U.S. DEPARTMENT OF ENERGY

Component Design Report:

Representing Hydrogen in the National Energy Modeling System

Revision 1

Prepared for:

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Disclaimer

Executive Summary

The use of hydrogen as an energy carrier is expected to substantially contribute to the achievement of deep decarbonization goals. However, introducing a significant role for hydrogen in the energy supply requires comprehensive changes across many sectors of the economy. An extensive infrastructure will need to be developed involving its production, transportation, storage, and utilization. Policies and incentives may be needed to overcome the significant market barriers that exist to the widespread adoption of hydrogen.

The National Energy Modeling System (NEMS) is the main energy markets projection and evaluation model from the U.S. Energy Information Administration (EIA). While NEMS contains complex endogenous representations of many components of the U.S. energy market participants, its representation of hydrogen infrastructure is limited. It is mainly focused on the use of hydrogen sourced from fossil fuels for refineries and as a vehicle fuel in the transportation sector. However, the role of hydrogen may be far broader than just transportation and refining.

The Office of Carbon Management (OCM) of the Office of Fossil Energy and Carbon Management (FECM) and the Hydrogen and Fuel Cell Technologies Office (HFTO) of the Office of Energy Efficiency and Renewable Energy (EERE) have been tasked with developing this Component Design Report (CDR). Both offices have coordinated with the U.S. Energy Information Administration (EIA) and OnLocation in developing this CDR to describe the NEMS enhancements necessary to model various hydrogen pathways.

NEMS is comprised of modules representing supply, conversion, and demand sectors of the energy economy. However, hydrogen introduces a considerable overlap in functionality between these sectors. This CDR discusses the design choices that must be made to represent hydrogen pathways and provides a recommendation on how the model enhancements may be structured. It also provides a list of NEMS modules that require changes and describes the data flow between modules necessary to represent the hydrogen pathways discussed earlier in the CDR.

A central feature of the proposed model enhancements is a new conversion module, the Hydrogen Market Module (HMM). This module will model various conversion processes, taking fuels from the coal, natural gas, electricity, and renewables modules and producing, storing, and transporting hydrogen to supply the Industrial, Commercial, and Transportation modules. In addition, the Electricity Market Module (EMM) will separately produce hydrogen for electricity production, storage, and utilization within the power sector as a seasonal storage option. The model enhancements will include the ability to transport a single homogenous hydrogen-natural gas blend in the Natural Gas Market module. The hydrogen natural gas blend will then be distributed to the demand modules of NEMS. Finally, the HMM will send captured CO_2 quantities to the Carbon Transportation, Utilization and Storage (CTUS) module. Like other modules, the HMM will provide the emissions module with the quantities of fossil fuels consumed and assumed to be combusted and the carbon sequestered.

The goal of the HMM is to minimize total system costs, that is, costs of production, storage, and transportation of hydrogen to meet the requirements from the other modules. The overall structure of the HMM will be a constrained mathematical program that will be used to guide the technology choices for capacity planning, while a separate optimization will determine annual hydrogen flows given production capacity, storage, and transportation. Costs will be based on a financial model that uses net present value of capital expenditures for each technology.

Hydrogen may be produced in a central location and distributed through a dedicated pipeline system or produced locally and self-supplied to specific locations. The HMM will provide sector specific hydrogen pricing for both centralized production and distribution and a regionally specific price of hydrogen for self-supply and may compete with the hydrogen production in the demand and conversion modules. Hydrogen production with steam methane reforming (SMR) for use in the refining sector will continue to be included in the Liquid Fuels Market Model (LFMM). Localized hydrogen production for transportation consumption may be modeled in the Transportation Demand Module (TDM), however, this may be in a reduced form rather than at the technology level. Hydrogen production for use with a seasonal storage component in the Electricity Market Module (EMM) is under development at EIA. This initiative will be incorporated into the current project. Finally, localized hydrogen production for industrial processes may be modeled in the Industrial Demand Module (IDM). This production is a closed source, being produced and consumed within the industrial module and is outside the scope of a national hydrogen network.

The recommendations of this CDR will be followed by an implementation plan that lays out the order of activities to be done to build these enhancements into NEMS.

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1. Introduction and Background

1.1. Role of hydrogen as an energy carrier

The use of hydrogen as an energy carrier is expected to contribute substantially towards the achievement of deep decarbonization goals. However, introducing a significant role for hydrogen in the energy supply requires comprehensive changes across many sectors of the economy and is a complex endeavor. An extensive infrastructure will need to be developed for its production, transportation, storage, and utilization.

The National Energy Modeling System (NEMS) is the main energy markets projection and evaluation model from the U.S. Energy Information Administration (EIA). While NEMS contains complex endogenous representations of many components of the U.S. energy market participants, its representation of hydrogen infrastructure is limited. It is mainly focused on the use of hydrogen (sourced from fossil fuels) for both refineries and as a vehicle fuel in the transportation sector. However, the role of hydrogen may be far broader than just in transportation.

The Office of Carbon Management (OCM) of the Office of Fossil Energy and Carbon Management (FECM), along with the Hydrogen and Fuel Cell Technologies Office (HFTO) of the Office of Energy Efficiency and Renewable Energy (EERE), and EIA in conjunction with OnLocation developed this Component Design Report to describe the enhancements to NEMS necessary to model hydrogen pathways in deep decarbonization scenarios.

1.2. Policy and other questions to be answered by adding hydrogen representation to NEMS

NEMS is predominantly used by EIA and outside entities to explore the impacts of changes in domestic energy policy. NEMS currently has a limited representation of the potential for hydrogen technologies, as hydrogen is only used in transportation, industrial processes, and refining. Adding additional hydrogen pathways as an option will better characterize the role of hydrogen within a deeply decarbonized energy system.

The purpose of the modeling will be to understand how hydrogen may be used in the energy economy and allow analysts to assess various policies to incentivize hydrogen production and usage. These may include direct incentives such as subsidies, research and development initiatives to lower technology costs, and tax credits for hydrogen production or consumption or complementary policies, such as carbon penalties that will incentivize low-carbon pathways over the status quo.

The potential importance of hydrogen comes from many models that have leveraged its use to meet net-zero decarbonization targets by 2050. For instance, hydrogen plays a key role in IEA's report "Net Zero by 2050 A Roadmap for the Global Energy Sector."[1] In the IEA scenario, hydrogen is produced from either fossil fuels or electrolysis. It is initially used in industry, refineries, and power plants as either a dedicated supply or a blend with natural gas. Over the course of the projection, as the price of electrolyzers is projected to fall, large-scale hydrogen storage can be used to address seasonal fluctuation in energy use and provide low-carbon dispatchable power. Furthermore, hydrogen use in energy carrier fuels such as ammonia absorbs a large fraction of hydrogen produced.[2] Similarly, in Princeton's Net-zero analysis, one scenario shows hydrogen consumption increasing almost six-fold by 2050, at which point hydrogen-based fuels will account for 13% of global final energy demand.[3]

1.3. Limitations of current hydrogen modeling in NEMS

In the most recent version of NEMS used by EIA to produce the Annual Energy Outlook (AEO2022), there are two modules where hydrogen is explicitly produced or consumed: the Transportation Demand Module (TDM) and the LFMM. Additionally, in the Industrial Demand Module (IDM), hydrogen is implicitly used as an intermediate feedstock for various chemical processes, including ammonia production, while it is assumed available for fuel cells in the TDM.

Liquid Fuels Market Module (LFMM)

In the LFMM, hydrogen is part of the utilities provided to refinery production. It is modeled as a process unit in the refinery process. Hydrogen may also be recovered from other refinery streams. For hydrogen production, the LFMM includes only one technology: gas steam methane reforming without carbon capture. It calculates the quantity of natural gas used to produce hydrogen, both as fuel and feed, and adds it to the total natural gas demand.

Transportation Demand Module (TDM)

In the TDM, hydrogen-powered fuel cells are one of the technologies available for light-duty and heavy-duty vehicles. Fuel cell vehicles are modeled similarly to other alternative-fueled vehicles with energy storage, such as electric vehicles or plug-in electric storage vehicles, but the price must include a battery and fuel cell stack plus hydrogen storage. The refueling infrastructure is not modeled explicitly. Fuel availability is one metric of the utility of a vehicle that affects the attractiveness of each alternative fuel vehicle type to consumers and hence vehicle sales shares. Once the vehicle stock is determined, the number of fueling stations is estimated to support the number of vehicles.

While economic competition is also modeled for alternative fuel freight trucks, the algorithms are different and simpler, reflecting the assumption that market penetration will more likely be

[1] IEA, *Net Zero by 2050 A Roadmap for the Global Energy Sector*, p 15. https://iea.blob.core.windows.net/assets/deebef5d-0c34-4539-9d0c-10b13d840027/NetZeroby2050-ARoadmapfortheGlobalEnergySector_CORR.pdf.
[2] Ibid, p 74.
[3] Net-Zero America, *Potential Pathways, Infrastructure and Impacts*, p 221. Princeton University. https://netzeroamerica.princeton.edu/the-report.

driven by government action than strictly through economics. The model reflects this by allowing for separate trends for fleet vehicles and non-fleet vehicles.

Industrial Demand Module (IDM)

Hydrogen is an intermediate input in various process flows. While hydrogen itself is not explicitly modeled any more than other intermediate streams, it is assumed that natural gas is converted to hydrogen, and the natural gas consumed is accounted for in the IDM. Hydrogen is used for chemical production, primarily ammonia.

1.4. Purpose of Component Design Report

The purpose of this Component Design Report (CDR) is to describe the modeling enhancements in NEMS needed to represent hydrogen production, transportation and storage, and consumption across all sectors of the energy system. Given the likely deep decarbonization context of a transition to a hydrogen economy, associated CO_2 emissions will need to be carefully taken into consideration. Some hydrogen technologies produce CO_2 emissions; carbon capture, utilization, and storage (CCUS) will be modeled with the appropriate connection to the carbon transport, utilization, and storage (CTUS) module.

This report is organized as follows. Section 2 provides an overview of the enhancements required to model hydrogen pathways in NEMS. It discusses the major changes needed, which will include substantial changes to the EMM and a new Hydrogen Market Module (HMM). Additional changes will need to be made to incorporate hydrogen in the demand modules and to provide inputs for hydrogen production from the supply modules.

As hydrogen markets can meet social benefit goals, they may therefore be the target of future policies, such as GHG policies. Section 3 provides metrics to measure the impact of hydrogen infrastructure that will be included in the modeling. These include production by technology type and the associated carbon emissions.

Section 4 describes policies that will influence the development of the hydrogen infrastructure. These might include policies that encourage low-carbon fuels or directly support hydrogen, such as tax credits or renewable fuel standards.

Section 5 provides the design philosophy. This includes the design and capabilities of HMM and the input preprocessors that describe hydrogen technologies that can be directly input into NEMS.

Section 6 describes the technologies that need to be characterized to complete the hydrogen pathways. Production technologies include the conversion of fossil fuels or biofuels to hydrogen or various electrolyzers that take electricity and produce hydrogen. Transportation of hydrogen between regions will be modeled through dedicated hydrogen pipelines connected to storage facilities. Finally, the key demand technologies such as fuel cells and industrial processes will be modeled within their respective modules.

Incorporating hydrogen pathways requires numerous trade-offs between maintaining the modular nature of NEMS while modeling the potentially ubiquitous nature of hydrogen pathways in the energy system. Possibly the most consequential design challenge is to maintain consistency between the EMM and HMM while representing hydrogen pathways with sufficient detail. Section 7 discusses the merits and demerits of various approaches, such as modeling self-supply of hydrogen as opposed to merchant production. In addition, the section covers various other design challenges, such as representing capacity planning or other penetration rates of technologies.

Section 8 provides details on the proposed new module: the HMM. It describes the optimization problem that will be solved. The amount of hydrogen production capacity must be projected in order to meet the needs of the other models. This requires various assumptions on penetration rates and technology changes. Because of the significant overlap in hydrogen production, careful coordination between the HMM and the EMM will be required to achieve convergence.

Section 9 explicitly lays out enhancements needed for existing modules. Each description includes a flow diagram to show linkages between modules and how the module will need to be modified to represent the production or consumption of hydrogen.

The Appendices include sample templates for characterizing technologies and definition of the Technology Readiness Level (TRL) scale.

2. Summary of Enhancements Required for Hydrogen Modeling

Incorporating additional hydrogen pathways within the NEMS modeling system involves many design decisions, in many cases without a clearly superior solution. Many of these alternatives are discussed in Section 7, "Design Challenges," below. This CDR is written with a single recommended design for each aspect addressed, however, this may not always reflect the final design.

A central feature of the model enhancements is a new conversion module, the Hydrogen Market Module (HMM). This module will model various supply and conversion processes, taking fuels from those NEMS modules representing coal, natural gas, renewables supply, and electricity from the Electricity Market Module (EMM), and supply hydrogen to those modules representing industrial, commercial, and transportation end uses. In addition, the Electricity Market Module (EMM) will separately produce hydrogen for seasonal storage. While the distribution of pure hydrogen between regions will be modeled in the HMM, hydrogen blends will be incorporated in the Natural Gas Market Module (NGMM), receiving hydrogen from the HMM. The hydrogen-natural gas blend will then be homogenously distributed throughout the rest of NEMS. Finally, the HMM will send captured CO_2 quantities to the CTUS module.

These enhancements will not require any new modeling techniques. The HMM will use standard constrained optimization algorithms and software, to integrate both production technologies and transportation and storage into a single least cost system. One of the key purposes of this CDR is to describe the increased interactions between modules needed to represent the hydrogen economy. A second purpose is to provide a representative set of technologies to accommodate technically feasible hydrogen pathways that markets and policies may support, either now or in the future. A flexible model is necessary to accommodate new technologies that may not currently be identified but may play a role in the future.

3. Metrics for Hydrogen Integration in the Energy System

3.1. Emissions for hydrogen production

A comprehensive accounting of carbon emissions will be necessary to assess the value of hydrogen in decarbonizing the economy. Carbon emissions from fossil fuels are evaluated in the Emissions Policy Submodule (EPM)[4] of the NEMS Integrating Module by multiplying fuels by emissions factors, taking into account carbon sequestered through the CTUS module. Like other modules, the HMM will provide the EPM with the quantities of fossil fuels consumed less carbon sequestered.

In addition to the sector carbon emissions calculated in the EPM, the HMM will derive total carbon emissions and also carbon emissions for each technology. Tracking indirect emissions associated with hydrogen production will be a challenging but important feature of the model, discussed in Section 7.8.

3.2. Production by technology shares

The HMM will record hydrogen production by technology: fossil fuel, electricity, and other. This will allow the recording of emissions from hydrogen production by source as required by expected policy considerations. The HMM will also disaggregate the cost of hydrogen by supply and transportation plus storage. This is particularly important while sending the price of hydrogen to demand modules, where there may be price differentiation based on regional transportation costs.

3.3. Penetration of technology in end-use consumption

Technology shares of hydrogen fueled end-use technologies in each end-use sector will also be calculated within each demand module. This will help track the growth of the hydrogen economy and provide feedback responses on various policies such as carbon or production credits for hydrogen in place.

4. Policies to Incentivize Hydrogen

4.1. Carbon Emission Mitigation Policies

Hydrogen production via fossil fuels meets current hydrogen demand (such as refining and petrochemical production), but other production methods and technologies have not penetrated

[4] The EPM is a submodule of the Integrating Module.

the market as they are not yet cost competitive. Studies[5] have shown that carbon pricing policies such as carbon taxes or cap and trade can accelerate the deployment of hydrogen technologies in the economy. NEMS is designed to incorporate carbon taxes and fees, and incorporation of hydrogen would be treated consistently under those policies without any change in methodology. Fossil fuel prices would reflect the carbon content of the fuel as if it were fully combusted, less the carbon sequestered in CCUS.

