

Zero by 40 Technoeconomic Assessment

Final Report | September 2025



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Zero by 40 Technoeconomic Assessment

Final Report

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New York State Energy Research and Development Authority

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Preferred Citation

New York State Energy and Research Development Authority (NYSERDA). 2025. “Zero by 40 Technoeconomic Assessment, Final Report.” Prepared by Electric Power Research Institute, Palo Alto, CA. nysesda.ny.gov/publications

Abstract

This report evaluates seven candidate dispatchable emissions free resources (DEFRs) that could provide clean, firm power to the New York State grid. The candidate resources include Hydrogen, Biofuels, Advanced Nuclear, Carbon Capture and Storage, Next-Generation Geothermal, Long-Duration Energy Storage, and Virtual Power Plants. The evaluation assesses each resource based on its performance attributes, readiness for 2040, emissions, cost, and other considerations. Each technology is individually discussed in its designated chapter and compared to other technologies in the Resource Comparison chapter. Each technology presents both advantages and challenges, requiring innovation and deployment support to scale up and help achieve a zero-emissions grid by 2040. Each technology can make valuable contributions to the grid.

Keywords

0x40, 2040, biofuels, carbon capture and storage, dispatchable emissions free resources, DEFR, electricity, firm, geothermal, hydrogen, long-duration energy storage, nuclear, performance attributes, readiness, renewable diesel, renewable natural gas, virtual power plants, zero emissions

Acknowledgements

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We would like to acknowledge the contributions from NYSERDA and the New York Department of Public Service (DPS). The NYSERDA and DPS teams provided guidance, review, and strategic prioritization for this project.

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We would also like to acknowledge the contributions from the National Renewable Energy Lab (NREL). The NREL team conducted modeling to estimate hydrogen prices in a New York-specific context and provided valuable insights into the logistics associated with hydrogen transport and storage.

NREL Contributors:

Joe Brauch, Yijin Li, Jesse Cruce, Laura Vimmerstedt

We would also like to acknowledge the contributions from Energy and Environmental Economics (E3). The E3 team developed a tool for estimating the biofuel supply, demand, and prices, which were central to the biofuels chapter of this study. The E3 team also supported the integration of modeling assumptions and findings from the *2025 Draft State Energy Plan*.

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Finally, we would like to acknowledge the many external experts who offered their time and expertise in conversations with the EPRI and NYSERDA teams over the course of the research process. The information and perspectives gained from these discussions helped shape the insights and findings of this report.

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Acronyms and Abbreviations

AACE	American Association of Cost Engineering
AC	alternating current
A-CAES	adiabatic compressed air energy storage
AD	anaerobic digestion
AMI	advanced metering infrastructure
AR	advanced reactor
ARDP	Advanced Reactor Demonstration Program
ASME	American Society of Mechanical Engineers
ASSBs	all-solid-state batteries
ATB	Annual Technology Baseline
ATJ	alcohol-to-jet
BECCS	bioenergy with carbon capture and storage
BESS	battery energy storage system
BOAK	between first- and Nth-of-a-kind
BTM	behind-the-meter
BWR	boiling-water reactors
C&I	commercial and industrial
CAES	compressed air energy storage
CAPEX	capital expenses
CCS	carbon capture and storage
CF	capacity factor
CfD	Contracts for Difference

CH ₄	methane
CLGS	closed-loop geothermal systems
Climate Act	Climate Leadership and Community Protection Act
CO	carbon monoxide
CO ₂	carbon dioxide
CO ₂ e	carbon dioxide equivalent
COL	Combined Operating License
CP	construction permit
CPUC	California Public Utilities Commission
CT	combustion turbine
CWA	Clean Water Act
DEC	New York State Department of Environmental Conservation
DEFRs	dispatchable emissions-free resources
DEP	New York City Department of Environmental Protection
DERMS	distributed energy resources management system
DERs	distributed energy resources
DiD	defense-in-depth
DLE	dry low-emission
DLN	dry low nitrogen oxides
DOD	U.S. Department of Defense
DOE	U.S. Department of Energy
DPN3	Distributed Network Protocol version 3
DPS	New York State Department of Public Service
DR	demand response
DSO	distribution system operator
ECCS	Emergency Core Cooling System
EGS	enhanced geothermal systems
EIA	U. S. Energy Information Administration
EOL	end-of-life
EOR	enhanced oil recovery
EPA	U. S. Environmental Protection Agency
EPC	engineering, procurement, and construction
EPRI	Electric Power Research Institute
EPZ	Emergency Planning Zone
ESP	Early Site Permit
EV	electric vehicle
Fe	iron
FEED	front-end engineering design
FEOC	Foreign Entities of Concern

FERC	Federal Energy Regulatory Commission
FHR	fluoride-salt-cooled high-temperature reactor
FOAK	first-of-a-kind
FORGE	Frontier Observatory for Research in Geothermal Energy
FT	Fischer-Tropsch
GA-EMS	General Atomics Electromagnetic Systems
GDE	gas diffusion electrode
GE	General Electric
GFM	grid-forming
GFR	gas-cooled fast reactors
GHG	greenhouse gas
gpm	gallons per minute
GSHPs	ground source heat pumps
Gt	gigatonnes
Gt-CO ₂	gigatonnes of carbon dioxide
GW	gigawatt
GWe	gigawatts electric
GWh	gigawatt-hour
GWP	global warming potential
GWP20	20-year global warming potential
H ₂	hydrogen
H ₂ O	water
H ₂ S	hydrogen sulfide
ha	hectares
HALEU	high-assay low-enriched uranium
HAZMAT	hazardous materials
HDSAM	Hydrogen Delivery Scenario Analysis Model
HEMS	Home Energy Management Systems
HHV	high heat value
HLW	high-level waste
HTGR	high-temperature gas reactor
HVAC	heating, ventilation, and air conditioning
HYPSTAT	Hydrogen Production, Storage, and Transmission Analysis Tool
IAEA	International Atomic Energy Agency
IEA	International Energy Agency
IEEFA	Institute for Energy Economics and Financial Analysis
INPO	Institute of Nuclear Power Operations
IRA	Inflation Reduction Act of 2022
IS	induced seismicity

ISO	independent operator system
ITER	International Thermonuclear Experimental Reactor
kg	kilogram
km	kilometers
KOH	potassium hydroxide
kW	kilowatt
kWh	kilowatt-hour
kWh/kg	kilowatt-hours per kilogram
LAES	liquid air energy storage
lb	pounds
LCA	life-cycle assessment
LCFS	Low Carbon Fuel Standard
LCOE	levelized cost of energy
LCOH	levelized cost of hydrogen
LCOS	levelized cost of storage
LDES	long-duration energy storage
LEU	low-enriched uranium
LFR	lead-cooled fast reactor
LHV	lower heating value
Li	lithium
LIB	lithium-ion battery
LLRW	low-level radioactive waste
LLWRs	large light water reactors
LP	low pressure
LPO	Loan Programs Office
LWA	Limited Work Authorization
LWRs	light water reactors
lwSMRs	light water small modular reactors
M&V	measurement and verification
m ²	square meters
m ³	cubic meters
MACRS	Modified Accelerated Capital Recovery System
MCFR	molten chloride fast reactor
MHI	Mitsubishi Heavy Industries
MIT	Massachusetts Institute of Technology
MMBtu	million British thermal units
MMBtu/Kg	million British thermal units per kilogram
MMT	million metric tons
mol%	mole percent

MOU	memorandum of understanding
MSR	molten salt reactor
mSv	millisieverts
MSW	municipal solid waste
MW	megawatt
MWe	megawatt electric
MWh	megawatt-hour
MWt	megawatt thermal
N ₂	nitrogen gas
N ₂ O	nitrous oxide
NaS	sodium-sulfur
NASA	National Aeronautics and Space Administration
NCR	U.S. Nuclear Regulatory Commission
NETL	National Energy Technology Laboratory
NG	natural gas
NGCC	natural gas combined cycle
NH ₃	ammonia
NO ₂	nitrogen dioxide
NOAK	Nth-of-a-kind
NO _x	nitrogen oxides
NRC	U.S. Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NWA	nonwires alternatives
NYCA	New York Control Area
NYISO	New York Independent Operator System
NYPA	New York Power Authority
NYS	New York State
NYSERDA	New York State Energy Research and Development Authority
O&M	operations and management
O ₂	oxygen
OCED	Office of Clean Energy Demonstrations
OEM	original equipment manufacturers
OH-	hydroxide
OH	hydroxyl radicals
OL	Operating License
OPEX	Operating Expenses
PANYNJ	Port Authority of New York and New Jersey
PCMs	phase-change materials
PDC	polycrystalline diamond carbide

PEM	proton exchange membrane
PFES	Prohibited Foreign Entities
PHES	Pumped Hydroelectric Energy Storage
PM	particulate matter
ppmv	parts per million by volume
PSC	New York State Public Service Commission
PSH	pumped storage hydropower
psi	pounds per square inch
PTL	power-to-liquid processing
PV	photovoltaic
PWA	prevailing wage and apprenticeship
PWR	pressurized-water reactors
R&D	research and development
RD	renewable diesel
RNG	renewable natural gas
RPVs	reactor pressure vessels
RTE	round-trip efficiency
RTOs	regional transmission organizations
SAF	sustainable aviation fuel
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCR	selective catalytic reduction
SDC	Standard Design Certification
SFR	sodium-cooled fast reactor
SHR	superhot rock geothermal
SIB	sodium-ion batteries
SMR	small modular reactor
SMR	steam methane reforming
SNF	spent nuclear fuel
SO ₂	sulfur dioxide
SOC	state-of-charge
SOEC	solid oxide electrolysis cell
SO _x	sulfur oxide
syngas	synthetic gas
t	metric ton
TES	thermal energy storage
tonnes/day	tonnes per day
TOU	time-of-use
TPV	thermophotovoltaic

TRISO	tristructural isotropic
TRL	Technology Readiness Level
TVA	Tennessee Valley Authority
TWh	terawatt-hours
UIC	Underground Injection Control
USD	U.S. dollars
v	volt
V2G	vehicle-to-grid
VLA	vented lead acid
VOC	volatile organic compound
VPPs	virtual power plants
VRLA	valve-regulated lead acid
VVER	Vodo-Vodyanoi Energetichesky Reaktor
WACC	weighted average cost of capital
WHO	World Health Organization
WWTP	wastewater treatment plant
Zn	zinc
ZnBr	zinc-bromide

Summary

In May 2023, the New York State (NYS) Public Service Commission (PSC) issued an order initiating a process “to identify technologies that can close the gap between the capabilities of existing renewable energy technologies and future system reliability needs, and more broadly identify the actions needed to pursue attainment of [New York State’s] Zero Emission by 2040 target.” New York State has engaged in this process by conducting a study to evaluate candidate technologies that could close the gap.

A 2040 zero-emission grid will require resources with a mix of attributes to maintain reliability requirements. These include resources that can provide energy and capacity for long durations, that are dispatchable and flexible with quick-start and fast ramping capabilities over multiple starts in a day, and that can provide inertial response, frequency control, dynamic reactive control, and high short circuit current contribution to the grid. Every resource does not need to provide every attribute, but the grid needs enough of each to maintain reliability.

Meeting these needs will require a diverse set of resources. This includes intermittent zero-emission energy resources such as solar and land-based and offshore wind, short-duration energy storage, legacy resources like hydropower and existing nuclear, dispatchable emissions free resources (DEFRs), transmission infrastructure, and other technologies that can provide grid services, like grid-forming (GFM) inverters. This report focuses on DEFRs.

This report evaluates seven candidate DEFR technology categories that could provide clean, firm power to the NYS grid to achieve a zero-emissions power sector. The candidate resources include hydrogen, biofuels (such as renewable natural gas [RNG] and renewable diesel [RD]), advanced nuclear, carbon capture and storage on thermal power plants, next-generation geothermal, long-duration energy storage (LDES), and virtual power plants (VPPs).

Given that these technologies are not currently deployed at scale, each is expected to require a varying degree of innovation and deployment support. However, all of these technologies can still contribute usefully to the grid, and any present challenges faced by an individual technology should not exclude it from consideration. Even as certain technologies may see structural deployment obstacles in some regions—for example, near urban settings—smaller and more targeted deployments remain possible.

To continue reliably serving New York State’s energy needs, the State will need to deploy resources with more limited infrastructure barriers in the near term. Technologies that require significant infrastructure build, such as new pipelines, fuel storage facilities, and additional transmission, add costs and complexity. Therefore, resources with fewer infrastructure needs will play a crucial role in reliably and cost-effectively providing zero-emission electricity.

Each resource has characteristics that make it better suited for some use cases over others.

Figures S-1 and S-2 show how these candidate resources were classified for comparison in this report. This classification is based on resource performance, as well as technology-specific supply, cost, and emission constraints that could affect availability. This resource classification approach is a simplification—in some configurations, technologies could fit into multiple classes.

Figure S-1. Candidate Technologies to Provide Clean, Firm Power in New York State

Technologies are grouped by their most likely use cases, although some configurations or technologies may span multiple categories.

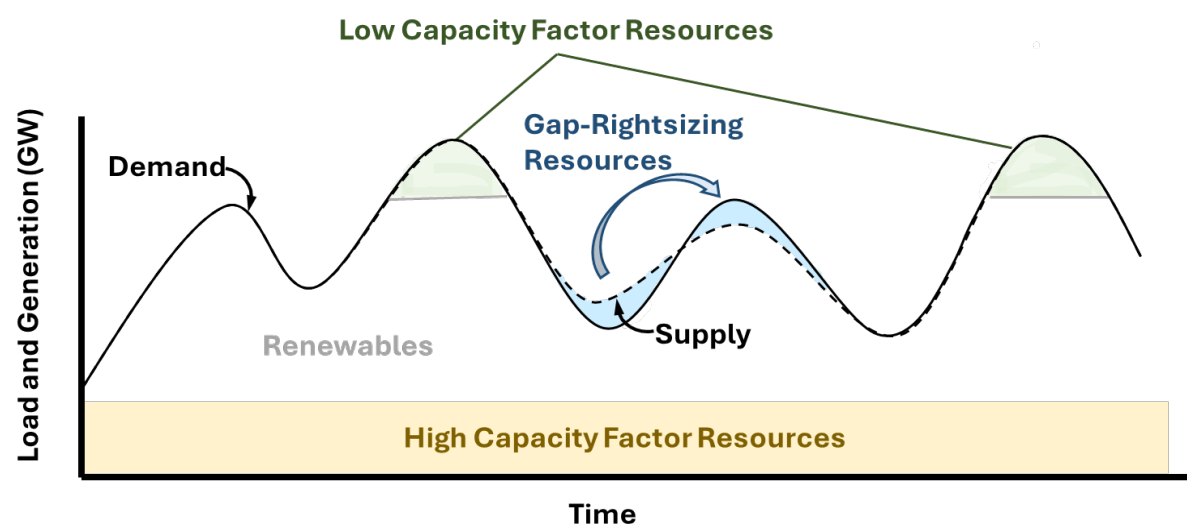
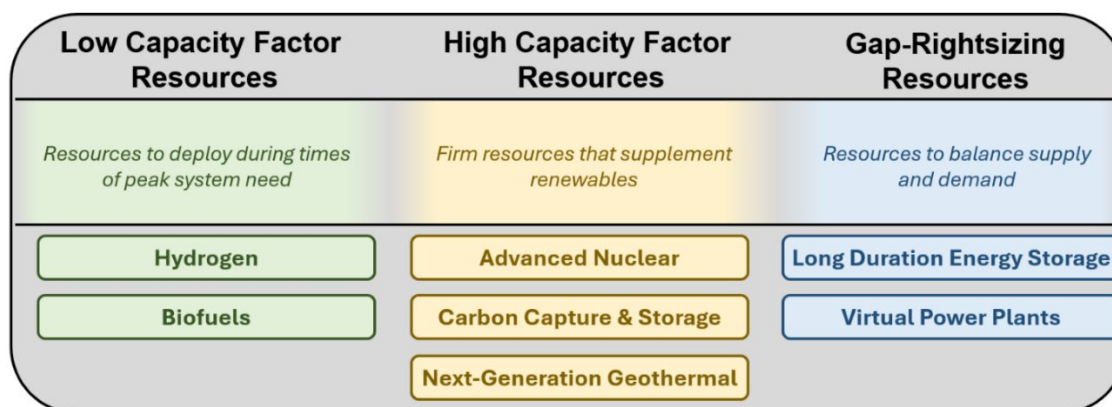


Figure S-2. Functional Categories of Clean Firm and Enabling Resources



- **Low capacity factor resources** such as hydrogen and biofuels like renewable natural gas and renewable diesel have low capital-to-operating cost ratios, which means that their cost of fuel primarily drives their cost of power generation. These resources offer reliable and fast ramping capabilities but may have a limited and more expensive fuel supply, making them best suited for meeting peak system needs.
- **High capacity factor resources** such as Nuclear, Carbon Capture and Storage on Thermal Power Plants, and Geothermal have high capital-to-operating cost ratios, which makes them more economical to deploy at high capacity factors. These technologies provide reliable, firm, baseload power that can meet demand growth and supplement renewables, but they tend to be less flexible.
- **Gap-rightsizing resources** such as LDES and VPPs can, respectively, shift supply from periods of low demand to periods of high demand and flatten the load curve by shifting peak load to times of lower demand. These resources do not generate new electricity but they can reduce the need to build new generation assets. They can be fast ramping, highly dispatchable, and modular, but are duration-limited.

S.1 Low Capacity Factor Resources

Low capacity factor resources offer the advantage of being highly flexible, duration-unlimited (provided fuel is available), and responsive to varying grid needs. They are expected to be needed for any future grid. However, their use will likely be limited due to high delivered fuel costs and limited fuel supply.

S.1.1 Hydrogen

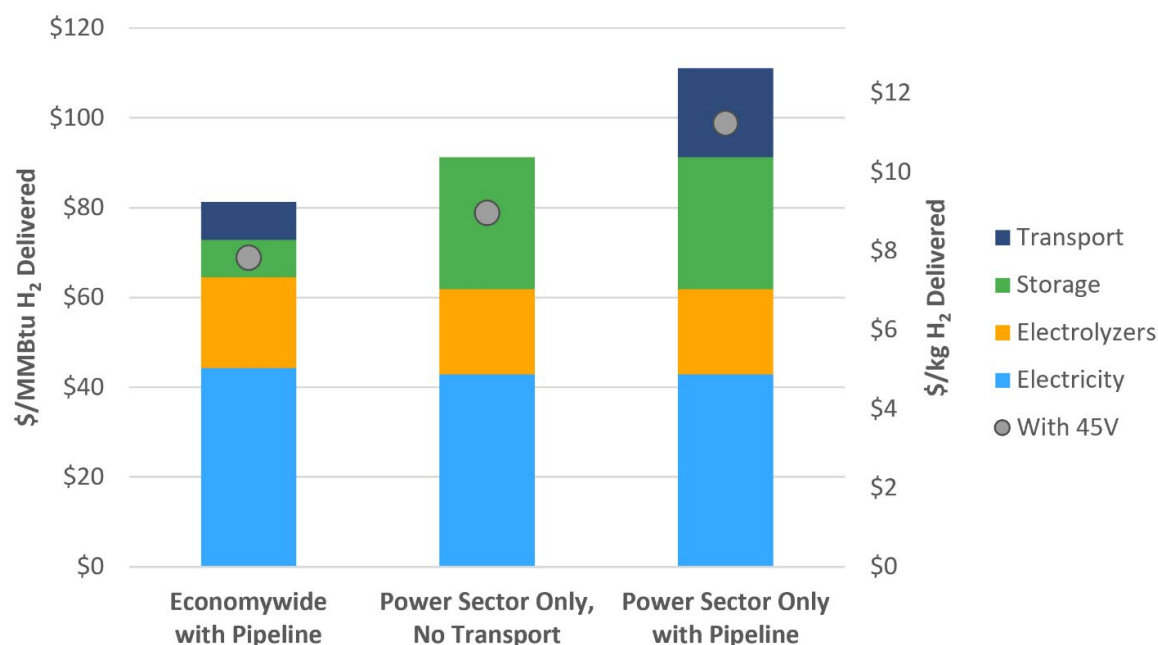
Hydrogen (H₂) is an alternative fuel that has long-term potential as a zero-to-low-carbon energy resource. H₂ can be produced through various processes that have different technology readiness levels, costs, emissions, and infrastructure implications. This report focuses on H₂ produced via electrolysis: “green H₂” if produced with renewable electricity or “pink H₂” if produced with nuclear electricity, and H₂ produced via steam methane reforming with carbon capture and storage (CCS): “blue H₂,” as the most likely low-carbon H₂ sources for a 2040 NYS power sector. H₂ is also expected to play a pivotal role in the decarbonization of other sectors such as heavy-duty transportation and industrial processes.

Power generation with H₂ can be achieved with turbines, fuel cells, or linear generators. Existing natural gas (NG) turbine sites could be leveraged for H₂ combustion, but will require retrofitting to become compatible with 100% H₂ firing. Fuel cells offer higher efficiency than turbines and are more modular, but face supply chain constraints, high cost uncertainty, and high H₂ purity requirements. Linear generators are fuel-flexible and modular, but this technology is less mature and, as a result, less ready compared to turbines and fuel cells.

H₂ viability is dependent on building out transportation and storage infrastructure. A major challenge for H₂ deployment is the development of storage and transportation infrastructure needed to ensure H₂ is available to generators when needed. Hydrogen costs are heavily influenced by the infrastructure deployed (Figure S-3). The most practical and economical way to supply the amount of H₂ required to meet statewide power sector needs is a shared system for H₂ production, bulk underground storage, and pipeline transport that is driven by multisector hydrogen demand (Figure S-3, left). If the bulk storage and pipelines are developed and used only by the power sector, as could be the case if other sectors lag in adoption, costs would meaningfully increase due to lower utilization and highly seasonal demand (Figure S-3, right). While pipelines are the most cost-effective method for transporting the necessary volume of hydrogen, they face significant permitting hurdles, long lead times, and siting constraints that render them an unlikely solution for 2040. Some Upstate New York demand could be met without a pipeline if H₂ production and bulk storage were co-located with power generation such that no H₂ transport is needed (Figure S-3, middle). Federal production tax credits, such as the Clean Hydrogen Production Tax Credit, Section 45V (Clean Hydrogen Credit), which had significantly lowered estimated hydrogen costs, are now being phased out earlier, which limits their potential applicability in and beyond 2040 to only projects that can begin construction by the end of 2027.

Figure S-3. Key Drivers of Green Hydrogen Cost: Electricity, Transport, Storage

Full tax credit eligibility requires construction to start before the credit phaseout date. Prices reported in 2023 USD.



In the absence of a pipeline, the logistics and costs associated with serving statewide reliability needs with hydrogen are potentially prohibitive. New pipelines require regulatory, siting, and permitting procedures and can have long construction timelines. In the absence of a pipeline, the modular transport (trucks, barges) and on-site storage (aboveground tanks) requirements to meet downstate needs create considerable logistical challenges. While blending H₂ into existing natural gas pipelines could lower initial deployment barriers by leveraging existing infrastructure to enable supply growth, the existing infrastructure is not designed to handle substantial quantities of hydrogen. Blending any meaningful amount of hydrogen would require a comprehensive compatibility assessment of safety, air quality, and reliability risks. For these reasons, according to the *2025 Draft State Energy Plan*, New York State does not currently support the blending of hydrogen into the existing natural gas pipeline system. Blending would also require an attribute tracking mechanism. Significant advancements in de-blending technologies would be needed to realize local improvements in co-pollutant emissions and air quality.

H₂ appears to hold greater near-term opportunities in Upstate New York, where opportunities to leverage low-cost and potentially curtailed renewables and co-locate production with geologic storage offer lower costs and fewer space constraints.

The scale of green H₂ production in 2040 will depend on renewable electricity availability. As electricity demand grows and aging fossil generators are retired, a rapid buildout of renewables will be required to produce hydrogen on top of meeting the growing grid demand. Hydrogen production using nuclear electricity (pink H₂) or steam methane reforming (SMR) with carbon capture (blue H₂) could unlock additional H₂ supply. However, blue H₂ generates significant upstream greenhouse gas (GHG) emissions, impacting the emissions contributions in New York State based on the Climate Leadership and Community Protection Act (Climate Act) accounting requirements.

The cost of hydrogen remains highly uncertain but is expected to be significantly higher than the cost of NG. The cost of renewable electricity and infrastructure largely drives the cost of green hydrogen. Lower-cost H₂ could be unlocked by leveraging otherwise curtailed renewables, but this use case is limited by low curtailed energy availability and challenging electrolyzer economics due to low utilization. Pipelines are the lowest cost option for transporting large volumes of hydrogen but are unlikely to be a viable statewide solution for 2040. In the absence of pipelines, there is additional upward uncertainty in hydrogen fuel cost due to the need for modular transport and onsite storage solutions. The cost of blue H₂ is estimated to be lower than that of green H₂ produced in New York State, but is still expected to be significantly more expensive than NG. Full Carbon Capture and Sequestration Tax Credits, Section 45Q (Carbon Capture Credits), are available to blue hydrogen projects that begin construction before 2033, which can lower costs.

Use of H₂ in a combustion turbine (CT) could generate nitrogen oxides (NO_x) emissions similar to those of a natural-gas-fired plant, while use of H₂ in a fuel cell or linear generator will have significantly lower NO_x emissions. However, in all cases, NO_x emissions are likely to fall on a total annual basis because a H₂ plant would be expected to operate at a lower capacity factor than a current NG plant, improving air quality for neighboring communities.

S.1.2 Biofuels

Biofuels are carbon-based fuels derived from renewable feedstocks that produce fewer net emissions relative to fossil fuels. These fuels are expected to be critical to the decarbonization of many hard-to-electrify sectors, including transportation, supplemental heating, and industry, but could also be useful for the power sector.

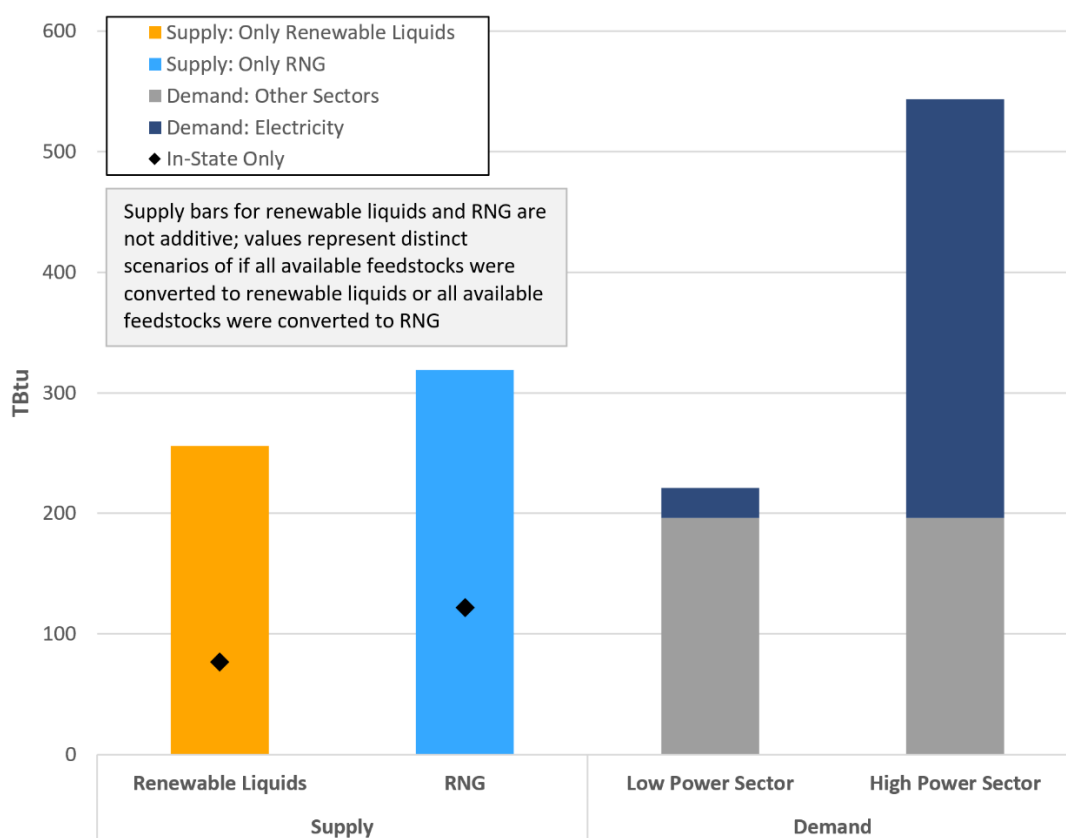
The biofuels most relevant to the power sector are RNG and RD because they are drop-in replacements for NG and fossil distillate.

RNG and RD can be produced from a variety of feedstocks that have different fuel production pathways, emissions implications, land-use implications, and infrastructure requirements.

Candidate feedstocks include waste-based feedstocks, such as landfill gas, wastewater, manure, food waste, and municipal solid waste (MSW), as well as plant-based feedstocks, including agricultural or forest residues and purpose-grown energy crops or trees. Each feedstock will require the development of aggregation mechanisms to collect them for upgrading to fuel.

RNG has relatively few infrastructure hurdles, but it is sourced from limited feedstocks that are also required for the decarbonization of other sectors. RNG is a drop-in alternative to NG and can therefore use existing NG pipelines and generators without retrofit. RNG is particularly appealing for Downstate deployment, where building new infrastructure is complex and space is limited. RNG can be produced from both anaerobic digestion (AD) and thermal gasification/methanation. Thermal gasification/methanation is currently at a lower readiness level than AD, requiring both technological and commercial advancement for market readiness before 2040. Based on an assessment of available feedstocks, both of these RNG production pathways, as well as access to non-NYS-based regional feedstock supplies, would be required to generate enough RNG to meet both peaking power sector demand and other sector demand (Figure S-4). As shown in Figure S-4, based on the feedstock supply assumptions in this study, RNG is most likely to serve as a peaking resource due to limitations of current feedstock sources.

Figure S-4. Supply and Demand Dynamics for Alternative Fuels



The use of RNG in the power sector has both local and statewide emissions consequences. Under the Climate Act’s gross accounting methodology, the point-of-use emissions per unit of electricity of NG and RNG are similar. Due to high costs and feedstock constraints as well as the increased renewable deployment underway, these plants are expected to operate at lower capacity factors than today, which would lead to reduced emissions and improved air quality. Under the NYS gross emissions accounting framework, using RNG as a peaking-only asset could result in approximately 1.9 million metric tons (MMT) of gross carbon dioxide equivalent (CO₂e) emissions in 2040, which is small relative to the 2050 limit of 62 MMT. If the role of RNG were to grow to be more of a baseload resource, gross emissions would total a more significant 16.2 MMT of gross CO₂e emissions, which is likely not viable under the 2050 economywide gross emission limit, given emissions from other difficult-to-decarbonize sectors. If fuel cells were used instead of CTs, these gross emissions would be meaningfully lower due to their higher efficiencies. In contrast, under the NYS net accounting framework and under IPCC accounting conventions, RNG has zero or close to zero net emissions. If RNG is blended with NG to leverage existing gas infrastructure, an attribute tracking mechanism would be required to appropriately account for emissions.

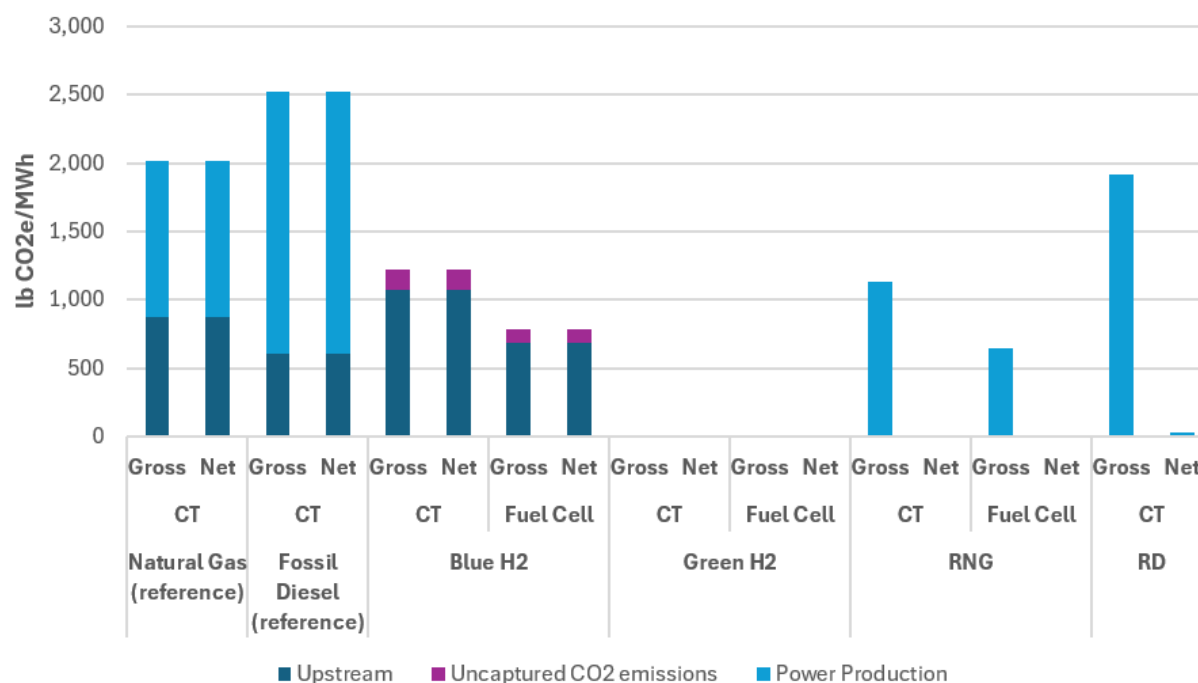
RD is a drop-in replacement for fossil distillate that is promising as a backup fuel for reliability needs, similar to the use of distillate in dual-fuel generating units today. RD holds an advantage of high energy density and existing transport and storage infrastructure. RD may be particularly important as the electric system eventually becomes winter-peaking with expected heating load electrification. Developing RD supply chains would also benefit other sectors that require renewable liquids. However, RD use in a CT has more than 65% higher gross GHG emissions on a per-megawatt-hour (MWh) basis than RNG, due to its lower heating value and resultant reduced plant efficiency. RD also has increased co-pollutant emissions compared to RNG, but is similar to fossil distillate.

The cost of RNG and RD will depend on the type of feedstock used to produce the fuel. Low-cost feedstocks for biofuel production include landfill gas and wastewater, while higher-cost feedstocks include municipal solid waste, energy crops, and agricultural residues. RNG cost will depend on the feedstock, but is expected to be significantly more expensive than NG. Similarly, the cost of RD depends on the feedstock and is expected to be significantly more expensive than fossil distillate. As lower-cost feedstocks are fully expended with demand from the power sector and other uses, biofuel prices may increase as production shifts to higher-cost feedstocks.

S.1.3 Tradeoffs: Low Capacity Factor Resources

Emissions impacts vary across the H₂ and biofuel resources. Electrolytic H₂ has no upstream or power production GHG emissions when produced from zero-emissions sources such as renewables or nuclear power. In contrast, under the NYS emissions accounting framework, blue H₂, RNG, and RD all produce gross GHG emissions (Figure S-5). Depending on the feedstock, RNG production can help reduce emissions in other sectors such as waste or agriculture. All fuels considered produce NO_x emissions during combustion. NO_x emissions can be managed with existing emission control technologies. RNG and RD also produce particulate matter (PM) that can impact local air quality; however, these emissions are mitigated with existing emission control technologies. If RNG and RD are used only for peaking, local air quality improvements are still likely compared to the current use of combustion resources.

