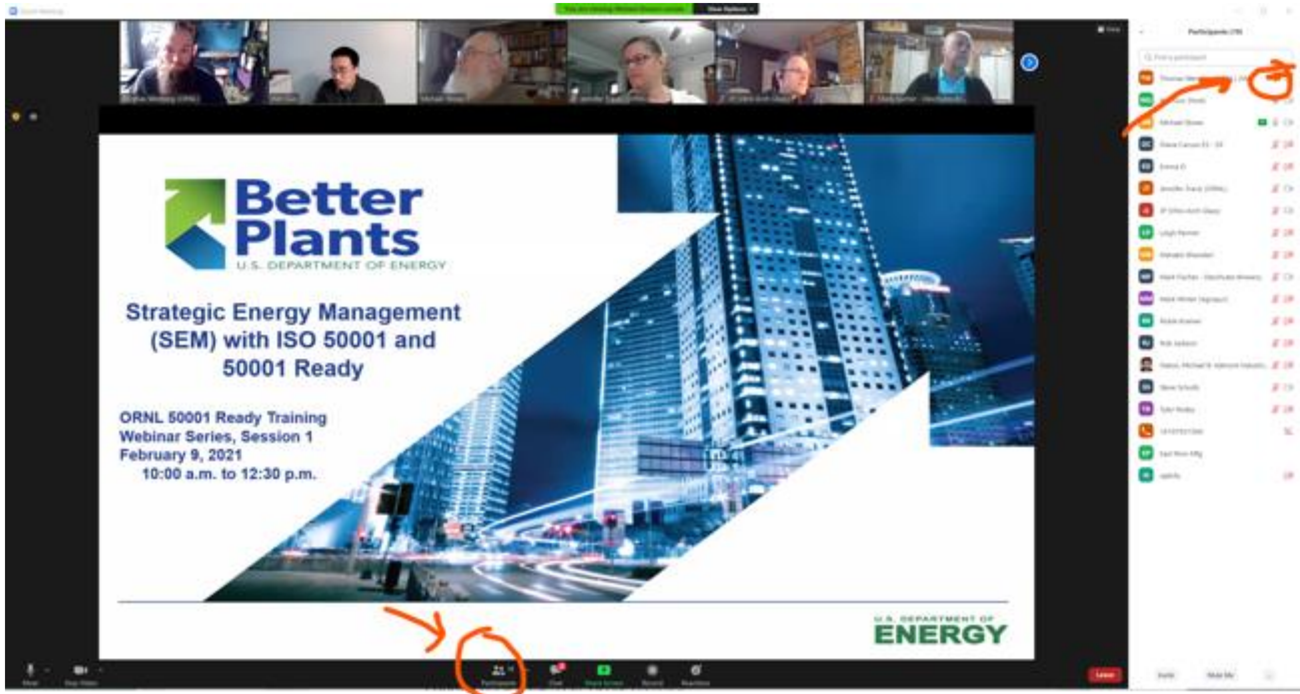
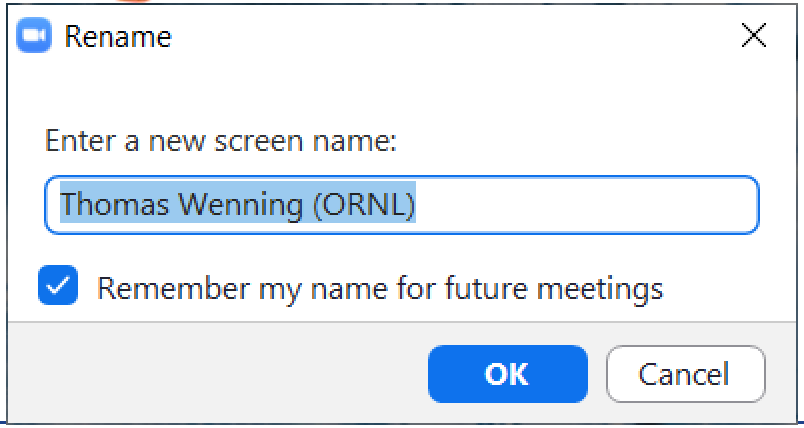
Rename Yourself to be your Real Name (Company Name)

1. Click on Participant list
2. Go to the right and hover over your name
3. Select “More” & “Rename”
4. Enter your company name in brackets
5. Turn on your camera ☺





Virtual Training: Combined Heat & Power Systems

Alternative Fuels for CHP

Session #2
December 10, 2024
10:00am – 12:30pm EST

Agenda

1. Review Session #1 Homework

2. Forecasts of Cost, Demand, and Supply of Hydrogen and RNG for CHP in 2030, 2040, and 2050, Barriers to Alternative Fuel Development, and Adoption & Potential Options to Overcome the Barriers and Realize the Market Potential
   - David Jones, *ICF*

3. Energizing CHP and Exploring Case Studies: Unlocking the Potential of Alternative Fuels
   - Cliff Haefke, *DOE Central and Midwest Onsite Energy TAPs*

4. Q&A

Today’s Speakers

David Jones

Senior Managing Consultant, Onsite Energy
ICF

Cliff Haefke

Director,
DOE Central and Midwest Onsite Energy TAPs

Review of Session #1 Homework

1. Which prime movers are better suited to provide high pressure steam?
2. Describe the Impact of run hours on payback on the investment.
3. In the DOE CHP eCatalog, list two of the four thermal outputs and three of the five prime movers available as search functions.
   DOE-CHP eCatalog | Welcome
4. What are four key configuration factors for CHP to provide uninterrupted operation during a grid outage.
5. CHP provides multiple attributes that increase energy resilience for manufacturers, utilities and communities. One such attribute is that CHP provides a continuous supply of electric and thermal energy. Which of the following additional attributes of CHP support energy resilience.
6. When compared to a back-up generation source, CHP systems typically have a higher initial capital cost but over time they represent a better capital investment. Why is that?

Review of Session #1 Homework

1. Which prime movers are better suited to provide high pressure steam?

- Gas turbine and a boiler/steam turbine system

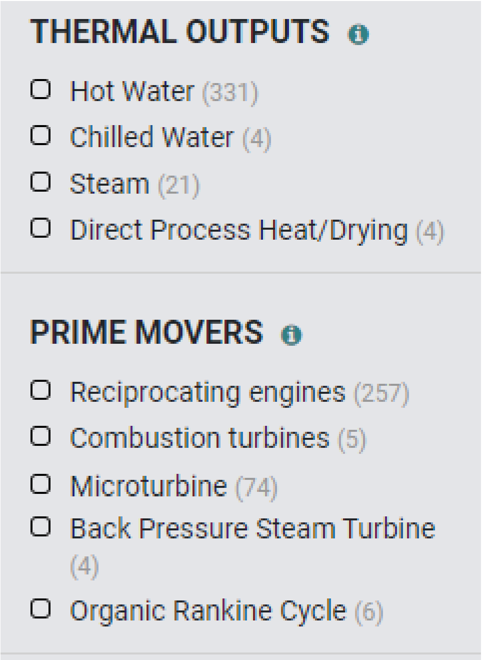
2. Describe the impact of run hours on payback on the investment.

- The return on investment is quicker with more CHP system run hours.
- With every hour that CHP operates, the facility/end-user is saving energy and saving money compared to operating separate heat and power systems. More run hours equals more savings, which leads to a faster return on the investment.

Review of Session #1 Homework

3. In the DOE CHP eCatalog, list two of the four thermal outputs and three of the five prime movers available as search functions. [DOE-CHP eCatalog | Welcome]

- Thermal outputs: Hot Water, Chilled Water, Steam, Direct Process Heat/Drying
- Prime Movers: Reciprocating Engines, Combustion Turbines, Microturbines, Back Pressure Steam Turbine, Organic Rankine Cycle



4. What are four key configuration factors for CHP to provide uninterrupted operation during a grid outage.

- black start capability
- capable of operating independent of the grid
- system must be sized to meet critical loads
- system configuration includes switchgear controls capable of disconnecting from and reconnecting to the grid (at the start and end of the event, respectively).

Review of Session #1 Homework

5. CHP provides multiple attributes that increase energy resilience for manufacturers, utilities and communities. One such attribute is that CHP provides a continuous supply of electric and thermal energy. Which of the following additional attributes of CHP support energy resilience.

   a. CHP can be configured to island from the grid and black start without grid power;
   b. CHP can operate without grid power support for multiple days;
   c. CHP enhances grid stability and relieves grid congestion;
   d. CHP supports a hybrid microgrid deployment for balancing renewable power and providing a diverse generation mix;
   e. CHP systems maintains critical facilities such as hospitals and emergency services operating and responsive to community needs;
   f. **All of the above**

Review of Session #1 Homework

6. When compared to a back-up generation source, CHP systems typically have a higher initial capital cost but over time they represent a better capital investment. Why is that?

   - This is due to CHP's ability to run continuously (with or without grid power) compared to backup generation that operates only when the grid is down. This typically results in CHP having a lower payback when compared to backup systems that sit idle for most of the year.

Forecasts of Cost, Demand, and Supply of Hydrogen and RNG for CHP in 2030, 2040, and 2050

David Jones

ICF

Acknowledgements

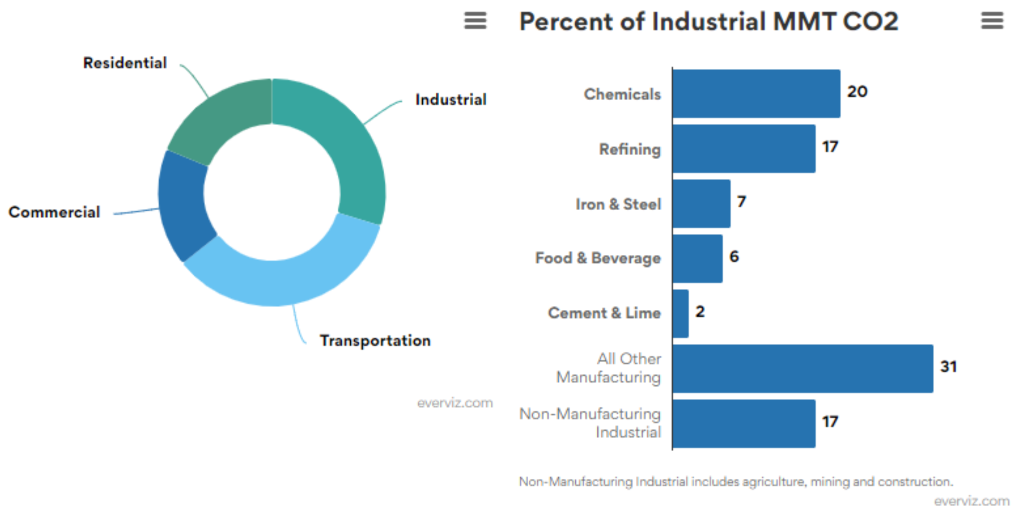
This presentation is based on analysis work completed in partnership with **Oak Ridge National Laboratory** under contract to the **U.S. Department of Energy, Industrial Efficiency & Decarbonization Office**.

Contributors:

The Importance of Alternative Fuels for CHP

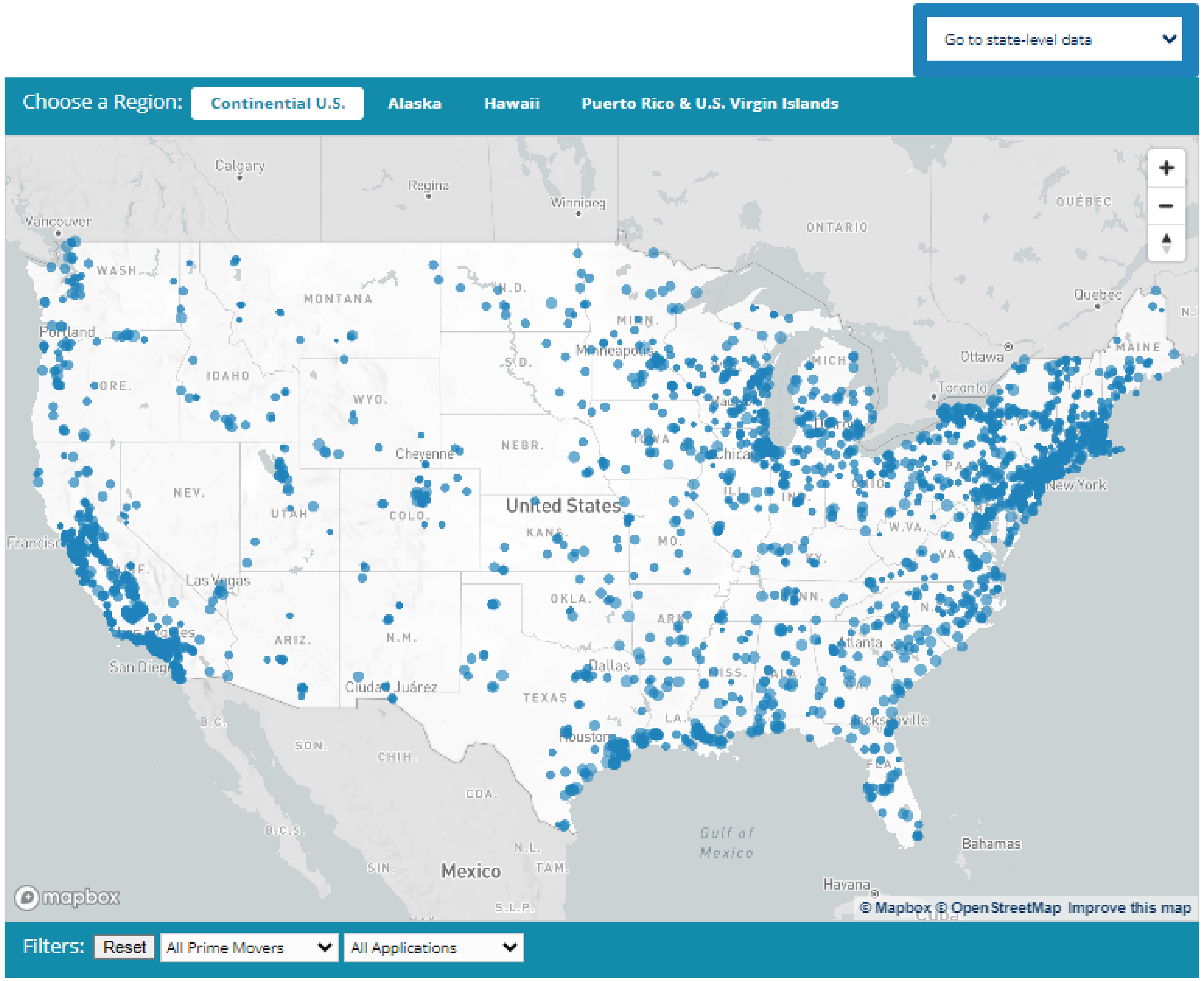
- As of 2020, the United States industrial sector accounts for 30% of U.S. primary energy-related carbon dioxide emissions.
  - These emissions are primarily attributed to electricity generation, the combustion of fuels for steam and process heating, and other energy-intensive manufacturing processes.
- DOE's Onsite Energy Program focuses on a broad range of technologies suitable for decarbonizing and supplying large energy loads, including combined heat and power (CHP) systems.
  - By efficiently capturing and utilizing waste heat, onsite CHP systems reduce the need for industrial boilers, avoiding their associated emissions.
  - CHP systems are fuel flexible, and operators will have time to incorporate alternative fuels to reduce onsite emissions before the grid decarbonizes.
- While CHP with natural gas can reduce carbon emissions now, **the use of CHP as a long-term decarbonization solution depends on transitioning to clean fuels.**

U.S. Primary Energy-Related CO2 Emissions by Economic Sector



Data Source: "Annual Energy Outlook 2021 with Projections to 2050," U.S. Energy Information Administration, Feb. 3, 2021. Note: The roadmap analysis covered only part of the chemicals (ammonia, methanol, ethylene, and BTX) and food and beverage (wet corn milling, soybean oil, cane sugar, beet sugar, fluid milk, red meat product processing and beer production) subsectors.

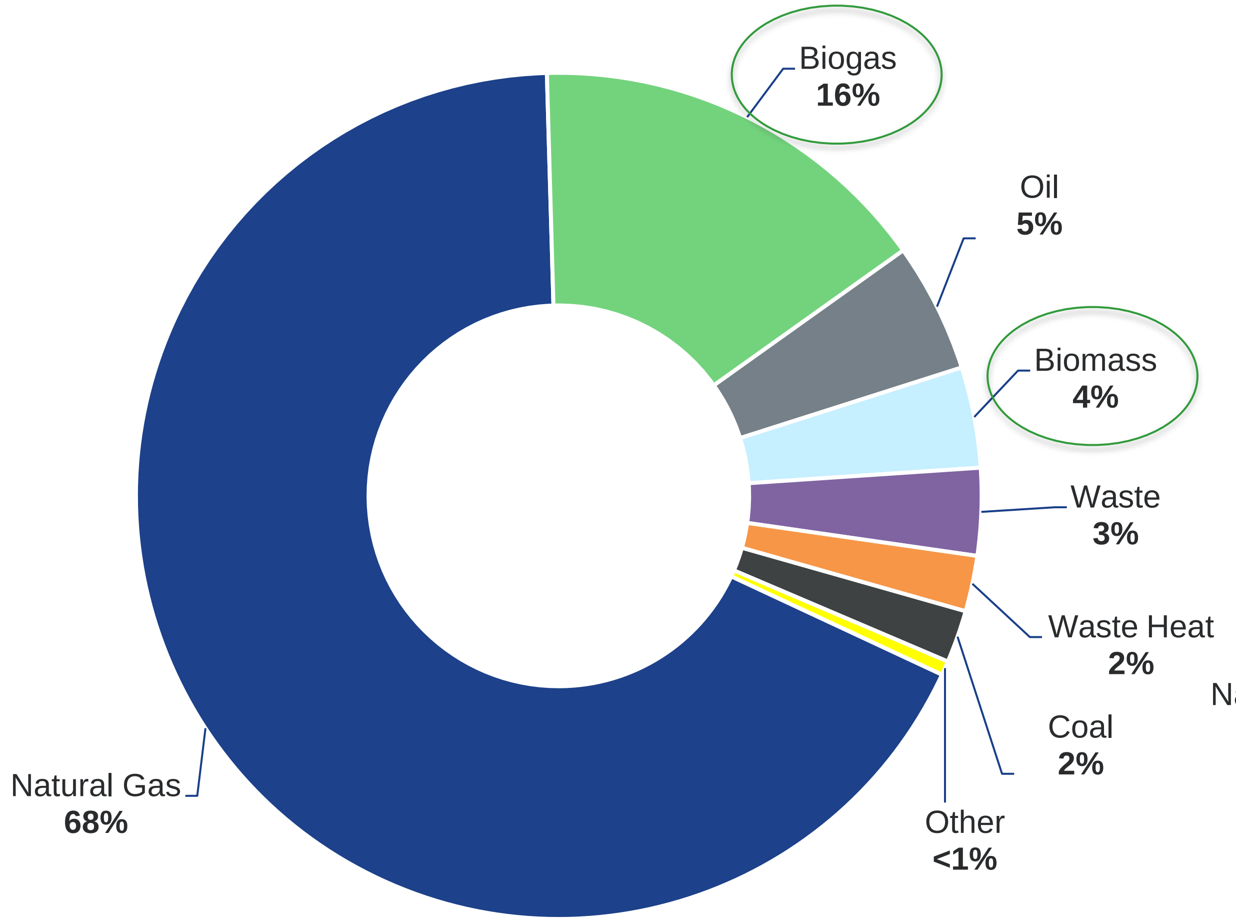
Combined Heat and Power (CHP) Installations in the United States



