Assumptions to the Annual Energy Outlook 2025: Hydrogen Market Module

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Abbreviations

Abbreviation	Description
AEO	*Annual Energy Outlook*
ATR	Autothermal reforming
CCS	Carbon capture and sequestration
CCATS	Carbon Capture, Allocation, Transportation, and Sequestration Module
EIA	U.S. Energy Information Administration
EMM	Electricity Market Module
EPM	Emissions Policy Module
FECM	Office of Fossil Energy and Carbon Management
H_2	Hydrogen
HMM	Hydrogen Market Module
HSM	Hydrocarbon Supply Module
IDM	Industrial Demand Module
IRA	Inflation Reduction Act
MMmt	Million metric ton
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Corporation
NGMM	Natural Gas Market Module
PEM	Proton exchange membrane
PNGM	Petroleum and Natural Gas Modeling Team
SMR	Steam methane reformer

Hydrogen Market Module Overview

The Hydrogen Market Module (HMM) of the National Energy Modeling System (NEMS) projects the quantity of hydrogen supplied by a variety of technology production pathways and the market price of hydrogen.

Key assumptions

Technologies

The HMM determines production technologies to deploy across the projection period from a variety of technology options. The set of technology choices and their associated capital costs directly affect the decision making of the module. The HMM models three technology classes for hydrogen production: natural gas feedstocks without carbon capture, natural gas feedstocks with carbon capture, and electrolysis-based technologies, which convert electricity into hydrogen. The second and third technology classes are emerging technologies that are competing for commercial penetration.

The following technologies are represented in the HMM:

- Steam methane reforming (SMR) without carbon capture and sequestration (CCS)
- SMR with CCS
- Proton exchange membrane (PEM) electrolysis

Other production technologies (including alkaline electrolysis and newer technologies such as autothermal reforming [ATR] and solid oxide electrolysis) are not represented in the HMM.

Historically, SMR production accounts for nearly 100% of on-purpose hydrogen supply in the United States. EIA publishes data on hydrogen in the *Petroleum Supply Annual* (PSA) and the *Manufacturing Energy Consumption Survey* (MECS), which inform historical estimates for SMR production and capacity.

Natural gas feedstock production technologies with CCS are not currently deployed widely on a commercial scale. Tax credit incentives such as the Section 45Q production tax credit could promote potential capacity growth of these technologies by improving their cost competitiveness relative to traditional SMR without CCS. ATR with CCS is not a technology option in the HMM; rather, the HMM represents carbon capture technology with the SMR and CCS technology option. In the current market, SMR with CCS exists, although at small scale.

Solid oxide, alkaline, and PEM electrolyzers all compete to produce hydrogen from water and electricity via electrolysis, and all three technologies require further cost improvements to become commercially competitive without policy intervention. Each technology differs in material costs and start-up times. For capital and operational costs of electrolyzers, PEM is the HMM’s current technology option for the electrolysis space due to its relatively fast start-up speed (important for matching variable renewable generation patterns) and relative prominence in research and deployment. We assume all electrolyzers are connected along high-voltage transmission lines, meaning electrolyzer operators pay transmission fees as part of their electricity prices but not distribution fees.

To implement the HMM for AEO2025, we did not model *off-grid electrolysis*, where an electrolyzer is co-located with a renewable energy source that is detached from the wider electricity grid.

Table 1 provides parameter estimates for each technology's capacity and associated costs. Generally, we obtained the values from the National Renewable Energy Laboratory's (NREL) H2A Lite model[1] for SMR without CCS and electrolyzers and from NREL's H2A model[2] for SMRs with CCS. We modified the electrolyzer operating capacity factor to reflect more typical operating behavior in the HMM. Table 2 provides estimates for our fuel consumption and carbon capture assumptions, which are also derived from the H2A and H2A Lite models.

Table 1. Hydrogen production capital and operating costs by technology

Parameter	Proton exchange membrane electrolyzer	Steam methane reforming (SMR)	SMR with carbon capture and sequestration
Operating capacity factor (percentage)	80%	90%	90%
Plant design capacity (kilograms of hydrogen per day)	56,500	483,024	483,000
Total capital cost (2020 dollars per kilogram)	$5.24	$2.00	$4.47
Total fixed operating costs (2020 dollars per kilogram of hydrogen)*	$0.26	$0.08	$0.21
Total variable operating costs (2020 dollars per kilogram of hydrogen)*	$0.02	$0.03	$0.04

Data source: U.S. Energy Information Adminstration, based on H2A and H2A Lite

* excluding fuel costs. Fuel costs are endogenously calculated by the National Energy Modeling System.

