered to be a safe upper limit within existing infrastructure [61]; this is adopted in this study.

We assess that hythane can be delivered from Alberta to Manitoba, Ontario, and California through existing inland NG transmission pipelines. Hythane can be delivered to Manitoba and Ontario through the TransCanada (TC) Mainline pipeline and to California through the 1240 km Gas Transmission Northwest (GTN) Foothills pipeline [62,63]. Due to the decline in NG exports from Alberta following the growth of unconventional NG production in the USA, the average use between 2016 and 2020 of the Mainline Prairie, Eastern Triangle Northern Ontario Line (NOL) recipient points, and Manitoba interconnects (spatial locations in Ref. [64]) was approximately 47%, 37%, and 24%, respectively [62]; this relatively low use of these lines provide an opportunity for hythane delivery through the TC Mainline. The average use of the Foothills pipeline between 2016 and 2020 was 73% and 52% for Kingsgate and Monchy (spatial locations in ref. [65]), respectively (with throughputs in the first quarter of 2021 at 43% below the five-year average) [63], also providing an opportunity for hythane export from Alberta.

The viable flow rate of hydrogen through the NG pipelines depends primarily on the existing system's maximum capacity to facilitate long-term planning. With a hythane flow rate of 324 million m^3 per day, we assess that Alberta can export an average of 1.05 million kg H_2 per day to California from the

Table 3 – Assumptions used for inland hydrogen pipeline transportation.

Parameter	Value
Interest rate for capital amortization	10%
Alberta installation factor (AF)	1.15
Maximum pipeline capacity	607 tonnes of hydrogen per day
Pipeline lifetime for capital amortization	40 years
Compressor lifetime	10 years
Pipeline diameter	12 inches
Compressor booster stations for the pipeline route to the export terminals in BC	18
Compressor booster stations for the pipeline route to California	40
Compressor booster stations for the pipeline route to Ontario/Quebec	47
Total compressor capital cost factors ($C_{IF} + OSBL + D\&E + Cont$)	2.09
Compressor power (per compressor)	3.83 MW

Table 4 – Cost of gaseous hydrogen pipeline transport from Alberta to inland destinations.

Inland destination	Hydrogen delivered (million kg H_2/year)	Capital cost (million \$)	Operating cost (million \$/year)
Ontario (city-gate)	232.69	3735.35	243.35
Quebec (city-gate)	223.38	4635.39	310.58
California (city-gate)	224.93	1549.83	228.28
British Columbia -Burnaby	232.69	1398.88	100.45
British Columbia -Kitimat	224.93	1397.16	94.05
British Columbia -Prince Rupert	232.69	1549.83	108.42

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GTN Foothills pipeline via the Kingsgate interconnect [63]. Through the TC Mainline pipeline, up to 1.32 million kg H_2 per day can be exported to the Emerson junction in Manitoba, and 1.20 million kg H_2 per day to the Ontario Eastern Triangle NOL recipient point (Table 5).

For the TEA, specific costs for hythane were also modelled using the TEA-enhanced FUNNEL-NGTL + H_2 model [4]. The specific cost of hydrogen transported within the hythane pipeline from Alberta to Manitoba, Ontario, and California were determined with Eq. (4) and Eq. (5), using existing NG costs and tolls. The. The cost values are adjusted to account for differences in the energy intensity of hydrogen and NG in the hythane mixture. Therefore, the cost of inland hythane transport is a function of the volume fraction of each fuel in the hythane mixture, and the sum of the pipeline fuel, tolls, and NG cost [42]. The cost of hydrogen used for fuel cost calculations is was \$13.82/GJ.

$$C_{hydrogen} = \frac{C_{Hy} - y_{NG} * C_{NG}}{y_{H2}} \tag{4}$$

$$C_{hydrogen\_E} = C_{hydrogen} \times U_{H2} \tag{5}$$

$C_{hydrogen}$ represents the total cost of hydrogen adjusted to $\$/m^3$-1,000 km, C_{Hy} is the hythane cost in $\$/m^3$-1000 km, C_{NG} is the cost of NG in $\$/m^3$-1000 km, and y is the fuel fraction component in the hythane mix. U_{H2} is the hydrogen energy intensity, and $C_{hydrogen\_E}$ is the resulting total cost of hydrogen transportation in \$/GJ-1000 km (data provided in Table 5). We note that at low hydrogen blending ratios (15% by volume) in existing pipelines, there is negligible corrosion impact and also no increase to the annual operation and maintenance cost of the NG pipeline is considered [4].

Ammonia pipeline. Ammonia pipelines are considered for large volumes of inland ammonia transport from the production facility to the export terminal for overseas delivery. Transporting ammonia through an inland pipeline is low risk and cost-effective, and also, ammonia is liquid in pipelines operated at 1723 kPa (kPa) pressure [42,66], a value adopted in this paper. Further liquefaction at the export terminal (as considered for the pathway requiring an inland gaseous hydrogen pipeline transport to the export terminal), is not considered for ammonia delivery to the overseas destination. Similar distances as the gaseous hydrogen pipeline from the production facility to the export terminals in BC are considered for the ammonia pipeline (as shown in Table 1).

For the TEA, the cost of the long-distance ammonia pipeline (Eq. 6) was calculated as a function of distance from correlations developed in a previous study [42]. k represents the distance of the ammonia pipeline in km to the shipping terminals in British Columbia (as shown in Table 1).

$$\text{Ammonia pipeline } (\$ / kg\ H_2) = ([0.00022 \times k] + 0.00564) \tag{6}$$

Table 5 – Characteristics and costs of hythane transport through the existing NG pipelines.

Assumption	Value
Hythane flow rate	324 million m^3 per day
Capacity for hydrogen blending at the Kingsgate interconnect of the GTN Foothills pipeline to California	1.05 million kg H_2 per day
Capacity for hydrogen blending to the Emerson junction of the TC Mainline pipeline for Manitoba	1.32 million kg H_2 per day
Capacity for hydrogen blending to the Eastern Triangle NOL point of the TC Mainline pipeline for Ontario	1.20 million kg H_2 per day
Cost of hydrogen ($C_{hydrogen}$)	\$0.0258/m^3–1000 km [42]
Cost of natural gas (C_{NG})	\$0.0252/m^3–1000 km [42]
Hydrogen energy intensity (U_{H2})	0.010 GJ/m^3 (based on LHV)
Natural gas energy intensity	0.033 GJ/m^3
Hythane energy intensity	0.030 GJ/m^3 (based on LHV)

Hydrogen liquefaction

Liquefying hydrogen can be preferred to compression when delivering large volumes over long distances, especially overseas [67]. The total liquefaction capacity around the world is reported to be about 355 tonnes/day, with over 84% in North America [67]. Large-scale hydrogen liquefaction is done through the Claude cycle, in which hydrogen is cooled in a cryogenic process from ambient temperature to −253° Celsius (°C) [67]. Typically, hydrogen liquefaction involves two refrigeration steps. First, hydrogen is compressed and then precooled to −190 °C using a liquid nitrogen refrigeration cycle. The precooled hydrogen is purified and passed through a heat exchanger loaded with a catalyst for ortho-to-parahydrogen conversion [68]. The process is energy-intensive due to the high compression power needed. In the second refrigeration step, hydrogen is cooled to −253 °C at ambient pressure. Individual hydrogen liquefaction plant processing capacities of 100 tonnes/day are considered in this study; the deployment of this plant size has been found to be feasible in the near to mid-term horizon [69,70].

For the TEA, the costs of the liquefaction facility were estimated using the Hydrogen Delivery Scenario Analysis Model (HDSAM) [71]. The HDSAM models the sizing of the liquefaction facility at the operational delivery pressure from the pipeline. We considered a processing capacity (Q) of 100 tonnes of hydrogen per day to be achievable in the near to the mid term. The capital cost of the liquefaction plant ($CAPEX_{LH}$) was estimated as function of Q (Eq. 7). The annual operating cost for the liquefaction facility is given in Table 6. The operating cost comprises the annual fixed cost (~4% of the capital costs) and the variable operating cost (primarily the cost of electricity consumption for the whole facility in a year). The electricity intensity (E_{H_2}) of the liquefaction plant denominated in $kWh/_{kg}$ was calculated with Eq. 8. The liquefaction facility is situated at an export terminal with facilities for storage and loading (required for the next stage). 15 days' worth of liquefaction capacity is assumed as the storage capacity. The maximum single storage tank size for liquified hydrogen is 3500 m^3 at an installed capital cost ($CAPEX_{LS}$) of \$9.95 million [66] (after conversion to 2020 Canadian dollars).

$$CAPEX_{LH}\ (\$) = 9.3 \times Q^{0.8} \times 10^6 \tag{7}$$

$$E_{H_2}(kWh/kg) = 13.92 \times Q^{-0.1} \tag{8}$$

Liquified hydrogen and ammonia overseas shipping

Fig. 1c shows a simple representation of the shipping route from the west coast of BC to Japan, South Korea, and China (in the Asia-Pacific). Shipping to the Asia-Pacific via the Pacific Ocean is the fastest route. As shown in Fig. 1c three ports on the west coast of BC were chosen as the originating ports (export terminals) – the ports of Burnaby, Kitimat, and Prince Rupert – because their closeness can facilitate the overseas export of goods from Alberta. Burnaby and Kitimat, respectively about 1180 km and 1200 km from Alberta., were selected due to the potential for resource sharing. Crude oil and refined products from the Trans Mountain Pipeline are currently exported from Burnaby [72], and an LNG facility is planned at Kitimat [73]. The Port of Prince Rupert was also selected because it is equally as close to Alberta for shipping to the Asia-Pacific region (at 1380 km). Other relevant export terminals in Eastern Canada, such as Port Saint John in New Brunswick (dashed highlight in Fig. 1b), were not considered due to the very long travel distance (and overly vast cost implications) for an inland hydrogen pipeline from Alberta.

The shipping route to the UK and Germany through the Panama Canal and the Atlantic Ocean is shown in Fig. 1d. Only the port of Burnaby was considered for these countries, as it provides the shortest travel route. A major port at each destination country was selected for hydrogen delivery. We chose the Port of Shanghai (China), the Port of Busan (South Korea), the Port of Tokyo (Japan), the Port of London (UK), and the Port of Hamburg (Germany) (Fig. 1c-d shows the spatial representation of these ports from Canada). The shipping distances and the average voyage days for sea travel to each overseas destination were estimated using a maritime calculator (Table 7) [74].

The TEA of hydrogen shipping to the overseas destination was done assuming the time charter system. In this system, the hydrogen exporter hires a carrier ship for some time and pays the associated fuel cost, port and passage fees, and the daily hiring fee [69,75]. The owner of the ship is responsible for the ship's operation and maintenance, but the merchant determines the route [75]. The fuel consumed by the ship is estimated, and the port and passage fees paid during transit are assessed based on the gross tonnage (GT) of the ship. The gross tonnage of the ship is determined with Eq. (9).

$$GT = V * (0.2 + 0.02\log_{10} \times\ V) \tag{9}$$

GT is the gross tonnage of the ship and V represents the volume of the ship (m^3). The fuel consumption and associated fuel costs depend on the propulsion and auxiliary engines of the ship or carrier. The total power needed for the propulsion engine (propeller) depends on the calm water resistance, service speed, and efficiencies of the ship [76,77]. The appropriate engine was selected using the Computerized Engine Application System (CEAS) for a two-stroke engine by MAN [78]. The CEAS generates the characteristics of the engine as well as the total fuel demand. A ship having the characteristics of the Med-Max LNG carrier [79] was considered in estimating the appropriate liquified hydrogen ship. The carrier has a volume of about 80,000 m^3 and a service speed of 17.5 knots (9 m per second), with a boil-off of about 0.2% per day [79], and the fill-up level of the storage capacity is about 94% [80] (Table 8). Further details of the general characteristics of the Med-Max LNG carrier such as the overall length, breadth, depth, and weight are provided in SI-Table A3. The ship propulsion efficiencies provided in Table 8 are based on basic principles reported by MAN [77]. We also approximated the rating of the auxiliary engine using gas tanker deadweight tonnage data from Goldsworthy et al. [81].

Port fees, as the name suggests, are the fees paid at the port for using the port and its facilities. In this study, the berthage fee,[1] harbour dues,[2] and wharfage fee[3] are based on the tariff schedule of the port of Burnaby, BC and the Port of St. John, New Brunswick [82,83]. Passage fees are paid when the ship makes a voyage through a passage, such as the Panama Canal. The passage fee is only applicable to European destinations since shipping in this case is routed through a passage (the Panama Canal). The hiring cost was assumed to be equivalent to the 2018 average for LNG carriers [83]. A liquified hydrogen ship may be expected to be more expensive than an LNG carrier because of a premium added due to more stringent insulation requirements for liquified hydrogen storage. But the premium is uncertain and unknown at this time and so is not considered in this work.

The calculated calm water resistance and effective towing power (at 9 m/s service speed and 100% hull efficiency) for the suitable liquified hydrogen ship are 970 kN and 8.7 Megawatt (MW), respectively, for a ship. Taking efficiencies into consideration, the brake power of the ship was derived to be 13 MW and the total installed power of the ship's propulsion engine was calculated as 16 MW. A 17 MW diesel engine (MAN B&W G70ME-C10.5) was selected from the CEAS based on the available configuration [78]. The selected engine consumes both heavy fuel oil (HFO) and distillate oils. From the specific fuel oil consumption (SFOC) plot of the selected engine under operational conditions, the SFOC was obtained as 158.7 g/kWh at the service speed. The selected fuel was intermediate fuel oil (IFO) 380. This fuel is composed of 98% HFO and 2% distillate [84]. The cost of this fuel was taken as the 2018 average spot price ($436/tonne) [85]. Table 9 presents the fuel consumption and the quantity of hydrogen boil-off during the voyage to each destination country.

Based on the ship tonnage (54,589 tonnes), the total port fees (cost for berthage, wharfage, and harbour dues) were calculated. The port dues were assumed to be the same in all ports, hence the values given apply to all the destination countries. The wharfage is the most significant, accounting for 81% of the total port dues. The loading and unloading times were considered to be one day each. The delivery of liquified hydrogen to each destination port involves loading

[1] Payment for using the berth where the shipping vessel may be moored or secured.

[2] This represents the fees often paid the government for using a public harbour or port in Canada.

[3] This is the fee charged at the export terminal before a ship is allowed to transport cargo or freight though it. It is often a compulsory fee paid for using the shipping yard to transport goods.

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Table 6 – Assumptions used for liquefaction plant analysis.

Parameter	Value	Comments/reference
Plant capacity	100 tonnes of hydrogen per day	Capacity feasible in the near to mid-term horizon [69,70]
Plant lifetime	30 years	From HDSAM [71].
Yearly operating hours	8760 h	For a regular year
Electricity price	$0.058/kWh	Relative price for large electricity consumption centres in BC
Duration for liquified hydrogen storage	15 days	To minimize any risk contingency with supply and shipping delays
Specific volume of liquid hydrogen	0.014 m^3/kg H_2	At 1 atm
Storage tank size for liquified hydrogen	3500 m^3	Maximum single tank capacity
Liquefaction plant electricity intensity (E_{H_2})	8.44 kWh/kg H_2	Based on Eq. 7
Liquefaction plant capital cost ($CAPEX_{LH}$)	$370.24 million	Based on Eq. 8
Liquefied hydrogen storage facility capital cost ($CAPEX_{Ls}$)	$9.95 million/unit	Adjusted to 2020 CAD [66]
Total annual operating cost	$35.91 million/year	Variable electricity costs + 4.10% of ($CAPEX_{Ls}$ + [6 × $CAPEX_{LH}$]).

Table 7 – Shipping distances and voyage days to the selected overseas destinations.

Destination	Shipping route	Estimated distance		Estimated one-way voyage days
		Nautical miles	km	
Japan	Burnaby to Port of Tokyo	4272	7912	10
	Kitimat to Port of Tokyo	3954	7323	9
	Prince Rupert to Port of Tokyo	3838	7108	9
China	Burnaby to Port of Shanghai	5110	9464	12
	Kitimat to Port of Shanghai	4794	8878	11
	Prince Rupert to Port of Shanghai	4678	8664	11
South Korea	Burnaby to Port of Busan	4623	8562	11
	Kitimat to Port of Busan	4132	7652	10
	Prince Rupert to Port of Busan	4196	7771	10
Germany	Burnaby to Port of Hamburg	9114	16,879	21
UK	Burnaby to Port of London	8820	16,335	21

Table 8 – Characteristics of the ship for overseas delivery.

Parameter	Values	Comments/Reference
Volume	80,000 m^3	[79]
Service speed	9 m/s	[79]
Boil-off	0.2% per day	[79]
Fill-up level of hydrogen storage	94% of capacity	[80]
Calm water resistance	970 kN	Obtained from calculations
Towing power	8.7 MW	Obtained from calculations
Brake power	13 MW	Obtained from calculations
Propulsion engine power	17 MW	
SFOC	158.7 g/kWh	From SFOC plot at 9 m/s
Carrier fuel type	IFO 380	[84]
Cost of carrier's IFO	$436/tonne	Average spot market price [85]
Calculated gross tonnage of carrier	54,589 tonnes	
Efficiencies		
Hull efficiency	100%	based on MAN [77]
Open water efficiency	62.5%	based on MAN [77]
Rotative efficiency	100%	based on MAN [77]
Shaft efficiency	95%	based on MAN [77]
Propulsion efficiency	68.7%	based on MAN [77]
Port fee, passage fees, and hiring costs		
Total port fees	$97,000	To all destination countries
Total passage fees	$291,684	Applicable to European destinations
Ship hiring cost (per voyage day)	$90,300	Applicable to European destinations

at the port in BC, unloading at the destination port, and return to BC. The total port fee calculated is approximately \$97,000. Shipping to Germany and the UK incurs an additional passage fee due to travel through the Panama Canal (Table 8). The hiring cost of the ship is approximately \$90,300 per voyage day; this is converted to 2020 CAD from the average sport charter rate of LNG carriers at the end of the year 2018 [83].

Similar to long-distance ammonia pipelines, the ammonia shipping cost is calculated as a function of the distance travelled (*k*) in km from the export terminal in BC to the overseas destination. The specific cost for ammonia shipping is shown in Eq. 10 from correlations developed in Okunlola et al. [10].

$$\textit{Ammonia shipping cost}\left(\$/_{kg\,H_2}\right) = (0.0000286 \times k) + 0.158 \qquad (10)$$

Hydrogen regasification and separation

Hydrogen regasification occurs at the destination port whereby liquified hydrogen is re-converted into gaseous hydrogen to facilitate domestic distribution. This is done by allowing the hydrogen to gain heat by passing it through a heat exchange unit. The regasification facility consists of storage tanks, liquified hydrogen pumps, and a heat exchange unit. In LNG regasification facilities, most of the capital cost in the regasification stage is from the storage tanks [86] and so only the cost associated with the storage tanks is considered here. The open rack vaporization unit design was adopted for hydrogen regasification because of its economic suitability and also because over 90% of vaporizers used at the export destinations assessed use this design [87]. The terminal also consists of liquid hydrogen storage tanks.

Hydrogen separation or extraction entails splitting hydrogen from either NG/hydrogen mixtures or ammonia at the respective destination. Pure hydrogen needs to be recovered from the hythane mix downstream or at the receiving import extraction station. While hydrogen can be recovered downstream, current recovery technology is limited to low hydrogen concentrations in the distribution pipeline network through low-pressure pressure swing absorption (PSA) [61]. The separated gases must be re-pressurized, increasing costs and energy requirements. Separation through PSA (at existing pressure points to avoid the additional compression requirements to reinject the NG into the system) is the most economically feasible method and is adopted in this research.

Hydrogen separation from ammonia at the destination country is also considered. Depending on the catalyst used, heat at high temperatures is supplied to dissociate ammonia into hydrogen and nitrogen [88].

Hydrogen regasification at the destination terminal. Since liquid hydrogen storage tanks are capital intensive, it is expected that the liquid hydrogen storage would account for the major cost at the regasification terminal [89]. Also, the cost data on the liquid hydrogen vaporizers are not publicly available, hence, only the cost associated with the storage tanks was considered. The storage capacity considered is that equivalent to the delivered volume of hydrogen for each destination. A 10% interest rate and a 20-year lifetime for amortization were considered to derive the annualized capital cost. The capital and operating costs of hydrogen regasification stations are based on the cost derived from the HDSAM [71]. The capital and annual operating costs of the regasification plant are given in Table 10. As shown in the table, the capital costs in the Asia-Pacific countries are similar. This is because of their relatively equal travel distances. Likewise, the capital costs in the UK and Germany are comparable, and about 2.5% less than those of the Asia-Pacific destinations (Table 10). The lower capital cost in Europe compared to the Asia-Pacific is a result of the lower delivered volume of hydrogen due to the higher boil-off impact driving the reduced hydrogen storage capacity.

Hydrogen extraction from hythane mixture at the destination. The cost of pure hydrogen recovery or separation from the hythane mixture with the PSA process is between \$0.44 and \$1.92/kg H_2 for 100–1000 kg H_2/day [61]. An average cost of \$1.18/kg H_2 was chosen for this paper.

Hydrogen separation from ammonia at the destination terminal. The extra cost of hydrogen extraction from ammonia at the overseas destination is \$1.07/kg H_2, obtained from available reconversion data [21], adjusted to 2020 CAD.

Results and discussion

The results are organized by presenting the analysis of the delivered costs of gaseous hydrogen from Alberta to inland and export destinations (Gaseous hydrogen delivery from

Table 9 – Fuel demand and boil-off of liquified hydrogen shipping to destination countries.

Destination	Export terminal	Fuel consumption (tonnes)	Hydrogen delivered (tonnes)	Boil-off quantity (tonnes)
Japan	Burnaby	1455	5216	108
	Kitimat	1348	5224	100
	Prince Rupert	1306	5227	97
China	Burnaby	1741	5195	130
	Kitimat	1634	5203	122
	Prince Rupert	1592	5206	118
South Korea	Burnaby	1574	5207	117
	Kitimat	1467	5215	109
	Prince Rupert	1431	5218	106
Germany	Burnaby	3106	5093	231
UK	Burnaby	3005	5101	224

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Alberta to BC, Eastern Canada, and California), followed by an analysis of the cost of hythane exports to the USA and Eastern Canada (Hydrogen delivery from Alberta to Eastern Canada and California using hythane). The results of the total supply chain delivered costs of hydrogen to Japan, South Korea, China, the UK, and Germany are analyzed in the Cost of delivering hydrogen to destination countries in the Asia-Pacific and Europe section, followed by a comparative assessment of the delivered costs with the domestic supply costs in the overseas destinations (Comparison of the hydrogen delivery costs from Alberta, Canada with domestic supply costs in the destination countries). Options to improve the cost-competitiveness of the inter-continental hydrogen export from Canada are assessed in the Options for cost reduction for overseas hydrogen delivery section, accompanied by a discussion of possible limitations to the study outcomes (Limitations section).

Gaseous hydrogen delivery from Alberta to BC, Eastern Canada, and California

Fig. 4 shows the overall costs of hydrogen delivery to British Columbia (BC)'s ports and destinations in Eastern Canada and California. The delivered cost is between \$2.99 and \$6.03/kg H_2. The contributions of the inland hydrogen pipeline costs to the total specific costs (72% of the delivered costs) are higher for longer distance inland delivery to the city-gate such as to Quebec (Eastern Canadian Province) than for shorter distance inland transport, i.e., to Burnaby in BC (where the pipeline costs represent 43% of the combined specific cost of hydrogen production and inland transport to the export terminal). In terms of the \$/kg per km delivered cost, the average pipeline transportation cost to all inland destinations is fairly equal at \$0.73/kg-km. The reformer unit, underground storage, and the PSA unit account for about 67% of the hydrogen production cost, while the pipeline capital costs contribute over 80% of the specific cost of the inland hydrogen transport through pipelines, with the operational costs accounting for the remainder.

Hydrogen delivery from Alberta to Eastern Canada and California using hythane

As detailed previously, to minimize the immediate capital cost of building a new gaseous hydrogen pipeline for inland exports, Alberta can export hythane to Manitoba and Ontario through the existing TC Mainline pipeline and to California through the GTN Foothills pipeline. As shown in Fig. 5, even with the inclusion of the cost of hydrogen extraction (or recovery) at the destination, exporting hythane through the existing long-distance NG pipeline networks is more than \$0.8/kg H_2 (16.7%) cheaper than gaseous hydrogen pipelines. From Fig. 5, the cost of low-pressure hydrogen recovery represents about 29–36% of the total cost of hythane delivery. The highest and cheapest cost of hythane delivery is through the GTN Foothills pipeline to California at \$4.03/kg H_2, and TC Mainline pipeline to Manitoba at \$3.27 kg H_2, respectively (Fig. 5).

Table 10 Capital and annual operating cost of the hydrogen regasification facility.

Destination	Export terminal	Capital cost (million \$)	Operating cost (million \$/year)
Japan	BC-Burnaby	371.61	12.65
	BC-Kitimat	372.18	12.70
	BC-Prince Rupert	372.18	12.70
China	BC-Burnaby	370.10	12.57
	BC-Kitimat	370.67	12.60
	BC-Prince Rupert	370.89	12.61
South Korea	BC-Burnaby	370.98	12.61
	BC-Kitimat	371.55	12.65
	BC-Prince Rupert	371.55	12.67
Germany	BC-Burnaby	362.86	12.19
UK	BC-Burnaby	363.40	12.21

Cost of delivering hydrogen to destination countries in the Asia-Pacific and Europe

Fig. 6 presents the overall costs of delivering hydrogen to Japan, South Korea, and China. The total delivery costs are lowest to Japan (\$6.65/kg H_2) and highest to China (\$6.99/kg H_2). This cost trend for the Asia-Pacific countries is due to their relative distances from the west coast of BC. Of the three export terminals to Asia, the specific delivery cost through the ports of Kitimat and Burnaby are the cheapest and the costliest, respectively (Fig. 6). The higher inland hydrogen pipeline transportation cost of gaseous hydrogen delivery from Alberta to the Prince Rupert terminal (\$3.12/kg H_2 as shown in Fig. 4) for liquefaction contributes to making hydrogen delivery through this route more costly than the Kitimat route in all cases.

As stated earlier, the shipping route to Europe is through the Panama Canal and the Atlantic Ocean and the delivery cost is calculated from Burnaby. As shown in Fig. 7, the average supply chain delivered costs of hydrogen to both Germany and the UK are approximately \$8.18/kg H_2 and \$8.14/kg H_2, respectively. Compared with delivery to Asia, the shipping and import terminal gasification specific costs increased from 11% to about 20% of the total supply chain costs. The farther travel/shipping distance from the Burnaby port in BC to Europe, compared to shipping to Asia, increases the overall costs of delivering hydrogen from Alberta to Germany and the UK. Despite having lower capital costs for the regasification supply chain, the specific cost of regasification in Europe is higher than in Asia-Pacific countries. Farther overseas delivery destinations get less hydrogen and, when aggregated on an annual basis (due to the lag time between deliveries), the specific cost of regasification is comparatively higher.

The hydrogen liquefaction process contributed the largest share of the delivered cost (about 37% and 31% of the total costs to Asia-Pacific and Europe, respectively). The capital cost accounted for about 59% of the specific cost of liquefaction, while the operating cost accounted for the remainder. The cost of utility (which is mainly electricity) accounted for about 48% of the operating cost. The electricity intensity of the process was found to be approximately 8.40 kWh/kg H_2 (the equivalent of 25% of the energy content in hydrogen), representing an electricity consumption of about 308 TWh/year. The shipping and import terminal regasification costs contribute the least to the delivered costs to all destination countries (approximately 8% and 10%, respectively). The

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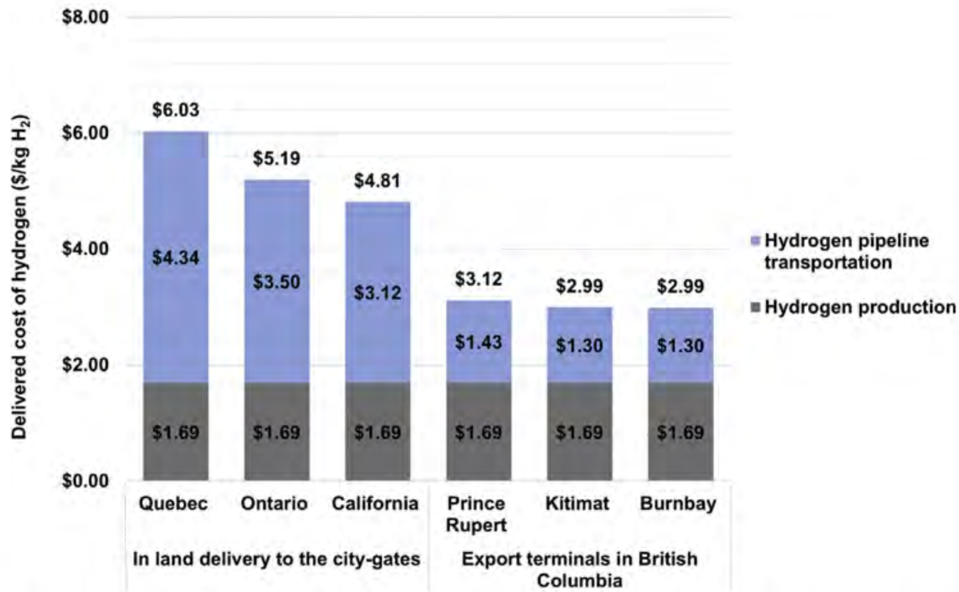

Fig. 4 – Specific costs of gaseous hydrogen delivery to BC, Eastern Canada, and California from Fort Saskatchewan in Alberta. 232.38, 223.69, and 224.93 million kg H_2 per year are delivered to the city-gates of Quebec, Ontario, and California USA, respectively (in-city distribution costs are omitted). 232.69, 224.93, and 232.69 million kg H_2 per year are transported through the inland pipeline to the export terminals Burnaby, Kitimat, and Prince Rupert in BC, respectively. Fig. 1b shows the straight-line inland transport route, and Table 1 shows the inland pipeline distance to each location.