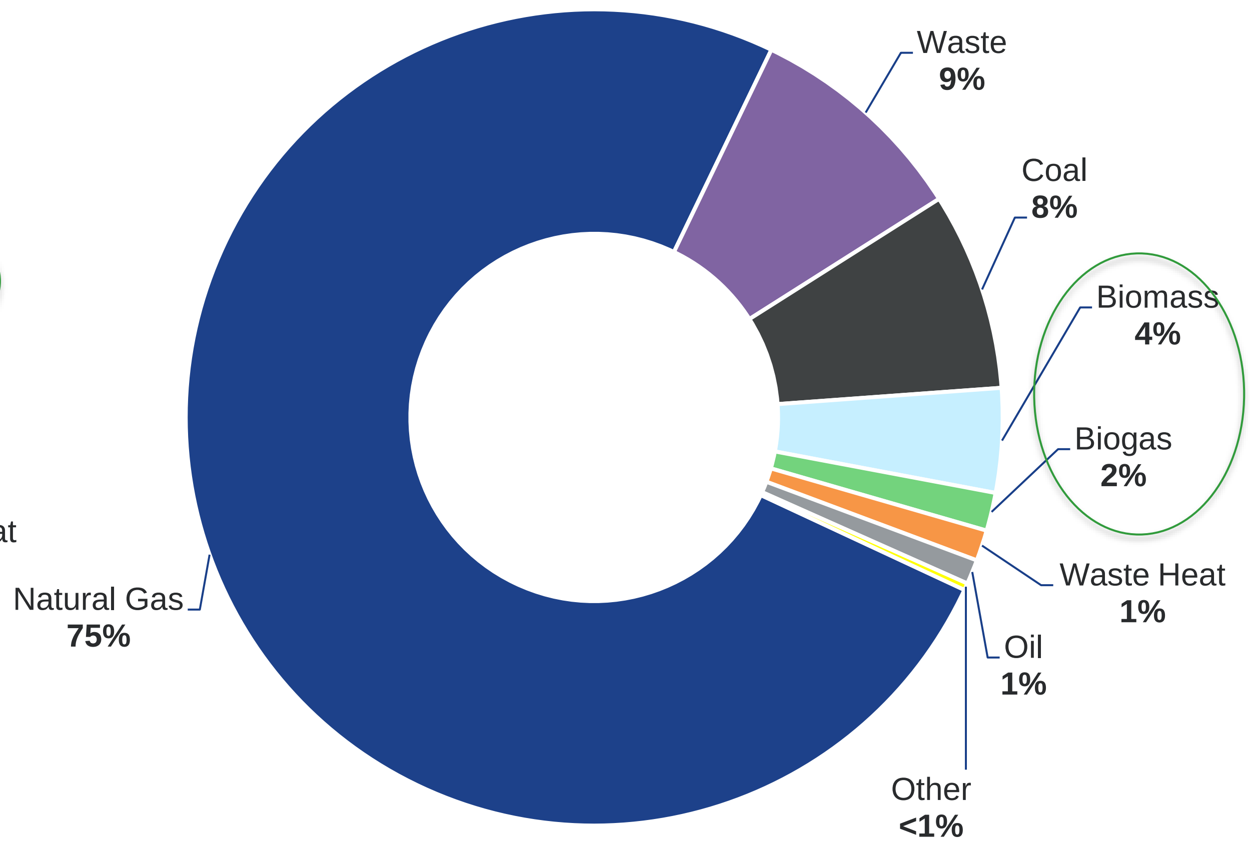
- **79.2 GW** of installed CHP at more than **4,000 sites**
- Estimated 6 percent of U.S. electric grid generating Capacity; 13 percent of annual grid generation
- Avoids more than **1.2 quadrillion Btus** of fuel consumption annually
- Currently avoids **over 200 million tons of CO_2** annually compared to separate heat and power production

Existing CHP by Fuel Type

By Site – 4,084 Sites



By Capacity – 79.2 GW



Source: DOE CHP Installation Database (U.S. installations through December 31, 2023 as of August 2024)

Current Status of RNG in the U.S.

Biogas and RNG as Fuels for CHP

What are Biogas and RNG?

- **Biogas** is a gaseous mixture of mostly methane and carbon dioxide. It is naturally-produced through the decomposition of organic material in landfills or anaerobic digesters. It can also be produced through thermal gasification of solid biomass or through methanation of hydrogen.
- **Renewable Natural Gas (RNG)** is a more purified version of biogas which has been upgraded to natural gas pipeline quality and can be used interchangeably with natural gas.

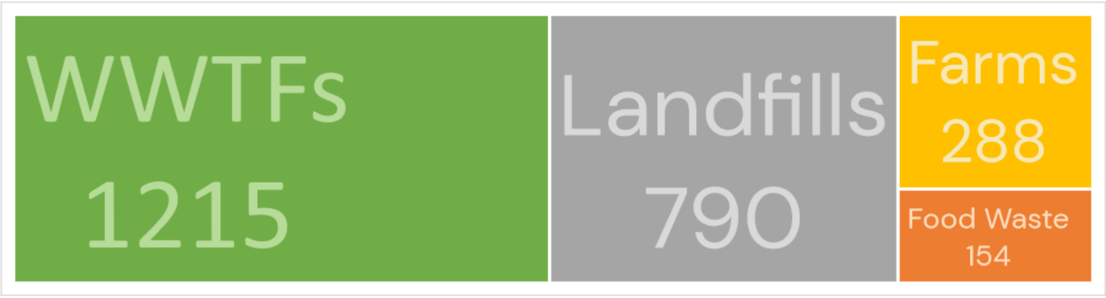
Sources and production pathways

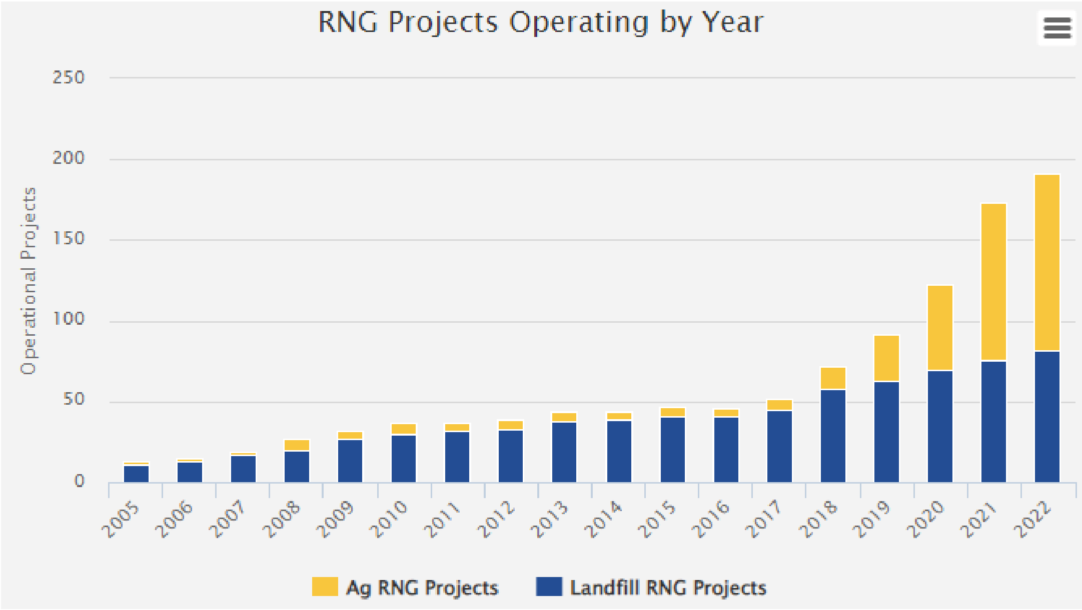
- Anaerobic digestion
  - Microorganisms break down organic material in a controlled, oxygen-free environment, creating biogas and digestate. Feedstocks include animal waste from livestock farms, sludge from wastewater treatment plants, and food waste.
- Landfill gas recovery systems
  - Landfill sites break down organic waste and produce biogas, or landfill gas (LFG).
- Thermal gasification
  - Solid biomass feedstock is heated to 800˚C (1,472˚F) in a controlled, aerobic environment, breaking down the organic compounds and creating syngas- mixture of carbon monoxide, carbon dioxide, hydrogen, and methane.
    - Feedstocks include biomass (dedicated energy crops, forest product residues, agricultural residues) and non-biogenic municipal solid waste.
- Power-to-Gas (P2G)
  - Hydrogen is methanated using carbon dioxide to form renewable natural gas.

Current Biogas and RNG Projects in the U.S.

- As of August 2023, there were 2,447 existing biogas capture and utilization efforts recorded nationwide.
  - 50% at wastewater treatment facilities (WWTFs), 32% at landfills, 12% at livestock farms, 6% at food waste processing facilities.
  - **87 out of 96 biogas projects (91%) that came online in 2023 produce pipeline-quality RNG.**
- As of 2022, more than 173 RNG projects from landfills and farms are in operation across 31 states:
  - More than 45% use landfill gas; 55% use anaerobic digestion of biogenic sources (agriculture or Ag projects)
  - The potential for RNG outweighs the current rates of utilization and number of operational projects.
  - ***RNG is needed to expand biogas use cases; thermal gasification is needed to fully realize RNG's potential.***

Operational Biogas Facilities in the U.S., by Feedstock

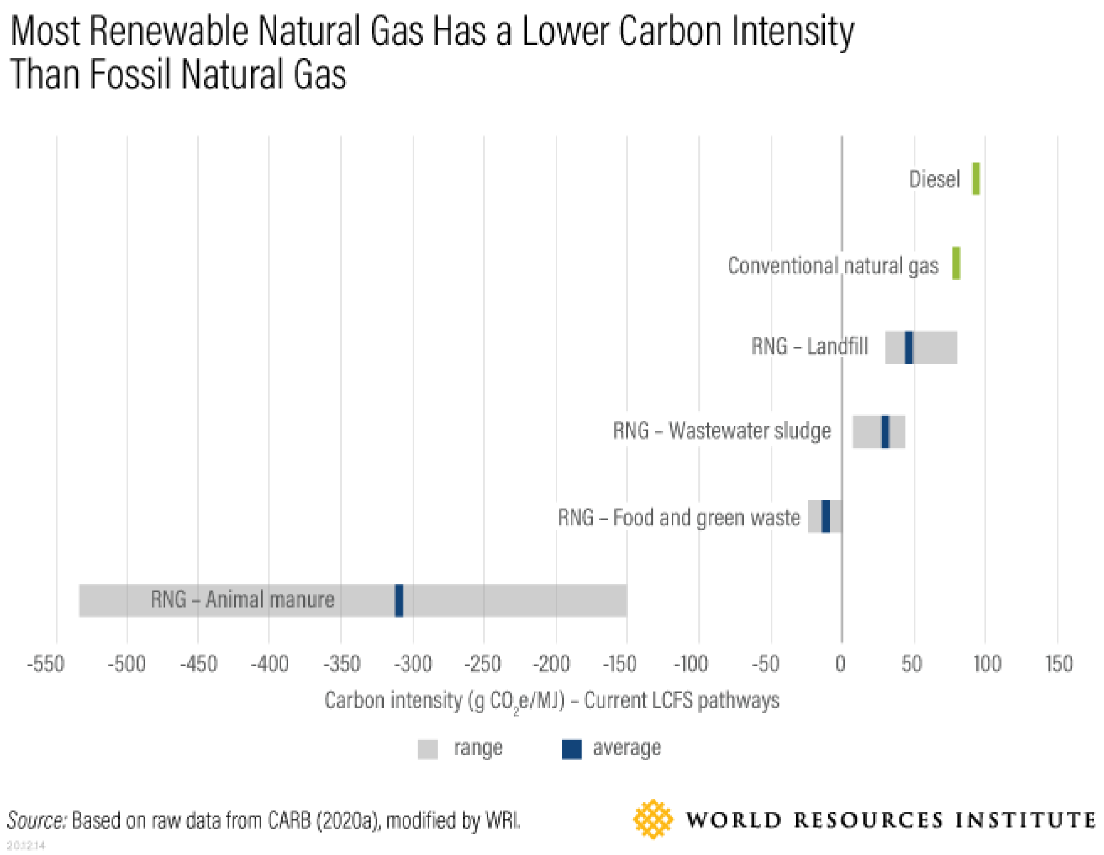




[Biogas State Profiles - American Biogas Council]
[Renewable Natural Gas Infographics: View at RNG Coalition — The Coalition For Renewable Natural Gas]

Emissions Accounting with RNG

- RNG can have a range of carbon intensity values, depending on the source of biogas and the accounting methods used.
  - RNG from animal manure and food waste – derived from biogenic resources – has negative carbon emissions values.
  - RNG from WWTFs and landfills has positive carbon emissions values, lower than conventional fossil fuels.
  - When RNG is injected into a natural gas pipeline, it is documented with Renewable Identification Numbers (RINs) that can be transferred to end users (similar to Renewable Energy Certificates, or RECs).
- GHG Protocol Inventory Accounting can pose challenges for RNG, as carbon emissions are produced on-site (Scope 1).
  - How can onsite emissions from RNG be offset by life cycle benefits? How can emission credits be verified? Need to develop standard practices.



[Is Renewable Natural Gas Environmentally Friendly? | MRR (odorizationbymrr.com)]

U.S. Policies and Goals for Biogas and RNG

- 1996 Clean Air Act
  - Requires the capture of methane from waste streams and landfills, capturing naturally-produced biogas.
- The Inflation Reduction Act (IRA) includes grants and tax credits for renewable fuels:
  - Rural Energy for America Program
    - Grants for up to 25% of the total project costs (renewable energy systems or energy efficiency improvements for agricultural producers and small businesses).
  - 45Z Clean Fuel Production Tax Credit (starting 1/1/2025)
    - $0.20 per gallon for non-aviation fuels with less than or equal to 50kg CO2e/MMBTU.
- Renewable Fuel Standard (RFS2)
  - Requires transportation fuels to contain a minimum volume of renewable fuels. RNG qualifies as an advanced biofuel.
  - RFS compliance is assessed through Renewable Identification Numbers (RINs), which can be traded or sold to companies who are obligated to meet RFS requirements for compliance, e.g. refiners and importers of gasoline or diesel.
- Low Carbon Fuel Standard (LCFS)
  - Encourages the production and use of greener transportation fuels, including RNG.
  - Suppliers receive tradeable credits for reducing the carbon intensity of the fuels they produce.

Volume Targets (billion RINs)[a]

	2023	2024	2025
Cellulosic biofuel	0.84	1.09	1.38
Biomass-based diesel[b]	2.82	3.04	3.35
Advanced biofuel	5.94	6.54	7.33
Renewable fuel	20.94	21.54	22.33
Supplemental standard	0.25	n/a	n/a

[a] One RIN is equivalent to one ethanol-equivalent gallon of renewable fuel.

[b] BBD is given in billion gallons.

Renewable Natural Gas Federal Laws & Regulations — The Coalition For Renewable Natural Gas (rngcoalition.com)
Alternative Fuels Data Center: Renewable Fuel Standard (energy.gov)
Low Carbon Fuel Standard | California Air Resources Board
Final Renewable Fuels Standards Rule for 2023, 2024, and 2025 | US EPA

Current Status of Hydrogen in the U.S.

Hydrogen as a Fuel for CHP

The primary hydrogen classifications and production methods are:

- **Green** hydrogen: Electricity is used to split water into hydrogen and oxygen, creating a zero-emission process if the electricity stems from renewable sources.
- **Grey** hydrogen: Methane is reformed to produce hydrogen though either Steam Methane Reforming (SMR) or Autothermal Reforming (ATR). SMR's production process has two CO2 emission streams; whereas ATR has one single CO2 emission stream.
- **Blue** hydrogen: Hydrogen is produced through SMR or ATR, but all carbon emissions are captured and stored (and potentially used). Carbon capture is simplified through ATR's single CO2 emission stream.
- **Pink** hydrogen (with nuclear power) is another potential zero-carbon source.

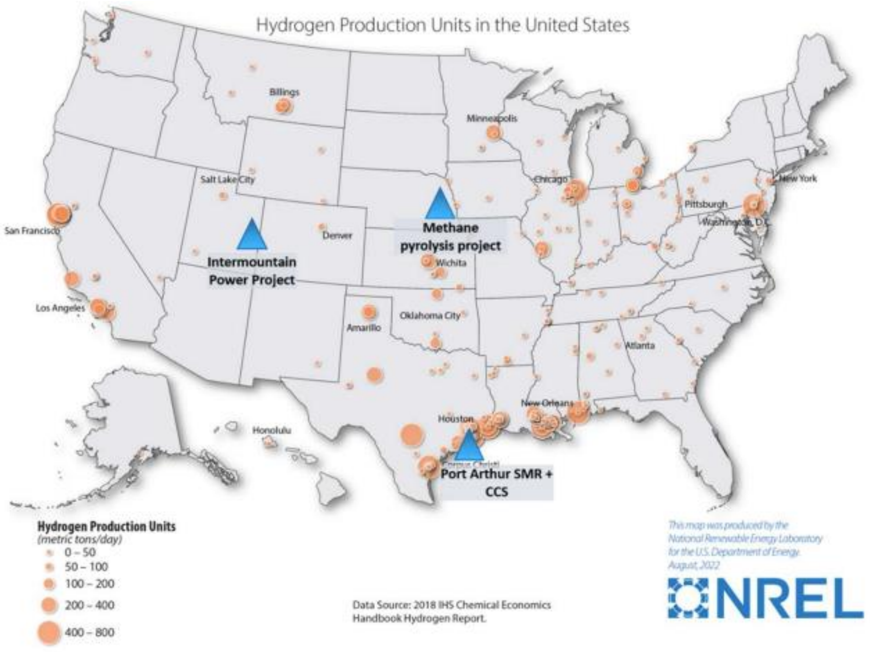
Hydrogen can be used to decarbonize CHP by reducing or replacing natural gas use, either by blending hydrogen with natural gas or by using pure hydrogen (depending on system configurations).

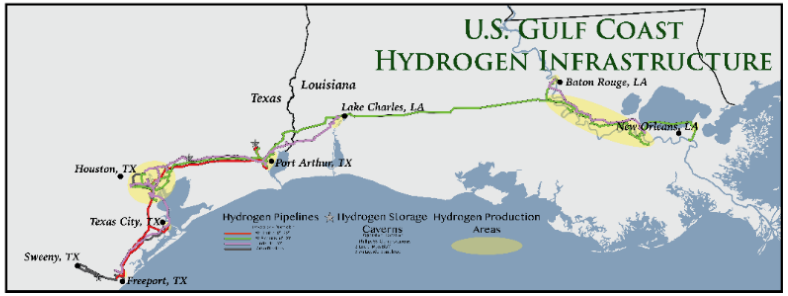
- **CHP can make the most efficient use of limited hydrogen resources.**
- CHP can operate with capacity factors over 90%, compared to 25-40% for PV/wind, enabling more emission reductions per MW installed.

Current Hydrogen Production and Infrastructure in the U.S.

- **U.S. hydrogen production totaled 13 million metric tons in 2021, an increase from 10 million metric tons in 2020.**
  - SMR was the most common hydrogen production method (95%) in 2020, followed by partial oxidation of natural gas via coal gasification (4%), and electrolysis (1%).
  - Three flagship projects are highlighted on the map:
    - Intermountain Power Project in Utah: the world's first gas turbine intentionally built and designed to operate 100% hydrogen.
    - Monolith's Methane Pyrolysis Project: uses 100% renewable electricity to convert fuels (conventional, biogas, or renewable natural gas) into hydrogen and carbon without scope 1 emissions.
    - Port Arthur's SMR+CCS Facility: captures the carbon dioxide released during the SMR hydrogen production process.