Direct subsidies for specific technologies may also be used to incentivize hydrogen production. The model must be designed with enough flexibility to account for a wide variety of potential policy designs that could include but are not limited to technology-specific tax credits, technology mandate-and-trade policies that are analogous to the Renewable Portfolio Standard (RPS), Renewable Fuel Standard (RFS), sector-specific incentives, or minimum price guarantees such as a Feed-in Tariff or similar policies. Due to their complexity, state-level requirements (such as California's Low Carbon Fuel Standard) or regional incentives will be considered but may be implemented in a later project phase. Results from the model will be compared with state level reports for consistency. Care will be taken in the design to avoid model structures that could preclude general classes of policies or, if such structures are unavoidable, at least have such limitations clearly noted in model design or documentation. Subsidies for particular hydrogen pathways or a subsidy for hydrogen with a cap on its carbon profile will also be reflected.

Hydrogen-specific standards, which might require hydrogen production pathways with specified levels of carbon dioxide emissions to be introduced into the energy system, would require specific implementation and emissions accounting. Additional policies might include subsidies for hydrogen production (such as a production tax credit) or for the infrastructure necessary to enable hydrogen distribution, which would lower the retail cost of hydrogen.

Policies to accelerate hydrogen production were recently passed in the Infrastructure Investment and Jobs Act[6] (Sections 40311-40315) and care will be taken to ensure that these policies are reflected in the modeling.

4.2. Implementation Issues of Policies to Incentivize Hydrogen

Carbon taxes are already incorporated within the model through increases in fuel prices and should operate without change. Direct subsidies for hydrogen production are easily incorporated within the model. As NEMS does not directly calculate lifecycle emissions, any standard requiring such emissions accounting would require estimates of carbon footprint as described in Section 7.8, where dynamic, regional life cycle emissions, calculated from NEMS output are suggested.

[5] IEA, *Net Zero by 2050: A Roadmap for the Global Energy Sector*, 2021. https://iea.blob.core.windows.net/assets/deebef5d-0c34-4539-9d0c-10b13d840027/NetZeroby2050-ARoadmapfortheGlobalEnergySector_CORR.pdf

[6] https://www.natlawreview.com/article/infrastructure-investment-and-jobs-act-accelerating-deployment-hydrogen

5. Design Philosophy

5.1. Hydrogen Market Module (HMM)

The varied technologies that can be used to produce hydrogen and transport it to the end-use sectors and the different ways in which it gets consumed are described in later sections. Given the wide variety of options available to create a market for hydrogen, finding pathways that represent the least cost configuration is challenging Any optimization approach involves a tradeoff between the level of abstraction of market conditions and the tractability of the model. It is well known that a constrained linear program (LP) with convexity maximizes total consumer and producer surplus. Introduction of a mixed integer program is computationally complex and removes the guarantee of a single unique solution. The most suitable technique to determine the least cost configuration for production, transportation, and storage within a single module, the HMM, is through the formulation of a LP[7] which under given constraints provides the most economical solution from among various options.

One drawback of using an LP is the possibility that initially solving for a single lowest cost technology in combination with endogenous cost reductions will lead to an unrealistic path-dependent solution, not allowing for any other technology options to grow and achieve market share. To address this issue, a market sharing algorithm can be used after each solution, which constrains the capacity build for the least cost technology and allows for other technologies to gain market share. In addition to capacity planning, the development of such an LP will also allow the HMM to provide the price per unit of hydrogen produced and delivered to the demand modules.

Deriving the equilibrium price and quantities across all modules will be through the Gauss-Siedel method used by NEMS. The constraints on the model will differ between production, transportation, storage, and end-use steps. There will also be additional balance constraints between the production and transportation and between the transportation and end-use of hydrogen. The model calculations will be subdivided into the financial costs of the technologies within each step on a regional and temporal basis. These will require cost inputs regarding each technology that are described in later sections of this report. The software development of these inputs and their updates will be the focus of this section.

5.2. Software to be used

The software used for the development of the HMM will be based on how well it can integrate with the existing NEMS structure and be maintained in the future based on available skillsets. Due to these reasons, it is proposed that the program for the module be written in AIMMS, and all the data processing and knowledge base conversion to model inputs be written in Python. It is also proposed that the inputs be stored in database form for easy update and retrieval. For prototyping, SQLite is preferred for its portability and ease of setup

Both AIMMS and Python are modern tools that are in current use for different parts of NEMS. AIMMS is currently used for the Natural Gas Market Module (NGMM) and Coal Market

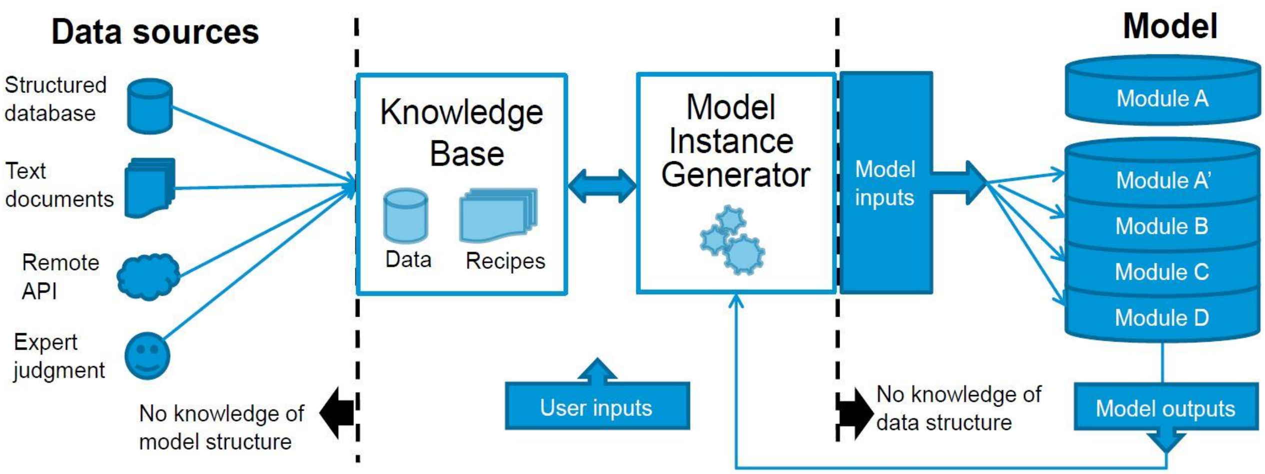
[7] Potentially with a quadratic objective function (QP).

Module (CMM) modules, while Python is used primarily for data pre-processing prior to NEMS runs. Both also have significant popularity in the general marketplace for optimization and data processing tools, respectively, and should provide a sufficient pipeline of skilled resources to maintain these tools in the near future. AIMMS provides access to many commercial solvers for purchase through its software, but it is likely that the use of CPLEX or Xpress should be sufficient. Python is open source and thereby provides access to thousands of packages developed and maintained by its large community of developers.[8] The use of some of these Python packages and databases to enhance the module development is described in the next section.

5.3. Knowledge-Based Modeling (KBM)

For the new hydrogen market module, a knowledge-based model (KBM) approach is proposed,[9] as seen in Figure 1 below. A KBM approach separates the process of data management and model management. The knowledge base may consist of disparate structured and unstructured data at different regionalities and may be updated with new information as it is made available and with expert input. The model instance generator contains functions that call the data in the knowledge database and supply them to the model in the format (regionality and temporal dimension) as required. The model itself is more general in nature as a result and can run more efficiently. There is no hard coding of data in the model, which makes future updates easier than with a traditional model approach, where the line separating data from the model structure can be blurry. The recently implemented International Electricity Market Module (IEMM) provides an example framework of a knowledge-based architecture, using a model instance generator to allow relatively easy reconfiguration of technology choice, regionality, and temporal resolution without needing to revise the underlying model code.

Figure 1. Knowledge-Based Modeling Approach



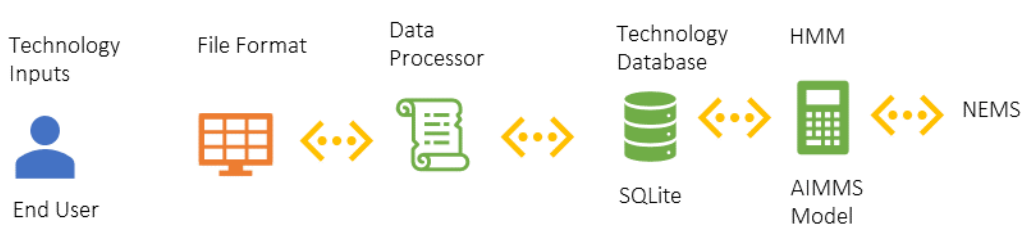
Source: U.S. EIA.

[8] For consistency with EIA, Python 3 is proposed.
[9] Daniels, David, "Knowledge-Based Modeling, Project Review Meeting," EIA, presentation dated March 26, 2015.

For this module, AIMMS and Python provide the right tools to develop and maintain a KBM approach. AIMMS models can be built in a standard configuration where all the inputs are read in from external files that can be as simple as text files or as complex as relational databases, therefore the type of input files are not constrained. Relational databases provide a way to store multiple levels of information that is easy to update and manage access. It is proposed that SQLite or, if needed, a more appropriate database be used to store inputs from the preprocessor and outputs from the model. It would also provide a way to merge the inputs and outputs of the HMM with other NEMS data and create reports for the end-user. Since the knowledge database used to create the inputs is most likely to be from disparate sources and in multiple units and time scales, a translation between them and the database is needed. These input sources can be in various forms, including text, csv, xml, or json files.

Model enhancements can be carried out using Python since it would provide future flexibility in case of new data being added in a unique form. It is also essential that any input method be easy enough for an analyst to use without requiring programming skills. One suggestion is to develop an interface to update basic end-user inputs to the model that rely on a predetermined structure and existing technologies. However, this approach will require resource allocation to sustain it in future years. Also, using such an interface for adding new data may require the background translation in Python to be updated, possibly rendering the interface obsolete over time. Instead, a Python based system can be developed where the user need only drop in new inputs in a pre-specified file format and configuration, to a given location. A batch file can be used to run the Python code in the background and update the database for the model to use. An example flow diagram for such an approach is shown in Figure 2 below.

Figure 2. Data Flow



Since many hydrogen production technologies are in the early development stage, it may be difficult to get all the characteristics of the technology needed when building the model. Using the KBM approach and its components described above, a functional model may still be built with an initial set of technology characterizations included. As newer technologies enter the mainstream and reliable data is available for them, the user input files (text, csv, xml, json etc.) along with the Python back-end can be used to update the list of technologies in the database that are available without making significant structural changes to the model itself. At the same time, as existing technologies evolve and mature, their information can be readily updated in the database through the user interface. Similarly, the model may require certain geographical (census regions), temporal (seasonal), supply chain (transportation/storage) aggregations in a different form from how they are presented in the raw data. The Python backend code will then contain functions that aggregate (state to census region) and disaggregate (annual to seasonal) data in the database for use in the model.

Input files will be either a common file format (text, csv, xml, json etc.), read in through Python, and stored in a relational database. The Python program would serve as the model instance generator and perform calculations necessary to put the data into a form consistent with the structure required. The results would be written by Python to a database that could be read by the AIMMS program. AIMMS itself will interact with NEMS through the restart files and files generated in a manner similar to NGMM and REStore today.

A standard example would be changing regionality. As has been demonstrated, the regionality used should be independent of the model structure. In this case, the underlying data will have locational granularity. The model generator will provide shares or aggregations to create a new regionality, creating the model inputs. Finally, the model will read in both the regionality and the values for each region. Another example where this approach would be particularly valuable would be adding additional conversion technologies. Adding a new technology should not require changes to the model structure, while changing parameters to existing technologies should, of course, be accomplished through changes in the input file.

Within NEMS, data exchange with the HMM and other modules will be through the restart file and other files, similar to NGMM and REStore today. By separating out data exchange with the rest of NEMS from the HMM inputs, the potential for a stand-alone HMM module can be realized.

6. Technology Description

This section lists and briefly describes technologies whose representation will need to be added to NEMS in order to represent hydrogen pathways. Because this is a CDR, the purpose is to describe changes to NEMS needed to characterize hydrogen pathways and how the technologies may be characterized within NEMS using the KBM paradigm described in Section 5.3, and a full technology characterization is not completed here. However, a full technology characterization has been started. Templates have been produced to guide such characterization efforts and discussions were conducted with hydrogen experts at three DOE National Laboratories (ANL, NETL, and NREL) to ensure technology lists were complete. Templates were provided to these experts to elicit technology parameters. These technology templates are shown in the Appendix.

This section also reports the Technology Readiness Level (TRL), as reported by IEA's Clean Energy Technology Guide.[10] TRLs provide a guide to the technical maturity of the technology.

[10] IEA, *ETP Clean Technology Guide*. https://www.iea.org/articles/etp-clean-energy-technology-guide.

International Energy Agency (IEA)'s TRL scale includes the standard 1-9 scale, as developed by NASA, where 1-4 is early research and prototyping, 5-6 is large prototyping, and 7-8 is light commercial deployment, and 9 is full commercial deployment. The IEA adds two more levels, 10-11, described as market readiness levels (MRLs), which describe a technology's stability and growth in the market: 10 represents commercial operation but lacking full integration into existing systems, and 11 represents fully stable and predictable growth in the marketplace. A full description of this scale is included in the Appendix.

6.1. Production

Table 1 below shows the list of available and known technologies for the production of hydrogen, along with their TRL. The TRL level only provides a guide to the potential for commercialization of a technology at a particular time, based on analysis by the IEA. The model will retain the flexibility to incorporate technologies as additional information becomes available. Furthermore, for technologies that are relatively new, the TRLs are not available and are left as "NA". Some of these technologies have been thoroughly researched by NREL's Hydrogen Analysis (H2A) production cost case studies[11] and are listed in Table 2. The H2A hydrogen production models and case studies provide transparent reporting of process design assumptions and a consistent cost analysis methodology for hydrogen production at central and distributed facilities.

Table 1. Hydrogen Production Technologies proposed for HMM

Hydrogen Type	Fuel Source	Technology	TRL
Fossil	NG	Steam methane reforming	11
Fossil	NG	Autothermal reforming	11
Fossil	NG	Steam methane reforming with CCUS	8-9
Fossil	NG	Autothermal reforming with CCUS	8-9
Fossil	NG	Pyrolysis	3-6
Fossil	Refinery Byproduct	Steam Cracking	NA
Fossil	Coal	Gasification with CCUS	5
Fossil	Coal	Gasification	9
Renewable	Biomass	Gasification	5
Renewable	Biomass	Gasification with CCUS	5
Renewable	Biomass	Bio-oil Reforming	NA
Renewable	Solar Thermal	Solar Thermochemical	3
Renewable	Solar Thermal	PEM electrolysis	NA
Renewable	Solar	Direct Solar Water Splitting	NA
Renewable	PV/Wind/Hydro	Alkaline electrolysis	9
Renewable	PV/Wind	PEM electrolysis	9
Electricity	Grid	Alkaline electrolysis	9
Electricity	Grid	PEM electrolysis	9
Nuclear	Nuclear	PEM electrolysis	9
Nuclear	Nuclear	Solid Oxide electrolysis	7

[11] https://www.nrel.gov/hydrogen/h2a-production-models.html.

NA = Not Available

Required input to the models includes capital and operating costs for the hydrogen production process, fuel type and use, and financial parameters such as the type of financing, plant life, and desired internal rate of return. The models include default values for many of the input parameters but are fully customizable. The models use a standard discounted cash flow rate of return analysis methodology to determine the hydrogen selling cost for the desired internal rate of return.