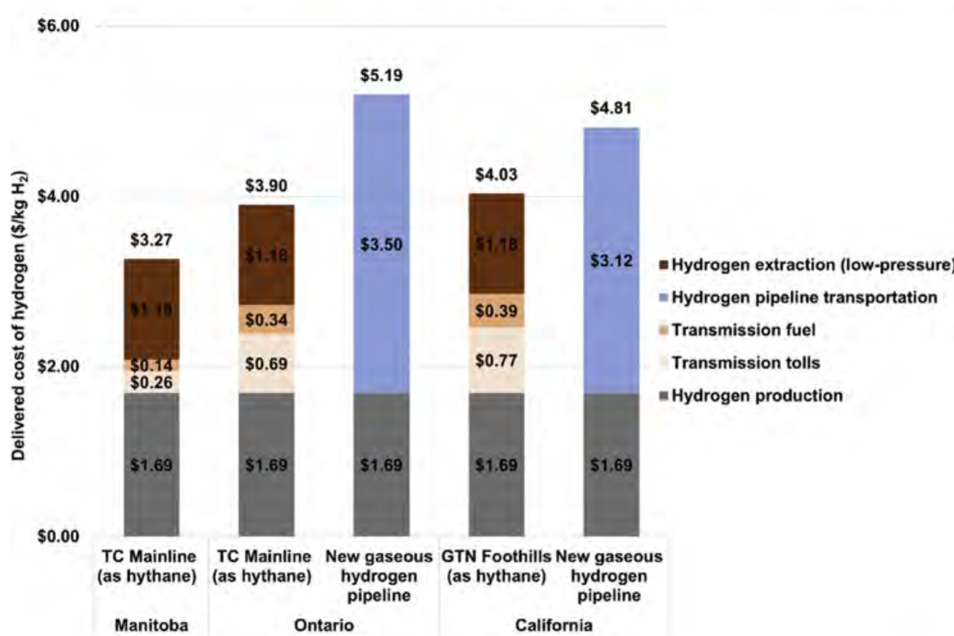

Fig. 5 – Delivered cost of hydrogen as hythane to the destination locations vs gaseous hydrogen pipelines from Alberta. Hydrogen is produced from Fort Saskatchewan in Alberta: 223.69, and 224.93 million kg H_2 per year are delivered to the city-gates of Ontario and California USA, respectively (in-city distribution costs are omitted). 1.32, 1.20, and 1.05 million kg H_2 per year are exported in form of hythane to the city-gates in Manitoba, Ontario and California USA, respectively, through the stated existing NG pipelines. Hythane transport costs include pipeline tolls and fuel costs. These costs represent fees for the pipeline losses and up to 80 kJ/GJ-km of the gas [90] during transport through the existing NG pipelines ([64,65]) to the chosen destinations.

hiring cost of the hydrogen ship accounted for over 62% of the specific cost of shipping (Fig. 8). The shipping costs per kg range from $0.51/kg H_2 (Port of Prince Rupert to the Port of Tokyo) to $0.69/kg H_2 (Burnaby to the Port of Shanghai). Shipping to Europe is more expensive than to the Asia-Pacific by more than a factor of 1.85. The range in the shipping costs

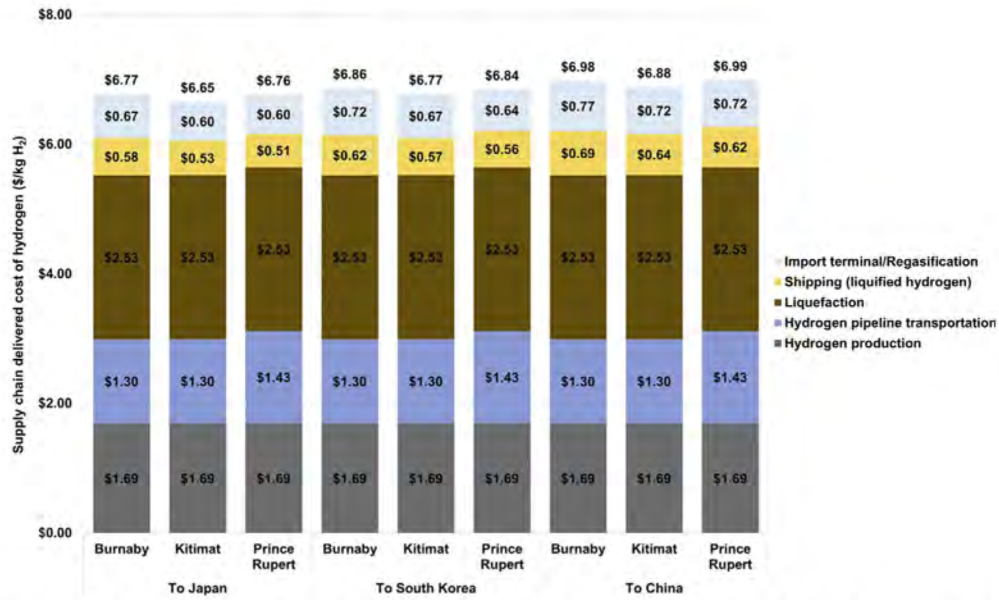

Fig. 6 — Breakdown of the total delivered costs of gaseous hydrogen to destinations in the Asia-Pacific from three Canadian ports on the Pacific Ocean. About 5.22, 5.21, and 5.20 million kg H_2 per year are delivered to the Port of Tokyo in Japan, Busan port in South Korea, and Port of Shanghai in China, respectively (in-city distribution costs are omitted). Fig. 1c shows the straight-line shipping route. Table 7 shows the shipping distance to each destination.

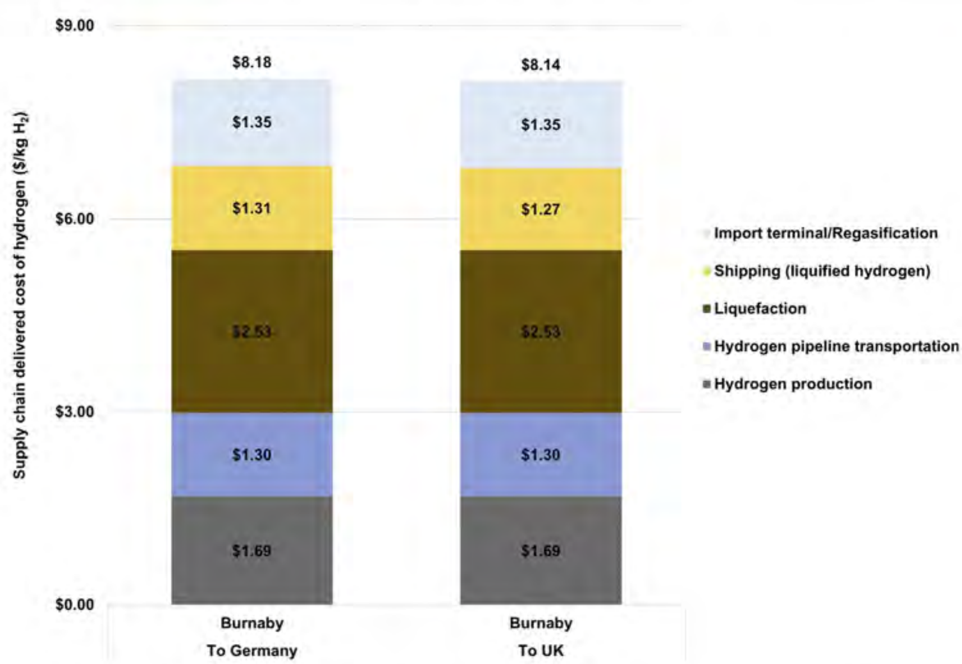

Fig. 7 Breakdown of the supply chain delivered costs of gaseous hydrogen to Germany and the UK from a western Canadian port through the Panama Canal and the Atlantic Ocean. About 5.09 and 5.10 million kg H_2 per year is delivered to the Port of Hamburg, Germany, and Port of London, UK, respectively (in-city distribution costs are omitted). Fig. 1d shows the straight-line shipping route. Table 7 shows the shipping distance to each destination.

is mainly due to the differences in the shipping distance (which also influences the volume of hydrogen that evaporates because of boil-off during the voyage, with farther destinations having higher specific shipping costs). The farther shipping distance to Europe also added to fuel costs and the passage fees through the Panama Canal (Fig. 8).

Comparison of the hydrogen delivery costs from Alberta, Canada with domestic supply costs in the destination countries

To assess the cost-competitiveness of hydrogen exports from Alberta to Asia and Europe, we compared the total supply

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chain supply costs (presented in Fig. 9) with domestic hydrogen supply costs in the destination countries.

For exports to the Asia-Pacific, we compared the delivered cost with the supply cost of hydrogen reported by APERC [20]. The APERC data allows us to compare the regional costs of hydrogen production for Japan, China, and South Korea; the cost assumptions are also comparable with the IEA's estimates [21]. In the case of Japan, domestic hydrogen production from electrolysis through solar and wind was reported to be approximately \$7.31/kg H_2 and \$6.89/kg H_2, respectively. Hence, hydrogen delivered from Alberta may be cost-competitive with both domestic electrolytic hydrogen supply sources in Japan (as shown in Fig. 9). For South Korea, the reported hydrogen production cost from both solar and wind is at least ~\$8.11/kg H_2, which is \$1.34/kg H_2 more than the lowest-cost delivery option to South Korea, suggesting an opportunity to deliver hydrogen from Alberta to the country (Fig. 9). As shown in Fig. 9, the domestic supply cost of hydrogen in China was reported to range between \$3.460/kg H_2 (for coal gasification with CCS) and \$5.30/kg H_2 (for wind-based electrolysis); this cost range also includes solar- and hydro-based electrolysis. Our assessment shows that hydrogen export to China from Alberta is more expensive than domestic production in China and therefore may not be cost-competitive.

Estimates of the current supply cost of blue hydrogen production in Germany are scarce. However, the IEA forecasts the cost of SMR-CCS in Germany to be about \$2.73/kg H_2 in 2030 [91]. Coleman et al. estimated the cost of hydrogen production from electrolysis using wind power for a power-to-gas plant to be in the range of \$5.40/kg H_2 to \$9.80/kg H_2, depending on the production rate [92]. Hydrogen production costs have been estimated for wind- and grid-based electrolysis in Germany to be \$5/kg H_2 and \$7.70/kg H_2, respectively [93]. Comparatively, from Fig. 9 (lower right side), our results show that the delivered hydrogen cost from Alberta (\$8.10/kg H_2) is uncompetitive with average domestic hydrogen production in Germany from either electrolysis or SMR-CCS. However, it is important to note that the production of large-scale green hydrogen may be challenging in the short to medium term in Germany. whilee blue hydrogen from Alberta can be produced on a large scale in the very short term. This provides an opportunity for blue hydrogen exports from Alberta to play a key role in the energy transition in Germany.

For comparison with the domestic hydrogen supply cost in the UK, the UK Hydrogen and Fuel Cell SUPERGEN (H2FC) hub forecasted that the cost of hydrogen production would be between \$2.850/kg H_2 (for SMR-CCS) and \$5.33/kg H_2 (for electrolysis) in 2020 without a carbon tax [94]. Another study reported domestic large-scale hydrogen production cost as \$2.96/kg H_2 (for SMR-CCS) to \$7.31/kg H_2 (for electrolysis) [95]. Given these reported costs in the UK, the calculated delivered cost of hydrogen from Alberta (\$8.10/kg H_2) is not competitive with average domestic hydrogen supply costs in the UK, especially with the domestic hydrogen supply cost from SMR-CCS (Fig. 9).

In general, we observed that hydrogen exported from Alberta is cost-competitive with electrolytic hydrogen supply costs in Japan and Korea, but uncompetitive with domestic hydrogen supply costs in China, Germany, and the UK in the long term. However, the need to diversify the sources of hydrogen supply beyond domestic production for energy and supply security reasons in Europe in the future could provide gradual access for delivered hydrogen from Alberta, Canada.

Comments on adopting other low-carbon hydrogen production pathways in Alberta on the delivered cost of hydrogen

Shifting to other alternative NG-based low-carbon production pathways with higher CC rates or lower GHG emissions, such as SMR-CCS with 85% CC, ATR-CCS, natural gas decomposition with CCS (NGD-CCS), and wind-based electrolysis may increase the hydrogen delivered cost to the destination

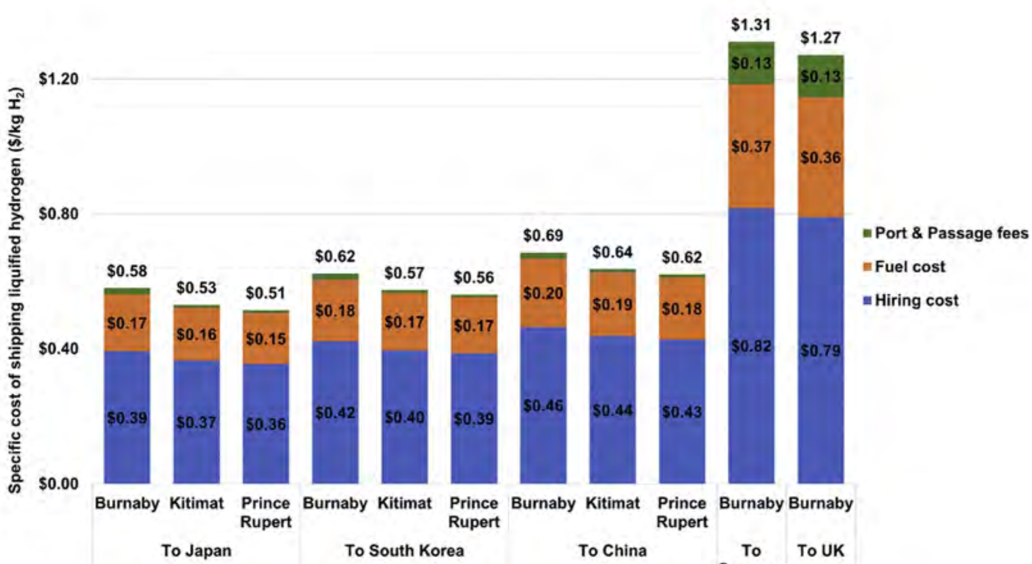

Fig. 8 – Breakdown of the shipping costs to the Asia-Pacific and Europe from western Canadian ports.

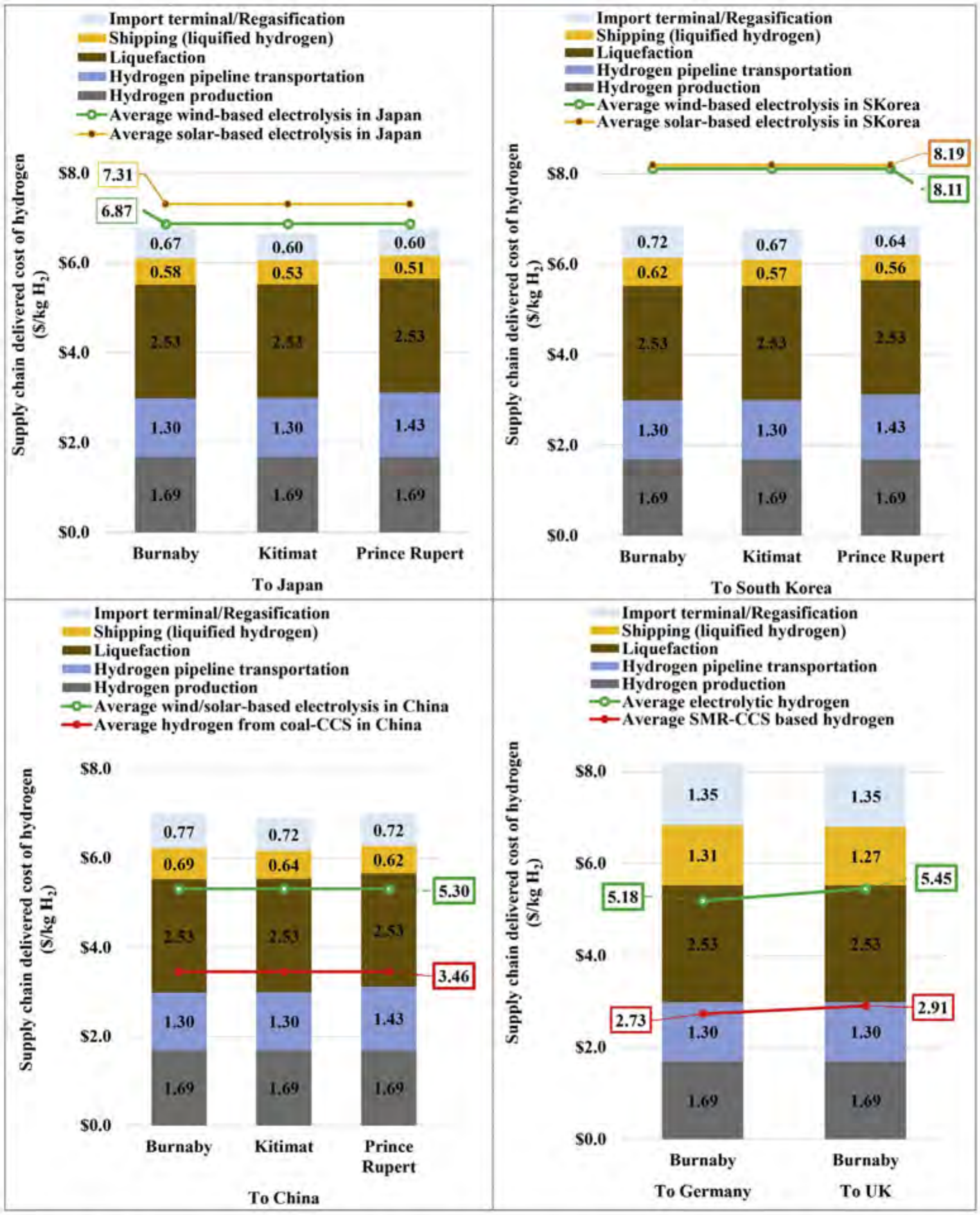

Fig. 9 Comparing the total supply chain delivered cost of gaseous hydrogen from Alberta, Canada with domestic supply costs in overseas destinations.

countries: we refer the reader to SI-section A2 for process descriptions of hydrogen production through ATR-CCS, NGD-CCS, and wind-based electrolysis.

As Table 11 shows, ATR-CCS minimally reduces the delivered cost to all destinations by 2% in the long term. But switching to SMR-CCS with 85% CC and NGD-CCS increases the delivered cost of hydrogen by 40% and 51%, respectively, to all destinations. Switching to wind-based electrolysis in Alberta with a hydrogen production cost of over $3.4/kg [45,46,48] doubles the delivered hydrogen cost to the destination countries, making it unsustainable to support long-term hydrogen exports from Alberta. A previous study also showed that the cost of SMR–CCS–based hydrogen production increases as the price of carbon increases: a carbon price of $150/tonne of CO_2 results in hydrogen production costs of $2.69/kg H_2 for SMR-CCS 52% CC [10], making the exported hydrogen about 59% costlier than without a carbon price and less cost-competitive with domestic production costs in the destination countries assessed.

Options for cost reduction for overseas hydrogen delivery

Increasing the pipeline diameter for inland gaseous hydrogen delivery

The impact of increasing the diameter of the long-distance hydrogen pipeline from Alberta to the export terminals in BC was assessed. Instead of the standard twelve-inch (12″) diameter pipeline, eighteen-inch (16″) diameter pipelines were considered. The larger pipeline would reduce the number of compressor stations required over the pipeline distance from 18 to 6. The associated capital and operational costs for the inland pipeline transportation stage of the export supply chain are reduced by an average of 7% and 64%, respectively (data provided in SI-Table A4). The OPEX reduction is driven primarily by the lowered electricity cost required to power the compressors and other ancillary units at the compressor stations (due to the lower number of stations), and thus, the specific cost of the inland hydrogen pipeline transportation stage decreases by about 33%.

Using Japan as the case study, we found that the overall supply chain delivered cost of gaseous hydrogen from Alberta to that country could drop from $6.65 to $6.24/kg H_2. This drop represents a 6.17% cost reduction sufficient to provide improved cost-competitiveness with domestic hydrogen supply or production options in Japan (Fig. 10).

Delivering hydrogen with ammonia as the primary carrier

The delivery cost of hydrogen from Alberta to Japan using ammonia as the carrier is about $4.93/kg H_2; this is at least 25.68% and $1.71 cheaper than delivering gaseous hydrogen (in liquefied form) from the shipping port in western Canada to the destination port in Japan (Fig. 11). Despite the inclusion of the reconversion costs of hydrogen from ammonia, the delivered cost to Japan is more cost-competitive with domestic production ($4.94/kg H_2 vs $7.09/kg H_2), thus, justifying the use of ammonia as the carrier. Using ammonia as the hydrogen carrier largely eliminates the significant liquefaction cost portion (about 37% of total supply chain cost) in the delivered cost of gaseous hydrogen through pipelines.

Limitations

The uncertainty associated with modelling and data (i.e., slopes and elevation of pipeline routes, the natural gas price, capital costs, interest rates, and electricity price) could influence the outcomes of this study. For instance, an increase in the interest rate from 10% to 20% could increase the hydrogen production cost by 18.8%, which could impact the long-term cost-competitiveness of hydrogen exports [49]. Similarly, the study assumes a single liquefaction plant capacity of at least 100 tonnes of hydrogen per day. Based on the power law that shows the proportionality between plant capacity and capital cost through the relative change in quantities, a reduction in the liquefaction plant scale could mean a higher capital cost per unit throughput, hence, an overall higher specific delivery cost to the destination countries. To leverage the benefits of economies of scale, developing and operating the system at maximum capacity is essential to align with the outcomes of this study. Some physical and socio-technical limitations on the hydrogen export infrastructure are also of concern.

Acceptance of hydrogen by the customer. Exporting hydrogen to Eastern Canada and California as hythane in existing long-distance NG pipelines is cheaper than in pure hydrogen pipelines by about $0.78 to $1.29/kg H_2 (with the hydrogen extraction cost) and $1.96 to $2.47/kg H_2 (without the hydrogen extraction cost). However, consumers (especially industrial users) that typically extract pure NG at different junctions along the pipeline route must be ready to accept hythane and also incur additional charges to separate NG from the mixture (at varying pressure levels).

Table 11 – Comparing the delivered cost of hydrogen to the chosen destinations based on different low-carbon hydrogen production pathways in Alberta. Hydrogen production costs for each respective production technology are the same for each shipping destination/route.

Destination	Canadian Shipping Port	SMR-CCS 52% CC		SMR-CCS 85% CC[a]		ATR-CCS 91% CC[b]		NGD-CCS 89% CC[b]		Wind-based electrolysis[c]	
		Hydrogen production ($/kgH$_2$)	Delivered cost ($/kgH$_2$)	Hydrogen production ($/kgH$_2$)	Delivered cost ($/kgH$_2$)	Hydrogen production ($/kgH$_2$)	Delivered cost ($/kgH$_2$)	Hydrogen production ($/kgH$_2$)	Delivered cost ($/kgH$_2$)	Hydrogen production ($/kgH$_2$)	Delivered cost ($/kgH$_2$)
Quebec (city-gate)		$1.69	$6.03	$2.36	$6.70	$1.66	$6.00	$2.55	$6.89	$3.42	$7.76
Ontario (city-gate)			$5.19		$5.86		$5.16		$6.05		$6.92
California (city-gate)			$4.81		$5.48		$4.78		$5.67		$6.54
Japan	Burnaby		$6.77		$7.44		$6.74		$7.63		$8.50
	Kitimat		$6.65		$7.32		$6.62		$7.51		$8.38
	Prince Rupert		$6.76		$7.43		$6.73		$7.62		$8.49
South Korea	Burnaby		$6.86		$7.53		$6.83		$7.72		$8.59
	Kitimat		$6.77		$7.44		$6.74		$7.63		$8.50
	Prince Rupert		$6.84		$7.51		$6.81		$7.70		$8.57
China	Burnaby		$6.98		$7.65		$6.95		$7.84		$8.71
	Kitimat		$6.88		$7.55		$6.85		$7.74		$8.61
	Prince Rupert		$6.99		$7.66		$6.96		$7.85		$8.72
Germany	Burnaby		$8.18		$8.85		$8.15		$9.04		$9.91
UK	Burnaby		$8.14		$8.81		$8.11		$9.00		$9.87

[a] Hydrogen production cost in Alberta from Okunlola et al. [10].
[b] Hydrogen production cost in Alberta from Oni et al. [49].
[c] Hydrogen production cost in Alberta from Olateju et al. [45,46,48].

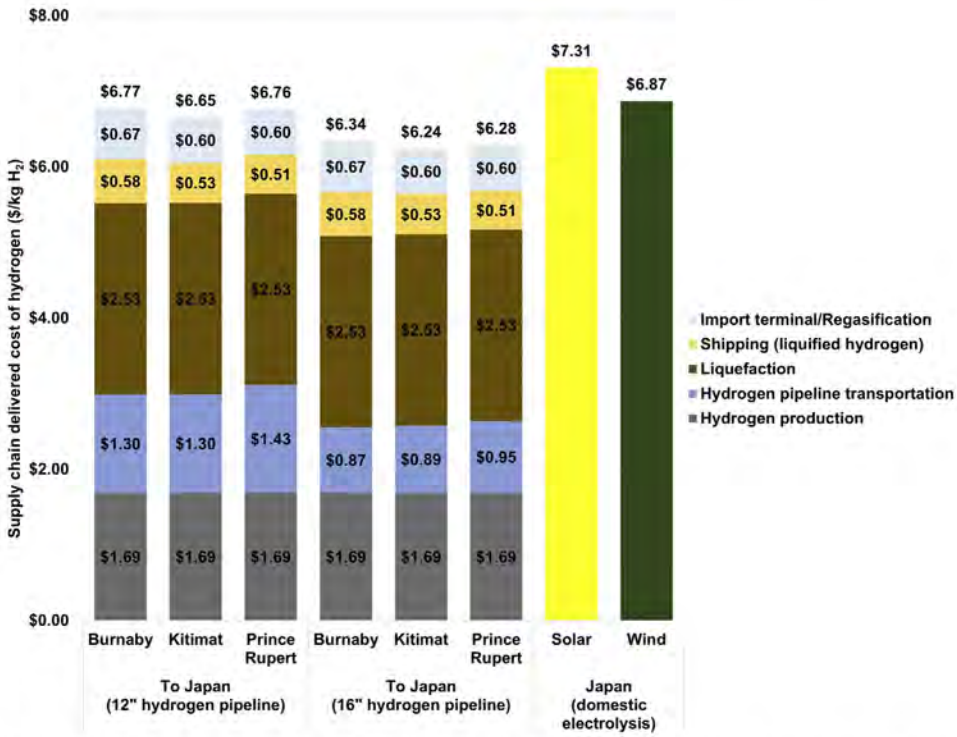

Fig. 10 – Delivered cost of hydrogen to Japan by increasing the inland hydrogen pipeline diameter from Alberta to the export terminals in BC from 12″ to 16″ compared to domestic production in Japan.

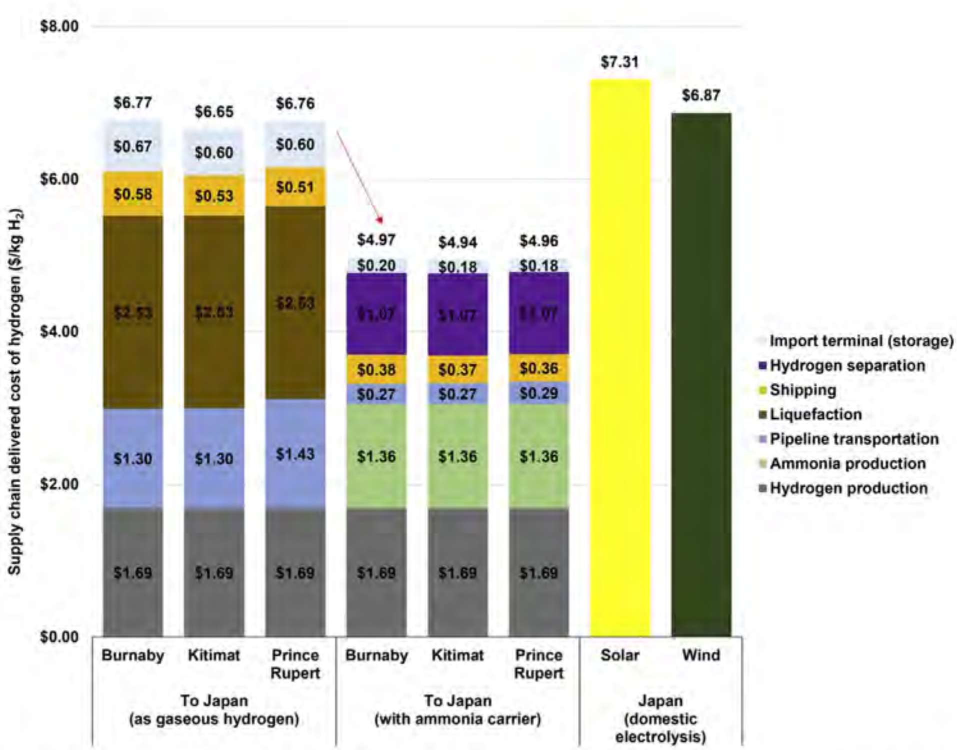

Fig. 11 – Delivered cost of hydrogen from Canada to Japan through ammonia and compressed/liquefied hydrogen via pipeline compared to domestic production in Japan.

Pipeline integrity. Due to the small molecular size of hydrogen, hydrogen pipelines are susceptible to leaks [96,97]. Safety issues with large-scale hydrogen pipelines need to be investigated. Hydrogen has low ignition energy of about 0.019 MJ compared to other flammable gases like ethane and methane (with ignition energy of 0.1 MJ) [96]. Consequently, there is a risk of explosion for hydrogen pipelines. Hydrogen embrittlement of the pipe material is a principal concern. Steel materials and weld joints can lose their ductility from the effect of hydrogen embrittlement [97].