- The U.S. has ~1,600 miles of dedicated hydrogen pipelines; salt caverns for hydrogen storage are geographically limited.
  - Over 90% of pipelines are in Texas, Louisiana, and Alabama, primarily serving refineries and ammonia plants in the region.





Source: RBN Energy Internal Report, 2023, https://rbnenergy.com/

[DOE National Clean Hydrogen Strategy and Roadmap (energy.gov)](https://energy.gov)

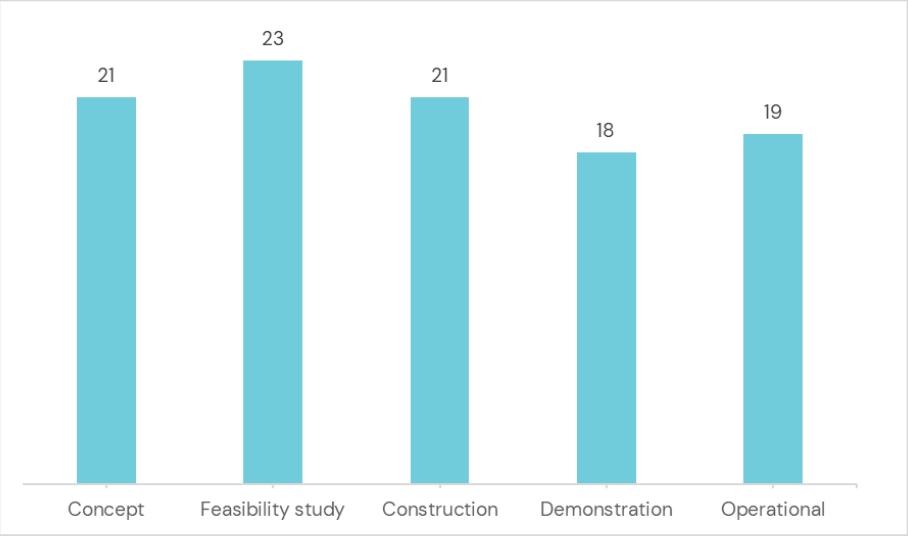
Current U.S. Low-Carbon Hydrogen Production Projects

IEA database of low-carbon hydrogen projects:

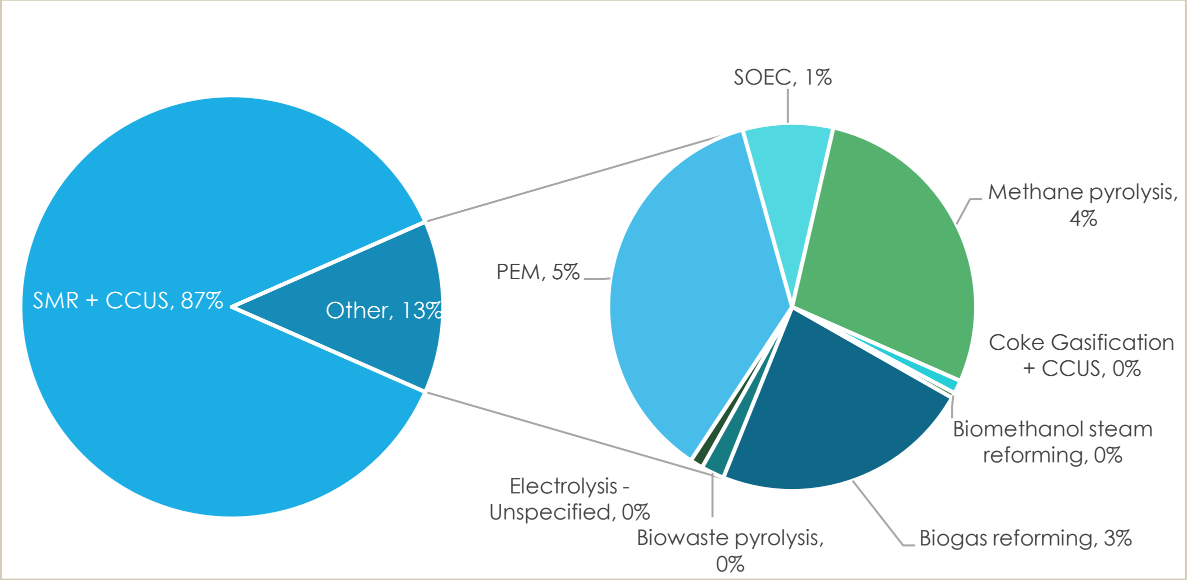
- **37 low-carbon H_2 projects** – both demonstration and full-scale operations
- Fossil-free hydrogen production is still a nascent pathway.
  - 87% of hydrogen produced from steam methane reformation + CCUS

End Use	# Projects
Mobility	11
Power/Electricity	6
Ammonia	3
Hydrogen-Natural Gas Blending	3
Other Misc.	2
Refining	1
Cogeneration	1
Synthetic Fuels	1

U.S. Hydrogen Projects, By Development Stage



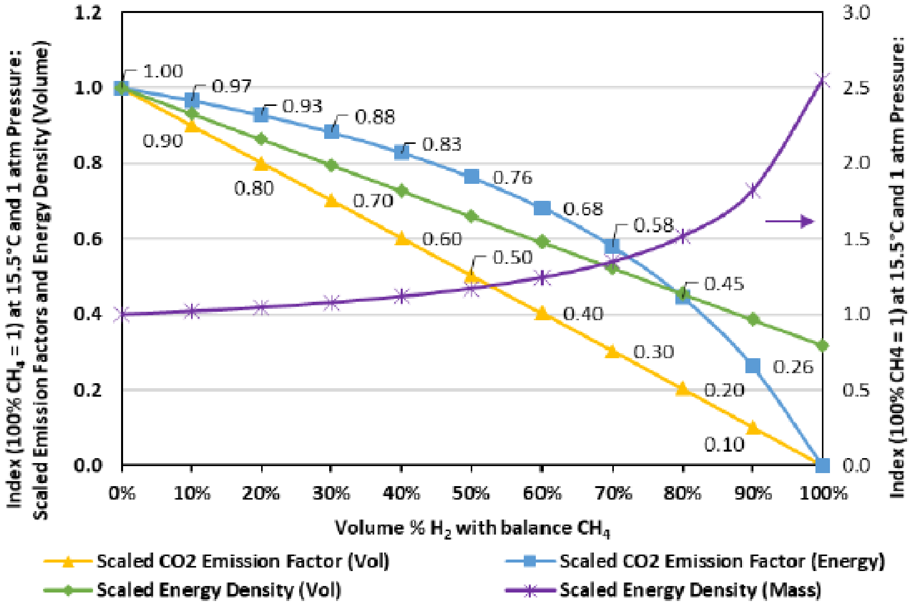
Active U.S. H2 Projects, by Technology (Kilotons H2/Day)



Hydrogen Blending

- Benefits of hydrogen blending: reduced carbon emissions and utilization of expansive, existing natural gas pipeline network.
- Hydrogen use considerations include safety for transport and the control of nitrogen oxide emissions released during combustion.
  - **Up to 15% hydrogen-by-volume blends are safe to inject into existing pipelines without major infrastructure modifications.**
  - The use of selective catalytic reduction (SCR) technology has proven to mitigate the release of NOX emissions.
- NREL developed the Pipeline Preparation Cost Tool (PPCT) to help determine which pipeline modifications are needed and the associated costs.
- Hawai'i Gas has been blending up to 15% hydrogen-natural gas blends for years.
- **CHP equipment can use hydrogen blends of 20-30% with minimal modifications required.**

CO2 Emissions for H2-Natural Gas Blends

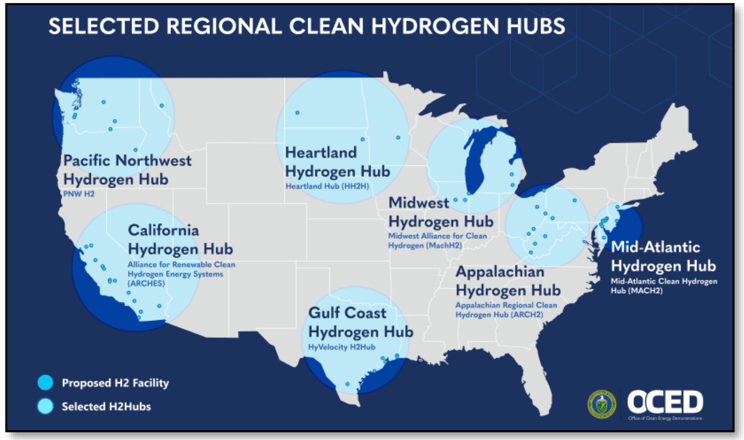


Energies | Free Full-Text | Impact of Hydrogen/Natural Gas Blends on Partially Premixed Combustion Equipment: NOx Emission and Operational Performance (mdpi.com)

Basic Information about NO2 | US EPA
EPRI Home
Hydrogen for Power Generation Whitepaper
Siemens Energy · Technical document · DIN A4 portrait – Template (siemens-energy.com)
HyBlend: Pipline CRADA Cost and Emissions Analysis (energy.gov)
Decarbonization | Hawaii Gas
https://crsreports.congress.gov/product/pdf/R/R46700

Hydrogen Cost Reductions Through Government Fundings and Tax Credits

- DOE launched the **Hydrogen Energy Earthshot (Hydrogen Shot)** in 2021 with the goal to reduce the production cost of clean hydrogen by 80% to $1/kg in 1 decade. This goal is only achievable through incentives.
  - Major investments made by the 2021 Bipartisan Infrastructure Law (BIL) will accelerate progress to achieve “1 1 1” goal:
    - $1 billion for Clean Hydrogen Electrolysis Program to improve the efficiency and cost effectiveness of electrolysis
    - $500 million for Clean Hydrogen Manufacturing and Recycling RDD&D
    - $8 billion for **Regional Clean Hydrogen Hubs** to advance the production, processing, delivery, storage, and end-use of clean hydrogen
    - National Clean Hydrogen Strategy and Roadmap



- The **Inflation Reduction Act** includes several key incentives to reduce the cost of hydrogen:
  - IRA 45V Clean Hydrogen Production Tax Credit
    - Up to $3/kg of hydrogen
  - IRA 45Q Carbon Sequestration Tax Credit
    - Up to $85/metric ton of CO2 captured and stored
  - IRA 45Y Clean Electricity Production Tax Credit
    - 0.3-1.5 cents per kWh produced from renewable energy

45V Production Tax Credit by Life Cycle Emissions

Carbon Intensity (kg CO_2e/kg H2)	Max Hydrogen PTC Credit ($/kg H2)
0-0.45	$3.00
0.45-1.5	$1.00
1.5-2.5	$0.75
2.5-4	$0.60

Inflation Reduction Act Summary: Energy and Climate Provisions | Bipartisan Policy Center
45Q-primer-Carbon-Capture-Coalition.pdf (carboncapturecoalition.org)

RNG Demand and Cost Projections

Future Biogas and RNG Demand and Resource Potential

- Future demand will be driven by:
  - biogas as feedstock for RNG, with demand from transportation, voluntary commitments by commercial and industrial customers, utility procurement programs, and
  - biogas as feedstock for renewable hydrogen.
- In 2019, ICF conducted a study on RNG *supply* potential for the American Gas Foundation.
  - The technical resource potential is based on the energy content of the resources, while assumptions for the utilization of feedstock were applied by ICF to develop low and high resource potential scenarios through 2040.
- Supply potential outweighs demand, but production supply is expected to remain constrained through 2030 as the transportation market saturates and demand from gas utilities increases.

	2030	2040
2019 AGF Study – Low Resource Potential	~900 BCF/yr	~1,800 BCF/yr
2019 AGF Study – High Resource Potential	~1,900 BCF/yr	~4,500 BCF/yr
2022 BCG Demand Study	~500 BCF/yr	~700 BCF/yr
2024 ICF Demand Outlook	~700 BCF/yr	~1,400 BCF/yr

Microsoft Word - AGF 2019 RNG Study Full Report - FINAL 12-18-2019 (1).docx (gasfoundation.org)
us-rng-article-v16.pdf (bcg.com)

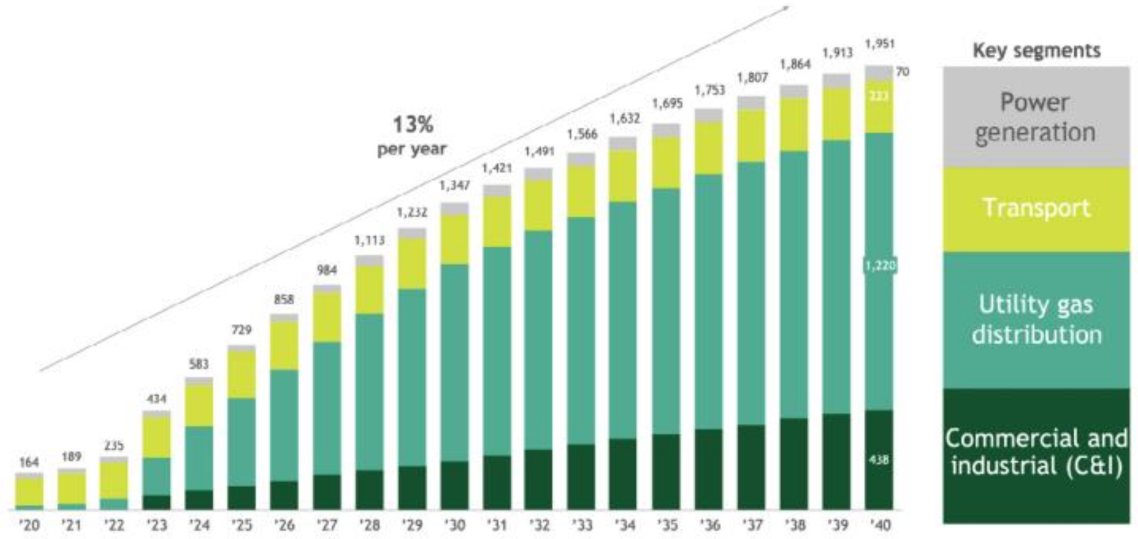
Future Demand for Renewable Natural Gas (BCG Outlook)

Boston Consulting Group outlook: RNG demand expected to increase 10x by 2040 to ~2 million MMBtu/day (700 BCF/year), with 4 demand drivers:

- Gas utilities and their local distribution companies at 22% CAGR
  - Expected to represent 40% of RNG demand by 2040
  - 70% of the top 20 LDCs have near- and/or long-term RNG adoption goals and currently drive prices for RNG
- Commercial and industrial at 11% CAGR
  - RNG will be a competitive decarbonization solution, especially for industrial applications requiring high heat
- Power generation at 6% CAGR
- Transportation at 3% CAGR
  - RNG transport fuel demand will be impacted by IRA-based and potential future incentives for electric and fuel cell vehicles (BEVs and FCVs)

Boston Consulting Group Outlook: RNG Demand through 2040

Exhibit 2: Total Expected RNG Demand, KMMBTU/d (Includes IRA)



ICF's RNG demand outlook is more optimistic, with demand reaching **600-800 BCF/year by 2030** (ten years earlier)

- More than 20 gas utility programs already in place
- Many energy companies are focused on RNG as a primary feedstock for near-term hydrogen production.

Biogas and RNG Resource Availability (2019 AGF Study)

- The low resource potential scenario will yield ~1,910 tBtu of RNG per year by 2040.
- The high resource potential scenario will yield ~4,510 tBtu of RNG per year by 2040.

- For comparison, the US consumed an average of 15,850 tBtu of natural gas per year between 2009-2018, of which 7,652 tBtu were in the industrial sector.

Figure 5. Estimated Annual RNG Production, Low Resource Potential Scenario, tBtu/y

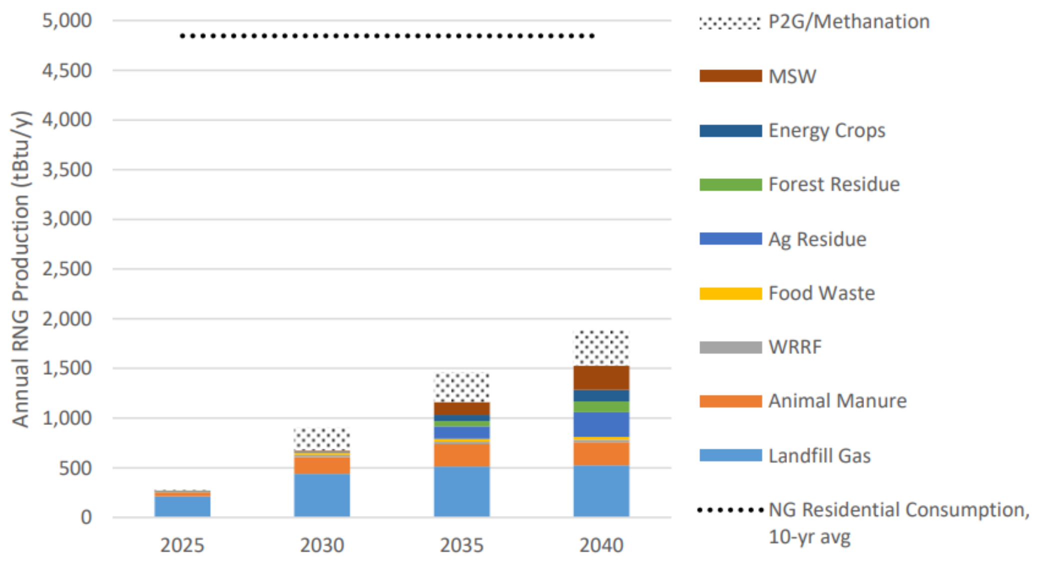
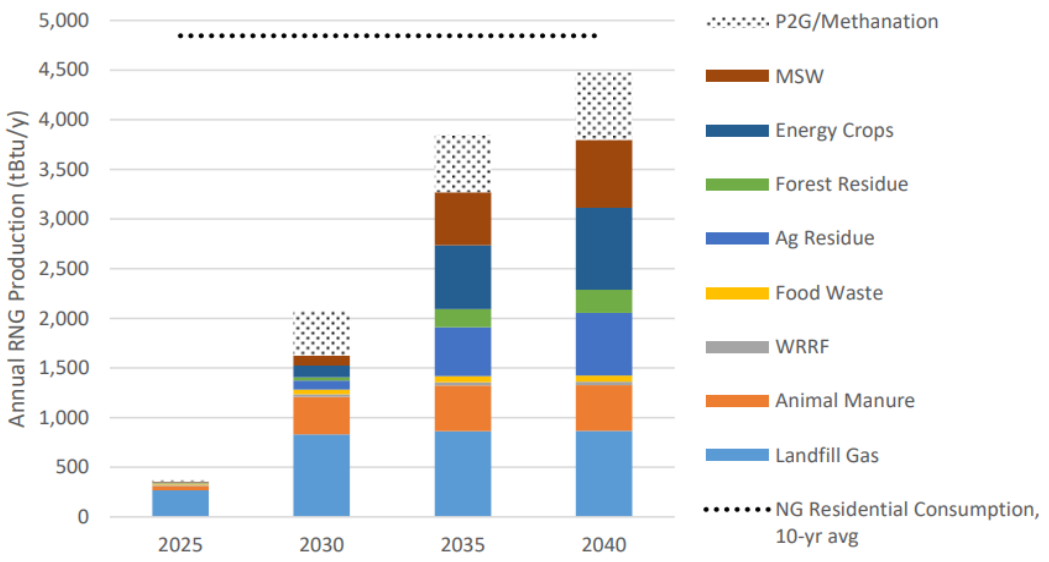


Figure 6. Estimated Annual RNG Production, High Resource Potential Scenario, tBtu/y



Microsoft Word - AGF 2019 RNG Study Full Report - FINAL 12-18-2019 (1).docx (gasfoundation.org)
us-rng-article-v16.pdf (bcg.com)

Biogas/RNG Market Expectations (2024 ICF Outlook)

Near-term demand will come from transportation fuel, utility offtake, and voluntary markets. There is unknown demand emerging for biogas as feedstock for renewable hydrogen production.