Table 2. Hydrogen Production Technologies modeled in H2A

Hydrogen Type	Fuel Source	Technology
Fossil	NG	Steam methane reforming
Fossil	NG	Steam methane reforming with CCUS
Fossil	Coal	Gasification with CCUS
Renewable	Biomass	Gasification
Renewable	Biomass	Bio-oil Reforming
Renewable	Solar Thermal	Solar Thermochemical
Renewable	PV/Wind	PEM electrolysis
Electricity	Grid	PEM electrolysis
Nuclear	Nuclear	PEM electrolysis
Nuclear	Nuclear	Solid Oxide electrolysis

Fossil Fuel

Steam Methane Reforming (with and without CCUS)

The most common method for hydrogen production today is through natural gas steam methane reforming (SMR), making up about 90% of global production[12]. Natural gas and steam react at high temperatures and pressure to form syngas, a mixture of hydrogen, carbon monoxide, and some carbon dioxide. The subsequent water shift reaction then produces hydrogen and carbon dioxide primarily. The SMR technology is economic and scalable. However, without CCUS, it produces roughly 9 kg CO_2 of direct emissions per kg of hydrogen.[13]

Autothermal Reforming (with and without CCUS)

Autothermal reforming is similar to steam methane reforming and uses steam or carbon dioxide in a reactor where methane is partially oxidized. The difference is that in place of air, an autothermal reformer uses pure oxygen to create steam for the process. It is generally used to have flexibility in the H2/CO ratio in the product stream. This process also creates carbon dioxide as a by-product that can be captured with CCUS technology.

[12] https://www.ge.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/future-of-energy/hydrogen-for-power-gen-gea34805.pdf.

[13] LePage, Kammoun, Schmetz, Richel, "Biomass-to-hydrogen: A review of main routes production, processes evaluation and techno-economical assessment," *Biomass and Bioenergy*, 144 (2021).

Pyrolysis

Pyrolysis is a high-temperature cracking of natural gas, specifically the methane molecule into carbon and hydrogen. The advantage of this process is that it produces no carbon dioxide release to the atmosphere but instead produces pure carbon that can then be added to landfills or used as feedstock in other processes.

Steam Cracking as a Refinery By-product Process

By-product hydrogen refers to pure hydrogen gas produced as a result of a process or processes dedicated to producing other products. For example, steam crackers in refineries convert hydrocarbon feedstock to light olefins via thermal cracking and produce hydrogen as a by-product during the process. It has been reported that producing hydrogen from steam crackers creates less life-cycle greenhouse gas emissions than the conventional centralized SMR pathway and is also cheaper compared to the conventional central SMR pathway.[14] However, the expansion of this source of hydrogen is dependent on the refinery process that supports it.

Coal Gasification (with and without CCUS)

Coal gasification is a well-established process where coal is reacted with water, air, or oxygen to produce mainly a syngas mixture (hydrogen and carbon monoxide) and carbon dioxide. It is primarily used on a large scale for industrial feedstocks. To produce hydrogen in large quantities, similar to steam methane reforming, a water gas shift reactor is used while converting carbon monoxide into carbon dioxide. Since the process produces a large quantity of CO_2 as byproduct, CCUS technology would have to be employed, in order to produce clean hydrogen. In addition, typically, with the use of CCUS, the fuel used is also switched to pure oxygen so that CO_2 removal is much cheaper. These types of Integrated Gasification Combined Cycle (IGCC) processes have been developed in the past with mixed success rates.

Biomass

Biomass is a renewable organic resource such as agricultural crop residue (for example, corn stover), energy crops (such as switchgrass or poplars), forest residue, municipal solid waste, or animal waste. This can be used to produce hydrogen, which can be considered renewable. Because plants consume carbon dioxide when growing, biomass can be considered low carbon (if not net neutral) with respect to the introduction of carbon dioxide in the atmosphere, although there are controversies surrounding the full lifecycle emissions that are dependent on growing and harvesting techniques).[15] As with other fossil fuel reforming processes, additional carbon capture removal systems are needed to produce clean hydrogen from these processes. Some of the processes that can be used to produce hydrogen are listed below.

Gasification (with and without CCUS)

Biomass gasification is carried out similar to coal gasification by reacting biomass with oxygen and/or steam at high temperatures. The difference is that biomass has a highly variable carbon

[14] Lee, D-Y., & Elgowainy, A., (2018) "By-product hydrogen from steam cracking of natural gas liquids (NGLs): Potential for large-scale hydrogen fuel production, life-cycle air emissions reduction, and economic benefit," *International Journal of Hydrogen Energy*, 43(43), 20143-20160, https://doi.org/10.1016/j.ijhydene.2018.09.039.
[15] https://www.energy.gov/eere/fuelcells/hydrogen-production-biomass-gasification.

composition depending on its source, with more complex molecules present. Since the exiting gas from this process contains a mix of hydrocarbon, another reforming step is usually carried out like the shift reactor in steam methane reforming to get a clean syngas mixture of hydrogen, carbon monoxide, and carbon dioxide.

Bio-oil reforming

Bio-oil reforming is similar to natural gas reforming with steam, but the biomass resources are first converted into ethanol or other bio-oils.

Renewable, Grid Electricity and Nuclear

Solar Thermochemical

Another key pathway is to use solar energy to create hydrogen without first converting it to electricity. There are several technologies that use heat from solar energy, such as solar thermochemical pathways. One solar thermo-chemical pathway uses a nickel ferrite cycle, where solar energy is used to heat nickel ferrite to a high temperature over (1400 degrees centigrade), resulting in hydrogen production from the dissociation of water.

PEM Electrolyzer Grid Electricity/Renewable Electricity/Nuclear Electricity/Solar Thermal Energy

Polymer electrolyte membrane (PEM) electrolyzers convert water and electricity into hydrogen and oxygen. They use pure water as an electrolytic solution, operate at relatively low temperature and pressure, and generally are capable of very flexible operations. While costs have been reduced[16], both membranes and catalysts (containing elements such as platinum) are expensive. The electricity needed may come from the grid or be specifically low carbon and be generated from renewable sources or nuclear power. By using heat in addition to electricity to produce hydrogen, the amount of electricity needed is reduced. Therefore, a combination of solar thermal energy and electricity may result in more efficient usage of the PEM electrolyzer.

Direct Solar Water Splitting

In solar water splitting, photovoltaic energy is used with a semiconductor material and an electrolyte to break down water into hydrogen and oxygen. Approaches include using a solar concentrator or a PV panel. This technology is relatively new.

Alkaline Electrolyzer Grid Electricity/Renewable Electricity

Alkaline electrolyzers use a mature technology that has been in use for many years. The electrodes operate within a liquid alkaline electrolyte solution, typically of potassium hydroxide or sodium hydroxide, at relatively low temperatures and pressures. Generally, these electrolyzers have relatively low capital costs and similar efficiencies as compared to PEM electrolyzers but tend to have lower current and power densities.

[16] https://www.osti.gov/biblio/1557965-manufacturing-cost-analysis-proton-exchange-membrane-water-electrolyzers

Solid Oxide Electrolyzer

Solid oxide electrolyzers use a solid ceramic material as the electrolyte. They operate at a much higher temperature than either PEM or alkaline electrolyzers, with the potential for greater efficiency. Some of the electricity may be replaced by high-temperature waste heat, increasing the efficiency of the process. High-temperature heat may be obtained from nuclear power plants.

6.2. Transportation

Pipeline

Pipelines are the primary option for the transport of hydrogen across long distances. The model would determine the cost of hydrogen transportation inside and across regions, based on available estimates of capital costs of pipeline construction for new pipelines and operating costs for new and existing pipelines. The capital costs include the cost of labor, equipment such as compressors, and right-of-way during construction. The operating costs include the power cost of the compressors. The template to be used for pipeline costs can be seen in the Appendix: Technology Templates. The pipelines that could be built would be selected from pre-determined options for new pipelines across regions. There are two ways in which hydrogen transport through pipelines can occur:

Dedicated

The pipeline network can be built solely for the transport of hydrogen, as is the case today with existing hydrogen pipelines. The difference would be a larger network serving distant customers and not just regional ones. A disadvantage of a dedicated pipeline would be the high capital costs involved due to right-of-way considerations, local regulations, and specific pipe material required for hydrogen.

Hydrogen Blends

Another mode for transport of hydrogen that will be considered in the HMM is through the use of blends, i.e., adding a small fraction of hydrogen to existing natural gas delivery pipelines. The assumption here is that the addition of hydrogen to natural gas in small amounts would not require a retrofit of either the pipelines or the end-use equipment. The acceptable range for such end-use conditions is between 5-20% hydrogen[17]. There would, however, be operating and fuel cost changes since hydrogen only has a third of the heating value of natural gas. With current technologies, the potential fraction for hydrogen use has a wide range, from as low as 3% to as high as 50%. However, since the delivery of hydrogen through pipelines implies the use of common infrastructure, the fraction of the blend would be limited to the lowest level that supports all end-use equipment. This maximum blend limit can be introduced in a specific year based on either technology readiness or a specific policy or regulation. The limit can be adjusted upwards in future years, exogenously, by providing a methodology through the inputs to update the end-use costs.

[17] https://www.nrel.gov/docs/fy13osti/51995.pdf.

Truck/Rail including liquefaction

Hydrogen can be transported as a liquid as an alternative to pipelines.[18] Liquefying hydrogen requires cooling it to cryogenic temperatures through a liquefaction process to allow for transporting it via cryogenic tanker trucks. The process can be expensive and can also involve losses due to boil-off during transport. Trucking liquid hydrogen is better than trucking gaseous products since larger volumes can be transported in liquid form. In the case of gaseous hydrogen, it is compressed to pressures of 180 bar or higher into long cylinders that are stacked on a trailer that the truck hauls.[19] These tube trailers can then transport hydrogen across different regions. Although both these options are relatively mature with reliable costs estimates available for them, they are part of the final distribution network in the delivery pathway for hydrogen. In order to limit the complexity in representing each final route in the model, a cost adder for the local delivery of hydrogen for end-use will be added through these methods.

6.3. Storage

Underground Storage

Saline Aquifers and Salt Caverns

Facilities for the large-scale storage of natural gas are located across the country. There are also hydrogen storage caverns in use today, connected to commercial hydrogen pipelines along the Gulf Coast. Although these provide reliability for commercial use in the short term, the expansion of hydrogen use to more demand sectors outside of refineries may require seasonal storage connected to the dedicated pipeline network described earlier. There have been studies on the characteristics and suitability of these caverns with proven costs[20]. These can serve as the basis for estimates of hydrogen storage.

Depleted wells and reservoirs

Another potential storage opportunity for hydrogen is depleted oil and gas wells and reservoirs. However, the potential suitability of these sites for hydrogen storage is not publicly available at this point. So, the model will open the possibility of adding these sites as a subset of long-term storage sites (including salt caverns mentioned above). The details, including capacity and cost estimates of these sites, can be added later, leveraging the use of the KBM approach.

It must be noted that apart from salt caverns in use for commercial purposes, there is no large scale use of other underground storage options for hydrogen and therefore there is some uncertainty whether these would be long-term options.

[18] https://www.energy.gov/eere/fuelcells/liquid-hydrogen-delivery.
[19] https://www.energy.gov/eere/fuelcells/hydrogen-tube-trailers.
[20] D.D.Papadias, R.K.Ahluwalia, Bulk storage of hydrogen, *International Journal of Hydrogen Energy*, Volume 46, Issue 70, 11 October 2021, Pages 34527-34541. https://doi.org/10.1016/j.ijhydene.2021.08.028.

Above-Ground Tank storage

Tank storage at the production facility is commonly used in the chemical industry and is meant to provide short-term to medium-term storage. For gaseous products like hydrogen, the compression requirements are either too high or require a large number of storage tanks to act as medium-term storage. For example, at 700 bar, hydrogen has a density of 42 kg/m^3. At this pressure, 5 kg of hydrogen can be stored in a 125-liter tank.[21] To store seven days' worth of output from an SMR producing 380,000 kg of H_2/day would require a storage tank capacity of 66.5 million liters (or 17.5 million gallons). For a 30 m diameter tank with 10,000 m^3 capacity, this translates to over 150 above-ground storage tanks. Similarly, a hydrogen combustion turbine with a capacity of 200 MW could be supported for 10 hours using a hydrogen storage capacity of 140,000 kg or over 125 such storage tanks (using an HHV of 135,000 Btu/kg of H2 and a heat rate of 9450 Btu/kWh for a H2 turbine[22]). In a NEMS context, this temporal granularity is unnecessary outside of the EMM since the rest of the modules only need to determine long-term or seasonal storage needs. Therefore, the use of local tank storage in the HMM is not considered. There is, however, the potential for this type of storage to be represented in other modules where self-production is a possibility, for example, the EMM or IDM. It can be represented as an adder while calculating the cost of the associated technology.

6.4. End-Use Consumption

The end-use of hydrogen for various sectors is in three general forms. One is through direct burning or combustion for heating purposes or to drive a turbine. Another is through use as feedstock, particularly in refinery processes, to produce bulk chemicals, or convert it to another energy carrier. A third is to consume hydrogen through its conversion to electricity and heat using a fuel cell.

In order to represent these uses, hydrogen end-use technologies must be added to the model in the context of the existing demand models. The technologies listed below include end-use hydrogen technologies that could be added to the demand models. The technology templates for these industries are included in the Appendix and reflect the input style of each end-use sector. Given the KBM paradigm, the model enhancements should be flexible enough to allow adding additional technologies as they become available.

Space Heating, Water Heating, and Cooking

Several research groups have pursued the use of hydrogen gas in homes for water heating, space heating, and cooking. This includes hydrogen-specific technologies and appliances, as well as studies on blending hydrogen into natural gas systems for use in existing appliances like gas stoves and heaters. In April 2021, Winlaton, a small village in North England, began supplying homes with hydrogen blended gas (up to 20% hydrogen) to fuel home heating and cooking appliances. This blend has not required any changes to pipes, appliances, burners, or boilers, but growing evidence suggests that blends up to 80% would not require changes to existing

[21] https://energies.airliquide.com/resources-planet-hydrogen/how-hydrogen-stored.
[22] https://www.ge.com/gas-power/future-of-energy/hydrogen-fueled-gas-turbines.

infrastructure.[23] HyDeploy[24] is a project focused on using hydrogen to heat homes in the UK. There are questions regarding the scalability of these examples to the large scale U.S. infrastructure. However, recent studies show that hydrogen for use in heating homes is significantly less efficient than electric heat pump alternatives.[25] At this time, there is no plan to add hydrogen heating and cooking to the residential model in NEMS.

Ammonia Production

Ammonia is conventionally produced through the Haber-Bosch process using fossil-derived hydrogen produced through steam methane reforming. While ammonia has been produced using hydrogen from electrolysis powered by large-scale hydroelectricity, the process is not widespread. IEA has estimated that electrolyzer itself has a TRL of 9-10; however, because ammonia production using variable renewable-powered electrolysis is less common, with large scale demonstrations and a handful of first of their kind commercial plants, IEA has estimated that this technology has a TRL of 8.

Steel

U.S. iron and steel production was responsible for 69.5 MMT CO_2e in 2016[26], and globally, the steel industry produces 7% of global carbon emissions. As steel demand is expected to increase (globally) a third by 2050, low carbon alternatives to current technologies remain a top priority for a decarbonized future. Hydrogen-fueled direct reduction of iron (H2DRI) from 100% electrolytic hydrogen is of the most promising of these technologies. While direct reduced iron (DRI) technology exists in the U.S., there are no H2DRI plants, reducing the iron solely with hydrogen. The IEA estimates that the TRL of 100% electrolytic hydrogen-based DRI is 5.

H2DRI involves reducing iron ore to iron without melting. Pre-heated iron ore is converted into direct reduced iron in a shaft reactor, where hydrogen is both the reducing agent and energy source. Direct reduced iron, or sponge iron, is produced and is usually compacted into hot briquetted iron (HBI) or fed into the electric arc furnace (EAF) to produce steel. The EAF melts iron to liquid steel, based fully on liquid steel from the EAF, HBI, and steel scraps. Vogl et al. (2018) showed that the production cost of steel from H2DRI is generally higher than other technologies but can be close to competitive when the cost of electricity is low.