Scale of hydrogen liquefaction plants and shipping vessels. The largest hydrogen liquefaction plant is reported to operate at 34 tonnes/day [98] and most of the recently built ones operate in the range of 5–10 tonnes/day [68,70]. At the current scale, several units would be required to satisfy the potential hydrogen export demand. This presents an economic challenge since economies of scale would not apply. To address this issue, liquefaction facilities with larger capacity are required. The scale-up of liquefied hydrogen plants has slowed down over the years given the low demand for hydrogen [70]. The practical maximum capacity for liquefied hydrogen is still uncertain but has not exceeded 35 tonnes/day; however, industry professionals have suggested that it could be increased to 100 tonnes/day, although such scale-up may be limited by component manufacturing [69,70]. Furthermore, unlike LNG carriers, liquified hydrogen carriers are not readily operational to support large-scale overseas hydrogen shipping. Nonetheless, there is a growing recognition for the need to build liquified hydrogen carriers, and Kawasaki Heavy Industries, Ltd. is constructing the first liquid hydrogen ship/carrier in Japan with a carrying capacity of 1250 m^3 [99].

Public perception of CCS. Hydrogen exports to Europe may be impacted negatively by unfavourable public perception of CCS technology. Studies show that many stakeholders in Europe do not favour the scale-up of CCS technology mainly because of the perception that CO_2 emissions should be reduced primarily by large-scale deployment of zero-emission renewable energy solutions [100,101]. However, achieving high carbon capture levels/rates and low life cycle CO_2 emissions in Alberta, at par with alternative RE-based hydrogen production pathways, could provide an option to the negative public perception towards NG-based hydrogen exports from Canada to the continent, provided the hydrogen is cost-competitive. This study did not consider possible penalties for NG-based hydrogen exports.

We note that this study investigated only the associated costs of hydrogen exports from Alberta, Canada to suitable destinations. Cost comparison with exports from other competing countries, such as cost-competitiveness with hydrogen exports from Australia to Japan, or North Africa to Germany, is not addressed in this study. In literature, low-carbon hydrogen exports to Japan from competing countries like Argentina and Australia have been found to fall between \$3.93 and \$12.77/kg H_2 [16,17,19,102] and about \$6.09 to \$7.27/kg H_2 from Chile [103] (adjusted to 2020 CAD). The variability in cost is due to variation in the primary hydrogen production pathway, carrier type, and quantity produced. Hydrogen exports from North Africa to Europe cost between \$6.34 and \$8.42/kg H_2 (adjusted to 2020 CAD) [104]. These cost ranges indicate that large-scale low-carbon blue hydrogen export from Alberta at roughly \$6.28/kg H_2 to either Japan or South Korea (owning to South Korea's geographical closeness to Japan) may compete with others. Alberta's blue hydrogen export is more expensive than North African hydrogen supplied to Europe. However, a comprehensive comparative analysis is required to identify the jurisdiction with the lowest overall supply chain cost of low-carbon hydrogen exports to the international destinations covered by this study. The comparative analysis should apply a common analytical boundary that considers the life cycle GHG footprint of the hydrogen production pathways in the exporting countries and the supply side constraints on hydrogen exports from each country to the international destinations covered by this study.

Conclusions

This study assessed the specific cost of delivering gaseous hydrogen from Alberta (Western Canada) to Eastern Canada (Manitoba, Quebec, and Ontario), California (USA), three Asia-Pacific countries (Japan, South Korea, and China), and two European countries (Germany and the United Kingdom). The assessment encompassed five supply chain stages: low-carbon hydrogen production from steam methane reforming integrated with 52% carbon capture and sequestration, long-distance inland hydrogen pipeline, hydrogen liquefaction, shipping, and regasification at the relevant import destinations. Three overseas export terminals at British Columbia (western Canada coast) were considered for gaseous hydrogen liquefaction and shipping.

The cost of hydrogen delivered from Alberta, Canada was found to be cost-competitive with primary domestic hydrogen production pathways in Japan and South Korea such as wind- or solar-based electrolysis. In China and Europe, the domestic supply of hydrogen through steam methane reforming with carbon capture and sequestration, coal gasification with carbon capture and sequestration, and electrolysis were found to be cheaper than the total supply chain cost of delivering gaseous hydrogen from Alberta. Thus, exports to these destinations are not cost-competitive in the immediate term. From our analysis on cost reduction options, delivering hydrogen as hythane (15% hydrogen with 85% natural gas by volume) through existing long-distance natural gas pipeline infrastructure to Ontario (an eastern province in Canada) and California, USA lowers the delivered cost by 25% and 16.7%, respectively. For overseas hydrogen delivery, we found that increasing the pipeline diameter reduces the number of compression stations required along the pipeline route to the liquefaction facility. Applying this option ensures a considerable drop in the total cost of the hydrogen pipeline infrastructure and reduces costs by 7.4%, sufficient to provide cost-competitiveness with domestic hydrogen production options in Japan. Alternatively, eliminating the requirement of liquefaction at the export terminal by using ammonia as the hydrogen carrier leads to cost savings of about 27.9% in the total overseas delivered cost of hydrogen from Alberta, Canada despite additional costs of ammonia production and hydrogen extraction from the compound.We also investigated using lower-carbon advanced hydrogen production technologies of steam methane reforming with 85% carbon capture, autothermal reforming with 91% carbon capture, and natural gas decomposition with 89% carbon capture. We found that only autothermal reforming with 91% carbon capture produces delivered costs close to the main analysis, thus retaining our conclusions based on hydrogen from steam methane reforming with 52% carbon capture. Since autothermal reforming provides a substantially lower carbon footprint, it may be the chosen technology to provide hydrogen export as international low-carbon hydrogen standards are developed and carbon prices increase.

To justify the export of low-carbon hydrogen to the Asia-Pacific, the delivered hydrogen from Alberta needs to be cheaper than or be cost-competitive with alternative delivery options from other countries such as Australia (considered to be best suited to supply low-carbon hydrogen to Japan and South Korea). Low-carbon gaseous hydrogen from Alberta, Canada offers a low-cost alternative source of hydrogen for Japan and South Korea at a time when policymakers in both countries are trying to diversify their hydrogen supply mix, minimize energy security risks, and meet their emissions reduction obligations. Leveraging the existing export supply chain for ammonia commodity trade, especially to Japan, can create an economic prospect for the province. As stated earlier, delivering low-carbon hydrogen from Alberta, Canada to Europe is uncompetitive with domestic blue hydrogen and electrolytic hydrogen production. However, there may be an opportunity for export in the short term as electrolysis technology is still developing and the demand for low-carbon hydrogen could exceed the domestic supply in Germany and the United Kingdom.

Further research should address the cost competitiveness of large-scale hydrogen export from western Canada to Japan or South Korea with exports from other viable low-carbon hydrogen-producing jurisdictions with sufficient trading links to both destinations. The study should integrate a common analytical boundary that considers demand and supply dynamics, life cycle GHG emissions, and policy costs within the exporting country. The results of this could help in policy formulation and investment decisions by decision-makers across the globe.

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.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.ijhydene.2021.12.025.

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TECHNO-ECONOMICS OF A NEW HYDROGEN VALUE CHAIN SUPPORTING HEAVY DUTY TRANSPORT

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The Transition Accelerator
L'Accélérateur de transition

TECHNO-ECONOMICS OF A NEW HYDROGEN VALUE CHAIN SUPPORTING HEAVY DUTY TRANSPORT

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ABOUT THE TRANSITION ACCELERATOR

The Transition Accelerator (The Accelerator) exists to support Canada's transition to a net zero future while solving societal challenges. Using our four-step methodology, The Accelerator works with innovative groups to create visions of what a socially and economically desirable net zero future will look like and build out transition pathways that will enable Canada to get there. The Accelerator's role is that of an enabler, facilitator, and force multiplier that forms coalitions to take steps down these pathways and get change moving on the ground.

Our four-step approach is to understand, codevelop, analyze and advance credible and compelling transition pathways capable of achieving societal and economic objectives, including driving the country towards net zero greenhouse gas emissions by 2050.

1 UNDERSTAND the system that is being transformed, including its strengths and weaknesses, and the technology, business model, and social innovations that are poised to disrupt the existing system by addressing one or more of its shortcomings.

2 CODEVELOP transformative visions and pathways in concert with key stakeholders and innovators drawn from industry, government, indigenous communities, academia, and other groups. This engagement process is informed by the insights gained in Stage 1.

3 ANALYZE and model the candidate pathways from Stage 2 to assess costs, benefits, trade-offs, public acceptability, barriers, and bottlenecks. With these insights, the process then re-engages key players to revise the vision and pathway(s), so they are more credible, compelling, and capable of achieving societal objectives that include major GHG emission reductions.

4 ADVANCE the most credible, compelling, and capable transition pathways by informing innovation strategies, engaging partners, and helping to launch consortia to take tangible steps along defined transition pathways.

ABOUT THE AUTHORS

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TRANSITION ACCELERATOR

Mohd Adnan Khan, PhD, is as an Energy Systems Analyst who joined the Transition Accelerator to help design pathways towards the establishment of a sustainable energy future. Adnan has a PhD in Material Science and Engineering and is passionate about working on renewable energy systems and contributing to the development of a future H_2 economy. He has over 8 years of industrial and academic experience leading research teams across the value chain of technology development and commercialization, driving innovation, and fostering collaboration among industry, government, and academia. He has published over 35 articles in top scientific journals, has 7 granted patents and now hopes his work will lead to the spin-out of consortia led projects, get change moving on the ground and help drive Canada towards a net-zero future.

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TRANSITION ACCELERATOR

David B. Layzell, PhD, FRSC is an Energy Systems Architect with the Transition Accelerator, a Faculty Professor at the University of Calgary, and Director of the Canadian Energy Systems Analysis Research CESAR Initiative. Between 2008 and 2012, he was Executive Director of the Institute for Sustainable Energy, Environment and Economy (ISEEE), a cross-faculty, graduate research, and training institute at the University of Calgary. Before moving to Calgary, Dr. Layzell was a Professor of Biology at Queen's University, Kingston (cross appointments in Environmental Studies and the School of Public Policy), and Executive Director of BIOCAP Canada, a research foundation focused on biological solutions to climate change. While at Queen's, he founded a scientific instrumentation company called Qubit Systems Inc. and was elected 'Fellow of the Royal Society of Canada' (FRSC) for his research contributions.

FIGURES, TABLES, BOXES

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LIST OF ABBREVIATIONS

ABBREVIATION	DEFINITION
AIH	Alberta Industrial Heartland, a region in Alberta which includes Edmonton, Strathcona, Fort Saskatchewan, Sturgeon, and Lamont counties
ATR	Autothermal Reforming
BEB	Battery Electric Bus
Blue H_2	Hydrogen produced from natural gas with carbon capture and storage
CESAR	Canadian Energy Systems Analysis Research
CCS	Carbon Capture and Storage
CCSU	Carbon Capture, Storage and Utilization
CO_2	Carbon Dioxide
CRF	Capital Recovery Factor
DTE	Drivetrain Efficiency
EOR	Enhanced Oil Recovery
EWMC	Edmonton Waste Management Centre
FCEB	Fuel Cell Electric Bus
GHG	Greenhouse Gas
GJ	Gigajoule (10^9 Joules)
Green H_2	Hydrogen produced by water electrolysis using intermittent zero-carbon electricity generated from wind and solar facilities
Gray H_2	Hydrogen produced from natural gas or coal without carbon capture and storage

H_2	Hydrogen
HDV	Heavy-Duty Vehicle: Vehicles with a gross vehicle weight rating >= 15 metric ton or tonne
HFCEV	Hydrogen Fuel Cell Electric Vehicle
HFS	Hydrogen Fueling Station
HHV	Higher Heating Value
ICE	Internal Combustion Engine
IF	Installation Factor
LCOH	Levelized Cost of Hydrogen
LDV	Light-Duty Vehicle
LH_2	Liquid Hydrogen
MDV	Medium-Duty Vehicle
NG	Natural Gas
NWR	Northwest Redwater
O&M	Operations and Maintenance
PJ	Petajoule (10^{15} Joules)
SF	Scale Factor
SMR	Steam Methane Reforming
SUT	Single Unit Truck
TCI	Total Capital Investment
TIC	Total Installed Cost
UC	Uninstalled Cost

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EXECUTIVE SUMMARY

Concerns about the adverse impacts of climate change have led Canada and other nations around the world to commit to net-zero greenhouse gas (GHG) emissions by 2050. The distributed, end use combustion of fossil-carbon based energy carriers (gasoline, diesel, jet fuel, natural gas) accounts for almost half of Canada's GHG emissions and another 24% can be attributed to their recovery and upgrading [1]. Clearly, the transition pathway to net-zero requires new energy systems where traditional fossil-carbon based fuels are replaced with zero-emission energy carriers that are produced with minimal or no GHG emissions.

While low carbon electricity will play a major role in replacing carbon-based fuels, there are certain sectors that require a zero-emission chemical energy carrier like hydrogen gas (H_2). Hydrogen is seen as the zero-emission fuel of choice for sectors such as heavy-duty transport, space heating in cold climates, many industrial sectors and as a backup for intermittent renewables in power generation.

The use of low GHG hydrogen to decarbonize our energy systems is of particular relevance in Alberta. The province is strategically positioned to be a global H_2 leader, blessed with excellent wind and solar resources to support electrolytic low GHG 'green' hydrogen production, as well as abundant natural gas and the geology for permanent CO_2 storage to make low GHG 'blue' hydrogen from fossil fuels.

Alberta currently produces more than 5000 tons of low-cost H_2 (about 0.9 to 1.4 C$/kg$_{H2}$) per day, but most is coupled to significant emissions of GHGs, and virtually all is used as industrial feedstocks for the production of crude oil, fertilizers, fuels, and chemicals. Decarbonization of the province's hydrogen has the potential to reduce the carbon intensity of these industrial processes, generate zero emission fuels for export to other nations, and provide low GHG fuel hydrogen to decarbonize domestic transportation, space heating and power generation.

Based on Alberta's energy system in 2018 [2], the potential domestic fuel hydrogen market is about 13,000 t_{H2}/year, with transportation accounting for 21%, building space and water heating for 37%, and industrial heat and power generation for 42%. However, the successful buildout of a fuel hydrogen economy will require the creation of new value chains that will connect hydrogen supply to new demand sectors and make hydrogen available at a reasonable cost at widely distributed locations.

Since Canadians pay 5 to 10 times more per unit of energy for transportation fuels than for heating fuels, the transportation fuel market for hydrogen, especially for heavy-duty vehicles, holds the greatest promise for early adoption. In the transportation fuel market, target retail prices for hydrogen should be in the range of 5 to 8 C/kg_{H2}$ to be competitive with the current prices for diesel. For heating markets in a net-zero future, retail hydrogen prices of 2-3 C/kg_{H2}$ is a reasonable target.

This report presents the design and techno-economic analyses of new value chains for delivering hydrogen from centralized production sites to fueling stations supporting heavy duty vehicles, including trucks, buses, and trains. It builds on earlier studies from CESAR [3-5] and the Transition Accelerator [6-8], that show hydrogen to be the net-zero fuel of choice for heavy duty vehicles, and analysis on the techno-economics of compressing and pipelining hydrogen [9,10].

While the findings presented here should have relevance to any region of Canada interested in centralized, low GHG hydrogen production, the model parameters were chosen for their relevance to the Edmonton Region Hydrogen HUB (https://erh2.ca/), where different sized (0.4, 2 or 8 t_{H2}/day) hydrogen fueling stations (HFS) were assessed at distances of 5, 40 or 300 km from a centralized production facility.

Three hydrogen transportation modes were considered including: (A) compressed hydrogen in tube trailers (TT) trucked to stations, (B) liquid hydrogen (LH_2) in cryogenic tanks trucked to stations, and (C) compressed hydrogen in pipelines to the station. Detailed techno-economic analyses of the various processing units across the different value chains revealed the pre-tax, refueling costs of hydrogen which were then compared with what is needed to be competitive with diesel fuel without public subsidies.

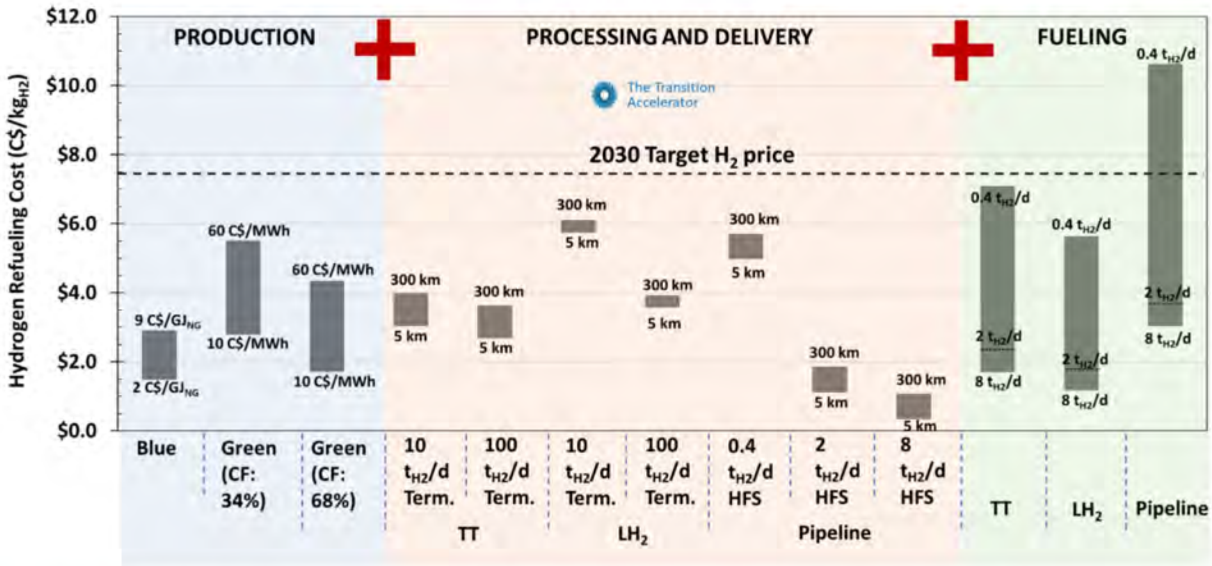

Figure ES. 1. Refueling cost of hydrogen (C$/$kg_{H2}$) for the different Supply Chains (A, B and C) and divided into production plus processing & delivery plus fueling cost.

Note: The black dash line represents the target hydrogen retail price based on a diesel cost of 1.25 C$/$L_{diesel}$, drive train efficiency of 0.86 PJ_{H2}/PJ_{diesel} plus a 2030 carbon price of 170 C$/$t_{CO2}$, without any fuel taxes on hydrogen. The analysis assumes use of large transmission pipelines capable of transporting 300 t_{H2}/day over 295 km and 100 t_{H2}/day over 35 km.

The techno-economic results revealed that processing, delivery and fueling of hydrogen is complex with several factors impacting the refueling cost of hydrogen. However, in a mature hydrogen economy, by employing economies of scale the total estimated refueling cost of hydrogen (**Figure ES. 1**) should be competitive with diesel for heavy duty transport at 5 to 8 C$/$kg_{H2}$ or 35 to 56 C$/$GJ_{H2}$. The **hydrogen costs can be summarized** as follows:

1. <u>**Production costs**</u>: The analysis reveals that to target a hydrogen refueling cost that is competitive with diesel in 2030, centralized production costs will have to be <3 C$/$kg_{H2}$. Green hydrogen production costs depend on the cost and near continuous availability of low-carbon electricity

supply. With the current cost of electrolyzers, if low-carbon electricity is available ≥68% of the time at low costs (< 30 C$/MWh), green hydrogen can be made for <3 C$/kg$_{H2}$. On the other hand, centralized blue hydrogen production via methane reforming represents the lowest cost (<1.8 C$/kg$_{H2}$) option in a province like Alberta with availability of low-cost natural gas and geology for CCS. Additionally, blue hydrogen offers the possibility of quickly getting to scale which will drive down costs.

2. **Processing and delivery costs**: As a low-density gas, the processing and delivery costs for hydrogen are high. In the early stages of market development with low demand (<1 t_{H2}/station/d), compressed hydrogen delivery via tube trailers makes the most sense for short distances, while liquid hydrogen delivery is more attractive for distances over 300 km. However, the processing and delivery costs with these supply chains (3-6 C$/kg$_{H2}$) are too high to be used in heating applications. In a mature market, dedicated pipeline delivery to large (≥2 t_{H2}/day) fueling stations will have lowest delivery costs (<1 C$/kg$_{H2}$) if there is large, aggregated demand (~1 t_{H2}/day per km of pipeline) to amortize the cost of the transmission pipelines.

3. **Fueling (HFS) costs**: The fueling station costs are impacted by delivery method (via TTs, liquid hydrogen tanks or pipelines), but in all cases, the larger the fueling station, the better the economics. This is also tied to the demand; with high utilization of the station's dispensing capacity critical to lowering fueling cost. The deployment of large fueling stations (≥2 t_{H2}/day) in combination with high utilization can lead to fueling station costs of 1.5-3 C$/kg$_{H2}$ depending on delivery method.

The techno-economic analyses identified a few key **observations**:

1. **Scale is critical**: The capital cost of many components in the value chain (e.g., liquefaction units, pipelines, compressors) have a much greater impact on the levelized cost of hydrogen at smaller scales than at large scales.

2. **Demand will drive down costs**: While employing economies of scale is important, it will only reap benefit if there is high utilization of the capacity of various process units. In other words, scale and demand must work together. Creating substantial demand (e.g., >2 t_{H2}/fueling station/day) in concentrated hydrogen hubs and corridors would be essential to economic viability. In transportation, this requires 100+ transit fuel cell buses, or 40+ Class 8 fuel cell trucks refueling daily at each station.

3. **Dedicated pure hydrogen pipelines are essential to enable use in multiple sectors**: With centralized hydrogen production, pipelines are the only practical option that enables opportunities in multiple sectors (transport, heat, power) and realize a cost and scale of supply that justifies the necessary infrastructure investments. Such a synergy among multiple demand sectors delivers benefits to all and should be integrated into strategic planning for the buildout of the hydrogen economy.

4. **Hydrogen value chain is capital intensive**: Hydrogen delivery and fueling costs are dominated by the capital expenditure that contributes 45-65% of the total cost per kg H_2 (assumes 8% return on investment).

5. **Technology development is necessary**: As a low-density gas, the compression and/or liquefaction are the costliest processing steps of the value chain. Technological improvements that increase

efficiency, reliability and lifetime of currently available compressors and liquefaction units will be critical to drive down cost of hydrogen.

To conclude, hydrogen not only offers a great opportunity to advance towards a clean future, but it is also an economic driver that opens up diverse opportunities. Yet as this study reveals, the challenges are substantial as fuel hydrogen value chains are complex, and the risks faced by investors are significant. Based on the techno-economic results, the report provides a few **recommendations** that can accelerate the adoption of hydrogen as a clean fuel.

1. **Strategic planning is needed** to fully utilize the potential of hydrogen and unlock significant economic value for Alberta and Canada. The government needs to work together with different stakeholders to develop strategic transition plans that coordinate and leverage current resources, infrastructure, know-how and expertise. A key part of the strategic planning would be to analyze the interdependencies among different demand sectors and plan infrastructure development, policies, and incentive programs accordingly. The results presented in the report indicate that pipelines are the only delivery option that would enable market opportunities in multiple sectors (transport, heat, power). Therefore, they should be integrated into planning the transition to a sustainable hydrogen economy.

2. **Creation of Regional Hydrogen Hubs and Economic Corridors** would be key to improve coordination and connect supply to demand. The work done in establishment of regional hubs such as the ERH2 could be used as a template to create similar hubs across the country. The energy transition is a complex challenge, and these hubs will be key to bring together various stakeholders from government, industry, and demand sectors to work together to minimize barriers.

3. **Mitigate investment risks**. The results indicate that the buildout of a new hydrogen value chain will be capital intensive. Therefore, there needs to be risk mitigation for that capital until demand increases. Policy makers and financial institutions need to employ various policies and financial tools to remove market barriers, ease regulatory burdens and mitigate investment risk which will attract private investment. Technical assistance, grants and interest free loans can play a critical role early in the project. Other tools could be in the form of guaranteed off-take agreements to meet utilization targets, or conditional capital to reduce utilization targets. Public finance institutions can make key contributions by providing investors with risk guarantees and other insurance tools.

4. **Support demand creation**. As mentioned earlier, while employing economies of scale is key, it fails without securing the demand for hydrogen fuel. Traditionally, most government policies and incentives programs have focused on low-carbon hydrogen production. Boosting the role of low carbon hydrogen in clean energy transitions requires a step change in demand creation. The results presented in this study indicate that for heavy-duty transport, significant demand will not materialize without a range of available vehicles at acceptable prices, together with predictable and affordable fuel prices. Therefore, incentive programs need to be developed to purchase heavy-duty fuel cell electric vehicles in parallel with programs to build a network of large size fueling stations.

5. **Promote innovation and pilot projects**. In an early market with many uncertainties, it will be important to provide support to shovel ready pilot projects and promote innovation. These projects will provide real world data and insights that must be made public, with transparent discussions, to identify bottlenecks to address.

1 INTRODUCTION

To limit the increase in global warming to less than 1.5°C, Canada and dozens of other nations have committed to net-zero greenhouse gas (GHG) emissions by 2050 [11]. Since the extraction, refinement, distribution, and combustion of fossil fuels accounts for over 80% of GHG emissions ([1]), a major effort is required to displace carbon-based energy carriers like gasoline, diesel, and natural gas with zero-emission energy carriers such as electricity and hydrogen (H_2).

In the transition to net-zero emissions, electrification of end-use energy demand has an advantage since much of the value chain infrastructure (e.g., electrical grid) and conversion technologies (e.g., heaters, heat pumps, motors, electric cars) already exist. While the electrical grid and conversion technologies may need to be upgraded or expanded, this can be done incrementally.

However, there are some sectors and regions of Canada where electricity as the energy carrier is hard to justify because of the need for large-scale seasonal storage (e.g., space heating in cold climates, backup for intermittent renewables), the weight of the storage media (e.g., batteries on vehicles), or the time it takes to 'refuel' (e.g., commercial trucks/trains/ships/planes). In such cases, H_2 is seen as the zero-emission fuel of choice.

Currently Canada produces over 8000 t_{H2}/day ([7]), which is primarily used as an industrial feedstock to upgrade bitumen, refine oil, or make ammonia and other chemicals (**Figure 1.1A**). Most of this H_2 is made by reforming natural gas, and the carbon dioxide (CO_2) byproduct is released to the atmosphere as a GHG. The resulting 'gray' H_2 is associated with emissions of 9 to 10 kg_{CO2}/kg_{H2} plus an additional 1.5 to 2 kg CO_{2eq}/kg_{H2} associated with the recovery and upgrading of the natural gas ([12]).

To achieve the net-zero objective, H_2 must be made with minimal or no GHG emissions. Large hydro-power resources position many provinces such as British Columbia, Ontario, and Quebec with a source of low carbon electricity [13] that can be used to make 'green' H_2 through water electrolysis. Other provinces such as Alberta and Saskatchewan with large fossil fuel resources and porous rocks that can be used for permanent CO_2 storage [14], can make 'blue' H_2. In the scenario where carbon capture utilization and storage (CCUS) permanently sequesters 90% or more of the GHG emissions, the total GHG emissions for blue H_2 should be less than 3 $kg_{CO2(eq)}/kg_{H2}$ ([7]). Furthermore, the implementation of new regulations on methane emissions ([15]) should lower the total GHG emissions for blue H_2 to <1.5 $kg_{CO2(eq)}/kg_{H2}$, a GHG intensity similar to the 'green' H_2 made from water electrolysis using renewables or nuclear ([16]).

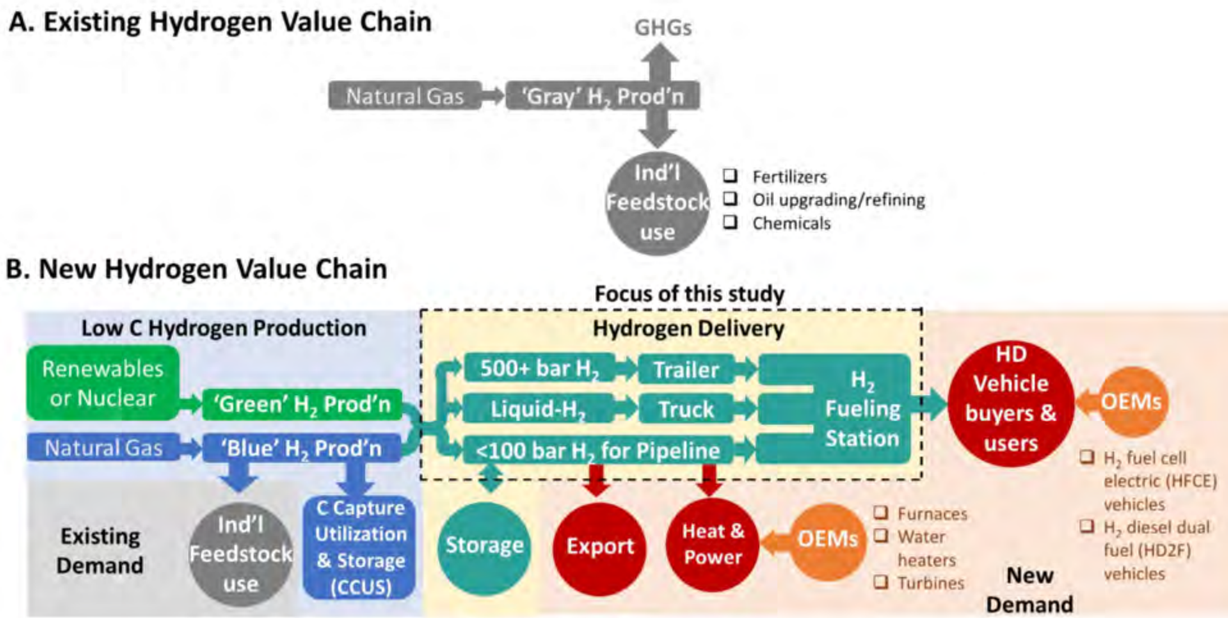

Figure 1.1. Comparison of Canada's existing H_2 value chain (A) and a new value chain (B) based on centralized production of H_2 and its use in fuel markets for heavy-duty (HD) vehicles, heat & power generation, and export.

Note: GHGs: Greenhouse Gases; OEMs: Original Equipment Manufacturers.

Transitioning to a net-zero energy system where H_2 is an end-use fuel will require the creation of new value chains that make H_2 available at a reasonable cost at widely distributed locations across Canada. One strategy involves the use of low carbon electrical grid, if available, to bring power to where it is needed or use dedicated renewable power to make 'green' H_2 on site (i.e., in a distributed manner). While this strategy would benefit from more study, the cost of grid connections [17], limited availability of low-cost renewable power at distributed locations around the city, high cost and small production capacity of water electrolyzers ([18]) will result in green H_2 that is two to three times the cost of blue H_2 ([7]). This will be discussed in more details later in the report.