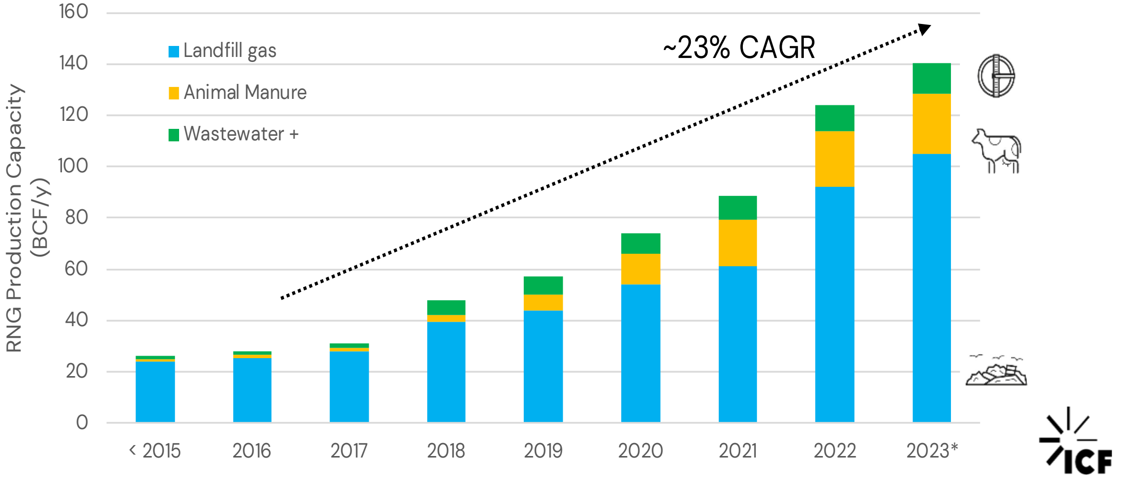
Demand will outstrip supply until at least 2030. Though ICF has a more bullish outlook for RNG *production* than other market analysts (e.g., upside potential of 500 BCF/y by 2030), the *demand* emerging is considerably higher (see table).

Production costs will moderate as larger market actors and utilities continue to engage more. Market is considered "bespoke" but there are scaling opportunities that can help to moderate costs. IRA incentives will help.

Realizing long-term RNG production potential will require feedstock diversification, move towards thermal gasification, and decarbonization policies. Biogas is in a period of transition—the next 3-5 years will determine if it is a 2-3% decarbonization solution or a 10-15% decarbonization solution.

CHP and industrial sector demand will overlap with "utility offtake" and "voluntary markets" (2030 estimates)

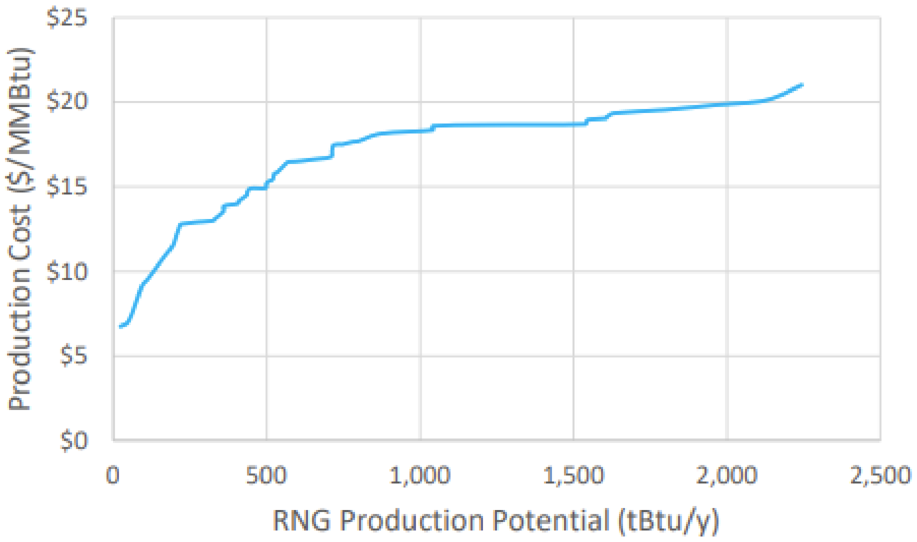
Sector	Est. Demand (BCF/y)	Comments
Transportation Fuel	110	Robust market in California; modest demand in emerging low carbon fuel markets (e.g., Oregon and Washington)
Utility Offtake	550	Boosted by regulatory commitments domestically, including in states like California, Colorado, Minnesota, Nevada, New Hampshire, Oregon, Vermont and in Washington DC
Voluntary Markets	100	Corporate commitments from industrial buyers (e.g., AstraZeneca, L'Oreal) and others (e.g., University of California)



Biogas and RNG Resources: Future Cost Projections (AGF)

- Costs are dependent on a variety of assumptions:
  - Feedstock costs
  - Revenue that might be generated via byproducts or other avoided costs
  - Expected rate of return on capital investments
  - Facility size and production capacity
  - Gas conditioning, upgrading, and compression costs
- Fixed price contracts for RNG are currently in the range of $20-$25/MMBtu, including IRA incentives.
  - IRA credits between $1/MMBtu and $9/MMBtu, depending on the source.
- According to the American Gas Foundation report, the majority of RNG produced in the high resource potential scenario should be available for under $20/MMBtu in the U.S. in 2040.
  - Cost reductions are possible as the RNG for pipeline injection market matures, production volumes increase, and the market evolves.

Figure 34. Combined RNG Supply-Cost Curve, less than $20/MMBtu in 2040



Note: After 2021-2023 inflation, these estimates will likely increase by ~30%

RNG Demand Expected to Grow to Approximately 2 Quads by 2050

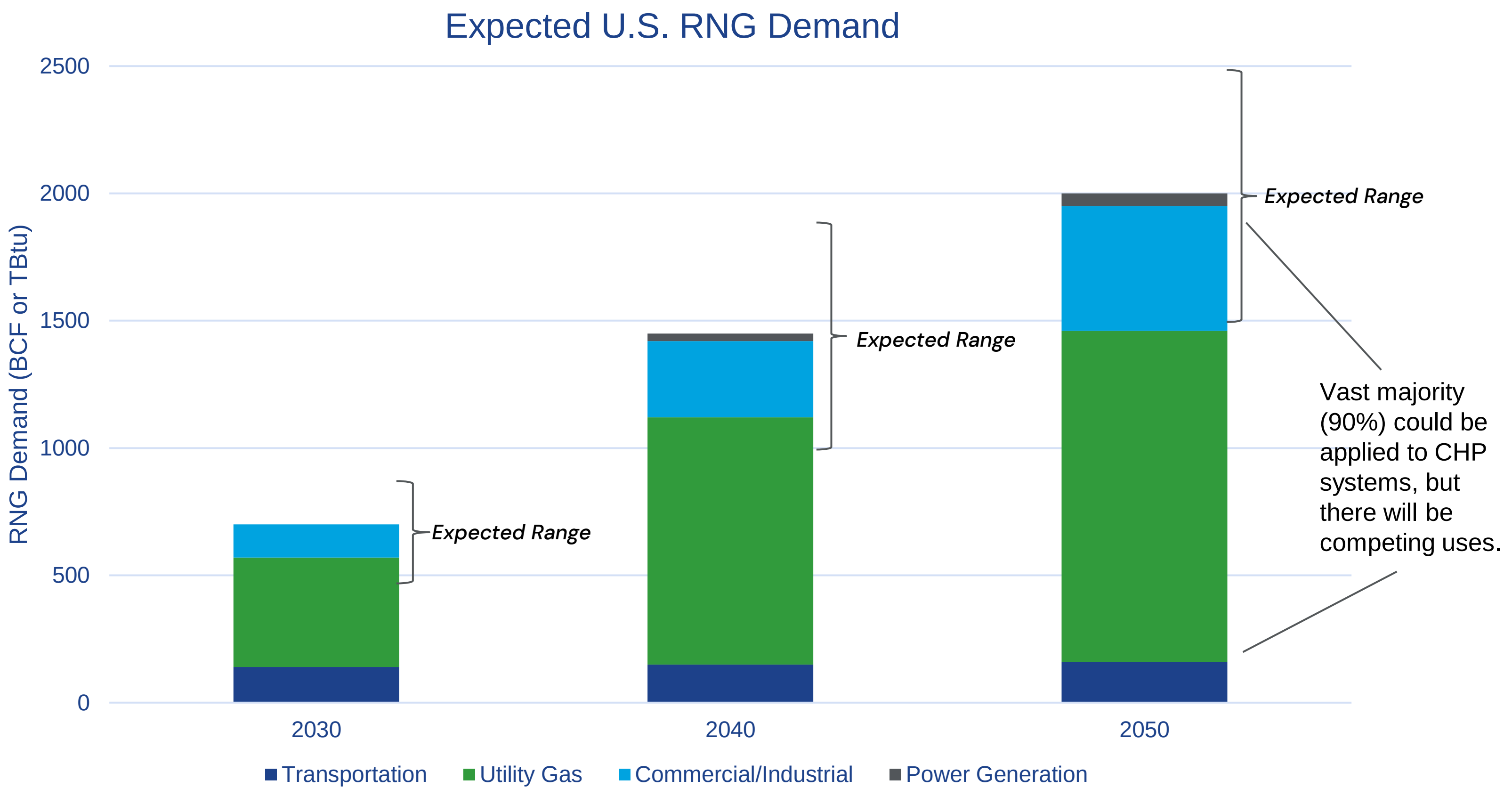
90% could potentially be applied to CHP

Biogas will continue to be used onsite for CHP and heating; **RNG market** will determine demand and supply for other sectors.

Based on a 2024 assessment of recent studies and market factors:

- **2030:** 500-900 BCF
- **2040:** 1,000-1,900 BCF
- **2050:** 1,500-2,500 BCF

Midpoint demand by sector shown on chart →



- Transportation market will be saturated by 2030; limited use for utility power generation.
- Most growth in utility gas and commercial/industrial sectors (can be applied to CHP, **~1,800 TBtu** in 2050).
- *Higher costs* as more agricultural and solid biomass resources are needed (more expensive than LFG).

Supply Expected to Meet Demand After 2030

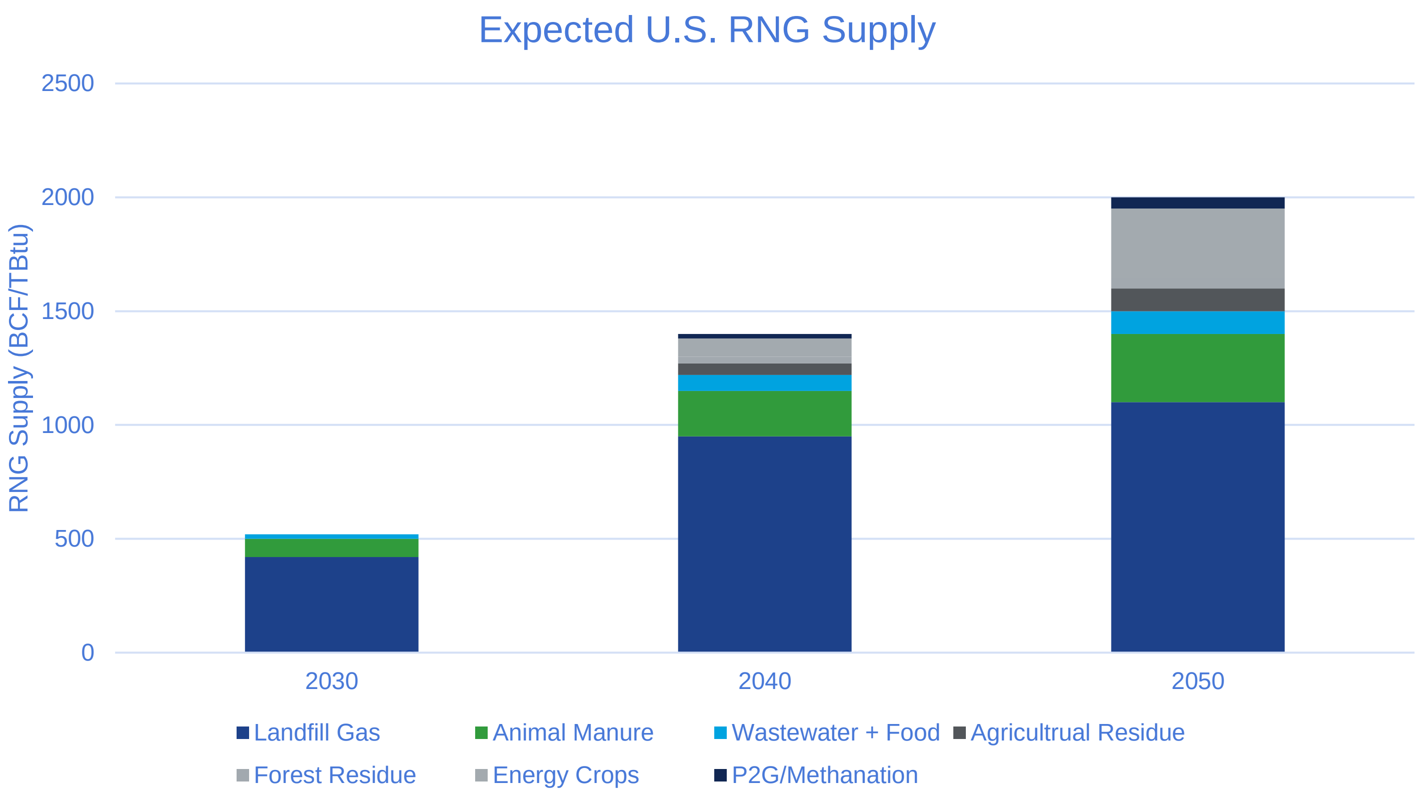
Costs will Increase

Supply estimates on the chart include expected sources of RNG.

Expected RNG Delivered Cost (2024 dollars*):

- 2030: $20/MMBtu
- 2040: $20-$25/MMBtu
- 2050: $25-$30/MMBtu

Higher-cost production methods (RNG from animal manure, thermal gasification) will increase the average costs.



- Majority of RNG will continue to come from landfill and agricultural digester resources.
- By 2040, advancements in thermal gasification will enable solid biomass resources to continue growing RNG supply.
- Potential for power-to-gas (P2G) in areas with no biomass resources and abundant renewable electricity.

Hydrogen Demand and Cost Projections

Overview of Hydrogen Demand Forecasts

The Department of Energy, National Petroleum Council, and American Petroleum Institute forecast the following hydrogen demands in 2030, 2040, and 2050:

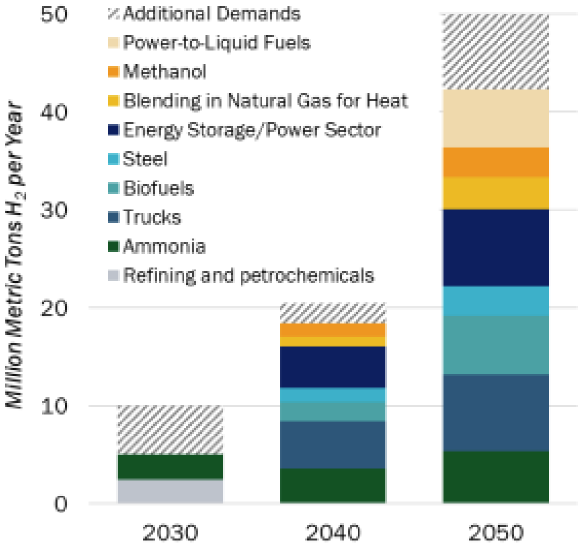
	2030 Demand	2040 Demand	2050 Demand
DOE Hydrogen Strategy & Roadmap	10 MMTpa (1,140 TBtu)	20 MMTpa (2,270 TBtu)	50 MMTpa* (5,690 TBtu)
NPC Harnessing Hydrogen Report - Stated Policy Scenario	12 MMTpa (1,360 TBtu)	14 MMTpa (1,590 TBtu)	18 MMTpa (2,050 TBtu)
NPC Harnessing Hydrogen Report - NetZero Policy Scenario	19 MMTpa (2,160 TBtu)	40 MMTpa (4,550 TBtu)	66 MMTpa (7,500 TBtu)
API Low Case Scenario	~1,200 TBtu	~5,300 TBtu	~9,900 TBtu
API High Case Scenario	~2,300 TBtu	~9,000 TBtu	~12,900 TBtu

*MMTpa = million metric tons per annum

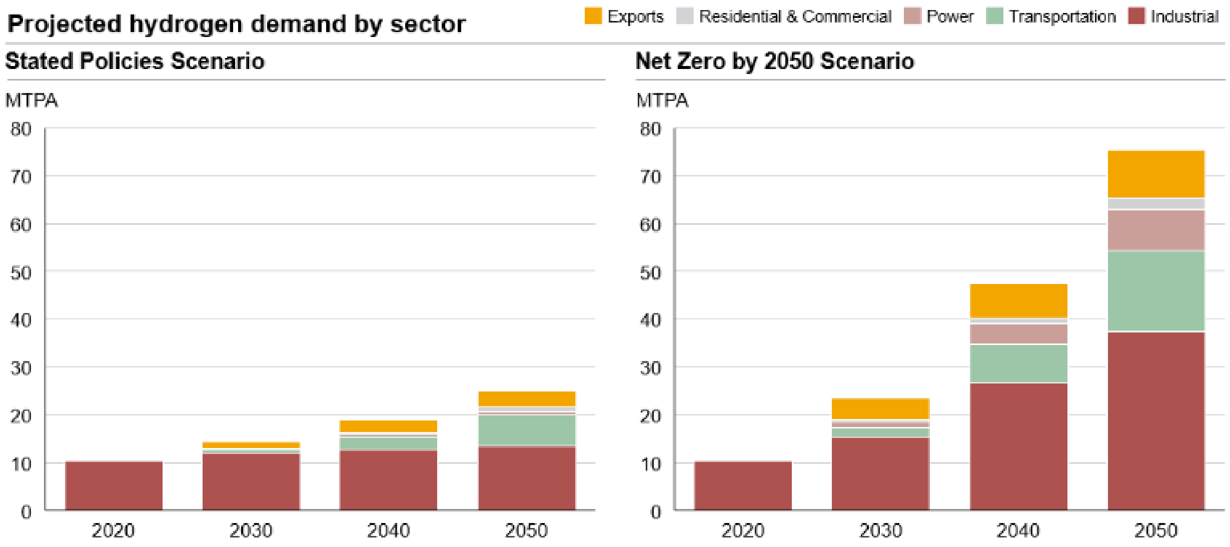
DOE and NPC Hydrogen Demand Forecasts

- The Department of Energy's Hydrogen Strategy Roadmap shows total hydrogen demand for the industrial, transportation, and power sectors reaching 50 MMT per year by 2050.
- The National Petroleum Council predicts that the total low carbon intensity hydrogen demand in in 2050 will be:
  - 66 MMT per year in a NetZero Scenario primarily for the industrial, transportation, and power sectors (excluding exports).
  - 18 MMT per year in Stated Policy Scenario for the industrial, transportation, and power sectors (excluding exports).