Figure S-5. Gross and Net Power Sector Greenhouse Gas Emissions from H₂ and Biofuel-Fired Plants

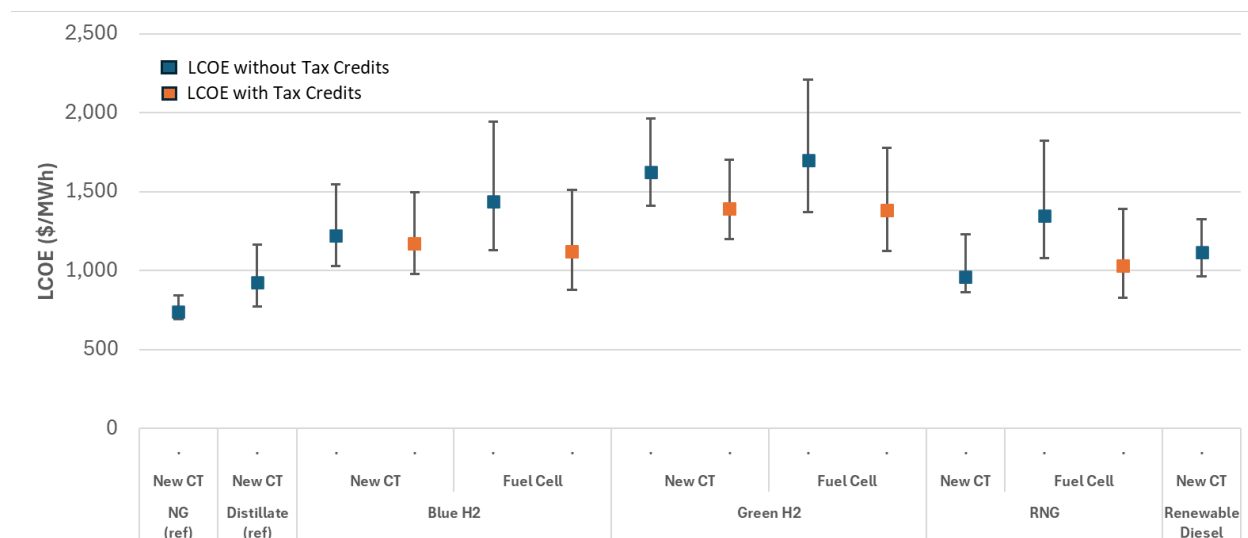


RNG is likely to be less expensive than green H₂ and has fewer infrastructure and permitting hurdles. RNG, classifiable as a drop-in fuel, can leverage existing infrastructure for transport and storage. The higher costs of H₂ from electrolysis are primarily driven by the cost of electricity and infrastructure needs. Some H₂ may be available at a low cost by leveraging otherwise curtailed renewables and siting near storage, but the economywide demand would still exceed potential supply from curtailed renewables. RNG prices are expected to be lower than H₂ but still higher than NG prices and will be highly dependent on economywide demand for different feedstocks.

Any resource that operates at a very low capacity factor will have a high levelized cost of energy (LCOE), but H₂ and biofuels face higher LCOEs largely due to increased fuel prices. Resources that run at low capacity factors have high LCOEs as capital costs are spread out over fewer hours. This is the case for NG peaker plants as well (Figure S-6). Even in today's system, peak hours see significantly elevated energy prices. While some capital expenses can be avoided by leveraging existing plants, those savings are not permanent because the plant will eventually need to be replaced. However, minimizing use through the deployment of complementary resources can help to mitigate system cost impacts from higher fuel prices.

Figure S-6. Levelized Cost of Electricity Comparison for New Build Fossil Fuel, Hydrogen, and Biofuel Power Plants

Full tax credit eligibility requires construction to start before the credit phaseout date. Prices reported in 2023 USD.



Both fuels will have near-term availability constraints, but H₂ availability has the potential to grow larger than biofuel availability over time. Feedstock quantities, limited by current waste streams and land use, and competition from other end uses, will determine biofuel availability for the power sector. As such, biofuel costs have the potential to increase with demand as the lower-cost feedstocks are fully utilized. In contrast, green H₂ availability is limited by access to zero- or low-carbon energy, still-developing supply chains, and infrastructure lead times. As more renewables are deployed and demand for H₂ grows over time, H₂ could become more readily available, potentially lowering costs.

S.2 High Capacity Factor Resources

High capacity factor resources are capable of providing large quantities of energy for extended periods, meeting current and new loads while reducing the need for high-footprint intermittent renewables and low capacity factor resources that are mostly idle. These technologies tend to be capital-intensive and have long lead times, requiring careful planning for integration into a 2040 grid. They can typically provide inertia and other key ancillary grid services to support a grid increasingly dependent on variable renewables. However, siting constraints and infrastructure requirements need to be addressed to foster deployment; remote facilities could necessitate substantial expansion of transmission to serve load centers, including Downstate New York.

S.2.1 Advanced Nuclear

Nuclear is a zero-emissions, low-footprint technology that has reliably provided firm power in the U.S. for decades. Nuclear has the highest energy density compared to other DEFR technologies and renewables, capable of producing over 1,600× more electricity per acre than wind, 200× more than solar, and 60× more than NG turbine plants, without directly emitting carbon dioxide (CO₂), NO_x, sulfur dioxide (SO₂), or PM. “Advanced” nuclear refers to reactors that differ from today’s conventional fleet in coolant type, fuel form, safety features, and deployment approach.

Advanced reactors come in a variety of designs and can address different demand requirement scenarios. Current advanced nuclear technology options include large light water reactors (LLWRs), light water small modular reactors (lwSMRs), and non-water-cooled reactors. lwSMRs are smaller (50–300 megawatt electric [MWe] per unit) derivatives of LLWR designs. Non-water-cooled reactors can vary in size and use alternative coolants such as gases or liquid metals/salts and alternative fuels, including high-assay low-enriched uranium (HALEU).

Advanced reactors are capable of more flexible operation than conventional reactors, but baseload power remains more economical. The high capital-to-operating cost ratio of nuclear reactors makes high capacity factor use more cost-effective. Other use cases for nuclear power include leveraging the significant thermal energy generated to support industrial process heat and hydrogen production. These applications are at a lower readiness than standard baseload power generation.

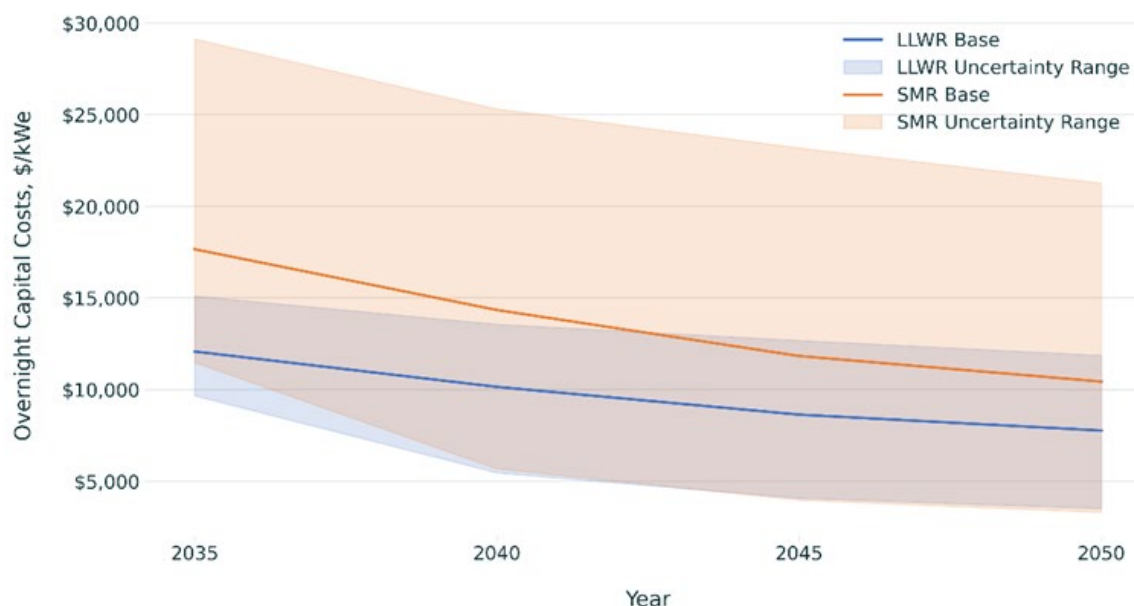
LLWRs are at a higher readiness level than lwSMRs and non-water-cooled reactors. LLWRs have a long history of successful commercial deployment in the U.S. and globally, while lwSMRs and non-water-cooled reactors have only been deployed in limited examples outside of the U.S. lwSMRs are more mature than non-water-cooled reactors as they leverage widely deployed light water technologies, established supply chains, and a domestic regulatory framework with extensive experience. lwSMRs are beginning to enter the Pilot and Demonstration phase in the U.S. and other relevant markets. lwSMRs and some non-water-cooled designs are deployable before 2040, but they require attention to development strategies to ensure timely deployment. However, these reactors may offer greater siting flexibility, along with potential long-term cost reductions enabled by modular deployment models that shift more construction off-site, streamline workflows, and enhance learning from more frequent builds of smaller units.

Deploying new nuclear in New York State before 2040 requires early planning. The next well-planned and executed LLWR project could take 10–12 years to deploy, including 4–5 years for planning and 6–7 years for construction and commissioning. However, federal intervention to streamline permitting could shorten these timelines. Additionally, as the industry matures, future builds could benefit from lessons learned in earlier projects, and Nth-of-a-kind (NOAK) timelines could approach 8–9 years. Some lwSMRs and non-water-cooled reactors may have shorter project lead times due to factory fabrication and design simplification, but significant uncertainty remains in these timelines. Deploying new reactors at or near existing nuclear sites could reduce near-term project timelines.

The cost of the next nuclear plant in New York State will depend on a number of factors. lwSMR and non-water-cooled reactor costs are currently more uncertain than LLWR costs due to a lack of deployments (Figure S-7). LLWRs are expected to be cheaper per kilowatt (kW) for the near future, but lwSMRs and non-water-cooled reactors have lower overall investment costs due to their smaller project sizes. lwSMRs and non-water-cooled reactors also have increased learning potential due to simpler designs, greater offsite fabrication and assembly, and smaller unit sizes. Coordinated market building could result in faster declines in per-kW capital costs relative to LLWRs. Cost reduction opportunities include selecting designs that have already been completed and standardized, establishing a project pipeline by deploying multiple reactors of the same design with the same workforce, building multiple reactors at a single site, and building at or near existing nuclear sites.

Figure S-7. Capital Cost Trajectory Scenarios for Nuclear Power Plants in New York State

Prices reported in 2023 USD. Compares projected capital cost trajectories for FOAK and NOAK deployments. Does not include a lower NOAK bound.



Careful planning for safety and waste management has underpinned past deployments and would continue for any future deployment. Nuclear power plants have been safely operated around the world, including in New York State, for decades and have one of the lowest mortality rates of any power generation source. A defense-in-depth safety approach combined with adherence to regulatory standards and guidance from nuclear safety oversight organizations reduces risk to workers and communities. New advanced reactors are designed to include enhanced passive safety features. Nuclear waste has been safely stored at reactor sites in the U.S. in the absence of a national centralized repository. Continued careful planning for safety and waste management will be critical for future deployment.

S.2.2 Carbon Capture and Storage

CCS is a mature technology in other industries that could leverage existing NG power plant sites.

The most mature capture technology is amine-based capture, which is already in commercial deployment on coal plants but is less mature on NG-fired plants. Other technologies, such as oxycombustion with CCS, membranes, advanced solvents, and cryogenic capture, are less mature but may offer advantages in the future.

CCS on NG-fired power plants is technically capable of operating flexibly but is best suited as a baseload resource. CCS can ramp quickly, but this results in either lower capture rates or a decrease in the plant's power output. Additionally, the high capital-to-operating ratio of CCS makes a high capacity factor the most economical use case.

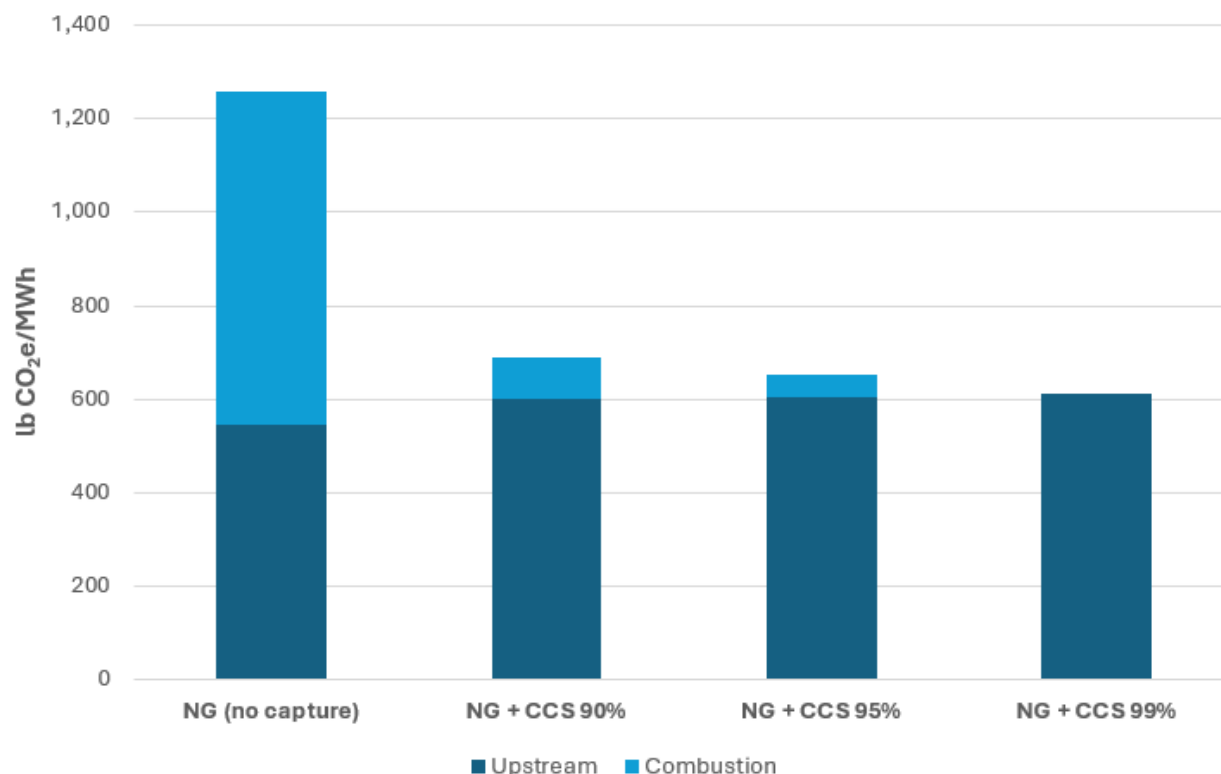
Existing NG plants can be retrofitted to perform amine-based carbon capture. Retrofitting existing plants is estimated to be approximately 45%–50% cheaper and has a lead time that is approximately 25% shorter than building a new plant, but it can be expected to roughly double the existing plant's footprint, which could limit applicability, especially in urban settings.

NG-fired power generation paired with CSS would require significant buildout of carbon transport and storage infrastructure. Pipelines are the most practical and economic transport option for the amount of captured carbon dioxide (CO₂) that an NG power plant would generate. New York State does not have any CO₂ pipelines, and building a new CO₂ pipeline system faces challenges in regulation, permitting, and public acceptance. Building out a CO₂ pipeline could benefit other hard-to-decarbonize end uses, such as industrial applications. Siting plants near potential storage locations could help mitigate the permitting and construction complexities associated with new pipeline projects.

New York State has limited opportunities for carbon storage. The Appalachian Basin has approximately 4.4 gigatons of carbon dioxide (Gt-CO₂) of theoretical capacity in New York State, which is sufficient to store the current power sector's emissions for 200 years. Other storage options include the Newark Basin, which is primarily located outside of New York, and offshore saline storage, which has a lower readiness level and would require substantial infrastructure investment. New York State would likely need to collaborate with neighboring states or rely on regional and federal initiatives to ensure adequate storage capacity. CO₂ utilization for biofuel production, metal fabrication, and other applications is promising but not yet at a scale that can accommodate power sector quantities of CO₂.

Even with capture rates exceeding 99%, CCS on NG-fired plants would not significantly reduce upstream emissions under NYS GHG accounting. Current CCS projects aim for 90%–95% capture rates, but these rates have not yet been demonstrated for long-term operation. Higher capture rates are possible, but they come with increased cost. The upstream emissions associated with fuel production and transportation account for nearly half of the GHG emissions of an NG-fired plant without capture under the NYS emissions accounting methodology (Figure S-8), and the incorporation of CCS on combustion plants does not mitigate these upstream emissions.

Figure S-8. Greenhouse Gas Emissions from Baseload Natural Gas Plant with Different Capture Rates



S.2.3 Next-Generation Geothermal

Geothermal power generation is a low-emissions and low-land footprint technology that is highly geographically dependent. Conventional geothermal relies on naturally occurring hydrothermal resources, while next-generation geothermal uses human-engineered reservoirs. Geothermal suitability in New York State depends on the geological landscape, which is largely unexplored. Given the more promising geology in other U.S. regions and current technology limitations, potential deployment in New York State through 2040 is likely <1 gigawatt (GW). However, with further innovation in drilling and stimulation techniques, high theoretical potential exists across the State for next-generation geothermal technologies in the long term.

Although conventional hydrothermal geothermal power generation is not available in New York, advanced technologies may be possible with further innovation. Most geothermal deployments are in the western U.S., where temperatures required for power generation can be reached at relatively shallow depths, approximately 2–5 kilometers (km). Next-generation geothermal technologies, such as enhanced geothermal systems (EGS) or closed-loop geothermal systems (CLGS), are possible in New York State, but they may require depths of approximately 8 km. No U.S. projects are currently pursuing these depths.

The most promising region for geothermal deployment is likely western New York, but significant test drilling is still required to fully understand the localized potential. Current depth estimates for potential geothermal resources are based on data from oil and gas wells. More testing will be required to determine the regions with the highest potential.

Costs for geothermal power generation at NYS-relevant depths are highly uncertain. Significant advancements in drilling technology will be required to economically access the depths relevant to NYS geology. However, advancements in drilling techniques already underway may help to lower costs quickly.

Induced seismicity and groundwater contamination are at considerably reduced risk for next-generation geothermal. While groundwater contamination has been associated with oil and gas hydraulic fracturing, similar contamination is a significantly reduced risk with geothermal power generation systems, as appropriate prevention measures can be applied. Similarly, because the fluid injected into the subsurface is also removed, induced seismicity is lower with geothermal systems than in the oil and gas extraction processes.

S.2.4 Tradeoffs: High Capacity Factor Resources

Advanced nuclear and CCS are more mature than geothermal for 2040 deployment in New York State. Readiness varies within each technology category (e.g., LLWRs are more mature than lwSMRs).

Nuclear and geothermal have no significant power sector emissions. In contrast, while CCS can capture up to 99% of combustion emissions, the upstream emissions associated with NG production are not mitigated by CCS technology. CCS using NG at scale would not be compatible with the 2050 economywide emissions limit per emissions accounting required by the Climate Act.

All high capacity factor resource technologies have relatively long lead times for deployment.

CCS would require new pipelines and storage, which have regulatory, siting, and permitting requirements. Minimizing the need for CO₂ transport by siting plants near storage could mitigate some of these effects. Nuclear plants are large and complex construction projects that experience long permitting and construction timelines. Leveraging existing, power-ready sites could help expedite timelines. Geothermal will require significant test drilling, as well as advancements in drilling technologies, to reach depths effective to New York's geography.

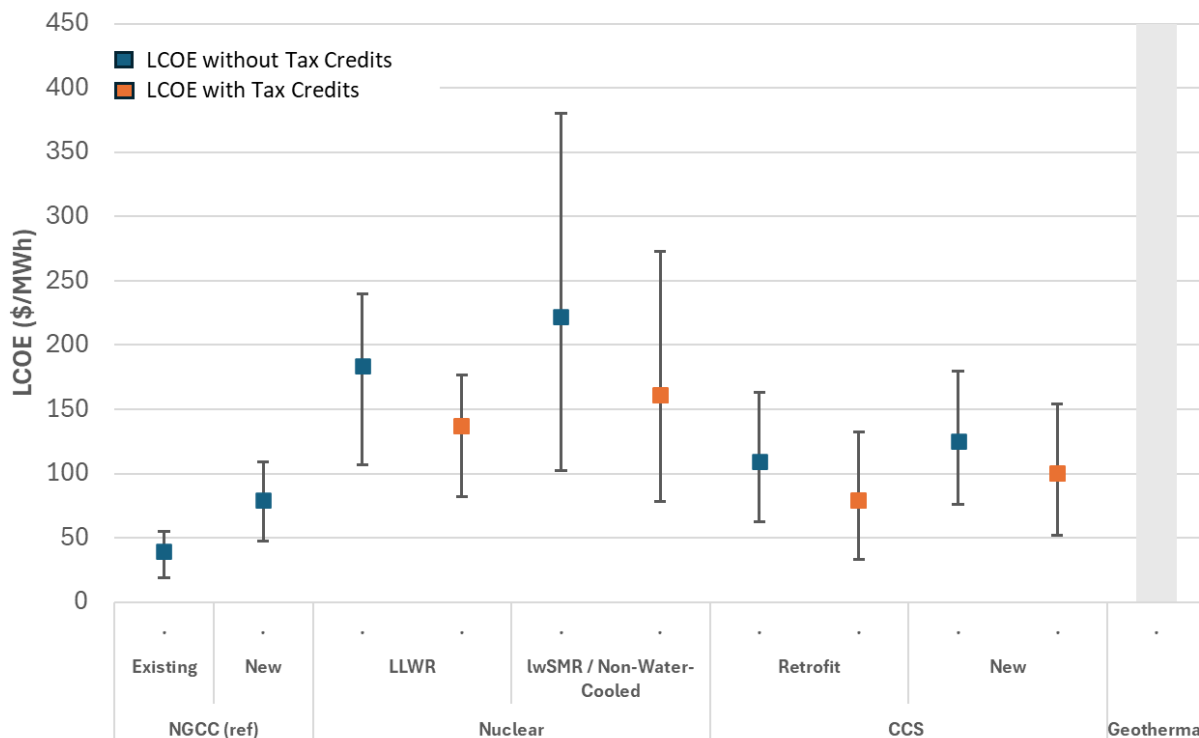
All high capacity factor resource technologies require attention to siting issues. Nuclear deployments at or near population centers require additional investigation and knowledge; geothermal requires specific subsurface conditions; and CCS requires expanded plant footprints and carbon transport infrastructure buildout. Serving load where siting these resources is not possible may require significant transmission buildouts.

For all high capacity factor resource technologies, focused attention is needed on environmental and safety considerations. CCS facilitates the continued use of fossil fuels, maintaining the need to account for broader environmental impacts from fuel production. Nuclear safety and waste disposal are important areas of concern and management of such is built into every phase, from design to decommissioning, through stringent regulation and deep industry expertise. Potential geothermal risks include seismicity and groundwater contamination, but these are not major risks in geothermal power generation if appropriate prevention measures are implemented.

CCS is currently the least expensive high capacity factor resource for New York, but nuclear and geothermal costs are expected to decrease rapidly. The LCOE for new-build CCS is currently expected to be lower than LLWR costs, with further savings expected for CCS retrofit applications (Figure S-9). However, nuclear has significant learning potential as projects are built that provide opportunities for nuclear costs to become more competitive. While CCS costs should also benefit from learning-by-doing and economies of scale, in some cases, this could be countered by expensive infrastructure requirements. Geothermal costs are too uncertain for NYS-relevant depths to be effectively compared with those of nuclear and CCS costs, but they are expected to decrease significantly as drilling technologies and techniques advance.

Figure S-9. Levelized Cost of Electricity for High Capacity Factor Resources

Full tax credit eligibility requires construction to start before the credit phaseout date. Uses expected 2040 cost and performance ranges. Assumes deployment between FOAK and NOAK for nuclear. Prices reported in 2023 USD.



S.3 Gap-Rightsizing Resources

Gap-rightsizing resources will have significant value in any 2040 grid due to opportunities for energy arbitrage and infrastructure cost avoidance. However, these resources are not sufficient to meet all grid needs due to duration limitations.

S.3.1 Long-Duration Energy Storage

LDES can provide avoided infrastructure benefits today and will become more important as the prevalence of intermittent renewables in the grid increases. LDES can provide grid benefits today, including avoided transmission and distribution infrastructure investment. While short-duration energy storage (<10 hours) alongside existing thermal generators meets most of the current grid's balancing needs, higher renewable penetration will introduce longer peak challenges that will require longer-duration energy storage (>10 hours) to manage, along with larger capacities.

Different energy storage technologies are better suited for different durations. This report examines 18 electrochemical, mechanical, and thermal energy storage technologies capable of operating for durations greater than 10 hours. Electrochemical and mechanical storage technologies are typically most suitable for short- to interday applications. Thermal storage technologies tend to be better suited for interday to multiday applications. However, optimal durations will depend on the specific use case for each project.

The LDES technologies with the highest technology readiness are pumped hydro, molten salt thermal energy storage, lead-acid batteries, and sodium-sulfur batteries. Generally, electrochemical and mechanical energy storage technologies are at a higher readiness level than thermal energy storage technologies.

Electrochemical storage technologies are more modular and can provide more grid services than mechanical or thermal energy storage technologies, but they currently require additional safety considerations and have higher costs and shorter lifetimes. These technologies also require inverters for grid interconnection, which limits contributions for certain ancillary services, such as inertia.

Thermal energy storage technologies can also help decarbonize industrial processes that require heat, typically provided by a fossil-fired boiler, including cement, steel, brewing, and a host of other processes. Multiple thermal energy storage technologies are being installed for commercial use for these types of applications, which can help accelerate this technology for power use by maturing the core technology.

LDES deployment potential can be limited due to space constraints and safety considerations. High-population-density areas have limited land availability, which competes with other energy technologies such as short-duration energy storage and thermal generation. Potential siting opportunities may include municipal-owned and privately owned land, as well as retiring fossil plant sites and integration with renewable energy projects. Upstate New York LDES potential is larger due to fewer space and population density constraints.

Emerging energy storage technologies are in the early stages of development, necessitating ongoing assessments to mitigate risks. Safety considerations are unique to each technology, creating challenges in standardization and efficient permitting processes. However, New York is a national leader in this area, having convened an interagency fire safety working group to ensure the safety of lithium ion battery energy storage systems across the State. The group produced a Fire Code Recommendations Report that informed the code development process in New York State.

Electricity market design changes will be needed to support market-based deployment of LDES.

Targeted market and regulatory reforms, incentivizing longer durations, are needed to support deployment and technological advancement.

S.3.2 Virtual Power Plants and Demand Response

Demand response is a grid management strategy that enables consumers to reduce consumption during critical periods of demand. Demand response programs have been successfully reducing the electricity consumption of large-scale consumers for decades. VPPs coordinate the response of distributed energy resources (DERs) to enable smaller-scale customers to participate in grid operations.

VPPs could serve a critical role in harnessing the inherent flexibility of DERs and load-flexible appliances already being deployed. These aggregated resources can provide economic value to consumers and services across multiple grid domains, from bulk system balancing to localized distribution support.

Recent studies show that VPPs could provide 8.5 GW of flexibility potential in New York State in 2040. Achieving this estimated technical potential requires improving conditions for customer acquisition and participation, standardizing communications and market interfaces, and addressing metering and telemetry costs. Programs with easier enrollment and lower user interference are expected to have a greater impact.

VPPs offer a cost-effective approach to balancing energy supply and demand. Short lead times and low capital costs relative to other technologies make VPPs a cost-competitive option for bridging the gap to a zero-emissions power sector.

S.3.3 Tradeoffs: Gap-Rightsizing Resources

LDES has the potential for longer discharge durations and higher operational certainty than VPPs, but can suffer energy losses. VPPs depend on customer participation, which requires appropriate mechanisms to ensure participation during peak events, especially on future peak winter days. LDES is more dependable, but it is also a net load on the grid due to the need to recharge and round-trip efficiency (RTE) losses. LDES can also, in some cases, have standby losses.

LDES has more siting limitations than VPPs. VPPs require very little footprint and can therefore be sited anywhere DERs are deployed. LDES, in contrast, requires regulatory and siting procedures due to footprint and safety considerations.

VPPs are expected to be lower-cost than LDES on a per-MWh basis. VPPs also offer the advantage of shorter lead times. However, VPPs face continuous changes in the underlying asset base as customers upgrade appliances, modify their participation preferences, or potentially withdraw from programs altogether.

S.4 No-Regret Actions

This study identifies several actions that can facilitate the readiness of these resources to achieve the scale needed for 2040.

Pursue a diverse set of resources to minimize the risk of overreliance on individual technologies.

Each of these candidate technologies could serve complementary roles in a 2040 grid. Low capacity factor resources will be vital on days with the most extreme power needs. High capacity factor resources could significantly reduce the land needed by the power sector while also providing vital inertia and other ancillary grid services to support a grid with increasing intermittent renewables and growing load. Gap-rightsizing resources can shift supply to times of greater need and reduce the need for upgrades to transmission and distribution infrastructure. Additionally, different resources are best suited to different geographic regions, making a mix necessary to best meet statewide needs.

Start early to increase the likelihood of readiness by 2040.

All resources considered here have deployment barriers that need to be addressed to meet the needs of a zero-emissions grid. Several have long lead times. Starting early can increase the likelihood of success of individual projects, while also increasing the opportunity for beneficial learning. Moreover, because

federal tax incentives are only available for a limited duration, starting early can increase the likelihood of taking advantage of those incentives.

Invest in grid-enhancing technologies early to minimize the need for backstop resources.

VPPs, energy storage, and other technologies, such as GFM inverters and dynamic line ratings, will be valuable assets for any 2040 grid. Deploying these resources early could reduce the need to build capital- and time-intensive generation and transmission projects.

Invest in innovation to enhance resource viability.

Most DEFR candidates are not yet ready for commercial deployment. Furthermore, additional emerging versions of technologies that are earlier on the readiness scale and, therefore, not included in the current detailed analysis, may offer promising cost reductions or performance improvements that could be achieved through research and development (R&D) investments. Investing in innovation can help accelerate readiness for 2040.

Develop strategies across industries for unlocking key resources with infrastructure

hurdles. Clean fuels such as hydrogen and biofuels, as well as CCS, could serve crucial roles in the decarbonization of sectors outside of the power sector. Coordination among sectors to build transportation and storage infrastructure in strategic locations could lower costs and enable more rapid deployment.

Engage early with technology developers, end users, and other stakeholders.

Early engagement can help to understand and identify potential projects, siting locations, and demonstration opportunities. Coordinating with industry and federal and State governments can facilitate national markets and accelerate cost reductions.

Conduct grid modeling to understand tradeoffs of relying on different resources.

Electric system modeling will be necessary to understand the most economic suite of technologies to deploy. Given the high level of cost uncertainty, it will be important to model a range of costs and performance attributes to understand how breakthroughs could affect which technologies are selected.

Conduct a regular reassessment of options and remain flexible as new technology options come online. This is a rapidly evolving space as new technologies capable of providing clean, firm power and grid services are being developed. Regularly evaluating the progress of these technologies and embedding flexibility into resource planning are critical for benefiting from improvements in cost and performance.

1 Introduction

1.1 The Climate Leadership and Community Protection Act

The Climate Leadership and Community Protection Act (Climate Act), signed into law in 2019, sets forth a framework to reduce the NYS greenhouse gas (GHG) footprint, transform electricity generation, advance technological solutions, and ensure equitable benefits across communities during the energy transition. Specifically, the Climate Act established a target of 100% zero-emission electricity by 2040 (0x40).

1.2 Zero by 40 Proceeding

As the electricity system transitions toward the Climate Act’s target for zero-emission electricity by 2040 (commonly referred to as “Zero by 40” or “0x40”), the New York State (NYS) Public Service Commission (PSC) has recognized the need to evaluate various technologies that could provide dispatchable power while meeting zero-emission requirements to help maintain grid reliability and resource adequacy. In May 2023, the PSC issued an order initiating a process “to identify technologies that can close the gap between the capabilities of existing renewable energy technologies and future system reliability needs, and more broadly identify the actions needed to pursue attainment of the Zero Emission by 2040 Target.”

To advance this work, the New York State Department of Public Service (DPS) held a technical conference in December 2023 (DPS 2023) that convened energy and technology experts to discuss the characterization of the “gap” (sometimes referred to as the “reliability gap”) with respect to resource adequacy, transmission security, and grid stability that might arise from shuttering fossil fuel-fired resources, and the technologies that could shrink or fill that gap.

This report further evaluates various dispatchable emission-free resources (DEFRs)¹ that could contribute to achieving a 100% zero-emission electricity system by 2040, with a focus on maintaining grid reliability and reducing emissions.

1.3 Grid Needs and State Action toward a Zero-Emissions Power Sector

The transition toward a zero-emissions grid will require growth and development of various components of the power sector. This report focuses on DEFRs, but this is just one of several types of resources necessary to develop to meet the 0x40 target.

- **Zero-emission energy resources:** New York State requires significant amounts of zero-emission energy resources to replace current fossil fuel generation. The New York State Energy Research and Development Authority (NYSERDA) and DPS have developed a Clean Energy Standard to procure onshore wind, solar, offshore wind, and other clean energy resources (NYSERDA 2025a). These resources will provide the foundation of New York State's zero-emission electricity system.
- **Short-duration storage:** Intraday load balancing will require expansion of short-duration energy storage. NYSERDA has established an Energy Storage Program to support the deployment of these resources (NYSERDA 2025b). These storage technologies can shift energy from times of excess renewable generation to other times within the same day.
- **DEFRs:** The power system will require firm resources that can provide electricity during extended periods of high demand and/or low renewable generation, such as winter weeks with increased heating loads from heat pumps coupled with lower renewable output, when short-duration storage would be drained. Some DEFRs can also provide zero-emission energy outside of challenging days and weeks.
- **Transmission infrastructure:** Additional investments in transmission infrastructure can reduce congestion and the need for firm resources. These can include in-state transmission to reduce congestion, regional transmission to exchange power with neighboring regions during critical periods, and dynamic line ratings and other technologies that can improve the utilization of existing transmission assets.
- **Grid-forming (GFM) inverters:** Technologies that can provide grid support services may offer more cost-effective approaches to maintaining reliability in some cases. GFM inverters can enable intermittent renewables and storage to provide additional services such as voltage support and frequency response. Incorporating GFM capabilities into renewable energy projects at the outset may be a cost-effective way to reduce the need for other resources.

A combination of these resources and infrastructure investments will be necessary to achieve a reliable, zero-emissions power sector by 2040.

Key Dispatchable Emissions-Free Resources Attributes

Dispatchable emissions-free resources (DEFRs) are defined as resources that produce zero emissions during operation, can be called on (dispatched) to provide energy and capacity when needed, and can operate reliably during extreme events and extended periods of low renewable generation.