Another alternative is to build new value chains around the centralized production of H_2 as shown in **Figure 1.1B**. This is the strategy and the focus of this report, with a particular emphasis on delivering H_2 to fueling stations supporting heavy duty vehicles, including trucks, buses, and trains.

This report analyzes the cost components associated with producing, transporting, and delivering low-GHG fuel H_2 for heavy duty vehicles in Canada. Three sizes of H_2 fueling stations (HFS) are assessed (0.4, 2 or 8 t_{H2}/day) at distances of 5, 40 or 300 km from a centralized H_2 production facility. Three H_2 transportation modes are considered including a) compressed H_2 in tube trailers (TT) trucked to stations, b) liquid H_2 in cryogenic tank trucked to stations, and c) compressed H_2 in pipelines to the station (**Figure 1.1B**). We calculate the pre-tax, levelized refueling costs of H_2 (LCOH) and compare that with what is needed to be competitive with diesel fuel without public subsidies.

While the findings presented here should have relevance to any region of Canada interested in centralized, low GHG H_2 production, the model parameters were chosen for their relevance to the Edmonton Region

Hydrogen HUB (https://erh2.ca/), and the Alberta Industrial Heartland (https://industrialheartland.com/) where current H_2 production exceeds 2000 t_{H2}/day along with world class infrastructure for CCUS ([8]).

The balance of this report is separated into the following topics:

- ☐ **Section 2: Market assessment for fuel hydrogen:** The size of Alberta's fuel H_2 market is assessed, focusing on the transport, building, and power sectors. In addition, calculations are made for the target price of H_2 when competing with diesel for a share of the heavy-duty transportation market.
- ☐ **Section 3: Cost of low carbon hydrogen production:** The cost of low carbon H_2 production in Canada is assessed for a range of feedstock costs and other factors.
- ☐ **Section 4: Design of different supply chains delivering hydrogen to fueling stations for heavy-duty vehicles:** The design of different supply chains is presented along with the techno-economic assumptions for delivering H_2 across distances of 5, 40 or 300 km to a heavy-duty fueling station using a tube trailer (TT) truck, liquid hydrogen (LH_2) truck or pipeline.
- ☐ **Section 5: Cost of processing and delivery of hydrogen:** Includes the capital, operating and energy costs for the central terminal, trucks and pipelines used to deliver hydrogen to respective fueling stations.
- ☐ **Section 6: Cost of hydrogen fueling stations:** Includes the capital, operating and energy costs for the respective fueling stations as function of delivery method and size (0.4, 2 or 8 t_{H2}/day).
- ☐ **Section 7: Levelized cost of hydrogen (LCOH) for heavy duty vehicles:** Draws on sections 3, 5 and 6 to calculate the LCOH at the fueling station using different delivery modes and compares this to the equivalent cost for diesel as a transportation fuel.
- ☐ **Section 8: Growing a fuel hydrogen economy in the Edmonton Region:** This section proposes a regional strategy for the deployment of H_2 fueling stations serving heavy-duty transport in the Edmonton Region.
- ☐ **Section 9: Recommendations:** Based on TEA, recommendations that can help accelerate the adoption of H_2 as a clean fuel are provided.

2 MARKET ASSESSMENT FOR FUEL HYDROGEN IN ALBERTA

2.1 Potential Markets for Fuel Hydrogen in Alberta

To estimate the potential market size for H_2 in Alberta in a net-zero future, three sectors were considered, and the following assumptions were made for the transition to clean energy carriers:

Transportation: Natural Resources Canada's (NRCan) Comprehensive Energy Use Database (CEUD, [2]), reported that vehicles in Alberta consumed 462 PJ_{hhv}/year of transportation fuel in 2018 (**Figure 2.1A**). Light-duty (LD) vehicles were the largest energy consumer followed by heavy-duty (HD) and medium-duty (MD) trucks, airplanes, and rail. Gasoline is the primary transport fuels for light duty (LD) vehicles while diesel is mainly used for buses, trucks, and rail. The remaining energy use is derived from aviation turbo fuel with minor contributions from electricity and natural gas.

As a first approximation of demand for fuel H_2 in Alberta's transportation sector in a net-zero future, the 2018 demand was allocated to electricity, biofuels, or H_2 (i.e., no allowance for population or economic growth), based on perceived 'fit-for-service'. In the transportation sector, most light-duty, personally owned vehicles, school buses and lighter-duty freight vehicles were assumed to shift to plug-in battery electric. H_2 was considered the fuel of choice for heavy-duty, and longer-distance freight vehicles. Biofuels and H_2 were assumed to share the market for aviation fuels.

The fraction allocated to H_2 is:

- ☐ Light-duty vehicles: 10%,
- ☐ School buses and medium duty trucks: 20%,
- ☐ Airplanes, passenger rail and off-road vehicles: 50%,
- ☐ Transit buses: 60%,
- ☐ Intercity buses and heavy-duty trucks: 80%
- ☐ Freight trains: 100%

Applying these fractions to Alberta's 2018 fuel energy demand resulted in an estimate that 40% (183.7 PJ_{hhv}/yr) of current demand would be displaced by H_2 (outer ring in **Figure 2.1**) with the remaining fulfilled by either low carbon electricity and/or biofuels. In most cases, it was assumed that the internal combustion engine (ICE) would be replaced with H_2 fuel cells, batteries, and electric motors, resulting in improvements in the relative efficiency of fuel use as summarized in **Table 2.1**. These estimates for relative efficiency were drawn from the literature [19] and were based on the high efficiency of fuel cells, benefits of regenerative braking and the avoidance of idling that characterizes fuel use in many ICE vehicles.

Using these assumptions and the transportation energy demand for Alberta in 2018, the estimated market for H_2 as a transportation fuel is 2797 t_{H2}/d (**Table 2.1, Item 8**). This is equivalent to about half of the 5400 t_{H2}/d that is currently produced in Alberta, and used as industrial feedstocks [8].

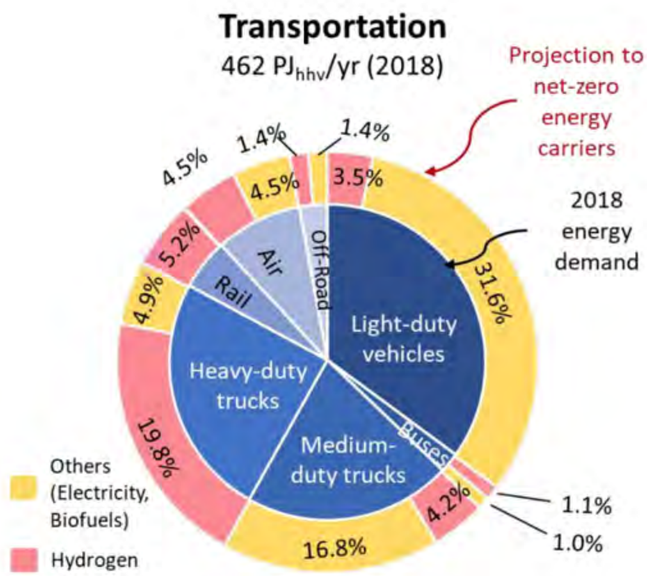

Figure 2.1. Energy use for transportation in Alberta by vehicle type in 2018 (inner circle) and proportion of energy use for each vehicle type that is projected to be served by H_2, low-carbon electricity or biofuels in a net-zero emission future.

Source: Data from NRCan's Comprehensive Energy Use Database [2].

Building Heating: Alberta's natural gas energy use for space and water heating in 2018 was 330 PJ_{hhv}/yr **(Figure 2.2)**, with 54% and 46% consumption coming from residential and commercial buildings, respectively. Large seasonal swings in energy demand (up to 10-fold) [20], and poor performance of heat pumps when faced with cold winter temperatures [21] make it difficult to envisage electrification of this sector, especially in a province like Alberta. Renewable natural gas was not considered a credible option due to severely limited supplies. Repurposing the existing natural gas infrastructure to H_2 was identified as the most credible alternative [22]. In the transition to a net-zero emission energy system, it was assumed that 75% of this heat energy requirement would be supplied by low carbon H_2, as summarized by the outer ring in **Figure 2.2**. In the building sector, H_2 would be combusted to provide space and water heating, similar to the combustion of natural gas today. In combustion, the lower heat value (LHV) of a chemical defines the useful extracted energy better than the higher heat value (HHV). Since the ratio of LHV/HHV for hydrogen (0.84) is 7% lower than the LHV/HHV for natural gas (0.90), a relative efficiency of 1.07 J_{H2}/J_{NG} was assumed (**Table 2.1, Items 9 and 10**) and the calculated average daily H_2 demand is 5094 t_{H2}/d (**Table 2.1, Item 11)**. There would be a large seasonal variation in this demand, from about 1000 t_{H2}/d in August to about 8000 t_{H2}/day in January [8].

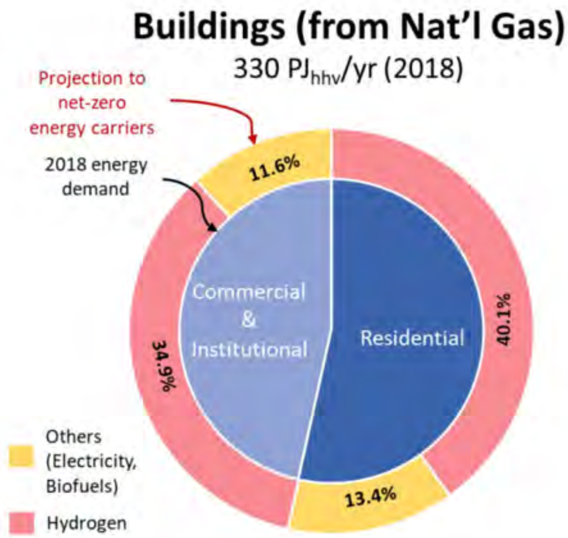

Figure 2.2. Natural gas demand for residential and commercial buildings in Alberta in 2018 (inner circle) and proportion of energy use for each building type that was projected to be served by H_2, low-carbon electricity or biofuels in a net-zero emission future.

Source: Data from NRCan's Comprehensive Energy Use Database [2].

Power Generation: In Alberta, annual electricity generation is about 86 TWh/yr (310 PJ_e/yr) **(Figure 2.3)** [23]. In recent years, coal-powered generation facilities have been gradually converted to lower carbon fuel sources, primarily natural gas, reflecting the impact of increased emissions costs on their profitability. Currently, most of the electricity in the province will be generated via natural gas-powered simple cycle, combined cycle, and cogeneration plants. At the same time, renewable electricity capacity in the form of solar, hydro and in particular wind has increased in the province. Between 2010 and 2017, Alberta's wind capacity doubled and is projected to double again by 2023 as Alberta continues its efforts to decarbonize the electricity grid [24]. Rising carbon taxes and a reduction in the benchmark allowed for emissions without taxes is expected to continue to drive this transition.

For larger scale industrial energy use in Alberta, continued use of natural gas, coupled to post-combustion carbon capture and storage (CCS) was calculated to be the most cost effective. However, H_2 is expected to be the fuel of choice for peak power generation / backup power generation and for a portion of industrial or building cogeneration. In a net-zero future where renewable sources are the major contributor to electricity generation, it is envisaged H_2 will be used as a dispatchable energy source, to firm peak demand, and contribute 10% of total annual electricity generation (i.e., 31 PJ_e/yr, **Table 2.1, Item 12**). In addition, H_2 will play a role in cogeneration of heat and power, contributing perhaps 20% of the electricity requirement (**Table 2.1, Item 13**). Assuming 33% efficiency of generating electricity from H_2 (e.g., single cycle gas turbines, relative efficiency of 3 J_{H2}/J_e), the total H_2 demand from the power sector would be 5397 t_{H2}/d (**Table 2.1, Item 14**).

Table 2.1. The calculation of potential demand for fuel H_2 in Alberta in a net-zero emission future using government estimates for fuel demand in 2018 [2]

Potential of hydrogen as fuel in Alberta							
Item Number	Sector	End use	PJ(FF)/yr (2018)	PJ(FF)/yr (2018) allocated to transition to Hydrogen	Relative efficiency (PJ(H2)/PJ(FF))	All Alberta	
						PJ(H2)/yr	t(H2)/day
1	Transport	LD vehicles	162.6	10% cars; 10% light trucks; 0% motorcycles	0.40	6.5	125
2		Buses	9.4	20% school ; 60% transit and 80% inter-city	0.59	3.0	57
3		MD trucks	97.1	20% of medium duty trucks	0.86	16.7	323
4		HD trucks	114.5	80% of heavy duty trucks	0.86	78.8	1523
5		Rail	24.4	50% passenger rail; 100% freight rail	0.55	13.2	256
6		Airplanes	41.5	50% passenger air; 50% freight air	1.0	20.8	401
7		Off road	13.4	50% of off-road vehicles	0.86	5.8	111
8	Total for transport					145	2797
9	Heat	Residential space and water heating	176.3	75% of natural gas use	1.07	141	2724
10		Commercial space and water heating	153.5	75% of natural gas use	1.07	123	2371
11	Total for heat					263	5094
12	Electricity generation	Peaking to firm intermittent renewables	31.0	10% of all generation	3.00	93	1799
13		Co-generation	62.0	20% of all generation	3.00	186	3598
14	Total for electricity generation					279	5397
15	Total hydrogen demand in Alberta					687	13289

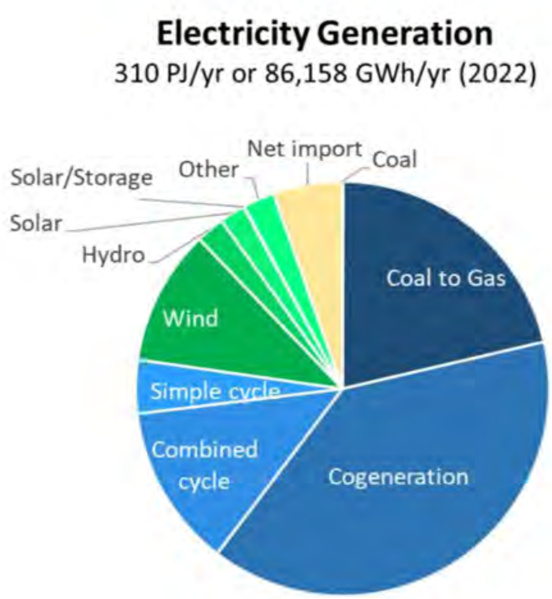

Figure 2.3. Electricity generation in Alberta by source in 2022 as documented by Alberta Electric System Operator (AESO) [23].

Total Potential Fuel Hydrogen Market in Alberta: In total, the estimated potential domestic demand for H_2 in Alberta is 13,289 t_{H2}/d (**Table 2.1, Item 15**), equivalent to 2.5 times the current industrial feedstock H_2 production in the province. The analysis does not account for increases in provincial energy demand associated with population or economic growth, or the production of low-carbon H_2 for export. Therefore, the use of H_2 as fuel in Alberta will not only require the construction of a new value chain but will also provide a great economic opportunity for H_2 producers and create jobs in the province.

2.2 What Fuel Hydrogen Markets Have the Greatest Near-Term Potential?

As a chemical based energy carrier, H_2 is easier (i.e., lower cost, less loss) to store than electricity, so it is preferred for heavy duty mobile applications, or where there are large seasonal swings in energy demand (e.g., space heating in cold climates). As noted above, H_2 also has potential to provide zero emission industrial heat and electricity in cases where the location, demand frequency or scale makes post combustion CCS unfeasible. However, which of these markets has the greatest near-term potential?

Figure 2.4 shows that per gigajoule of energy, Canadians pay considerably less for heating fuels than for transportation fuels. Given this current reality, the heavy-duty transportation market is the most promising market for fuel H_2. Therefore, special attention needs to be paid to the costs associated with moving and processing the fuel, so it is available to heavy-duty vehicles at strategically located fueling stations.

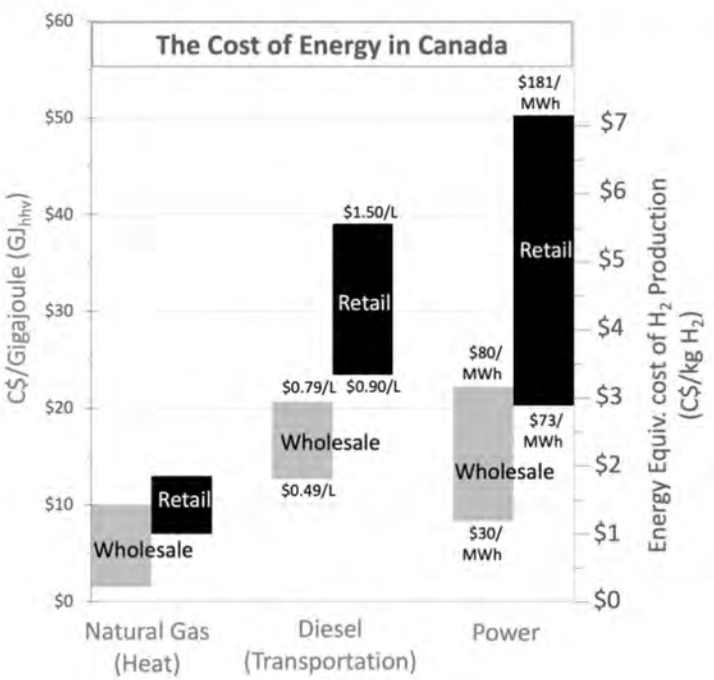

Figure 2.4. Approximate wholesale and retail costs for building heating, transportation fuels and electrical power in Canada.

In Alberta, heavy-duty freight currently pays 24-40 C$/$GJ_{diesel}$ versus 3-4 C$/$GJ_{NG}$ used for heat and power generation. For H_2 to be competitive on an energy basis with current diesel price, without requiring government subsidies, the refueling cost of H_2 at the pump needs to be between 3.3 5.5 C$/$kg_{H2}$, not counting for drivetrain efficiency (DTE) for HFCE vehicles versus conventional diesel trucks [7].

For example, if the relative efficiency of a HFCE locomotive is 0.55 J_{H2}/J_{diesel} (**Table 2.1, Item 5**), the target price for H_2 could be between 6 and 10 C$/$kg_{H2}$. For heavy-duty trucks driving long intercity routes, the relative efficiency is expected to be about 0.86, and with that value, **Figure 2.5** shows the target price of H_2 versus diesel as function of different carbon prices of 50 C$/$t_{CO2}$ in 2022, 110 C$/$t_{CO2}$ in 2026 and 170 C$/$t_{CO2}$ in 2030. These are the announced carbon taxes by the federal government in Canada [25,26].

The results indicate that higher carbon prices on diesel use is advantageous for the adoption of H_2 in heavy-duty transport. For example, at a retail price of ~1.25 C$/$L_{diesel}$ [25,26], the target retail price of H_2 in 2022 would be 5.9 C$/$kg_{H2}$, 6.7 C$/kg_{H2} in 2026 and 7.4 C$/$kg_{H2}$ in 2030. The refueling cost of H_2 will be a major factor in the acceptance of HFCEVs in the heavy duty freight industry because of its impact on the levelized cost of driving in C$ per km and is equal to the sum of production, delivery and fueling station cost.

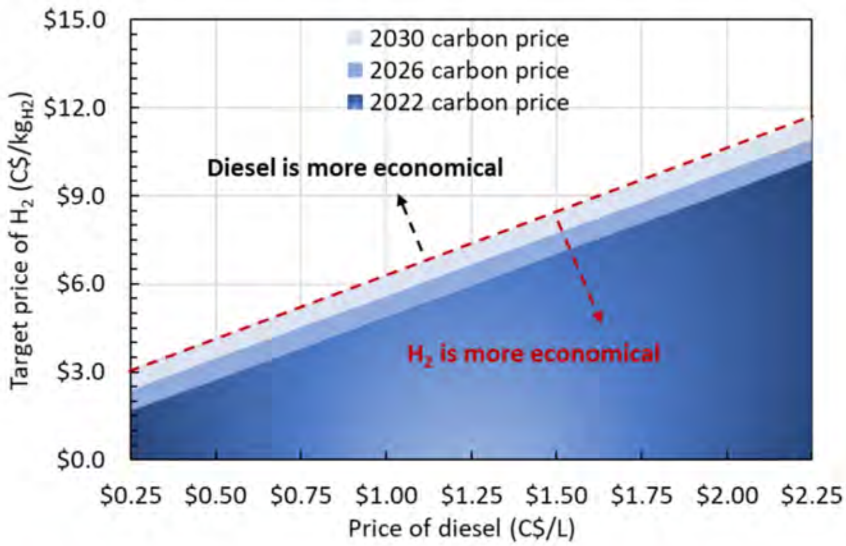

Figure 2.5. Target price of H_2 (C$/$kg_{H2}$) in Alberta calculated based on retail price of diesel and federal carbon pricing targets.

Source: Targets for federal carbon pricing targets taken from report titled: "2020 expert assessment of carbon pricing systems: A report prepared by the Canadian Institute for Climate Choices" [25].

3 PRODUCTION COSTS OF LOW CARBON HYDROGEN

3.1 Green Hydrogen from Water Electrolysis

'Green' H_2 is produced from water electrolysis powered by low carbon electricity. Proton exchange membrane (PEM) electrolyzers tend to be the system-of-choice due to their compact design, high efficiency (52–69%, LHV basis) at high current density (>1–2 Amps/cm^2), fast response, dynamic operation (0–160% of the nominal load), low temperature operation (20–80 °C), and the ability to produce ultrapure H_2 at elevated pressures (30–80 bar) [16,27].

Table 3.1. Model parameters for PEM electrolyzer costs as reported in IEA 2019 report [28].

PEM Water Electrolyzer		Today	2030	Long term
CAPEX	C$/kWe	1180	920	590
Efficiency (LHV)	%	64	69	74
Annual OPEX	% of CAPEX	1.5	1.5	1.5
Stack lifetime (operating hours)	hrs	95000	95000	100000

With the current efficiency of PEM technology (52 kWh/kg$_{H2}$), each MWh of generation has the potential to generate about 19 kg H_2. Therefore, 1.5 MWh/day of electricity is needed to support a single municipal hydrogen fuel cell electric (HFCE) bus, 3 MWh/day is needed to fuel one HD HFCE truck or train, and about 105 MWh/day is needed to support a 2 t$_{H2}$/day fueling station.

The production costs of H_2 from water electrolysis are influenced by various technical and economic factors, including the capital cost (CAPEX) of the electrolyzer, its conversion efficiency (kWh/kg$_{H2}$), electricity costs and annual operating hours. Using model parameters from the International Energy Agency (IEA) Future of Hydrogen (2019) report as summarized in **Table 3.1**, and assuming a 8% return on capital cost investment, the LCOH today, by 2030 and in the future was calculated as a function of the electricity price and annual operating hours (**Figure 3.1A to C**).

The results indicate that the key cost determinant of H_2 produced from water electrolysis is the price of the electricity. For example, an increase in the electricity price from 20 to 100 C$/MWh can increase the LCOH by 2-3 times, irrespective of the electrolyzer CAPEX. Furthermore, there is a significant impact of annual operating hours on the LCOH, which are in turn determined by the capacity factor of electricity/power source.

In today's scenario, there is a significant challenge for economically viable (< 3 C$/kg$_{H2}$) green H_2 production, requiring near-continuous access (ideally 6000+ hrs/year) to low-cost (< 30 C$/MWh), low-carbon electricity. Large hydro-powered provinces such as British Columbia, Ontario, and Quebec have reported the availability of excess or surplus low-carbon electricity [13,29-31]. Since electricity is expensive to store, this excess electricity could be used to make green H_2 through water electrolysis.

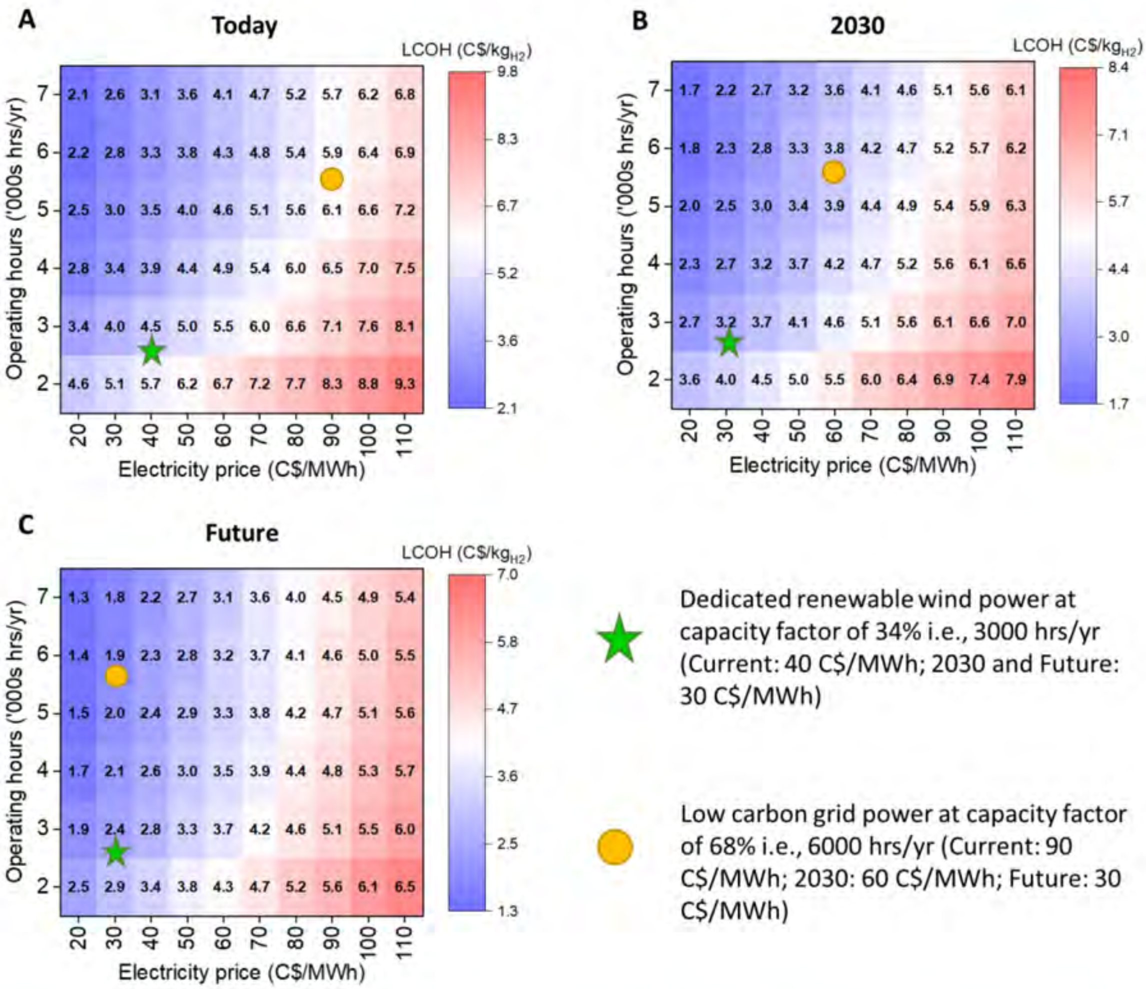

Figure 3.1. The effect of electricity cost (C$/MWh) and annual operating hours (hrs/year) on the cost of green H_2 production for a 4.2 MW PEM Electrolyser today (A), in 2030 (B) and in the future (C) when the market is mature.

Note: The symbols on each chart show the approximate production costs for scenarios in which either low-cost wind power with only 34% capacity factor is used to make H_2 (Green star) or higher cost low carbon grid power available 68% of the time is used to make H_2 (Yellow circle).

Source: Model adapted from the IEA Future of Hydrogen (2019) report [28].

Provinces like Alberta currently do not have low-carbon grid power available to produce green H_2. In such provinces, dedicated renewable power such as that from centralized wind farms could be used for electrolysis. However, the low-capacity factor (34%) and current costs of wind electricity (40 C$/MWh) in the province will make it challenging to make low-cost green H_2. Yet in the near term, i.e., by 2030, the lower cost of PEM electrolyzers will make it possible to use dedicated renewable wind power to produce green H_2 at a competitive cost in centralized locations in the province.

Alternatively, electrolytic H_2 production can also be carried out at or near the site of demand, eliminating the cost of H_2 transport. However, bringing the electricity to the site of demand is not without cost. Grid connection charges in Canada can add 20 to 30 C$/MWh or more to the cost of power generation [17], and as noted above, the cost of the electricity has a major impact on the LCOH production.

In the long-term scenario, with the forecasted decline in PEM electrolyzer costs [32], green H_2 could be produced at < 3 C$/kg$_{H2}$, with electricity prices < 50 C$/MWh, available for 3000+ hrs/year. This would allow flexibility with various options to produce green H_2 at competitive prices across the country.

3.2 Blue Hydrogen from Natural Gas

Blue H_2 is produced by steam reforming of natural gas (SMR) and capturing 90% or more of the CO_2 so it can be permanently sequestered in the sub-surface. The carbon capture and storage (CCS) process differentiates blue H_2 production from conventional 'gray' H_2 production which accounts for most of the 8000+ t_{H2}/day that occurs in Canada today. Most of the current H_2 is used as an industrial feedstock for oil upgrading / refining or fertilizer / chemical production, not as a fuel / energy carrier that is being proposed in this study.

A typical centralized industrial-scale steam methane or autothermal reformer designed to make blue H_2 produces 400 to 800 t_{H2}/day and generates 1.3 to 2.6 Mt_{CO2}/yr for CCS. This scale of CCS is required for the cost-effective sequestration of the CO_2 in porous rocks at least 1 km underground. Not all regions of Canada have the geology needed for CCS, but the Western Canadian Sedimentary Basin (WCSB, includes northern British Columbia, Alberta, and southern Saskatchewan) is an ideal location for low-cost blue H_2 production due to the supply of low-cost natural gas, and a geology that can safely and securely store the CO_2 by-product [8].