DOE Hydrogen Strategy Roadmap for Industrial, Transportation, and Power Sectors



NPC's 2024 Harnessing Hydrogen Report

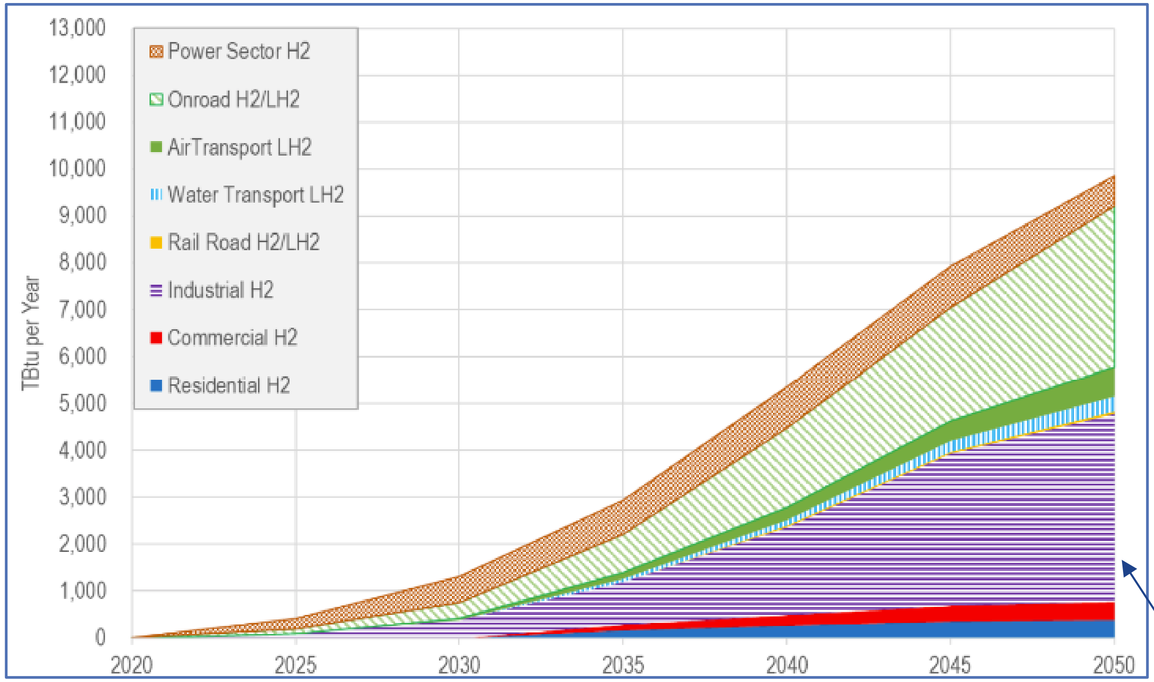


U.S. National Clean Hydrogen Strategy and Roadmap (energy.gov)
HARNESSING HYDROGEN - A Key Element of the U.S. Energy Future (npc.org)

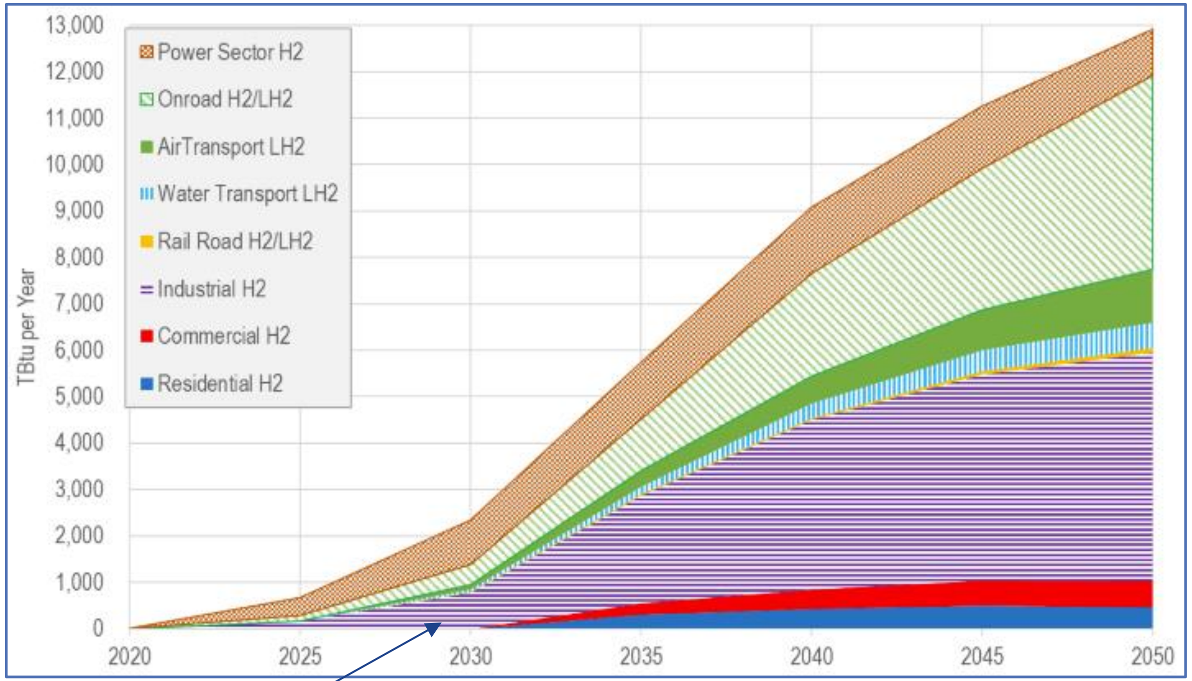
ICF Hydrogen Demand Forecasts

- ICF study (2022) on hydrogen demand shows a **growing need for hydrogen in the industrial sector**, which could include industrial CHP applications.
  - Assumes that policies could be implemented with a 2050 willingness to pay of \$150 - \$250 per metric ton of avoided CO2e.
  - Demand for hydrogen by end-users and power plants could reach 9.9 quadrillion BTU for the \$150/MT CO2e (low case) scenario and 12.9 quadrillion BTU for the \$250/MT CO2e (high case) scenario.

Hydrogen Consumption: Low Case, Technology Agnostic



Hydrogen Consumption: High Case, Technology Agnostic



Industrial Demand

Cost Forecasts Overview

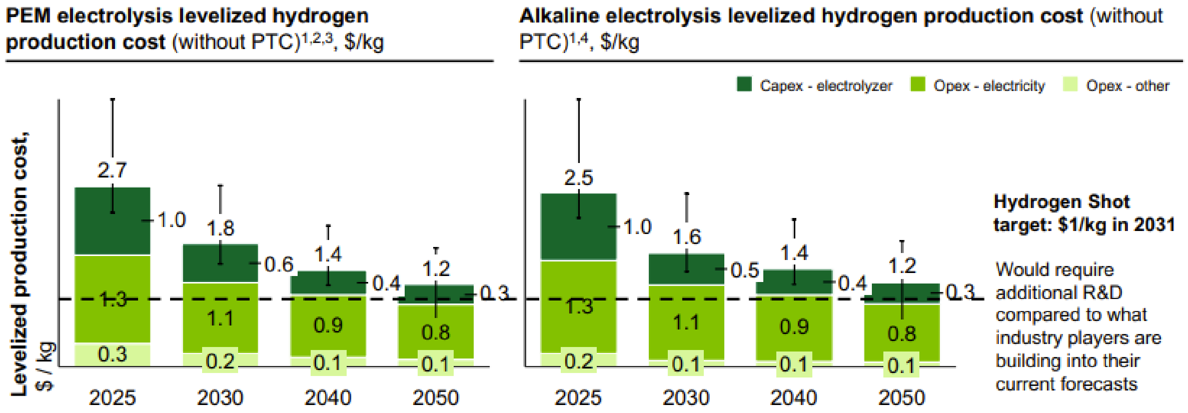
The Department of Energy and National Petroleum Council forecast the following unsubsidized hydrogen production costs in 2030, 2040, and 2050:

	2030		2040		2050	
	LCOH – Blue H2	LCOH – Green H2	LCOH – Blue H2	LCOH – Green H2	LCOH – Blue H2	LCOH – Green H2
DOE Hydrogen Strategy & Roadmap*	$1.2/kg	$1.6-1.8/kg	$1.2/kg	$1.4/kg	$1.2/kg	$1.2/kg
NPC Harnessing Hydrogen Report	$1.92-3.17/kg	$4.75-7.72/kg	$1.98-3.24/kg	$3.79-6.32/kg	$1.96-3.16/kg	$3.02-5.15/kg
Deloitte Assessment of Green Hydrogen for Industrial Heat**	$1.9/kg *with IRA credit*	$0.8-1.2/kg *with IRA credit*	$2.8/kg	$2.2-2.4/kg	$2.4/kg	$2.0-2.4/kg

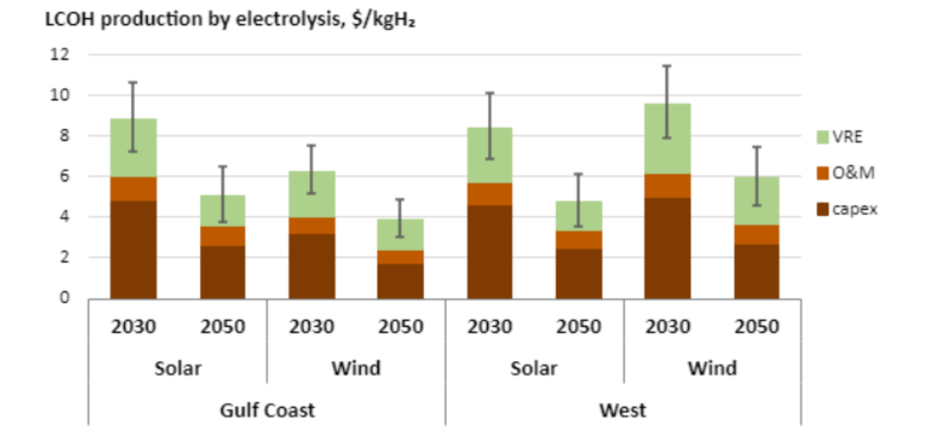
*2020 Dollars
**Low policy scenario assumes IRA incentives expire in 2033 and carbon pricing is phased gradually after 2040, from $0 to $67/Mt by 2050.

DOE and NPC Green Hydrogen Production Cost Forecasts

- Both DOE and NPC studies indicate that the cost of green hydrogen will <u>not</u> meet the DOE Hydrogen Shot $1/kg target by 2031 without tax credits (such as the 45V PTC) or other incentives.
  - Sufficient wind and solar overbuild is key to reducing the cost of green hydrogen produced from renewable energy.
    - Higher capacity utilizations of the electrolyzer with wind typically result in lower LCOH production than solar.
    - Hydrogen storage might be needed to account for electricity intermittencies and demand profiles.
  - DOE predicts the cost of green hydrogen production from onshore wind without tax credits to be $1.2/kg by 2050*.
  - NPC predicts the cost of green hydrogen production without tax credits in 2050 to be $3.02-5.15/kg, varying by region and policy scenario**.



At equivalent production costs, delivered costs for electrolytic hydrogen will be higher than reformation-based hydrogen due to higher storage costs

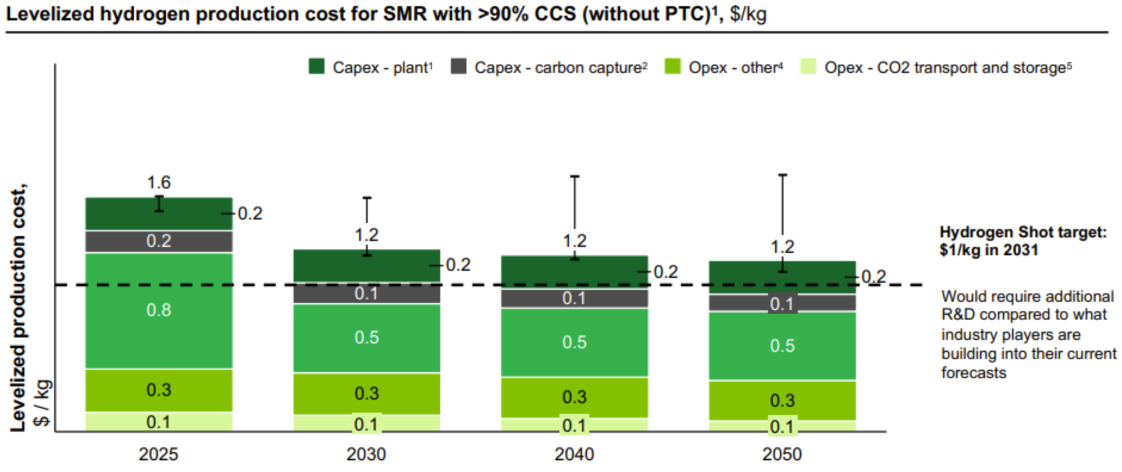


Note: Unsubsidized production when VRE capacity matches the electrolyzer capacity (no VRE overbuild). Error bars indicate the range of LCOH$_p$ for a low case (capex -$500/kW$_e$, power consumption -2 kWh$_e$/kgH$_2$ vs. base case) and high case (capex +$500/kW$_e$, power consumption +2 kWh$_e$/kgH$_2$ vs. base case).

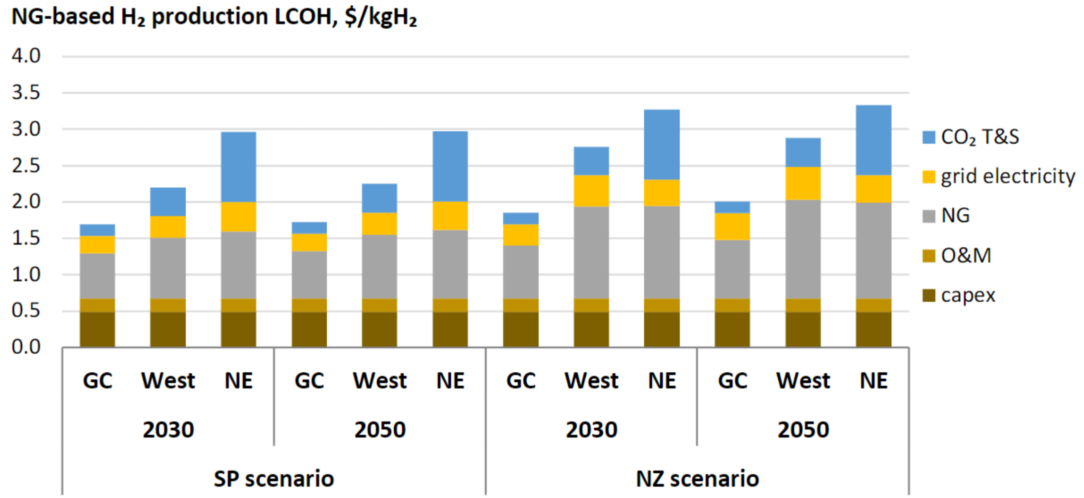
*Assuming $17/MWh; 2020 Dollar
**Assuming $42/MWh-$61/MWh, depending on the region

DOE and NPC Blue Hydrogen Production Cost Forecasts

- Both DOE and NPC studies indicate that the cost of blue hydrogen will not meet the $1/kg target by 2031 without tax credits (such as the 45V PTC or 45Q) or other incentives.
  - NPC predicts more expensive natural gas and electricity prices by 2050 with more stringent climate and decarbonization goals, increasing the levelized cost of hydrogen (LCOH).
    - Natural gas prices account for ~50% of the levelized production costs of blue hydrogen.
  - DOE predicts the cost of hydrogen production without tax credits will stabilize at $1.2/kg* by 2050. *2020 Dollar
  - NPC predicts the cost of hydrogen production without tax credits in 2050 to be $1.96-3.16/kg, varying by region and policy scenario.



1 These levelized costs use industry estimates for capex costs developed in 2020 using 2020 USD. Forecasted capex values may differ between sources
2 SMR facility capex (100k Nm^3/h capacity): $215 million (2025 onwards)
3 CCS capex (100k Nm^3/h capacity facility): $140 million (2025), $135 million (2030), $120 million (2040), $110 million (2050)
4 Natural gas reference case: $4.3 / MMBtu (2025), $3 / MMBtu (2030 onwards); assumes non-renewable natural gas; natural gas high case based on EIA Annual Energy Outlook 2022 high oil price scenario; natural gas low case based on EIA Annual Energy Outlook 2022 low oil price scenario
5 Includes O&M, catalyst replacement, electricity, and water costs
6 CO2 transport and storage: $48/tonne CO2 (2025), $44/tonne CO_2 (2030), $39/tonne CO2 (2040), $35/tonne CO2 (2050)
Source: Hydrogen Council, EIA Annual Energy Outlook 2022

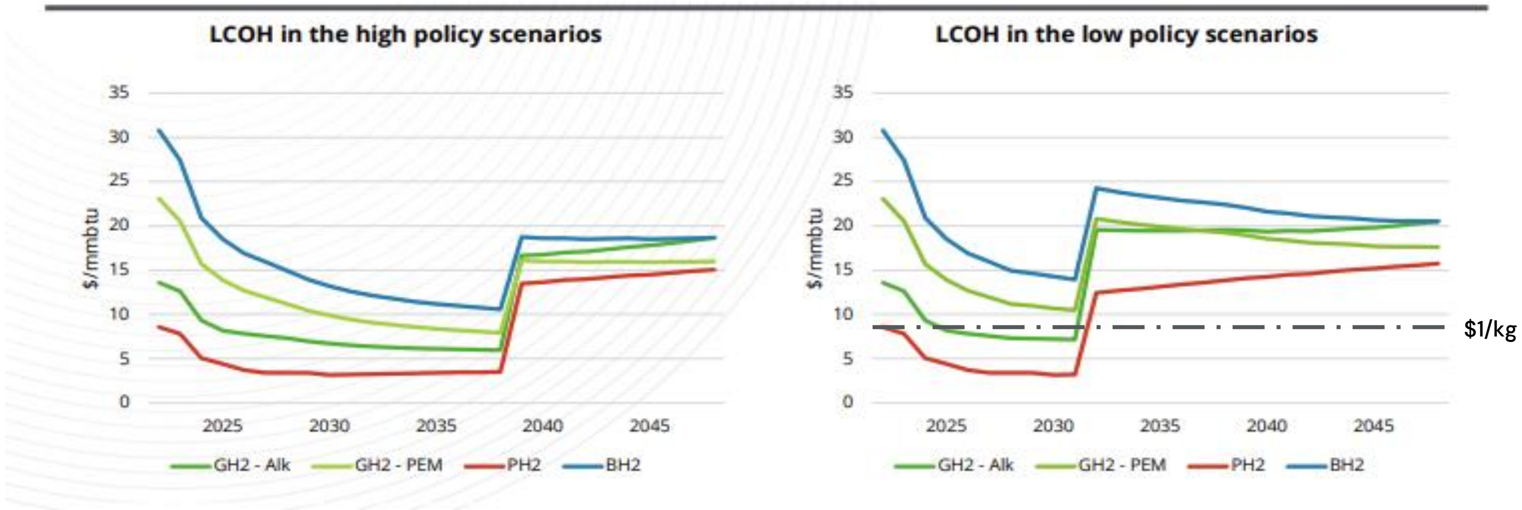


Note: Unsubsidized production via ATR + 95% CO_2 capture. GC = Gulf Coast, NE = Northeast, SP = Stated Policies scenario, NZ = Net Zero scenario. Does not include costs due to California cap and trade regulation.