The New York Independent System Operator (NYISO) outlined the specific attributes needed for reliability in the *2023–2032 Comprehensive Reliability Plan* (NYISO 2023). While every DEFR does not need to provide every attribute, the grid needs enough of each to maintain reliability, including:

1. **Dependable fuel sources:** Ability to provide carbon-free energy and to be brought online when required
2. **Nonenergy limited capability:** Ability to provide energy for multiple hours and days regardless of weather, storage, or fuel constraints
3. **Dispatchability:** Ability to follow instructions to increase or decrease output minute-to-minute
4. **Quick-start capability:** Ability to come online within 15 minutes
5. **Flexibility:** Ability to be dispatched through a wide operating range with a low minimum output
6. **Fast ramping:** Ability to increase or reduce energy output based on changes to net load that may be driven by changes to load or intermittent generation output
7. **Multiple starts:** Ability to be brought online or switched off multiple times throughout the day as required, based on changes to the generation profile and load
8. **Inertial response and frequency control:** Ability to maintain power system stability and arrest frequency decline postfault
9. **Dynamic reactive control:** Ability to support grid voltage
10. **High short-circuit current contribution:** Ability to ensure appropriate fault detection and clearance

This report explores the relative advantages and challenges associated with potential DEFR technologies.

1.4 This Report

1.4.1 Technologies Evaluated

This report evaluates potential resources that can provide firm energy and capacity in a zero-emissions power sector. The study examines seven technology categories that could serve as DEFRs. These technologies are grouped into three resource groups based on their expected operational characteristics. While some resources can be configured to serve different roles, these groupings reflect constraints on costs, emissions, and availability in New York State, which are discussed later in the report.

Low capacity factor resources² can be deployed during periods of high demand and low renewable generation, offering reliability, fast-ramping capabilities, and no duration limitations, assuming fuel availability, but are not operated as baseload units due to plant economics. Low capacity factor Resources include:

- Hydrogen
- Renewable natural gas (RNG) and renewable diesel (RD)

High capacity factor resources operate the majority of the year and can provide reliable baseload power, including power during challenging events, but are less suitable for fast ramping or frequent starts and stops. High capacity factor resources include:

- Advanced nuclear
- Carbon capture and storage (CCS) on thermal plants
- Geothermal

Gap-rightsizing resources can help balance supply and demand to adjust the capacity gap. While they do not generate electricity directly, they enhance the utilization of other clean resources. Gap-rightsizing resources include:

- Long duration energy storage (LDES)
- Virtual power plants (VPP)

Figure 1 provides an illustrative example of the role of these different DEFR resource groups. While renewables play a significant role in overall power generation, the high capacity factor resources supplement renewables by providing an additional source of baseload power. Low capacity factor resources help to meet peak demand when renewables are insufficient. Gap-rightsizing resources can shift generation or load, increasing the value of renewable generation by mitigating intermittency to balance supply with demand.

Figure 1. Role of DEFR Resource Types in Meeting Electricity Demand

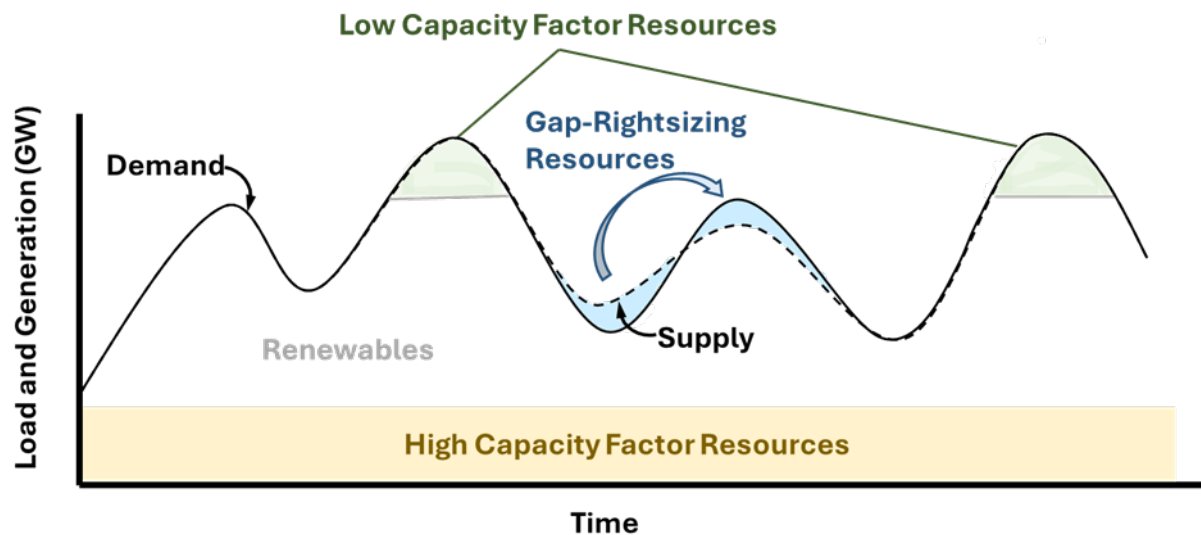


Figure 2. Functional Categories of DEFR Resource Types

Low Capacity Factor Resources	High Capacity Factor Resources	Gap-Rightsizing Resources
<i>Resources to deploy during times of peak system need</i>	<i>Firm resources that supplement renewables</i>	<i>Resources to balance supply and demand</i>
Hydrogen	Advanced Nuclear	Long Duration Energy Storage
Biofuels	Carbon Capture & Storage	Virtual Power Plants
	Next-Generation Geothermal	

This report primarily compares resources within each resource grouping rather than across groups. It is difficult and potentially misleading, for example, to compare the cost of resources that provide fundamentally different value to the grid, but comparing resources that operate similarly can yield useful conclusions. Ultimately, electric system modeling is necessary to determine the least cost mix of resources, which is beyond the scope of this study. This report, however, includes some qualitative discussion on tradeoffs across groups.

1.4.2 Individual Technology Sections

Each technology section includes the following:

- **Technology overview:** Provides a high-level description and overview of operational principles of each technology, including the range of technology variants evaluated.
- **Performance attributes:** Reviews the technical capabilities and limitations of each technology. For newer technologies where performance characteristics have not been fully tested, the report distinguishes between technologies that are ready now and those that may be ready by 2040.

The performance attributes assessed for technologies throughout this report include the following:

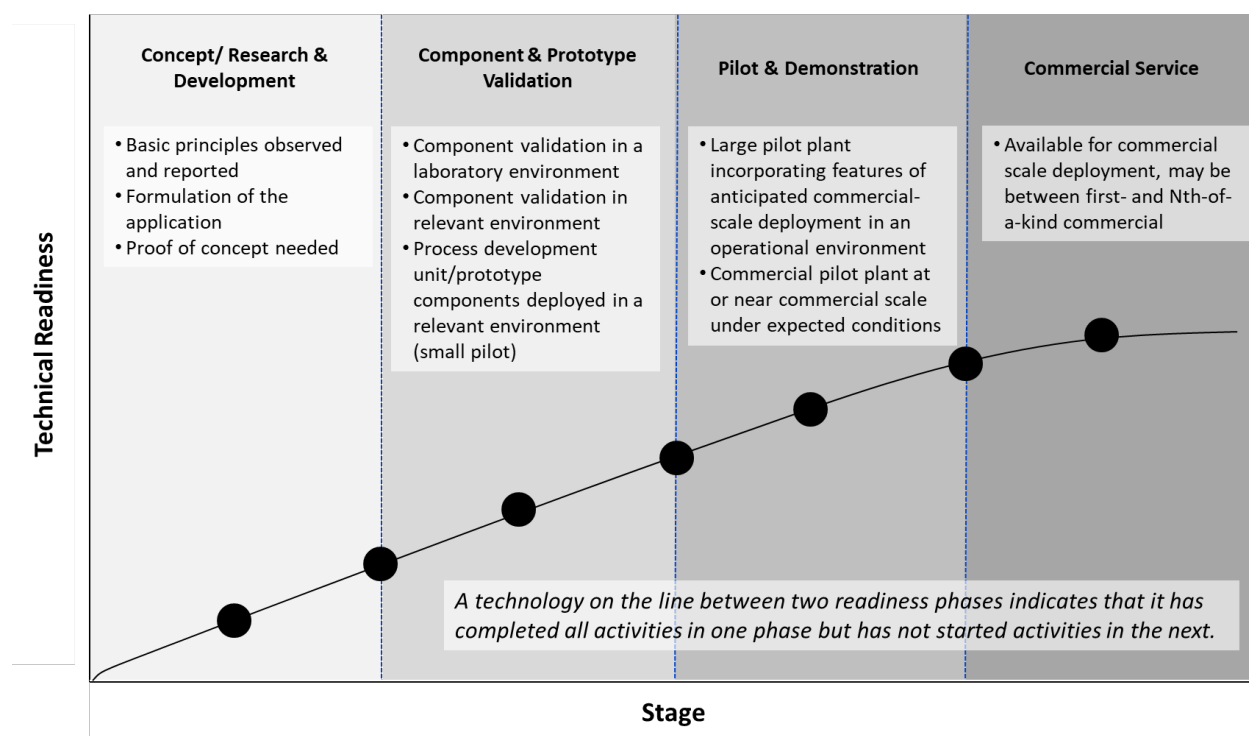
- **Inertial response:** Ability to adjust the electrical power output of a generator in response to a generation and load imbalance to maintain frequency within stated performance bounds
- **Primary frequency response:** Ability to take rapid actions (within seconds) to arrest and stabilize frequency in response to frequency deviations
- **Voltage and reactive power:** Ability to produce and absorb reactive power to control system voltage to acceptable levels
- **Ramping:** Ability to increase or decrease real power (MWs) in response to system load changes, scheduling, or output of other system resources to maintain reliability and compliance with system standards
- **Cycling capability:** Ability to start up and shut down more than once per 24-hour period
- **Short minimum run time:** Ability to have a minimum run time (the amount of time the resource would have to run after starting) of less than or equal to 2 hours per start
- **Black start:** Ability to start up and inject power into the electrical grid, or remain energized, even if the rest of the grid is down
- **Capacity factor:** Ability to represent the extent to which a power plant is used compared to its maximum potential output over a defined period (annually, here)
- **Minimum stable output:** Ability to maintain the lowest power level (expressed as a percentage of rated capacity) at which a resource can sustain stable operation while remaining online

Readiness for 2040: Reviews the technology, commercial, infrastructure, and supply chain readiness of each technology for deployment by 2040. The section also analyzes deployment timelines and geographic constraints in New York State.

Technology readiness is evaluated using a standardized rubric across technologies. The evaluation criteria this study uses consolidates the generalized 9-point Technology Readiness Level (TRL) scale put forth by the National Aeronautics and Space Administration (NASA) and adopted by myriad organizations and researchers into the four categories Figure 3 summarizes:

1. **Concept/Research and Development (TRL 1–3):** At least one of the following has been completed by at least one technology design:
 - Basic principles observed and reported
 - Formulation of the application
 - Proof of concept needed
2. **Component and Prototype Validation (TRL 4–6):** At least one of the following has been completed by at least one technology design:
 - Component validation in a laboratory environment
 - Component validation in a relevant environment (e.g., a lab or a small process development unit that simulates the operational environment)
 - Small pilot: Process development unit/prototype components deployed in a relevant environment
3. **Pilot and Demonstration (TRL 7–8):** At least one of the following has been completed by at least one technology design:
 - Large pilot plant: Integrated, fully functional prototype incorporating features of anticipated commercial-scale deployment in an operational environment.
 - Commercial pilot plant: Deployment of system at or near commercial scale in final form under expected conditions, concluding fundamental system development. A successful deployment at ~100% of the capacity required for commercial-scale deployment would be considered a first-of-a-kind (FOAK) commercial achievement.
4. **Commercial Service (TRL 9):** The technology is available for commercial-scale deployment and may be provided with enforceable performance guarantees. Deployments at this stage may be between FOAK and Nth-of-a-kind (NOAK) commercial.

Figure 3. Categories Used to Evaluate Readiness of DEFR Technologies



Enabling infrastructure and supply chain readiness were also evaluated across a common set of infrastructure categories and with a common set of evaluation criteria.

As applicable to the individual technology, general infrastructure and supply chain considerations include:

- **Transmission and grid integration:** Ability to connect to the electrical grid, considering transmission expansion, congestion, interconnection, and flexibility; includes the need for new high-voltage transmission lines and substations.
- **Fuel supply chain and waste management:** Infrastructure for fuel production, transport, storage, and disposal.
- **Cooling water and thermal management:** Infrastructure for managing heat from power generation processes; includes cooling water availability and other considerations of water access and allowable thermal discharges.
- **Siting and land use:** Land requirements, siting regulations, proximity to load centers, and load co-location potential.
- **Supply chain:** Readiness of supply chains for deployment, operation, and maintenance; includes availability of raw materials, subcomponents, and manufacturing and assembly needed to build a plant.

The study evaluated infrastructure and supply chain readiness using the following evaluation categories:

- **No significant buildout required:** The existing infrastructure and/or supply chain is likely sufficient for deployment, requiring minimal modifications.
- **Buildout required with short lead time:** The necessary infrastructure and/or supply chain is well-understood, and deployment can likely proceed with minor upgrades or expansions within typical project timelines.
- **Buildout required with long lead time:** The technology itself is well-understood and can be deployed, but infrastructure and/or supply chain expansion is likely constrained by permitting, supply chain delays, workforce limitations, other external bottlenecks, and/or the extensive scale of buildout required.
- **Infrastructure not ready with fundamental development needed:** The required infrastructure and/or supply chain is not yet deployed at scale, and significant technological advancements or demonstration projects are needed before deployment can proceed.

To ultimately assess the potential readiness for the technology to make meaningful contributions to the 0x40 target in New York State by 2040, the study gave additional consideration to the unique characteristics of New York State's geography, built environment, and existing infrastructure to evaluate the suitability of each technology. Where possible, the study estimated indicative lead times using data from deployed projects. In other cases, it used engineering studies, expert judgment, or similar technologies.

Emissions and other considerations: Quantifies the GHG emissions of each technology using the New York State Department of Environmental Conservation (DEC) accounting methodology for electric sector emissions, as well as co-pollutants, and discusses relevant considerations around air quality, safety, water use, land use, and workforce.

Cost: Provides a cost analysis of each technology, including capital expenses (CAPEX), operating expenses (OPEX), future projections, and levelized cost of electricity (LCOE). While LCOE can be an incomplete and potentially misleading metric for comparing technologies with significantly different operating profiles and technology characteristics, it can provide a high-level comparison of resources within the same category in lieu of capacity expansion modeling.

The cost of many of these resources is highly uncertain because many have not been deployed at scale. To ensure comparable uncertainty ranges for the costs of various emerging technologies, this study uses standard ranges inspired by the American Association of Cost Engineering (AACE) cost estimate classes, based on technology maturity (AACE 2011):

- -35%/+65% High uncertainty in cost estimates
- -23%/+35% Medium-high uncertainty in cost estimates
- -15%/+20% Medium uncertainty in cost estimates
- -10%/+13% Medium-low uncertainty in cost estimates
- -7%/+9% Low uncertainty in cost estimates

All cost analyses are performed in 2023 USD, which corresponds to the start of the study.

Scalability for 2040: Presents Conservative, Moderate, and Advanced scenarios around the potential scale of deployment of each technology in New York State by 2040.

1.4.3 Resource Comparison

In addition to the individual technology section, this report includes a resource comparison section that compares the technologies within a resource category (low capacity factor resources, high capacity factor resources, and gap-rightsizing resources) across the evaluation criteria explored within the technology sections. The resource comparison section also includes a high-level discussion of qualitative tradeoffs between categories.

1.5 Related Efforts

Several key NYSERDA workstreams inform this work, both completed and underway, that have helped progress the understanding of these resources, including but not limited to:

- *New York Hydrogen Assessment (NYSERDA 2022)*
- *The Blueprint for Advanced Nuclear Energy Technologies (NYSERDA 2025a)*
- *The 2025 New York Draft State Energy Plan and Pathways Analysis (NYS Energy Planning Board 2025)*
- *The Grid of the Future Study (Brattle 2025a, 2025b)*
- Various other NYSERDA innovation and technology demonstration efforts

1.6 Tax Credit Availability

In July 2025, President Trump signed H.R. 1 into law. H.R. 1 affects many of the energy tax credits implemented under the Inflation Reduction Act of 2022 (IRA), many of which apply to the technologies discussed in this report. Although many provisions in H.R. 1 remain uncertain, this section summarizes the provisions most relevant to the seven technologies analyzed in this study.

Foreign Entities of Concern (FEOC): Many credits now include foreign entity restrictions, which prevent certain FEOCs from accessing these credits or providing significant material assistance to projects that qualify for them. Uncertainty still surrounds the implementation of these restrictions and may create market uncertainty and supply chain challenges.

Nuclear, Geothermal, LDES, Fuel Cells, and clean hydrogen-fired power generation remain eligible for technology-neutral tax credits—Clean Electricity Investment Tax Credit (ITC) Section 48E (Clean Electricity ITC) and Clean Electricity Production Tax Credit (PTC) Section 45Y (Clean Electricity PTC). In some cases, as with fuel cells, these technologies have more opportunities under H.R. 1. Projects typically need to begin construction by 2033 to receive a full credit, which could create a deployment challenge. While the phaseout starting in 2033 aligns with one bookend of the Inflation Reduction Act timeline, the Act could have allowed credits to remain available longer depending on the broader decarbonization of the national electric sector. Similarly, the tax credit for Carbon Capture and Sequestration, Section 45Q (Carbon Capture Credit), remains available for projects, like CCS and blue hydrogen production, that begin construction before 2033. Projects shown in this report to receive a credit in 2040 are assumed to have begun construction ahead of the credit phaseout.

Clean Hydrogen Production Tax Credit, Section 45V (Clean Hydrogen Credit), phaseout was accelerated under H.R. 1, requiring production facilities to begin construction before the end of 2027. The Clean Hydrogen Credit applies for the first 10 years of a production facility's lifetime, so even if a facility begins construction before the phaseout, hydrogen fuel credits are unlikely to remain available long after 2040.

Clean Fuel Production Tax Credit, Section 45Z (Clean Fuel Credit), was extended from expiring at the end of 2028 to the end of 2029; however, it remains inapplicable to 2040.

Accelerated phaseouts of solar and wind eligibility for technology-neutral tax credits (Clean Electricity ITC, Clean Electricity PTC) and the accelerated phaseout of the Electric Vehicle (30C) tax credits are likely to have a dampening effect on VPP deployment and green hydrogen viability.

In addition to changes to tax credits, federal actions have created uncertainty for many projects that received funding for pilot, demonstration, and deployment, which are critical for technology development. Overall, this remains an actively developing space, and the full effects of H.R. 1 and

other federal policy changes are still unknown and cannot be fully captured at this time. In this work, the analysis reflects H.R. 1 developments as currently understood.

1.7 Note on Uncertainty

While this report covers a wide range of technologies, it is not comprehensive, and technologies not covered may still be relevant to achieving the 0x40 target. The information presented reflects the current state of knowledge, with the understanding that data on emerging technologies contain inherent uncertainty and will likely change in the coming years. In some cases, an emerging version of a technology may offer promising cost reductions or performance improvements, but is considered too early in the technology readiness scale to have likely deployment by 2040 or have reliable data for detailed analysis today. Many of these technologies are highlighted in callout boxes throughout the report.

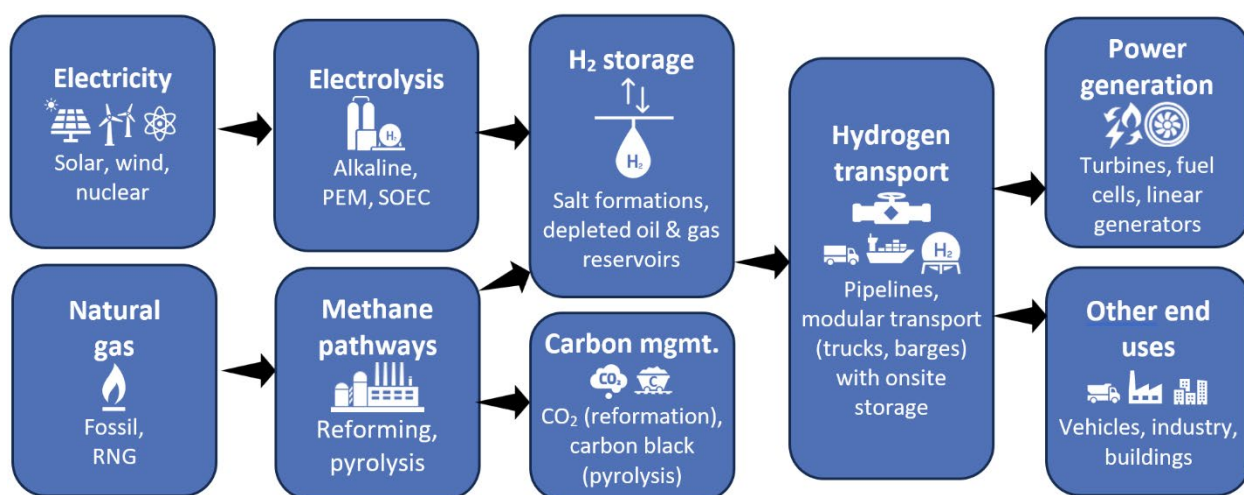
This report does not aim to eliminate resources from consideration but to provide technical information to inform the pathway toward zero-emission electricity by 2040, which will ultimately require a mix of resources. Each resource is presented with both its advantages and challenges to support informed decision-making.

2 Hydrogen

2.1 Overview and Subcategorization of Hydrogen Technologies

Hydrogen is an energy carrier with potential to help decarbonize New York State’s power sector as a low- to zero-carbon fuel that can be stored in large quantities over long time periods for use during critical peak hours. The route from the original energy source to hydrogen to peak-time electricity can take many pathways (Figure 4), with considerations and challenges for each step in the path. Understanding the entirety of the hydrogen technology landscape is necessary to evaluate hydrogen as a firm power resource.

Figure 4. Pathways from Primary Energy Source to Hydrogen to Peaking Power



2.1.1 Hydrogen Production Technologies

Hydrogen can be produced from many different sources, each with different readiness, cost, emissions, and infrastructure implications. Figure 5 describes the different types of hydrogen.

Electrolytic hydrogen is produced from water and electricity using an electrochemical process called electrolysis, in which an electrical potential is applied to electrodes that are in contact with water.

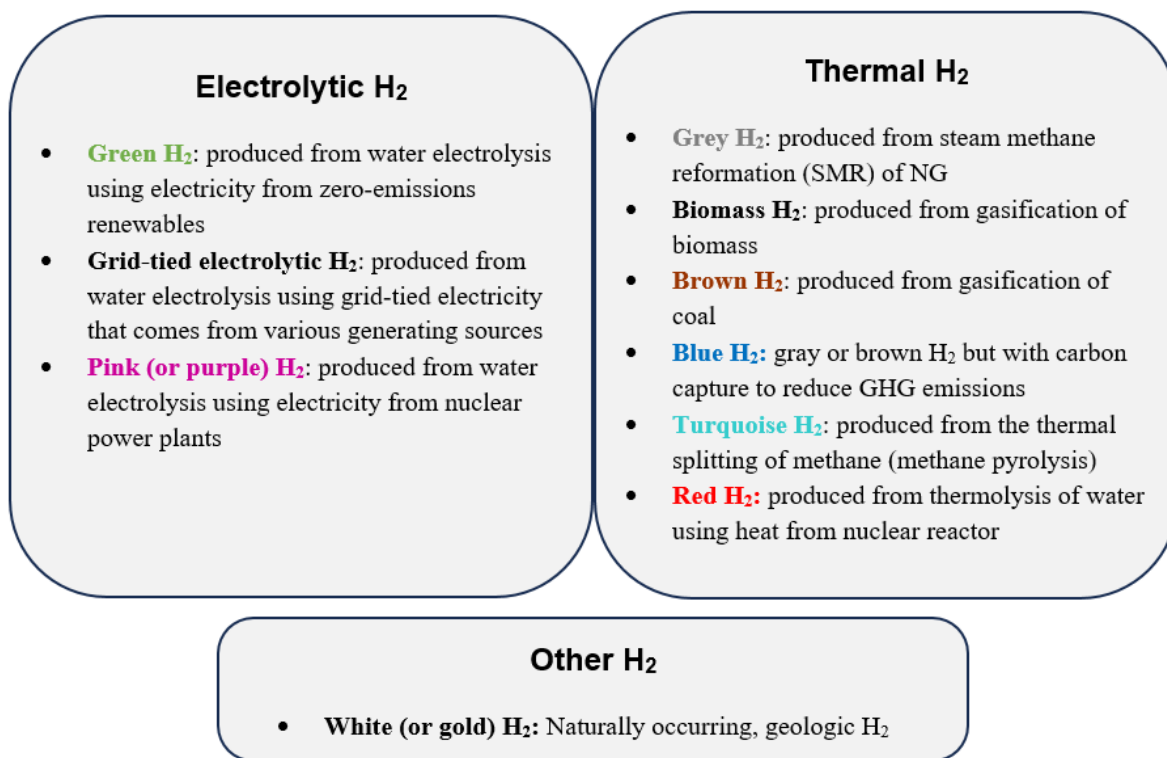
The only products of this process are hydrogen gas and oxygen gas. When the electricity required for electrolysis is sourced from zero-emission renewables, this kind of hydrogen is referred to as “green hydrogen.” When the electricity is sourced from nuclear reactors, it is referred to as “pink hydrogen.”

This report covers three primary types of electrolyzers, each with distinct characteristics. They are described in the following sections.

Hydrogen can also be derived thermally from fossil or biomass sources, using steam methane reforming (SMR), gasification, or methane pyrolysis (“turquoise hydrogen”), or from water using thermolysis. Some of these processes result in CO₂ emissions, but can be integrated with carbon capture to reduce emissions. Hydrogen produced via fossil fuels with carbon capture is often referred to as “blue hydrogen.” This report covers blue hydrogen and turquoise hydrogen as the most likely fossil-derived hydrogen production sources for a 2040 NYS power sector.

Finally, hydrogen can be found underground in naturally occurring reservoirs and has been referred to as “white hydrogen” or “gold hydrogen.” Naturally occurring hydrogen is produced by natural geochemical processes underground, such as the reaction of water with iron-rich rocks or radiolysis. It accumulates in subsurface reservoirs where it can be extracted much like oil or natural gas (NG). Given the limited experience in finding and extracting naturally occurring hydrogen and the high level of uncertainty regarding its available volumes, it is not covered in this report and is not expected to be a consequential recoverable resource for meeting the 0x40 goal based on current knowledge of available reserves.

Figure 5. Types of Hydrogen



The following sections describe the different hydrogen production technologies covered in this report.

2.1.1.1 Alkaline Electrolyzers

Alkaline electrolysis uses a strong alkaline solution as the electrolyte. In this process, water is decomposed into hydrogen and oxygen gas by passing an electrical current between two electrodes separated by a membrane. Alkaline technologies have historically been deployed in baseload operations, but many new alkaline technologies have demonstrated enhanced operational flexibility, which is particularly important for use with intermittent renewable electricity supplies. Evaluation of the performance of these systems in the near term will help better understand the design and balance of plant considerations to support system flexibility. Battery storage systems can also support compatibility with intermittent renewables.

2.1.1.2 Proton Exchange Membrane Electrolyzers

Proton exchange membrane (PEM) electrolysis is a method of producing high-purity hydrogen by splitting water molecules into hydrogen and oxygen using a proton-conducting solid polymer membrane and electricity. PEM technology can be designed for a greater ability to use intermittent renewable energy than alkaline electrolyzers, but research and operational system experience are still required to better understand the impact of flexible operation on stack lifetime. Further research into these effects could provide more confidence to the industry and accelerate adoption.

2.1.1.3 Solid Oxide Electrolysis Cell Electrolyzers

Solid oxide electrolysis cell (SOEC) electrolyzers use high-temperature steam electrolysis, where water molecules are split into hydrogen and oxygen using electricity and a ceramic membrane that conducts O^{2-} ions (rather than a liquid OH^- electrolyte for alkaline and a H^+ polymer conducting membrane for PEM). SOEC technology offers potential efficiency advantages over other electrolyzer types when coupled with a high-temperature heat source, but it is currently less mature than alkaline and PEM technologies.

2.1.1.4 Steam Methane Reforming with Carbon Capture and Sequestration

SMR is the primary method of hydrogen production in the U.S. today. This kind of hydrogen is sometimes referred to as “grey hydrogen.” The methane reformation generates CO_2 emissions, but incorporating carbon capture and sequestration significantly reduces carbon emissions. The resulting low-carbon hydrogen is often referred to as blue hydrogen. The reforming process involves reacting methane with steam under high temperatures and pressure to produce hydrogen and carbon monoxide (CO). The carbon monoxide can then be converted to carbon dioxide through the water-gas shift reaction,

and the resulting CO₂ is captured and stored, preventing its release into the atmosphere. This process produces low-carbon hydrogen but cannot be carbon-free due to the CO₂ not captured during reforming and, under NYS emissions accounting, the upstream emissions associated with fuel production. Using biogenic sources of methane from waste streams to produce hydrogen could have additional benefits, including the avoidance of potential methane release or flaring and upstream NG emissions. However, biogenic sources face supply limitations. Section 3 discusses biofuels.

2.1.1.5 Methane Pyrolysis

Methane pyrolysis is a process for producing hydrogen from NG with minimal carbon emissions. It involves the decomposition of methane into hydrogen and solid carbon, without the formation of carbon dioxide. The process is carried out in a high-temperature reactor, where methane is heated to temperatures above 1,000 degrees Celsius (°C) in the absence of oxygen. The resulting hydrogen can be used as a clean fuel, while the solid carbon can be utilized in various industrial applications or stored for future use. However, the current demand for solid carbon is lower than the expected supply produced in a power sector use case. Ongoing research aims to optimize reactor designs, improve catalyst performance, and scale up the technology for commercial deployment. As with SMR, using biogenic sources of methane from waste streams could have additional benefits. A further advantage of methane pyrolysis is that methane could be converted to hydrogen on-site at the power plant, potentially avoiding challenges associated with transporting and storing hydrogen and CO₂. This approach could leverage existing NG pipelines for fuel transport. However, it comes with challenges such as ensuring sufficient gas flow in times of greatest need.

2.1.1.6 Comparison of Hydrogen Production Technologies

Each hydrogen production pathway involves trade-offs. Table 1 summarizes key parameters for comparison (EPRI 2023h, CICE 2024, Graforce n.d.).

Table 1. Key Attributes of Hydrogen Production Technologies

Parameter	Alkaline	PEM	SOEC	SMR+CCS	Pyrolysis
Typical-Capacity	Modular and scalable	Modular and scalable	Modular and scalable	Typically large (50–300 tonnes/day)	Varies (5–300 tonnes/day)
Electrical Efficiency kWh/kg H ₂	49.92	55.0	38.4	1.4	Thermal: 4 Catalytic: 10 Plasma: 14
Gas Efficiency MMBtu/kg H ₂	—	—	—	0.15	Thermal: 0.27 Catalytic: 0.25 Plasma: 0.21
Stack Degradation	1%–1.5%/year	1.5%/year	20%/year	N/A	N/A
Ramping Capabilities	Battery may be needed to follow intermittent renewables	Expected to follow intermittent renewables	Thermal components may require continuous operation	Expected to run continuously	Varies by technology

Alkaline systems are slightly more energy-efficient than PEM systems, although their load following capabilities are not as well established. SOEC systems can be more efficient than alkaline or PEM systems, especially when coupled with a heat source such as a thermal power plant, but stack degradation is not well understood and is expected to remain high in the near future. Thermal technologies, such as SMR+CCS and pyrolysis, require less electrical input due to more thermodynamically favorable chemistry: The chemical bonds between hydrogen and carbon in methane molecules are weaker than the bonds between hydrogen and oxygen in water molecules, so they require less energy to break. SMR with CCS is expected to operate at baseload, while pyrolysis operational flexibility varies by technology: thermal and catalytic pyrolysis typically operate continuously, while plasma methane pyrolysis can operate flexibly.

2.1.2 Hydrogen Storage

2.1.2.1 *Underground Geologic Storage*

Underground hydrogen storage in salt domes and bedded salt formations involves creating large, stable caverns within these geological structures. Salt domes, which are thick, naturally occurring salt formations, are particularly well-suited for hydrogen storage due to their impermeability and structural integrity. The process of creating caverns involves injecting water into the salt formation to dissolve the salt and make a cavern, then removing and disposing of the brine. Bedded salt formations, which are layers of salt interspersed with other sediments, can also be used for hydrogen storage, although they may require more careful site selection and engineering to ensure stability and containment.

Depleted oil and gas reservoirs offer another viable option for underground hydrogen storage.

The process of storing hydrogen in these reservoirs involves injecting hydrogen into the porous rock formations that previously held oil or gas. Prospective sites should be screened for potential microbial or geochemical interactions and caprock and well integrity to mitigate the risk of hydrogen loss due to subsurface interactions or leakage. On withdrawal, the hydrogen is expected to contain impurities from residual hydrocarbons or other substances present in the reservoir. Therefore, it must be cleaned using processes such as pressure swing adsorption or membrane separation to ensure the hydrogen meets the required purity standards for its intended use.

Aquifers and hard rock-lined caverns are additional methods for underground hydrogen storage.

Aquifers, which are water-bearing porous rock formations, can be used to store hydrogen, though this method is less common due to potential water contamination issues. Hard rock-lined caverns, constructed within stable rock formations such as granite or basalt, offer an alternative option. These caverns are lined with materials to prevent hydrogen leakage. While these methods are less developed than salt caverns and depleted reservoirs, they offer potential for future hydrogen storage solutions.

2.1.2.2 Aboveground Storage Tanks

In aboveground hydrogen gas storage, the hydrogen is stored in gas cylinders and vessels at pressures typically between 175 and 700 barometric pressure (bar) and 2,500 to 10,000 pounds per square inch (psi). These tanks are made from coated steel, aluminum, or composite materials, depending on the required pressure ranges and capacities. For stationary aboveground storage applications, multiple gas cylinders can be stacked horizontally and vertically, manifolded together, and mounted in a supporting frame.

Gaseous hydrogen has low volumetric energy density, which creates challenges in the high footprints required for storage. To increase its density, hydrogen can be condensed from a gas to a liquid by compressing and cooling it in stages. Once liquefied, hydrogen is stored in insulated cryogenic tanks designed to minimize heat transfer and prevent boiloff. Some liquid hydrogen storage includes systems to capture and reliquefy boiloff vapor, returning it to the liquid state, which incurs an ongoing parasitic load. When hydrogen is needed for use, it is typically flashed back to a gaseous state by reducing the pressure and allowing the liquid to absorb heat. While liquefaction increases hydrogen density by 44%, effectively lowering the storage footprint requirement, it incurs a steep energy penalty of 30%–40% (EPRI 2023i).

Other high-density hydrogen storage options of lower maturity levels include the temporary conversion of the H₂ to other chemicals with higher densities, such as ammonia (see callout box), metal hydrides, organic hydrocarbons, or other materials.