Several initiatives use or plan to use this technology. HYBRIT (Hydrogen Breakthrough Ironmaking Technology) began the operation of a pilot project in summer 2020 in Norrbotten, Sweden, some of that production fueled by renewable-based hydrogen in August 2021. An industrial-scale demonstration plant is planned by 2026. HBIS began construction on a hydrogen DRI demonstration plant in the Hebei province, China, in 2021. The first phase of the project,

[23] https://www.wired.co.uk/article/hydrogen-uk-heating.
[24] https://hydeploy.co.uk/about/.
[25] LETI 2020, *Hydrogen: A decarbonisation route for heat in buildings?* https://www.leti.london/_files/ugd/252d09_54035c0c27684afca52c7634709b86ec.pdf.

[26] US EPA, *2011-2016 Greenhouse Gas Reporting Program Industrial Profile: Metals*. October 2018. https://www.epa.gov/sites/default/files/2018-10/documents/metals_2016_industrial_profile.pdf.

which will produce 0.6 Mt of iron per year and use hydrogen from coke oven off-gases. IEA estimates a TRL of 5 for this technology.

Glass

Most of the energy in the Glass industry is consumed by melting glass. The glass industry is pursuing many low-carbon technology options, including alternative fuels, electric furnaces, oxy-fired furnaces, waste heat recovery, plasma glass melting, and process intensification. Several projects, including HyGlass, HyNet, and Kopernikus P2X, focus on using hydrogen as an alternative fuel carrier for combustion.[27]

The use of hydrogen for combustion results in new combustion conditions that are not well understood in melting glass, and many uncertainties exist. Hydrogen production would result in higher flame temperatures, changing flame lengths, flame velocities, and lower emission factors, which influence heat transfer. Outstanding questions include whether heat transfer from the hydrogen flame is sufficient for glass melting, and there is ageneric concern whether NOx emissions can be maintained at acceptable limits from hydrogen combustion.

Cement

The cement industry accounts for 8% of global CO_2 emissions, and the Global Cement and Concrete Association, a global cement industry group representing 80% of the cement production outside of China, has committed to reducing CO_2 emission by 25% by 2030 and reaching net zero by 2050.[28] Most cement industry decarbonization strategies focus on CCUS, because most cement industry emissions are process emissions formed in the calcination process. However, some strategies mention hydrogen fueled kilns as contributing to emissions reductions by 2050. The IEA classifies partially hydrogen fueled cement kilns as having a TRL of 4, in the early prototype stage.[29] This technology could be added to the cement industry in NEMS if a technology characterization can be estimated, given this technology is so early in its development.

Fuel Cell Vehicles

Hydrogen fuel cells are a potential competitor with electrification as a zero-emission technology for road transport. The NEMS TDM projects passenger travel demand and light-duty vehicle market share and uses various decision choice algorithms to disaggregate vehicle types by technology. The TDM includes both methanol and hydrogen fuel cells vehicles as categories of alternative fuel light-duty vehicles. Fuel cells are also potentially applicable for other transportation modes such as marine or rail. The module also includes hydrogen-fueled fuel cells

[27] Zier et. al. "A review of decarbonization options for the glass industry" *Energy Conversion and Management*, 2021

[28] GCCA, *Concrete Future: The GCCA 2050 Cement and Concrete Industry Roadmap for Net Zero Concrete,* 2020. https://gccassociation.org/concretefuture/wp-content/uploads/2021/10/GCCA-Concrete-Future-Roadmap-Document-AW.pdf

[29] IEA, *ETP Clean Energy Technology Guide*, November 2021. https://www.iea.org/articles/etp-clean-energy-technology-guide

as a technology for freight transportation, though its representation is simplified compared to that of other light-duty vehicles. Enhancement to hydrogen fuel cells for LDVs and maritime is not within the scope of this initial effort.

Ammonia as Fuel for Transport

Ammonia is 50% more energy-dense than hydrogen fuel. Ammonia-fueled engines have been in development for road transport and shipping. IEA defines ammonia fueled ICE engines as having a TRL of 4-5. Ammonia is also being pursued as fuel for marine shipping. Although no vessels using ammonia exist, several companies are pursuing the technology and are planning to produce the first ammonia-fueled shipping vessels by 2024. While specific ammonia demand modeling is not within the scope of this initial effort, ammonia demand, including ammonia demand for transportation uses, will be exogenously estimated. Expanded demand for ammonia will serve as a proxy for increased transportation needs.

Combined Heat and Power (CHP)

Combined heat and power (CHP) is a common energy-efficient technology used to produce electricity and capture the waste heat as useful thermal energy, which can be used for steam, heat, or industrial processes. CHP units are typically at facilities that use both electricity and thermal energy, such as industrial facilities, hospitals, and other commercial facilities, or used for district energy by a utility. Hydrogen can be used in Fuel Cell CHP installations.

Generic Industrial Heat

While the use of hydrogen as a heat source is less developed than hydrogen as a feedstock, hydrogen provides one of the few options to decarbonize industrial high temperature heat. However, as industrial high temperature heat is extremely process specific, hydrogen technologies will also be industry specific, such as the steel and glass industries mentioned above. However, lower heat generic boilers, while not used today are being investigated as a means of decarbonizing general industrial heat. For example, the UK has put out a call for evidence of the effectiveness and feasibility of hydrogen ready industrial boilers to help decarbonize industry.[30]

While much of the decarbonization from hydrogen in the industrial sector will come from the steel industry and CHP technologies mentioned above, generic industrial heat could potentially play an important role in deep decarbonization scenarios in the mid to late century. Generic boiler technologies exist within the IDM and could be modified to include hydrogen-fueled boilers. However, this is not likely to be part of the initial effort. This is discussed in more detail in Section 9.3.

[30] https://www.gov.uk/government/consultations/enabling-or-requiring-hydrogen-ready-industrial-boiler-equipment-call-for-evidence.

7. Design Challenges

The following section outlines various design challenges of adding hydrogen to NEMS. Recommended model enhancements, taking into consideration these challenges, are described in Section 9.

7.1. Coordination between EMM and HMM

As discussed previously, several hydrogen production technologies employ electricity, and at the same time, hydrogen turbines or fuel cells are electricity consumers. Therefore, close coordination between the EMM and HMM will be needed, and decisions will need to be made about in which modules each component of each hydrogen pathway is best located.

In particular, electrolysis for hydrogen production can be modeled in either the HMM, EMM, or both. In the EMM, renewable or low-carbon electricity would be used to electrolyze water into hydrogen. The hydrogen would be stored locally and later used to replace natural gas in limited peak periods. Therefore, hydrogen might serve as a substitute for other electricity storage technologies. Hydrogen provides a different value proposition than batteries for storage. While batteries have generally equivalent charging/discharging capabilities, the combination of using electricity in electrolyzers to produce hydrogen and combustion turbines to turn it back into electricity means the rate of consumption of electricity and its production are much more nearly independent. This gives hydrogen storage cost advantages over battery storage at higher discharge durations.

Hydrogen production can also take place outside of the EMM. Should hydrogen production occur in multiple modules, the overall equilibrium solution should find a least-cost solution for hydrogen production across all modules. In NEMS, this is achieved by the transfer of prices and quantities between modules. Therefore, the typical mechanism for establishing equilibrium would be in setting the price of hydrogen across modules. Because hydrogen production and consumption are tightly coupled between various modules, providing a module design that both utilizes the strengths of each module, minimizes overlap between pathways in each of the modules, and is likely to converge to a market equilibrium is challenging.

Coordinating hydrogen production using shared electricity generating technologies

There are a large number of permutations of possible hydrogen production pathway representations involving the HMM and EMM. Each has unique advantages and disadvantages in the ease of reaching an equilibrium while maintaining a tractable model, as shown in Table 3.

Table 3 lists the benefits and detriments of three illustrative design choices: keeping all hydrogen production from electricity within the EMM and having the EMM sell merchant hydrogen to other sectors, producing hydrogen in both the EMM and HMM while using only grid electricity in the HMM, or producing hydrogen only in the HMM. The first row of the table shows the scenarios. The second row lists where electricity for hydrogen production would occur in each of the scenarios.

The third row examines the impact in each of the three scenarios of having utility-level renewable resources built in more than one module. There are a limited number of sites for renewable energy, particularly for siting wind resources. If electricity production from renewable sources occurs in more than one module, the model would need to coordinate site usage across multiple modules. Given that this is a capacity planning feature, it would make convergence challenging and raise the potential for double-counting available sites.

The fourth row describes the impact of temporal resolution. The EMM has a granular resolution, including nine time slices in the EMM and 576 in the Renewable Storage (REStore) module. The EMM would use hydrogen to shift electricity load from one period to another and fill in peak loads where natural gas combustion turbines would otherwise be used. The cost of hydrogen used in this way is not the same as if it were generated at a constant rate. If the price of hydrogen produced in the HMM is to be competitive in the EMM, the HMM must then replicate in some way how the EMM uses hydrogen. This requires pricing in seasonality in the HMM to match the EMM's requirements. A fixed load shape could be used to represent electricity purchases from the EMM and hydrogen output to the EMM. This can model all of the costs associated with hydrogen production and storage. However, it either requires replication at the same granular level of detail in the EMM capacity planning submodule (ECP) or is only an approximation to the calculations in the EMM, leading to inconsistencies between the modules.

The fifth row notes that endogenous cost reductions depending upon installed capacity would also be more difficult to calculate when capacity planning using the same technology is in different modules. This can be achieved by sharing information about prior capacity additions between modules in a similar fashion as is currently done for distributed PV where the costs in the residential and commercial modules are impacted by PV additions in the utility as well as building sectors.

The sixth row looks at calculating environmental impacts in each of these design proposals. Since electricity is a homogenous product, the environmental impact (such as carbon footprint) of hydrogen produced outside the EMM using grid electricity will be difficult to estimate. Alternatively, the HMM could be constrained to purchase only renewable or carbon-free electricity from the EMM to produce hydrogen. This could be implemented through quantifying the demand for carbon-free power or through a financial pass-through such as a renewable energy credit. However, the pricing of such electricity would be challenging for the EMM. Another alternative would be for the HMM to purchase grid electricity, where the price would reflect carbon intensity. Assuming a decarbonized grid, that is, where all electricity would be generated from low-carbon sources, electricity would be low-carbon and no further tracking would be necessary. However, for any policies that depend upon incentives for low-carbon hydrogen, ensuring that low-carbon electricity is properly incentivized in the EMM would also be challenging.

Table 3. Possible Representation of Hydrogen Production

Development Decision	Module Development Approach		
	Hydrogen Production from Electricity in EMM Only	Hydrogen Production in HMM Only	Hydrogen Production in EMM and HMM
Where electricity is produced	All generation in EMM	Electricity consumed from grid and produced on-site	HMM uses grid electricity for hydrogen production
Level of aggregation of renewable resources	Aggregated access to wind and solar supply curves for both hydrogen production and power plants	Potential double counting of wind and solar resources for both electricity in HMM and EMM	No double counting of wind and solar resources
How much temporal granularity	Sub-annual operation of hydrogen production plants can be determined based on REStore hourly availability	A fixed load shape (or potentially more than one) would be used to represent electricity purchases from EMM	An exogenously determined fixed load shape (or potentially more than one) would be used to represent electricity purchases from EMM
Ease of applying endogenous learning	No need to coordinate joint learning among power and hydrogen technologies	Tight integration of EMM and HMM to track technology used in both hydrogen and electricity production, not just prices and quantities	Tight integration of EMM and HMM for technology types for hydrogen production, not just prices and quantities
Ease of developing lifecycle analysis of hydrogen production	Allows tracking of renewable-based hydrogen if use dedicated renewable energy resources	HMM cannot track what type of electricity used for hydrogen production; a framework will be developed using both exogenous estimates and NEMS outputs Tracking feasible for on-site electricity	HMM cannot track what type of electricity used for hydrogen production; a framework will be developed using both exogenous estimates and NEMS outputs
Whether EMM will self-supply hydrogen, and be the sole module providing hydrogen from electrolyzers,	EMM now responsible for all hydrogen production from electrolyzers to all other models. Storage and transportation, and hydrogen production from all other pathways in HMM	Very challenging to replicate granular representation of electrolyzer hydrogen pathway outside of EMM. Integration with EMM renewable resource capacity planning is poor for onsite electricity generation: grid electricity loses temporal resolution	Very challenging to replicate granular representation of electrolyzer hydrogen pathway outside of EMM to create true least-cost solution

As discussed in Section 7.8, determining LCA factors within the NEMS framework is challenging. The initial design will include census region LCA factors for each hydrogen technology, using estimates of the fuel type used and its lifecycle carbon footprint. These factors will be adjusted yearly as the energy mix changes. Developing a solution that is both computationally tractable, converges and still provides sufficient detail for policy analysis may require testing several forms of the model, with varying amounts of data that must be exchanged between the EMM and HMM. Therefore, prototyping and testing on EIA's system will be required before the approach can be finalized.

The seventh row looks at the role of non-electricity-based hydrogen production technologies. Either such technologies are included in the EMM, vastly increasing the complexity of the EMM, or all hydrogen production from non-electricity sources will take place outside of the EMM. The equilibrium solution should find a least-cost solution for hydrogen production. If the EMM self-supplies hydrogen, its cost reflects the detailed analysis available in the EMM, including price duration curves and competition with other equivalent electricity storage approaches. Since this level of detail is not available in the HMM, prices would not be comparable with the EMM. As an alternative, hydrogen production with storage would also be modeled in the HMM, and either the EMM would be responsible for reporting hydrogen and storage requirements or use an assumption about the annual capacity factor of hydrogen use in the EMM.

The development approach in column two of the table would mean that the EMM would be responsible for hydrogen production through the use of electricity for all sectors, in competition with other hydrogen pathways. This would substantially complicate the role of the EMM and it would be difficult to ensure a least cost solution. The development approach in column three would require ignoring all of the detail in the EMM to accurately project the value of hydrogen production to the utility sector. The third development representation, shown in column four is recommended as the best compromise. Hydrogen production will occur in both the EMM and HMM, with electricity purchased from the EMM for hydrogen production in the HMM. The HMM will model both the production and interregional transport of hydrogen. Although NEMS operates annually throughout its projection period, in order to accommodate sub annual changes in hydrogen production or demand, adding a flexible number of time slices within each model year is proposed. This will allow evaluating storage as an option for inter-temporal shifting of hydrogen production.

Coordinating shared modeling elements between EMM and HMM

Endogenous technology changes such as learning, technological optimism, and market penetration should be coordinated between models. For instance, hydrogen production using electrolyzers would be common between the EMM and HMM. In this case, the number of units installed across all modules should affect the endogenous cost reductions. Should the HMM contain dedicated renewable power plants for hydrogen production, both wind and solar plants would compete with resources used in the EMM. Similarly, any endogenous changes in cost for these technologies would need to reflect the total number of units in all modules. This increases the communication requirements between modules.

7.2. Self-supply of hydrogen within modules and selling merchant hydrogen across modules

Hydrogen production is currently represented in multiple modules. For instance, hydrogen production in the LFMM is used in refining, while it is used in an intermediate component in the IDM (such as in ammonia production).

In the enhanced model version, the EMM, IDM and LFMM will have self-production of hydrogen that competes with merchant hydrogen available from the HMM. The challenges of synchronizing the EMM and HMM decisions on hydrogen production have been discussed in the previous section. Similar problems will occur between the LFMM and IDM and the HMM. In the case of the LFMM, hydrogen is brought in as a utility but with specific costs available as inputs. In addition to making their own hydrogen, refineries should have the opportunity to buy merchant hydrogen from the HMM (including associated transportation costs). In both the LFMM and IDM, existing and planned hydrogen facilities will be modeled in their respective modules, while the HMM will have multiple sectoral prices for hydrogen, reflecting the availability of hydrogen from a centralized location and price reflecting sectorally differentiated self-supply from localized production.