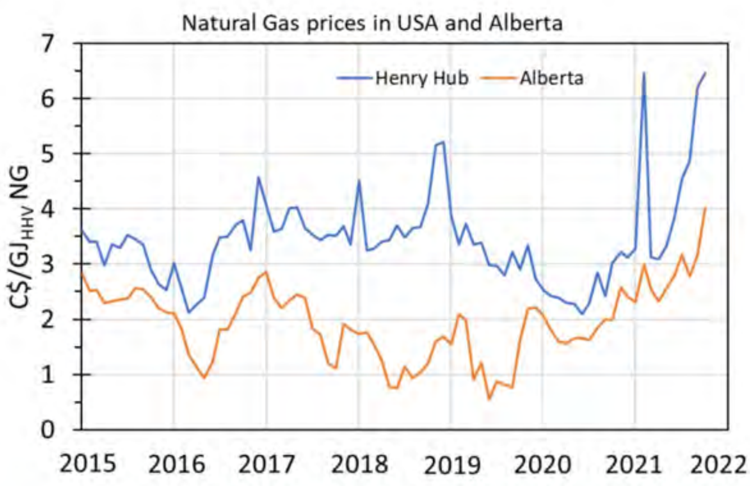

Figure 3.2. Comparative prices for natural gas (C$/GJ$_{HHV}$ NG) in the United States (Henry Hub [33]) and Alberta [34] from 2015-2021.

Source: US$ to C$ conversion was done using historical data [35].

The cost of blue H_2 is sensitive to natural gas prices which have been relatively stable in North America from 2015-2021 (**Figure 3.1**) but have seen a sharp spike recently [33,34]. **Figure 3.2** provides a breakdown of LCOH production as a function of natural gas prices (C$/$GJ_{HHV}$ NG) and production scale (t_{H2}/day). The calculations were done for a current, 2030 and a future scenario based on the IEA Future of Hydrogen (2019) report, and assuming an 8% return on capital cost investment. The analysis reveals that the current cost of blue H_2 at large (≥ 300 t_{H2}/day) centralized production facilities would be <1.70 C$/$kg_{H2}$ when natural gas prices are ≤4 C$/$GJ_{NG}$.

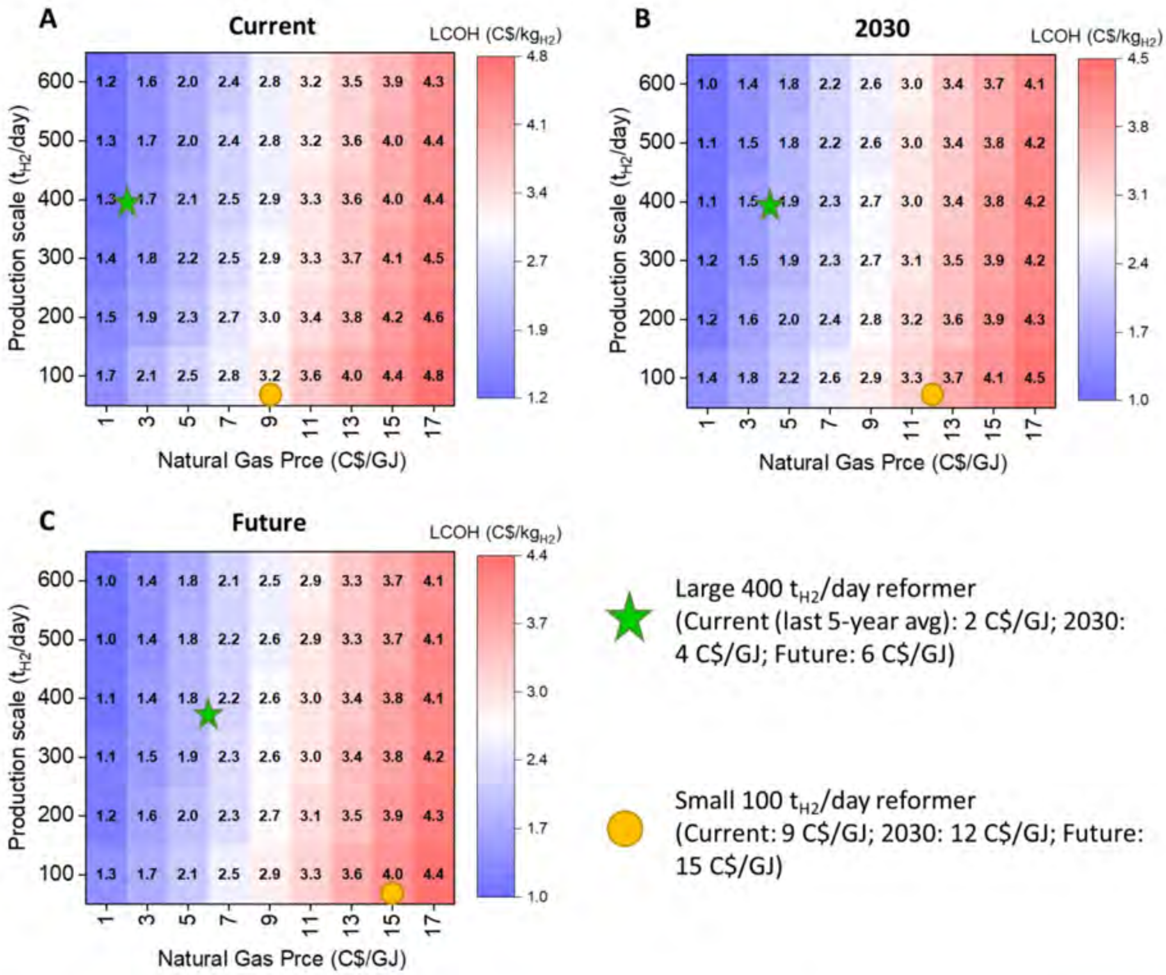

Figure 3.3. The effect of natural gas prices and scale of production (t_{H2}/day) on the cost of H_2 (LCOH) from a steam methane reformer coupled to carbon capture and storage today (A), in 2030 (B) and in the future (C).

Note: The symbols show the approximate production costs for scenarios in which either large reformer with low-cost natural gas (Green star) or small reformer with higher priced natural gas (Yellow circle) is used.

Source: Model adapted from the IEA Future of Hydrogen (2019) report [28].

This scenario is relevant for Alberta since the province is currently one of the lowest cost producers of blue H_2 in the world. With improvements in large scale deployment of technologies linking H_2 production to CCUS, the LCOH is projected to decrease even further to <1.5 C$/kg$_{H2}$ if natural gas prices remain stable. Furthermore, even if the natural gas price increases to 6 C$/GJ$_{NG}$, the cost of blue H_2 production would still be ≤2 C$/kg$_{H2}$. The maturity of reforming technologies means that even in markets that can only support smaller scale reformers (e.g., 100 t$_{H2}$/day) and with high natural gas price (e.g., 9-15 C$/GJ$_{NG}$), the cost of blue H_2 would be 3.5 to 4.2 C$/kg$_{H2}$, and competitive with green H_2 production, discussed above.

3.3 Turquoise Hydrogen from Natural Gas

Currently there is much interest in the development and commercialization of novel technologies for the production of H_2 from natural gas using a conversion technology where the byproduct is carbon black (elemental carbon) rather than gaseous CO_2. If cost effective, these 'methane pyrolysis' technologies to produce "turquoise hydrogen" could be deployed anywhere there is natural gas supply, even if there is not potential for carbon capture and storage. This could rapidly expand the availability of fuel H_2 for transportation, building or heat and power markets by piggybacking on existing natural gas infrastructure.

Companies working on this technology include:

- Ekona Power (https://www.ekonapower.com/)
- Aurora Hydrogen (https://aurorahydrogen.com/)
- New Wave Hydrogen (https://www.newwaveh2.com/)
- BASF (https://www.basf.com/ca/en/who-we-are/sustainability/we-produce-safely-and-efficiently/energy-and-climate-protection/carbon-management/interview-methane-pyrolysis.html)
- Modern Electron (https://modernelectron.com/)

Since these technologies are not yet commercial, little, or no publicly available details exist on their efficiency, the quality and purity of the end product, costs involved and market demand for carbon black. Hence, it is difficult to predict when or what markets the produced H_2 is best suited to fill.

4 DESIGN OF HYDROGEN SUPPLY CHAINS FOR HEAVY-DUTY TRANSPORT

To have any hope of meeting net-zero 2050 objectives, efforts must begin immediately to build fuel H_2 demand, and the supply to meet that demand. As noted above, using proven technologies, the most cost-effective, low-carbon fuel H_2 production is done centrally, either by piggybacking on industrial 'blue' H_2 production or making 'green' H_2 where excess electricity is generated and therefore not exposed to charges for grid distribution.

While distributed fuel H_2 production may have a significant role in a future H_2 economy, the sheer scale of demand (13 kt_{H2}/day, just for Alberta, **Table 2.1**) in a net-zero future means that a substantial system will be required for moving H_2 to where it is needed.

As stated earlier, the heavy duty transportation market is the most promising early adopter market for fuel H_2. Consequently, the costs associated with moving and processing the fuel require special attention, so it is available to heavy-duty vehicles at strategically located HFS's.

The refueling cost of H_2 at HFS's will be a major factor in the acceptance of HFCEVs. The refueling cost of H_2 at the dispenser comprises of the production, delivery cost and fueling station (HFS) cost.

H_2 refueling cost =

Production cost + Processing and delivery cost + Fueling station (HFS) cost

The production cost of H_2 includes all costs incurred in producing H_2 from its feedstock, while the processing and delivery cost includes costs associated with processing and transporting H_2 to the HFS's. The processing and delivery costs depend on the scale, distance, and processing technology used to transport H_2, while the HFS cost is linked to the delivery method and station size. This analysis is based on three different supply chains for H_2 delivery from centralized production facilities to heavy-duty HFS's, where the stations vary in size (0.4, 2 or 8 t_{H2}/day) and are 5, 40 or 300 km from the production facility. The three different supply chains analyzed in this study (**Figure 4.1**) consists of: A) Compressed H_2 via tube trailer (TT) trucks, B) Liquid H_2 via LH_2 trucks or C) Compressed H_2 via pipelines.

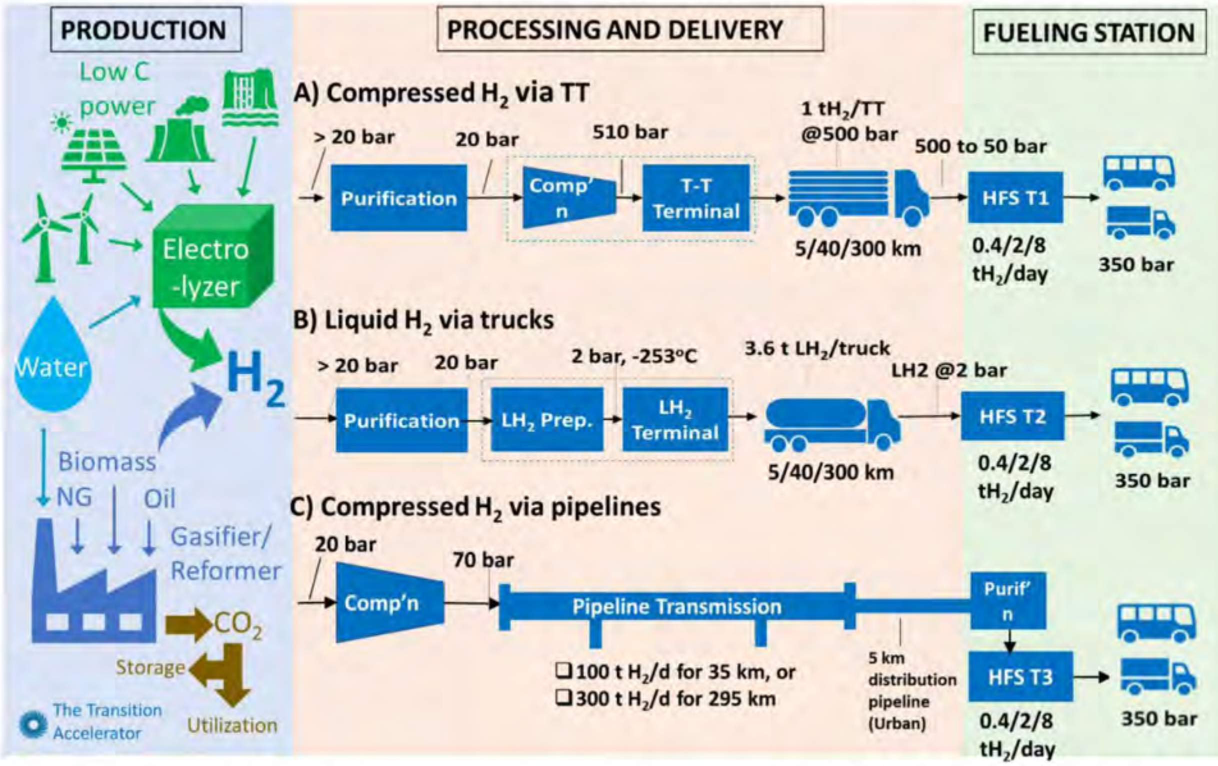

Figure 4.1. H_2 delivery routes from a centralized production facility to HFS's for heavy-duty freight via: A) Compressed H_2 via tube trailers, B) Liquid H_2 via trucks or C) Compressed H_2 via pipelines.

A few important notes and assumptions used in the analysis are listed below:

- The costs were calculated assuming an 8% return on capital cost investment and reported in 2019 Canadian dollars (C$).
- The analysis was done assuming a large H_2 hub which serves multiple HFS's.
- Three different delivery distances were analyzed: 5 km, 40 km, or 300 km.
- Central compressor, TT terminal, liquefier and LH_2 terminals are assumed to be placed on/near production site and designed as large-scale facilities (10-100 t_{H2}/day).
- The HFS's were analyzed operating at three different scales: 0.4 t_{H2}/day, 2 t_{H2}/day and 8 t_{H2}/day and dispensing H_2 at 350 bars.
- Large transmission pipelines were modelled for transporting 300 t_{H2}/day over 295 km distance and 100 t_{H2}/day over 35 km. It was assumed that in a large H_2 hub these pipelines would be serving industrial sites, power generation facilities and end-users for residential and commercial heat.

The techno-economic analysis of compressors and pipelines was conducted using the methodology described in The Transition Accelerator's technical reports on "Techno-economics of H_2 compression" [9] and "Techno-economics of H_2 pipelines" [10]. The techno-economic modelling of central terminals and trucking costs was performed using the H_2 delivery scenario analysis model (HDSAM) developed by Argonne National Laboratory [36]. The HDSAM model is an open-source software package that is built on an Excel interface to calculate H_2 delivery and refueling costs based on user defined market demand scenarios. The model calculates the capital and operating cost of various refueling components and their respective contribution to the total H_2 cost [37]. The data in the model are based on quotes from vendors, open literature, industry and stakeholder input, and basic engineering design calculations. In addition, the model has gone through careful examination and an annual review is conducted by industry experts [38,39]. The HFS costs were calculated using the Heavy Duty Refueling Station Analysis Model (HDRSAM), also developed by Argonne National Laboratory [40]. Unlike HDSAM, HDRSAM focuses solely on refueling station costs for heavy-duty vehicles and optimizes various design aspects such as the size and power required for compressor/pumps, storage, and refrigeration at the HFS.

4.1 Compressed Hydrogen Delivery via Tube Trailer Trucks

The literature on techno-economic analysis of H_2 delivery costs suggests that when HFCEV market penetration is high (i.e., H_2 demand > 50 t_{H2}/day) and delivery distances are long (> 100 km), the most economical delivery modes are pipelines and liquid H_2 trucks [37,41,42]. However, during an initial period when the HFCEV market penetration is lower, delivery via TT trucks could be an interim solution.

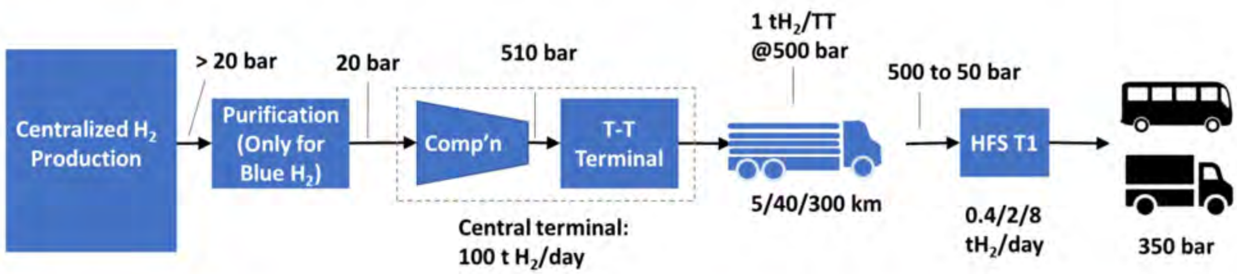

Figure 4.2. Schematic of Supply Chain A delivering compressed gaseous H_2 via tube trailers.

Figure 4.2 shows a schematic of Supply Chain A that delivers H_2 to HFS's using TT trucks. If the H_2 source is from an SMR plant, a central purification unit must be used to attain fuel cell grade purity H_2. A pressure swing adsorption (PSA) unit is the industry standard for H_2 purification and can reduce CO emissions to ≤ 0.2 ppm, as required by fuel cells [43]. Methanation is the alternate technology for purifying gas streams but cannot purify to less than 10 ppm CO [43]. Only the the additional cost of increasing H_2 purity to < 0.2 ppm CO and 300 ppm N_2 from a PSA unit is considered, which is assumed to be available at the SMR plant. This comes at an additional cost related to an increase in PSA adsorbent volume [43,44].

A central terminal was designed to compress, store, and dispense H_2 to tube trailers at 500 bars. The terminal is designed with storage and TT loading diaphragm compressors operating at an isentropic efficiency (η_{isen}) of 60% [9]. The storage consists of multiple medium (200 bars) and high pressure (400 bars) units, 20 kg in size each, with total storage time of 0.1 days and total storage capacity equal to 22% of terminal capacity [36,37]. The remainder of the terminal consists of piping, supply, electrical and instrumentation components [36].

Upon loading from the terminal, the trucks deliver the TT with compressed H_2 at 500 bars to the HFS at distance of 5, 40 or 300 km. Therefore, the round trip considered was 10, 80 and 600 km respectively where an empty truck returns to terminal. The TT truck is assumed to have a total capacity of 1 t_{H2}/truck, and runs on diesel at a cost of 1.2 C$/$L_{diesel}$ with an average truck mileage of 3.3 km/L_{diesel}.

The gaseous HFS is designed for 350 bar cascade dispensing at fast fueling rate of 7.2 kg/min with an average of 80 kg H_2 dispensed amount per vehicle. It consists of compressors, a medium-pressure buffer storage system, refrigeration unit, dispenser, and other control hardware as shown in **Figure 4.3** [37,45]. Gaseous H_2 is delivered to the HFS via the TT, where it is left behind as part of the storage system at the gaseous HFS. The assumption is that the TT tanks can never be completely emptied, with a minimum pressure of 50 bars. The function of buffer storage is to satisfy a predefined dispensing rate during peak-demand hours [45]. To allow for fast refueling, the H_2 from the high-pressure storage system is directed by a dispenser into the vehicle's onboard tank via a refrigeration unit, which pre cools the H_2 to about ~5 °C to avoid overheating the vehicle's tank. The dispenser measures the flow rate of H_2 and keeps track of the amount of H_2 dispensed into the vehicle's onboard storage tank. Meanwhile, the compressor can operate to refill the idle banks of vessels (i.e., those not discharging to the dispenser) in a predefined order [45]. Like the terminal, (η_{isen}) of the HFS compressors was assumed to be 60%. When all the pressure vessels in the tube trailer are drawn down to the return pressure, the tube trailer is replaced with another fully loaded tube trailer.

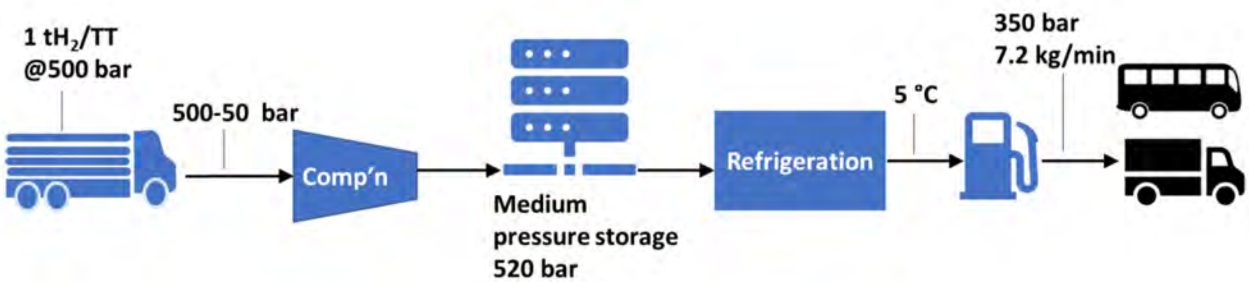

Figure 4.3. Schematic representation of a gaseous HFS supplied by TT.

Source: Adapted from References [37,39,46].

4.2 Liquid Hydrogen Delivery via Trucks

While gaseous H_2 is supplied to the HFS via TT's or pipelines, liquid H_2 is stored in an onsite cryogenic tank, which is replenished by a liquid H_2 truck. **Figure 4.4** shows a schematic of Supply Chain B that is the LH_2 delivery route adopted in this analysis. The central purification process in the supply chain was considered to be identical to Supply Chain A. The outlet of the SMR purification unit goes to the LH_2 terminal consisting of the liquefier unit and the LH_2 terminal facility consisting of pumping and storage equipment. The liquefier in this analysis was designed based on a conventional three-step liquefaction process: compression, cooling (via liquid nitrogen and heat exchangers) and expansion. The LH_2 terminal is designed with LH_2 pumps which operate at an isentropic efficiency (η_{isen}) of 60%, and LH_2 storage was designed to handle plant outages assumed to be 10 days/yr [36]. The remainder of the terminal consisted of piping, supply, discharge, electrical and instrumentation components. Upon loading from the terminal, the truck delivers the LH_2 to the HFS at distance of 5, 40 or 300 km. Therefore, the round trip considered was 10, 80 and 600 km respectively where an empty truck returns to terminal. The LH_2 trucks are assumed to have a total capacity of 3.6 t_{LH2}/truck, running on diesel at a cost of 1.2 C\$/L_{diesel} with an average truck mileage of 2.7 km/L_{diesel}.

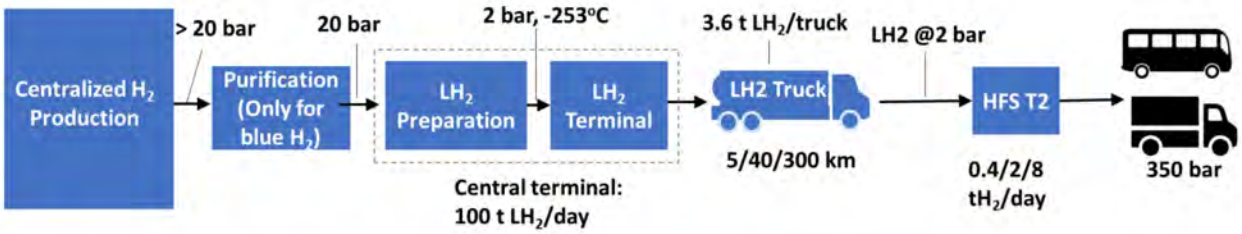

Figure 4.4. Schematic of Supply Chain B delivering liquid H_2 via trucks/tankers.

Like the HFS of Supply Chain A, the liquid HFS was designed for 350 bar cascade dispensing at fast fueling rate of 7.2 kg/min into HDV with an average of 80 kg H_2 dispensed per vehicle. The liquid H_2 from the cryogenic storage tank is pressurized by a cryogenic pump and then gasified via an evaporator as shown in **Figure 4.5** [37]. The medium-pressure gaseous H_2 from the evaporator is stored in the storage system, which is later precooled to 5°C by the cooling unit before being dispensed into the vehicle tanks. The pre-cooling unit in this configuration utilizes the cryogenic H_2 to cool the H_2. It is important to note that the boil off losses for the LH_2 supply chain were considered when calculating the H_2 cost.

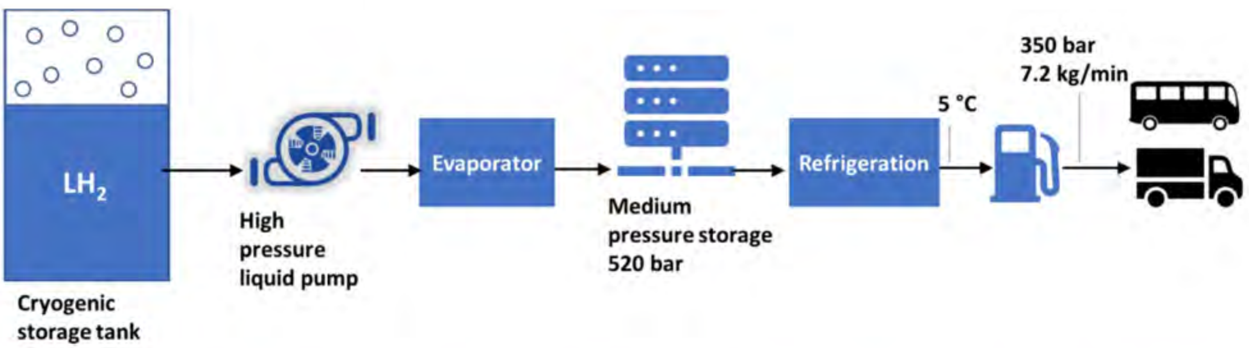

Figure 4.5. Schematic representation of a liquid HFS supplied by liquid H_2 truck and stored in a cryogenic storage tank.

Source: Adapted from Reference [37].

4.3 Compressed Hydrogen Delivery via Pipelines

Figure 4.6 shows a schematic of Supply Chain C that is the pipeline route adopted in this analysis. A key difference versus the TT or LH_2 route is that there is no need for a central terminal for distribution of H_2.

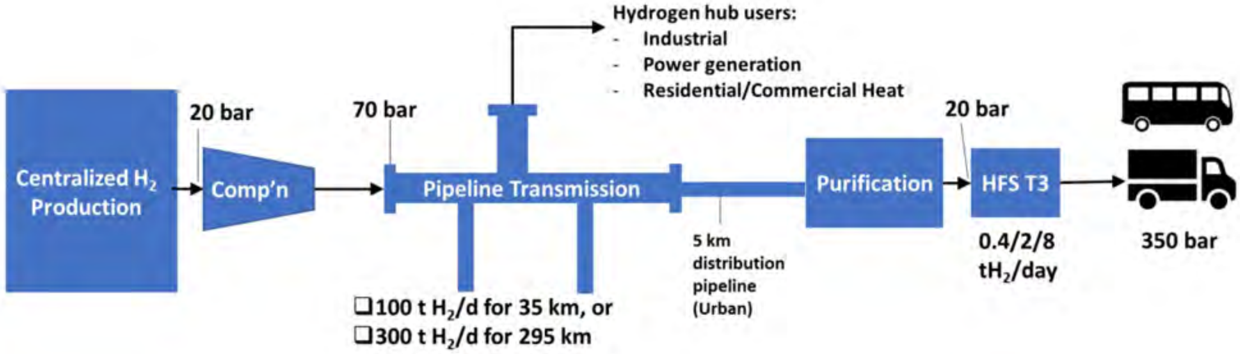

Figure 4.6. Schematic of Supply Chain C delivering compressed gaseous H_2 via pipelines.
Source: Adapted from Reference [37].

A central inlet compressor with η_{isen} of 80% was used to compress H_2 from 20 to 70 bars for the transmission pipeline [9]. The inlet compressors were designed at the same size/scale as the transmission pipeline i.e., 100 t_{H2}/day (35 km pipeline) and 300 t_{H2}/day (295 km pipeline).

The gas flow calculation methodology described in The Transition Accelerator's technical report on "The techno-economics of hydrogen pipelines" [10], was used to optimize pipeline size and costs. For the 295 km transmission pipeline with a capacity of 300 t_{H2}/day, a 12-inch steel pipeline with inlet pressure of 70 bar, outlet gas velocity of 30 m/s, pipe roughness of 0.0178 mm and flow temperature of 15 °C was used. For the 35 km pipeline, a 6-inch pipeline was used to transport 100 t_{H2}/day. In both cases no enroute compression stations were used along the transmission pipeline. The distribution pipelines were designed to be dedicated pipelines servicing the different size HFS's (0.4 t_{H2}/day, 2 t_{H2}/day and 8 t_{H2}/day), with sizes of 1.5-inch, 2-inch, and 3-inch respectively.

The HFS design for the pipeline scenario was identical to the TT route as shown in **Figure 4.7**, except that the inlet pressure was lower at 20 bar, resulting in increased compression power, storage requirement and associated costs. A summary of all design parameters used in the analysis is provided in **Table 4.1**.

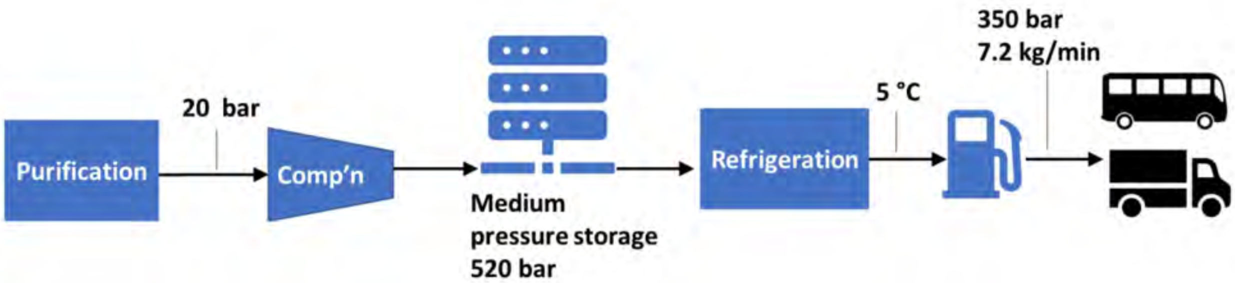

Figure 4.7. Schematic representation of a pipeline supplied HFS.
Source: Adapted from Reference [37].

Table 4.1. Summary of techno-economic parameters used in analysis of the three different supply chains.