Impact of Policies on Levelized Cost of Hydrogen (LCOH)

- Deloitte's scenario-based LCOH analysis suggests:
- Tax incentives are vital to reducing the cost of hydrogen:
  - IRA directly and significantly affects the delivered costs of green, pink (nuclear), and blue (SMR w/CCUS) hydrogen.
  - Spikes in LCOH are due to IRA production tax credits ending: 2040 for high policy and 2033 for low-policy.
  - Both scenarios include carbon pricing, starting in 2030 for high policy and 2040 for low policy.
- Low-cost renewable electricity is likely to be required to drive long-term cost reductions for green hydrogen.
- Deloitte's analysis has prices spiking immediately after policy incentives are lifted, but the 10-year production tax credit should extend lower costs into the 2040s. This chart represents the LCOH for new production facilities coming online.

Levelized Cost of Hydrogen (LCOH) by Policy Scenario



GH2 = green hydrogen
PH2 = pink hydrogen
BH2 = blue hydrogen

us-advisory-assessment-of-green-hydrogen-for-industrial-heat.pdf (deloitte.com)

Clean Hydrogen Potential for Industrial Sector and CHP (ICF Outlook)

- Clean hydrogen production and use will increase with IRA production tax credits and hydrogen hubs, but **hydrogen will not be ready to replace natural gas for most applications until the 2030s**.
  - Hydrogen will first be used in applications that already utilize hydrogen (not replacing natural gas), or applications that are willing to pay a higher cost (forklifts/trucks).
  - By 2030, the cost of hydrogen will be lower and supply will be higher, enabling industrial facilities to start replacing natural gas consumption - first with hydrogen blends, and then with dedicated pipelines.
- **Industrial facilities with strong decarbonization targets may opt for onsite hydrogen production**.
  - Particularly those located far from hydrogen distribution hubs and CCS geology.
- Blue hydrogen (SMR with CCS) will be the predominate production technology in the 2020s, with green (electrolytic) hydrogen increasing.
- Hydrogen demand (and supply) expected to ramp up in 2030s and 2040s, met primarily by new green hydrogen production.
  - Lower share available for industrial/CHP applications compared to RNG, but higher quantities produced.
- **Demand for decarbonization and policies supporting hydrogen will enable long-term growth and availability as a fuel for CHP.**

Hydrogen Demand Could Exceed 4 Quads by 2040, 8 Quads by 2050

40% could potentially be applied to CHP

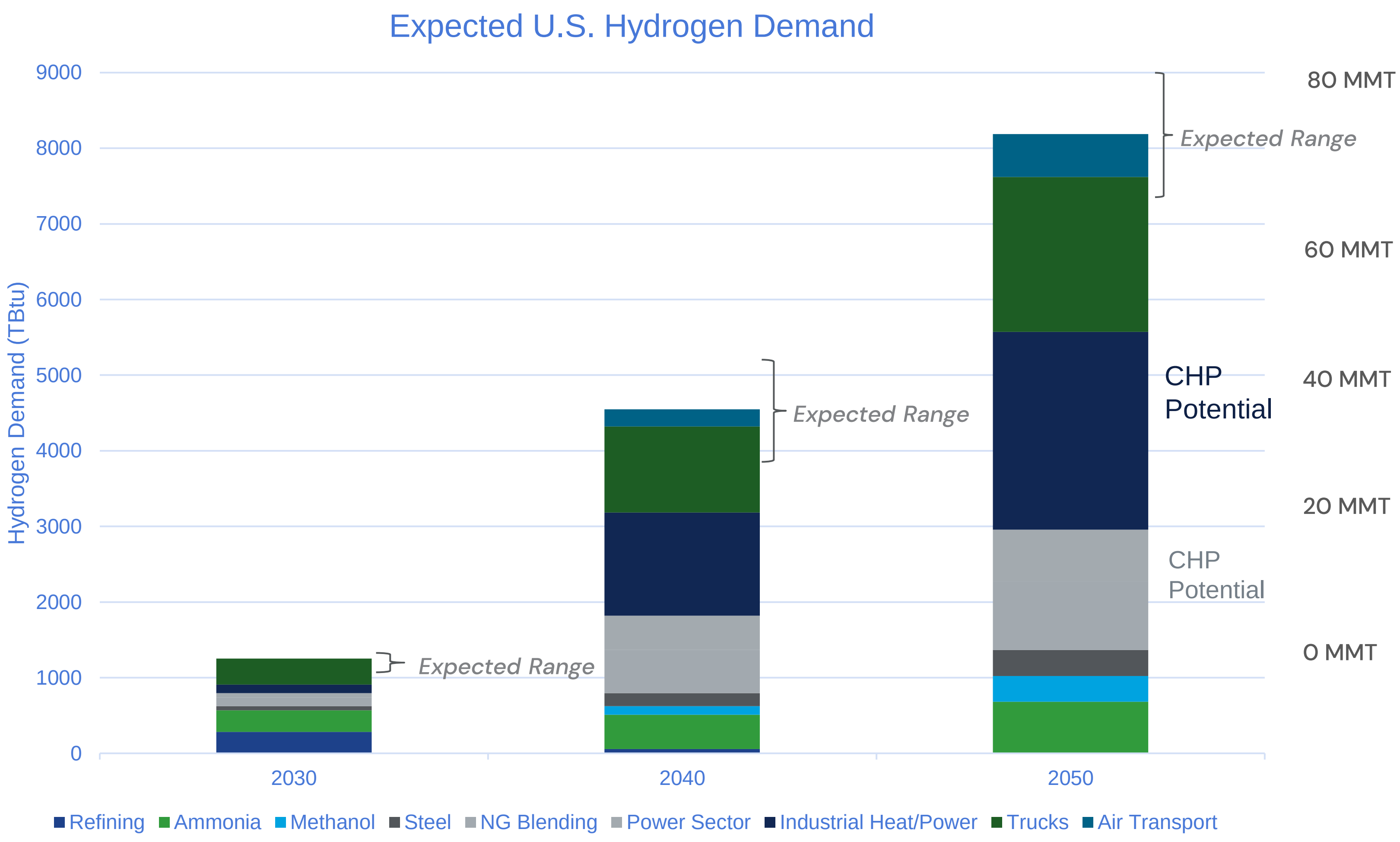
Hydrogen demand is expected to grow in the 2030s and 2040s, including for industrial heat and CHP applications.

Based on a 2024 assessment of recent studies and market factors

- **2030:** 10-12 MMT (~1,200 TBtu)
- **2040:** 35-45 MMT (~4,600 TBtu)
- **2050:** 64-80 MMT (~8,200 TBtu)

Midpoint demand by sector shown on chart →

Costs will reach $8-10/MMBtu ($1/kg) with IRA credits, and settle around $15/MMBtu ($2/kg) in the 2040s*.



- Expect most growth in Industrial Heat/Power, Trucks, and NG Blending
- Overall, ~**3,500 TBtu** could potentially be applied to CHP in 2050

*Average cost projections

Barriers and Potential Options for RNG

U.S. DEPARTMENT OF
ENERGY

Key Barriers for RNG as a Fuel for CHP

Insufficient supply hindering easy access and widespread adoption of RNG use

High costs of RNG compared to other fuels and other decarbonization options limiting the willingness to transition from conventional fuels and a business-as-usual approach

Uncertainty of RNG's impact on emissions accounting leading to investment hesitation from energy companies and private investors

Barrier(s)	Options
	1. Incentives to Reduce Cost of RNG
	2. Valuation of Carbon Emission Reductions
	3. R&D for Thermal Gasification Technology Improvements
	4. Standardization of Emissions Accounting
	5. Waste Management Policies and Regulations
	6. Solid Biomass Feedstock Resource Management
	7. Partnerships between Utilities and Municipal Waste

BARRIER LEGEND

Insufficient supply

High costs of RNG compared to other fuels and other decarbonization options

Ambiguity of RNG's impact on emissions accounting

Key Barriers for RNG as a Fuel for CHP

Insufficient supply hindering easy access and widespread adoption of RNG use – *need to expand to solid biomass feedstocks, but technical and cost challenges with thermal gasification*

- Supply is inherently limited – not enough resources to recover economically compared to natural gas
- Large amounts of waste and other feedstocks that could be converted to RNG – need better understanding of local availability and cost to collect and convert these resources
- Competing uses of RNG (transportation, power sector, industrial heating)

High costs of RNG compared to other fuels and other decarbonization options limiting the willingness to transition from conventional fuels and a business-as-usual approach

- High capital and operating costs
- Low natural gas prices
- Cost of thermal gasification and transportation of solid feedstocks

Uncertainty of RNG's impact on emissions accounting leading to investment hesitation from energy companies and private investors

- Lack of clear GHG accounting system for RNG as a decarbonization strategy: GHG Protocol to clarify with market-based mechanisms

Benefits of Potential Market and Policy Options for RNG

Option	
1	**Incentives aimed at reducing costs of RNG (such as extension of IRA 45Z) will:** a) **enable RNG to compete with fossil fuels,** allowing industrial facilities to use zero-carbon fuels, and b) **provide a viable path to decarbonization** for facilities with high-temperature heating and CHP.
2	**Creating emissions reduction requirements (i.e., proposed EPA Waste Emissions Charge) will**: a) **encourage low-emission fuels** such as RNG and thus **increase supply**, b) **narrow the cost gap** between fossil and renewable natural gas, and c) prompt the development of **transparent emissions accounting** guidance for RNG.
3	**Investments in thermal gasification R&D, potentially with DOE Bioenergy Technologies Office, will**: a) encourage collection and utilization of solid biomass feedstocks to **increase the supply of RNG**, and b) **reduce the cost per unit** of fuel produced through thermal gasification.
4	**Standardized emissions accounting of biogas/RNG through GHG Protocol will**: a) credit consumers' emissions inventory, **incentivizing adoption** to reach emissions reduction targets.

Benefits of Potential Market and Policy Options (continued)

Option

5 **Implementing policies and regulations for waste management techniques will:**

a) **expand the availability** of waste which can be used for RNG production, and

b) make **RNG production more cost effective** by reducing tipping fees and other costs associated with waste disposal.

6 **Effective resource management of solid biomass feedstocks, as recommended in the DOE 2023 Billion Ton Report, will:**

a) **increase the supply of RNG** produced through solid biomass thermal gasification and co-digestion with wet waste.

7 **Enabling partnerships between utilities and municipal waste operations will:**

a) **create a market for RNG** post-production thus utilizing excess supply of biogas, and

b) further incentivize RNG production at municipal waste facilities to **increase RNG supply.**

Barriers and Potential Options for Hydrogen

Overview: Key Barriers for Hydrogen as a Fuel for CHP

- **Insufficient supply and infrastructure** hindering easy access and widespread adoption of hydrogen use
- **High costs of hydrogen compared to other fuels and other decarbonization options** limiting the willingness to transition from conventional fuels and a business-as-usual approach
- **Hydrogen market uncertainty** leading to investment hesitation from private and utility investors
- **Specific challenges for hydrogen use in industrial CHP facilities**

Barrier(s)	Options
	1. Incentives to Increase Hydrogen Supply
	2. Hydrogen Infrastructure Investments
	3. Methane Pyrolysis Pilots for Clean Onsite Hydrogen Production
	4. R&D for Technological Advancements
	5. Incentives to Reduce Hydrogen Costs
	6. Valuation of Carbon Emission Reductions
	7. Proof of Concept, Demonstration Projects, Case Studies
	8. Clarify and Standardize Regulations

BARRIER LEGEND

- *Insufficient supply and infrastructure*
- *High costs of hydrogen compared to other fuels and other decarbonization options*
- *Hydrogen market uncertainty*
- *Specific challenges for hydrogen use in industrial CHP facilities*

Overview: Key Barriers for Hydrogen as a Fuel for CHP

Insufficient supply and infrastructure hindering easy access and widespread adoption of hydrogen use

- Limited hydrogen supply
- Volatility of hydrogen supply – need a reliable source or large amount of storage due to variable production; potential for grid outages to impact supply
- Lack of transportation and storage infrastructure

High costs of hydrogen compared to other fuels and other decarbonization options limiting the willingness to transition from conventional fuels and a business-as-usual approach

- High cost of hydrogen production and transportation
- Policy focus on other decarbonization options, e.g., electrification incentives

Hydrogen market uncertainty leading to investment hesitation from private and utility investors

- Negative public perceptions (safety)
- Uncertainty in future availability of hydrogen, delivery options, and tax credits

Specific challenges for hydrogen use in industrial CHP facilities

- Highly varying peaks and high-volume heat/steam demand at industrial facilities
- Curtailing operations while equipment is replaced or modified to accommodate hydrogen use
- Additional SCR equipment may be required to remove NOx

Key Barriers for Hydrogen as a Fuel for CHP

Specific challenges for hydrogen use in industrial CHP facilities

- Highly varying peaks and high-volume demand for industrial processes.
  - Variations in demand and high volumes could pose challenges for hydrogen supply.
    - Solid oxide fuel cells have a slow transient response, a limiting factor for operations with varying power demands.
    - Storage may be needed at both source and site for a 100% hydrogen solution.
- Perception of hydrogen not being feasible for high-volume industrial applications.
- Onsite clean hydrogen production is expensive; more R&D is needed.
- Need to replace combustion equipment for more than 20-30% blends; potential need for additional SCR equipment due to higher NOx formation.
- Ramping down operations while equipment is replaced or modified for hydrogen.
  - Industrial customers often want a guarantee that operations will not need to be shut down
  - Limited and costly onsite storage options and access to pipeline infrastructure.
- Lack of policy to promote hydrogen uptake in the industrial sector.
  - Decarbonization goals have been driving hydrogen demand in the cement industry, but increased policy would expand hydrogen use across the entire industrial sector.
- Insufficient low-cost renewable electricity to power loads for onsite electrolyzers.

Benefits of Potential Market and Policy Options for Hydrogen

Option	
1	**Implement incentives to increase hydrogen supply will:** a) **boost supply** and promote the build out of **more infrastructure** (transportation and storage), and b) **reduce cost** due to expanded hydrogen markets and less competition for available hydrogen supply.
2	**Increased hydrogen infrastructure investments (transportation and storage) will:** a) enable **easier and more widespread access** to hydrogen supply, and b) **reduce constraints** for onsite hydrogen use at industrial facilities.
3	**Promoting R&D and deployment of methane pyrolysis technologies will:** a) offer **scalable onsite hydrogen generation** options for industrial facilities, and b) **reduce the cost of hydrogen** when taking advantage of existing carbon black market (rubber, asphalt, medical devices, aerospace composite materials, and concrete).
4	**Promoting R&D for technological advancements in electrolyzers will:** a) **lower the cost per kilogram** of hydrogen, and b) **create more supply** with the same inputs due to increased system efficiency.

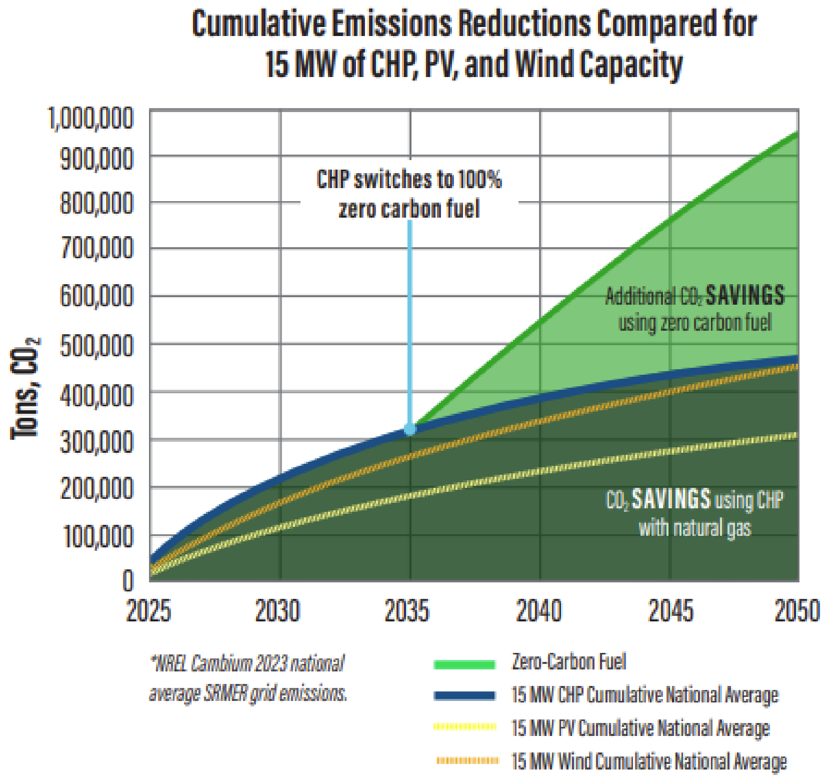
Benefits of Potential Market and Policy Options (continued)

Option	
5	**Incentives aimed at reducing the cost of hydrogen will**: a) help **close the cost gap** between hydrogen and fossil fuels, and b) **provide a viable path to decarbonization** for facilities with high-temperature heating and CHP.
6	**Creating value for carbon emission reductions will:** a) disincentivize fossil fuel use and **reduce the cost difference** between fossil and low carbon fuels, and b) **simplify the business case** for industrial companies to achieve emissions reductions, particularly in hard-to-electrify applications, using low carbon fuels.
7	**Deploying and publicizing pre-commercial deployments will**: a) demonstrate **viable industrial integration pathways,** and b) **assure financiers & stakeholders** of hydrogen readiness.
8	**Clarifying and standardizing regulations will:** a) **increase transparency** of offtake and delivery options and **lower overall market uncertainty**, and b) **optimize hydrogen project timelines** and therefore promote quicker **infrastructure build-out**.

Key Takeaways

Key Takeaways: RNG and Hydrogen for CHP

- Biogas has been used in CHP applications for decades, and RNG produced from biogas – or from solid biomass feedstocks – can be applied to CHP, replacing natural gas with no modifications.
- Hydrogen has been used at refineries and ammonia/methanol production facilities, and new efforts to develop clean hydrogen resources will increase supply and availability for facilities with CHP.
- **RNG and Hydrogen can be used efficiently in fuel-flexible CHP systems to improve carbon emission reductions** (see chart) while maintaining the energy resilience benefits of onsite heat and power.
- The future availability and applicability of RNG and Hydrogen for CHP will depend on federal/state/utility programs, policies, and incentives to facilitate infrastructure planning.
- Organizations that rely on CHP's reliable heat and power for manufacturing operations and energy-intensive buildings can continue to realize the efficiency, emissions, and resilience benefits of CHP while meeting greenhouse gas reduction targets.
- Using RNG and Hydrogen in higher efficiency systems like CHP extends supplies over time.