Ammonia

Ammonia (NH₃) is a compound composed of nitrogen and hydrogen, commonly used in fertilizers and industrial processes. Hydrogen can be converted to ammonia by combining it with nitrogen gas (N₂) in the presence of a catalyst either at high temperatures and pressures or using an electrochemical potential. It can then be used as an energy storage medium, where it offers several benefits, including easier transportation and storage compared to hydrogen, due to its higher volumetric energy density and existing global supply chain infrastructure. However, ammonia is highly toxic and can burn the eyes, respiratory tract, and skin (EPRI 2025i). Its low laminar flame speed and the potential for high NO_x emissions during combustion present operational challenges. Ammonia can either be converted back (or “cracked”) to hydrogen before being used for power generation or burned in gas turbines directly for power generation. Neither of these technologies has reached maturity yet. NH₃ cracking is being used at a small scale but faces scalability challenges. NH₃ combustion is not yet fully developed, but research suggests that the operational challenges of combustion and NO_x formation could be mitigated with combustors specifically designed for ammonia (EPRI 2024k). Ammonia’s potential as an energy carrier is promising, particularly for long-distance transport and storage, and for use in direct combustion turbines (CTs), and reciprocating engines, but challenges related to NO_x and toxicity must be managed.

2.1.3 Hydrogen-capable Power Generation Technology

2.1.3.1 Combustion Turbines

Combustion turbines operate by compressing air and mixing it with fuel in a combustion chamber, where the mixture is ignited to produce high-temperature, high-pressure gases. These gases expand through a series of turbine blades, causing them to spin and drive a generator that produces electricity. NG combustion turbines (CTs) currently play an important role in providing firm electric power to New York State. These existing thermal sites could be retrofitted to combust an NG/hydrogen blend or pure hydrogen. Alternatively, due to the aging nature of the existing fossil fleets, new thermal plants designed for 100% H₂ combustion could be deployed. Currently, hydrogen use in large CTs is limited to blends.

2.1.3.2 Fuel Cells

Hydrogen fuel cells for power generation convert chemical energy directly into electricity through an electrochemical reaction combining hydrogen and oxygen to generate water and heat as the only byproducts. PEM fuel cells facilitate the reverse reaction of PEM electrolyzers by converting H₂ to protons, which are shuttled across a proton-conducting membrane and combined with oxygen (O₂) to generate electricity with water and heat as byproducts. Solid oxide fuel cells (SOFC) operate at high temperatures and convert O₂ to oxygen ions, which are transported across a solid oxide electrolyte and combined with H₂ to generate electricity and water. SOFC technology is more commonly used for stationary power generation applications today, typically operating at baseload. In contrast, PEM fuel cell power plants are expected to be able to operate more flexibly and may experience cost declines due to efficiencies and economies of scale from the heavy-duty vehicle market. Because fuel cells operate by electrochemical reactions, they lack mechanical rotation and thus do not provide grid inertia unless paired with GFM inverters. Recent Electric Power Research Institute (EPRI) research has shown there are nearly 30 commercial vendors of hydrogen fuel cells, many of which are available in the several hundred kilowatt size ranges allowing for scaling in a modular fashion. Fuel cells face higher cost uncertainties and more supply chain bottlenecks compared to combustion technologies, but offer benefits in their lower nitrogen oxide (NO_x) emissions, modular nature, higher fuel efficiency, and quiet operation (EPRI 2024h).

2.1.3.3 Linear Generators

Linear generators produce electricity by combining a fuel such as hydrogen with oxygen in a chemical reaction inside a sealed cylinder. Linear generators can operate with hydrogen, NG/RNG, or ammonia. The reaction of the fuel with oxygen releases energy as expanding gases, which push opposing pistons into reciprocating motion. The pistons directly drive a linear alternator, converting their back-and-forth movement into electrical power. The primary benefits of this approach to power generation compared to gas turbines are the potential for higher efficiency, lower NO_x emissions, and fuel flexibility. Additionally, currently commercially available linear generator products are available in smaller units around 250 kW, which allows them to be scaled in a modular fashion. The modular units, low emissions, and fuel flexibility together could provide some flexibility in siting and air permitting to system owners. However, linear generators are less ready than H₂ CTs or fuel cells.

2.2 Performance Attributes

The unique characteristics of different fuels and generator types result in differing abilities to provide certain grid services. Table 2 shows the relative strengths and weaknesses of some relevant power-generating options. Using hydrogen as a fuel for grid power is an active area of research, so there is uncertainty with some attributes due to a lack of real-world experience.

Table 2. Comparison of Hydrogen and Related Technologies by Grid Services and Attributes

Italicized entries indicate a lack of real-world U.S. demonstration.

Attribute	Turbine (New or Retrofit, Blended or 100% H ₂)	H ₂ Linear Generator	PEM H ₂ Fuel Cell ^a	Solid Oxide H ₂ Fuel Cell ^b
Inertial Response (Rotational)	Typically provides attribute a spinning turbine provides rotational inertia	Does not provide attribute no rotational inertia unless paired with GFM inverter	Does not provide attribute no rotational inertia unless paired with GFM inverter	Does not provide attribute no rotational inertia unless paired with GFM inverter
Ramping	Typically provides attribute <i>expected to ramp quickly by 2040</i>	Typically provides attribute research suggests potential to ramp quickly	Typically provides attribute research suggests potential to ramp quickly	Does not provide attribute typically operates at baseload
Cycling Capability	Typically provides attribute <i>expected to cycle load by 2040</i>	Typically provides attribute research suggests ability to cycle load	Typically provides attribute research suggests ability to cycle load	Does not provide attribute typically operates at baseload
Short Minimum Run Time	Typically provides attribute research suggests potential to operate for short run times	Typically provides attribute research suggests potential to operate for short run times	Typically provides attribute research suggests potential to operate for short run times	Does not provide attribute typically operates at baseload
Black Start	May sometimes provide attribute <i>feasible under specific situations and configurations</i>	May sometimes provide attribute <i>feasible under specific situations and configurations</i>	May sometimes provide attribute <i>feasible under specific situations and configurations</i>	May sometimes provide attribute <i>feasible under specific situations and configurations</i>
Capacity Factor	Flexible Expected to be limited by fuel supply rather than technical barriers	Flexible Expected to be limited by fuel supply rather than technical barriers	Flexible Expected to be limited by fuel supply rather than technical barriers	Flexible Expected to be limited by fuel supply rather than technical barriers
Minimum Stable Output	Typically provides attribute. <i>Expected to operate below full load by 2040</i>	Typically provides attribute Research suggests potential to operate below full load	Typically provides attribute Research suggests potential to operate below full load	Does not provide attribute Typically operates at baseload

^a PEM fuel cells need highly purified hydrogen. Using blended hydrogen would require additional equipment to reform and purify the fuel.

^b SOFCs can operate on NG by producing H₂ in situ or run directly on pure H₂. This flexibility allows them to accept hydrogen blended into NG at any concentration, potentially enabling allowing higher capacity factors.

The following summarizes the key takeaways from Table 2:

- Turbines provide rotational inertia, while fuel cells and linear generators do not unless paired with GFM inverters.
- Ramping, cycling, and part-load operation have not been demonstrated with hydrogen turbines, but these capabilities are expected to be possible by 2040 with continued research. Linear generators and PEM fuel cells are currently capable of flexible operation.
- SOFCs have primarily operated as baseload assets because their high operating temperature limits their ability to start up and ramp quickly. SOFCs can require hour-long startup times when starting from room temperatures. Their ramp rates range from 1-10% per minute, and there is uncertainty regarding whether regular ramping of SOFCs may affect stack lifetime (NREL 2024a). SOFCs will therefore need to improve dynamic performance before they can be deployed as low capacity factor assets. Various efforts to improve operational flexibility of SOFCs are currently at laboratory or demonstration levels of technical maturity.
- Hydrogen-fueled power generation may provide black-start services in specific situations and configurations.
- All hydrogen power generation assets are expected to have lower capacity factors than NG assets in the current NYS power system due to limited fuel availability and higher costs (see further discussion in Section 2.2.3). However, no technical barriers are foreseen to operating hydrogen power plants at capacity factors comparable to gas-fired power plants.

The following offers additional details on key hydrogen attributes.

2.2.1 Fuel Purity Requirements

Hydrogen purity requirements vary among generator types due to their different operational needs and sensitivities. Combustion turbines are less sensitive to impurities that might be present in the fuel. In contrast, PEM fuel cells require very high hydrogen purity, often exceeding 99.9%, to prevent catalyst poisoning and ensure efficient and reliable operation. The stringent purity requirements for these fuel cells stem from their reliance on electrochemical reactions at low temperature, where even trace impurities can significantly degrade performance and lifespan. SOFCs can run on NG (converting it to hydrogen in situ), as well as on pure hydrogen or a hydrogen–NG mixture. Because SOFCs are already designed to handle hydrocarbons like methane, they are less sensitive to those impurities compared to PEM fuel cells. However, minor impurities, such as sulfur in the form of hydrogen sulfide (H₂S), can still impact SOFC performance, although low levels of sulfur contamination may allow for full recovery of fuel cell performance (Ziomek-Moroz 2005). Linear generators can operate on NG, hydrogen, or a mixture of both fuels. Moreover, current technology developers indicate that linear generators should be capable of accepting hydrogen with less stringent purity requirements than PEM fuel cells.

Purity requirements for different power generation technologies influence the selection of suitable storage technologies. Geologic storage options, particularly depleted oil and gas reservoirs, tend to introduce impurities to stored hydrogen. Purification technologies exist to return the hydrogen to fuel-cell-quality purity levels, but they come at an added cost.

2.2.2 Round-trip Energy Losses

Electrolytic hydrogen may be better suited than other technologies for seasonal storage due to its low cost per unit of energy stored in underground resources, but the RTE is much lower. If an electrolyzer requires 51 kilowatt-hours (kWh) of electricity per kilogram of hydrogen and a generator produces 13 kWh of electricity per kg of hydrogen, only 26% of the original energy is left after these chemical conversions. Additionally, gas phase storage incurs an estimated 10% energy penalty, and liquefaction could incur an estimated 30%–40% energy penalty. All transportation options, whether by pipeline or truck, would incur an energy penalty, although higher for trucking. Table 3 shows these losses in terms of energy efficiency, assuming hydrogen’s lower heating value (LHV) of 33.3 kilowatt-hours per kilogram (kWh/kg) and an efficiency of 40%, which is typical of a hydrogen-fired turbine. A fuel cell would have a higher efficiency (~60%), resulting in lower overall losses.

Table 3. Efficiencies of Components in the Power-to-Hydrogen-to-Power Process

Process	Electrolysis	Storage	Power Generation	Total
Assumed Conversion	$\frac{1\text{ kg } H_2}{51\text{ kWh}}$	—	$\frac{13\text{ kWh}}{1\text{ kg } H_2}$	—
Percent Efficiency	65%	60%–90%	40%	16%–24%

2.2.3 Expected Capacity Factors of Hydrogen Power Generation

The annual capacity factor of NYS power-generating units using hydrogen as a fuel is expected to be significantly lower than that of the existing NG-fired fleet of peaking assets due to the comparatively high cost of hydrogen, which will be discussed in the following section on cost. NYSERDA’s *2025 Draft State Energy Plan* used capacity expansion and production cost modeling to identify a cost-effective resource mix for meeting load over time. Due to high hydrogen prices, the hydrogen peaker plants in that modeling only ran at a capacity factor of 2% in 2040 compared to the 2024 nationwide average of 14.7% capacity factor for gas turbines (NYS Energy Planning Board 2025, EIA n.d.a). This capacity factor is expected

to fluctuate depending on the severity of the weather in any given year, which introduces uncertainty regarding the amount of hydrogen required to meet seasonal needs (see Section 2.2.4). Given the high losses throughout the process of producing, storing, transporting, and converting it back to electricity, and the cost of new infrastructure, hydrogen is expected to remain more expensive than NG.

Additionally, the availability of renewable electricity dedicated to hydrogen production could become limited, depending on load requirements, whether due to economic development or the electrification of fuel loads, or limitations in the rate at which new wind and solar energy can be added to the NYS grid. In this case, the limited availability of hydrogen fuel from domestic State sources could limit the capacity factor of hydrogen-fired power-generating assets.

Relying on nuclear electricity or SMR with carbon capture has the potential to increase hydrogen supply, but these technologies introduce additional logistical and emissions challenges, respectively.

2.2.4 Fuel Availability during Critical Times

Although the NG system that provides fuel to New York State's current fleet of turbine power plants is thoroughly built out and technically mature, supply constraints occur on cold days of very high energy demand, during which dual-fuel power plants switch to burning distillate. Similarly, demand for hydrogen as a peaking asset would depend on the weather in a given year. This uncertainty necessitates having extra fuel available to meet reliability needs. Though hydrogen could theoretically be stored on-site, this presents technical and economic challenges (see Sections 2.3.3 and 2.5). For a peaking power plant to meet its reliability obligations, it would be critical to develop a solution to ensuring hydrogen-fired grid reliability assets have access to fuel during peak energy demand hours.

2.3 Readiness for 2040

2.3.1 Latest Deployment Trends

The vast majority of hydrogen produced in the U.S. today is grey hydrogen, which is derived from unabated reformation of NG. This carbon-intensive hydrogen is primarily used in industrial applications, such as ammonia production for fertilizer, petroleum refining, and methanol production for chemicals. These sectors are concentrated in certain regions, such as the Gulf Coast, particularly Texas and Louisiana, which have developed shared infrastructure networks (pipelines, storage) to support existing hydrogen use. Due to the established infrastructure and high demand, these industrial applications offer the most economically viable near-term opportunities for deploying cleaner hydrogen, particularly

hydrogen produced through reforming with carbon capture, as well as electrolytic hydrogen powered by renewable energy. While hydrogen for power generation in places like New York State presents a less economical use case in 2040, and the State currently lacks the supporting infrastructure seen in other regions, New York State stands to benefit from the cost reductions driven by initial deployments in more established hydrogen industrial centers if those initial deployments proceed.

The U.S. Department of Energy (DOE) estimated that in 2024, announced clean hydrogen production capacity increased 26% to 14 million tonnes per year, about 60% of this capacity coming from low-carbon reformation and 40% from electrolysis. This estimate does not include the 3 million tonnes per year from the Regional Clean Hydrogen Hubs (H₂Hubs) program (DOE 2024e). Federal policy changes, including the earlier phaseout of the Inflation Reduction Act's Clean Hydrogen Credit 45V, could impact the viability of these projects.

2.3.1.1 Noteworthy Projects

The following are four noteworthy hydrogen-related projects:

Constellation Nine Mile Point

Although New York State does not have existing industrial scale hydrogen production, there is some pilot-scale hydrogen production currently. In 2023, as part of a \$14.5 million cost-share project between the DOE and Constellation, the Nine Mile Point Nuclear Generating Station began producing 560 kilograms (kg) of electrolytic pink hydrogen per day to supply hydrogen for its operational needs that had previously been delivered by truck (DOE 2025a, DiGangi 2023).

Brentwood Hydrogen Cofiring Demonstration

In 2022, the New York Power Authority (NYPA), EPRI, and General Electric (GE) jointly conducted a hydrogen blending project at NYPA's Brentwood Power Station. This collaborative effort demonstrated the burning of a hydrogen-NG blend on an LM6000 gas turbine to identify the resulting impact on combustion emissions—CO₂, NO_x, and CO—along with the effect on gas turbine operation. The turbine was operated on hydrogen blends ranging from 5% to 44% by volume (EPRI 2023g).

Regional Clean Hydrogen Hubs Program

In 2022, DOE's Office of Clean Energy Demonstrations (OCED) issued a \$7-billion funding opportunity announcement to support 6–10 hydrogen hubs under the Regional Clean Hydrogen Hubs program, funded under the Bipartisan Infrastructure Law.

The funding will provide a 50% cost share, and the projects must be executed within 8–12 years (depending on size and complexity). The following hubs were selected:

- Appalachian Hydrogen Hub (ARCH₂)
- California Hydrogen Hub (ARCHES)
- Heartland Hydrogen Hub (HH₂H)
- Gulf Coast Hydrogen Hub (HyVelocity H₂Hub)
- Mid-Atlantic Hydrogen Hub (MACH)
- Midwest Hydrogen Hub (MachH₂)
- Pacific Northwest Hydrogen Hub (PNWH₂)

The program aims to support hydrogen production, delivery, storage, and end use by establishing a network of producers, consumers, and infrastructure. Some selected projects target power generation as an end-use, which should accelerate technical understanding of hydrogen-fired power generation. Recent federal policy changes have introduced uncertainty about the future of these hydrogen projects.

Advanced Clean Energy Storage Project, Delta, Utah

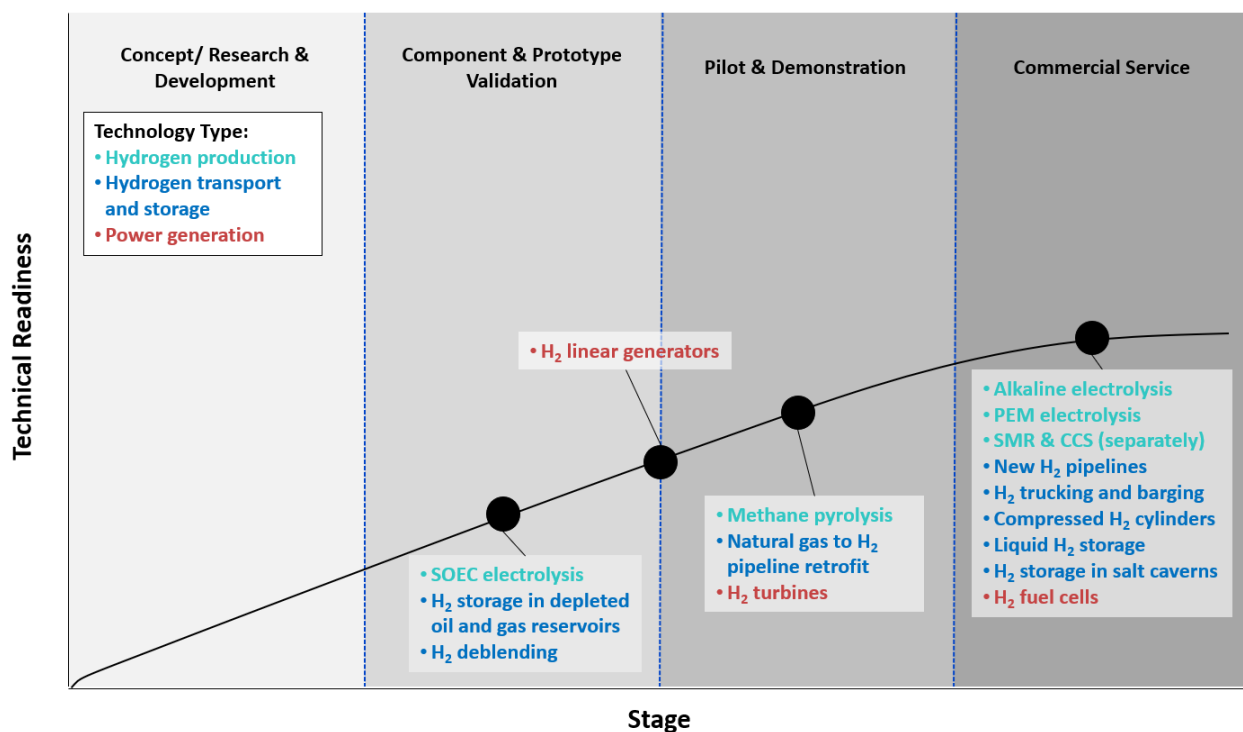
The Advanced Clean Energy Storage project in Delta, UT (ACES Delta), is a noteworthy hydrogen use case currently under development. The facility integrates 220 MW (100 tonnes of H₂ per day) of alkaline electrolysis capacity, featuring two caverns capable of storing 300 gigawatt-hours (GWh) of hydrogen (MHI 2023). The hydrogen will supply two gas turbines at a nearby power plant whose combined electric power capacity is 840 MW. The turbines will initially use up to 30% hydrogen blended with NG and plan to burn 100% hydrogen by 2045. The primary advantage of this project's approach is the close siting of hydrogen production, seasonal storage, and power generation, obviating the need for extensive new hydrogen transport infrastructure.

2.3.2 Technology Readiness Dynamics

Hydrogen technologies for producing, storing, transporting, and converting it to electricity are at various stages of readiness. Figure 6 presents the readiness levels of these technologies.

Figure 6. Technology Readiness of Hydrogen Production, Transport, and Power Generation

A technology remains in its current readiness phase until it completes all activities in that phase. When placed on the line between two readiness phases, a technology has completed all activities in one phase but has not started the next. The figure provides a high-level comparison of technologies but does not reflect variation in technological maturity within a category.



Additional technologies and details are discussed in the sections below.

2.3.2.1 Hydrogen Production

Alkaline Electrolysis Technology Readiness

Alkaline is the oldest electrolysis technology, having provided decades of commercial service. Though currently the most mature and lowest-cost electrolysis option, the industry can likely reduce costs as it scales up and achieves manufacturing efficiencies. Researchers are also pursuing improvements in alkaline electrolyzers' current density, operating pressure, and operational flexibility (ramping ability and low-load operations).

Proton Exchange Membrane Electrolysis Technology Readiness

PEM electrolysis also operates at the commercial-service stage. PEM remains generally more costly than alkaline, but its performance advantages (i.e., wider operating range, rapid start-stop capability, higher current density), combined with anticipated cost declines, are increasing its market deployment. Scaling up this deployment is expected to lower costs by improving productivity and reducing labor costs.

Solid Oxide Electrolysis Cell Electrolyzers Technology Readiness

SOEC is currently in the technology component validation and unit prototyping phase. Although no large commercial SOEC currently exists, the technology has demonstrated positive results at smaller scales in controlled conditions. The next milestones include demonstrations at conditions more indicative of full-scale deployment and larger-scale manufacturing capacity. In addition to the need for demonstrating the existing SOEC technology at scale, the industry's primary focus for technology development for SOEC is materials research and development (R&D), particularly for electrolytes and electrodes, to improve the durability, lifetime, and cost-effectiveness.

Steam Methane Reforming with Carbon Capture and Sequestration Technology Readiness

Most (about 95%) of the hydrogen generated in the U.S. today is produced via SMR, making the technology highly mature. Carbon capture and sequestration is also a mature technology because it has been used for enhanced oil recovery (EOR) for decades. Limited experience exists with combining the two processes, largely due to the lack of economic incentives to decarbonize hydrogen production. SMR with carbon capture has already been demonstrated at scale. Efforts are underway to demonstrate higher rates of capture, around 95%.

Methane Pyrolysis Technology Readiness

Methane pyrolysis technology for hydrogen production is in the technology demonstration stage, with some early small-scale deployments. Monolith's Olive Creek 1 (OC1) plant in Nebraska is the largest operating methane pyrolysis facility, producing carbon black as the primary product and hydrogen as a byproduct. Methane pyrolysis currently costs more than electrolysis or low-carbon reforming. However, if costs can become competitive with other hydrogen production technologies, the economics could reverse such that the hydrogen becomes the primary product, with carbon black as the byproduct. Key

areas for further development include optimizing reactor designs and improving catalyst performance and longevity to reduce the levelized costs of hydrogen. Additional solutions beyond markets and applications may be needed to manage the supply of carbon black at the scale required for the hydrogen needed for power generation.

2.3.2.2 Power Generation

Combustion Turbines Technology Readiness

Combusting hydrogen in gas turbines for power generation is in the technology demonstration phase of readiness. Demonstrations of hydrogen blending in grid-scale CTs have been successfully conducted, including up to 44% by volume at NYPA Brentwood Power Station, though the hydrogen cofiring did not include operation during startup and shutdown, so the findings are not necessarily indicative of standard operations.

Some CT models are currently available with the capability to combust up to 100% hydrogen (Webb et al. 2023). These are generally smaller units, such as the 45 MW aeroderivative turbine used in the Brentwood demonstration. These kinds of turbines are currently used at many peaking power plants in New York State. Larger frame turbines can currently accept some blended hydrogen and are expected to be capable of accepting 100% by 2030 in new builds and with retrofits to existing turbines. The lack of deployment to date is due to a lack of demand and high hydrogen fuel costs rather than inherent technical barriers.

Beyond the CTs themselves, a power plant capable of accepting high hydrogen concentrations would have different specifications for piping, joints, fuel offloading and fuel-blending skids, turbine controls systems, continuous emissions monitor systems, safety sensors and leakage detectors, heat recovery system generator (HRSG) furnace ductwork, selective catalytic reactor (SCR), standoff distances, and air permits. These specifications could be implemented on newly built plants or applied as retrofits to existing plants. Additional research and demonstrations are needed to understand these details, but they are not expected to pose technical impediments to deploying hydrogen combustion power generation. A 100% hydrogen-capable full-scale plant has not yet been demonstrated, either newly built or retrofit, so additional challenges may arise that have not yet been identified.

Fuel Cells Technology Readiness

Stationary fuel cells for power generation have been commercially deployed for years in applications where their quiet operation and high efficiency (especially in combined heat and power configurations) are valuable. Most of the stationary fuel cells currently operating in the U.S. use NG or biogas, which typically require a reformer to convert the methane to hydrogen before it is purified and directed into the fuel cell. Direct hydrogen fuel cells would not need reformers, but they would need some of the same upgrades to balance of plant components that would be expected for hydrogen-fired turbine plants discussed earlier. A significant barrier to the broader adoption of hydrogen fuel cells is cost. Improved manufacturing scale and efficiency through increased deployment could improve the economics for grid-scale applications. SOFCs would need improvements in start times and ramp rates before they could be deployed as low capacity factor resources.

Linear Generators Technology Readiness

Linear generators are in the early stages of commercial deployment. Mainspring Energy, a developer of linear generators, has successfully deployed commercial installations of its product, but these early deployments have been optimized to use NG. The readiness of using 100% hydrogen in linear generators may currently be between unit prototyping and technology demonstration. American Electric Power announced a memorandum of understanding (MOU) in 2022 for a pilot project in Oklahoma, which aims to evaluate the technology's performance in real-world conditions (Mainspring Energy 2022). In 2024, EPRI conducted a series of short-term witness tests as part of its low-carbon distributed generator demonstration projects to evaluate the generator's performance, block loading, and black-start capabilities using NG. These pilot projects are essential for generating the data and experience needed for broader commercial deployment.

2.3.3 Infrastructure and Supply Chain Readiness Dynamics

Building out the necessary infrastructure for using hydrogen in New York State's electric sector likely presents greater challenges than the readiness of assets for hydrogen production or power generation. Under current economic and technology conditions, the State's most economically viable renewable resources are located in Upstate New York, making it a more attractive region for electrolytic hydrogen production. Although Downstate New York is closer to high-density populations and energy loads, hydrogen production there must overcome infrastructure challenges associated with urban density. Pipeline delivery may be more cost-effective than other modular methods for long-term, grid-scale, hydrogen-fired power generation in New York City and Long Island (Zones J and K). However,

pipelines face significant permitting hurdles, long lead times, and siting constraints that make them an unlikely solution at scale for 2040. Modular delivery methods like trucks or barges face scalability and safety challenges. These may be appropriate for pilots or demonstrations, but the costs would remain high, and the large number of vehicles or barges transporting fuel would create inconvenience and increased risks. Downstate New York also lacks geologic storage, and sufficient aboveground on-site storage for a power plant to run through a high-demand event would be land-intensive and present security challenges.

One option to mitigate H₂ transportation and storage challenges would be to co-locate H₂ production and power generation Upstate near renewable deployments and rely on electricity transmission to provide power to the Downstate New York regions rather than transporting the H₂ itself. However, this approach could require additional Upstate-to-Downstate transmission.

Table 4 outlines the infrastructure and supply chain considerations for hydrogen, while subsequent sections discuss the various factors that affect the feasibility of hydrogen storage and transport.

Table 4. Infrastructure and Supply Chain Readiness of Hydrogen Technologies in New York State

Technology	Transmission & Grid Integration	Fuel Supply Chain & Waste Management	Cooling Water & Thermal Management	Siting & Land Use	Supply Chain
Blue H₂ Retrofit Turbine	No significant buildout required for existing assets	Long lead time SMR equipment supply chain is mature, but requires scale-up; fuel delivery infrastructure readiness depends on method (see below)	No significant buildout required	No significant buildout required for existing assets	Short lead time Some H ₂ components would need supply chain scale-up
Blue H₂ New Turbine	Short lead time Could be sited near transmission more easily than larger or location-dependent technologies	Long lead time SMR equipment supply chain is mature, but requires scale-up; fuel delivery infrastructure readiness depends on method (see below)	No significant buildout required	Short lead time Could be sited more easily than larger or location-dependent technologies	Short lead time Some H ₂ components would need supply chain scale-up
Blue H₂ Fuel Cell	Short lead time Could be sited near transmission more easily than larger or location-dependent technologies	Long lead time SMR equipment supply chain is mature, but requires scale-up; fuel delivery infrastructure readiness depends on method (see below)	No significant buildout required	Short lead time Could be sited more easily than larger or location-dependent technologies	Long lead time Fuel cell manufacturing capacity needs scale-up; PEM fuel cells vulnerable to supply risks
Green H₂ Retrofit Turbine	No significant buildout required for existing assets	Infrastructure not ready Electrolyzer manufacturing would require scale-up; PEM electrolyzers vulnerable to supply risks; fuel delivery infrastructure readiness depends on method (see below).	No significant buildout required	No significant buildout required for existing assets	Short lead time Some H ₂ components would need supply chain scale-up
Green H₂ New Turbine	Short lead time Could be sited near transmission more easily than larger or location-dependent technologies.	Infrastructure not ready Electrolyzer manufacturing would require scale-up; PEM electrolyzers vulnerable to supply risks; fuel delivery infrastructure readiness depends on method (see below).	No significant buildout required	Short lead time Could be sited more easily than larger or location-dependent technologies	Short lead time Some H ₂ components would need supply chain scale-up
Green H₂ Fuel Cell	Short lead time Could be sited near transmission more easily than larger or location-dependent technologies.	Infrastructure not ready Electrolyzer manufacturing would require scale-up; PEM electrolyzers vulnerable to supply risks; fuel delivery infrastructure readiness depends on method (see below).	No significant buildout required	Short lead time Could be sited more easily than larger or location-dependent technologies	Long lead time Fuel cell manufacturing capacity would need scale-up; PEM fuel cells vulnerable to critical mineral supply risks

Fuel delivery: Fuel delivery infrastructure readiness depends more on the delivery method than the power generation asset type. If hydrogen is produced, stored, and converted to electricity in one area, hydrogen transportation and delivery infrastructure would not be necessary. Hydrogen delivery by blended pipeline would require very little buildout, but would require extensive and detailed engineering assessments to qualify the pipeline for hydrogen service, as hydrogen can cause embrittlement in pipeline steels. Delivery by barge would require moderate buildout for port modifications and on-site storage. A dedicated hydrogen pipeline network connecting bulk hydrogen storage facilities to power plants would require significant buildout. The following sections offer a detailed discussion of hydrogen transport and storage considerations.

Supply chain: Many of the hydrogen-fired power generation technologies face potential supply chain challenges. All would require hydrogen-rated balance of plant components, the market for which is currently far smaller than that of equivalent NG balance of plant components. As the market for these hydrogen-rated components increases, potential bottlenecks may occur if supply and demand do not move at the same rate. The capacity to produce fuel cell systems at high manufacturing rates does not yet exist, and considerable investments in manufacturing development and facilities are needed to enable such production. Increasing the scale of fuel cell manufacturing may create shortages of rare input materials such as iridium, which are used in PEM fuel cells, PEM electrolyzers, and other technologies. Considering the small scale of linear generator deployment to date, the technology may face similar manufacturing challenges to navigate as it scales up.

Electricity supply: Because the key input to electrolytic hydrogen is electricity, hydrogen-fired power generation is vulnerable to any supply issues affecting the broader electricity sector. As New York State's entire economy seeks to decarbonize, emissions-free electricity demand will increase. If other sectors have a greater willingness to pay or are deemed a higher priority, the hydrogen industry may face shortfalls of electricity to procure for electrolysis. As more intermittent renewables connect to the grid, some renewables that would otherwise be curtailed during periods of excess supply could instead be used for electrolysis. Still, curtailed supply is likely sufficient for only a subset of hydrogen production needs.

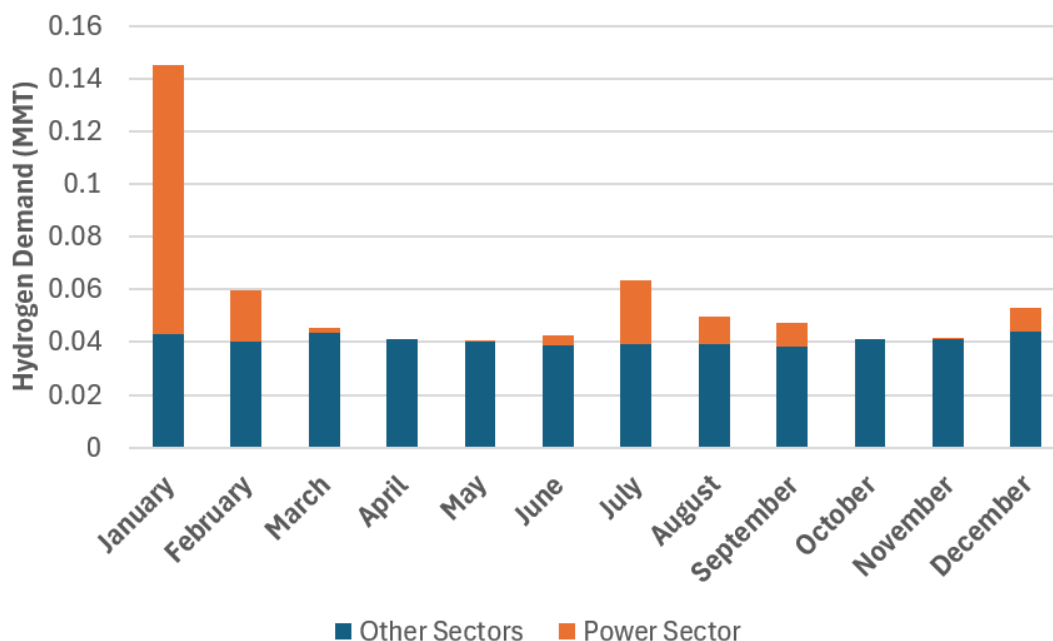
The following sections detail the unique infrastructure considerations associated with the statewide deployment of hydrogen.

2.3.3.1 Shared Infrastructure

The economic deployment of large-scale infrastructure requires high utilization to lower costs. Infrastructure for storing and transporting hydrogen does not currently exist at scale in New York State. Therefore, the cost of developing these assets could significantly increase the final delivered fuel price if the capital expense of that infrastructure is spread over a small amount of hydrogen. Because the hydrogen demand for peaking power is highly seasonal (Figure 7, power sector demand as modeled in New York State’s *2025 Draft State Energy Plan*), hydrogen infrastructure serving only the power sector would be poorly utilized, leading to high costs per kilogram. These costs could be substantially lowered if other sectors with flatter annual demand profiles used the infrastructure. New York State does not have the large, steady hydrogen demands of refineries and ammonia production facilities that other states have, so the primary sectors to share hydrogen infrastructure costs may be transportation (light duty, medium duty, heavy duty, and off-road vehicles), industry, and district steam, as considered in the *New York Hydrogen Assessment* (NYSERDA 2022). Without this shared infrastructure, hydrogen for the power sector may be limited to regions in Upstate New York where hydrogen production, geologic storage, and power generation could all be located in proximity.