In addition to building production capacity endogenously, the HMM also assumes near-term production capacity can be added exogenously from hydrogen production projects under construction. We base these projects on trade press reporting and other public and subscription-based sources.

Table 2. Energy consumption and CO_2 emissions by technology

Parameter	Proton exchange membrane electrolyzer	Steam methane reforming (SMR)	SMR with carbon capture and sequestration
Electricity consumption (kilowatthours per kilogram of hydrogen)	54.3	0.13	1.5
Natural gas consumption[a] (million British thermal units per kilogram of hydrogen)	—	0.16	0.17
Natural gas feedstock share[b] (percentage of total consumption)	—	83%	83%
CO_2 produced from feedstock (kilograms of CO_2 per kilogram of hydrogen)	—	9.37	9.97

[1] The HMM uses the H2A Lite model assumptions as basis for SMRs and electrolyzers. Last updated July 2023
[2] The HMM uses the H2A model assumptions as basis for SMRs with CCS. Last updated August 2022

Carbon capture efficiency (percentage)	—	—	96.3%

Data source: U.S. Energy Information Administration, based on H2A and H2A Lite
Note: "—" means data is not applicable
[a] Includes feedstock as well as heat and power
[b] Currently based on Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) 2018

Byproduct hydrogen supply

According to our estimates, about 24% of the hydrogen produced in the United States annually is produced as a byproduct from chemical plants and other industrial facilities where hydrogen is not the main product. Because 24% of production is significant to the market and is determined as a function of an aggregate of other industrial activities unrelated to the HMM's objective function, the Industrial Demand Module (IDM) provides this supply of byproduct hydrogen exogenously. We assume byproduct hydrogen to grow proportionately with the industrial sectors that produce it through the projection period. We also assume it is sold as merchant hydrogen at a price low enough to compete with on-site production using SMR.

Prices and sector markups

The HMM calculates the wholesale price of hydrogen, which represents the marginal cost of supplying a census division with one more unit of hydrogen. We apply exogenous sector markups (Table 3) to the wholesale price to capture additional logistic costs associated with delivering hydrogen to end-use sectors.

Table 3. End-use sector price markups

Sector	2024$ per kilogram hydrogen
Industrial	$0.33
Electric power	$0.33
Transportation	$7.05
Refining	$0.33

Data source: U.S. Energy Information Administration

The HMM assumes that most hydrogen supply is co-located with demand centers. The HMM assumes about 100 yards of pipeline connects production to demand across most sectors. The transportation sector incurs a significantly higher markup and reflects the cost of compressors, pumps, storage, dispensers, refrigeration, heat exchange units, and other equipment required to build a refill station for hydrogen-fueled vehicles with on-site hydrogen production.

Interregional pipelines

The HMM uses representative pipelines to establish the cost of shipping hydrogen between census divisions. We assume pipeline costs to be equivalent to 110% of the cost to build natural gas pipelines.[3] This extra cost is due to the higher quality materials and extra monitoring required to handle the small

[3] For more information on natural gas and hydrogen pipeline costs, see *The Techno-Economics of Hydrogen Pipelines*, Section 5.1

size of the H_2 molecule, which can cause embrittlement of steel and require improved measures to prevent leaks.

We assume pipeline segments are 100 miles long with an inlet compressor station and enroute compressors located between every pipeline segment to maintain a given pipeline flow rate. Table 4 provides select assumptions used to generate the capital and operational costs for the 18-inch representative pipelines within the HMM (Table 5).