10 Minute Break

Better Plants®
U.S. DEPARTMENT OF ENERGY

Energizing CHP and Exploring Case Studies: Unlocking the Potential of Alternative Fuels

Cliff Haefke

DOE Central and Midwest Onsite Energy TAPs

Agenda

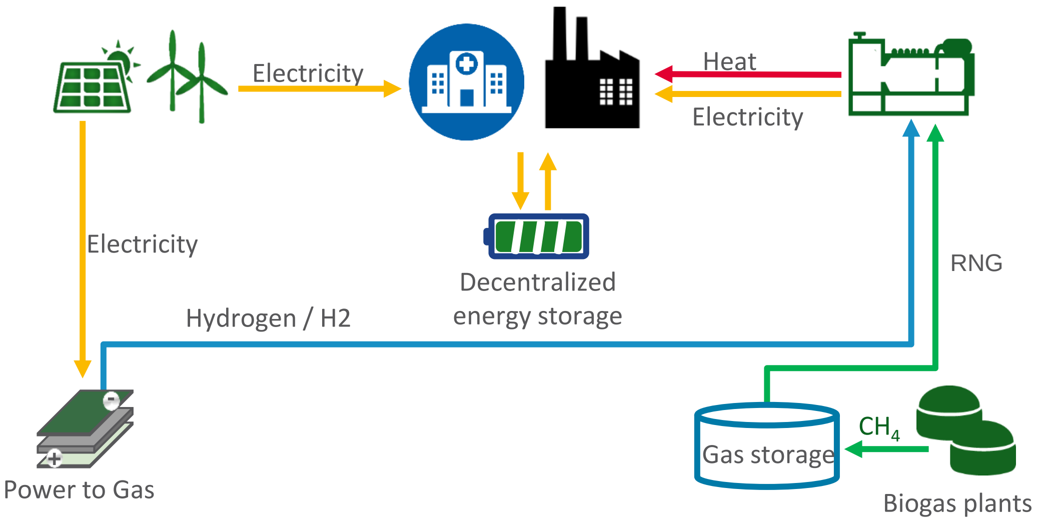
- Considerations for Operating CHP Systems with Alternative Fuels
- DOE CHP Packaged Systems eCatalog
- Example Case Studies of Alternative Fueled CHP Systems

Considerations for Operating CHP Systems with Alternative Fuels

CHP and Decarbonization

- CHP is fuel flexible - CHP currently uses renewable fuels, low carbon waste fuels, and hydrogen where available, and will be ready to use higher levels of biogas, renewable natural gas (RNG) and hydrogen in the future
- CHP is the most efficient way to generate power and thermal energy, and can reduce CO_2 emissions now and in the future
- Net-zero CHP can decarbonize industrial and commercial facilities that are difficult to electrify
- Net-zero CHP can decarbonize critical facilities that need dispatchable on-site power for long duration resilience and operational reliability
- CHP's high efficiency can extend the supply of renewable, low carbon and hydrogen fuels
- CHP can provide dispatchable net-zero generation and regulation support to maintain the long-run resource adequacy of a highly renewable grid

CHP in a Decarbonized Economy

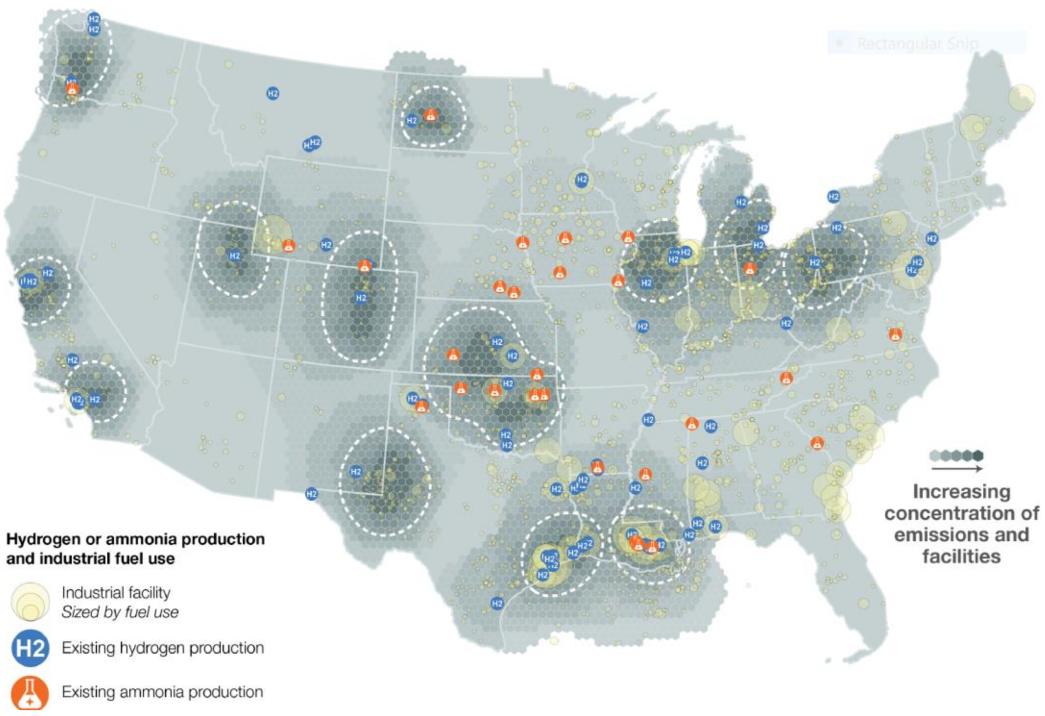


Source: Based on 2G Energy

Renewable and Hydrogen Fueled CHP

- Existing CHP systems can utilize biogas and biofuels.
- All natural gas-fueled CHP is compatible with renewable gas (RNG).
- Most existing turbines and engines can operate on hydrogen mixtures up to 10-40%.
- All major engine and gas turbine manufacturers are working on the capability to operate at high levels of hydrogen, targeting 2030 for 100% hydrogen prime movers.
- CHP systems can be changed out or modified in the field to 100% hydrogen-fuel blends

The ultimate scale of renewable and hydrogen-fueled CHP deployment will depend on resource availability.

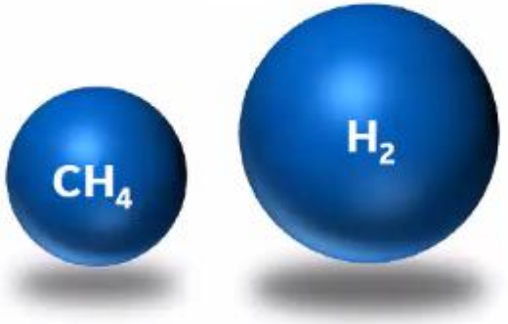


Source: Atlas of Carbon and Hydrogen Hubs, Great Plains Institute, February 2022

Use of Hydrogen will Require System Changes

Fuel System

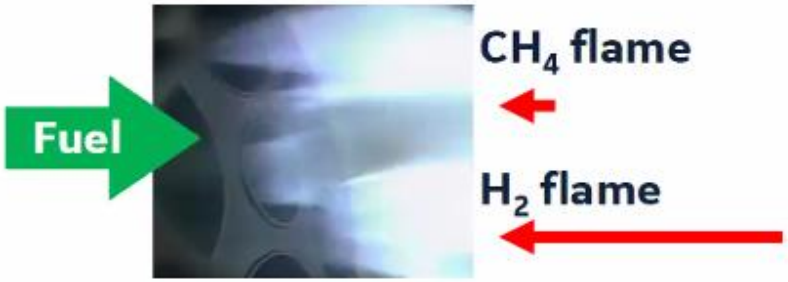
Methane (CH_4): 912 lb/ft^3
Hydrogen (H_2): 275 lb/ft^3



To deliver the same energy content, hydrogen requires 3X more volume flow

Combustion System

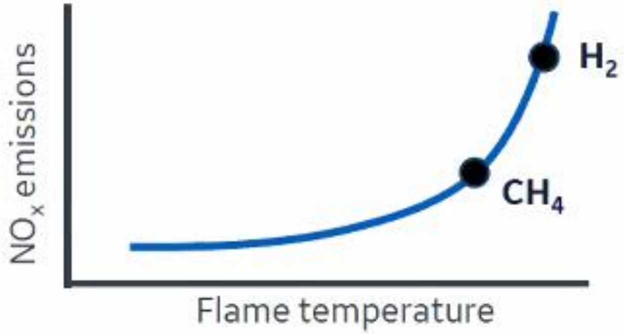
Methane (CH_4): ~30–40 cm/sec
Hydrogen (H_2): ~200–300 cm/sec



Hydrogen flames may increase risk of damage to combustion hardware

Emissions Aftertreatment

Methane (CH_4): ~3,565 °F
Hydrogen (H_2): ~4,000 °F



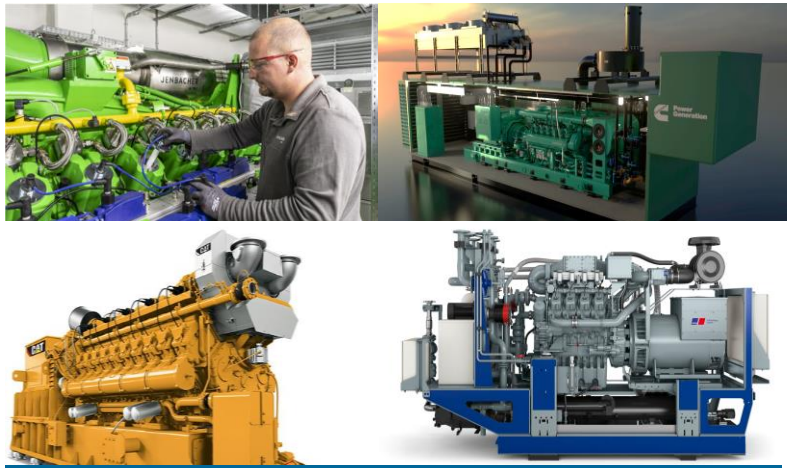
Operating on hydrogen may increase NO_x emissions

Design Differences between Natural Gas and Hydrogen Combustion Turbines

System/Procedures	H_2 Volume Impact on Turbine: 0% – 10% – 30%[1]	10% – 30%[1] – 50% – 70%[1]	50% – 70%[1] – 100%
Burners and combustion chamber	No change	Modified burner may be required	New burner design
Combustion monitoring system	n.a.	n.a.	n.a.
Fuel supply system	No change	Ensure all components Stainless Steel	Pipe diameter increase Purging system
Control/protection systems	No change	Additional gas detection	All hazardous area electrical equipment to Gas Group IIC
O&M Procedures	No change	Leak check of gas fuel system after maintenance inspections	Start-up/shutdown on conventional fuel
	No modifications needed	**Smaller modifications may be required**	**Modifications needed**

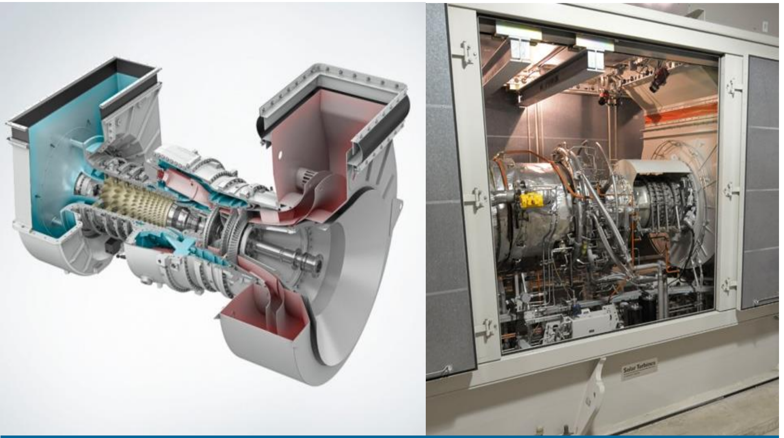
Source: Siemens Energy 2021

CHP Prime Mover Hydrogen Status



RECIP ENGINES SOME @ 100% H_2 TODAY - TARGET 2030

MICROTURBINES 70 TO 100% H_2 TESTING

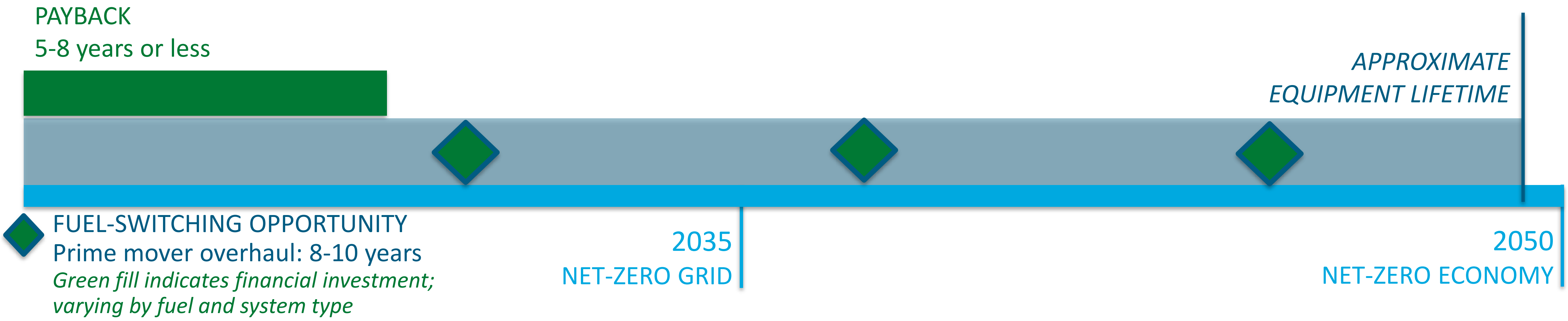


GAS TURBINES SOME @ 100% H_2 TODAY - TARGET 2030

FUEL CELLS 100% H_2 COMPATIBLE TODAY

CHP Life Cycle Offers Multiple Opportunities for Fuel Switching

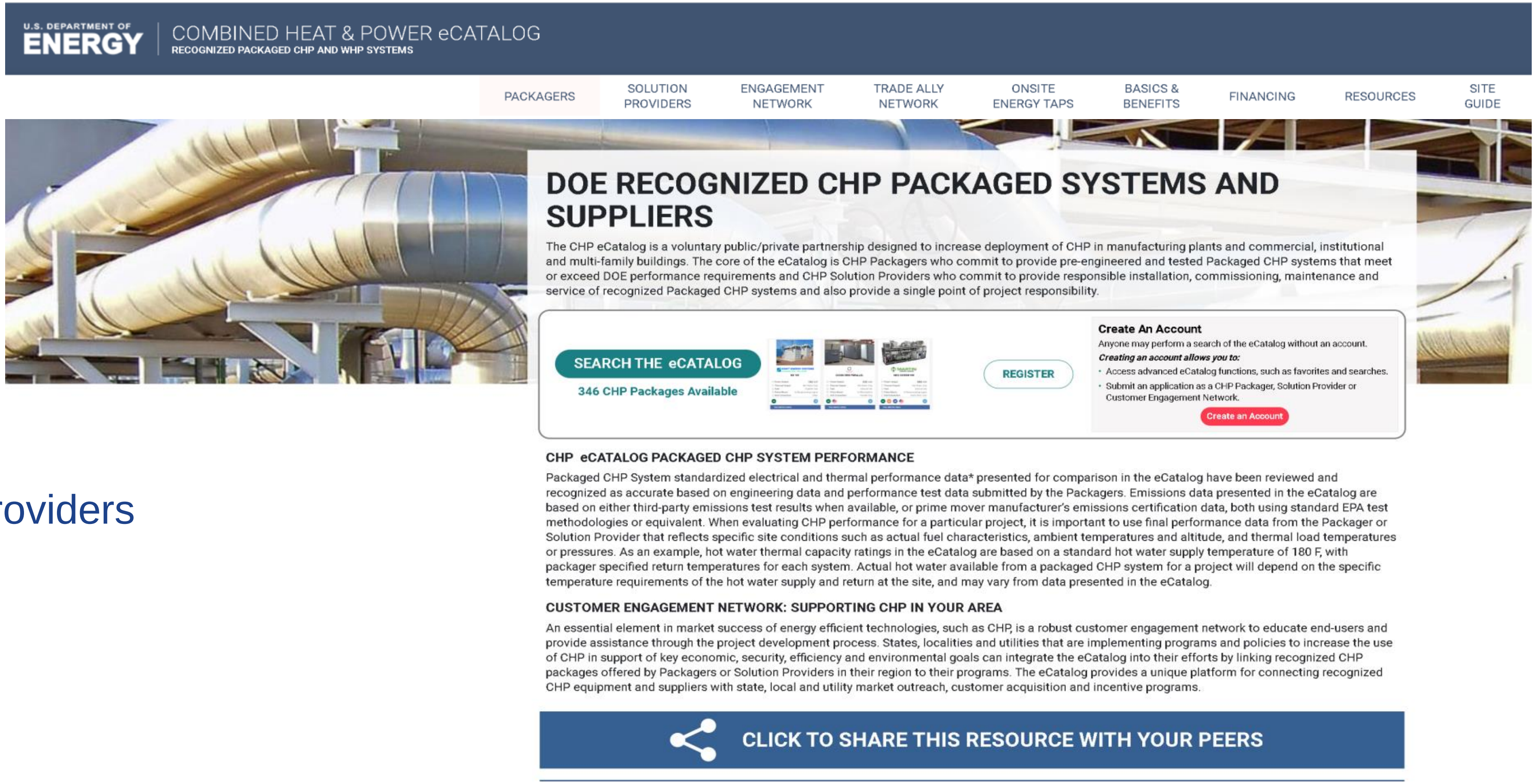
- Payback periods and regular maintenance schedules offer multiple decision points for reoptimization of emissions reduction measures as the grid evolves and other decarbonization options mature:
  - Payback: Typical payback for CHP installations is between 6–8 years. After the initial equipment and installation costs are recovered, future investment decisions can be based on operating costs only.
  - Fuel-switching opportunity: Industrial CHP prime movers require periodic overhauls on an 8 to 10-year cycle (at ~10 to 15% of the original installation cost), which offer at least three opportunities to switch fuel or select an alternate decarbonizing path.