Component	Supply Chain A	Supply Chain B	Supply Chain C
Terminal	100 t_{H2}/day. 20 to 510 bars. $\eta_{isen} = 60\%$. 0.1-day storage capacity.	100 t_{H2}/day. RT to 253 °C. $\eta_{isen} = 60\%$. 10 day storage capacity.	---
Trucking/Pipeline	1 t_{H2}/TT. 500 bar TT pressure. 3.3 km/L_{diesel}.	3.6 t_{H2}/truck. LH_2 @ -253 °C. 2.7 km/L_{diesel}.	12 inch (295 km)/6-inch (35 km) transmission pipeline + 3/2/1.5-inch distribution pipeline. Inlet compressor: 20 to 70 bars.
HFS	350 bar cascade dispensing. Fueling rate of 7.2 kg_{H2}/min. Avg dispensed amount per vehicle of 80 kg. Inlet pressure: 500-50 bar.	350 bar cascade dispensing. Fueling rate of 7.2 kg_{H2}/min. Avg dispensed amount per vehicle of 80 kg. Inlet: Liquid H_2 at 2 bar	350 bar cascade dispensing. Fueling rate of 7.2 kg_{H2}/min. Avg dispensed amount per vehicle of 80 kg. Inlet pressure: 20 bar.

5 PROCESSING AND DELIVERY COSTS

5.1 Central Purification Costs

If the H_2 is sourced from a central 'blue' H_2 production facility, it must be purified according to the requirements of PEM fuel cells used in transport vehicles. PEM fuel cells require extremely pure H_2 due to the platinum catalysis that drives the reaction. Presence of reactive impurities such as hydrogen sulfide or carbon monoxide can deactivate the catalyst and degrade the entire fuel cell. The H_2 purity requirements for PEM fuel cell applications are listed in ISO 14687 standard [43] and summarized in **Table 5.1**.

Table 5.1. Fuel quality specification for PEM fuel cell road vehicle application in ISO/FDIS 14687 [43].

Constituents	PEM fuel cell grade
Hydrogen Fuel index	99.97%
Total non-hydrogen gases	300 µmol / mol
Water	5 µmol / mol
Total hydrocarbon except methane (C1 equivalent)	2 µmol / mol
Methane	100 µmol / mol
Oxygen	5 µmol / mol
Nitrogen	300 µmol / mol
Carbon dioxide	2 µmol / mol
Carbon monoxide	0.2 µmol / mol
Total sulfur compounds	0.004 µmol / mol

Methanation and pressure swing adsorption (PSA) are currently the two available technologies that could be used to reduce carbon monoxide from H_2. Pressure swing adsorption (PSA) is the industry standard for H_2 purification and can reduce CO emissions to ≤ 0.2 ppm, as required by fuel cells [43]. Methanation is the alternate technology for purifying gas streams but cannot purify to less than 10 ppm CO [43]. When used to reduce carbon monoxide levels to those considered here, PSA also reduces other impurities to levels with low impact on the end users considered.

PSA uses adsorbent technology to purify H_2 from a gas mixture and is typically part of the SMR unit. PSA operates on the principle that some gaseous components adsorb preferentially to others on highly porous materials. These materials adsorb larger amounts of impurities at high partial pressure than at low partial pressure [44]. Thus, the column is fed with a high-pressure feed gas containing impurities and the pressure is then lowered to regenerate and then to purge the column. To reduce the partial pressure and desorb impurities, the adsorber pressure is swung from the higher feed gas pressure to lower tail gas pressure.

Besancon and coworkers [44] reported the impact of varying targeted H_2 purity on parameters of the reformer and the PSA. In the study, a PSA used in an industrial reformer is modelled, and the impurity concentration (and H_2 loss) is varied by changing the PSA adsorbent volume. The simulation results for a SMR, showed that a decrease in CO level from 250 ppm (industrial grade H_2) to < 0.2 ppm requires an increase in adsorbent volume from 13.6 m^3 to 15.8 m^3 (Δ = 2.2 m^3) and results in a decrease in hydrogen yield by 2.1%.

The Hy4Heat hydrogen purity report [43] reported a cost benefit analysis based on the parameters presented by Besancon study [44], to reflect the impact of using a PSA to purify H_2. The results tabulated in Table 30 and 32 of the report [43], indicate that under the simulated parameters by Besancon, an increase in purity from industrial grade H_2 to fuel cell grade H_2 would result in a 16.2% increase in PSA capital costs. Depending on the initial cost of the PSA unit, the levelized cost of energy (LCOE) to increasing purity of H_2 in SMR unit from 250 ppm CO to < 0.2 ppm CO is between 0.07-0.09 p/kWh. Based on a conversion factor of 1 pence = 0.017 2019 C$ [47], the resulting cost of central purification would range from 0.04-0.05 C$/$kg_{H2}$.

5.2 Central Terminal Costs

Reliable H_2 distribution via compressed gas TT or LH_2 trucks will require a central terminal facility for compression/liquefaction, storage, and distribution. This is one of the major advantages of Supply Chain 'C' which distributes H_2 directly from the production site to respective HFS's via pipelines, eliminating the need for a central facility with an extra compression/liquefaction step. For the compressed H_2 route, the central terminal consists of large-scale storage and truck loading compressors, utilizing diaphragm compressors. It is assumed that H_2 is delivered to the terminal at 20 bar inlet pressure where is it compressed and stored in medium and high-pressure storage tanks, at 200-400 bars pressure. Similarly, the LH_2 terminal consists of a large-scale liquefaction facility based on a conventional liquefaction process that follows three steps, namely compression, cooling (via liquid nitrogen and heat exchangers) and expansion. Both the compressed H_2 and LH_2 terminals consist of storage tanks that helps meet daily variations in supply and demand, and to maintain a reliable supply during seasonal variations or outages.

Figure 5.1 presents the terminal costs in (A) C$/year and (B) C$/kg_{H2} as function of terminal size (t_{H2}/day). The annualized costs indicate that installing and operating LH_2 terminals would be significantly more expensive with total annualized costs of ~20 million C$/year versus ~8 million C$/year for a compressed H_2 terminal, at a scale of 10 t_{H2}/day. At a scale of 100 t_{H2}/day, these costs can exceed more than 120 million C$/year for the LH_2 terminal and 60 million C$/year for the compressed H_2 terminal (**Figure 5.1A**).

The annualized costs (C$/year) can be converted into levelized costs (C$/$kg_{H2}$) by dividing the annualized costs with the total H_2 dispensed at the terminal in a given year. The results indicate the dominant role of capital expenditure (CAPEX), contributing between 40-60% to the total terminal cost, which is a result of the high cost of compressors and liquefier units.

The results also indicate the importance of capitalizing on economies of scale, whereby the levelized terminal cost decreases with increasing the terminal size. In particular, liquefier units have higher benefit of operating at large scale as indicated by the dashed red lines in **Figure 5.1B**. Comparatively, the cost for the LH_2 terminals decreases by 2.2 C\$/kg$_{H2}$ versus 0.4 C\$/kg$_{H2}$ for compressed H_2 terminal, when terminal sizes increase from 10 t$_{H2}$/day to 100 t$_{H2}$/day.

Another important difference in the operation of the two different terminals is the higher electricity costs associated with operating a LH_2 terminal at ~1.0 C\$/kg$_{H2}$ versus ~0.3 C\$/kg$_{H2}$ for the compressed H_2 terminal, at a 100 t$_{H2}$/day terminal size. The higher electricity costs are a result of the energy intensive liquefaction process (~9 kWh/kg$_{H2}$) which needs ~3 times higher energy versus compression (~3 kWh/kg$_{H2}$). This electrical usage accounts for ~27% and ~9% of the lower heating value (LHV) of H_2 for the LH_2 and compressed H_2 terminal, respectively.

The terminal costs were also analyzed by categorizing them based on the different equipment used in the terminal i.e., the compressors/liquefier, storage, and remainder of terminal which consists of piping, electrical connections, instrumentation, the building and other structures. The results presented in **Figure 5.2A**, indicate that compression or liquefaction (including pumping) is the costliest component, contributing > 80% to the terminal cost.

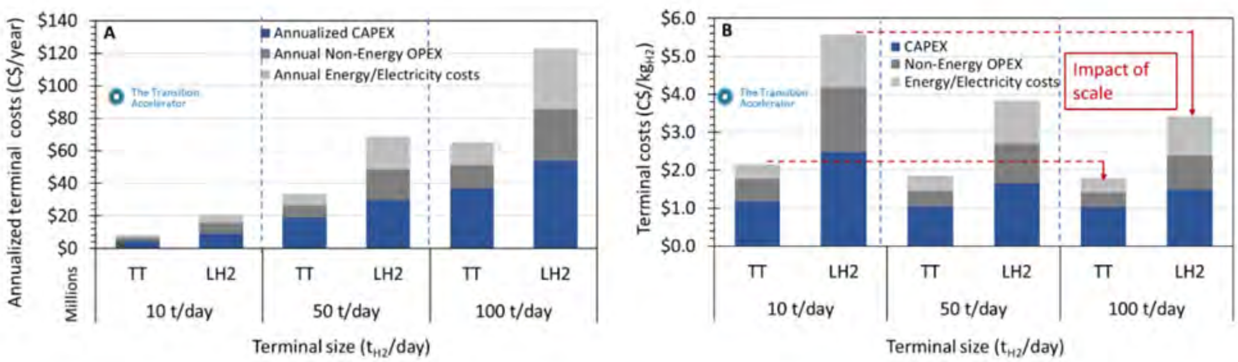

Figure 5.1. Central terminal costs in: (A) C\$/year and (B) C\$/kg$_{H2}$ as function of terminal size (t$_{H2}$/day) and divided into CAPEX, Non-energy OPEX and energy/electricity costs.

A breakdown of the CAPEX, non-energy operating expenditure (OPEX) and electricity costs (**Figure 5.2(B-D)**) based on contributions from different components indicates that CAPEX and non-energy OPEX costs are a comprised of the costs associated with the compressors/liquefier and storage units, while the remainder of the terminal facility namely the piping, supply, discharge, electrical and instrumentation components has a negligible contribution [40]. Additionally, the electricity costs in the terminal are only a result of the compression or liquefaction process.

The results suggest that a combination of technological improvements to increase the efficiency of compression, liquefaction and economies of scale can be employed in the future to reduce costs. However, due to thermodynamic limitations on the energy requirement for compression and liquefaction, the costs of a central terminal facility will remain significant. Therefore, it could be beneficial to reduce this extra step which is possible with the use of pipelines as proposed in Supply Chain 'C'.

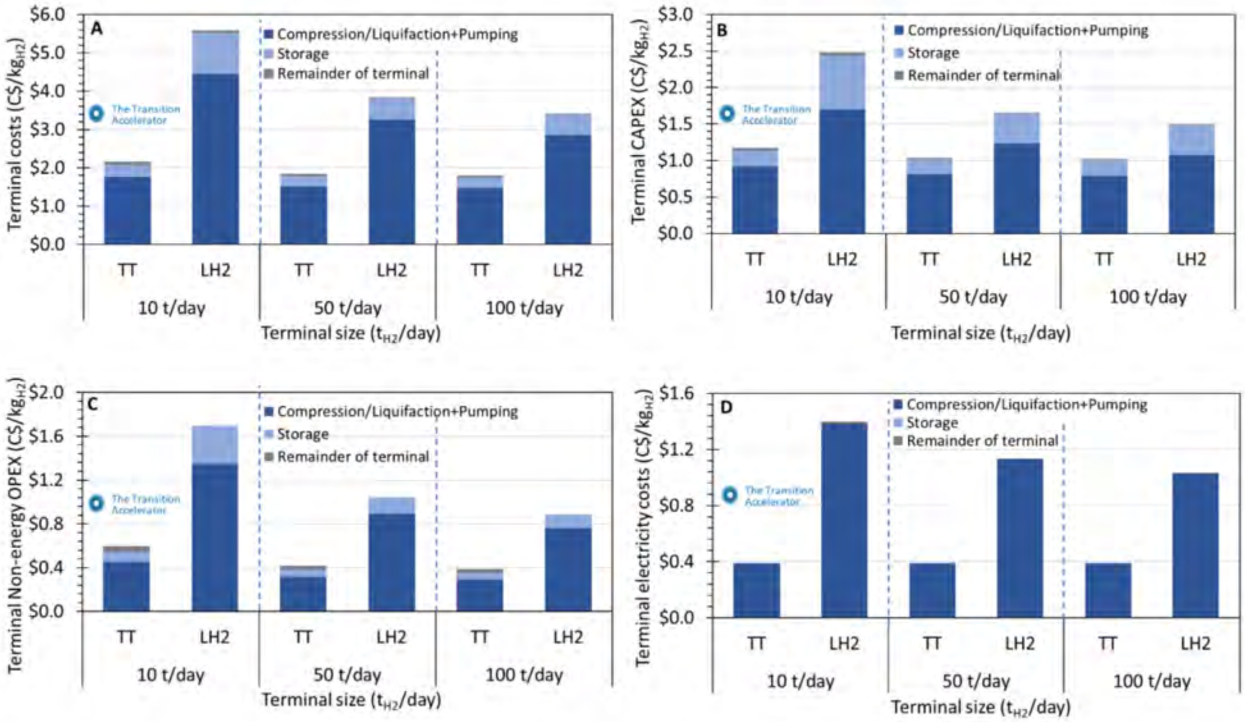

Figure 5.2. (A) Central terminal costs (C\$/kg$_{H2}$), (B) Terminal CAPEX, (C) Terminal Non-energy OPEX and (D) terminal electricity costs based on scale and H_2 delivery method i.e., TT or LH_2.

Note: The costs are further divided into contributions from different components such as compression, liquefaction (includes pumping), storage, and the remainder of the terminal.

5.3 Trucking Costs

After processing the H_2 at the central terminal, the H_2 can be delivered to respective HFS's via TT or LH_2 trucks. Truck delivery of gasoline and diesel fuel from refineries or storage terminals to fueling stations is well established. However, it is necessary to compress or liquify H_2 for transport because of its low volumetric energy density.

The first delivery mode considered in Supply Chain 'A' examines compressed gaseous truck transport. These are large trucks carrying TT's containing H_2 at a high pressure of 500 bar and a capacity of 1 t_{H2}/TT. The TT is filled at the central terminal, attached to the truck, and then driven to the respective HFS where it is left behind as part of the storage system at the gaseous HFS. It is assumed each truck cab makes several round trips per day between the central terminal and HFS's (including time for connecting a full TT to the truck cab, traveling between the plant and the HFS, dropping off a full TT and picking up an empty one, and returning the empty trailer to the H_2 plant. The number of truck cabs is determined by the total H_2 demand, truck capacity, the average time of each trip (including loading and unloading), and truck availability.

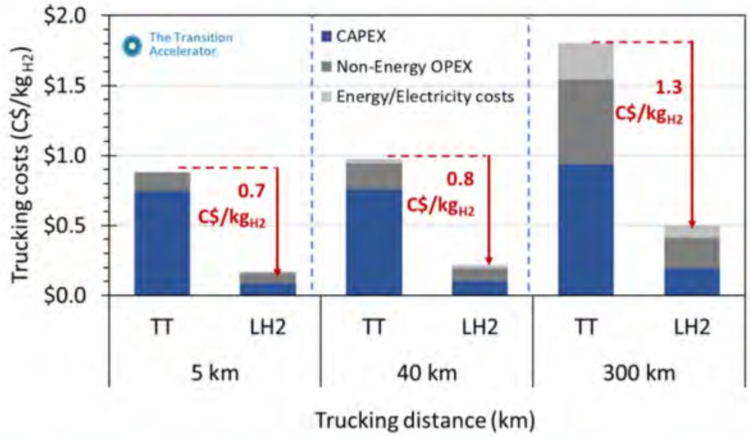

Figure 5.3. Trucking costs (C$/kg$_{H2}$) via TT or LH_2 trucks for different delivery distances (5, 40 or 300 km) and divided into: (A) CAPEX, (B) Non-energy OPEX and (C) energy/ electricity.

Table 5.2. Summary of assumptions used for compressed gas and LH_2 trucks [36].

Compressed gas truck	LH_2 truck
Truck capacity: 1 t_{H2} Max tube pressure: 520 bar Minimum tube pressure: 50 bar Truck yearly availability: 98% Time to pick up trailer at terminal: 1.5 hours Time to drop off trailer at terminal: 0.5 hours Time to drop off trailer at station: 1.5 hours Driver cost per truck: C$ 120,000/yr Diesel cost: C$ 1.2/L Truck mileage: 3.3 km/L Cab cost: C$ 163,996 TT cost: C $1,440,058	Truck capacity: 3.6 t_{LH2} Tank temperature: 253 °C Boil off losses at loading/unloading: 5% Truck yearly availability: 98% Loading time at terminal: 3 hours Unloading time at station: 3.5 hours Driver cost per truck: C$ 120,000/yr Diesel cost: C$ 1.2/L Truck mileage: 2.7 km/L Cab cost: C$ 174,340 TT cost: C $1,440,058

The second delivery mode in Supply Chain 'B' is based on liquid H_2 truck delivery. Each liquid H_2 truck consists of a truck cab and a large single liquid H_2 tank with a capacity of ~ 3.6 t_{H2}/tank. Like compressed gas trucks, the LH_2 trucks also fill their tanks at a central liquefaction terminal and then deliver to the respective LH_2 HFS. However, unlike TTs, LH_2 tanks are not left at the HFS. The large capacity of the LH_2 tank allows for fewer trucks and trips to supply a network of HFS. The main factors that determine H_2 delivery costs of both compressed gas and LH_2 trucks are the capital costs of the truck cabs and tube trailers/LH_2 tanks, the driving distance, the driver labor cost, diesel fuel cost, and operations and maintenance (O&M) costs. The detailed assumptions are listed in **Table 5.2**.

Figure 5.3 shows the trucking costs for Supply Chains 'A' and 'B' and as expected, the results show higher delivery costs as the distance between production site and HFS increases. Even when delivery distance increase, the trucking costs are dominated by capital costs of the TT or LH_2 truck while fuel (diesel) costs are only a minor contribution. In the near future, it can be expected that these delivery vehicles would be the first to be converted into HFCEV's. Lastly, the results also indicate that trucking via LH_2 trucks is more economical versus TT and the advantage for LH_2 trucking is magnified with increasing distance. The larger capacity of LH_2 trucks means multiple HFS's can be fueled in a single trip and although LH_2 tanks cost more than TT, the trucking cost per unit of H_2 delivered is lower due to the large capacity.

5.4 Pipeline Costs

As an alternative to trucking, a combination of transmission and distribution pipelines can also be used for delivering the hydrogen to HFS's. **Figure 5.4** shows the total installed costs/km of steel pipelines as function of nominal pipe size (NPS) for transmission and distribution lines. The total installed costs of the pipeline include material, labor, right of way and other miscellaneous costs. These costs were calculated using the HDSAM model developed by the Argonne national laboratory and are based on historical data for natural gas pipelines in the United States [36]. The detailed cost equations are available in The Transition Accelerator's report on "Techno-economics of H_2 pipelines" [10].

With small pipelines, the installed cost per km has little dependence on pipeline diameter as material costs are a relatively small fraction of total costs. The labor and right of way costs dominate in such a scenario. With larger pipes (>24 NPS), the installed cost per km is more sensitive to material costs. Additionally, the labor costs are higher for distribution versus transmission pipelines, because it includes pavement removal and replacement in urban areas.

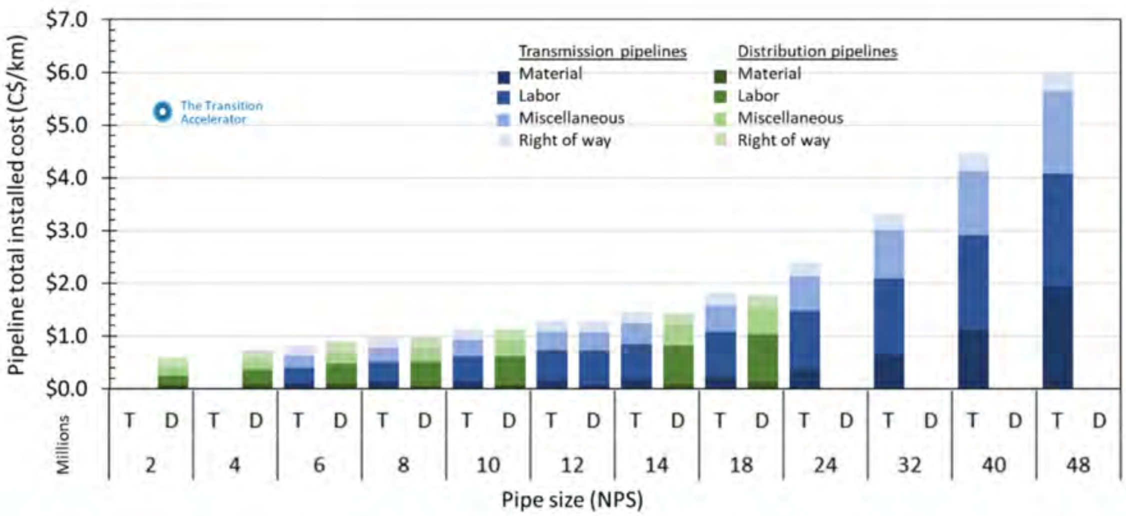

Figure 5.4. Total installed costs (TIC) of transmission (blue) and distribution (green) pipelines as function of nominal pipe size (NPS).

Note: TIC is divided into material, labor, right of way and other miscellaneous costs. T: Transmission pipelines. D: Distribution pipelines.

Since the results indicate that pipeline construction and installation is an expensive process costing millions of C$/km, substantial demand for H_2 will be required to amortize the cost over time.

5.4.1 Transmission Pipeline Cost

The ideal time to minimize the cost of gas transport via pipeline is during the initial design and construction, where gas flow calculations, project demand and other limitations are combined to optimize pipeline size, compressor units, flow rates, operating pressures etc. To gauge the appropriate transmission pipeline sizes for the different scenarios presented in Supply Chain 'C', gas flow calculations for different pipeline lengths of 295 km and 35 km, were conducted. The inlet pressure was assumed to be at 70 bars, outlet gas velocity of 30 m/s, flow temperature of 15 °C and a pipe roughness of 0.0178 mm. A single compressor station was modelled at the inlet of the transmission pipeline, using a centrifugal compressor with compression ratio per stage (x) of ~2.1, isentropic efficiency (η_{isen}) of ~80% and a motor efficiency ~95%.

Figure 5.5A shows the calculated pipeline capacity (t_{H2}/day) and pressure drop (bar) as function of nominal pipe size (NPS) for a 295 km long transmission pipeline. Pipe selection depends on many factors such as expected flow rates or volume, acceptable pressure drops and pipeline costs. Based on an assumed HFS inlet pressure of 20 bar and demand of 300 t_{H2}/day, the gas flow calculations indicate that pipes ≥ 12 NPS are required.

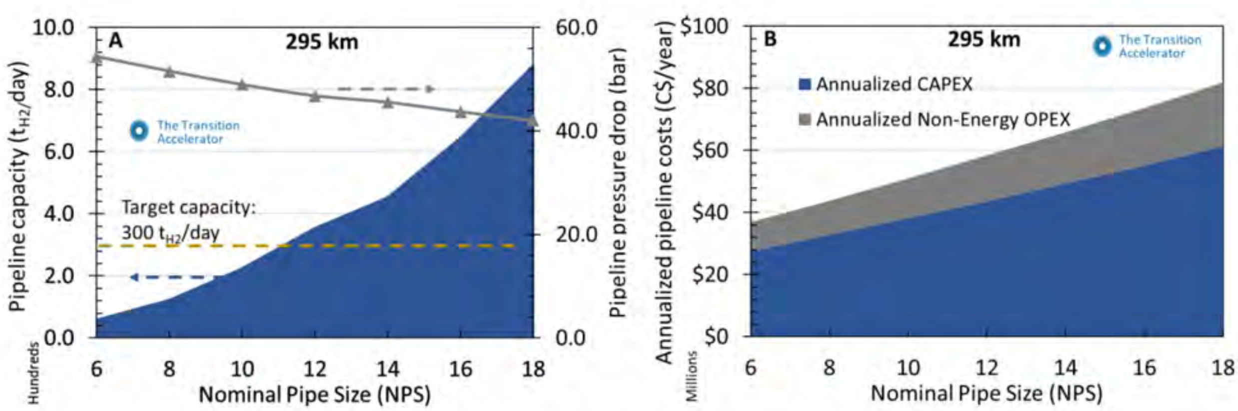

Figure 5.5. (A) Pipeline capacity (t_{H2}/day), pressure drop (bar) and (B) Annualized pipeline costs (C$/year) as a function of nominal pipe size (NPS) for a 295 km long transmission pipeline.

Note: The gas flow calculations were performed using an inlet pressure of 70 bars, outlet gas velocity at 30 m/s, flow temperature of 15 °C and a pipe roughness of 0.0178 mm.

The cost of the pipeline also is a key factor in pipe selection. **Figure 5.5B** shows the total annualized costs for a 295 km pipeline as function of pipe size, calculated over a lifetime of 50 years and at a discount rate of 8%. Since these costs are in millions of C$/year and increase with pipe size, it is critical to select a pipe large enough to allow for an adequate supply of gas to flow through but not so large that it remains underutilized and drives up the capital investment and H_2 delivery costs. Since the maximum demand in the proposed scenario was assumed to be 300 t_{H2}/day, a 12-inch steel pipe with a capacity of ~ 352 t_{H2}/day, was selected to model the transmission pipeline system costs over 295 km.

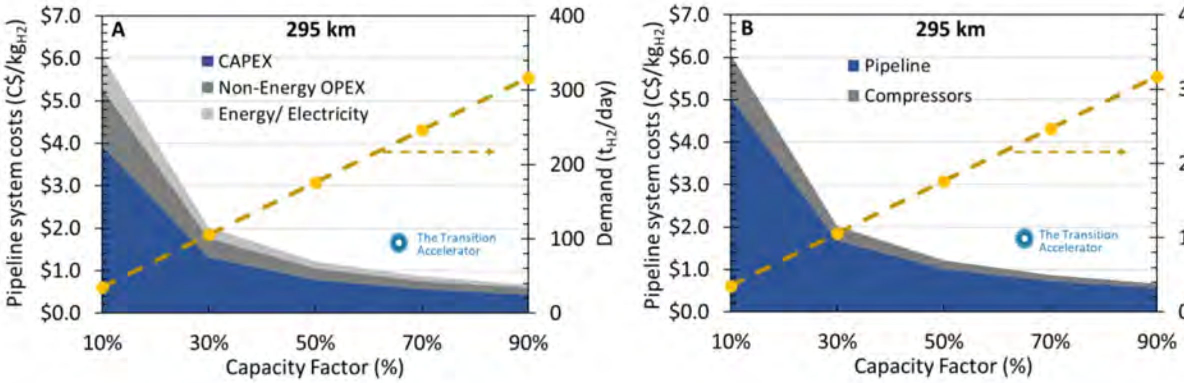

Figure 5.6. Pipeline system costs (C$/kg$_{H2}$) and demand (t$_{H2}$/day) for a 295 km long transmission pipeline as a function of average capacity factor (%) and divided into: (A) CAPEX, Non-energy OPEX and electricity costs or (B) Pipeline and compression costs.

Note: Inlet pressure is 70 bars, outlet gas velocity is 30 m/s, flow temperature is 15 °C and the pipe roughness is 0.0178 mm.

Ideally, a pipeline should be utilized at maximum capacity to lower the delivery cost of H_2. However, pipelines are designed with a higher capacity than the average flow rate to account for time variations in flow and allow for expansion. This leads to underutilized capital, which is modeled as an average capacity factor. **Figure 5.6** shows the pipeline system costs (C$/kg$_{H2}$) and calculated demand (t$_{H2}$/day) as a function of the average capacity factor (%). These costs have been divided into: (A) CAPEX, Non-energy OPEX and electricity costs or (B) Pipeline and compression costs. The results indicate the importance of working at high-capacity factors to reduce pipeline delivery costs. At a demand of 300 t$_{H2}$/day (utilization ~85%), the pipeline system costs are as low as 0.72 C$/kg$_{H2}$, with the major contribution from pipeline costs at 0.59 C$/kg$_{H2}$ and only 0.13 C$/kg$_{H2}$ due to compression. It is important to note that the pipeline delivery costs are capital intensive, with CAPEX contributing ~ 65% to the costs. These costs could be supported through government grants in an initial transition period where H_2 demand is not enough to attract private investment.

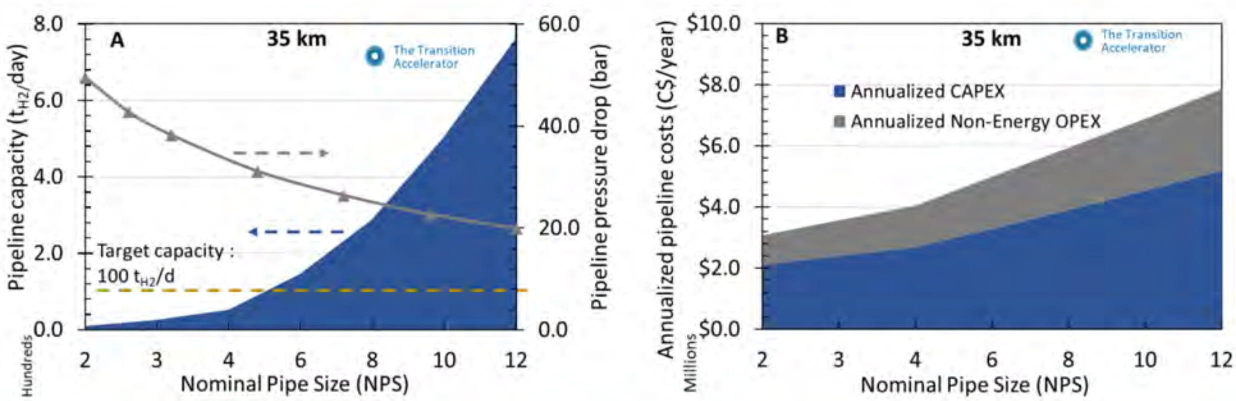

Figure 5.7. (A) Pipeline capacity (t$_{H2}$/day), pressure drop (bar) and (B) Annualized pipeline costs (C$/year) as a function of nominal pipe size (NPS) for a 35 km long transmission pipeline.