Table 4. Assumed hydrogen pipeline operational and construction parameters

Parameter	Value
Pipeline life (years)	50
Discount rate (percentage)	8%
Pipeline availability (percentage)	90%
Compressor life (years)	15
Material cost adjustment*	1.1
Outlet gas velocity (meters per second)	35
Inlet pressure (bar)	70
Pipe roughness (millimeters)	0.0178
Suction pressure of inlet compressor (bar)	20
Flow temperature (kelvin)	288.15
Hydrogen gas gravity	0.0696
Hydrogen viscosity (kilograms per meter per second)	0.0000087

Data source: Khan, M.A., Young, C. and Layzell, D.B. (2021). "The Techno-Economics of Hydrogen Pipelines." *Transition Accelerator Technical Briefs* Vol. 1, Issue 2, Pg. 1–40
* Cost adjustment relative to estimated material costs for natural gas pipelines

Table 5. Representative 18-inch hydrogen pipeline cost parameters

Origin	Destination	Annual capacity (million metric tons of hydrogen per day)	Energy intensity (kilowatthours per kilogram of hydrogen)	Non-energy OpEx* (dollars per kilogram of hydrogen)	Total capital cost* (billion dollars)
New England	Middle Atlantic	0.00111	0.62733	0.06263	$0.79
Middle Atlantic	New England	0.00111	0.62733	0.06263	$0.79
Middle Atlantic	East North Central	0.00146	1.21180	0.11470	$1.96
East North Central	Middle Atlantic	0.00146	1.21180	0.11470	$1.96
Middle Atlantic	South Atlantic	0.00146	1.35792	0.13612	$2.34
South Atlantic	Middle Atlantic	0.00146	1.35792	0.13612	$2.34
East North Central	West North Central	0.00146	1.21180	0.11470	$1.96
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East North Central	South Atlantic	0.00146	1.35792	0.13612	$2.34
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East North Central	East South Central	0.00146	1.21180	0.11470	$1.96
East South Central	East North Central	0.00146	1.21180	0.11470	$1.96
West North Central	West South Central	0.00146	1.79627	0.20038	$3.48
West South Central	West North Central	0.00146	1.79627	0.20038	$3.48
West North Central	Mountain	0.00146	1.65015	0.17896	$3.10
Mountain	West North Central	0.00146	1.65015	0.17896	$3.10
South Atlantic	East South Central	0.00146	0.91957	0.07186	$1.19
East South Central	South Atlantic	0.00146	0.91957	0.07186	$1.19
East South Central	West South Central	0.00146	1.21180	0.11470	$1.96
West South Central	East South Central	0.00146	1.21180	0.11470	$1.96
West South Central	Mountain	0.00146	2.23462	0.26464	$4.63
Mountain	West South Central	0.00146	2.23462	0.26464	$4.63
Mountain	Pacific	0.00146	1.35792	0.13612	$2.34
Pacific	Mountain	0.00146	1.35792	0.13612	$2.34

Note: Costs are in 2022 dollars.
* Energy fuel costs are endogenously calculated by the National Energy Modeling System.
Data source: U.S. Energy Information Administration

The HMM receives total capital costs and operating costs excluding costs of energy consumption for compressors as exogenous values calculated by the representative pipelines. Endogenous electricity prices obtained from the EMM affect variable compressor costs throughout the projection period.

For AEO2025, the HMM allows interregional hydrogen pipelines to begin building in 2030.

Storage

The HMM does not represent short-term storage (that is, volumes that only last days or weeks), but it does represent seasonal large-volume storage.

Hydrogen literature commonly cites three geological options for underground seasonal storage: domal and bedded salt caverns, depleted gas reservoirs, and aquifers. The HMM only allows salt caverns as a storage option because it is the only geological option used to store hydrogen in the United States. Salt caverns do not exist in every census division, limiting where the HMM will consider building storage capacity to census divisions that have the required geology. Due to this limitation, we did not provide the New England Census Division and South Atlantic Census Division the option to build hydrogen storage in the HMM.

The HMM will have the option to inject or withdraw hydrogen from storage each season, but total withdrawals and injections must balance across seasons within a year. We assume that seasonal storage will allow producers to take advantage of seasons with higher renewable electricity generation to store hydrogen made from electrolyzers to be used during seasons with lower renewable electricity generation.

As with the pipeline methodology, storage capacity expansion costs are built around a representative cost assessment based on the parameters in Table 6.