Figure 7. Average Daily Hydrogen Demand by Month in 2040, Mid Power Demand Scenario

Based on economywide use from the *New York Hydrogen Assessment* (NYSERDA 2022) and Power Sector use from the *2025 Draft State Energy Plan*, Net Zero A Scenario



2.3.3.2 Hydrogen Transport

Due to the lack of hydrogen pipelines in most areas, modular transportation methods such as trucking are used to transport hydrogen today. However, the significant volumes of hydrogen needed for power generation necessitate physical and operational infrastructure to support such volumes, which may include pipelines or terminal facilities using marine deliveries. Table 5 summarizes the infrastructure readiness of each hydrogen transport mode, and the subsequent sections describe the readiness of each transport option.

Table 5. Infrastructure Readiness of Hydrogen Transport Modes in New York State

Transport Mode	Network & Supporting Infrastructure	Siting, Permitting & Land Use	Workforce & Supply Chain
Pipeline	Long lead time May have long, unpredictable timelines; repurposing NG infrastructure may be possible	Long lead time Right-of-way access and permitting may be challenging	Long lead time Requires specialized equipment and skilled labor
Truck	No significant buildout required, but compression or liquefaction facilities are required	Long lead time Regional restrictions complicate hydrogen transport	Short lead time Additional trained truck drivers will be needed.
Shipping	Long lead time Port infrastructure would require upgrades	Long lead time Port expansion requires land and permitting	Long lead time Port upgrades require equipment and skilled labor

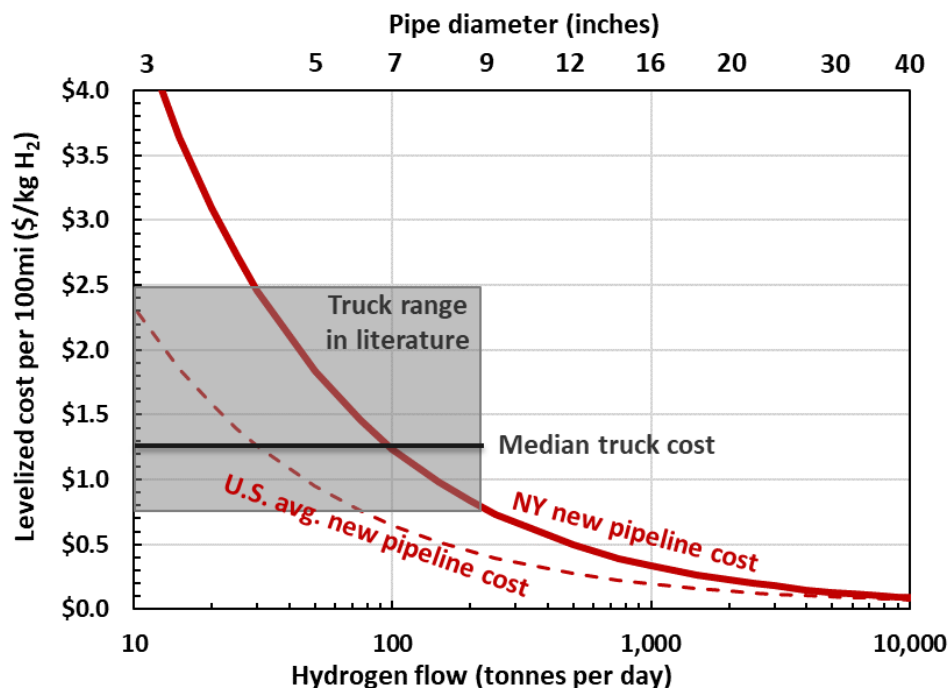
2.3.3.3 Hydrogen Pipelines Infrastructure Readiness

If hydrogen demand is relatively constant day-to-day, pipelines are estimated as the more economical strategy above ~100–200 tons per day, as Figure 8 illustrates. A single 239 MW F-class turbine with an efficiency of 75 kilograms of hydrogen per megawatt-hour (kg H₂/MWh) would use over 400 tonnes per day, and Zones J and K currently host over 13,000 MW of turbine capacity. Recent modeling for this study, using the National Renewable Energy Laboratory’s (NREL) Hydrogen Production, Storage, and Transmission Analysis Tool (HYPSTAT), indicates that, even accounting for the power sector’s seasonal demand, power sector demand alone could make a pipeline more economical than trucking in New York State. However, further research is still needed to address the logistical challenges associated with using a pipeline for highly irregular demand.

Figure 8. Hydrogen Transmission Costs for New Pipelines and Tube-Trailer Trucks

Based on literature and HYPSTAT modeling.

Source: Figure B-3, New York Hydrogen Assessment (NYSERDA 2022).



New Hydrogen Pipelines

New hydrogen pipelines are a mature technology with existing codes and standards. Using existing rights-of-way where available can facilitate pipeline deployment. However, new hydrogen pipelines face other deployment hurdles such as permitting challenges, long lead times, and siting constraints that make them unlikely to deploy at a meaningful scale before 2040.

Retrofit Natural Gas Pipelines

Some distribution pipelines in New York State are already rated for 100% hydrogen because they were replaced with polyethylene during routine maintenance. Older steel transmission pipelines will require retrofitting, such as adding lining material, and engineering critical assessments to qualify existing materials for hydrogen service. Current guidance in the American Society of Mechanical Engineers (ASME) B31.12 standard requires laboratory testing of base pipe and weld metal, evaluating chemical composition, hardness, yield strength, ultimate tensile strength, and the presence of any weld inclusions, at a minimum of one sample per mile, or 1.6 kilometers (km). In addition to upgrading the pipeline material, equipment at compressor stations would need to be replaced. Retrofitting a gas transmission

line would be logistically challenging because existing customers would be cut off from NG for the project's duration, and all customers would need to be prepared to switch from NG to hydrogen at the same time. Because hydrogen carries less energy per unit of volume, the pipeline would be expected to be able to transport less energy.

Blended Pipelines

Blending lower levels of hydrogen into existing NG pipelines could lower initial deployment barriers by incentivizing supply growth until enough demand exists to justify building a dedicated hydrogen pipeline network. Consensus is lacking on the conditions under which hydrogen blending is compatible with NG transmission and distribution networks, partly because of the wide variation in pipeline age and condition (Topolski et al. 2022). This heterogeneity is evident across New York State, where the gas network was not designed to accommodate substantial quantities of hydrogen blending. In the near term, a maximum of 20% by volume is expected due to compatibility with end-use appliances, but each NG transmission and distribution system requires specific compatibility assessment, including a detailed evaluation of safety and reliability risks, before blending hydrogen. For example, a study commissioned by the California Public Utilities Commission found that a single, systemwide injection standard could not be determined due to excessive uncertainty with blends exceeding 5% (Penchev 2022). The study recommended a 3-year timeline to conduct large-scale demonstration projects at 5%–20% hydrogen to develop and demonstrate mitigation strategies to address safety and performance issues; conduct laboratory studies to consider safety and performance concerns with materials and equipment used in California's NG infrastructure; and engage with utilities, industry, regulatory agencies, and community stakeholders.

Large areas of uncertainty surround widespread hydrogen blending in existing NG infrastructure that require additional research, including compatibility with pre-1970s U.S. pipeline system steel, materials characterization of polymer pipelines, effects of hydrogen on other equipment components (e.g., valves, meters, pressure regulators), and the applicability of current maintenance and repair procedures (Topolski et al. 2022). Additionally, prior economic studies of hydrogen blending have not fully considered the costs that will factor into assessing and modifying an existing NG network for hydrogen blending (Topolski et al. 2022). This gap has, in part, motivated the development of DOE's Blending Pipeline Analysis Tool for Hydrogen (NREL 2024c, Topolski et al. 2024).

Blending low levels of hydrogen into existing NG pipelines would also have consequences for both local air quality and statewide GHG emissions, which are discussed in Section 2.4.1.

Overall, while blending H₂ into existing NG pipelines could lower initial deployment barriers by leveraging existing infrastructure to enable supply growth, the existing infrastructure is not designed to handle substantial quantities of hydrogen. Blending any meaningful amount of hydrogen would require a comprehensive compatibility assessment of safety, air quality, and reliability risks. For these reasons, according to the *2025 Draft State Energy Plan*, New York State does not currently support the blending of hydrogen into the existing natural gas pipeline system.

Deblending

The pipeline blend could either be used as-is or deblended to produce separate, pure streams of NG and hydrogen. While hydrogen deblending technology is developing and scaling up, it is still in the prototyping stage, with current deployments operating at far lower capacities than would be needed to supply power generation assets. Should deblending technology become feasible, if a power plant wanted to avoid emissions from combusting a blended fuel and instead sought to burn 100% hydrogen from a blended pipeline, the power plant would either need to upsize its gas interconnection or add on-site storage. A more technically and economically feasible option would be to burn the blended gas directly and use a resource tracking mechanism to account for emissions. If a generator used blended gas as opposed to pure hydrogen, local emissions from NG use would persist. Declining gas throughput and growing economywide hydrogen demand, as is expected under deep decarbonization scenarios, will limit the long-term viability of hydrogen blending. Any hydrogen blending should be viewed as a transitional approach to a more dedicated hydrogen infrastructure.

Carbon Dioxide Pipelines

If New York State produced low-carbon hydrogen via reformation with carbon capture, it would need to develop CO₂ pipelines to transport the carbon from the reformation facility to the sequestration site in addition to the hydrogen pipelines. The dynamics of CO₂ transport and storage are explored in Section 5. An advantage of methane pyrolysis is the ability to create carbon black, which is easier to transport and store than gaseous CO₂.

Modular Hydrogen Transportation Infrastructure Readiness

Trucks: Shipping hydrogen by truck is a mature and economically deployed technology that is currently the primary method for transporting hydrogen between locations not connected by pipeline. Shorter distances are more economically covered with gas-phase shipping. Conversely, longer distances (over ~250 miles) are better suited for liquid-phase trucking, where the increased density (more hydrogen per trailer) compensates for the energy losses of liquefaction.

Trucks were delivering hydrogen to the Nine Mile Point Nuclear Generating Station before the electrolysis project was implemented, and they also delivered hydrogen for the Brentwood Power Station hydrogen blending demonstration.

A full-scale peaking power plant would require a volume of hydrogen delivery not well-suited for trucks. Assuming hydrogen gas trailers carrying 800 kg each and a power-generating efficiency of 75 kg/MWh, each 57 MW aeroderivative turbine would require about 5 trucks per hour, and each 239 MW F-class turbine would require about 22 trucks per hour. With liquid hydrogen, the aeroderivative would require about 1 truck per hour, and the frame turbine would require approximately 5 per hour, assuming 17,000-gallon trailers carrying 3,800 kg of liquid hydrogen (ANL n.d.).

Recent modeling conducted for this study using NREL's HYPSTAT and 2025 Draft State Energy Plan hydrogen demand estimates suggests that even if Zone J demand were divided equally throughout the year, it would require over 200 tonnes (over 200 gas trailers or over 50 liquid trailers per day) of hydrogen to be supplied to the city per day. These estimates do not include the extra hydrogen that would be required to be stored on-site for reliability purposes.

Developing enough on-site storage that the hydrogen could be delivered in advance over a longer time at a lower rate of truck traffic presents its own challenges, discussed later, and would not significantly reduce the overall risks posed by moving so many trucks of hydrogen fuel through urban streets, because a similar number of trucks would still be needed. Overall, the volume of trucks required to meet Zone J demand in the absence of a pipeline appears to be infeasible.

Regional restrictions, such as the Port Authority of New York and New Jersey's (PANYNJ) hazardous material regulations, further complicate hydrogen transport (PANYNJ 2009).

Barges: Liquid hydrogen has been successfully transported by barge for specific applications, such as by NASA to move hydrogen rocket fuel 900 miles from Louisiana to the Kennedy Space Center in Florida via both inland and open-ocean waterways (NASA 2025a).

Barging liquid hydrogen to load centers in Downstate New York presents unique challenges. The population density and narrow, winding channels in parts of New York City's waterways carry safety and security challenges. New port infrastructure would be required for unloading and handling liquid hydrogen, and issues related to zoning and permitting would need to be addressed.

Barges could carry much more hydrogen than trucks, but would still require many deliveries. A barge carrying 143.8 tonnes of liquid hydrogen (equivalent to NASA's barge transporting a space launch system core stage) could supply a 57 MW aeroderivative turbine for 33 hours and a 239 MW F-class turbine for 8 hours (NASA 2022).

2.3.3.4 Hydrogen Storage

The power demand for hydrogen would be highly seasonal, so storage would be needed to hold large quantities of hydrogen built up over months of production to discharge it quickly during the peak demand hours. Additionally, the amount of hydrogen required for a given winter or summer peak season depends on the weather and is therefore uncertain. Thus, in order to meet reliability needs, excess hydrogen would need to be stored seasonally. Such volumes would require low costs per unit of storage capacity (measured in dollars per kilogram, or \$/kg, of working gas) and minimal losses (such as from liquid hydrogen boiloff). They would likely only be feasible with geologic underground storage.

Underground Hydrogen Storage Infrastructure Readiness

Salt caverns: Salt caverns offer numerous advantages for hydrogen storage in the power sector. Large storage volumes can be created economically through brine extraction, leaving an open cavern with fast injection and withdrawal capabilities. Though hydrogen storage in salt caverns is not common today, many salt caverns, such as those used to store NG in Schuyler County, NY, could potentially be retrofitted to store hydrogen.

The *New York Hydrogen Assessment* analysis assumed this NG storage capacity could hold 8,000 tonnes of hydrogen, with the potential to create an additional 16,000 tonnes of new salt cavern capacity, bringing the total to 24,000 tonnes of hydrogen. These storage facilities are expected to have limits on injection and withdrawal rates, which could inhibit quick access to large amounts of hydrogen in short timeframes.

The *New York Hydrogen Assessment* assumes an injection rate of 3% total capacity per day and a withdrawal rate of 10% per day.

Depleted oil and gas reservoirs: Given the porous nature of the storage medium, depleted oil and gas reservoirs may not be able to inject and withdraw hydrogen as quickly as a salt cavern, though a wide range of injection/withdrawal rates (2.4%–11.9%) have been modeled (EPRI 2024b). Mixing with residual hydrocarbons would necessitate greater cleanup and purification of the withdrawn hydrogen, but their potential capacity is significantly greater. New York State currently has 126 million cubic feet of NG storage capacity in such facilities (EIA n.d.b). If converted to hydrogen, the fleet of storage resources could offer 254,000 tonnes of storage capacity (Lackey 2023). This is likely more capacity than would be needed given the lower expected capacity factor of hydrogen-fired power generation compared to current NG power plants.

Although purification would likely be necessary for salt caverns as well, the cleanup needed for depleted oil and gas reservoirs is expected to be more intensive, particularly if the hydrogen will be used in PEM fuel cell applications. Modeling has demonstrated that purification of hydrogen stored in depleted oil and gas reservoirs to purity levels sufficient for fuel cells and pure hydrogen pipelines is technically feasible using existing technology such as pressure swing adsorption or cryogenic distillation (EPRI 2024b).

Aboveground Hydrogen Storage Infrastructure Readiness

Aboveground hydrogen storage is not expected to be economically viable on its own for seasonally balancing hydrogen supply and demand due to high capital costs, which do not decrease significantly with larger deployments in the same manner as salt caverns. However, aboveground storage would be necessary for 100% hydrogen-firing power plants that are not connected to a pure hydrogen pipeline. It may also be needed for resiliency if pipeline delivery of hydrogen during critical hours cannot be guaranteed, unless other backup fuels are available.

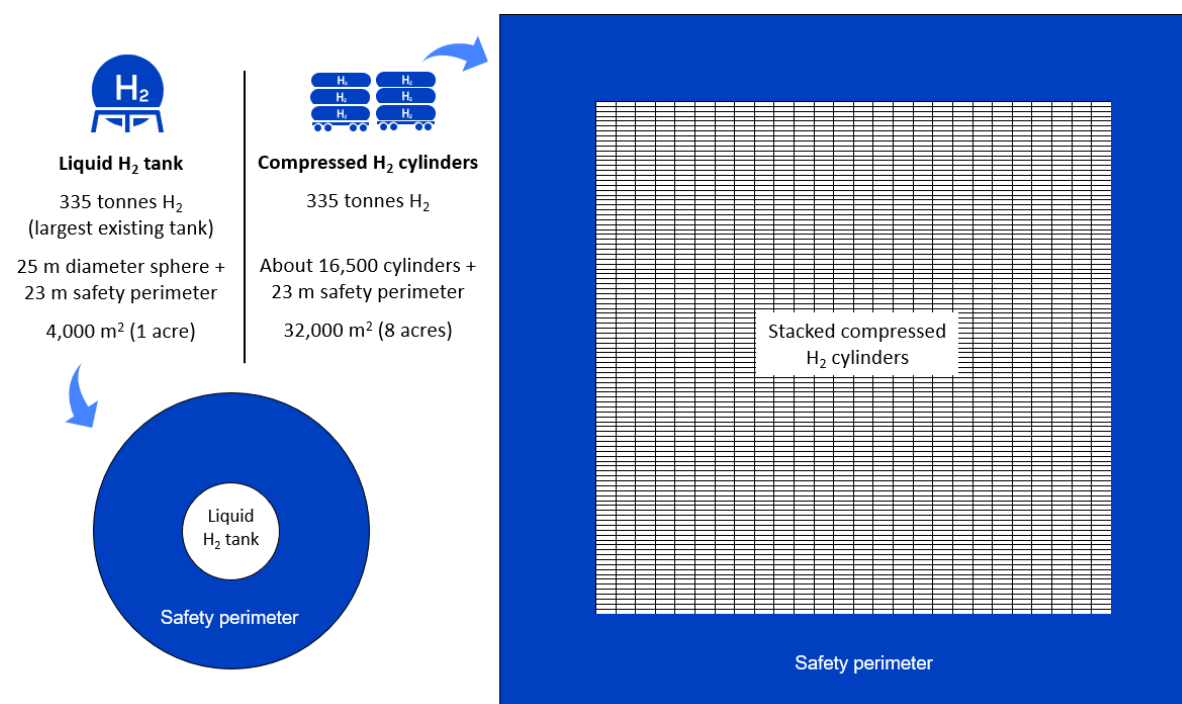
Compressed gas cylinders: Storing hydrogen as a compressed gas is a mature technology used in sectors like transportation, where the benefits of industrial experience, technical simplicity, and high discharge rates outweigh the high capital costs.

Liquid hydrogen: Liquifying hydrogen and storing it in insulated tanks is a mature technology used in applications that require large amounts of hydrogen stored densely, for example, NASA fueling rockets.

Gaseous hydrogen has a low energy density, which may make storing it above ground in quantities relevant for power generation impractical due to cost and land availability. Liquid hydrogen has a much higher energy density than gaseous hydrogen, making it potentially more suitable for applications in areas that are land-constrained and lack viable geology for underground storage, such as Downstate New York. The Kennedy Space Center in Florida has the world's largest liquid hydrogen storage tank, which is used to fuel rockets for NASA's new Space Launch System. The spherical storage tank, completed in 2022, has a capacity of 1.25 million gallons (4732 cubic meters [m³] or 335 tonnes). This amount of hydrogen could fuel a single 239 MW frame turbine for less than 19 hours (assuming an efficiency of 75 kg H₂/MWh) (EPRI 2023i). Storing an equivalent amount of gaseous hydrogen, assuming the specifications stated above, would require about 16,000 cylinders and 32,000 square meters (m²) or 7.9 acres, compared to about 4,000 m² or 1.0 acres, for a liquid storage tank, inclusive of the safety perimeter (Figure 9). The capital cost of so many cylinders is also expected to be higher than that of large liquid hydrogen tanks. The *New York Hydrogen Assessment* assumes capital expenses of \$800/kg of working capacity for gas storage, and the contract for the liquid NASA tank was \$60.3 million, or \$180/kg. Storage costs are discussed further in Section 2.5.2.

Figure 9. Estimated Land Area Requirements for Storing 335 Tonnes of Hydrogen as Liquid versus Gas

This quantity could fuel a single 239 MW frame turbine with an efficiency of 75 kg H₂/MWh for less than 19 hours.



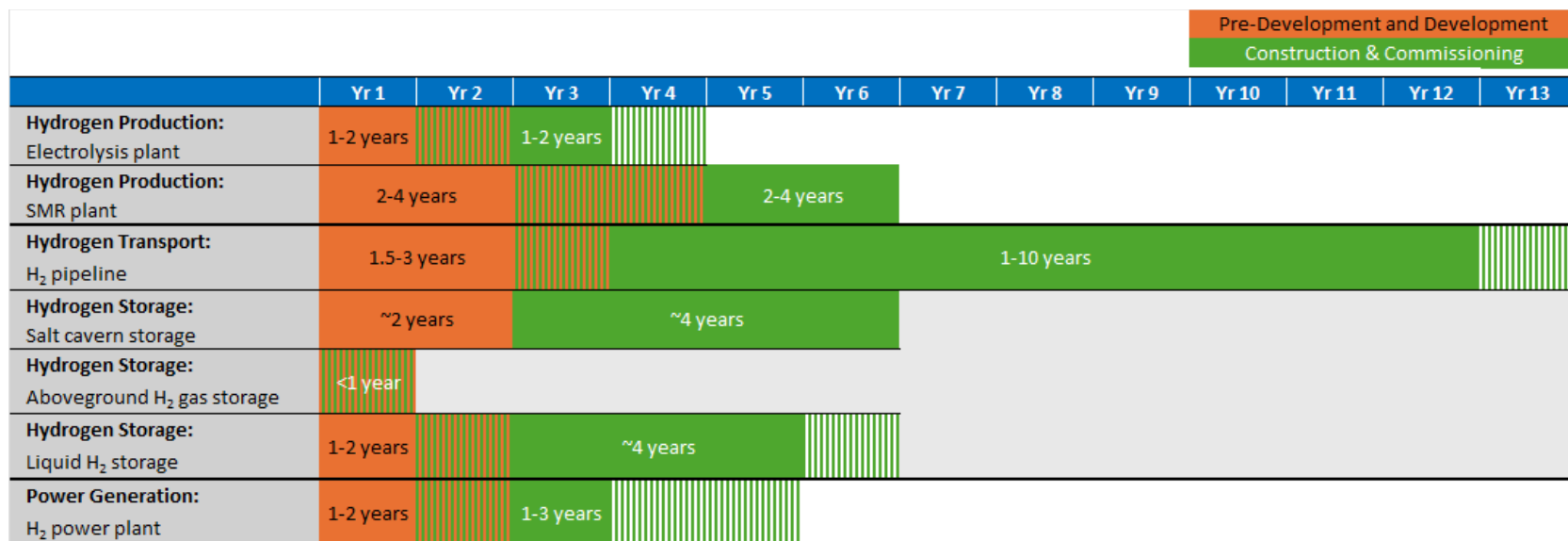
Aboveground Storage Round-Trip Efficiency

Liquid hydrogen faces drawbacks in round-trip efficiency (RTE) due to liquefaction and boiloff. The energy required for liquefaction can consume 30%–40% of the fuel’s energy content, a significant energy penalty compared to 10% for compressing hydrogen gas (HFCTO n.d., Moradi 2019). Boiloff varies with factors such as tank size and insulation or refrigeration technology, but can be approximated at around 0.03% per day (ANL n.d.). Using liquid hydrogen storage for power generation faces challenges not relevant to other use cases. NASA can fill its tank over a span of weeks and empty it on a scheduled date. New York State’s zero-emissions firm power assets are only expected to be called on 2%–3% of the year (NYS Energy Planning Board 2025). The timing of these events is unpredictable, so the optimal timing of filling and emptying to minimize boiloff and transport logistics would not be achievable.

2.3.4 Project Lead Times

The successful deployment of hydrogen in the power sector will require the coordinated buildout of production, transport, storage, and power generation assets. The following sections discuss the lead times associated with these projects. Figure 10 provides lead time estimate ranges for each component.

Figure 10. Project Lead Times for Hydrogen Technologies



2.3.4.1 *Hydrogen Production Lead Times*

A large-scale electrolysis facility could take up to 2 years to construct (EPRI 2023h). Predevelopment activities, including obtaining permits for water withdrawals and establishing electrical supply, may take 1–2 years before construction can begin (EPRI 2023n). Construction of an SMR plant could be expected to take twice as long, about 4 years (EPRI 2023h). Given the additional complexities of permitting and stakeholder engagement in a reformation process, the predevelopment activities would also likely take at least twice as long as those at an electrolysis facility.

A key bottleneck that could impact the development of a large electrolysis facility is the procurement of enough carbon-free electricity to operate the plant profitably. For low-carbon reformation, the likeliest holdup would be a CO₂ pipeline to carry away the captured emissions. As discussed in the section on CCS, a CO₂ pipeline could take 10–15 years to develop.

2.3.4.2 *Hydrogen Transport Lead Times*

Before undertaking a hydrogen pipeline project, planners must establish confidence that utilization will be sufficiently high to recover the capital expenses. Because the power sector’s hydrogen demand is so concentrated in just a few winter and summer months, a pipeline serving only power generation would likely not be financially viable. Infrastructure sharing with other sectors that have flatter annual demand profiles plays a critical role in developing a hydrogen pipeline network and, by extension, in enabling hydrogen-fired power generation in Downstate New York.

Once investment decisions are made, a new hydrogen pipeline project is expected to take 3–13 years, including predevelopment (EPRI 2023n). These notional timeline estimates are highly generalized, and the varying complexities and distances of pipeline projects result in a wide range in project development duration. The complexity of building a pipeline through dense urban environments would likely cause projects in Downstate New York or in other urban areas of the State to take longer than in more rural areas.

Retrofitting pipelines may be a less time-intensive project. They would likely encounter fewer issues with permitting and regulatory hurdles, but generalizations are difficult because the conditions of different sections of the pipeline may affect the project duration. An NG to hydrogen pipeline conversion in the Netherlands was completed between 2017 and 2018, including initial testing and cleaning (Top 2022).

The downtime of the pipeline would be a key factor in project feasibility because interrupting the fuel supply to all downstream customers would be highly disruptive. Additionally, all end users would need to be prepared to switch from NG to hydrogen simultaneously, which would be logistically difficult.

Some hydrogen could be blended into the existing network, but the maximum concentration depends on the age and condition of the pipeline, and a detailed safety and reliability assessment would be needed. A conservative threshold would be 5%, but for the near future, 20% by volume is likely the maximum, limited by customer applications if not the pipeline network. However, according to the 2025 Draft State Energy Plan, New York State does not currently support the blending of hydrogen into the existing natural gas pipeline system. Deblending, which faces near-term technical questions of scale and logistics discussed earlier, would require some lead time for installation of deblending units, balance of plant upgrades to be 100% hydrogen capable, additional NG connection infrastructure, and/or on-site hydrogen storage. Directly firing hydrogen at concentrations below 20% and procuring additional hydrogen attributes through a resource tracking mechanism may require some minor plant modifications, but the project times are expected to be shorter than those of competing options, including new pipelines or deblending.

2.3.4.3 *Hydrogen Storage Lead Times*

Solution mining a new salt cavern is expected to take about 2 years (Patel 2022). Including the predevelopment, aboveground infrastructure, initial injection, and testing, the full project could take around 6 years based on the ACES Delta experience, which commenced in 2019 and is expected to be completed in 2025 (Patel 2023a). Projects to repurpose NG salt caverns for hydrogen storage may have a shorter duration but would require time for replacing compressors, upgrading piping components, possibly drilling additional wells, and injecting the initial hydrogen (EPRI 2024c). Converting a depleted oil and gas reservoir storing NG to store hydrogen would require most of the same upgrades as converting a salt cavern facility. Both kinds of retrofits would likely require the addition of a purification system to separate the hydrogen from the residual hydrocarbons in the storage space.

Aboveground compressed hydrogen cylinders can be delivered to a site by truck and provide services very quickly. Installing more permanent racking, manifolds, and other site infrastructure will require additional time and resources. For a very large aboveground compressed hydrogen storage facility that required clearing and leveling large areas, the site work and installation would scale up in proportion to the size of the facility.

Recent experience with liquid hydrogen tank facilities suggests a minimum 4-year construction period (NASA 2018b, NASA 2025b).

2.3.4.4 Hydrogen Power Generation Lead Times

A new hydrogen simple cycle power plant is expected to require 1–2 years of predevelopment and 1–3 years of construction and commissioning, resulting in a total lead time of 2–5 years, depending on the project’s complexity, size, and specific circumstances (EPRI 2023n). Fully retrofitting an NG-fired power plant to combust 100% hydrogen has not been executed before, so an accurate estimation of the timeline of such a project cannot be determined at this time. Because peaking gas turbine plants provide important resiliency to the power grid, any outage of this duration should be planned to avoid peak times of the year and avoid several plants being upgraded concurrently. This may necessitate staggering plant upgrades and starting the process of retrofitting the turbine fleet years in advance. A new hydrogen fuel cell power plant may take 3 years to deploy (NREL 2024a). Due to the modularity of the units, linear generators may be installed in about one year. Including predevelopment, the total lead time is expected to be about 18 months (Patel 2023b).

A key potential bottleneck to the deployment of these power-generating technologies is procuring the manufactured equipment. For example, gas turbines have historically experienced cycles of supply and demand mismatches, resulting in very long equipment lead times and project delays (Clark 2025). Proposed plants relying on hydrogen-capable turbines, fuel cells, or linear generators could all be exposed to this risk.

2.3.5 Geographic Suitability and Constraints

New York State’s geography presents challenging supply and demand dynamics, with most of the renewable energy resource potential located in Upstate New York and most of the load concentrated in Downstate New York. Upstate projects may be more feasible in the near term as Downstate faces challenges related to the scarcity of available land for renewable power generation and hydrogen storage. Today, Downstate power demand is met primarily through a combination of transmitting power directly via transmission lines and delivering NG to Downstate power plants via pipelines. Hydrogen is one strategy for replacing the latter portion, and shared pipeline infrastructure is one approach for supporting Downstate use of hydrogen, although it is subject to deployment challenges. The electric transmission component could also be expanded, allowing more units to be located Upstate, where hydrogen infrastructure challenges are less acute. With increased electric transmission capacity, hydrogen

could be produced, stored, and converted back into power in a single area Upstate (possibly near renewable or nuclear power generation) and sent to demand centers as electricity. When hydrogen was not being produced or used for power, the extra transmission capacity could allow more renewable energy to be used directly. Increasing electric transmission capacity can be challenging, but it would complement many technologies beyond hydrogen for achieving a zero-emissions grid.

2.3.6 Readiness Summary

The adoption of hydrogen as a fuel in the NYS electric sector is highly dependent on new or upgraded infrastructure to store hydrogen and transport it to power plants during peak demand hours. Because the hydrogen molecule is small compared to methane, hydrogen can leak more easily from pipelines and storage tanks, requiring specialized materials and designs, so existing NG infrastructure cannot be used for 100% hydrogen without modification. Hydrogen has a lower volumetric energy density than NG, so it requires more space for the same energy content, necessitating larger storage volumes or liquefaction to increase its density.

The most acute potential bottleneck for hydrogen infrastructure is providing hydrogen to power-generating units in Zones J and K, where 62% of simple cycle NG capacity is located, 9,054 MW out of 14,488 MW statewide (NYISO 2024a). Without a pipeline providing on-demand hydrogen delivery from geologic storage facilities in Upstate New York to end-users in these Downstate New York zones, the hydrogen would need to be transported by truck or barge and stored locally. This strategy would require hundreds of trucks per day to Zone J and acres of on-site storage. Overall, in the absence of a pipeline, the modular transport and on-site storage requirements to meet Downstate demand are daunting. Until enough economywide demand is developed to justify a pipeline and other outstanding economic and safety concerns are addressed, H₂ is expected to be more feasible Upstate, where opportunities to co-locate production with underground storage offer fewer infrastructure challenges.

The RTE of power from hydrogen to power is lower than that of other modes of energy storage. If the necessary new hydrogen infrastructure can be developed, large amounts of carbon-free electricity would be needed. As economywide decarbonization and electrification accelerate across New York State's energy-demanding sectors, the State may face constraints on the amount of carbon-free power-generating capacity it can create by 2040. If carbon-free electricity constraints materialize, hydrogen would become

a less viable energy storage strategy. Nuclear-powered electrolyzers or the production of hydrogen using SMR with CCS could create more hydrogen supply, but these are long-lead-time technologies that would require early action to be deployed before 2040. Additionally, SMR with CCS would have significant emissions implications, as discussed in the next section.

2.4 Emissions and Other Considerations

2.4.1 Emissions

2.4.1.1 Greenhouse Gases

Under New York State’s Climate Act GHG accounting framework, electric sector emissions include direct emissions from power generation and fugitive upstream emissions from fossil fuel production. One advantage of using hydrogen as a fuel for the electric sector is the absence of GHG emissions at the power plant. When hydrogen is produced electrolytically using renewable electricity or nuclear power, upstream fossil emissions are also avoided, resulting in a zero-emissions fuel. Hydrogen produced via NG reformation with carbon capture, sometimes called blue hydrogen, includes emissions from upstream NG production and CO₂ from the reformation process that is not captured and permanently sequestered.³ Due to the energy requirements of the reformation process, blue hydrogen requires more NG per unit of peaking electricity than combusting NG directly. As a result, the emission reductions from using blue hydrogen instead of NG are considerably less significant (Figure 11).

Emissions for blue hydrogen production also depend on the power generation source for the SMR process. Figure 11 shows the emissions if power is sourced from zero-emissions sources. Emissions would be higher if the power were sourced from the NG that also serves as the source of H₂.

Blue hydrogen emissions also depend on the method of power production. Fuel cells have higher efficiencies than CTs, so the upstream emissions per megawatt-hour of fuel are lower for fuel cells than for CTs.

The following figures do not include the emissions associated with CO₂ transport and storage.

Figure 11. Greenhouse Gas Emissions from Hydrogen-fired versus Natural Gas Peaking Power

Values in pounds of CO₂e/MWh produced. Blue hydrogen production assumes 90% carbon capture rate.