Note: The gas flow calculations were performed using an inlet pressure of 70 bars, outlet gas velocity at 30 m/s, flow temperature of 15 °C and a pipe roughness of 0.0178 mm.

Following the same methodology, pipeline capacity (t_{H2}/day) and pressure drop (bar) were calculated for a 35 km long transmission pipeline as shown in **Figure 5.7**. The 35 km distance leads to higher outlet pressures and lower annualized costs compared to the 295 km long transmission pipeline. In this scenario, a 6-inch steel pipe with a capacity of ~140 t_{H2}/day, was selected to analyze the costs over 35 km. **Figure 5.8** shows the pipeline system costs (C$/$kg_{H2}$) and calculated demand (t_{H2}/day) as a function of average capacity factor (%) for the 35 km transmission pipeline. In this case, the assumed demand of 100 t_{H2}/day with a ~75% capacity factor helps achieve pipeline system costs of 0.3 C$/$kg_{H2}$. Unlike long distance pipelines which are capital intensive, there is an equally important contribution from the electricity cost of compression. Nonetheless, the results indicate that if the demand is high enough, then a pipeline could be a low-cost option to transport H_2. This was described in The Transition Accelerator's report on "Techno-economics of H_2 pipelines" [10], which stated that for short distance pipelines that operate with only an inlet compressor, **"a demand of ~1-1.2 t_{H2}/day/$km_{pipeline}$ is needed to drive economic viability"**.

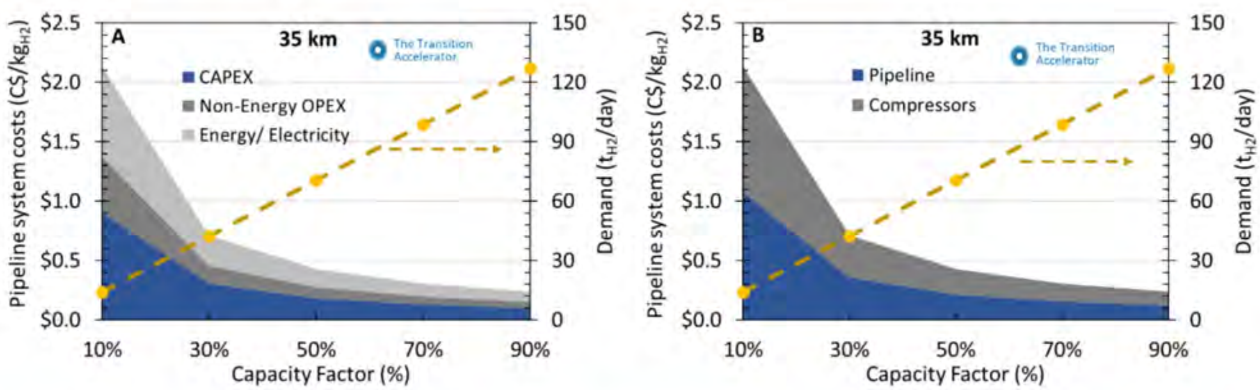

Figure 5.8. Pipeline system costs (C$/$kg_{H2}$), demand ($t_{H2}$/day) for a 35 km long transmission pipeline as a function of average capacity factor (%) and divided into: (A) CAPEX, Non-energy OPEX and electricity costs or (B) Pipeline and compression costs.

Note: Inlet pressure is 70 bars, outlet gas velocity is 30 m/s, flow temperature is 15 °C and the pipe roughness is 0.0178 mm.

5.4.2 Distribution Pipeline Cost

The design of Supply Chain 'C' as presented in Section 4.3, was based on dedicated distribution pipelines servicing the HFS's of different size: 0.4 t_{H2}/day, 2 t_{H2}/day and 8 t_{H2}/day, with an inlet pressure of 20 bar. Based on these design parameters, pipe size and costs were optimized, and the results are shown in **Figure 5.9**. The distribution pipelines were assumed to have an inlet pressure of 25 bars, outlet gas velocity of 20 m/s, flow temperature of 15 °C and a pipe roughness of 0.0178 mm. The gas flow calculations suggested the use of 1.5-inch, 2-inch, and 3-inch dedicated pipelines servicing the 0.4 t_{H2}/day, 2 t_{H2}/day and 8 t_{H2}/day HFS's. As a result, the annualized costs for short distance distribution pipelines are < 1 MM C$/yr and we observe a modest increase in pipeline costs relative to an increase in pipeline capacity. The pipeline system costs (C$/$kg_{H2}$) of these distribution pipelines with respect to HFS size is discussed next.

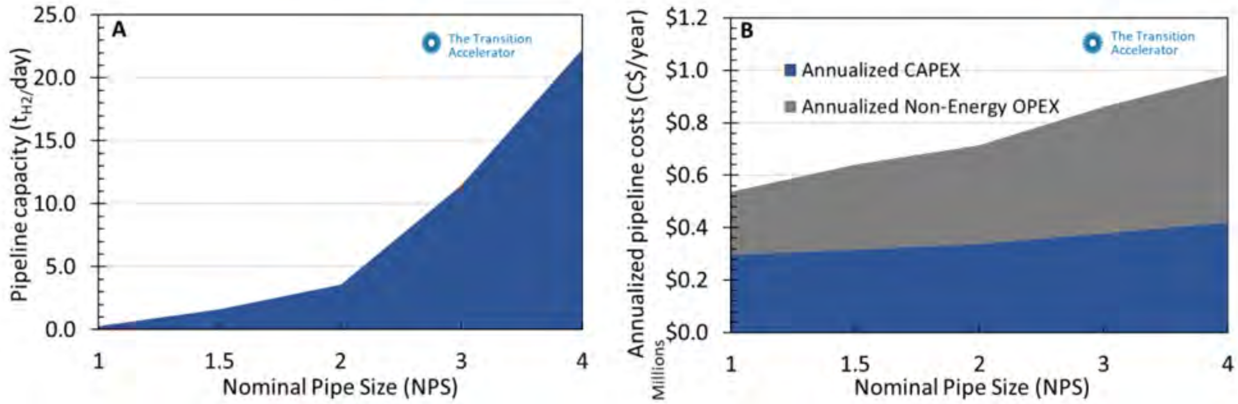

Figure 5.9. (A) Pipeline capacity (t_{H2}/day) and (B) Annualized pipeline costs (C$/yr) as a function of nominal pipe size (NPS) for a 5 km long distribution pipeline.

Note: The gas flow calculations were performed using an inlet pressure of 25 bars, outlet gas velocity at 20 m/s, flow temperature of 15 °C and a pipe roughness of 0.0178 mm.

5.4.3 Total Pipeline Cost

A summary of pipeline delivery costs of the different routes analyzed to deliver H_2 from production facility to respective HFS's is presented in **Figure 5.10**. The results indicate that 5 km long dedicated distribution pipelines have delivery costs of 5.03 C$/$kg_{H2}$, 1.15 C$/kg_{H2} and 0.36 C$/$kg_{H2}$ supplying 0.4 t_{H2}/day, 2 t_{H2}/day and 8 t_{H2}/day, respectively to the HFS's. Therefore, dedicated pipeline delivery will only be economically feasible to large sized HFS's.

For longer distances of 40 and 300 km, the total delivery costs using pipelines can be calculated by adding the cost of the 5 km distribution line with the respective transmission pipeline (35/295 km). The levelized pipeline system costs for a 40 km distance are 5.33 C$/$kg_{H2}$, 1.46 C$/kg_{H2} and 0.67 C$/$kg_{H2}$ delivering H_2 to fueling stations of different sizes, namely: 0.4 t_{H2}/day, 2 t_{H2}/day and 8 t_{H2}/day, respectively. The cost contribution of the 35 km transmission pipeline transporting 100 t_{H2}/day is only 0.3 C$/$kg_{H2}$.

Similarly for 300 km distance, the costs vary from 5.75 C$/$kg_{H2}$ to 1.08 C$/$kg_{H2}$ depending on HFS size and the contribution of the 295 km transmission line is only 0.72 C$/$kg_{H2}$.

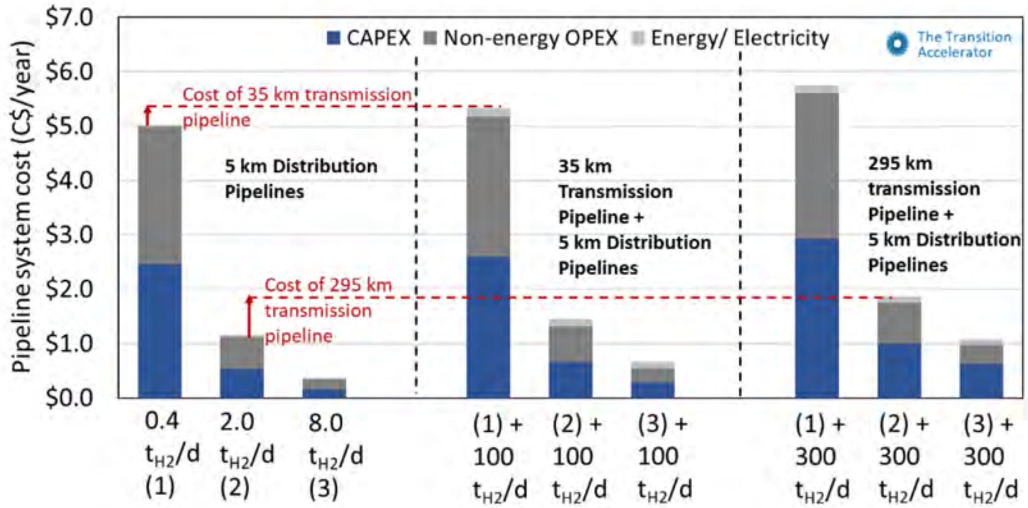

Figure 5.10. Pipeline system costs (C\$/kg_{H2}) for Supply Chain 'C' as a function of different delivery distances, HFS size and divided into: (A) CAPEX, Non-energy OPEX and electricity costs.

5.5 Hydrogen Processing and Delivery Costs

This section draws on the results presented in sections 5.1 5.4, to calculate the H_2 processing and delivery costs for Supply Chains A, B or C, i.e., delivery by TT's, LH_2 trucks or pipelines. For delivery via TT or LH_2 trucks, the cost of the central terminal (Section 5.2) and trucking (Section 5.3) were added to compare versus pipeline delivery (Section 5.4). **Figure 5.11** provides a comparison of H_2 processing and delivery costs across the three value chains as function of both distance and HFS size.

The first observation is that the HFS size only impacts the delivery cost in Supply Chain C, based on dedicated pipeline delivery to respective HFS. The results highlight that dedicated pipeline delivery will only be economically feasible to large heavy-duty HFS's that are dispensing ≥ 2 t_{H2}/day. Large size HFS's are the expected norm for heavy-duty transport as large Class 8 trucks will typically be carrying anywhere between 50-80 kg of H_2 fuel per vehicle.

Secondly, the results clearly indicate that pipelines are the lowest cost option to deliver H_2 at scale followed by TT and LH_2 trucks.

The third observation is that within the distances (5-300 km) analyzed in this study, the total processing and delivery cost via the LH_2 route is higher versus TT delivery due to the expensive liquefaction step. However, the results also indicate that delivery via LH_2 trucks will be more attractive for long distances (> 300 km) versus TT delivery.

Lastly, the analysis reveals that processing and delivery of H_2 is capital intensive, with CAPEX contributing 45-65% to processing and delivery costs, irrespective of delivery method. However, it is important to note that these costs are not the refueling cost of H_2 at the dispenser, which also comprises of the HFS cost as discussed next.

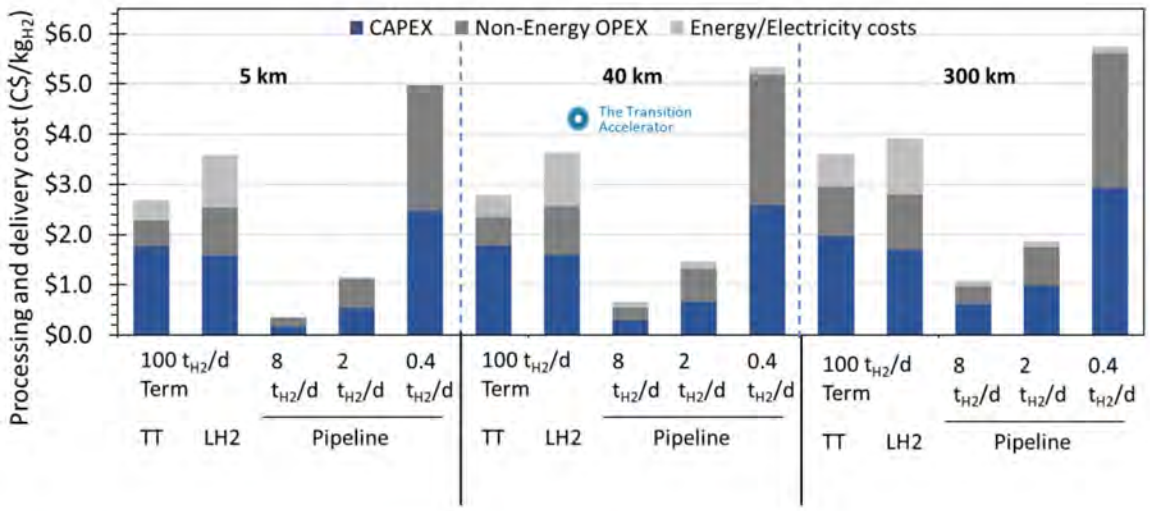

Figure 5.11. Processing and delivery costs (C$/kg$_{H2}$) for Supply Chains A, B and C, and divided into: CAPEX, Non-energy OPEX and electricity costs.

6 HYDROGEN FUELING STATION COSTS

6.1 Hydrogen Fueling Station Purification Costs

In the case of H_2 delivery by pipeline, the cost of further purification on site at the HFS must be considered. As mentioned earlier, PSA purification is the primary technology adopted for H_2 purification at centralized large-scale production facilities. Recently there have been several reports and pilot scale demonstrations of PSA purification for small-scale distributed H_2 production scenarios at HFS's [48-50]. Cerniauskas and coworkers [51] reported the capital and operating costs of a PSA unit for downstream H_2 purification. The capital cost can be calculated using the following correlation:

$$PSA_{capex} = a + b \times \frac{Q}{n_{H2}}$$

Where Q is the H_2 flow rate (mol/s) at the purification outlet and n_{H2} is the H_2 concentration in the feed flow. The PSA parameters are summarized in **Table 6.1**.

Table 6.1. Model parameters for a PSA unit deployed at pipeline-supplied HFS

Source: Adopted from Reference [51].

PSA parameters	Value
n_{H2}	98%
a	664,800
b	16,537,000
Lifetime	20
Operation and Maintenance (%)	4%
Recovery Rate (%)	93%
Electricity requirement (kWh/kg_{H2})	2.46

Using these parameters, the cost of onsite purification was calculated as shown in **Figure 6.1**. The results indicate that there will be a significant cost associated with small-scale on-site purification for small sized HFS's. However, with a large size HFS (8 t_{H2}/day), the purification costs are relatively low (< 0.4 C$/$kg_{H2}$) with the major contribution from electricity costs.

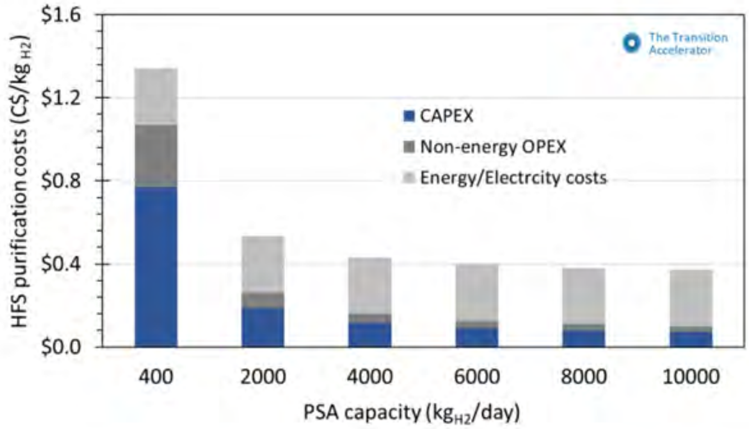

Figure 6.1. Purification costs for a pipeline supplied HFS (Supply Chain C), as a function of PSA capacity and divided into: CAPEX, Non-energy OPEX and electricity costs.

6.2 Hydrogen Fueling Station Costs based on Delivery Method

It is widely accepted that HFS's are the most complex component of the supply chain and have a significant contribution to the total refueling cost of H_2 at the pump [37,41,46]. Sections 4.1-4.3 described the design of the respective HFS's, and the operating parameters were summarized in **Table 4.1**. All the different HFS's are designed to address a typical hourly demand as shown in **Figure 6.2A**. The capacities of the compressor and buffer storage are interdependent [37,46] and defined by the hourly fueling-demand profile, which was taken from data by Chevron, based on statistics from its gasoline stations [52]. This data was based on light-duty passenger vehicles and does not ideally represent the demand profile at a heavy-duty HFS. However due to unavailability of the respective data, the HFS costs were modelled based on Chevron light-duty vehicles data [52]. The HFS size or dispensing capacity was controlled by changing the number of vehicles, as shown in **Figure 6.2(B-D)** [41,45]. The vehicle fill time dictates the maximum number of vehicles fills possible per hour per dispenser. Thereafter the number of dispensers required was calculated based on number of vehicles queued up to fuel at peak hours and the maximum number of vehicles fills possible per hour per dispenser. Based on the fueling rate of 7.2 kg/min and hourly demand, the number of dispensers was 1, 1, and 2 for HFS of size 0.4 t_{H2}/day, 2 t_{H2}/day and 8 t_{H2}/day.

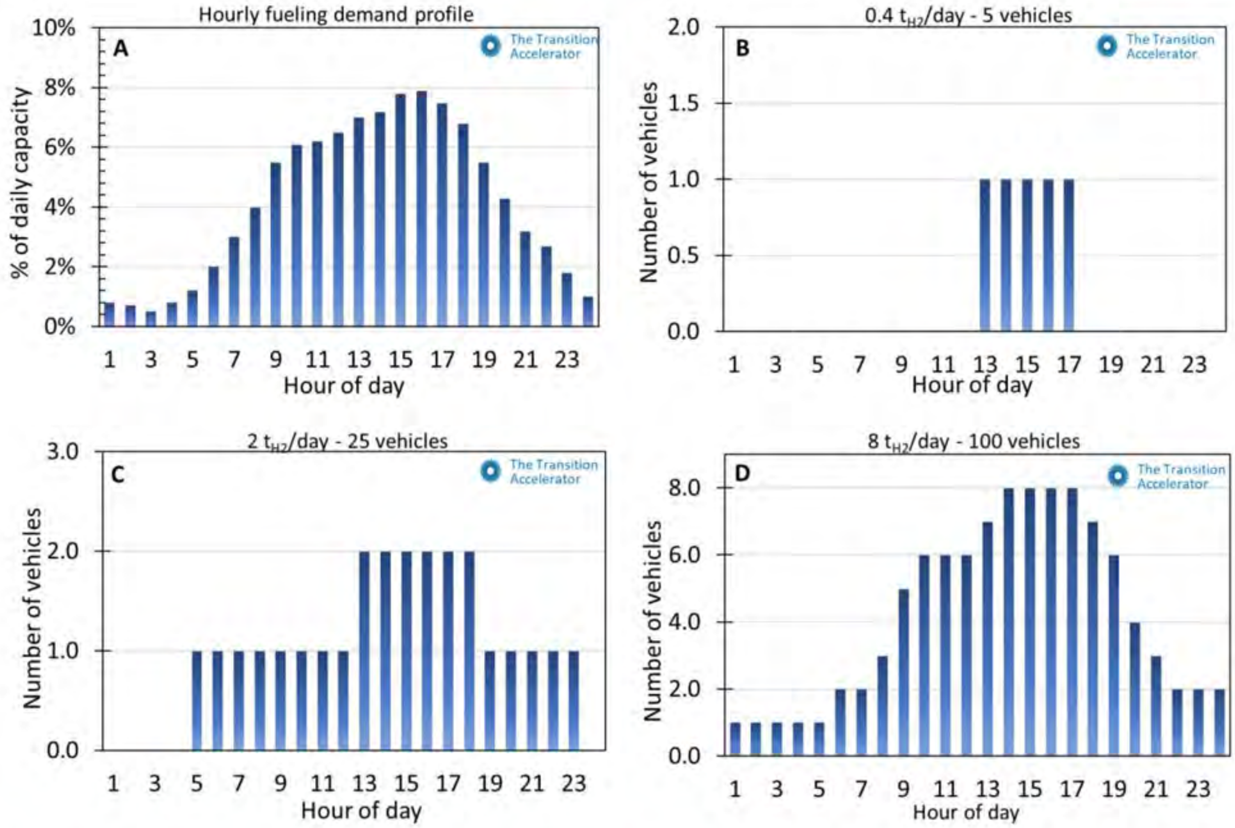

Figure 6.2. (A) Hourly fueling-demand profile for a Chevron gas station for light-duty vehicles [52] and number of vehicles for each hour for (B) 0.4 t_{H2}/day, (C) 2 t_{H2}/day and (D) 8 t_{H2}/day based on an average dispensed amount per vehicle of 80 kg.

Figure 6.3 presents the HFS costs in (A) C\$/year and (B) C\$/kg_{H2} as a function of HFS size (t_{H2}/day). The results imply that pipeline supplied HFS's are the costliest followed by TT supplied HFS's, and the LH_2 HFS's have the lowest cost. This trend is irrespective of the size of the HFS.

The first observation is that all the HFS's are capital intensive with CAPEX costs contributing 50-70% of the total levelized costs. The second key takeaway is on the importance of going to scale with any type of HFS. At small scales (0.4 t_{H2}/day) HFS's are expensive to install and operate with levelized costs between 5-9 C\$/kg_{H2}, which will not be feasible in any transportation market. Small fueling stations can be deployed for pilot demonstrations but the ability to quickly add capacity will be critical to reduce costs.

While building large size HFS's is key to reduce costs, it will only work when there is a demand for the H_2. In other words, the H_2 available at the station must be sold to amortize the cost of the station. In an early market, it is expected that the majority of HFS's will be underutilized. This will lead to significant impact on the cost of H_2 and the results for a 2 t_{H2}/day TT supplied HFS is presented in **Figure 6.4**. At 100% utilization, the levelized HFS cost is 2.29 C\$/kg_{H2} but increases sharply to 11.13 C\$/kg_{H2} at a 20% utilization factor. To give some context to the demand for a 2 t_{H2}/day fueling station, it will require 40 class 8 trucks using 50 kg_{H2}/day, or 80 transit buses using 25 kg_{H2}/day, or 2000 cars using 1 kg_{H2}/day to fully utilize the capacity of station. This suggests that certain H_2 fuel subsidies will be required to bring down the HFS costs during the initial deployment phase, which will be discussed in more detail in Section 9.

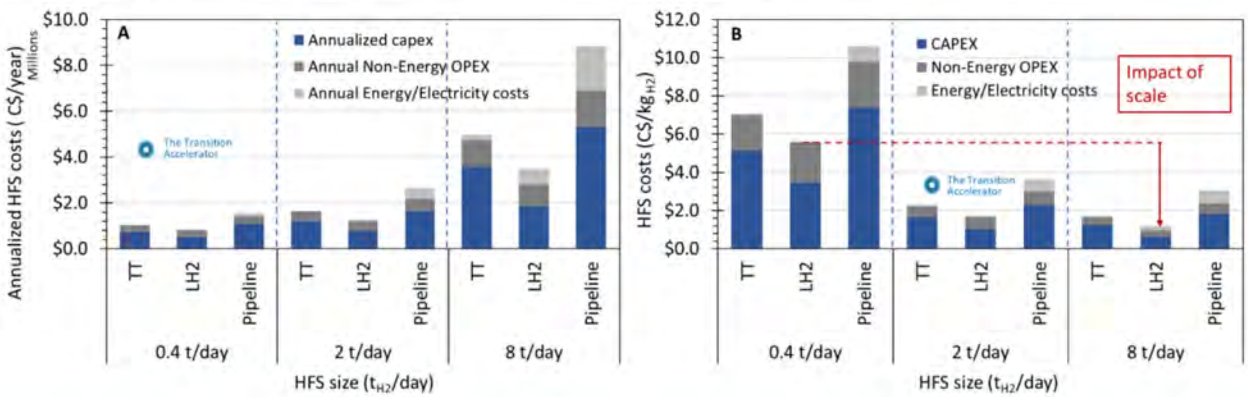

Figure 6.3. HFS costs in: (A) C$/year and (B) C$/kg_{H2} as a function of HFS size (t_{H2}/day) and divided into CAPEX, Non-energy OPEX and energy/electricity costs.

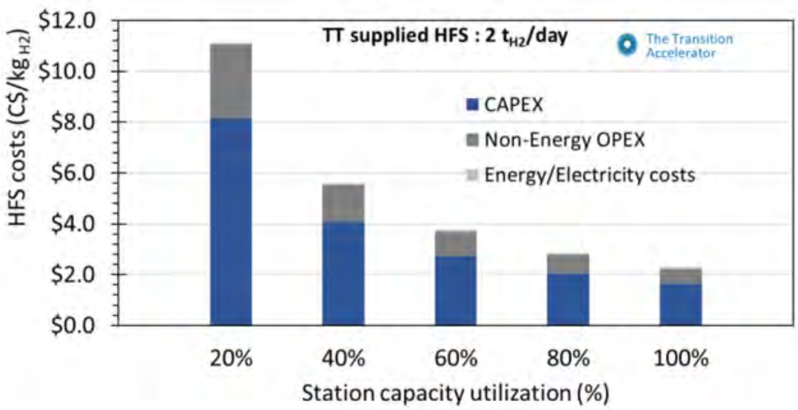

Figure 6.4. HFS costs of 2 t_{H2}/day TT supplied HFS as a function of capacity utilization (%).

The HFS costs were also analyzed by looking at the contribution from different components. The results presented in **Figure 6.5**, suggest that in small (0.4 t_{H2}/day) HFS's, both compression and storage are costly components. For pipeline supplied HFS's the cost of purification is also significant at small scales (0.4 t_{H2}/day). However, the storage and purification units exhibit a strong economy of scale and in larger HFS's the compressors become the costliest component. Additionally, LH_2 stations have a lower cost per kg since liquid storage costs less than gas storage and liquid H_2 pumps cost less than H_2 gas compressors. This is validated by looking at the breakdown of CAPEX and non-energy OPEX costs by different components as shown in **Figure 6.5B and C**. However, this is counteracted by the high costs of liquefaction at the central terminal as discussed in section 5.2. TT supplied HFS's are less expensive than the pipeline supplied HFS's as gaseous truck delivery has lower station storage costs because the tube trailers comprise most of the storage system (only a small high-pressure buffer storage tank is used to top off the vehicles). In addition, the high pressure H_2 delivery by TT to the HFS also reduces the compression energy requirement and this is observable by looking at the electricity costs in **Figure 6.4D**, that are the highest for pipeline supplied HFS, followed by LH_2 HFS and are the lowest for a TT supplied HFS. However, the lower costs for TT supplied HFS are counteracted by the extra compression and storage costs at the central H_2 terminal, as discussed in section 5.2.

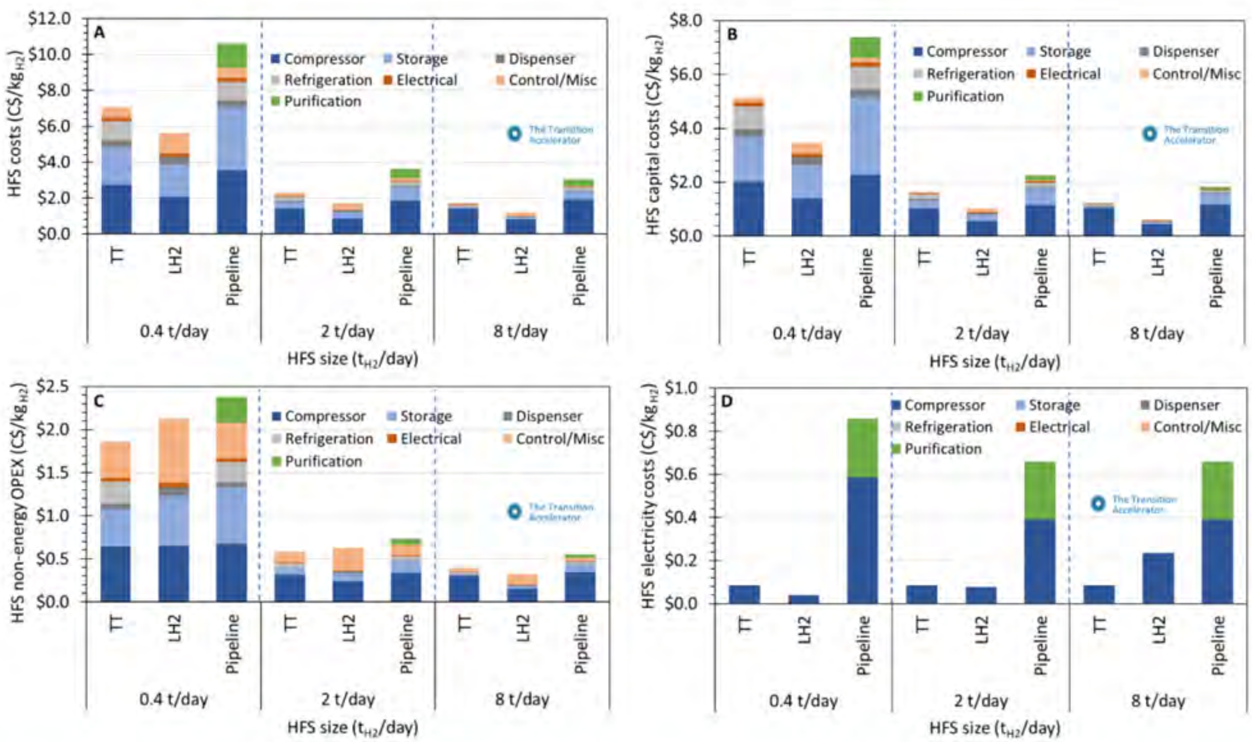

Figure 6.5. (A) HFS costs (C$/kg$_{H2}$), (B) HFS CAPEX, (C) HFS Non-energy OPEX and (D) HFS electricity costs as a function of HFS size (t$_{H2}$/day).