Table 6. Assumed representative salt cavern storage operational and construction parameters

Parameter	Value
Cushion gas percentage (percentage)	30%
Hydrogen cost (dollars per kilogram)	$5.89
Mining cost (dollars per cubic meter)	$30.07
Leaching[a] plant cost (dollars per kilogram)	$6.54
Site characterization (dollars)	$150,372
Mechanical integrity cost (dollars per kilogram)	$3.01
Total hours of operation (hours per year)	5,600
Compressor size (kilograms per hour)	2,000
Compressor capacity (kilotons of hydrogen)	11.2
Capital cost per compressor (dollars)	$12,003,192
Compressor power (kilowatthours per kilogram of hydrogen)	2.20
Water requirement (liters per kilogram of hydrogen)	50
Water and cooling cost (dollars per 100 liters of water)	$0.03
Well capital cost (dollars per well)	$1,503,717
Formation pressure (pounds per square inch)	2,000
Formation temperature (kelvin)	310.9
Weight (grams per mole)	2.016
R[b] (kPa*l*(1/mol)*l/k)	8.31

Data source: U.S. Energy Information Administration, Based on Sandia National Laboratories, *A Life Cycle Cost Analysis Framework for Geologic Storage of Hydrogen: A User's Tool*; Chen, Fangxuan et. al. "Capacity Assessment and Cost Analysis of Geologic Storage of Hydrogen: A Case Study in Intermountain-West Region USA." *International Journal of Hydrogen Energy*, Vol. 48, Issue 24, Pg. 9,008–9,022

[a] Process of dissolving salt with water to create an underground storage cavern

[b] R = ideal gas constant

The HMM assumes a cost estimate of about $100,000,000 (in 2022 dollars) based on a storage volume of 580,000 cubic meters, a large enough estimate to offset initial capital costs and levelized over a larger amount of working gas.

Learning

The HMM features a non-linear learning algorithm that captures reduced capital costs over time through *learning by doing*. As the module builds more capacity, future builds are cheaper. This calculation is handled exogenously from the module, meaning the module does not see the benefits of learning with perfect foresight and so cannot intentionally build capacity in the short term with the goal of reducing costs of future builds.

The learning function has the following form:

$OC(C) = a*C^{-b}$

Where C is the cumulative capacity for the technology.

The progress ratio (pr) is defined by the speed of learning (how much costs decline for every doubling of capacity). The reduced capital costs for every doubling of cumulative capacity (learning rate, or LR) is an exogenous parameter input for each technology. The progress ratio and learning rate are related by the following:

$pr = 2^{-b} = (1-LR)$

The parameter *b* is calculated from the second equality above (b = -(ln(1-LR)/ln(2))). The parameter *a* is computed from the following initial conditions:

$a = OC(C_0)/C_0^{-b}$

Where C_0 is the initial cumulative capacity. For PEM electrolyzers, we use existing global capacity for the initial cumulative capacity.

By defining the learning rate *LR*, parameters *a* and *b* can be calculated every iteration and cost reductions applied to each technology.

Table 7 provides learning parameters for each production technology. Learning rates decay across periods, and the length of each period (in terms of the number of cumulative capacity doublings) can be variably assigned by technology. More mature technologies, such as SMR without CCS, may be represented by fewer learning periods, indicating they will not gain substantial cost reductions via learning by doing.

Table 7. Learning parameters by production technology

Technology	Period 1 learning rate (LR1)	Period 2 learning rate (LR2)	Period 3 learning rate (LR3)	Period 1 doublings	Period 2 doublings	Minimum learning by 2035
Proton exchange membrane electrolyzers	0.15	0.07	0.01	1	4	0.25

Steam methane reforming (SMR)	—	—	0.01	—	—	0.01
SMR with carbon capture and sequestration	0.08	0.04	0.01	1	2	0.05

Data source: U.S. Energy Information Administration

In addition, each technology is assigned a minimum learning rate by 2035. This rate represents the percentage reduction in capacity cost that will exist regardless of total capacity additions. This minimum learning rate represents cost reductions from activities such as research and development, international technology breakthroughs, and a lower perceived market risk resulting in a lower cost of capital.

Short-term capacity expansion elasticities

To represent logistical constraints in building new hydrogen production capacity, the HMM uses short-term elasticities that make it more costly to build new capacity once the amount of added capacity for a production pathway reaches certain capacity expansion steps (Table 8). Each capacity expansion step has an associated cost multiplier, so the amount of capacity added for a production pathway in each step has its capital cost multiplied by the cost multiplier. We assume that newer technologies, such as electrolysis, have more cost elasticity relative to mature technologies, such as SMR, due to limitations in capital, expertise in construction, and other logistics.