7.3. Capacity planning and foresight

Capacity planning is required for long-term capital projects. There are various possibilities for its representation in models. The EMM and LFMM use three planning periods to represent the economic time horizon and make their planning decisions once each modeling year. The NGMM uses a single future period planning run which allocates additional capacity if it is economic, including a hurdle rate. The CTUS uses a mixed integer programming algorithm to design a transportation network for the whole time horizon once at the beginning of the cycle.

Because hydrogen production facilities are long-lived assets, capacity planning decisions in the HMM are needed to determine how to best meet expected growth in demand for hydrogen at least cost. Furthermore, capacity planning will be necessary for hydrogen transportation by pipeline, as such projects take many years to complete. This project design does not propose to fix the number of periods representing the planning horizon at this time but allows a structure that might include a varying number of periods, all but the first representing a varying number of years.

How best to use foresight in the capacity planning process is also a complicated problem. There are several different approaches to foresight. Using information from all the forecast years as determined in previous cycles and, as the model converges, capacity planning can approximate perfect foresight. In this way, capacity planning will incorporate future conditions along with the current year conditions before making a capacity decision. Alternatively, myopic foresight would require capacity decisions based only on the current year. This would likely mean capacity decisions would always lag the optimal amount of capacity when total demand is increasing.

Implementation of any of these methods will require trade-offs between complexity and fidelity to the real-world processes. Given the tight integration between the HMM and EMM, one approach would be to follow the ECP and use a three-period look-ahead. This would be computationally challenging and may not provide intuitive outcomes. Alternatively, a single forecasting period could be used, and a new capacity could be added only if its value significantly exceeds its cost, i.e., using a hurdle rate to price new capacity. At the other extreme, perfect foresight could be assumed, meaning that capacity would always be available when needed.

7.4. Representation of pipeline structure (including new paths vs. current right-of-way)

The representation of transport pathways in the HMM will have an impact on the model development and its computational time. At this point, the transportation of hydrogen through pipelines is only being considered from a transmission (trunkline) point of view, with regional and local distribution being handled by various means such as direct pipes to end-use and truck delivery of liquid and gaseous hydrogen. The distribution of hydrogen at this subregional level would be represented by means of a cost adder or hookup fee. For transmission, the challenge is whether or not to represent the hydrogen pipeline network in its entirety, which means giving the model options for individual pipelines connecting regions and then choosing the least cost network that satisfies demand or modeling simplified region-to-region transmission.

Although a discrete representation of the pipeline network as discussed in the Requirements Document could yield granular cost estimates of regional costs for transmission, developing such and solving such a model would add considerable complexity, and this approach is not recommended.

Solving network transportation problems with discrete pipeline capacities usually requires a mixed-integer program (MIP). MIPs are notorious for being hard to solve and can yield different results based on the starting point and algorithm used. Although solvers like CPLEX and Xpress are able to solve these types of problems with no issues, they still can take 10+ minutes to solve. A good example of this type of problem is the CTUS model in use in NEMS today that can take up to 20 minutes to solve, although the average time is in the order of a few minutes. It is OnLocation’s experience that in modeling cases significantly different than the Reference case, such as for deep decarbonization cases, the full 20 minutes can be used. Because CO_2 is a byproduct of all other sectors to be sequestered, it is only run at the beginning of every cycle to build the optimal pipeline network. In the case of the HMM, however, production can change every year in the cycle based on demand, and as a result, the delivery of hydrogen has to be updated every year. Adding a MIP would create a large slowdown in the NEMS model if used. Moreover, representing detailed options for building pipelines requires additional information to be gathered regarding their possible locations, adding another layer of complexity to the model development process. One reason why one might favor the use of detailed pipeline networks is that the granular cost estimates can then be used to calculate the transport adders passed to the demand modules of NEMS. However, most NEMS modules already, for simplicity, use a regional aggregate for prices, and this would be no different for the prices coming from the

HMM. As a result, the granularity, although still useful from a reporting and analysis perspective, will not enable significantly more accuracy in NEMS model results.

For the above reasons, a detailed pipeline network model in the HMM is not recommended. Rather, transmission pipelines can be represented in an aggregated form at a regional level. All that would have to be calculated is the number of pipes of standard lengths that would need to be built in a given region, given the demand inside and outside that region, and given the average capital cost of installing new pipelines and the average energy usage while operating new and existing pipelines. In this structure, the model form can also be limited to an LP or, at most, a Quadratic Program (QP) form.

7.5. Hydrogen blend limits

Any hydrogen blend from the NGMM will be a homogenous product. That is, as currently constructed, NEMS cannot feasibly model different blend levels at different locations. Therefore, any hydrogen blend limit would have to be low enough to be useable across all natural gas consumers. Furthermore, there are costs associated with upgrading pipelines to transport hydrogen blends. While modeling pipeline costs for higher-level blends could be added to the NGMM, this seems more consistent with a later phase of the project, which would also reflect incremental conversion costs for consuming high-level blends, not just transporting them.

7.6. Incorporation of local transport options

Hydrogen may be transported through truck or rail to serve local markets[31]. The model will have both centralized production and storage of hydrogen and an option for localized production that is not burdened with aggregate regional transportation and storage costs but no specific representation of local transport. Local transportation will be represented as an adder to the price of hydrogen.

7.7. Technology penetration

There are several conflicting factors that impact technology penetration. Endogenous cost reductions occur as process improvements and scaling reduces production costs. Technological optimism reflects the fact that initial units of technology tend to be more expensive than anticipated. Finally, technology penetration reflects both the limits on how fast production can be expanded and market inertia, including factors not otherwise modeled, that prevent a least-cost technology from very rapid expansion and slow its increase in market share. Several of these factors are discussed below.

Endogenous cost reduction in different sectors

Learning algorithms reflect that technology costs usually decline as total installed capacity increases. There are various algorithms for this. The technological optimism factor reflects the inherent tendency to underestimate costs for new technologies. Learning factors represent

[31] https://www.osti.gov/biblio/1483989-economic-data-modeling-support-two-regional-case-studies-nuclear-renewable-hybrid-energy-systems-analysis-technical-economic-issues

reductions in capital costs as the number of installed units increases. A typical one-factor learning curve may be described as

$$\mathrm{C(x)} = C_0 \left(\frac{x}{x_0}\right)^{b_i}$$

where $C(x)$ is the total cost, C_0 is the initial cost and the parameter b_i is set so that each doubling of installed capacity of type i produces the exogenously set fraction reduction of cost.

An expansion of this equation is

$$\mathrm{C(x)} = C_0[(1-\alpha) + \alpha \left(\frac{x}{x_0}\right)^{b_i}]$$

where α is the fraction of the original capital cost subject to learning, in this way, learning can be applied to those portions of a technology where learning is applicable. By dis-aggregating capital costs in this way, learning can also be applied to common components across technologies.[32] This is the technique currently used for generation technologies in the EMM.

Because there are common components across modules, cost reductions determined in one module should impact costs in the other modules using the same technology. However, in order to maintain consistent costs across multiple modules, similar cost reduction algorithms must be used across modules, or a single algorithm taking installations from all modules and deriving a common cost reduction factor.

Market Penetration

A typical market penetration algorithm used in NEMS is the Mansfield Blackman technology penetration algorithm, which represents the rate at which a new technology's market share may increase. It creates an S-shaped penetration curve. It may be expressed as:

$$ln(\frac{ms_t}{(L-ms_t)}) = C_1 + C_2(t-t_i)$$

where ms_t is the market share at period t, L is the maximum market share, $C_1$is a function of L and the initial share N_0 and C_2 is governing the rate of diffusion. The value of ms_t is calculated in the model, yielding capacity builds, while the other parameters are exogenously determined.[33]

The EMM uses other approaches to model market penetration. In particular, it sets a percentage limit on the increase of any particular technology after a specified number of units have been built. Furthermore, the ECP uses a market sharing algorithm to mitigate the tendency of the linear program used for capacity planning to find a "corner", or "winner-take-all" solution.

[32] Ouassou, J.A.; Straus, J.; Fodstad, M.; Reigstad, G.;Wolfgang, O. "Applying Endogenous Learning Models in Energy System Optimization," *Energies* 2021, 14(16), 4819. https://doi.org/10.3390/en14164819.
[33] Packey, D., *Market Penetration of New Energy Technologies*, NREL/TP-462-4860, 1993.

Another useful tool to assess market penetration may be Market Readiness Levels (MRLs). Similar to TRLs, which report the technical status of technologies, MRLs report on the non-technical aspects of bringing a technology to market, such as business development and scalability in the marketplace. Instead of a scale separate from TRL, the IEA adds two levels to their 1-9 TRL scale to describe three stages of technology in the market: introduction, traction, and stability. Others describe MRL on a 1-9 scale where MRL 1-3 describe the ideation of technology and basic research for the market needs of that product; MRL 4-5 describe market testing; MRL 6-7 describe market traction, and MRL 8-9 describe market scaling and stability. While TRLs of various hydrogen technologies are readily available in the literature, MRL is not widely available, other than where they are estimated by IEA and may require elicitation from technology experts.

Retrofits in the Industrial Sector

Currently, in the IDM, the total production each year includes the remaining capacity from the base year, added capacity from previous years, and any new capacity required for the given year[34]. The existing capacity from the base year is the part left over from base year capacity retiring at a linear rate. The added capacity in previous years also retires but using a survival function that rapidly rises/falls in the start and end years of its life but retires approximately linearly in intermediate years. The share of technology that is prevalent for base capacity and capacity added in previous years does not change, i.e., there are no retrofits for existing capacity in the IDM calculations. This will be reflected in the penetration of hydrogen technologies in various industries considered since the new capacity is a small fraction of the total, and the majority of the mitigation opportunity lies within the existing capacity either through retirements substituted by new sites or retrofits of existing units by new technology. We propose to change the retirement rate for existing stock to accelerate the adoption of retrofit technologies, which would be added as an option. We will vintage the stock so that only existing stock would get the accelerated retirement.

7.8. Implementing policies that distinguish carbon intensity of hydrogen production

NEMS accounts for carbon emissions from the energy sector by summing the carbon emissions created by the combustion of fuels for energy at the end of each model iteration. A carbon tax is applied as a markup based on the carbon content of the fuel. Therefore, in the energy conversion modules such as the EMM (or the HMM), the cost of different carbon intensities flows through the model as a markup on inputs to the fuels. As a result, policies that distinguish between hydrogen pathways explicitly based on the full lifecycle emissions of a hydrogen pathway are problematic to model in NEMS. For this to be accurately modeled, carbon emissions must be

[34] OnLocation, Inc., *CCUS in Cement Industry: Conceptual Design Report for NEMS Implementation*, July 30, 2021. Prepared by OnLocation, Inc. for DOE Office of Fossil Energy.

assessed across the entire production pathway of the fuel. However, this would be challenging within NEMS, as fuels are considered homogeneous when passed between models. Note that energy markets will also need to become more differentiated to support a full lifecycle analysis as most fuels are treated as commodities, with the most obvious exception being renewable-based electricity that is sometimes sold as a differentiated product to consumers or treated through a parallel market of renewable electricity credits.

An important example of this problem would be assigning the lifecycle emissions profile to hydrogen produced from electricity through electrolysis. While electrolysis itself is essentially zero carbon, the carbon emissions from electricity production must be included along with those of extraction of the fuel used in a lifecycle framework. This would require assigning a production pathway to the electricity used in electrolysis, assigning specific technologies to each pathway, and collecting carbon emissions data from each module in turn.

Determining the carbon emissions footprint for individual technologies in NEMS is challenging. NEMS only tracks energy-related carbon emissions; methane emissions from the production, transportation, and distribution of all fossil fuels (including coal and natural gas) are not currently recorded. Furthermore, the nature of the fuel transportation models precludes identifying the source (and thus the carbon characteristics) for any particular regional demand For instance, methane emissions from natural gas production depend on the production region. As natural gas flows through the NGMM as a single homogenous product, the source of the gas at the demand region level is not identified. Therefore, the carbon footprint of hydrogen depends on the flow of natural gas with an unknown provenance. There is a similar problem with electricity used for hydrogen production. In any region, the carbon footprint of electricity depends on the generation technology mix and the carbon footprint of the input fuels. Because electricity is a homogenous product, its carbon intensity cannot be determined outside of the EMM.

Integrating full life cycle emission within NEMS is out of the scope of this effort. To approximate life cycle factors, the HMM will estimate census regional emission factors for hydrogen production. A lifecycle framework will be built that will incorporate both existing exogenous estimates from the literature, such as upstream oil and gas emission factors, and annual key metrics available from NEMS outputs, such as electricity generation mix and natural gas production.

7.9. Modeling end-use hydrogen technologies along with other decarbonization strategies

Many industries and companies are taking a comprehensive approach toward evaluating their practices and developing plans to decarbonize in the future. These plans all contain multiple strategies using multiple technologies to use less energy and reduce emissions. While some of these plans contain hydrogen use, none of these plans include hydrogen as the sole strategy for decarbonization. Additionally, many of these hydrogen technologies are in the very early phases of research and development, and specific technology characterization/parameterization are not available in the literature. In the coming years, hydrogen technologies will compete with these other strategies, many of which are also not yet well defined, in end-use sectors. Including these competing decarbonization technologies and strategies in end-use sectors, while not within the scope of this effort, will yield a more balanced representation of end-use hydrogen, especially in the industrial sector.

8. HMM Features

8.1. Overall optimization problem structure

The overall structure of the HMM will be a constrained linear or quadratic program. In this formulation, an objective function is to be minimized or maximized while not violating a set of constraints. While a linear program includes only linear constraints and a linear objective function and is generally is less complex to solve than a quadratic program, the nature of the objective function means the solution may have a constant price over a range of quantities, and small changes in the inputs may result in very large changes in the solution.[35] Adding a quadratic objective function yields changing prices as the solution quantities change and likely results in only small changes for small changes in the model inputs at the cost of increased complexity in determining a solution.

Each period will uniquely represent the production, transportation, and storage of hydrogen. For capacity planning purposes, more than one period will be represented within the optimization program. Each period will represent a single year or a range of years. Within a year, a flexible number of time slices will disaggregate supply and demand into representative time slices in the year. Hydrogen production can be reallocated between time slices through the use of storage.

In the HMM, the objective will be to minimize costs of production, storage, and transportation to meet hydrogen requirements from the other modules. The primary input will be quantities of hydrogen required. Outputs include quantities of fuel converted to hydrogen, direct CO_2 outputs (which may be sequestered), and prices of hydrogen. Additionally, a local production and transportation technology option will be added to compete with centralized hydrogen production, transportation, and large-scale storage. Prices will be based on the dual (or marginal) values from the solution of the optimization program, modified with markups to include factors that otherwise cannot be included within an optimization model.

The HMM will include technologies for hydrogen production such as those as shown in Table 1. Feedstock prices will be input from the NEMS supply and conversion models. Electricity prices will come from the EMM. The HMM will provide quantities of electricity required, and the EMM will provide the corresponding prices. Alternatively, there is the potential to provide a price curve for various quantities of electricity provided. This will help with convergence between the fuel dispatch submodule of the EMM and the HMM in each iteration and reduce the number of model cycles required, and may be used to reflect different attributes (such as carbon

[35] i.e., technically this is referred to as a basis change.

intensity) that may not otherwise be communicated between modules. Natural gas prices will come from the NGMM, coal from the CMM, and biomass from the RFM.