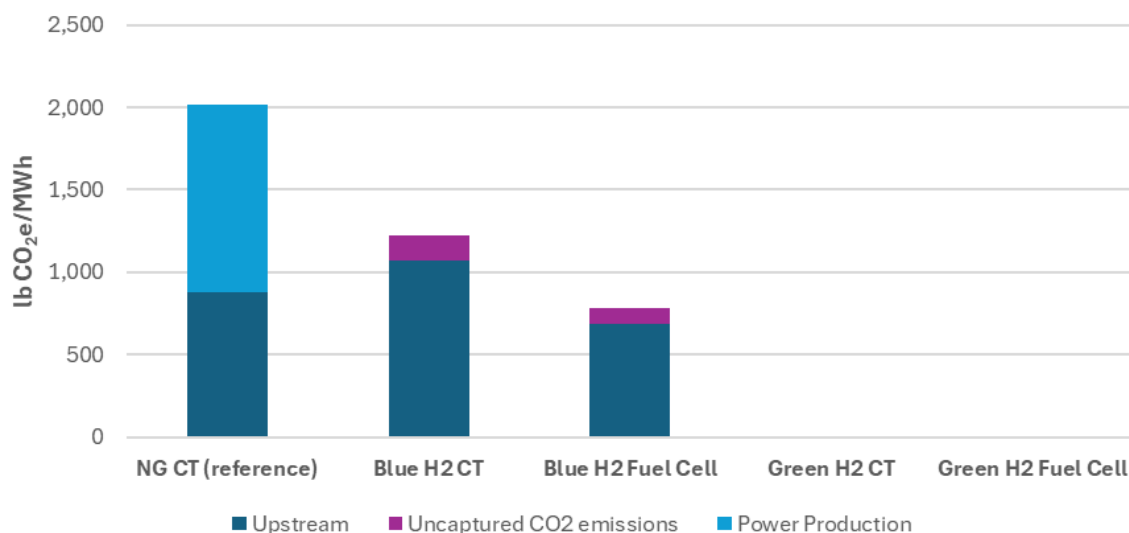
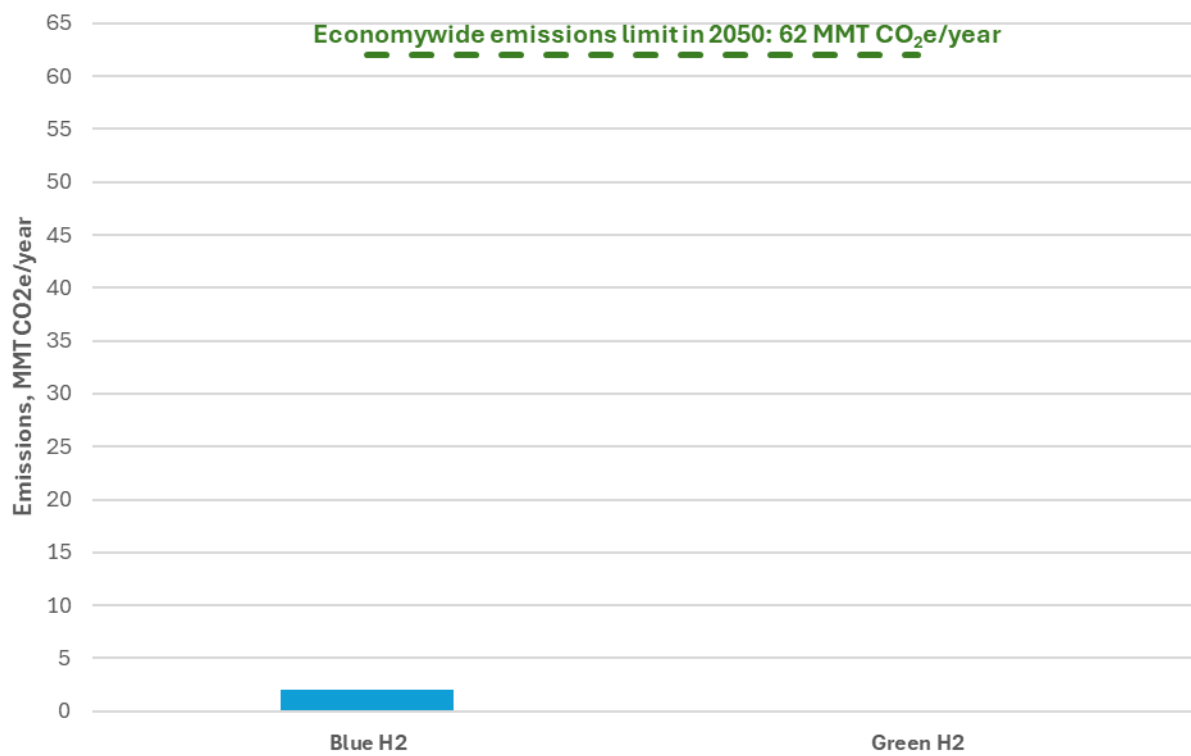


Figure 12 shows the total annual emissions if hydrogen were used to meet the 2040 peaking demand modeled in the *2025 Draft State Energy Plan*, Net Zero A scenario, which is 3,621 GWh. The use of blue hydrogen in CTs to meet this demand would result in 2.0 million metric tonnes (MMT) of carbon dioxide equivalent (CO₂e) emissions, which is relatively small compared to the 2050 economywide limit of 62 MMT CO₂e but would still require emissions reductions in other sectors. Any further emissions reductions from other sectors would be challenging because residual 2050 emissions are allocated to the hardest-to-decarbonize end uses. For example, modeling from the *Draft SEP* suggests 38 MMT would be needed for nonenergy sectors, like waste and agriculture. If plants were needed for more than this minimal amount of generation, emissions would be expected to scale proportionally. Green or pink hydrogen, in contrast, would result in zero power sector emissions.

Figure 12. Annual Equivalent Metric Tonnes of Carbon Dioxide Emissions by Power Sector under Low-Demand Scenario



Hydrogen itself is considered an indirect GHG because, although it does not trap heat itself, it reacts in the atmosphere to alter the concentrations of potent GHGs like methane and ozone. When hydrogen leaks into the atmosphere, it consumes hydroxyl radicals (OH) that would otherwise break down methane, resulting in higher methane levels and thus increased warming. Additionally, these chemical reactions can also increase stratospheric water vapor, further contributing to global warming through indirect radiative forcing.

2.4.1.2 Co-Pollutant Combustion Emissions

Combustion of both NG and hydrogen produces NO_x emissions. NO_x emissions can contribute to concentrations of pollutants of concern, nitrogen dioxide (NO₂) and ozone. Researchers need to conduct more studies to characterize NO_x emissions from hydrogen combustion, but technical issues with stack monitoring calculations, originally designed for NG combustion, complicate this uncertainty.

Controls are traditionally used to ensure emissions meet regulatory requirements. In NG turbines, emissions of NO_x can be reduced by water injection to lower the combustion temperature or by SCR to convert the NO_x exiting the turbine to N₂ and water (H₂O) in the presence of a catalyst and a reducing agent, typically ammonia. Because the stoichiometric flame temperature of hydrogen is higher than that of NG, combusting hydrogen in NG turbines could result in NO_x emissions that are higher than those produced by combusting NG for the same amount of energy produced. Though researchers need to conduct more research to fully characterize hydrogen combustion performance in dry low-emission (DLE) turbines, current research has demonstrated that systems explicitly designed for pure hydrogen combustion can effectively limit NO_x emissions to levels comparable to those from NG (Webb et al. 2023). Changing the air-to-fuel ratio to lower combustion temperatures also lowers NO_x emissions.

SCR is a mature technology, and systems exist that are capable of ramping as fast as an aeroderivative turbine, allowing them to maintain NO_x emissions within permitted levels throughout operation, including startup. While the amount of NO_x generated by a hydrogen turbine has not been well characterized, estimations of SCR retrofits can be developed to assess sensitivities of potential NO_x levels (EPRI 2022h). An evaluation of an aeroderivative gas turbine with a baseline SCR inlet NO_x level of 25 ppmv and an outlet NO_x level of 2.5 parts per million by volume (ppmv), a typical NO_x permit limit for an aeroderivative turbine firing NG in New York State, was conducted for scenarios of SCR inlets 50% and 100% above baseline and constant SCR outlet levels. The calculations showed the lifetime costs of the additional catalyst volume and ammonia usage were about \$175,000 for the 50% increase case and \$240,000 for the 100% increase case. These costs would not be prohibitively expensive in the context of retrofitting a gas turbine, so controlling NO_x emissions should not be seen as a roadblock to retrofitting existing turbines to use hydrogen.

Hydrogen-fired turbines may emit less total annual NO_x because they are expected to operate less frequently than gas turbines due to the higher marginal cost of using a more expensive fuel. This conclusion assumes that alternative generation sources would be available to replace the difference between current gas plants and expected future hydrogen plants.

Hydrogen fuel cells and linear generators are expected to produce significantly lower NO_x emissions relative to hydrogen turbines. Fuel cells electrochemically convert hydrogen and oxygen directly into electricity without combustion, producing negligible amounts of NO_x (DOE n.d.a). Linear generators

use low-temperature chemical reactions to create piston movement and are expected to produce low NO_x emissions (estimated below 0.07 lb/MWh) relative to turbines (estimated at 0.43 lb/MWh) without SCRs (CEC 2024a).

Low levels of hydrogen blending into NG systems for residential and small commercial applications not designed or retrofitted for the blended fuel and where emissions mitigation technologies are not practically implementable would have uncertain impacts on NO_x emissions, depending on the appliance, configuration, and blend level (Mac Kinnon et al. 2025, Fang et al. 2023). The hydrogen portion of the blend is not expected to emit particulate matter (PM) or other co-pollutants.

2.4.2 Other Considerations

Currently, no large-scale hydrogen production facilities operate in New York State, so new facilities would need to be built for hydrogen to play a meaningful role in the State’s electric sector. These facilities would impact nearby communities through their demands for water, land, and workforce. Table 6 provides estimates of these parameters (EPRI 2023h, EPRI 2023f). Power-generation assets could leverage existing sites, creating transitional workforce opportunities and lowering disruptive community impacts. The following sections discuss various considerations relevant to hydrogen deployment.

Table 6. Resource Requirements of Hydrogen Production Technologies Affecting Local Communities

Technology	Alkaline	PEM	SOEC	SMR+CCS	Pyrolysis
Modeled Capacity	1.5–50 tonne/day	1.5–50 tonne/day	1.5–50 tonne/day	50–300 tonne/day	1.2–6.5 tonnes/day currently (future deployments expected to be larger)
Water Consumption	7.8 gal/kg H ₂	9.7 gal/kg H ₂	^a	6.4 gal/kg H ₂	Negligible
Land Requirements	2.8-8.8 acres	2.8-5.5 acres	2.8-6.4 acres	3–6 acres	Less than 5 acres
Labor Requirements	2–10 staff	2–10 staff	2–15 staff	35–45 staff	2–10 staff

^a Water consumption for SOEC was not included in the referenced study, but SOEC may achieve lower total water consumption due to its higher thermal efficiency at high operating temperatures, which allows the hydrogen product to be cooled by preheating the incoming water or steam.

2.4.2.1 Air Quality

Air emissions near power plants would see a positive impact if NG were replaced with hydrogen because co-pollutant emissions from hydrogen combustion are limited to NO_x, and overall pollutant emissions would be eliminated or reduced: particulate matter (PM) emissions would be eliminated, and NO_x

emissions could be reduced overall. As discussed earlier, even in the case of pure hydrogen combustion, with appropriate technology, NO_x emissions could be effectively limited to levels comparable to those from NG. They may fall on a total annual basis because a hydrogen plant would be expected to operate at a lower capacity factor.

2.4.2.2 Safety

Hydrogen is not inherently more or less dangerous than other fuels, all of which have unique properties and safety-related trade-offs. Hydrogen has a wide flammability range and low ignition energy relative to other fuels, which necessitates careful handling to prevent accidental fires.

Hydrogen is colorless and odorless, and its flame is nearly invisible, which makes detection challenging. However, various sensor technologies are being designed and deployed to address this issue, playing a crucial role in ensuring the safe use of hydrogen.

Hydrogen's small molecular size allows it to permeate materials and escape through tiny openings, requiring specialized, high-quality containment materials and more sensitive leak detection equipment than used for NG. Hydrogen can also chemically interact with the microstructure of certain materials, leading to embrittlement and weakening of infrastructure components. Proper material selection and rigorous testing are therefore essential to mitigate these risks. While even small hydrogen leaks can lead to dangerous accumulations and potential explosions if ignited, hydrogen's high buoyancy and rapid diffusivity in open air also serve as an important safety advantage. Ultimately, while hydrogen possesses unique characteristics, many existing safety practices can be adapted and applied. Effective risk management for hydrogen mirrors established protocols in other fuel industries, focusing on robust materials, design, operation, and maintenance procedures, with a strong emphasis on hazard elimination, leak detection, and comprehensive, expert-reviewed training programs for personnel, including clear PPE guidelines.

The logistical challenges associated with using trucks to transport quantities of hydrogen suitable for power generation were discussed earlier, but the necessary volume of trucks would also increase the traffic of hydrogen fuel trailers, introducing new risks.

2.4.2.3 Land Use

Hydrogen production facilities will typically need to be strategically placed near electricity generation, end-users, and/or transport and storage assets to minimize infrastructure costs and transmission losses. While these facilities are relatively compact (Table 6), the land-use intensity of the renewable energy required to produce electrolytic hydrogen would be significant. Hydrogen produced with nuclear electricity or SMR + CCS would have lower land-use impacts, but these solutions also face logistics and emissions challenges.

The land-use intensity of hydrogen power generation assets is similar to that of NG, and existing sites could be leveraged to minimize the land-use impact of hydrogen-fired power generation.

2.4.2.4 Water Use

Electrolytic hydrogen production consumes water to generate hydrogen, resulting in a greater water need compared to some power generation technologies that can reuse cooling water. Some technologies are developing electrolyzers that are compatible with impure water sources, such as seawater, to reduce the impact on freshwater consumption.

2.4.2.5 Workforce

An emerging hydrogen industry in New York State would require a trained workforce for both construction and operational roles and could see implementation challenges if this workforce does not materialize. Initiatives are underway to develop training programs to avert these personnel bottlenecks (EPRI 2025e). Working with hydrogen requires specialized knowledge and skills, but skills can be mapped from adjacent industries. Leveraging existing power generation sites for hydrogen power generation creates transitional workforce opportunities for local communities. The distributed nature of some hydrogen applications may lead to geographically dispersed job creation, which can impact local economies and necessitate regional workforce development strategies.

2.5 Cost

Multiple layers of costs factor into the final cost of power generated with hydrogen, including fuel costs, storage costs, transport costs, and power generation costs. This section explores the impact of these inputs and pathways.

2.5.1 Fuel Cost

The fuel cost is the major driver of the high costs associated with power generation using hydrogen fuel. Green hydrogen point-to-gate fuel costs in this section were developed by NREL using its HYPSTAT tool, which supported the 2025 *New York Hydrogen Assessment*. For this power-sector-oriented report, several adjustments were made to the model inputs to better focus on power sector dynamics for hydrogen as a peaking asset. The inputs were adjusted as follows:

- **Demand inputs:** Power sector hydrogen demand was updated to reflect the new 2025 *Draft State Energy Plan* Pathways results for the Net Zero A scenario. Other sector hydrogen demand, modeled here for the Economywide with Pipeline infrastructure scenario, was kept consistent with the *New York Hydrogen Assessment*.
- **Imports:** The *New York Hydrogen Assessment* assumes that 50% of the hydrogen supply could be supplied with imports from other states, with limited restrictions on availability. For this modeling exercise, a more conservative outlook on imports was assumed so that the costs would more accurately reflect how demand fluctuations affect cost. This report assumes zero hydrogen imports.
- **Storage:** To accommodate the highly variable power sector hydrogen demand, new storage options were introduced to the scenarios explored here, including new salt caverns, depleted oil and gas reservoirs, and liquid tank storage. An additional feasibility assessment is necessary to understand the full potential.
- **Infrastructure scenarios:** This modeling exercise also explored new scenarios, including a scenario in which the power sector alone drives hydrogen demand. Additional scenarios that limited pipeline availability were also explored, primarily to illuminate logistical challenges, and they are incorporated into Section 2.3.3.

EPRI estimated blue hydrogen costs using current SMR costs sourced from the *Low-Carbon Energy Supply Technology Cost and Performance Study*, multiplied by a regional adjustment factor for Upstate New York, and future costs are calculated with learning-based cost projection factors (EPRI 2023h, EPRI 2025c).

2.5.1.1 Green Hydrogen

The major drivers of green hydrogen cost are electricity, transport and storage infrastructure, and electrolyzers.

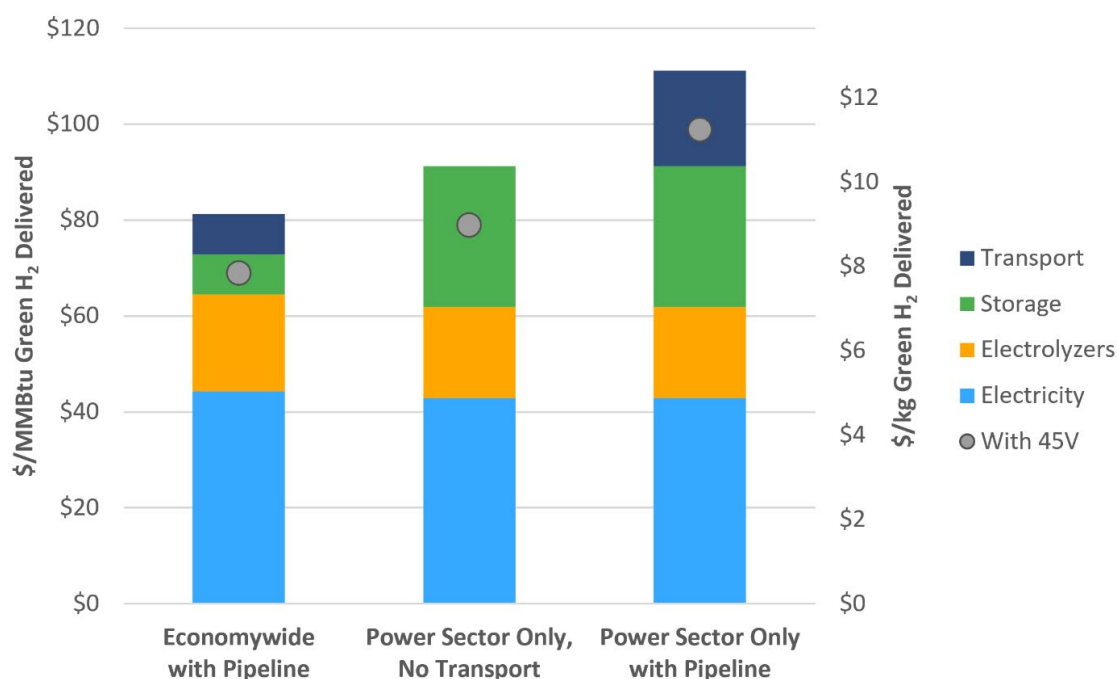
Transport and Storage Infrastructure

Figure 13 depicts green hydrogen fuel cost for three infrastructure scenarios:

1. **Economywide with Pipeline:** The first scenario assumes a hydrogen pipeline network is developed to transport hydrogen statewide, including Downstate New York to Zones J and K. The costs of the transportation infrastructure are shared among other sectors of the economy that will use hydrogen, including vehicles, industry, and district heating. This infrastructure scenario is most cost-effective, but it relies on shared adoption and pipeline availability. As discussed in other sections of this chapter, while pipeline transport is more cost-effective for large volumes than more modular options such as trucking or barging, pipelines face permitting challenges, long lead times, and siting constraints that make them an unlikely solution at scale for 2040.
2. **Power Sector Only with Pipeline:** This scenario represents a NYS energy system in which a hydrogen pipeline network is developed to transport hydrogen statewide, including Downstate New York to Zones J and K, but the costs are borne entirely by the power sector. Due to the lack of cost share and the lower utilization, the specific costs of transporting and storing each unit of hydrogen are more expensive in this scenario. Similar to the economywide scenario, this scenario would face challenges associated with timely pipeline deployment.
3. **Power Sector Only with No Transport:** This scenario assumes no hydrogen pipeline is developed. Due to the economic and logistical challenges of transporting hydrogen by truck or barge, this scenario assumes that hydrogen power generation is available only in Upstate New York, where hydrogen production, storage, and power generation can all be located close together. Unlike the other two scenarios, NREL did not specifically model this scenario. It was derived by excluding the transportation cost component from the power sector, specifically in the pipeline scenario. In this case, additional electric transmission capacity could be needed to transmit the electricity generated Upstate to serve Downstate New York regions during peak hours.

Figure 13. Delivered Green Hydrogen Cost in 2040 under Varying Infrastructure Scenarios

Values in 2023 USD.



Electricity Cost

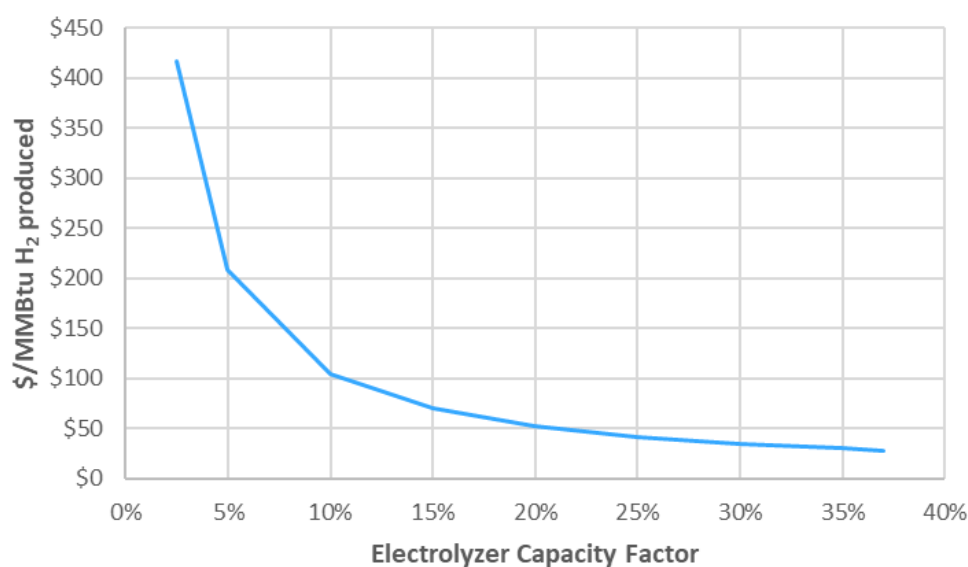
In addition to the infrastructure scenario, the key drivers of green hydrogen cost are electricity cost and electrolyzer cost, which account for 55% and 25% of the H₂ cost in the economywide scenario, respectively. The analysis depicted in Figure 13 derived 2040 clean electricity cost estimates from the 2023 New York Large Scale Renewables Supply Curve. Electricity cost uncertainty can further increase the cost of H₂ fuel. Some green hydrogen can potentially be produced using otherwise curtailed renewable energy as intermittent renewable energy is deployed in the power sector. Given that electricity typically accounts for 45%–60% of the cost of green hydrogen, as demonstrated earlier, low or no-cost electricity could significantly reduce the price of hydrogen. However, the extent to which lower-cost hydrogen could be available will depend on whether electrolyzers can be deployed economically at the associated capacity factor of curtailed renewables. Hydrogen at the scale of power sector demand will likely significantly exceed the hydrogen that could be produced exclusively from curtailed renewables. Figure 14 shows the effect of electrolyzer capacity factor on the cost of hydrogen produced, assuming zero-cost electricity. Theoretically, if electrolyzers can operate flexibly enough to capture curtailed electricity and capacity factors could reach 15% or 30% with zero-cost electricity, the levelized cost of hydrogen (LCOH) could approach costs as low as \$70 per million British thermal units (/MMBtu)

or \$35/MMBtu, respectively, excluding tax credits. However, if curtailed renewable power availability is lower, the capital and fixed operations and management (O&M) components of LCOH rise sharply as the electrolyzer capacity factor decreases, resulting in very high LCOH values. This simplified exercise does not capture transmission costs that are still expected to be incurred regardless of whether the power would be otherwise curtailed.

Figure 14. Levelized Cost of Hydrogen Assuming Zero-Cost Electricity at Varying Electrolyzer Capacity Factors

Values in 2023 USD. Tax credits are not included in LCOH values.

Source: EPRI (2025f).



If nuclear electricity were used to produce hydrogen, the cost of electricity is estimated to be higher than with renewables. However, unlike the renewables scenarios, which assume a capacity factor of 37% to match the renewable power generation, a nuclear-powered electrolyzer could have a capacity factor of 90% or more, resulting in a lower levelized capital component of the hydrogen cost and offsetting the higher input electricity cost.

Electrolyzer Cost

Electrolyzer cost is another key driver of green hydrogen fuel costs and depends on the type of electrolyzer technology used. Figure 13 assumes PEM technology. Alkaline electrolyzers are expected

to be less expensive than PEM electrolyzers for near-term deployments, but as deployments of PEM increase, the cost difference is expected to shrink, so PEM and alkaline electrolyzers could have similar costs approaching 2040. SOEC costs are too uncertain to predict at this stage of development.

2.5.1.2 Blue Hydrogen

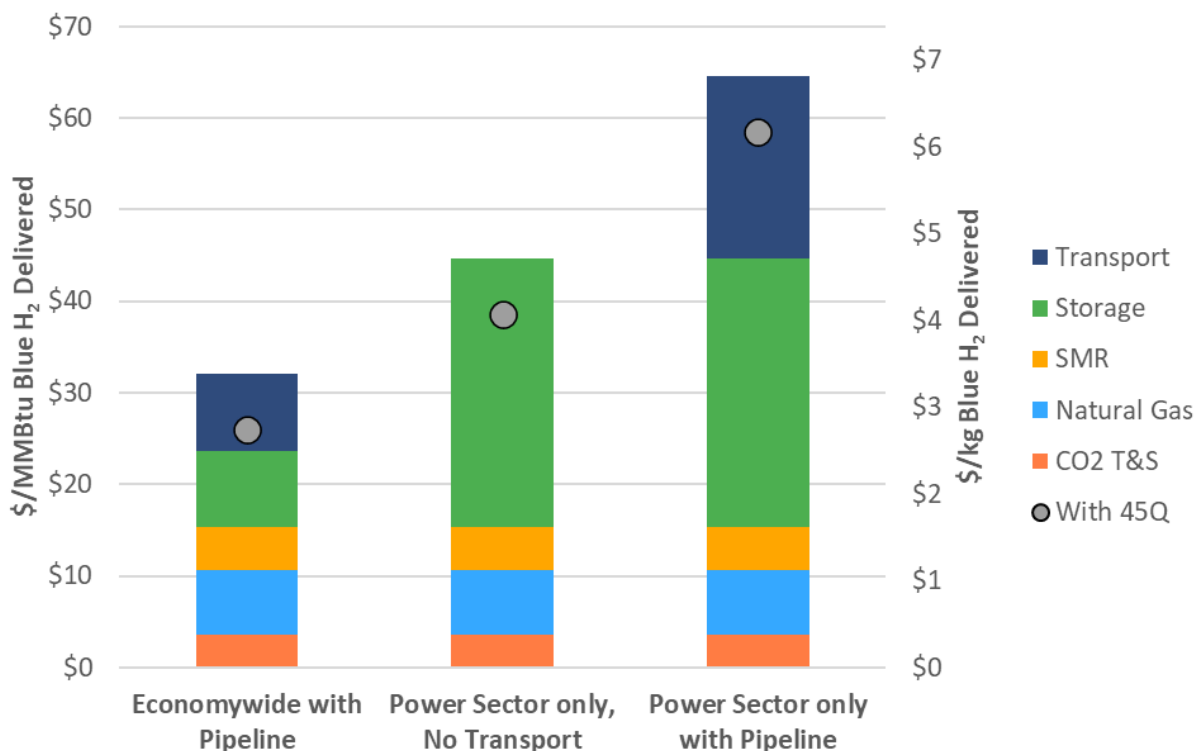
The cost of blue hydrogen, or hydrogen produced via SMR with carbon capture, is much lower than the cost of green hydrogen. The main drivers for blue hydrogen cost are the cost of NG, SMR capital and operating costs, and CO₂ transport and storage costs.

Transport and Storage Infrastructure

Blue hydrogen may face similar transport and storage infrastructure challenges as green hydrogen. Figure 15 shows blue hydrogen costs broken down by component for the same three infrastructure scenarios described earlier for green hydrogen. In reality, blue hydrogen would be expected to be produced in different locations, resulting in varying infrastructure costs, but this analysis did not explore these dynamics. Additionally, blue hydrogen may have different storage needs than green hydrogen due to differing production profiles. This analysis assumed that storage dynamics are dominated by peak demand profiles rather than supply, so that blue hydrogen and green hydrogen scenarios would have similar storage needs and costs. However, detailed modeling with constant hydrogen output from blue hydrogen would be needed to determine more accurate storage needs and costs to meet hydrogen power demands using blue hydrogen. Similar to the green hydrogen scenarios described above, while pipelines remain likely to be the most cost-effective transport method for large volumes of blue hydrogen, they face considerable challenges that make them unlikely to be deployable by 2040. In the absence of a pipeline, costs would be expected to be higher than those shown in Figure 15.

Figure 15. Delivered Blue Hydrogen Cost in 2040 under Varying Infrastructure Scenarios

Full tax credit eligibility requires construction to start before the credit phaseout date. Prices reported in 2023 USD.



Natural Gas Cost

The main driver for the cost difference between green and blue hydrogen is the fact that the NG fuel required for blue hydrogen production (assumed to be \$5/MMBtu for this analysis, with an uncertainty range of \$4–\$10/MMBtu) is less expensive than the renewable electricity required for green hydrogen production (the levelized electricity cost in the NREL model for green hydrogen production is calculated to be \$0.149/kWh, equivalent to \$44/MMBtu, in the economywide scenario).

Steam Methane Reforming with Carbon Capture and Storage Costs

The capital costs for an SMR facility with CCS are similar to those of electrolyzers, but the capacity factor of SMR could be as high as 90%, whereas the average NYS renewable capacity factor is assumed to be 37%. The high capacity factor of SMR drives down the capital cost component of the levelized fuel cost.

Carbon Dioxide Transport and Storage

Blue hydrogen faces the additional logistical challenges and costs associated with the transport and storage of captured CO₂. This analysis assumes an average CO₂ transport and storage cost of \$42.5/tonne, based on the CCS assessment in this report. While this cost is a relatively small portion of the levelized fuel cost, it can vary significantly depending on the economywide scale of CCS deployment and the distance between the hydrogen production facility and the CO₂ storage location.

2.5.1.3 Hydrogen Fuel Tax Credits

Figure 13 and Figure 15 also show the effect of federal tax credits.

The Clean Hydrogen Production Tax Credit (45V), established under the Inflation Reduction Act, offers a financial incentive for hydrogen producers, providing up to \$3/kg of clean hydrogen produced over 10 years beginning when the facility is placed in service. This technology-neutral credit is structured into four tiers based on the carbon intensity of the hydrogen production process, with the highest credit value awarded to hydrogen with life-cycle GHG emissions below 0.45 kg of CO₂e per kilogram of hydrogen. The credit value can be increased 5× if the project meets the prevailing wage and apprenticeship (PWA) requirements. Blue hydrogen typically receives lower credits (\$0.60–\$0.75/kg) due to residual emissions from incomplete capture and upstream methane leaks, while green or pink hydrogen qualifies for the full \$3.00 credit by achieving near-zero emissions. Due to recent federal policy changes, hydrogen production facilities must begin construction before January 1, 2028, which presents a significant deployment challenge. The credit lasts for the first 10 years of a facility's lifetime. Assuming a project begins completion in 2027 and takes 2–4 years to build, these credits are therefore unlikely to be available for long after 2040, and qualifying projects would need to begin very quickly.

The Carbon Capture Section 45Q Tax Credit offers financial incentives for carbon capture, utilization, and storage at power plants or industrial sources, which can be more beneficial to blue hydrogen producers than 45V. Established under the Internal Revenue Code and enhanced by the Inflation Reduction Act, this originally offered a credit of \$85 per metric ton (t) for geological storage of qualified carbon oxide and \$60 per metric ton for utilization. Under the H.R. 1, the provision equalizes the credit amount for CCS, whether the carbon is stored permanently or used in products or for EOR. The H.R. 1 also adds FEOC requirements to the eligibility for Carbon Capture Credits. The credit is

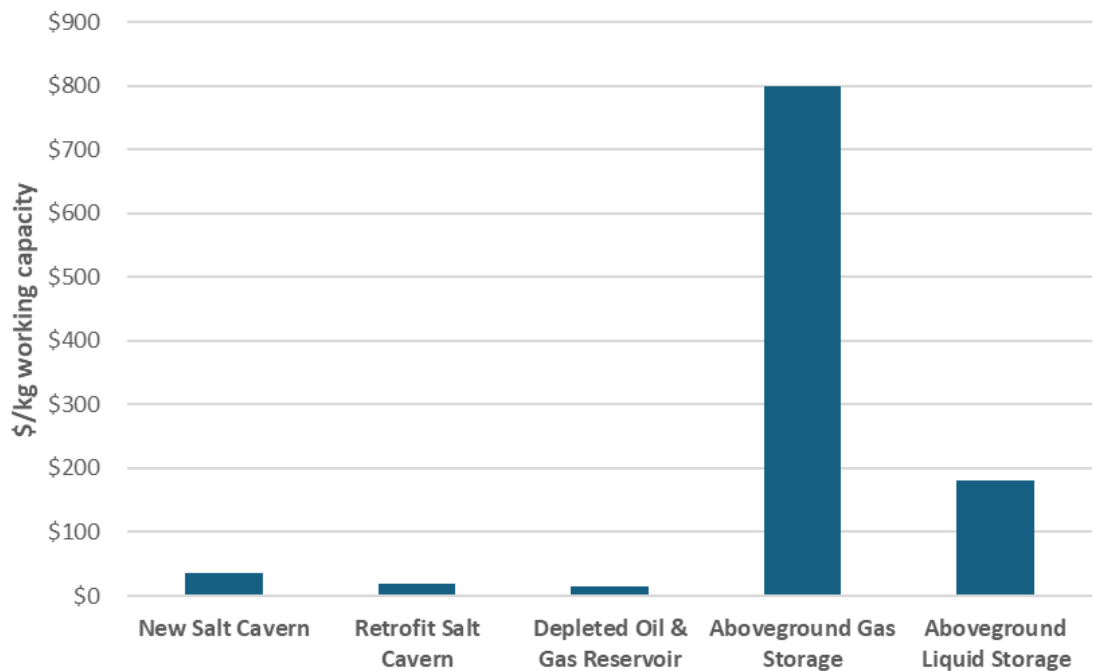
available for 12 years after the capture equipment becomes operational. Full credit value requires compliance with PWA standards during the construction phase. Construction must begin on the project prior to 2033 to be eligible for full credit. This extended availability compared to the Clean Hydrogen Credit creates more opportunities for blue hydrogen projects in the long term.

2.5.2 Storage Costs

The ability to store large amounts of energy over extended temporal spans is an important feature of hydrogen. The capital costs for different storage options in Figure 16 are sourced from the *New York Hydrogen Assessment*, except the liquid hydrogen storage case, which was based on the new liquid hydrogen tank at the Kennedy Space Center (NASA 2018a). The NREL HYPSTAT model developed a mixture of these storage options, resulting in the levelized transport costs depicted in Figures 17 and 19. Overall, neither gaseous nor liquid aboveground hydrogen storage tanks are well-suited for seasonal hydrogen storage due to logistical (boiloff) and economic (infrequent cycling) reasons. Geologic storage options are best suited for seasonal storage, while tank storage is better suited for on-site intra- to interday storage. While the model built out significant amounts of geologic storage to meet peaks, the feasibility of deploying such large amounts of storage is uncertain and could impact costs.

Figure 16. Capital Costs of Hydrogen Storage Capacity

Values expressed in 2023 USD.



The costs presented in Figure 16 represent only the specific capital costs of hydrogen storage, but other considerations, such as operational costs, affect the delivered cost of hydrogen and the applicability for given use cases. All gas storage options, including geologic formations and aboveground compressed cylinders, would require energy for compression, up to a 10% energy penalty, and liquid storage would require energy for liquefaction, up to a 30%–40% energy penalty (HFCTO n.d., Moradi 2019).