DOE CHP Packaged Systems eCatalog

U.S. DEPARTMENT OF
ENERGY

DOE Combined Heat and Power (CHP) eCatalog



Fuel Flexible CHP Systems

- 43 recognized Packagers
- 28 Recognized Solution Providers
- 346 CHP Packages
  - 278 - Natural Gas/RNG
  - 46 - Digester Gas
  - 4 - Landfill Gas
  - 3 - Propane
  - 63 - Natural Gas/Hydrogen Blends (5 to 40%)
  - 5 - 100% Hydrogen

https://chp.ecatalog.ornl.gov/

Example Search: Digester Biogas Fueled CHP Systems in the eCatalog

AV Available | SP Solution Provider | AP Assurance Plan | CE Local Support | OD Outdoor Install | FP Within Footprint | %H_2 H_2 Blend Capable | # Installed | ★ Favorite

FLEXENERGY SOLUTIONS

GT333S DIGESTER GAS

Power Output:	330 kW
Thermal Output:	Hot Water Only
✔ Fuel:	Digester Gas
Prime Mover:	1x Microturbine
Grid Connection:	Black Start, Auto

AV — 11

FULL MATCH (100%)

AB A Better Way

ECOMAX 6 BIO 1.1 HW

Power Output:	624 kW
Thermal Output:	Hot Water Only
✔ Fuel:	Digester Gas
Prime Mover:	1x Reciprocating engine
Grid Connection:	Parallel Only

AV SP AP — 1245

FULL MATCH (100%)

CAT

CG170-20 POWER HEAT MAX CONTAINER BG

Power Output:	1,960 kW
Thermal Output:	Hot Water Only
✔ Fuel:	Digester Gas
Prime Mover:	1x Reciprocating engine
Grid Connection:	Black Start, Auto

AV — 169

FULL MATCH (100%)

Example Search: Hydrogen-Blend Fueled CHP Systems in the eCatalog

AV Available · SP Solution Provider · AP Assurance Plan · CE Local Support · OD Outdoor Install · FP Within Footprint · $\%H_2$ H_2 Blend Capable · # Installed · ★ Favorite

AGENITOR 406 NG

Power Output:	241 kW
Thermal Output:	Hot Water Only
Fuel:	Natural Gas
Prime Mover:	1x Reciprocating engine
Grid Connection:	Black Start, Auto

AV SP AP CE $\%H_2$ 3850

FULL MATCH (100%)

CHP2500 - G3520H HW

Power Output:	2,390 kW
Thermal Output:	Hot Water Only
Fuel:	Natural Gas
Prime Mover:	1x Reciprocating engine
Grid Connection:	Black Start, Auto

AV $\%H_2$ 169

FULL MATCH (100%)

Solar Turbines
A Caterpillar Company

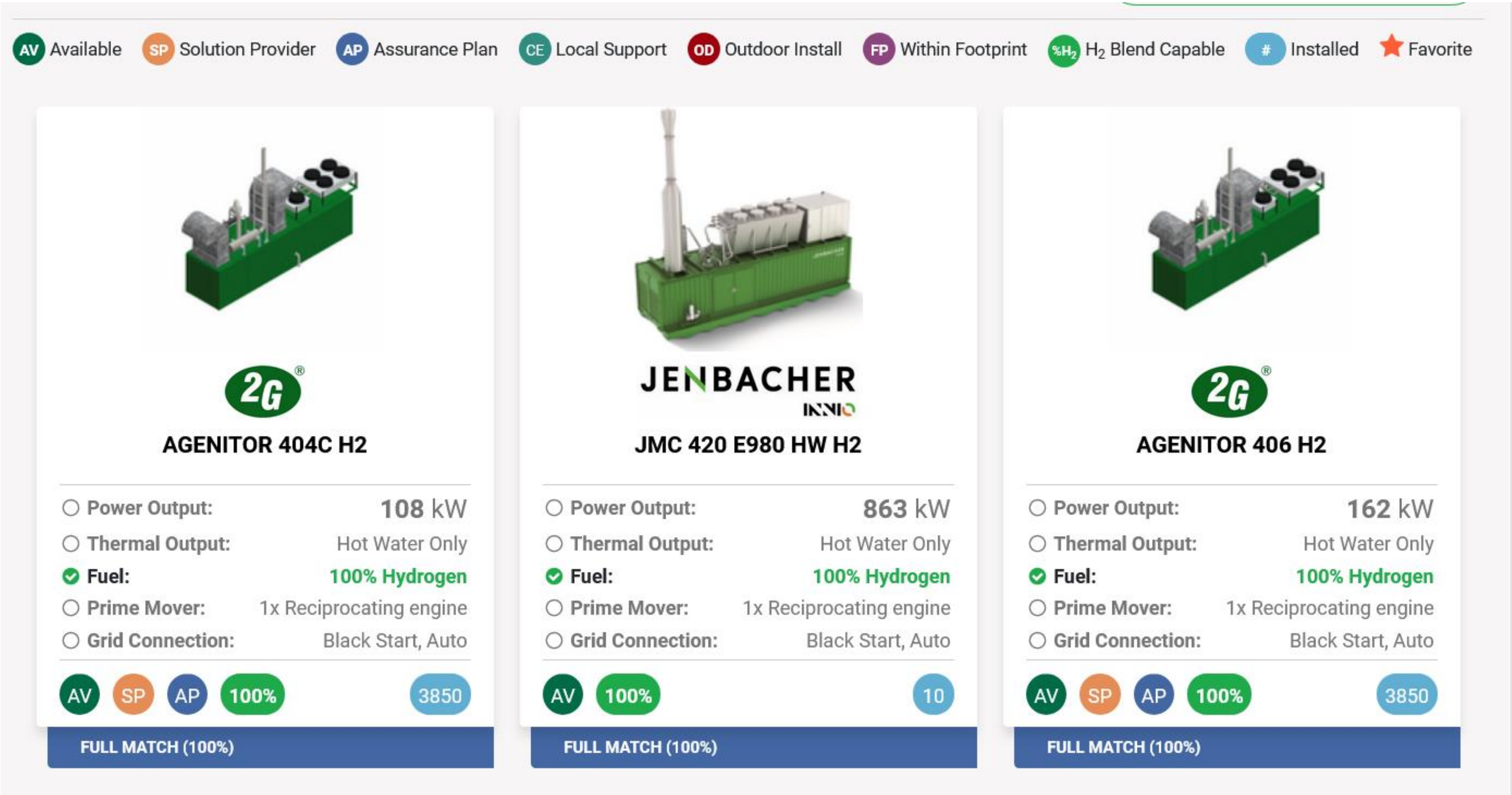
TAURUS 70

Power Output:	7,918 kW
Thermal Output:	Process Heat Only
Fuel:	Natural Gas
Prime Mover:	1x Combustion turbines
Grid Connection:	Black Start, Auto

AV $\%H_2$ 0

FULL MATCH (100%)

Example Search: 100% Hydrogen Fueled CHP Systems in the eCatalog



Case Studies of Hydrogen, and Direct Use Biogas and Landfill Gas Fueled CHP Systems

U.S. DEPARTMENT OF ENERGY

Case Studies of Hydrogen, Biogas, and Landfill Gas Fueled CHP Systems

- Hydrogen
  - Duke Energy / Clemson University – South Carolina
  - Eight Flags Energy CHP Plant – Florida
  - District Energy St. Paul - Minnesota
- Biogas [direct use]
  - Paul Bruner Water Pollution Control Plant - Indiana
  - Downers Grover Sanitary District – Illinois
  - St. Cloud Nutrient, Energy and Water (NEW) Recovery Facility– Minnesota
- Landfill Gas [direct use]
  - Gundersen Health - Wisconsin
  - GM Fort Wayne Assembly Plant – Indiana

Duke Energy / Clemson University
Clemson, South Carolina

The Duke Energy owned and operated CHP system at Clemson reduces emissions by 49,000 MT CO2e annually.

Project Snapshot: Utility Partnership Model

Application	Utility + College/University
Capacity	17.8 MW
Prime Mover	Gas Turbines & Steam Turbines
Fuel Type	Natural Gas / Hydrogen
Thermal Use	District Energy
Installation Year	2020

Project Highlights:

Clemson University, Duke Energy, and Siemens Energy partnered on a pilot project to study the use of green hydrogen for energy storage and as a low/no carbon fuel source for the CHP plant. The project, called H2-Orange, will evaluate hydrogen production, storage, and co-firing with natural gas. The 15 MW gas turbine is capable of up to 65% hydrogen.

Source: https://chptap.lbl.gov/profile/438/ClemsonUniversityDukeEnergy-Project_Profile.pdf

Project Testimonial

One of the primary goals in Clemson's Sustainability Plan is for the university to be "a model of energy sustainability" and become carbon neutral by 2030. Combined heat and power, and solar energy combined with various innovative energy storage strategies will play important and complementary roles in achieving this goal over this decade"
- Tony Putnam, Executive Director of Utility Services at Clemson University

"By locating generation sources near load centers with a high thermal demand, this results in one of the most efficient units in the Duke Energy fleet ."
- Zachary Kuznar, Managing Director of Regulated Renewables at Duke Energy

Eight Flags Energy CHP Plant Fernandina, Florida

CHESAPEAKE UTILITIES

Project Snapshot: CHP Hydrogen Test Program

Application	Pulp and Paper Mill
Capacity	23 MW
Prime Mover	Combustion Turbine
Fuel Type	Natural Gas (and hydrogen blending)
Thermal Use	Process Steam, Hot Water
Installation Year	2016

Source: https://www.youtube.com/watch?v=1UaNWrRBMpo

Project Highlights:

Chesapeake Utilities Corporation successfully blended hydrogen with natural gas to power the Company's Eight Flags Energy CHP. The Eight Flags CHP hydrogen test program was intended to refine the operational practices and requirements for safe transportation and injection of hydrogen into a distribution system.

Source: Chesapeake Utilities Corporation Completes Testing of Hydrogen Blending in Continued Move Toward Lower Carbon Energy Sources - Chesapeake Utilities Corporation

Project Testimonial

"Natural gas has been the obvious choice for years; blending hydrogen with natural gas provides even lower carbon impacts without sacrificing the qualities that make natural gas a desired industrial fuel choice."

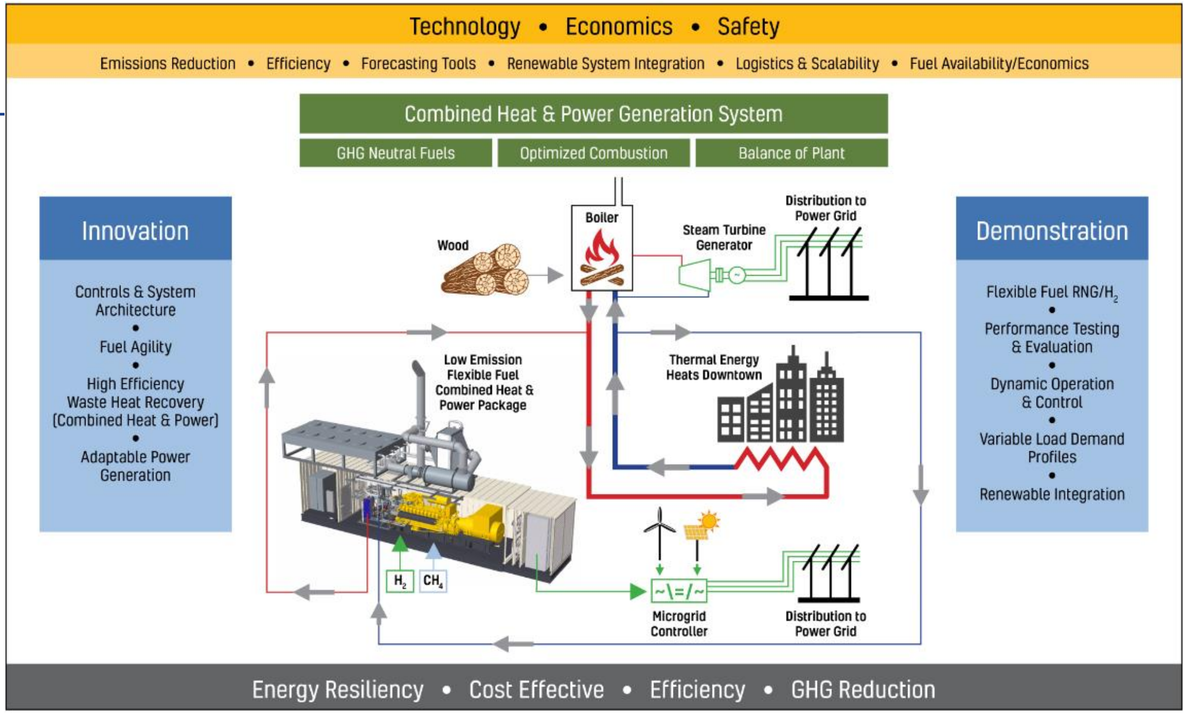
- Jeff Householder, President and CEO.

District Energy St. Paul (DESP)
St. Paul, Minnesota

DISTRICT ENERGY ST. PAUL™

Project Snapshot: Hydrogen Blending R&D Project

Application	Downtown District Energy System
Capacity	2 MW
Prime Mover	Reciprocating Engine
Fuel Type	Hydrogen or Hydrogen Blends
Thermal Use	Space Heating and Cooling
Installation Year	2025



Project Highlights:

Caterpillar Inc., the National Renewable Energy Laboratory (NREL), and District Energy St. Paul will demonstrate a 2MW flexible natural gas/hydrogen combined heat and power (CHP) system at a municipal generating station. This project will demonstrate natural gas/hydrogen flexible fuel CHP systems for stationary power applications.

Project Testimonial

"As a leading authority on CHP systems and the deployment of advanced energy technologies that promote sustainability, District Energy St. Paul is the ideal choice for hosting this demonstration. The project will help Caterpillar further extend our expertise in hydrogen-fueled power systems performing under the highest expectations of real-world applications."
- Jason Kaiser, VP for Caterpillar's Electric Power Division

Source: https://www.energy.gov/sites/default/files/2022-09/1.13%20-%20Singh.pdf

Paul L. Bruner Water Pollution Control Plant
Fort Wayne, Indiana

CITY UTILITIES
WATER THAT WORKS

Project Snapshot: Energy Neutral by 2030

Application	Wastewater Treatment Plant
Capacity	800 kW
Prime Mover	Reciprocating Engines
Fuel Type	Biogas
Thermal Use	Hot Water
Installation Year	2015

Project Highlights:

In October 2015, the operation of two 400 kW spark ignited, reciprocating engine / generator CHP systems began. The two units have operated, on average, at over 91% availability,
providing approximately 6,426,300 kWh annually, satisfying approximately 31.5% of the facility's electric requirements.

Source: https://chptap.ornl.gov/profile/179/Paul_L_Bruner_Water_Pollution_Control_Plant-Project_Profile.pdf

WPCP Anaerobic Digester Tanks
(Photo Courtesy of WPCP)

Two 400kW Engine Driven CHP Systems w/ Heat Recovery
(Photo Courtesy of WPCP)

Project Testimonial

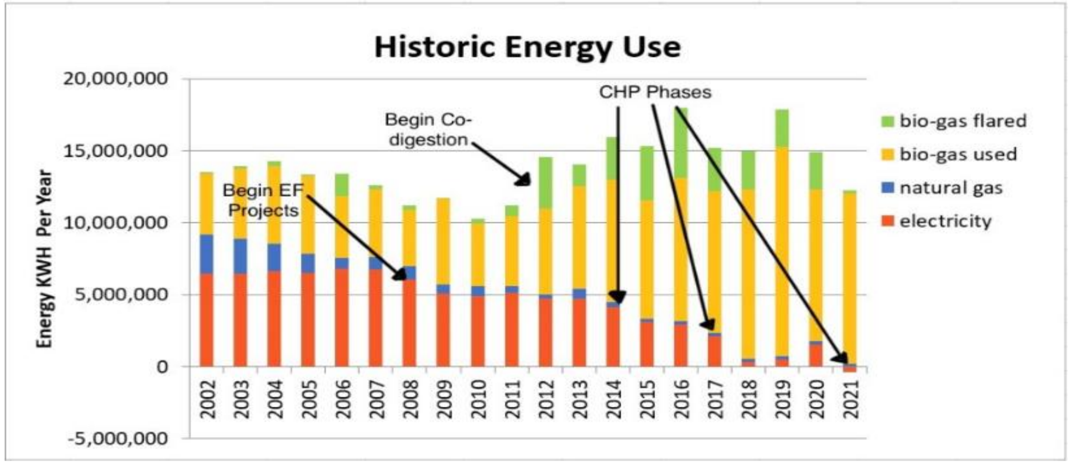
"The installation and operation of the CHP system has provided us both greater operating efficiency and resiliency, while launching our corporate efforts to become energy neutral".
- Douglas J Fasick, Chief Sustainability Officer, City of Fort Wayne

Downers Grove Sanitary District
Downers Grove, Illinois

Project Snapshot: Net Zero Energy Plant

Application	Wastewater Treatment Plant
Capacity	750 kW
Prime Mover	Reciprocating Engines
Fuel Type	Biogas and Co-Digesting FOG
Thermal Use	Hot Water
Installation Year	2014, 2017, 2021

375kW CHP Engine/Generator Set
Source: DGSD



Project Highlights:
The CHP system is fueled by anaerobic digester generated biogas. The renewable fuel is generated from the plant's five anaerobic digesters, three primary and two secondary, which are utilized to stabilize the sludge removed from the wastewater. The CHP system produces 3,254 kBtu/hr of thermal energy that is recovered in the form of hot water and utilized to keep the mesophilic anaerobic digesters at the proper operating temperature (95° to 98° F) to ensure maximum digester efficiency.

Project Testimonial
"The key to continued net zero energy operation at our plant is maintaining the high availability factor and trouble-free operation with our entire biogas fueled CHP system"
- Amy Underwood PE, General Manager, DGSD

Source: https://chptap.ornl.gov/profile/58/DownersGrove-Project_Profile.pdf

St. Cloud Nutrient, Energy and Water (NEW) Recovery Facility
St. Cloud, Minnesota

CITY OF ST.CLOUD MINNESOTA

Project Snapshot: Microgrid CHP System

Application	Wastewater Treatment Plant
Capacity	1.26 MW
Prime Mover	Reciprocating Engines
Fuel Type	Biogas (including co-digestion)
Thermal Use	Hot Water
Installation Year	2016

CHP Units 1 and 2 – Total 1.26 MW Biogas Fueled
Source: St. Cloud NEW Recovery Facility

220 kW (left, installed 2017) and 240 kW (right, installed 2020) Solar Arrays
Source: St. Cloud NEW Recovery Facility

Project Highlights:

By achieving their net zero energy goal, the local utility generated power now serves as a backup to the onsite generated renewable power (CHP and solar arrays). Through the effective use of the biogas fueled CHP system, the NEW Recovery Facility is removing over 8.5 million pounds of CO_2 annually from the atmosphere

Project Testimonial

"Generating our own power on-site through the use of biogas from our digesters to fuel our CHP system has improved electric service reliability while significantly reducing our natural gas costs."
- Emma Larson, Assistant Public Utility Director

Source: https://chptap.ornl.gov/profile/477/St_Cloud_Nutrient_Energy_and_Water_Recovery_Facility-Project_Profile.pdf

Gundersen Health System
Onalaska, Wisconsin

GUNDERSEN HEALTH SYSTEM®

Project Snapshot: Landfill Gas-to-Energy System

Application	Healthcare
Capacity	1,137 kW
Prime Mover	Reciprocating Engine
Fuel Type	Landfill Gas
Thermal Use	Space Heating/Cooling, Hot Water
Installation Year	2012/2016

CHP Engine Generator Set with Heat Recovery and Gas Clean Up
Source: DOE CHP TAP

Project Highlights:

A landfill gas collection system was already in place at the La Crosse County landfill, located 1.5 miles from the clinic and was collecting an average of 300 cubic feet of landfill gas per minute that was subsequently flared. Recognizing an available resource, Gundersen teamed up with La Crosse County to explore a public-private partnership to develop a landfill gas-to-energy project.

Project Testimonial

"The project (cost) is paying back quite nicely because it's off-setting a big portion of our electricity bill as well as our natural gas bill and we're providing a revenue stream for the county."
- Jeff Rich, Executive Director, GL Envision, Gundersen Health System

"This is a good use of a previously unused natural resource and it is an excellent example of what a public-private partnership can achieve in our community."
- Hank Koch, Solid Waste Director, La Crosse County

Source: https://chptap.ornl.gov/profile/92/GundersenOnalaska-Project_Profile.pdf

GM Fort Wayne Assembly Plant
Fort Wayne, Indiana

GM

Project Snapshot: LFG CHP – DOE Better Project Award

Application	Manufacturing
Capacity	1,600 kW
Prime Mover	Reciprocating Engines
Fuel Type	Landfill Gas
Thermal Use	Space Heating/Cooling
Installation Year	2020

Project Highlights:
The plant educed its carbon emissions by 30% since 2019 with a recently-added CHP system. Heat recovery units were added to existing landfill gas powered generators and now 80% of the site's building heating needs are met by the recovered waste heat. The site achieved savings of over 140,000 metric tons of CO2 equivalent since the addition of heat recovery in 2023.

Source: https://chpalliance.org/wp-content/uploads/2019/08/DOE-IEDO_Meegan-Kelly.pdf

Project Testimonial
"As a Better Climate Challenge Goal Achiever, GM has reduced its greenhouse gas emissions by 50% and is sharing its successful strategies with others. Learning from leaders is key to accelerating the clean energy economy of the future."
- Jeff Marootian, Principal Deputy Assistant Secretary for Energy Efficiency and Renewable Energy

Questions?

U.S. DEPARTMENT OF ENERGY

Kahoot and Q&A

Please use your phones to join our fun Kahoot game, testing your CHP Virtual Training Session #2 knowledge.

Thank you!