Merchant hydrogen production will be modeled within the HMM and will be made available for other modules. Hydrogen production for use in peak periods is under development at EIA, and as discussed previously there are compelling reasons to represent it in the EMM rather than the HMM. Finally, localized hydrogen production for industrial processes may continue to be modeled in the industrial module. The IDM will also have an option of consuming hydrogen at the price supplied by the HMM. This may lead to a possibility where, depending on the scenario run, the energy consumption linked to the hydrogen used by the IDM may be accounted for either in the IDM or in the HMM, depending on the option chosen. It is recommended that the NEMS reporting in the FTAB be modified to account for the energy consumption related to hydrogen use in either the IDM or HMM, and adjust the other one accordingly.

Certain industries will be treated as self-contained with respect to hydrogen: industries that produce as much as they consume. Other industries will have the ability to purchase hydrogen. Therefore, the HMM should be able to sell hydrogen to all sectors that use it, as appropriate to the use case in each sector, irrespective of whether hydrogen is self-produced in that sector (i.e., should reflect as appropriate the competition between self-produced and commodity hydrogen). Similarly, excess hydrogen self-produced by consuming sectors should be available for purchase by the HMM, again, as appropriate to the sector-specific use case. The primary sectors where hydrogen may be sold to the HMM would be from hydrogen production in the EMM, LFMM or IDM. This is illustrated in the bi-directional pathways for hydrogen for these sectors in the section Linkages to Other Modules. Enhancements to linkages between the EMM other modules are shown in Figure 4, where excess hydrogen production, if competitively priced, may be sold to the HMM. The relative benefits of modeling hydrogen production as self-supply by sector will be discussed in more detail in Section 7.2.

Capacity Planning and Allocation of Production Technologies

As described above, the overall design of the HMM will be a constrained optimization program. The model will be run in two modes: a multi-year planning mode and a single-year operational mode. In the planning mode, the objective will be to minimize the total cost of meeting hydrogen demand using available conversion technologies. Components of the objective function representing the first period will only include operating costs, while for all subsequent years total costs will be used. Converting total costs as a single number will be accomplished through standard financial modeling. Each technology is assumed to be characterized with capital costs, efficiencies, and other operating costs (identified through the input templates). Combined with fuel prices, interest rate information, assumed rate of return, and any credits that the technology may receive based on policy, a net present value (NPV) can be calculated for each of the technologies per unit of capacity. Combined with the transportation and storage costs for delivery of hydrogen, minimizing the sum of these components will yield the optimal allocation over all the technologies that meets the given demand. Capacity planning will only be performed on the first iteration of any model year. For the operating mode of the model that runs every iteration, capacity is fixed and incorporates any changes in capacity from the prior year. This first period is executed using input from the other modules for that year. This mode of the model will be executed during each iteration, providing equilibrium prices across the NEMS modules.

As discussed in Section 5.1, output of the capacity planning optimization program will be adjusted by a market sharing algorithm. This will mitigate the winner-take-all (or over-optimization) that is inherent in the constrained optimization approach.

Transportation and Storage

The HMM will have an aggregated transportation and storage representation along with technology allocation in the constrained optimization program. Each period will have multiple time slices. Hydrogen production can then be reallocated between time slices through the use of storage. Additionally, a local production and transportation technology option will be added to compete with centralized production, transportation large-scale storage. Effectively, the HMM uses regional and interregional demand to determine a price for hydrogen, which includes production, transportation, and storage for the delivery of hydrogen within the region and outside of it.

8.2. Regionality

The HMM will exchange data with almost every other module in NEMS. Since there are many different regionalities across NEMS, there may not be an optimal regionality for the HMM. It is likely that the HMM will have the tightest coordination with the EMM. For instance, regional electricity prices will come from the EMM. Furthermore, any competition for hydrogen production will be between the EMM and the HMM. Hydrogen production costs will reflect the cost of feedstock or electricity. Therefore, hydrogen pricing to the EMM would be for the EMM fuel regions. The most likely source of seasonality in hydrogen demand would also be for electricity production, which implies that long-term storage should be for electricity production. Because regionality will be flexible under the KBM architecture, the best candidate balancing convergence, granularity, and model execution time may be finalized after model integration. Therefore, it is proposed that the HMM will initially use census divisions, but this could be modified through the development of the model.

8.3. Foresight

Because hydrogen production facilities are long-lived assets, capacity planning decisions within the HMM are needed to determine how to best meet expected growth in demand for hydrogen at least cost. Design challenges related to foresight were discussed in Section 7.3 above. The hydrogen demands and fuel prices used in capacity planning for the HMM will be based on previous cycle solutions and thus represent near-perfect foresight. This is similar to the technique used in the EMM and LFMM.

8.4. Endogenous cost reduction and constraints on capacity builds

Endogenous cost reduction and capacity build constraint algorithms were discussed in Section 7.7 above. There are many choices for such algorithms. A simple default approach while allowing for more sophisticated algorithms in the future is proposed. Technology constraints will be modeled as a percentage limit on the increase of any particular technology at the national level. Cost reductions will be a percentage reduction based on exponential growth (i.e., percentage reduction for each doubling of units delivered) in nationwide installed capacity. In addition, market share from the capacity planning function of the HMM will be smoothed across multiple technologies to represent uncertainty rather than the winner-take-all values that are inherent to the LP solution.

8.5. Hydrogen Accounting

The HMM will serve as the centralized repository for summarizing hydrogen production, transportation, and consumption across NEMS. The HMM will provide a comprehensive account of all hydrogen produced in all modules by technology class. The HMM will also account for hydrogen storage requirements across all modules and of dedicated hydrogen pipelines. This will include expenditures each year, including a summary of capital and operating costs in the HMM.

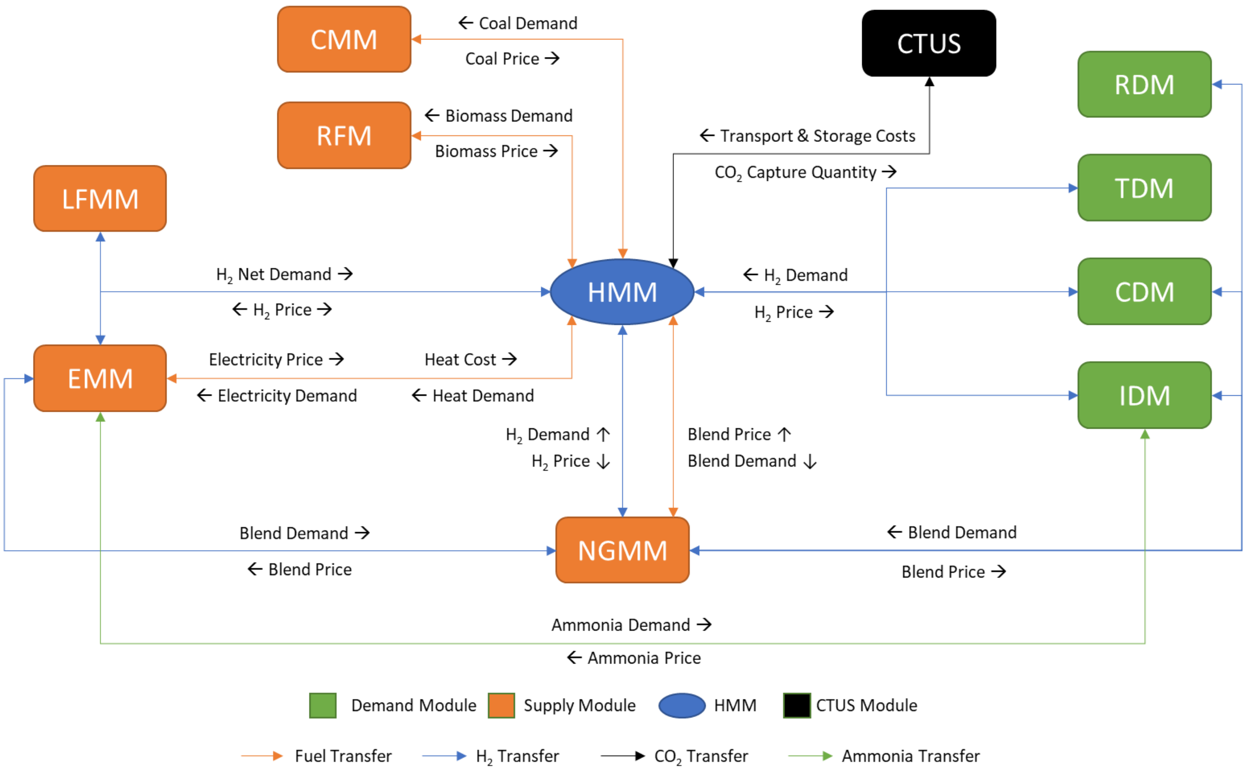
The model will also then include a method to calculate the contribution of different hydrogen technologies to end-use consumption by distributing the share of production by technology (less losses) uniformly across all end-use sectors. Consumption would be reported across end-uses, while production would be reported by technology types.

9. Module Enhancements

The interactions between modules are summarized in Figure 3. Note that all modules transfer data between each other through the Integrating Module. However, it is more informative to refer to data flows between modules, even though the data flow technically goes through the integrating module. The HMM will be the key module in the production and distribution of hydrogen. Production of hydrogen will come from a variety of sources, including electricity, natural gas, biofuels, and coal. The HMM will compete across all technologies for the least cost solution to meet hydrogen demand. The output will then be quantities of fuel required and hydrogen produced. The HMM will provide electricity quantities, while the EMM will provide electricity prices. Similarly, biomass prices and quantities required will be exchanged with the Renewable Fuels Module (RFM), and natural gas and coal prices and quantities will be exchanged with the NGMM and CMM, respectively.

Hydrogen may be blended with natural gas in the NGMM. Since there will be only one natural gas blend ratio, hydrogen (through the gas blend) will be provided to all modules that otherwise use natural gas: the LFMM, EMM, and the demand modules: residential, commercial, industrial, and transportation. For the residential module, blended hydrogen is the only hydrogen option considered, so no changes to the residential module are anticipated, and the module is not discussed further.

Figure 3. Module Interactions in Enhanced Modules



Hydrogen will also be supplied to the other demand modules from the HMM. The transportation, commercial and industrial modules will explicitly provide hydrogen quantities required to the HMM, given the prices set by the HMM. They will each contain hydrogen technologies and perform economic competitions to determine their deployment and usage.

Finally, hydrogen production technologies using fossil fuels or biomass emit CO_2, and thus CCUS may be included to manage carbon. Quantities of CO_2 will be sent to the CTUS module, and the price of hydrogen from the HMM will reflect the cost of its disposal. Since the hydrogen production will be represented regionally and not through individual site locations, the CO_2 captured will also be sent to the CTUS using the same regionality but distributed over the region using standard plant capacity for each technology. This is similar to how enhanced oil recovery (EOR) sites are represented in the CTUS today.

When NEMS reaches equilibrium, the price for fuel should reach the point on the supply curve representing all of the quantities demanded from the other modules. Because of the Gauss-Seidel algorithm, demand for each fuel is derived sequentially. As long as the implicit slope of the supply and demand curves is relatively shallow, convergence is likely. However, in several places, this becomes problematic. For instance, biomass curves can be very steep as different types of categories of biomass are accessed. Biomass is used for liquid fuels, electricity, and potentially for hydrogen production. Careful coordination between these demands will be required so that biomass quantities will converge to an equilibrium value.

9.1. Electricity Market Module

Hydrogen can serve as an alternative to other power storage technologies. Hydrogen can serve as the equivalent of power storage by producing hydrogen for storage when net loads (load minus available solar and wind generation) and electricity prices are low and later using it for power production with combustion turbines during peak times. The entire electrolyzer, on-site storage, and hydrogen combustion turbine pathway will be considered one technology. As such, it will compete within the EMM with other alternative storage technologies.

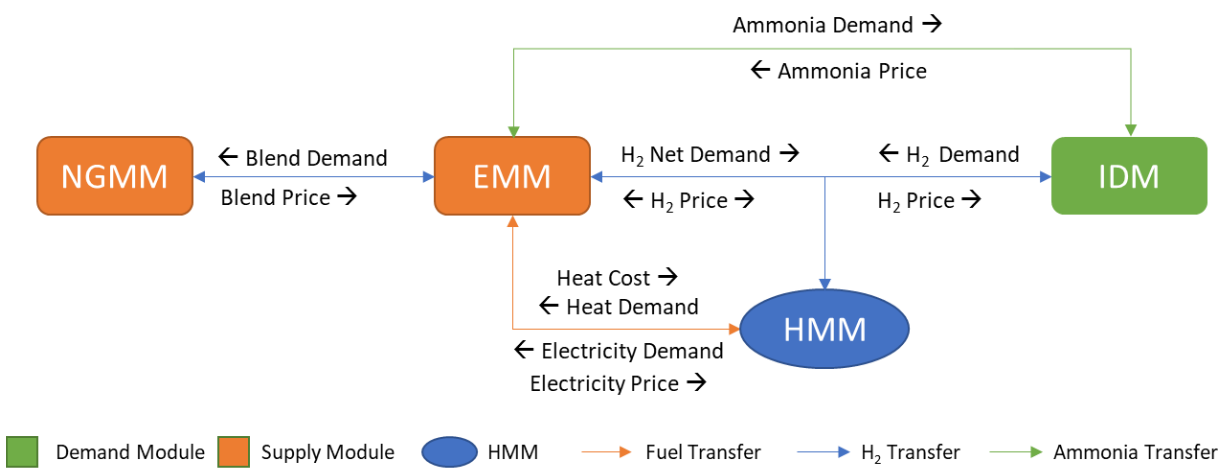
Renewable energy/hydrogen storage/hydrogen combustion

In scenarios where only carbon-free power is allowed, hydrogen turbines can provide a dispatchable generation source to complement other renewable energy sources such as wind and solar. The REStore model provides the EMM with a more granular representation of the load duration curve to support planning and policy decisions around the incorporation of renewables to meet load. In particular, REStore values storage that shifts load between periods. Hydrogen can serve the same role as storage. Therefore, outside of the REStore submodule, the EMM must allocate this electricity load shifting requirement across technologies, including hydrogen and more traditional storage.

Linkages to Other Modules

Enhancements to linkages between the EMM other modules are shown in Figure 4.

Figure 4. EMM interactions with the HMM.



Direct Combustion of Ammonia

Ammonia can be used as an energy carrier. In this pathway, low-carbon hydrogen is used to produce ammonia. The ammonia may be combusted with specialized turbines to produce electricity. This pathway is analogous to hydrogen combustion but requires modeling significantly different parameterization of ammonia storage as opposed to hydrogen.

High Temperature Heat

High temperature heat used in conjunction with electrolyzers can significantly improve their efficiency. In order to model this technology in the HMM, information on available heat must be available to the HMM. In this model, such heat will only be provided from the EMM. The cost of such heat would be the opportunity cost of providing it through any reduced efficiency of the heat source.

Blended Hydrogen for Combustion

Because the EMM consumes natural gas from the NGMM, hydrogen will be consumed any time the hydrogen blend ratio is positive. It will be assumed that the blend ratio is low enough that incumbent capacity would not need retrofits.

Sell Power for Hydrogen Generation

In the EMM, excess hydrogen, otherwise unnecessary for the production of electricity, will be available for purchase by the HMM. The net hydrogen flow will be represented, along with the price.

Sell Power to HMM

Hydrogen production using electricity will also occur in the HMM. Rather than a single price and quantity pair, the EMM will provide a supply curve of electricity. There will be steps of the quantity supplied for each price. In this way, prices will be able to reflect the cost of electricity with specific characteristics, such as renewable electricity that can be provided to the HMM for hydrogen production.