Underground storage options, especially depleted oil and gas reservoirs, would require gas cleanup if the hydrogen were expected to be used in fuel cells for power generation or vehicles, which could add significant costs. However, these requirements could be less stringent if the hydrogen were to be used in turbines or boilers. Underground geologic storage also faces regional limitations because some areas lack the necessary subsurface conditions. Aboveground compressed gas cylinders are expected to have high capital costs on a per-kilogram basis. However, their modularity could make them well-suited for applications with high utilization, such as vehicle fueling stations, because filling and discharging the cylinders daily (as opposed to seasonally) allows the capital costs to be spread over a greater volume of kilograms of hydrogen over the asset's lifetime. Liquid storage tanks offer greater geographic flexibility than underground storage and lower specific costs than compressed gas aboveground storage, making them economically viable today for certain applications where the filling and emptying schedules can be planned to minimize losses due to boiloff, such as NASA's use of liquid hydrogen to fuel rockets. In large, well-insulated tanks, the boiloff losses can be kept relatively low: the Hydrogen Delivery Scenario Analysis Model (HDSAM) estimates 0.03% per day. However, these losses become more significant for smaller or less insulated tanks.

2.5.3 Transport Costs

As discussed in Section 2.3.3, pipelines are the more economical transportation strategy for power sector volumes of hydrogen. The levelized cost of an economywide pipeline will depend on its use, as depicted in Figure 13, which shows that pipeline transport costs increase from \$0.91/kg (\$8.40/MMBtu) in the Economywide scenario to \$2.12/kg (\$20/MMBtu) in the Power Sector Only scenario. If a pipeline is not available, the costs associated with trucking equivalent volumes of hydrogen are expected to be significantly higher.

2.5.4 Delivered Fuel Cost Summary

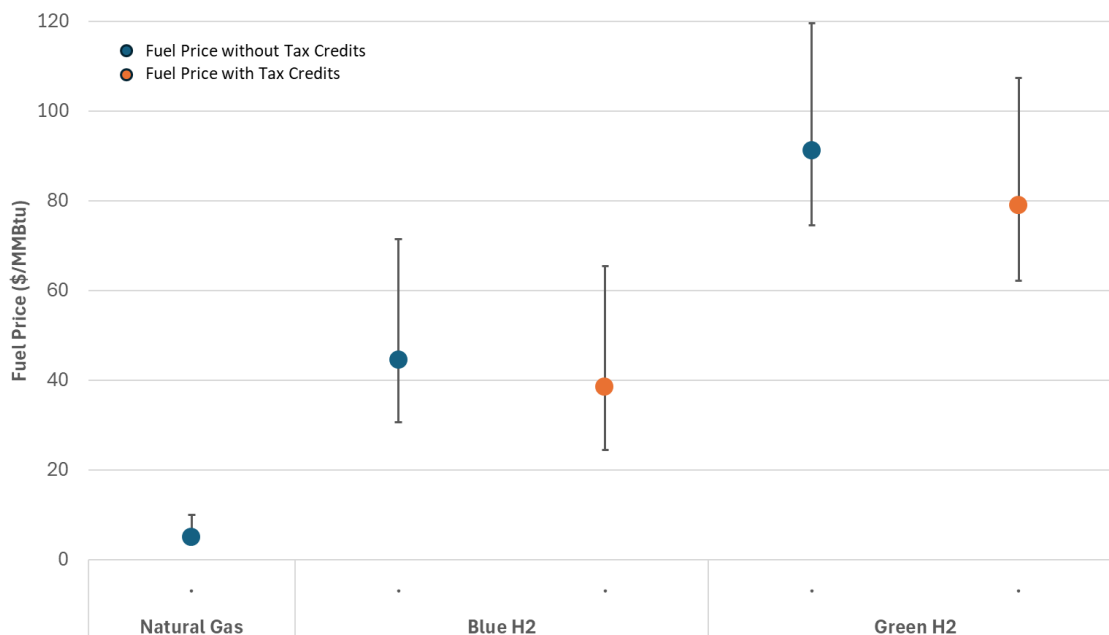
This section compares the delivered prices of blue and green hydrogen to the estimated cost of natural gas, showing that estimated hydrogen costs significantly exceed those of natural gas. The cost of NG in 2040 remains uncertain, but this analysis assumes a range of \$4–\$10/MMBtu during high-demand hours

when peaking units are deployed. Different fuels qualify for different tax credits. Blue hydrogen qualifies for the Carbon Capture Credit (\$85/tonne or approximately \$6/MMBtu), available for 12 years after the capture equipment becomes operational on projects that began construction prior to 2033. Green hydrogen qualifies for the maximum Clean Hydrogen Credit (\$3/kg or \$24.9/MMBtu) due to its zero life-cycle GHG emissions, but only for projects that begin construction before 2028.

Overall, the cost of hydrogen remains highly uncertain but is expected to be significantly higher than NG. The cost of blue hydrogen is estimated to be lower than that of green hydrogen, but is still expected to be higher than that of NG. The cost of green hydrogen depends on the cost of electricity, transport and storage infrastructure, as well as electrolyzer cost and capacity factor. The cost of blue hydrogen depends on the cost of NG, transport and storage infrastructure, SMR + CCS costs and capacity factors, and carbon transport and storage costs. Figure 17 incorporates transport and storage uncertainty derived from the three scenarios described in Section 2.5.1, as well as electricity cost uncertainty for green hydrogen and NG cost uncertainty for blue hydrogen. Notably, the fuel costs given below do not reflect the upward cost uncertainty associated with more modular transport methods such as trucks and barges.

Figure 17. Natural Gas Prices Compared to Projected Future Hydrogen Prices

Full tax credit eligibility requires construction to start before the credit phaseout date. Prices reported in 2023 USD, with and without tax credits.



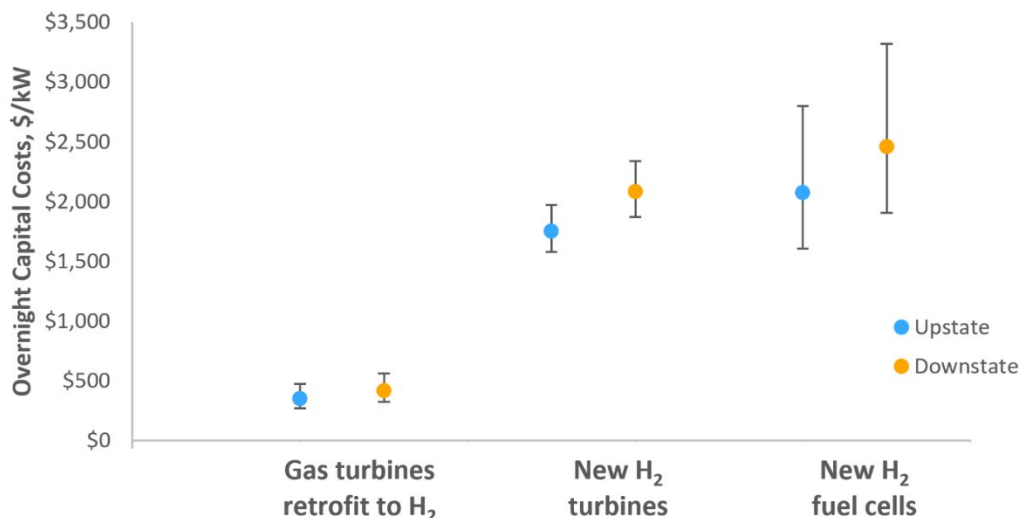
2.5.5 Power Generation Costs

2.5.5.1 Capital Costs

The costs of hydrogen-capable power-generating units are uncertain due to the lack of commercial deployment. Options for new-built assets include aeroderivative turbines, frame turbines, fuel cells, and linear generators. Because New York State currently relies on a fleet of NG turbines for peaking power, the least expensive and most logistically feasible strategy for developing hydrogen power generation in the State may be retrofitting existing plants. The costs of open-cycle NG power plants in New York State, considering current market conditions, were estimated for the *2025 Draft State Energy Plan* (SEP) and are leveraged for this study. These estimates are informed by the NREL Annual Technology Baseline (ATB) and the NYISO Demand Curve Reset process. It is assumed the cost to retrofit an existing turbine plant equals 25% of the capital costs of the indicative new hydrogen asset. This is an approximation because a full retrofit of an NG power plant to use 100% hydrogen has not been executed and will be site-dependent. Fuel cell cost assumptions are based on estimates for an NG SOFC (NREL 2024a). The fuel cell costs from the NREL ATB are scaled by a factor derived from the ratio of the SEP turbine costs to the ATB turbine costs in order to capture the local market conditions affecting power plant components and skilled labor. A wide uncertainty band accounts for cost differences with PEM fuel cells and the hydrogen balance of plant components. Figure 18 shows a range of overnight capital costs for deploying hydrogen power generation technologies for 2040.

Figure 18. Estimated Overnight Capital Costs for Hydrogen Power Generation Deployment in New York State, 2040

Values expressed in 2023 USD.



2.5.5.2 Operating and Maintenance Costs

Operating costs are derived from the 2024 NREL ATB cases for open-cycle turbines and SOFC (NREL 2024a). The fixed O&M costs are adjusted for NYS labor rates. The variable O&M rates for hydrogen-firing turbines are adjusted up by \$0.15/MWh to account for the additional ammonia that may be needed for NO_x emissions mitigation. Table 7 shows the O&M costs assumed for this study.

Table 7. Estimated Operating and Maintenance Costs of Hydrogen Power Plants in Upstate New York in 2040

Values expressed in 2023 USD.

Cost Component	H ₂ Turbine	H ₂ Fuel Cell
Fixed O&M (\$/kW/year)	\$25.43	\$44.47
Variable O&M (\$/MWh)	\$7.35	\$7.92

2.5.6 Funding and Other Subsidies Available to Hydrogen-fired Power Plants

The Clean Electricity ITC provides a financial incentive for power generators using hydrogen and other clean energy technologies, offering a base credit of 6% of qualified investment costs that can be increased to 30% after meeting the PWA requirements. Power generators can receive additional credit increases of up to 10% for meeting domestic content requirements and another 10% for projects located in energy communities. This technology-neutral credit applies to facilities beginning construction after December 31, 2024. For most technologies, including CTs, qualifying projects must have a GHG emissions rate not greater than zero, which is expected to exclude both new build and retrofit hydrogen CTs using blue hydrogen. However, under H.R. 1, fuel cell property is entitled to the Clean Electricity ITC regardless of emissions, so fuel cell plants using both green and blue hydrogen are expected to be eligible.

The Clean Electricity PTC is a technology-neutral, performance-based tax credit available to facilities generating electricity with zero or negative GHG emissions. It provides a base credit of ~\$6/MWh, rising to ~\$28/MWh after meeting PWA requirements (credit values are adjusted to 2023 USD and are approximate). Additional bonus credits of 10% are available for projects located in energy communities or using domestic content. The Clean Electricity PTC is available to facilities placed in service after 2024. It is issued for each kilowatt-hour of qualifying electricity produced and sold to an unrelated party over 10 years. Emissions must not exceed zero, which generally restricts eligibility to green or pink hydrogen-powered facilities. The Clean Electricity PTC cannot be combined with the Clean Electricity ITC for the same facility.

Whether the Clean Electricity ITC or Clean Electricity PTC is more optimal for a given project depends on the ratio of levelized capital expenses to levelized operating expenses at the expected capacity factor. Because hydrogen-powered generators are expected to have low capacity factors, the Clean Electricity ITC may be a more optimal strategy for most.

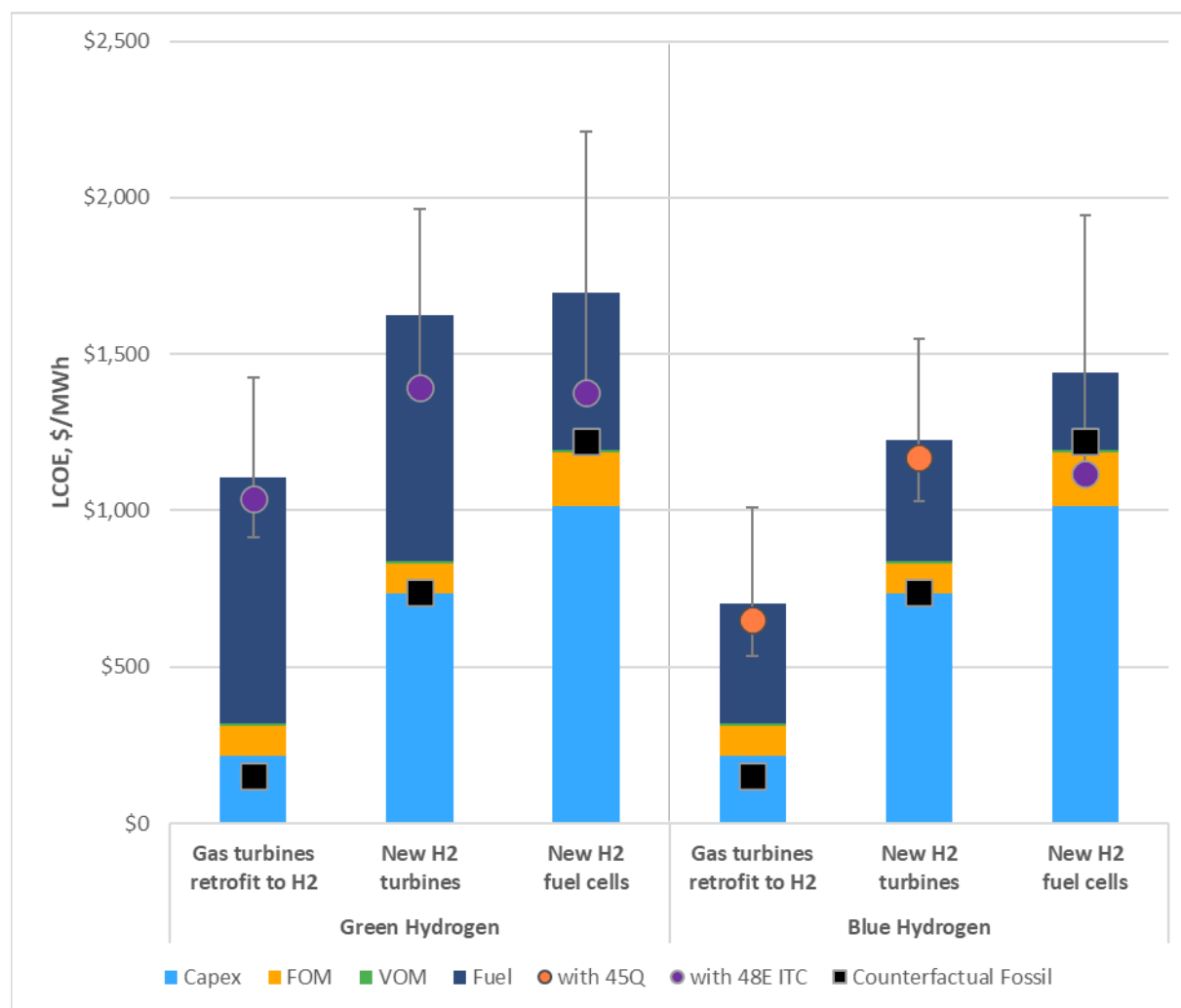
Under the new provisions in the recently passed H.R. 1, clean hydrogen power-generation projects remain eligible for the Clean Electricity ITC and Clean Electricity PTC, with phaseout slated to begin for projects starting construction in 2033 and later. In contrast, as discussed earlier, the Clean Hydrogen Credit is limited to hydrogen production facilities that start construction before 2028 and is unlikely to be available for long after 2040.

2.5.7 Levelized Cost of Electricity

The LCOE for any low capacity factor resource is expected to be high due to its low capacity factor. Figure 19 presents the calculated LCOE for blue and green hydrogen-fired power generation in 2040, assuming a capacity factor of 3%. The error bars represent uncertainty in capital, operating, and fuel costs. Fuel cost uncertainty includes the infrastructure uncertainty derived from the three scenarios described in Section 2.5.1, as well as electricity cost uncertainty for green hydrogen and NG cost uncertainty for blue hydrogen. Colored dots represent Clean Electricity ITC or Carbon Capture Credit inclusion, though construction would need to start on the project prior to 2033 for full credit eligibility. A 12-year life is assumed for retrofit projects, reflecting the shorter life of existing equipment. Appendix A provides additional details on the assumptions used in LCOE calculations.

Figure 19. Calculated Levelized Cost of Electricity of Hydrogen Power Generation Technology

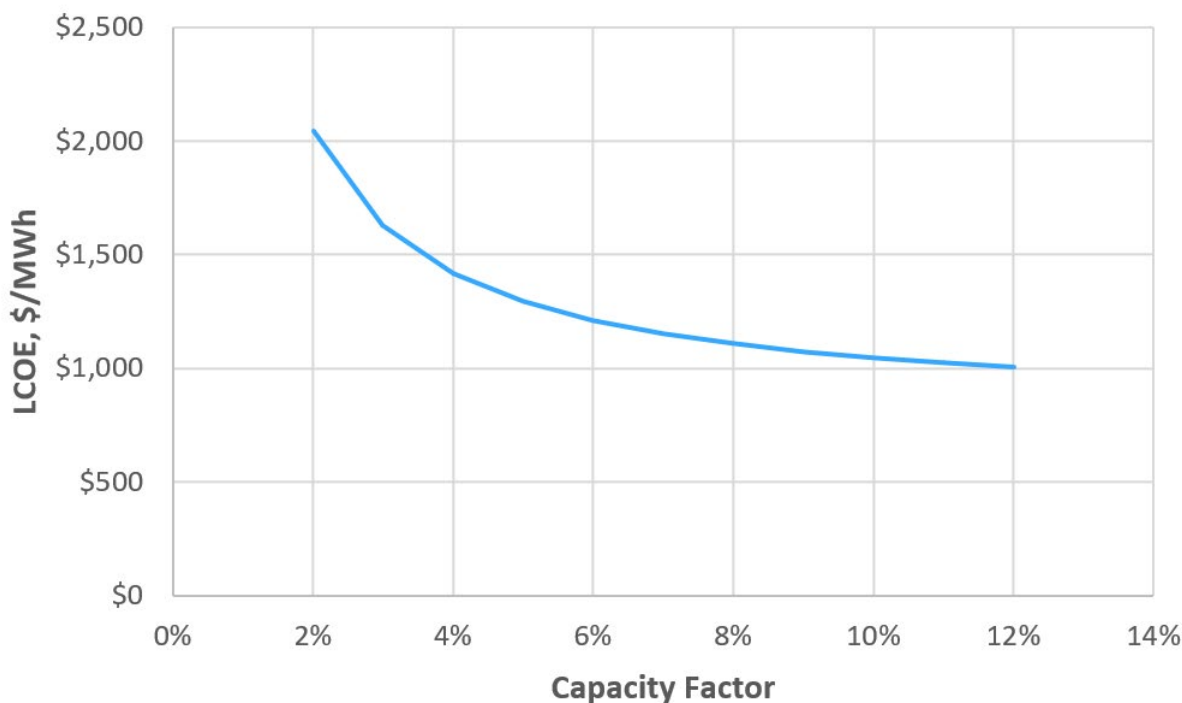
Full tax credit eligibility requires construction to start before the credit phaseout date. Prices reported in 2023 USD.



Overall, hydrogen-fired power generation is expected to have a high cost per MWh and would likely be reserved for periods of extreme demand. The number of these peak hours will vary with weather conditions, which in turn influences the capacity factor of such peaking units. At these low capacity factors, the LCOE is particularly sensitive to changes in use because costs are spread over fewer operating hours, a pattern common to all resources used infrequently. Figure 20 illustrates the LCOE for a new turbine firing green hydrogen across capacity factors ranging from 2% to 12%.

Figure 20. Levelized Cost of Electricity for a New Green Hydrogen-fired Turbine by Annual Capacity Factor

Values expressed in 2023 USD.



2.6 Scalability for 2040

The scalability scenarios for hydrogen-powered generation assets in New York State differ between Upstate New York and Downstate New York. In Zone J, scalability likely depends on either a pipeline delivering hydrogen from Upstate or out-of-state, or the development of barging infrastructure. Building a new U.S. pipeline typically takes 3–13 years to implement, and the complexities of building new infrastructure in such a dense environment would likely add time, making the completion of such a project by 2040 possible but uncertain (EPRI 2023n). The timeline for converting an NG pipeline to hydrogen is also highly uncertain. Blending hydrogen into existing pipelines and using an attribute tracking solution is another alternative, subject to detailed safety and reliability assessment, but due to low blend rates, it does little to offset on-site NG consumption.

Upstate New York offers more options for implementing hydrogen technology for power generation. The development of a hydrogen pipeline network offers the greatest opportunity for hydrogen power generation in Upstate as well as Downstate New York. In the absence of a pipeline network, electrolyzers,

and hydrogen-capable power generation assets could be built near underground storage facilities. The expected project timeline of the ACES Delta project suggests that such facilities could be constructed before 2040. The scalability of these co-located hydrogen facilities may depend on the availability of carbon-free electricity and the time to connect the new facilities to the grid with enough transmission capacity to run the electrolyzers and export the generated electricity.

This section outlines potential pathways for hydrogen integration in New York State by 2040.

2.6.1 Conservative Scenario

As a conservative scenario, a multisector hydrogen pipeline network is assumed not to be developed in New York State by 2040. Under this scenario, the only deployment of hydrogen power generation occurs in Upstate New York, where electrolyzers and hydrogen turbines or fuel cells are sited near underground hydrogen storage facilities, minimizing transport requirements. In this scenario, most renewable electricity is used directly to meet power sector energy demands. However, hydrogen generation could use renewable energy that would otherwise be curtailed, with the hydrogen stored for use during times of extreme need. No capacity is assumed for Downstate New York.

2.6.2 Moderate Scenario

Under a moderate scenario, an extensive hydrogen pipeline may not have been built, but some additional deployment is feasible. An increase in hydrogen-dedicated renewables could facilitate more hydrogen production, and more geographically diverse underground storage opportunities could also be considered. This allows for additional Upstate New York power generation deployment near depleted oil and gas reservoirs or bedded salt formations, in addition to the salt domes used in the conservative scenario.

Limited Downstate New York deployment is also possible without a pipeline. Hydrogen power generation deployments within Zones J and K could occur on a pilot scale, depending on modular delivery methods (e.g., trucks, barges) and on-site storage. Power generation without a pipeline would likely not be scalable due to the logistical and economic challenges discussed earlier, and these deployments could be implemented primarily as demonstrations, pending the availability of pipeline delivery at a later time.

2.6.3 Aggressive Scenario

An advanced scenario could involve the development of a statewide hydrogen pipeline network, as well as necessary hydrogen production and storage infrastructure to support peaking power plants and other end-use sectors. Under this scenario, sufficient hydrogen could be delivered during critical high-demand hours to peaking power plants throughout the State, including into Zones J and K.

This infrastructure buildout would likely be economically viable only with hydrogen adoption in other sectors of the NYS economy, especially the less seasonally variable medium- and heavy-duty transport and off-road vehicle sectors. This scenario would require that the challenges facing pipeline deployment such as permitting, long lead times, and safety concerns be overcome in the near future. New policies and programs would be needed to achieve this level of wide-scale deployment by 2040.

In addition to an aggressive buildout of hydrogen infrastructure, this scenario relies on continued growth of carbon-free primary electric power generation for electrolysis, unlocked through increased dedicated renewables, potentially supplemented with nuclear electricity or SMRs with CCS for hydrogen production. It also assumes that retrofits of NG power plants to accept hydrogen, or newly built hydrogen power plants, could be deployed at scale before 2040. Given the number of challenges facing this level of deployment, this scenario is likely to be extremely challenging to achieve by 2040.

2.6.4 Beyond 2040

Hydrogen is expected to remain a peaking-only resource due to its high cost relative to renewables and other clean firm generation sources. However, as demand for hydrogen continues to grow in other sectors, lowering the unit costs of shared infrastructure, and significant deployments of electrolyzers, low-cost storage, and power generation assets bring capital costs down the learning curve, levelized hydrogen costs could drop significantly. The primary driver of hydrogen cost is likely to remain the cost of electricity. However, as more renewable resources are developed, opportunities may grow to leverage the low-cost, otherwise curtailed renewable energy to produce hydrogen at a reduced price. Electrolyzers employing this strategy would operate at lower capacity factors, which increases the levelized capital cost of hydrogen production and may offset the savings from cheaper electricity. Hydrogen can play a significant role in the decarbonization of other sectors like industry and hard-to-electrify transportation. The extent of its role in the NYS power sector will depend on cost declines relative to other DEFR technologies.

2.6.5 Scalability Summary

Regardless of the scenario, hydrogen will only be able to provide a portion of the electricity needed to achieve a 0x40 electricity system due to high costs and infrastructure buildout challenges.

However, the scenarios described earlier could help meet reliability needs on very challenging weeks to varying degrees.

The conservative and moderate scenarios could be achieved even if demand for hydrogen remains low in other sectors, but under these scenarios, hydrogen would primarily be limited to applications in Upstate New York. Additional resources would be needed to meet the baseload and peaking needs, especially for Downstate New York.

The advanced scenario could meet a larger fraction of the peaking demand, but it would necessitate developing a robust economywide hydrogen market to support the required infrastructure network, which will be unlikely before 2040.

2.7 Conclusion

Based on the previous assessment, the following key observations are offered to inform future consideration of hydrogen deployment in New York State:

Hydrogen (H₂) is an alternative fuel that has long-term potential as a zero-to-low-carbon energy resource. H₂ can be produced through various processes that have different technology readiness levels, costs, emissions, and infrastructure implications. This report focuses on H₂ produced via electrolysis: “green H₂” if produced with renewable electricity or “pink H₂” if produced with nuclear electricity, and H₂ produced via steam methane reforming with carbon capture and storage (CCS): “blue H₂,” as the most likely low-carbon H₂ sources for a 2040 NYS power sector. H₂ is also expected to play a pivotal role in the decarbonization of other sectors such as heavy-duty transportation and industrial processes.

Power generation with H₂ can be achieved with turbines, fuel cells, or linear generators. Existing natural gas (NG) turbine sites could be leveraged for H₂ combustion, but will require retrofitting to become compatible with 100% H₂ firing. Fuel cells offer higher efficiency than turbines and are more

modular, but face supply chain constraints, high cost uncertainty, and high H₂ purity requirements. Linear generators are fuel-flexible and modular, but this technology is less mature and, as a result, less ready compared to turbines and fuel cells.

H₂ viability is dependent on building out transportation and storage infrastructure. A major challenge for H₂ deployment is the development of storage and transportation infrastructure needed to ensure H₂ is available to generators when needed. Hydrogen costs are heavily influenced by the infrastructure deployed. The most practical and economical way to supply the amount of H₂ required to meet statewide power sector needs is a shared system for H₂ production, bulk underground storage, and pipeline transport that is driven by multisector hydrogen demand. If the bulk storage and pipelines are developed and used only by the power sector, as could be the case if other sectors lag in adoption, costs would meaningfully increase due to lower utilization and highly seasonal demand. While pipelines are the most cost-effective method for transporting the necessary volume of hydrogen, they face significant permitting hurdles, long lead times, and siting constraints that render them an unlikely solution for 2040. Some Upstate New York demand could be met without a pipeline if H₂ production and bulk storage were co-located with power generation such that no H₂ transport is needed. Federal production tax credits, such as the Clean Hydrogen Production Tax Credit, Section 45V (Clean Hydrogen Credit), which had significantly lowered estimated hydrogen costs, are now being phased out earlier, which limits their potential applicability in and beyond 2040 to only projects that can begin construction by the end of 2027.

In the absence of a pipeline, the logistics and costs associated with serving statewide reliability needs with hydrogen are potentially prohibitive. New pipelines require regulatory, siting, and permitting procedures and can have long construction timelines. In the absence of a pipeline, the modular transport (trucks, barges) and on-site storage (aboveground tanks) requirements to meet Downstate needs create considerable logistical challenges. While blending H₂ into existing natural gas pipelines could lower initial deployment barriers by leveraging existing infrastructure to enable supply growth, the existing infrastructure is not designed to handle substantial quantities of hydrogen. Blending any meaningful amount of hydrogen would require a comprehensive compatibility assessment of safety, air quality, and reliability risks. For these reasons, according to the *2025 Draft State Energy Plan*, New York State does not currently support the blending of hydrogen into the existing natural gas pipeline system. Blending would also require an attribute tracking mechanism. Significant advancements in de-blending technologies would be needed to realize local improvements in co-pollutant emissions and air quality.

H₂ appears to hold greater near-term opportunities in Upstate New York, where opportunities to leverage low-cost and potentially curtailed renewables and co-locate production with geologic storage offer lower costs and fewer space constraints.

The scale of green H₂ production in 2040 will depend on renewable electricity availability. As electricity demand grows and aging fossil generators are retired, a rapid buildout of renewables will be required to produce hydrogen on top of meeting the growing grid demand. Hydrogen production using nuclear electricity (pink H₂) or steam methane reforming (SMR) with carbon capture (blue H₂) could unlock additional H₂ supply. However, blue H₂ generates significant upstream greenhouse gas (GHG) emissions, impacting the emissions contributions in New York State based on the Climate Leadership and Community Protection Act (Climate Act) accounting requirements.

The cost of hydrogen remains highly uncertain but is expected to be significantly higher than the cost of NG. The cost of renewable electricity and infrastructure largely drives the cost of green hydrogen. Lower-cost H₂ could be unlocked by leveraging otherwise curtailed renewables, but this use case is limited by low curtailed energy availability and challenging electrolyzer economics due to low utilization. Pipelines are the lowest cost option for transporting large volumes of hydrogen but are unlikely to be a viable statewide solution for 2040. In the absence of pipelines, there is additional upward uncertainty in hydrogen fuel cost due to the need for modular transport and onsite storage solutions. The cost of blue H₂ is estimated to be lower than that of green H₂ produced in New York State, but is still expected to be significantly more expensive than NG. Full Carbon Capture and Sequestration Tax Credits, Section 45Q (Carbon Capture Credits), are available to blue hydrogen projects that begin construction before 2033, which can lower costs.

Use of H₂ in a combustion turbine (CT) could generate nitrogen oxides (NO_x) emissions similar to those of a natural-gas-fired plant, while use of H₂ in a fuel cell or linear generator will have significantly lower NO_x emissions. However, in all cases, NO_x emissions are likely to fall on a total annual basis because a H₂ plant would be expected to operate at a lower capacity factor than a current NG plant, improving air quality for neighboring communities.

3 Biofuels

3.1 Overview and Subcategorization of Biofuels

Biofuels are combustible gases and liquids derived from organic matter that have been processed through conversion technologies into energy carriers, serving as alternatives to fossil fuels. Biofuels could serve as an important pathway for achieving New York State’s zero-emissions power sector goal by 2040, offering drop-in replacements for conventional fuels that can leverage existing infrastructure for transport, storage, and power generation. The fuels are often considered lower in carbon when accounting for reduced upstream carbon and methane emissions associated with the organic feedstocks, compared to typically imported fossil fuels. This report focuses on fuels that can be used in the electric sector, specifically RNG and RD.

RNG is a pipeline-quality gas derived from biomass or other renewable resources. RNG is considered a drop-in replacement for NG, meaning it can be safely employed in any end use typically fueled by NG.

Biogas is a precursor to RNG. It is produced through anaerobic digestion (AD), gasification of organic wastes, or landfill gas recovery. The biogas generated from these processes contains large fractions of methane and carbon dioxide as well as other contaminants and must undergo purification and upgrading to produce RNG. Biogas is typically either used on-site or upgraded to RNG. This report focuses on the latter.

RD is a lower-carbon distillate substitute that meets ASTM International (ASTM) Standard D975 specifications for ultra-low sulfur diesel, making it fungible in nearly all distillate applications despite having a significantly lower GHG footprint. It can be produced from various biomass feedstocks using several potential conversion technologies, including hydroprocessing, gasification followed by Fischer-Tropsch (FT) synthesis, alcohol-to-jet (ATJ) processing, or power-to-liquid processing (PTL). RD should not be confused with biodiesel; biodiesel is an oxygenated ester produced from the transesterification of vegetable oils and animal fats and is not a drop-in replacement for distillate, given blending and storage restrictions, while RD is a drop-in hydrocarbon. Biodiesel is typically used for blending with petroleum distillate in transportation fuels and is not a focus of this report.

Figure 21. Process Flow Diagram of Biofuels Production and Use

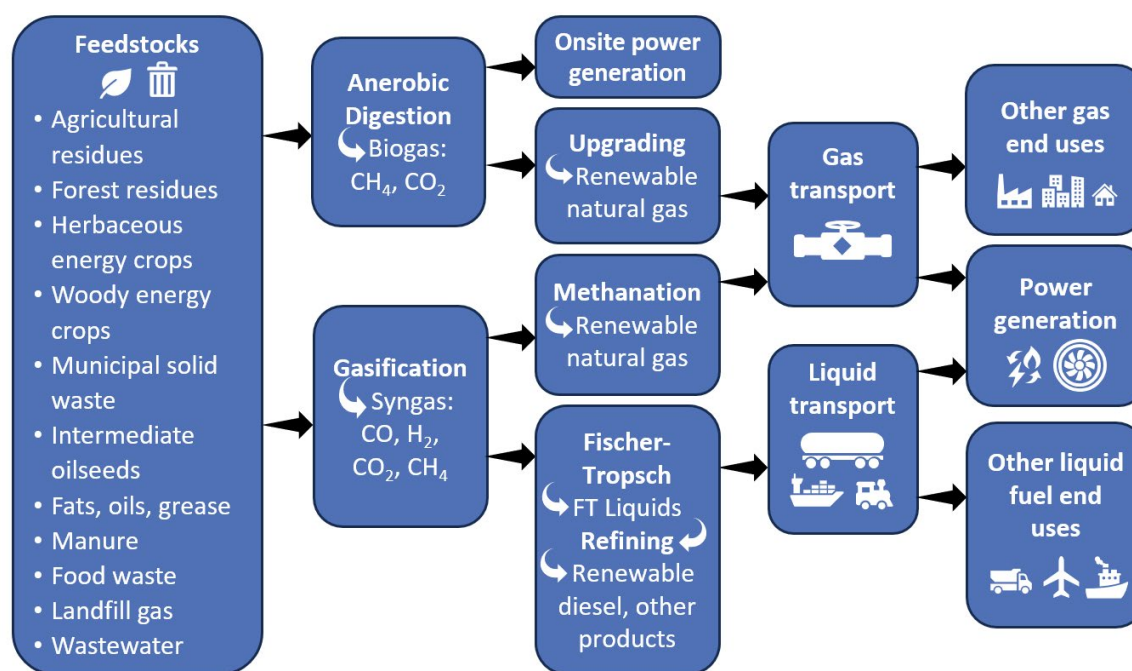


Figure 21 shows a simplified representation of a complex economy of feedstocks, processes, intermediaries, products, and end uses, with a focus on fuels most relevant to the power sector. Different feedstocks have different expected pathways, advantages, and challenges that are not captured in the visualization.

RNG and RD are considered peaking-only, low capacity factor resources in this report due to supply constraints, costs, and gross emissions considerations, as discussed later. In New York State’s power system today, low capacity factor peakers run primarily on NG, and many are capable of dual-fuel operation, meaning they can run on distillate fuel when needed. Power plant distillate operation typically occurs during periods of extreme cold weather when building heating NG demands are prioritized over power generation. This section assesses the viability of meeting the low capacity factor, dispatchable need with RNG or RD. This could include only RNG, a combination of RNG and RD, or solely RD.