Table 8. Production capacity expansion steps and cost multipliers

	SMR and SMR with CCS	Electrolysis
Step upper bound		
Step 1	1 MMmt	.075 MMmt
Step 2	2 MMmt	0.2 MMmt
Step 3	3 MMmt	0.4 MMmt
Cost multiplier		
Step 1	1	1
Step 2	2.25	2.25
Step 3	4.5	4.5

Data source: Energy Information Administration

Note: Step upper bounds are for each census division for steam methane reforming (SMR) and SMR with carbon capture and sequestration (CCS) and for each region in the Electricity Market Module for electrolysis. MMmt=million metric tons

Legislation and Regulations

Tax credits

All core AEO cases project energy market trends that assume current laws and regulations; therefore, the HMM uses two tax credits (Sections 45Q and 45V) recently passed into law to evaluate hydrogen production technologies and their economic viability. To initially implement the HMM in NEMS, we assume that only hydrogen production by electrolyzer can receive the Section 45V tax credit, and SMR with CCS can receive Section 45Q. By law, hydrogen producers are not allowed to receive both credits. Both policies are assumed to expire within the model under the law.

Section 45Q production tax credit

Section 45Q of the U.S. tax code provides a performance-based production tax credit (PTC) for carbon management projects, which capture carbon oxides (carbon dioxide and its precursor, carbon monoxide) from eligible industry and power facilities as well as directly from the atmosphere. The Carbon Capture, Allocation, Transportation, and Sequestration (CCATS) Module provides the HMM both the price of carbon and the final credit value by census division. This price is based on the proportion of carbon used for fossil fuel production with enhanced oil recovery versus the amount stored in geologic formations.

Section 45V production tax credit

Section 45V of the U.S. tax code provides a hydrogen PTC subsidy to suppliers based on the carbon intensity of hydrogen production: the lifecycle greenhouse gas emissions intensity (equivalent kilograms [kg] of CO_2) resulting from 1 kilogram of hydrogen produced (kg CO_2e/kg H_2). The U.S. Department of the Treasury's guidance outlines the requirements to earn a given level of the PTC, which may be as much as $3/kg for hydrogen produced with a carbon intensity of 0.45 kg CO_2e/kg H_2 or less.

The HMM uses the December 2023 proposed guidance for its Section 45V-related assumptions in AEO2025. Given the proposed guidance, AEO2025's HMM assumes electrolyzers can consume clean electricity and claim the Section 45V PTC through two pathways:

- **Curtailment**
  Under this pathway, electrolyzers can consume otherwise curtailed electricity from renewable sources. Electrolyzers that consume electricity via this pathway do not pay reliability adders on the electricity price with the assumption that generators would rather sell near cost than allow generation to be curtailed and not sold into the market at all.

- **Energy Attribute Certificates (EACs)**
  The HMM also allows electrolyzers to consume clean electricity via EACs. These certificates verify that electricity coming from a specific generator is clean. Electrolyzers can draw electricity from the general grid, but purchases of these certificates document that the source of the hydrogen producer's electricity is clean and eligible for the Section 45V PTC provided they meet three criteria:
    - Deliverability—The EAC must be generated and consumed in the same region that the electrolyzer is consuming it in. For the HMM, we assume that the EACs must be created by a generator and consumed by an electrolyzer in the same EMM region.
    - Incrementality—The generator that produces the EAC must be built within three years of an in-service date of an electrolyzer that retires the EAC.
    - Hourly time matching—The electrolyzer must retire the EAC in the same hour that the EAC is generated. Although Section 45V provides a few years to phase in hourly time

matching, the HMM assumes that time matching begins immediately with the HMM's first model year in 2023.

In addition, the HMM assumes that the hourly electricity price electrolyzers pay via EACs includes the wholesale price of the electricity plus transmission and reliability adders.

The electricity the HMM can consume to produce Section 45V-eligible hydrogen using otherwise curtailed electricity is limited by the hourly renewable generation curtailed as projected by the EMM. Likewise, the electricity purchased via EACs is also constrained by the hourly renewable generation projected by the EMM to ensure that any electricity consumed to produce hydrogen using the Section 45V PTC is clean.