Buy Hydrogen from the HMM

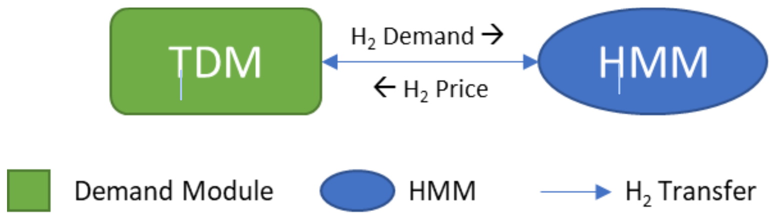
An annual hydrogen price will be provided by the HMM to the EMM. This price represents pro-rata hydrogen flow to the EMM. This price would be used by the EMM to choose whether to self-supply hydrogen or purchase it from the HMM.

9.2. Transportation Demand Module

Linkages to Other Modules

Enhancements to linkages between the IDM other modules are shown in Figure 5.

Figure 5. TDM interactions with the HMM.



Light and Heavy-Duty Vehicles

In the transportation sector, hydrogen is currently implicitly represented through the provision of fuel cell options for vehicles, where the demand for hydrogen is assumed to come from conversion from natural gas. Fuel cells are an option within the Light Duty Vehicle (LDV) submodule and for trucks in the Freight submodule. The LDV module contains the capability for three submarkets (urban, suburban, and rural) for hydrogen that allows for different delivered hydrogen prices, however, the HMM will not use this differentiation. The freight truck model currently has a simple algorithm for determining market shares among truck types based solely on relative fuel prices and user-specified adoption parameters with the exception of natural gas trucks, where the incremental cost of the trucks is compared to the fuel savings relative to diesel trucks. A complete market share determination would include a competition of all truck types taking into consideration lifecycle costs (capital and fuel) as well as perhaps relative availability of fueling infrastructure.

The TDM will be enhanced to explicitly provide hydrogen demand to the HMM. The HMM will provide hydrogen prices specific to the TDM. The price of hydrogen at the retail level depends upon the distribution pathway. For simplicity, the HMM will provide a price, and appropriate adjustments will be made exogenously by location (urban vs. rural, etc.) within the TDM. In particular, explicit provision of hydrogen pricing will be differentiated for fuel cell light vs. heavy-duty vehicles to reflect potentially different final stage delivery costs.

Rail

In the rail transportation submodule, fuel consumption is modeled as a function of miles traveled and efficiency. Hydrogen can be introduced as an alternative to diesel fuel for rail transportation.

Marine

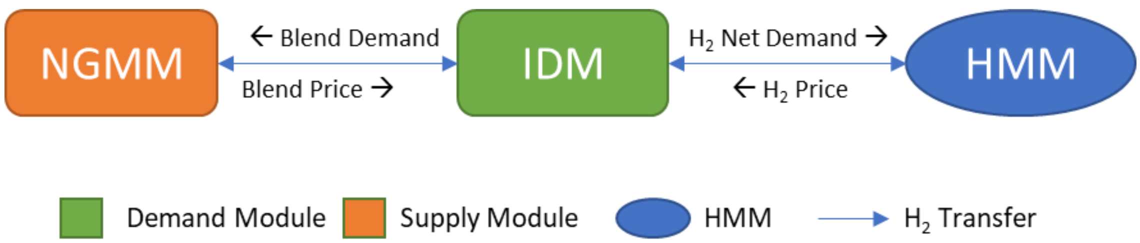
Hydrogen is a candidate fuel for large vessels. Marine consumption of hydrogen will not be explicitly modeled. Demand for hydrogen for marine uses will be aggregated along with other transportation uses.

9.3. Industrial Demand Module

Linkages to Other Modules

Essential changes to the IDM to include hydrogen supply/price flows from the HMM to the IDM and hydrogen demand flows to the HMM from the IDM. Enhancements to linkages between the IDM other modules are shown in Figure 6.

Figure 6. IDM interactions with the HMM.



Additionally, hydrogen fueled end-use technologies will be added to the IDM.

Energy Intensive Industries

Hydrogen technologies will be added to three energy-intensive industries to reflect hydrogen fuel use: iron and steel, cement, and glass. Pure hydrogen direct iron reduction in the steel industry and hydrogen fired kilns in the cement and glass industry can be added as new technologies without disrupting the flow of the current sector specific modules within the IDM. Hydrogen technologies will simply be modeled as new technologies within the existing paradigms. The technology templates given to hydrogen experts to elicit technology characteristics are the same format as current technologies within the IDM. As detailed in Section 6.4, hydrogen fired cement kilns are an early prototype technology, and an estimate of technology characterization may not be possible. If available, this technology will be added to the IDM. IDM will be enhanced to introduce hydrogen into all three of these industrial processes.

Further detailed in Section 7.7, the IDM does not currently model retrofits, and under the current modeling paradigms, these technologies would be slow to adopt. Enhancing the IDM to account for retrofits is beyond the scope of this effort, but adoption of these new technologies could be accelerating by increasing the retirement rate of existing plans and increasing plant turnover.

Hydrogen for Boiler and CHP Use

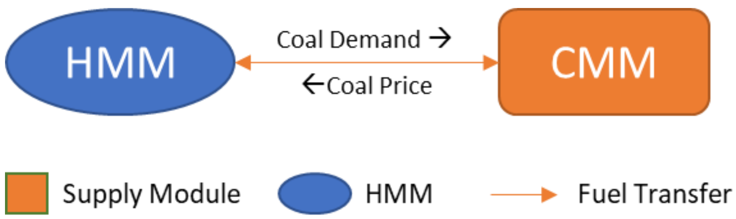
The IDM defines specific boiler technologies for the iron and steel industry and the paper industry, a generic boiler technology used by other industries, and CHP technology. While the paper and steel industries are unlikely to use hydrogen fueled boilers, the generic boiler technology could be altered to use hydrogen as fuel.

For the generic boiler technology, fuel shares are determined in the IDM through logit shares based solely on changes in relative fuel costs using exogenously specified efficiencies by fuel type. To accommodate the use of hydrogen would require a revision of how boiler fuel shares are calculated and would likely not be addressed in the first phase of the hydrogen implementation as it is unclear at this time its potential demand.

Natural gas CHP technologies are defined for various levels of steam loads in the IDM, and a hydrogen-fueled CHP technology could be added, although the algorithm would need to be modified to account for competition between the natural gas and hydrogen CHP rather than being just a competition with purchased electricity as currently configured.

9.4. Coal Market Module

Figure 7. CMM interactions with the HMM.



Add Demand for Coal Gasification from HMM

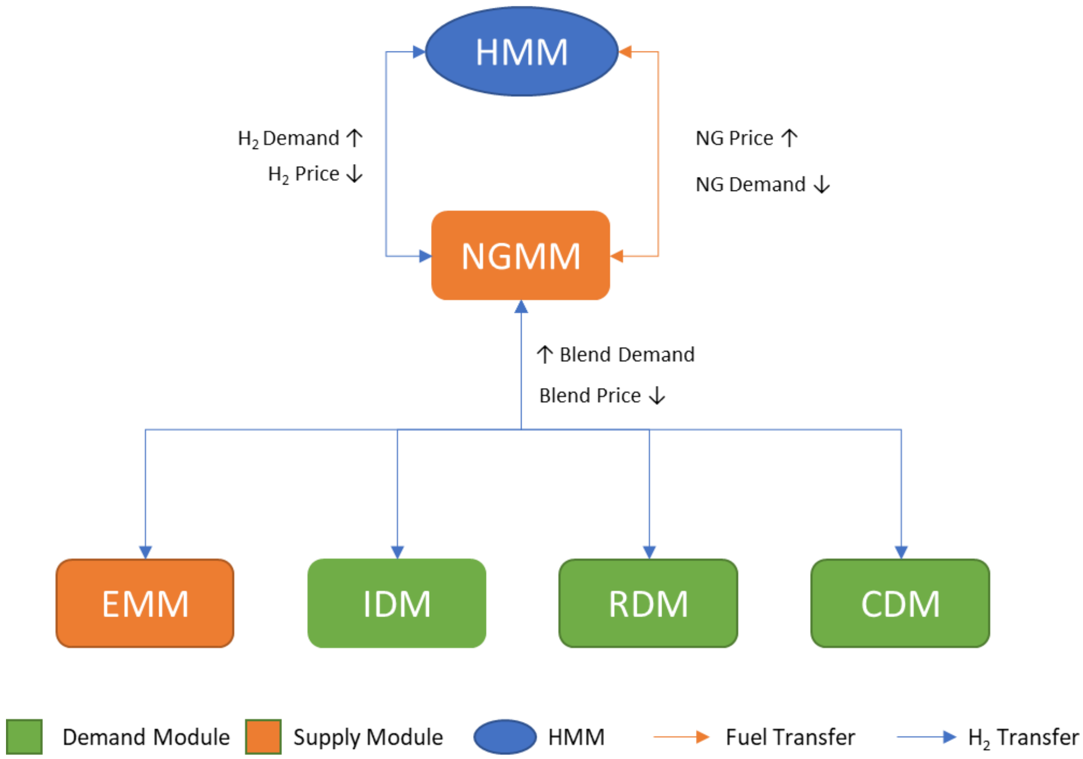
Coal gasification may be used to produce hydrogen. The HMM will provide the coal module with quantities of coal required for gasification at a price set by the coal module, which will estimate the industrial price. Coal demand from the HMM will then be added to the total demand for coal. These links can be seen in Figure 7.

9.5. Natural Gas Market Module

Linkages to Other Modules

The NGMM will receive hydrogen and send natural gas to the HMM. All other interactions with the other modules will remain the same. Linkages to other modules are shown in Figure 8.

Figure 8. NGMM interactions with the HMM.

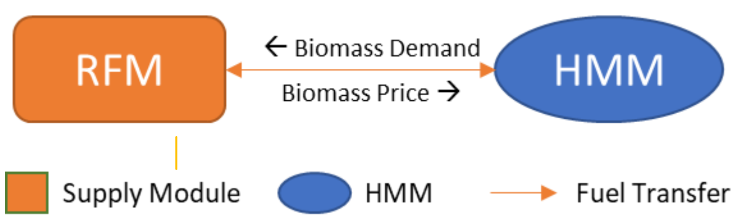


Add Blended Hydrogen with Limits

The NGMM will allow hydrogen natural gas blends to be distributed in place of natural gas. The model will choose hydrogen or natural gas based on relative prices, but a maximum blend level will be exogenously set. The blend level is assumed to be homogenous across the entire system. Therefore, it must be set low enough so that it can be used throughout the transmission and distribution system. The NGMM will send the hydrogen required to the HMM to meet the blend requirements. Pricing of the resulting blend will reflect the components of natural gas and hydrogen.

9.6. Renewable Fuels Module

Figure 9. RFM interactions with the HMM.



The HMM will provide the LFM with biomass requirements, while the RFM will provide the price based on the total biomass supplied for all modules (see Figure 9).

Challenges and Approach for Using Biomass Consumption Curves

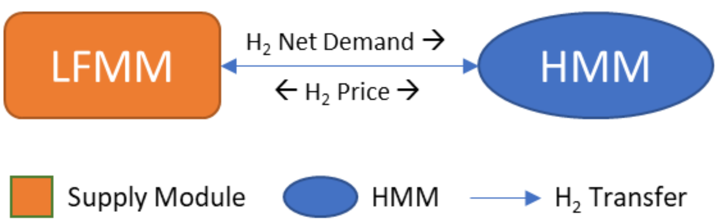
Biomass can be used in several different modules, including production of liquid fuels in the LFMM, power production in the EMM either through cofiring with coal or in a dedicated facility, and gasification for hydrogen in the HMM. The HMM will provide the RFM the quantity of biomass required given the price supplied. While these uses for biomass are relatively uneconomic today, with carbon policies the incentives for each of these modes will become far greater. Therefore, the biomass required by each individual module will be a significant portion of the supply curve, which means each sector's demand could lead to significant biomass price changes. This makes convergence to equilibrium prices challenging. A typical solution would be to extrapolate a set of supply steps from the price-quantity pair, which in combination with relaxation between iterations may mitigate convergence issues.

9.7. Liquid Fuels Market Module

Linkages to Other Modules

Hydrogen will be provided from the HMM at a unique price for this module. The hydrogen price will reflect transportation and economies of scale for refining use. Hydrogen from the HMM will compete with hydrogen generated within the model. CO_2 captured from hydrogen production in the LFMM will be added to other CO_2 captured from this model and sent to the CTUS. Enhancements to linkages between the LFMM other modules are shown in Figure 10.

Figure 10. LFMM interactions with the HMM.



Hydrogen is an important feedstock to the refining industry. Key uses include hydrocracking and desulfurization, both of which are important elements in the production of diesel fuel. In the LFMM, hydrogen production is already represented through a Steam Methane Reforming (SMR) process unit. The current SMR technology as modeled at EIA does not include carbon capture, but a capture option can be introduced both as retrofits for existing production capacity as well as for new units.[36]

CHP is explicitly represented in the refining sector. Hydrogen could be used to reduce the carbon profile of refining by introducing a low carbon fuel. Therefore, hydrogen will be presented as an alternative to natural gas as a utility for various heat applications and CHP.

Hydrogen will be available as merchant supply from the HMM or produced from within the LFMM. Of course, hydrogen is likely to be more expensive than using natural gas directly, so

[36] This has been done previously in an alternative version of NEMS developed for FECM.

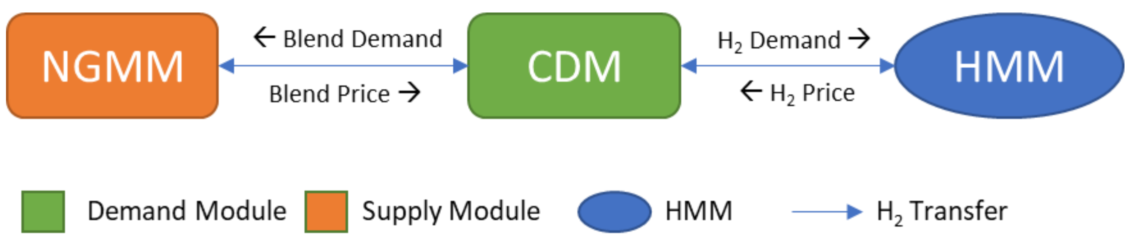
the only motivation for it use in heat and CHP applications would be if there are policies in place penalizing carbon emissions.

9.8. Commercial Demand Module

Linkages to Other Modules

Enhancements to linkages between the Commercial Demand Module (CDM) and other modules are shown in Figure 11.

Figure 11. CDM interactions with the HMM



CHP

There will be a niche market for hydrogen-fueled CHP in commercial facilities. These facilities will have the potential for relatively large demands which can use waste heat from a fuel cell and consume power. Such locations might be hotels, hospitals, recreational facilities, or similar loads. CHP is modeled in the CDM along with distributed energy resources, and CHP technologies are parameterized as such. Hydrogen-fueled CHP technologies could be added here.

Heating

Blended hydrogen will come from the NGMM. However, it is assumed that incumbent technologies will be sufficient to accommodate any hydrogen blends. There will be no provision for enhancing the model with retrofits.