Note: Costs are divided into contribution from different components: Compressor, storage, dispenser, refrigeration, electrical and control system.

It is important to highlight that HFS costs are highly sensitive to demand profile. For example, a back-to-back filling profile requires additional compression and storage capability which could significantly increase costs [41]. Furthermore, various configurations and cost optimization strategies for HFS's could be used to bring down the costs. However, a detailed analysis of all these configurations and strategies is beyond the scope of this report.

7 SUMMARY: REFUELING COST OF HYDROGEN

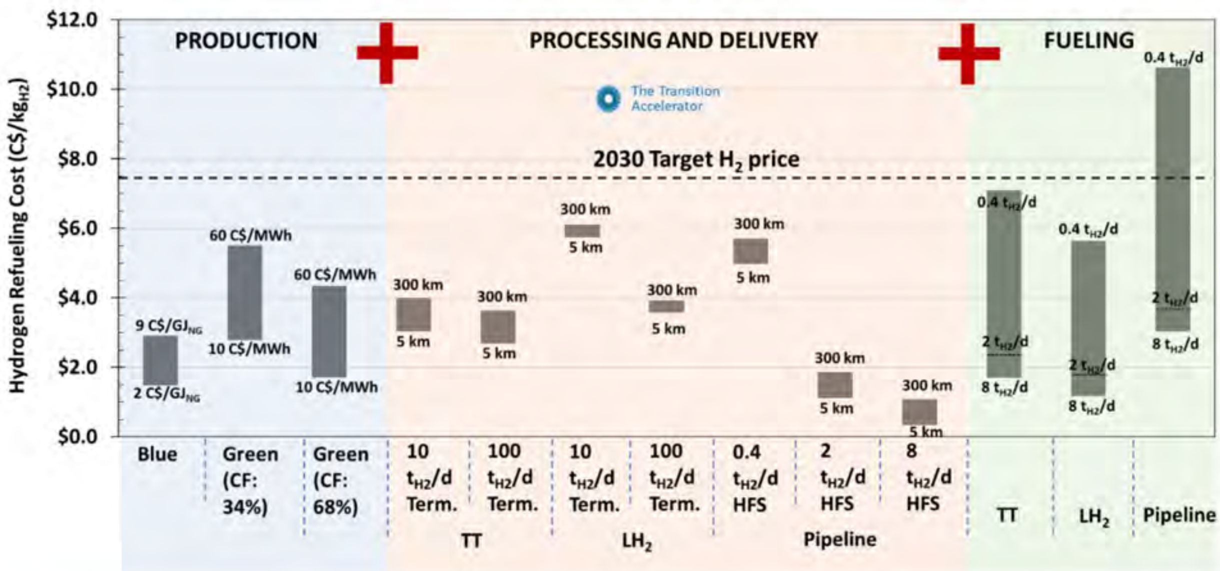

Figure 7.1. Refueling cost of H_2 (C$/$kg_{H2}$) for the different supply chains (A, B and C) and divided into production plus processing & delivery plus fueling cost.

Note: The black dash line represents the target H_2 retail price based on a diesel cost of 1.25 C$/$L_{diesel}$, drivetrain efficiency of 0.86 PJ_{H2}/PJ_{diesel} plus a 2030 carbon price of 170 C$/$t_{CO2}$, without any fuel taxes on H_2. The analysis assumes use of large transmission pipelines capable of transporting 300 t_{H2}/day over 295 km and 100 t_{H2}/day over 35 km.

The results presented in Sections 3, 5 and 6 are summarized in **Figure 7.1** as a function of critical parameters that determine the refueling cost of H_2. The production costs are presented for both blue and green centralized H_2 production as a function of natural gas (2 to 9 C$/$GJ_{NG}$) or electricity (10 to 60 C$/MWh) price, respectively. For green H_2 production costs, the impact of the capacity factor of power source is also presented. The processing plus delivery costs is presented for various Supply Chains as function of delivery distance (5 to 300 km). These costs are also categorized as function of central terminal size (10 and 100 t_{H2}/day) for Supply Chains A (TT) and B (LH_2) and HFS size (0.4 to 8 t_{H2}/day) for Supply Chain C (pipelines). Finally, the HFS/fueling costs are also presented as a function of HFS size (0.4 to 8 t_{H2}/day).

As stated earlier, the refueling cost of H_2 at the dispenser can be calculated from **Figure 7.1** as sum of production, processing plus delivery and fueling (HFS) cost. As an example, the lowest refueling cost calculated in the analysis was ~4.6 C$/$kg_{H2}$ based on using blue H_2 produced at a large central reformer with a natural gas price of 2 C$/$GJ_{NG}$ and delivered over a short distance of 5 km via a dedicated distribution pipeline to a large 8 t_{H2}/day HFS. Interestingly, the highest delivery cost of ~20.3 C$/$kg_{H2}$, would also be via pipeline delivery, in the case of green H_2 being produced via dedicated renewable electricity at a cost of 60 C$/MWh, and delivered over a distance of 300 km using a 295 km trunkline and 5 km distribution pipeline, to a small 0.4 t_{H2}/day HFS.

A few important observations can be summarized as follows:

- **Production costs:** The analysis reveals that to target a H_2 refueling cost that is competitive with diesel in 2030 at ~7-8 C$/$kg_{H2}$, the production costs will have to be < 3 C$/$kg_{H2}$. Currently this is only possible with centralized blue H_2 production irrespective of the natural gas or electricity price. In the future with an expected drop in electrolyzer costs, green H_2 production is expected to be competitive.
- **Processing and delivery costs:** The results also reveal that dedicated pipeline delivery will have the lowest costs as long as there is large demand (~1 t_{H2}/day per km of pipeline) to amortize the cost of the transmission pipeline and the distribution network supplies H_2 to large size HFS's. On the other hand, while trucking costs with LH_2 are low, total delivery costs are severely impacted by liquefaction costs. However, these costs can be significantly decreased by employing large scale facilities.
- **Fueling (HFS) costs:** The results indicate that LH_2 HFS's are relatively less expensive versus gaseous-supplied HFS's and irrespective of delivery mode, small sized HFS's will not be feasible if H_2 refueling costs must compete with diesel.

Figure 7.2 illustrates the processing plus delivery plus fueling costs (excluding production costs) for an ideal scenario whereby H_2 is delivered within a large mature hub which contains large (100 t_{H2}/day) central terminals for distribution and large sized (2 and 8 t_{H2}/day) HFS's. The costs are divided into: (A) CAPEX, non-energy OPEX and electricity costs or (B) Compression/Liquefaction and other costs. The results indicate that the delivery and fueling costs are CAPEX dominated with ~45-65% contribution for the different supply chains. In addition, the analysis highlights that compression and/or liquefaction are the costliest processing steps of the supply chains.

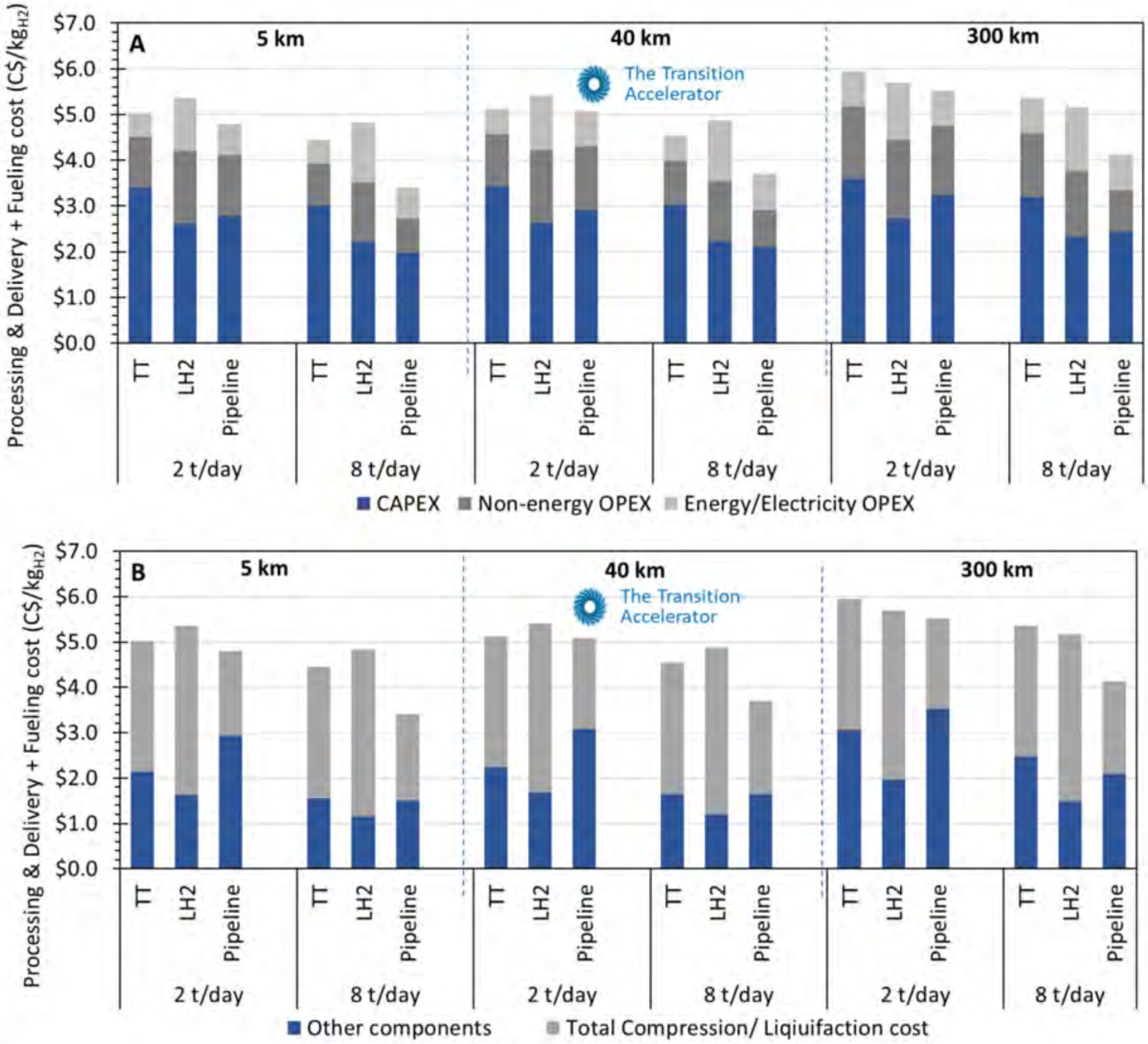

Figure 7.2. Processing & delivery plus fueling costs (C$/kg$_{H2}$) for a scenario where H_2 is delivered in a large mature hub which contains large (100 t$_{H2}$/day) central terminals for distribution and large size (2 and 8 t$_{H2}$/day) HFS's.

Note: Costs are divided into (A) CAPEX, Non-energy OPEX, energy/electricity costs and (B) Compression/Liquefaction and other costs.

The analysis resulted in the following **key takeaway messages:**

1) Scale/Demand is critical: The levelized cost of various components greatly depends on scale. There is a significant cost advantage by employing economies of scale, particularly for liquefier units, pipelines and HFS's. While employing economies of scale is important, it will only reap benefit if there is high utilization of the capacity of various process units. In other words, scale and demand must work together. Creating substantial demand (e.g., >2 t$_{H2}$/fueling station/day) in concentrated hydrogen hubs and corridors would be essential to economic viability. In transportation, this requires 100+ transit fuel cell buses, or 40+ Class 8 fuel cell trucks refueling daily at each station. This was demonstrated in **Figure 6.4** where we showed that the cost of an underutilized 2 t$_{H2}$/day HFS can increase exponentially.

2) **Small HFS are not feasible:** Even in under optimized conditions where the delivery components are operating at large scale, the use of a small sized (0.4 t_{H2}/day) HFS is not economically feasible. However, in an early market with a low number of HFCEVs, it is likely that small sized HFS's that require a lower capital investment will be deployed. Therefore, it is critical that these HFS's are designed with the capability to increase capacity quickly as H_2 fuel demand increases.

3) **Demand will dictate suitable delivery option:**
   a. Delivery via TTs is more suitable in an early market whereby delivery and fueling are done at a smaller scale. This is because scale has a lower impact on the cost of central compression versus liquefaction or dedicated pipelines.
   b. Liquefaction is highly sensitive to scale and adds substantially to the H_2 fuel cost (+3 C$/$kg_{H2}$) but reduces the cost of both truck delivery and HFS infrastructure. Therefore, LH_2 is the technology of choice for larger stations (2 to 8+ t_{H2}/day) that are further from the site of production, especially if pipeline infrastructure is not available.
   c. In a mature market where the H_2 fuel is delivered at scale (100s of t_{H2}/day) and large HFS's (≥ 2 t_{H2}/day) are deployed, delivery via pipeline will be the lowest cost.

4) **Pipelines are essential to enable H_2 use in multiple sectors:** Given current technologies and potential demand for H_2 fuel (Refer to Section 2.1), pipelines are the only practical option that enables opportunities in multiple sectors (transport, heat, power) and realize a cost and scale of supply/demand that justifies the necessary infrastructure investments. This synergy among multiple demand sectors delivers benefits to all and should be integrated into strategic planning for the energy transition in Canada.

5) **New value chain is capital intensive:** H_2 delivery and fueling costs are dominated by the CAPEX contribution that is ~45-65% for the different supply chains. Additionally, as economies of scale are employed to drive down the costs, the required capital investment will be in millions of C$. Therefore, as we move forward various policies and financial instruments will be required to remove market barriers, mitigate this risk, and accelerate the transition. This will be discussed further in Section 9.

6) **R&D required on compression and liquefaction technology:** The analysis also highlights that the compression and/or liquefaction are the costliest processing steps of the supply chains. Technological improvements that increase efficiency, reliability and lifetime of currently available compressors and liquefaction units will be critical to reduce both capital and operating expenses.

8 GROWING A FUEL HYDROGEN ECONOMY IN EDMONTON REGION

The results presented in the previous section, illustrate the importance of minimizing barriers in connecting supply to demand. The analysis also indicates the scale of the challenge in developing a new value chain which will take coordinated effort between different stakeholders to quickly scale up demand and drive down costs. Moving forward, a key step would be the creation of regional hydrogen hubs and economic corridors to improve coordination and connect supply to demand. While the findings presented here should have relevance to any region of Canada, the analysis is of particular relevance to the Edmonton Region Hydrogen HUB (ERH2) (https://erh2.ca/), and Alberta Industrial Heartland (AIH) (https://industrialheartland.com/). Regional hubs such as the ERH2 are key to bring together various stakeholders from government, industry, independent think tanks, end users and Indigenous leaders to launch strategic projects and kickstart the H_2 economy. Edmonton and the AIH region are strategically positioned to be a global H_2 leader, whereby current H_2 production capacity exceeds 2000 t_{H2}/day along with world class infrastructure for CCUS ([8]). To this end, potential demand centres for heavy-duty H_2 freight and corridors which can connect H_2 supply with demand are identified.

Connecting supply to demand is one of the greatest challenges associated with building-out a new H_2 value chain. Centralized H_2 production facilities in AIH are in close proximity to each other and adjacent to existing H_2 and CO_2 pipeline assets [8,53]. The region is underlain by geological formations with large sequestration potential at the right depth for permanent CO_2 storage. More importantly, supply is also in close proximity to corridors/areas in and around Edmonton that have potential for substantial demand for H_2.

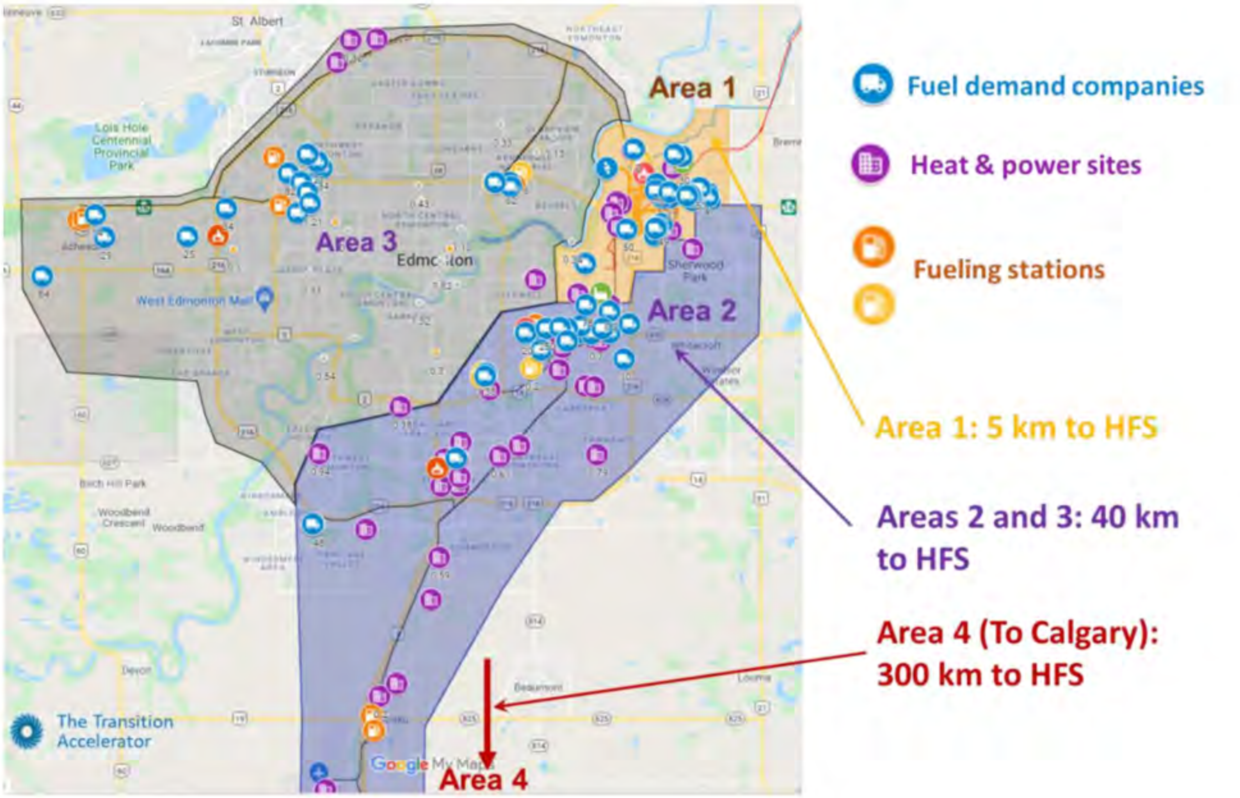

Figure 8.1. Areas in Edmonton/AIH region where supply can be connected to demand for H_2 use as transportation fuel for heavy-duty freight.

Of the approximately 34,000 heavy-duty vehicles (HDV) registered in the Edmonton region for commercial transportation [8,54], the majority are associated with commercial carriers found along Highway 16 which cuts across the north side of the City of Edmonton. There is another industrial corridor that moves across from the north-east side of the city of Edmonton (**Figure 8.1**) i.e. Sherwood Park, bisecting the south-east quadrant of the city, 40 km down to Edmonton International Airport (EIA) [8]. The estimated fuel demand for heavy-duty freight from this region is ~ 23 PJ diesel/yr [8]. Based on a DTE of 0.86 GJ_{H2}/GJ_{diesel} and the energy density of H_2, the potential H_2 demand from the heavy-duty freight sector in the region can be calculated to be about ~382 t_{H2}/day.

There is also significant fuel demand associated with trucks on major highways moving from the region to cities such as Calgary and Fort McMurray, representing potential H_2 demand of ~150 t_{H2}/day [8]. The 300 km Calgary-Edmonton highway is the busiest representing a potential demand of ~93 t_{H2}/day [8]. Furthermore, municipal fleets in the region can play a key role in building H_2 fuel demand. Municipal fleet buses account for ~3% of the city's diesel demand, which translates into ~ 20 t_{H2}/day demand [8].

Several large refueling stations can be found in the same regions (**Figure 8.1**), providing heavy-duty trucks and municipal vehicle fleets with diesel fuel. Ideally, HFS's would be co-located with diesel at existing stations. One advantage of targeting the commercial carrier segment is that only a few, high-capacity stations are needed to supply a large fuel market. This is essential for rapid transition of the fuel supply and delivery systems that can compete with the incumbent diesel market without ongoing public investment. Based on the analysis of supply, potential demand, and HFS locations we propose the buildout of HFS's in four different zones/areas as the base case to developing a new H_2 value chain as identified on the map in **Figure 8.1**. On an average the various HFS's in these areas would be 5, 40 and 300 km respectively from a central H_2 production site.

Therefore, the TEA results of the different supply chains analyzed in this study can be applied to the region as follows:

- Compressed H_2 TT delivery could be used in an initial market with low demand and short distances. This could be envisioned as a feasible option for initial pilot demonstrations such as those in the Sherwood Park area or at/near EIA. Furthermore, since a TT supplied HFS can potentially be converted to a pipeline supplied HFS, the TT route can be adapted to increasing demand and offers a pathway to cost competitiveness.
- LH_2 truck delivery can be a solution when there is a small to medium H_2 demand and long distances involved. Moreover, LH_2 delivery is an ideal option to distant remote locations where building of pipelines is not feasible in the near to medium term. This route can be envisioned in transporting H_2 from Edmonton to Calgary until demand is high enough to justify building a pipeline.
- To achieve retail costs for fuel H_2 that are competitive with current diesel prices, pipeline transport of H_2 to various HFS's in Edmonton and to Calgary offers the most potential. However, to justify the infrastructure investments, an 'economy-of-scale' is needed that is best achieved by H_2 pipelines following transportation corridors to serve the transport sector in the region while also delivering fuel H_2 for power generation and buildings in a net-zero future.

9 CONCLUSIONS AND RECOMMENDATIONS

Underpinned by a global shift toward decarbonization, H_2 is receiving unprecedented interest and investments. At the beginning of 2021, over 30 countries have released H_2 roadmaps, the industry has announced more than 200 H_2 projects, and governments worldwide have committed more than 70 billion US$ in public funding. This momentum exists along the entire value chain and is accelerating cost reductions for H_2 production, transmission, distribution, retail, and end-use.

The Government of Alberta also recently released its H_2 Roadmap detailing the role of a clean H_2 economy in Alberta's future. With an established oil and gas industry, rapidly growing renewable sector, and access to ideal geology for permanent storage of carbon dioxide, the onus is on Alberta to fully utilize the potential of H_2 in its net-zero journey and unlock significant economic value for the province. Yet the challenges ahead are substantial as H_2 value chains are complex, and the risks faced by investors are significant. Co-ordination problems between different parts of value chains persist, costs are changing quickly, and technologies are developing rapidly. Therefore, it will take smart policies and a concerted effort on behalf of industry, government, and consumers to grow supply and demand.

Based on the results discussed in this report, there are a few recommendations that can accelerate the adoption of H_2 as a clean fuel and highlight the synergy between different demand sectors. These recommendations cover various critical needs such as scaling up demand, developing infrastructure that caters to different sectors, attracting investors, reducing costs, and ensuring refueling infrastructure is strategically located. The recommendations are as follows:

1. **Develop strategic plans and regional hubs.**
2. **Target economies of scale and mitigate investment risks.**
3. **Support demand creation.**
4. **Promote innovation, strategic projects, and knowledge-sharing.**

9.1 Develop Strategic Plans and Regional Hubs

As mentioned earlier the Governments of Canada and Alberta have released their respective H_2 Strategy [55] and Roadmap [22]. These reports summarize how H_2 can be used to support decarbonization efforts and describe policy pillars required to make sure the full potential of H_2 can be tapped. These were vital first steps to provide stakeholders with certainty about the future marketplace of H_2.

In the context of Alberta, H_2 not only offers a great opportunity to advance towards a clean future but as an economic driver that creates diverse opportunities. As summarized in Section 2.1, the potential demand for H_2 fuel in the province is ~13,289 t_{H2}/day. If domestic and international export potential is added to this, the economic opportunity ahead will be in billions of C$ per year. This will also have widespread, direct, and indirect social and economic benefits, where new employment opportunities are created to support the H_2 economy. In the next step, to activate their strategies and roadmaps, government should create a strategic suite of policies and incentive programs that stimulate demand in coordinated ways that will be economically sustainable in the long-term.

A key part of the strategic planning would be to analyze the **interdependencies among different demand sectors** and plan infrastructure development for the future accordingly. The analysis presented in this report highlights that transportation presents the first target sector for H_2 fuel use (Section 2.2), as it can attract a much higher price versus heat or power generation. In an early market scenario where demand is low, the development of a new value chain around the use of TTs and LH_2 trucks to deliver H_2 fuel for transport will make more economic sense. However, the strategic planning must consider that pipelines will represent the lowest-cost delivery option in a mature market where demand is higher. More importantly, the high cost of H_2 compression for tube trailers, or of liquefaction for LH_2 transport, undermines the economic viability for H_2 fuel to be used for electricity generation or for space/water heating in buildings. Given current technologies, pipelines are essential in enabling all three market opportunities and realizing a scale of supply and demand that justifies the necessary infrastructure investments. The use of pipelines to deliver H_2 fuel for transport will **lead to a virtuous cycle** that enables different demand sectors and delivers benefits to all. Therefore, this should be integrated into strategic planning for the energy transition in Canada.

In addition, as highlighted in the previous section, moving forward, a key step would be **the creation of regional H_2 hubs and corridors to improve coordination and connect supply to demand**. As an example, the build out of HFS's along key transport corridors should be targeted, as discussed in section 8. Commercial carriers and fleet vehicles with high daily mileage along these fixed corridor routes present a promising opportunity, that could help increase the utilization rate of refueling stations on the main routes they use. Other opportunities exist with fleet vehicles at industrial sites, clusters and at ports. The work done in the establishment of regional hubs such as the ERH2 could be used as a base case template to form similar hubs across the country. The energy transition is a complex challenge, and these hubs will be instrumental in bringing together various stakeholders from the government, industry, and demand sector to work together to minimize barriers.

9.2 Target Economies of Scale and Mitigate Investment Risks

The factors limiting H_2 use today are economic rather than technological, as H_2 is not yet cost competitive compared to conventional fuel options such as diesel. The key takeaway message from this report is that: '**Scale Matters**', and the cost benefits of economies of scale in H_2 supply and distribution must be realized. Thereafter, once we get to 'efficiencies of scale', an economically viable system will take over. Getting to scale will require significant capital investment in millions of C$ that supports infrastructure development for delivery and refueling. However, the capital investment will only pay back if the equipment is well utilized, so there must be risk mitigation for that capital till demand increases. Therefore, policy makers and/or financial institutions need to employ various policies and financial tools to remove market barriers, ease regulatory burdens and **mitigate investment risk** which will attract private investment. Technical assistance, grants and interest free loans can play a critical role early in the project. Other tools could be in the form of time-bound capacity payments in exchange for a fixed or indexed H_2 delivery price to incentivize build-out at scale, or guaranteed off-takes to meet utilization targets, or conditional capital to reduce utilization targets. Public finance institutions can make key contributions by providing investors with risk guarantees and other insurance tools.

9.3 Support Demand Creation

While employing economies of scale is key, it fails without securing the demand for H_2 fuel. Thus, supporting demand creation goes hand-in-hand to ensure quick ramp-up to maximize utilization and gain the benefit of economies of scale. The focus of most government policies is on producing low carbon H_2, while measures to increase demand receive less attention. Boosting the role of low-carbon H_2 in clean energy transitions requires a step change in **demand creation**. For the heavy-duty transport sector, non-financial incentives like priority lanes, zones and parking spaces can help, but significant demand will not materialize without a range of available vehicles at acceptable prices, coupled with predictable and affordable fuel prices. Currently, both vehicles and H_2 delivery costs are high due to a low production volume and lack of infrastructure. These costs are expected to decrease dramatically with an increase in production, technology improvements and buildup of associated infrastructure. Until then, vehicle purchase and fuel subsidies along with other tools, such as carbon pricing and credits, will be required to incentivize fuel-switching from diesel to H_2. These demand building policy tools and programs should be designed to support an achievable rate of adoption, and need to be coordinated in scope, scale, and timeline with infrastructure development plans, policy tools, and programs.

9.4 Promote Innovation, Pilot Projects, and Knowledge-Sharing

As discussed in Section 7, the results indicate that compression and liquefaction are the costliest components of the supply chains, contributing >50% to refueling costs. **Technological innovation** that increases efficiency, reliability, lifetime and reduces the manufacturing costs of currently available compressors and liquefaction units will be critical to drive down both annualized capital and operating expenses in the long term. Therefore, research efforts on these key components will be important in the next few years. In addition, R&D efforts are needed to drive down fuel cell stack, material, and manufacturing costs, as well as other HFCEV specialty component costs such as H_2 storage tanks.

Importantly, providing **support to shovel-ready projects** can kick-start the scaling up of low-carbon H_2 production, development of infrastructure to connect supply sources to demand centres, and manufacturing capability from which later projects can benefit. These pilot projects can be used to explore 'fit for service' potential of H_2-using vehicles under real-world conditions in Alberta and across Canada, helping prepare demand sectors for adoption of hydrogen at scale. Insights must be made public, including transparent discussions of pros and cons, to assess the viability of H_2 vehicles for specific end-uses. When evidence of 'fit for service' has been achieved, public support will be required to deploy dozens to hundreds of HFCE and/or H_2-diesel vehicles (including buses, trucks, trains) in partnership with municipalities or companies, relying on multiple HFS's. The Transition Accelerator has played a key role in launching strategic demonstration projects such as the Alberta Zero-Emission Truck Electrification Collaboration (AZETEC) [56] and Alberta Zero-Emission Hydrogen Transit (AZEHT) [57] together with key industrial players and different levels of government organizations. The AZETEC project involves the development of two HFCEV trucks running between Edmonton and Calgary along with the mobile refueler. Similarly, AZEHT involves the purchase and testing of two HFCEV buses for Edmonton and Strathcona County. These projects will play a key role in laying the foundation for Alberta's energy transition.

Lastly, as highlighted earlier, the H_2 value chain is complex and the successful adoption of H_2 will require **effective communication and knowledge sharing** between different stakeholders. During this phase, government, Hubs, and non-profit think tanks, such as The Transition Accelerator can play a key role to ensure there is effective knowledge sharing and an accessible market for everyone.

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