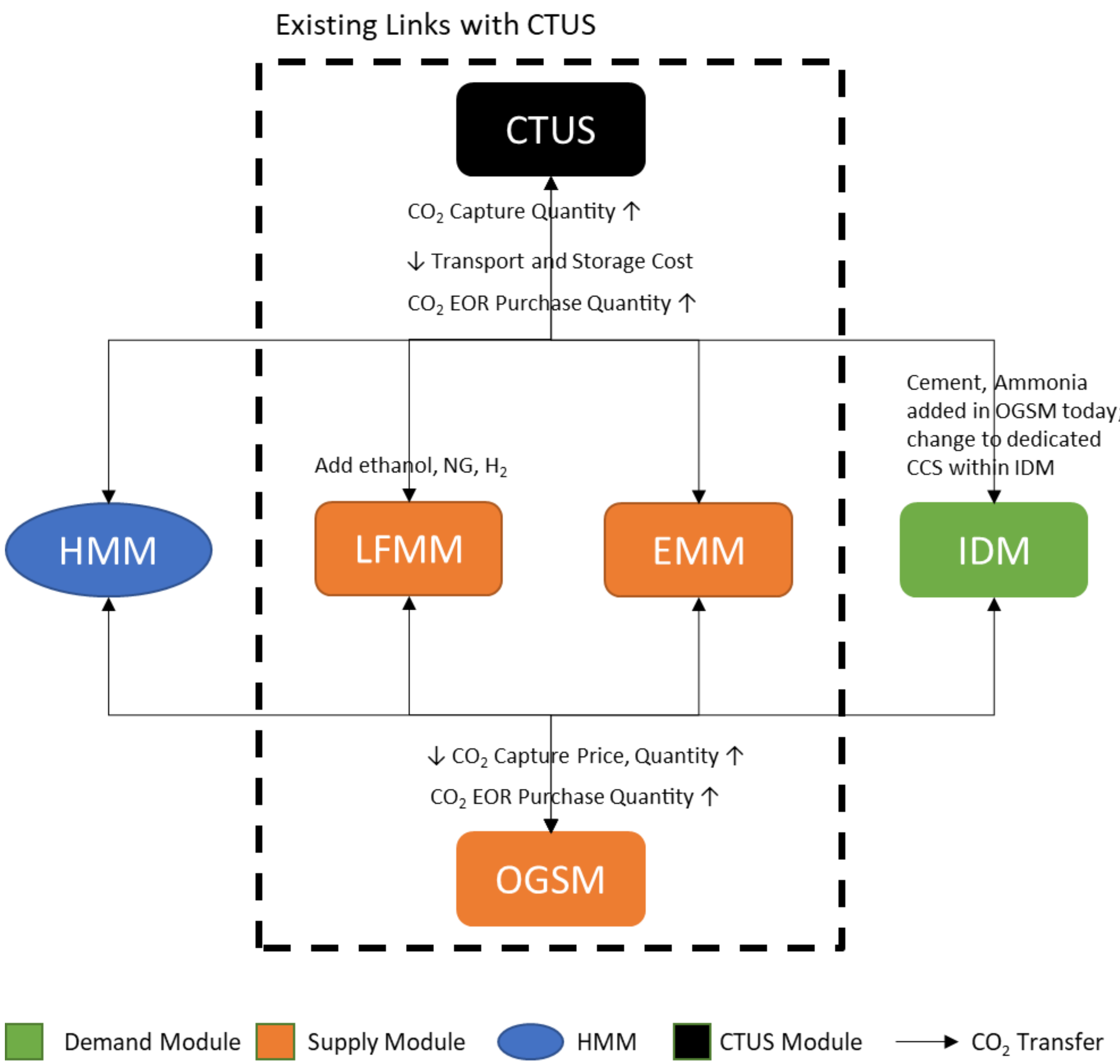
9.9. Carbon Transportation, Utilization and Storage

Linkages to Other Modules

In addition to the existing linkages between the EMM and CTUS and the new connection between the CTUS and HMM, other connections between the CTUS and other NEMS modules could be introduced. For example, if the hydrogen production through SMRs is retrofitted to use CCUS in the LFMM, the captured CO_2 would be connected to CTUS as well. Another possibility is the industrial model which could be adding CCUS capabilities to specific industries in future NEMS versions. Today, CO_2 captured from ammonia and cement industries is made available for EOR within the OGSM module. However, the quantity and price are not based on actual IDM production of ammonia or cement, and the cost of CO_2 is not reflective of any kind of carbon capture retrofits or pipeline transportation of CO_2 from these industrial sites. In the future, these quantities could be connected to the CTUS or replaced by representation within IDM. Linkages between the CTUS and other modules are shown in Figure 12.

CO_2 captured from hydrogen production units (at the regional level, disaggregated sub-regionally) will be passed to the CTUS module. The CTUS module also requires the approximate locations of these quantities, even if they are only representative since it uses this information to build out the CO_2 pipeline network at the beginning of each cycle. Because the CTUS only executes once per cycle, information on CO_2 will need to be included in the restart file in order for the CTUS module to properly allocate it either for EOR or saline storage. The CTUS in turn, will provide the transport and storage costs of CO_2 by fuel region, as it is doing today to EMM and LFMM. This may change the amount of CO_2 captured in subsequent cycles and is expected to reach an equilibrium between the quantity of CO_2 and the transport and storage costs.

Figure 12. CTUS interactions with the HMM.



10. Appendix: Technology Templates and Supporting Figures

The following templates are based on NREL's Hydrogen Analysis (H2A) Production Models,[37] which include cost calculations for transport and sequestration of CO_2. Some of the more disaggregated costs would be combined before being used within the HMM. Although transport and storage of CO_2 from the HMM will be handled through the CTUS module of NEMS, the cost structure used in the H2A models is adapted here to provide a template.

10.1. Production

Table 4. Production Template

Technical Operating Parameters and Specifications		Units
Operating Capacity Factor		%
Plant Design Capacity		kg of H2/year
Financial Input Values		
Reference year		
Assumed start-up year		
Basis year		
Length of Construction Period		Years
Capital Spent in 1st Year of Construction		%
Capital Spent in 2nd Year of Construction		%
Capital Spent in 3rd Year of Construction		%
Capital Spent in 4th Year of Construction		%
Start-up Time		Years
Plant life		Years
Analysis period		Years
Depreciation Schedule Length		Years
Depreciation Type		
Equity Financing		%
Interest rate on debt		%
Debt period		Years
Fixed Operating Costs During Start-up		%
Revenues During Start-up		%
Variable Operating Costs During Start-up		%
Decommissioning costs		% Of depreciable capital
Salvage value		% Of total capital

[37] https://www.nrel.gov/hydrogen/h2a-production-models.html

Inflation rate		%
After-tax Real IRR		%
State Taxes		%
Federal Taxes		%
Total Tax Rate		%
WORKING CAPITAL		% Of operating costs
Energy Feedstocks, Utilities, and Byproducts		
Feed Name		Usage per kg H2
Natural Gas		
Biomass		
Coal		
Electricity		
Total Energy Costs (less product credits)		BasisYear_$/year
Reduction in Energy Costs due to efficiency increase		%
Capital Costs		
H2A Total Direct Capital Cost		BasisYear_$
H2A Carbon Sequestration Total Direct Capital Cost		BasisYear_$
Indirect Depreciable Capital Costs		
Site Preparation		BasisYear_$
Engineering & design		BasisYear_$
Process contingency		BasisYear_$
Project contingency		BasisYear_$
Other Depreciable capital		BasisYear_$
One-time Licensing Fees		BasisYear_$
Up-Front Permitting Costs		BasisYear_$
Total Depreciable Capital Costs		BasisYear_$
Non-Depreciable Capital Costs		
Cost of land		BasisYear_$/acre
Land required		Acres
Land Cost		BasisYear_$
Other non-depreciable capital costs		BasisYear_$
Total Non-Depreciable Capital Costs		BasisYear_$
Total Capital Costs		BasisYear_$

Reduction in Capital Costs due to learning		%
Fixed Operating Costs		
Total plant staff		
Burdened labor cost, including overhead		BasisYear_$/man-year
Labor cost		BasisYear_$/year
G&A rate		% Of labor cost
G&A		BasisYear_$/year
Licensing, Permits and Fees		BasisYear_$/year
Property tax and insurance rate		% Of capital/year
Property taxes and insurance		BasisYear_$/year
Rent		BasisYear_$/year
Material costs for maintenance and repairs		BasisYear_$/year
Production Maintenance and Repairs		BasisYear_$/year
Other Fees		BasisYear_$/year
Other Fixed O&M Costs		BasisYear_$/year
Total Fixed Operating Costs		BasisYear_$/year
Variable Operating Costs		
Other Materials and Byproducts		Usage per kg H2
Cooling Water		
Demineralized Water		
Process Water		
Oxygen		
Sulfuric Acid		
Steam		
Compressed Inert Gas		
Total Non-Energy Operating Costs		BasisYear_$/year
Other Variable operating costs (for the first year)		
Other variable operating costs		BasisYear_$/year
Other Material Costs		BasisYear_$/year
Waste treatment costs		BasisYear_$/year
Solid waste disposal costs		BasisYear_$/year
Total Unplanned Replacement Capital Cost Factor		% Of depreciable costs/year
Royalties		BasisYear_$/year
Operator Profit		BasisYear_$/year

Subsidies, Tax Incentives		BasisYear_$/year
CO_2 sequestration O&M costs and credits		BasisYear_$/year
Process Carbon Tax		BasisYear_$/metric ton carbon
Process CO_2 produced		kg / kg H2
Process Carbon Tax		BasisYear_$/year
Upstream Carbon Tax		BasisYear_$/metric ton GHG
Upstream CO_2 equivalent GHG produced		kg / kg H2
Upstream Carbon Tax		BasisYear_$/year
Total Variable Operating Costs		BasisYear_$/year

10.2.Transportation

Table 5. Transportation Template

Hydrogen Pipeline Costs (USD)		Units
Capital Costs		
Adjustment factor (Natural Gas Pipeline -> H2 Pipeline)		
Material Capital		BasisYear_$
Labor		BasisYear_$
Right of Way and Damages		BasisYear_$
Miscellaneous (Surveying, engineering, supervision, etc.)		BasisYear_$
Pipeline Capital Cost Per Mile		BasisYear_$/mile
Capital Cost Adder for Distribution		BasisYear_$/kg H2
O&M Costs		
Pipeline cost in $/mi-yr for fixed length		BasisYear_$/year
O&M Cost Adder for Distribution		BasisYear_$/kg H2
Hydrogen Pump Costs		
Capital Costs		
Inlet Pressure		psia
Outlet Pressure		psia
Pump Power		kW
Pump Fixed Cost		BasisYear_$
Pump Variable Cost		BasisYear_$
Pump Capital Cost		BasisYear_$
Electricity Costs		

Compression Costs		BasisYear_$/year
Electricity consumption		kWh/kg H_2
O&M Costs		
(Total Other Equipment Cost) * O&M Factor		BasisYear_$/year
Hydrogen Other Equipment Costs		
Capital Costs		
Hydrogen Surge Tank		BasisYear_$
Pipeline Process Control System		BasisYear_$
O&M Costs		
(Total Other Equipment Cost) * O&M Factor		BasisYear_$/year

10.3.Storage

Table 6. Storage Template

Hydrogen Storage (Saline) Calculations		
Hydrogen Storage Cost Breakdown		Units
Capital Costs by Stage		
Regional Evaluation		BasisYear_$
Site Characterization		BasisYear_$
Permitting		BasisYear_$
Ongoing Capital Expenses		
Operations		BasisYear_$/year
Post Injection Site Care & Site Closure		BasisYear_$/year
Total ongoing capital expenses		BasisYear_$/year
Expense Costs by Stage		
Regional Evaluation		BasisYear_$/year
Site Characterization		BasisYear_$/year
Permitting		BasisYear_$/year
Operations		BasisYear_$/year
Post Injection Site Care & Site Closure		BasisYear_$/year

Hydrogen Storage (Tank) Calculations		Units
Hydrogen Storage Cost Adder		BasisYear_$/kg H2

10.4. End-Use

Steel

Table 7. Steel Template

Technology	HDRI-EAF	Unit
Base Capacity Shares	x	
Initial Added Tech Share (2013)	x	
Capital Cost		($/1000 Tonnes)
O&M ($/1000 Tonnes)		($/1000 Tonnes)
Fuel Use (ELEC)		(MMBtu/kT)
Fuel Use (NG)		(MMBtu/kT)
Fuel Use (HFO)	0	(MMBtu/kT)
Fuel Use (Coal)	0	(MMBtu/kT)
Fuel Use (Met. Coal)		(MMBtu/kT)
Fuel Use (MMBtu/kT) (Hydrogen)		(MMBtu/kT)
Non-Fuel Use (GJ/kT) (Oxygen)		(GJ/kT)
Non-Fuel Use (GJ/kT) (Steam)		(GJ/kT)
Year of Technology Obsolescence	x	
CO_2 Emissions		(T/kT)
α (Logit parameter)	x	
State-of-the-Art Factor		

Cement

Table 8. Cement Template

Technology	Hydrogen Burner	Units
Base Capacity Shares	x	
Initial Added Tech Share (2013)		
Capital Cost		($/1000 Tonnes)
O&M		($/1000 Tonnes)
Fuel Use (ELEC)		(MMBtu/kT)

Fuel Use (MMBtu/kT) (NG)	0	
Fuel Use (MMBtu/kT) (HFO)	0	
Fuel Use (MMBtu/kT) (Hydrogen)		(MMBtu/kT)
Fuel Use (MMBtu/kT) (Pet Coke)	0	
Fuel Use (MMBtu/kT) (Pet Pitch)	0	
Non-Fuel Use (GJ/kT) (Oxygen)	0	
Non-Fuel Use (GJ/kT) (Steam)	0	
Year of Technology Obsolescence		Year
Particulate Emissions		(T/kT)
α (Logit Parameter 1)	x	
δ (Logit Parameter 2)	x	
Combustion CO_2		CO_2 (T/GJ)
Heat Service		(GJ/T)
Allocation by Type (Wet Process)		
REI for State-of-the-Art		

Glass

Table 9. Glass Template

Technology	Hydrogen Combustion Furnace			
	Flat Glass	Container Glass	Blown Glass	Fiber Glass
Base Capacity Shares	x	x	x	x
Initial Added Tech Share (2013)				
Capital Cost ($/1000 Tonnes)				
O&M ($/1000 Tonnes)				
Fuel Use (MMBtu/kT) (ELEC)				
Fuel Use (MMBtu/kT) (NG)				
Fuel Use (MMBtu/kT) (Hydrogen)				
Year of Technology Obsolescence	x	x	x	x
CO_2 Emissions (T/kT)				
alpha	x	x	x	x
REI for State-of-the-Art				

Combined Heat and Power (CHP)

Table 10. CHP Template

	Hydrogen Fueled CHP - Reference Case			Hydrogen Fueled CHP - Rapid Technology Development Case		
	Total Installed Cost (2015$/kW) in 2015, before cost (2005$/kW)[38]	Overall Heat Rate (Btu/kWh) (hhv)	Overall Efficiency	Total Installed Cost (2015$/kW) in 2015, before cost (2005$/kW)	Overall Heat Rate (Btu/kWh) (hhv)	Overall Efficiency
2003						
2004						
2005						
…						
2049						
2050						

10.5.TRL descriptions

Figure 13 below describes TRLs and MRLs as described by IEA[39]

[38] NEMS requires for CHP costs to be in 2005$ for costs before 2015, and 2015$ for CHP costs in 2015 through 2050.

[39] IEA (2021), ETP Clean Energy Technology Guide, IEA, Paris https://www.iea.org/articles/etp-clean-energy-technology-guide

Figure 13. Readiness Levels

Readiness levels

1	Initial idea Basic principles have been defined
2	Application formulated Concept and application of solution have been formulated
3	Concept needs validation Solution needs to be prototyped and applied
4	Early prototype Prototype proven in test conditions
5	Large prototype Components proven in conditions to be deployed
6	Full prototype at scale Prototype proven at scale in conditions to be deployed
7	Pre-commercial demonstration Prototype working in expected conditions
8	First of a kind commercial Commercial demonstration, full-scale deployment in final conditions
^ Technology readiness	
v Market readiness	
9	Commercial operation in relevant environment Solution is commercially available, needs evolutionary improvement to stay competitive
10	Integration needed at scale Solution is commercial and competitive but needs further integration efforts
11	Proof of stability reached Predictable growth

Source: IEA (2020), Clean Energy Innovation, IEA, Paris https://www.iea.org/reports/clean-energy-innovation