3.1.1 Fuel Production

First-generation biofuels such as corn- or soy-based ethanol and transesterified biodiesel currently dominate U.S. biofuel production. These fuels are sourced from crops also used for food production, but are not drop-in substitutes for conventional fuels. This report focuses on advanced biofuel production of drop-in fuels for the power sector, namely RNG and RD. Feedstocks for RNG and RD production are

diverse. They can come from agricultural and forestry waste residues, wastewater, landfills, municipal solid waste (MSW), and other sources, as well as purpose-grown energy crops (lignocellulosic energy crops, both woody and herbaceous), oil seeds, and logs. Feedstocks come with different tradeoffs in their cost, total supply potential, preprocessing requirements, GHG emissions, and environmental impacts. For example, the use of energy crops could significantly increase the available supply of RNG and RD, but would also have higher land use, soil erosion, fertilizer use, and runoff impacts.

Table 8. Candidate Feedstocks for Advanced Biofuel Production

Not all feedstocks can be used interchangeably across all conversion processes.

Source: IRENA (2016), Jeswani (2020), NYSERDA (2022c), and EPRI (2023m).

Feedstock	Description
Food Waste	Food waste from grocery stores, cafeterias, restaurants, and private homes
Municipal Solid Waste	Waste remaining after diversion of recyclable waste products, includes construction debris, some plastics
Landfill Gas	Naturally occurring anaerobic digestion of organic waste in landfills
Wastewater Resource Recovery	Waste liquids and solids biproduct from the treatment of household, commercial, and industrial wastewater
Animal Manure	Produced by livestock, including dairy cows, beef cattle, swine, sheep, goats, poultry, and horses
Agricultural Residue	Unusable portion of crops, stalks, straw, stems, leaves, branches, and seed pods
Forestry Residue	Waste from logging, forest and fire management activities, milling residues, logging residues
Oils and Lipids	Waste oils and fats, purpose-grown oilseed crops, algae, pyrolysis oil, hydrocarbon intermediates
Energy Crops	Grasses, trees, and annual crops that can be grown to supply uniform and consistent feedstocks (switchgrass, miscanthus, jatropha, sorghum, poplar, etc.)

Converting these feedstocks into usable energy carriers requires similarly diverse conversion processes. Several processes produce drop-in replacement fuels like RNG and RD. These feedstocks can all contribute to RNG and RD supply, but not all work interchangeably across all conversion processes, and the costs of their respective pathways vary. The cost of delivered fuel from a given feedstock depends heavily on the specific source. Sectors beyond the power sector can use RNG and RD, and feedstocks can

be used to produce other drop-in fuels (e.g., aviation fuel, hydrogen). Total supply, therefore, will depend on competition across the economy. Competition among regions and states will influence the availability of out-of-state feedstock supply. The feedstocks that make the greatest contribution to both RNG and RD technical potential are municipal solid waste, agricultural residues, and energy crops (DOE 2024a).

3.1.1.1 Renewable Natural Gas

Producers can generate RNG by upgrading biogas from the AD of wastes, manures, residues, and energy crops, or by recovering it from landfill gas. Alternatively, some feedstocks are better suited for undergoing thermal gasification first to produce synthetic gas (syngas), a gas mixture primarily consisting of carbon monoxide and hydrogen, followed by methanation of syngas to produce RNG. The following sections discuss these pathways.

Anaerobic Digestion

Anaerobic digesters use microorganisms to convert organic matter, such as animal manure, food waste, municipal solid waste, or other cellulosic material, into biogas in an oxygen-free environment. Most anaerobic digesters are built using “wet” AD, where the content of total solids may be as high as 15%. “Dry” AD is less common and can process biomass with a higher percentage of solids, typically ranging from 20% to 55%. Both methods can use a wide range of organic materials as feedstocks, though the physical state and solids content of the feedstock determine their suitability for wet or dry digestion (Biogas World 2022). Wet AD typically uses animal manure, wastewater, food waste, or crop residues. Dry AD feedstocks include yard waste, organic municipal solid waste, and can also include crop residues or manures if the feedstock supply has a high enough percentage of total solids. Dry digestion has lower water and power needs, but also offers lower yields and reduced flexibility in feedstock (Renegon 2024). Cellulosic biomass from energy crops or agricultural and forest residues can also be used in dry AD after undergoing mechanical, thermal, and chemical processing (Hashemi 2021).

Digestion of biomass produces biogas, a mixture containing methane and CO₂, typically with a molar mass of about 40%–50% CO₂. This CO₂ is separated from biogas in upgrading and can be captured at low costs for potential sequestration or secondary uses.

Landfill Gas Recovery

For landfill gas recovery, similar to AD, the organic wastes within landfills naturally decompose into gaseous material, which includes biogas and other constituents that are captured and then purified to isolate methane (RNG). Landfill gas recovery is an uncontrolled AD process in which the gas recovery system may not capture some portion of the methane. The biogenic fraction of landfill methane is directly correlated to the composition of these landfills. Recovering and reusing landfill gas can help prevent the release or flaring of methane, thereby reducing emissions in the waste sector.

Biogas and Landfill Gas Refining

As noted earlier, both biogas from AD and landfill gas may be refined to produce pipeline-quality RNG. The refining process requires separation and drying to separate usable methane from water and byproducts (including CO₂), followed by upgrading to pipeline-usable quality. The process typically first removes moisture through condensers to alleviate downstream corrosion. Particulate matter is then removed using technologies such as coalescing filters or water-gas scrubbers. Hydrogen sulfide and siloxane are then removed using an application-dependent combination of scrubbers and adsorbents to ensure removal of harmful constituents. This process typically creates a gas fuel suitable for on-site power generation. To create RNG suitable for pipeline injection, the biogas must be refined further: CO₂ is removed through processes such as pressure-swing adsorption, water scrubbing, or membrane separation. Other constituents such as nitrogen, volatile organic compounds, and oxygen may also be removed. At this point, the resulting RNG meets NG pipeline standards and can be compressed and injected into the system (NYSERDA 2022c).

Gasification and Methanation

A third pathway to produce RNG is the biomass gasification and methanation of energy crops, municipal wastes, and residues (IEA 2019). The thermal gasification of biomass to produce RNG occurs over a series of steps (NYSERDA 2022c), beginning with feedstock preprocessing to prepare materials for gasification. This process generates syngas, which then undergoes subsequent filtration and purification to remove excess dust and other potential contaminants like hydrogen sulfide and carbon dioxide. This is followed by methanation, where the purified syngas is converted to methane and dried prior to pipeline injection. While gasification is a well-established technology that can use numerous sources of cellulosic

biomass, many of which are less compatible with AD, the syngas processing via methanation has limited commercialization. Gasification also produces tar, which complicates methanation; however, some early-stage companies are working to overcome these challenges by developing methods to produce syngas with reduced tar and lower costs (EPRI 2023m).

3.1.1.2 Renewable Diesel

There are four major pathways to produce RD: (1) hydroprocessing, (2) alcohol-to-jet processing, (3) biomass gasification with FT synthesis, and (4) power-to-liquid processing. Each of these processes also produces a range of other hydrocarbons that can be used in other sectors.

Hydroprocessing

Hydroprocessing of lipids (waste oils and fats, oilseed crops, algae, and other oils) chemically deoxygenates these lipids using hydrogen to produce a range of paraffinic hydrocarbons, which include ~80% RD and other co-products such as sustainable aviation fuel (SAF) and renewable naphtha. The vast majority of RD produced today is based on this process, and it is currently the most economical of the four pathways. However, the supply of the oil-based feedstocks is relatively limited. Oil crops may require more pretreatment and extraction processes on-site compared to waste oil streams, but offer a greater potential source of supply. Most hydroprocessing of feedstocks relies on on-site H₂ production to produce the required hydrotreater feedstock. As of January 2024, the U.S. had 22 RD facilities producing 4.3 billion gallons of “renewable diesel and other biofuels” per year, though none are located in New York State (EIA 2024c).

Alcohol-to-Jet Processing

ATJ processing is the second most mature pathway for producing RD. This process converts alcohol-based feedstocks, such as ethanol or isobutanol, into liquid hydrocarbons, including fractions of jet fuel, RD, and renewable gasoline. Any process that produces ethanol—cellulosic or otherwise—could be coupled on-site with an ATJ system to produce jet fuel and RD. Conventional corn-based, sugar cane-based, or catalysis-produced ethanol from other cellulosic feedstocks can all be used in this process.

Gasification with Fischer-Tropsch Synthesis

Gasification with FT synthesis converts cellulosic biomass (energy crops, agricultural and forest residues) and municipal wastes to syngas. The syngas can be upgraded to a range of hydrocarbons at high temperatures and pressures using an FT reactor. The weight of the synthetic crude oil and the average

and mix of lengths of its contained hydrocarbons depend on temperature, pressure, and the catalyst in the reactor. The distillate feed from FT synthesis is a mixture of liquids that can be separated into products, including RD and SAF (Bann et al. 2017, Pavlenko et al. 2019).

Power-to-Liquid Processing

PTL processing uses CO₂ as a feedstock rather than the abovementioned waste- or crop-based feedstocks. This pathway requires an input of power for on-site hydrogen production. The CO₂ is reacted with hydrogen to produce CO, which then undergoes the FT synthesis with additional hydrogen to produce liquid hydrocarbons, including RD. Fuels produced from CO₂ using this method are often referred to as “e-fuels” and can be considered a form of carbon utilization.

3.1.2 Feedstock Availability

The availability of RNG and RD for electricity generation depends on several factors, including the availability of feedstocks within New York State, access to feedstocks from surrounding states, the availability of conversion technologies, such as thermal gasification, feedstock accumulation, and preprocessing infrastructure, and the competing demand for feedstocks from other alternative fuels and sectors.

An analysis was conducted using a Biofuels Optimization Tool developed by E3 (Energy + Environmental Economics) to assess the potential for RNG and/or RD that could be used in electricity generation. This tool was developed to support the *New York State Climate Action Council Scoping Plan* (CAC 2022) and updated it for the *2025 Draft State Energy Plan* process incorporating more recent conversion costs and updated feedstock information from DOE’s *2023 Billion-Ton Report* (DOE 2024a). The tool can inform feedstock availability and fuel prices based on scenario-specific assumptions related to economywide demand, allowable feedstocks, and regional access to feedstock.

The availability of feedstocks for producing renewable fuels will impact the amount and price of RNG and RD available for electricity generation. This analysis assumes that New York State can access all in-state feedstocks for use in fuel production, as well as a portion of regional feedstocks (a population-weighted share of 7.7% of the feedstocks available in states east of the Mississippi River). Because conversion efficiencies differ across feedstocks and fuels, the amount of RNG versus renewable liquids produced from the same amount of available feedstock will vary. The orange column in Figure 22 represents the available supply if all feedstocks were used to make liquid fuels, while the blue bar represents the available supply if all feedstocks were used to make RNG. Note these bars are not

additive. In reality, the supply for a mix of RD and RNG production would fall somewhere in between the two bars. While the overall analysis assumes 100% of New York State feedstock and 7.7% of feedstocks available from surrounding states are available for producing renewable fuels, the diamonds indicate the volume produced from in-state feedstock only.

In addition to the impact of feedstock availability on production volume, the availability of conversion technologies will also impact the overall production volume. Achieving the full amount of RD or RNG shown in Figure 22 assumes that all technology conversion pathways are available for production.

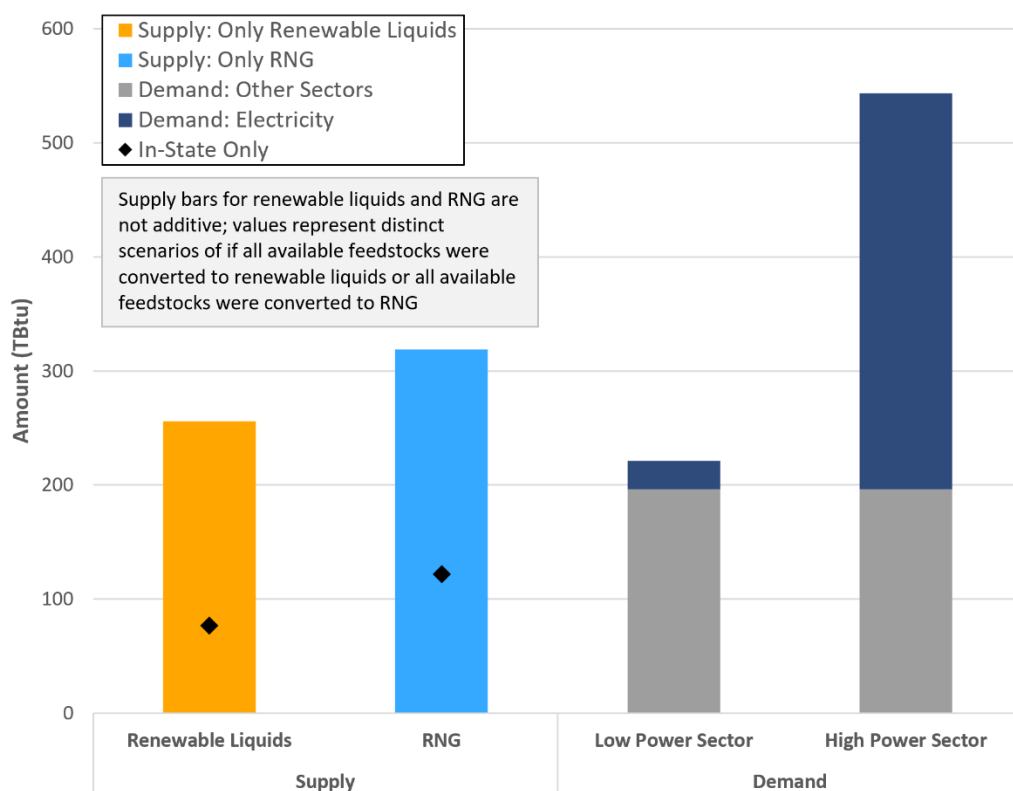
Finally, the power sector will face competition for renewable fuel supply from other sectors, especially those that cannot be easily electrified and will therefore rely on renewable fuels to meet economywide gross emissions limits. The demand bars to the right of Figure 22 show two potential demand scenarios. Both scenarios assume the use of renewable fuels to help meet the transportation, building, and industrial sector needs based on the *2025 Draft State Energy Plan* Net Zero A scenario as represented in the green bars.

The Low Power Sector scenario assumes that RNG and RD are used only for peaking, based on modeling from the *2025 Draft State Energy Plan*, which assumed hydrogen as a proxy DEFR and showed these units operated at only 2% capacity factors in 2040 in the Net Zero A scenario. The scenario uses a heat rate of 9.72 MMBtu/MWh to generate the Low Power Sector estimate, consistent with a typical peaking plant.

The High Power Sector scenario explores a hypothetical upper limit of renewable fuel demand, using RNG to meet all 2040 Net Zero A scenario load requirements beyond that met by existing nuclear and renewable generation (assumed to be a minimum of 70% of total generation by 2040). This scenario uses a heat rate of 6.075 MMBtu/MWh to generate a high demand estimate, consistent with a typical combined cycle baseload plant.

Notably, using fuel cells instead of turbines to meet the power sector demand would reduce fuel use due to their higher efficiency, by about 40% compared to a peaking plant and about 10% compared to a combined cycle baseload plant.

Figure 22. Supply and Demand Dynamics for Renewable Natural Gas and Renewable Diesel



The supply and demand dynamics in Figure 22 show there is insufficient feedstock supply to meet economywide demand in the High Power Sector scenario. In other words, New York State would need to limit the use of RNG or RD for power generation beyond peaking plants. To meet the lower demand limit, New York State would need to unlock many feedstocks and conversion pathways, as well as regional feedstock supplies.

Furthermore, as discussed further in Section 3.4.1, meeting the High Power Sector demand scenario with RNG could result in annual gross power sector emissions of 16.2 MMT of CO₂e, which would risk the ability to achieve the 2050 economywide gross emission limit of approximately 62 MMT CO₂e, for which most residual 2050 emissions are expected to be used in the hardest to decarbonize sectors (e.g., waste, agriculture, aviation). Under the Low Power Sector scenario, annual gross power sector emissions from RNG are approximately 1.9 MMT, which could be easier to offset through reductions in other sectors. RD would have larger gross GHG emissions implications. This further emphasizes the need to limit RNG and RD use in the power sector to select peaking applications.

3.1.3 Power Generation

Like hydrogen, power generation with RNG can be achieved with turbines, fuel cells, or linear generators. Turbines use combustion to generate high-temperature, high-pressure gases that cause a turbine to spin and generate electricity. Turbines capable of burning RNG are already deployed throughout the State and can switch to RNG without requiring retrofit, offering a significant advantage in lead times over fuel cells and linear generators.

However, fuel cells and linear generators offer distinct advantages over turbines. Fuel cells convert chemical energy into electricity using an electrochemical reaction, while linear generators react fuels with oxygen to release energy as expanded gases. Both fuel cells and linear generators operate with higher efficiency and fewer co-pollutants than turbines and therefore have lower gross GHG and co-pollutant emissions per megawatt-hour. They are also more modular than turbines, providing some siting flexibility. Linear generators offer an additional advantage of fuel flexibility, which means they could operate with pure RNG, H₂, or a blend of the two fuels.

Power generation with RD can be achieved only with turbines. Turbines capable of burning RD are already deployed across the State and can switch to RD without requiring retrofit.

3.2 Performance Attributes

Table 9 summarizes performance attributes of RNG and RD.

Table 9. Comparison of Renewable Natural Gas and Renewable Diesel Technologies by Grid Services and Attributes

Attribute	RNG Turbine	RD Turbine	RNG Linear Generator	RNG Solid Oxide Fuel Cell
Inertial Response (Rotational)	Typically provides attribute Provides rotational inertia	Typically provides attribute Provides rotational inertia	Does not provide attribute No rotational inertia unless paired with a GFM inverter	Does not provide attribute No rotational inertia unless paired with a GFM inverter
Ramping	Typically provides attribute Can be used in peaking applications	Typically provides attribute Can be used in peaking applications	Typically provides attribute Expected to ramp quickly	Does not provide attribute May take up to an hour to ramp due to heat requirements
Cycling Capability	Typically provides attribute Can cycle load	Typically provides attribute Can cycle load	Typically provides attribute Expected to be able to cycle load	Does not provide attribute Typically operates at baseload
Short Minimum Run Time	Typically provides attribute Can be used in peaking applications	Typically provides attribute Can be used in peaking applications	Typically provides attribute Expected to be suitable for peaking applications	Does not provide attribute Typically operates at baseload capacity
Black Start	Typically provides attribute Can provide black-start support similar to conventional NG	Typically provides attribute Can provide black-start support similar to conventional distillate	May sometimes provide attribute May be able to provide black-start support in specific situations and configurations.	May sometimes provide attribute May be able to provide black-start support in specific situations and configurations.
Capacity Factor	Flexible Expected to be limited by fuel supply rather than technical barriers	Flexible Expected to be limited by fuel supply rather than technical barriers	Flexible Expected to be limited by fuel supply rather than technical barriers	Flexible Expected to be limited by fuel supply rather than technical barriers
Minimum Stable Output	Typically provides attribute Can operate flexibly	Typically provides attribute Can operate flexibly	Typically provides attribute Expected to operate flexibly	Does not provide attribute Typically operates at baseload

The following summarizes the key takeaways from Table 9:

- Turbines generally provide multiple grid services valuable to a 2040 grid, including inertia, ramping, and black-start capabilities.
- Linear generators and fuel cells can offer some of these attributes depending on configuration. Linear generators are expected to operate more flexibly than fuel cells.

- SOFCs operating on hydrocarbon fuels face the same ramping and quick-start challenges as SOFCs operating on hydrogen. SOFCs will need improvements in dynamic performance before they can be deployed with RNG as low capacity factor resources. Faster ramp rates can be achieved by preheating the fuel cells, though this approach would increase fuel consumption and reliance on other DEFRs to provide fast-start and fast-ramping needs. PEM fuel cells are capable of very fast ramp rates and start times but are not compatible with hydrocarbons unless paired with a reformer, which introduces new cost and logistical challenges.

The following offers additional details on key biofuels attributes.

3.2.1 Renewable Natural Gas

RNG is nearly chemically identical to conventional NG, although conventional NG and any other petrochemically derived fuels will contain other residual hydrocarbons, such as ethane or propane, and slightly more particulate contaminants and heavy metals that remain after the fuel is processed. RNG will not contain these contaminants. These slight differences in fuel composition compared to conventional NG can result in a slightly varied heating value but should have a minimal impact on power generation applications. For resource planning purposes, these technologies should be considered to perform nearly identically. The heat rate of a simple cycle turbine typically ranges between 9.08 and 10.30 MMBtu/MWh, depending on the turbine type (EPRI 2024f). A solid oxide fuel cell using RNG may have a heat rate between 4.96 and 5.54 MMBtu/MWh, with the less efficient estimate for 2035 and the more efficient estimate an optimistic projection for 2050 (NREL 2024a). Linear generators have a targeted heat rate of 7.58 MMBtu/MWh (CEC 2024a).

3.2.2 Renewable Diesel

Gas turbines capable of burning liquid fuels like distillate are advantageous for peaking power generation in New York State because they can perform reliably when constraints on the gas pipeline system restrict the use of pipeline gas for electricity. Because RD is chemically nearly identical to fossil diesel, it is expected to perform nearly identically in dual-fuel turbine systems. Turbines burning distillate fuel are expected to perform slightly less efficiently than burning gas, about 2%–3% higher heat rate for frame turbines (EPRI 2025h).

3.3 Readiness for 2040

3.3.1 Latest Deployment Trends

Domestic production capacity of RD and other biofuels was estimated to be 4.328 billion gallons per year in 2024 by the U.S. Energy Information Administration (EIA 2024c). The EIA does not widely report RNG production, but the U.S. Environmental Protection Agency (EPA) records data on RNG projects through programs such as the Landfill Methane Outreach Program (LMOP) and AgSTAR. It estimates that in 2023, 102 landfill RNG facilities and 135 agricultural RNG facilities were operating in the U.S. (EPA 2025a).

At least 39 on-farm anaerobic digesters operate in the agricultural areas of Western New York, the Finger Lakes region, and the Southern Tier. The Newtown Creek Wastewater Treatment Plant is an RNG demonstration project that processes 250 million gallons of wastewater and 220 tons of organic waste daily. As a result, the plant produces a slurry that can be used for composting and biogas. Approximately 40% of the biogas is used to power the plant, and the remaining 60% is provided to National Grid to be upgraded into RNG. When the biogas-to-grid system is not functioning, the extra gas is flared at the plant (NYS Energy Planning Board 2025).

For economic reasons, most of the U.S.-produced RNG and RD is used in sectors other than power generation, primarily transportation. For example, New York City has become the first city on the East Coast to transition municipal fleet vehicles to RD. New York City began transitioning its garbage trucks, ambulances, work trucks, and emergency generators, among others, to RD in September 2023. This change displaced an estimated 12 million gallons of fossil distillate fuel between September 2024 and October 2024 (NYC 2024). Today, wind and solar are typically lower-cost sources of renewable electricity than combustion of biogenic gaseous or liquid fuels, whose value to the power sector lies in the ability to decarbonize critical peaking hours on a grid dominated by intermittent capacity.

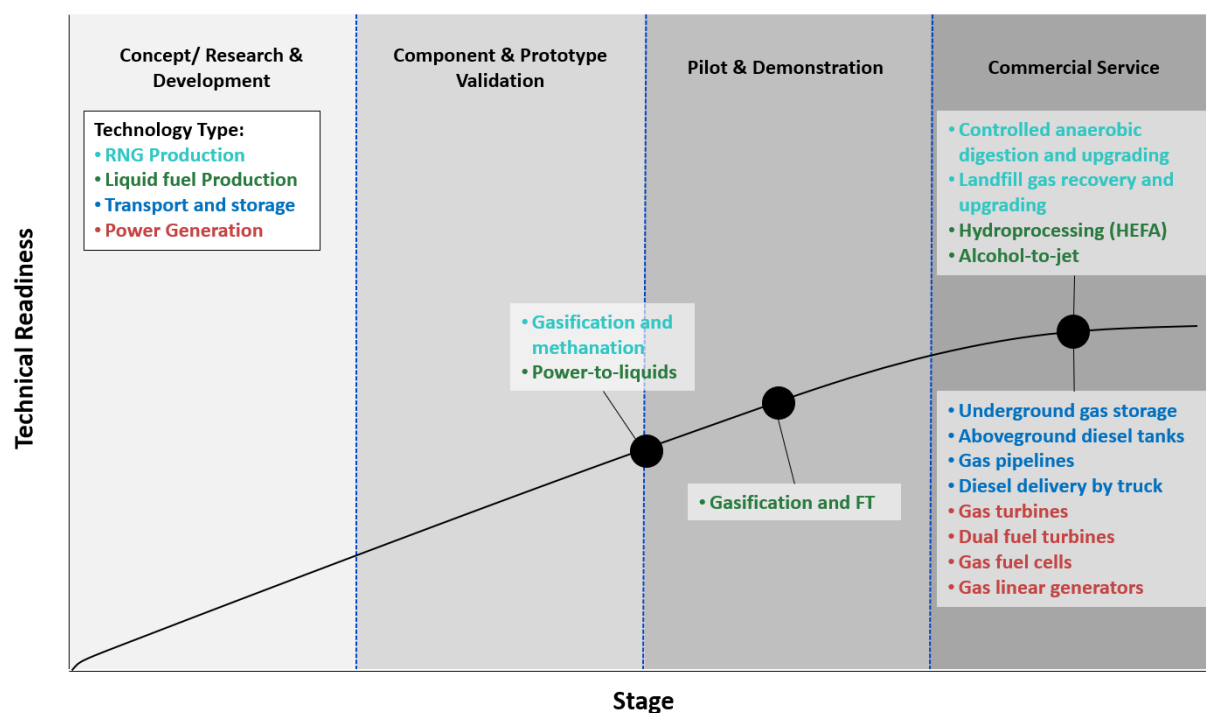
Despite the lack of RNG and RD power generation deployment in the U.S. to date due to the demand of the transportation sector and high cost relative to power from NG, wind, and solar, other countries are deploying biogenic drop-in replacement fuels more broadly. For example, in 2022, the United Kingdom (UK) injected 6.8 terawatt-hours (TWh) of RNG into its gas network, accounting for 0.9% of the country's total NG supply (DESNZ 2024a).

3.3.2 Technology Readiness

Figure 23 presents the various stages of technology readiness for different biofuels technologies.

Figure 23. Current Technology Readiness of Biofuel Production and Power Generation Technologies

A technology remains in its current readiness phase until it completes all activities in that phase. A technology on the line between two readiness phases indicates that it has completed all activities in one phase but has not started activities in the next. The figure provides a high-level comparison of biofuel production and power generation technologies, but does not reflect the variation in technological maturity within a category.



3.3.2.1 Fuel Production

AD is a mature technology widely deployed globally for biogas production from organic feedstocks, such as agricultural waste, wastewater, and landfills. Collecting landfill gas requires different techniques than capturing biogas from controlled anaerobic digesters at farms or wastewater treatment plants (WWTPs), but the technology for doing so is mature. Biogas upgrading to RNG is also a well-established technology. This pathway is commercially viable in some contexts, but high capital costs and inconsistent national policy incentives hinder scalability. The deployment of AD facilities to provide RNG for California's Low Carbon Fuel Standard indicates that the primary barrier to scale-up is commercial rather than technological. The New York City Department of Environmental Protection's (DEP)

Newtown Creek project is an example of AD at a WWTP. In January 2025, the DOE announced \$6.9 million in funding for nine AD projects aimed at supporting local waste-to-energy management solutions for transportation energy needs, reflecting its focus on transportation-related end uses (DOE EERE n.d., BioCycle 2025).

Thermal gasification and FT synthesis technologies for liquid fuel products are mature for some fossil feedstocks, including coal, but biomass-specific systems face challenges like tar management and feedstock flexibility. Gasification of biomass also faces commercial barriers due to high capital costs, operational complexity, and competition with cheaper fuel sources. The technology is seeing some early deployment, including Fulcrum BioEnergy's Sierra BioFuels plant in Nevada, the world's first commercial-scale facility converting landfill waste into renewable transportation fuels via gasification and FT, although this facility ceased operation in 2024 (Fulcrum BioEnergy 2022, Bettenhausen 2024). DG Fuels is currently developing a biomass gasification and FT plant in Louisiana that will be one of the largest SAF production facilities in the world when it opens in 2028 (Surgenor 2024). DOE has supported technologies like gasification and FT through initiatives including its Clean Fuels and Products Shot and its Sustainable Aviation Fuel Grand Challenge, although the research in these technologies tends to focus on sectors like transportation rather than power generation.

Thermal gasification and methanation for RNG are at a lower readiness level than gasification with FT. Though no full-scale facilities are operational, this pathway has been demonstrated at pilot scale with woody biomass in the U.S. by the California Energy Commission (CEC 2020, CEC 2024b). Therefore, it is categorized between Component and Prototype Validation and Pilot and Demonstration.

Hydroprocessing of fats, oils, and greases into liquid fuels is a mature technology with multiple commercial deployments in the U.S., including the Diamond Green Diesel plant in Port Arthur, TX, the largest such producer in North America and second-largest in the world (Diamond Green Diesel 2021).

ATJ processing is also at the stage of commercial service, with one commercial deployment in the U.S., the Freedom Pines Fuels plant in Georgia, which started production in early 2024, and others planned in the coming years (LanzaJet 2024). Distillate fractions of this process can include RD.

PTL processing has been validated at pilot scale (Lydian 2025). Multiple commercial-scale deployments are under development in the U.S. with expected online dates in the next few years (HIF 2025, Infinium 2025). Therefore, the technology is categorized between component and prototype validation and pilot and demonstration.

Hydroprocessing can be paired with other technologies, such as hydrothermal liquefaction and pyrolysis, to use a wider range of feedstocks, but these processes are less scalable, less carbon-efficient, less feedstock-flexible, require more processing to meet product quality, and are less mature than the aforementioned pathways.

Technology readiness also varies by feedstock. AD is mature for all the major feedstocks expected for this pathway, including manure, food waste, and wastewater sludge. Gasification feedstock readiness is driven by various levels of industry experience and degrees of feedstock heterogeneity, with coal as the most mature but not relevant to 0x40, followed by woody biomass, then agricultural residues, and municipal solid waste as the least mature. Hydroprocessing is mature for waste oils and fats as well as oilseeds, the primary feedstocks expected for this pathway. ATJ is mature for energy crops like corn and sugarcane, but is in the demonstration phase for lignocellulosic feedstocks such as agricultural and forestry residues, which are more scalable.

3.3.2.2 Power Generation

Gas turbines are mature technology. New York State's current electric grid has a fleet of gas turbines, many of which are dual-fuel, allowing them to burn distillate during peak winter hours when the gas supply is reserved for building heating. These assets are expected to accept RNG and RD with little to no modifications.

Stationary fuel cells for power generation have been commercially deployed for years in applications where their quiet operation and high efficiency (especially in combined heat and power configurations) are valuable. Most of the stationary fuel cells currently operating in the U.S. use NG or biogas, which typically require a reformer to convert the methane to hydrogen before it is purified and directed into the fuel cell. SOFCs will need to see improvements in ramping and quick-start capabilities before they can be deployed as low capacity factor resources.

Linear generators are in the early stages of commercial deployment. Mainspring Energy, a developer of linear generators, has successfully deployed commercial installations of its product optimized to use NG.

3.3.3 Infrastructure and Supply Chain Readiness Dynamics

Compared to hydrogen, RNG offers distinct infrastructure advantages. Table 10 illustrates the infrastructure and supply chain considerations for biofuels.

Table 10. Comparison of Renewable Natural Gas and Renewable Diesel Technologies by Infrastructure and Supply Chain Readiness in New York State

Technology	Transmission & Grid Integration	Fuel Supply Chain & Waste Management	Cooling Water & Thermal Management	Siting & Land Use	Supply Chain
Existing RNG Turbines	No significant buildout required for existing assets	Infrastructure not ready significant buildout needed to collect and process feedstocks	No significant buildout required for existing assets	No significant buildout required for existing assets	No significant buildout required for existing assets
Existing RD Turbines	No significant buildout required for existing assets	Infrastructure not ready significant buildout needed to collect and process feedstocks	No significant buildout required for existing assets	No significant buildout required for existing assets	No significant buildout required for existing assets
New RNG Turbines	Short lead time Easier to site small plants near transmission	Infrastructure not ready significant buildout needed to collect and process feedstocks	No significant buildout required	Short lead time Easier to site small plants	Short lead time Mature supply chain and workforce
New RD Turbines	Short lead time Easier to site small plants near transmission	Infrastructure not ready significant buildout needed to collect and process feedstocks	No significant buildout required	Short lead time Easier to site small plants	Short lead time Mature supply chain and workforce
RNG Fuel Cells	Short lead time Easier to site small plants near transmission	Infrastructure not ready significant buildout needed to collect and process feedstocks	No significant buildout required	Short lead time Easier to site small plants	Long lead time Manufacturing scale-up likely required
RNG Linear Generators	No significant buildout required Smaller units may ease siting	Infrastructure not ready significant buildout needed to collect and process feedstocks	No significant buildout required	No significant buildout required Smaller unit sizes could make siting easier.	Long lead time Manufacturing scale-up likely required

Renewable Natural Gas

Because it meets pipeline standards, RNG can be injected into New York State's existing NG network, connecting large underground storage facilities with power plants throughout the State. In contrast, hydrogen would need new or retrofitted pipelines, or it would need to be delivered by other means unless it can be consumed on-site. Because the injected RNG would be mixed with NG and used across sectors, energy attribute tracking systems would be needed to ensure the RNG's environmental benefits are accurately attributed to power generation. As discussed in Section 3.4.1, blending RNG into the existing infrastructure would have emissions and local air quality considerations. The local air emissions from power plants would maintain similar levels of pollutants per unit of energy as today, though feedstock supply constraints and additional costs of procuring RNG attributes would likely lead to lower capacity factors and thus lower overall emissions.

Renewable Diesel

The infrastructure readiness dynamics of RD for power generation are also favorable. Many of the critical NG power plants in New York State, especially in Zones F through K, are dual-fuel capable, with estimates of the total available distillate-fired capacity in these zones ranging from 9,000 to 11,500 MW (NYSRC 2024). During critical hours, especially on cold days, gas delivery can be curtailed for power generation, but liquid fuel can be stored on-site for backup. Because fueled power plants are expected to have lower capacity factors in a zero-emissions power sector than in the current system, liquid fuel could be technically well-suited for this highly peaking need, although an increase in liquid fuel usage could lead to higher emissions and local health impacts and likely require additional permitting. The infrastructure for delivering liquid fuel to dual-fuel power plants is well-established. Fossil distillate is typically delivered to dual-fuel power plants in New York State via tanker trucks using existing road-based logistics and stored on-site in bulk storage tanks. As a drop-in replacement, RD is expected to be able to utilize these same resources with negligible modification.

Fuel Supply Chain

A more significant barrier is the infrastructure needed upstream for the accumulation, transportation, and preprocessing of feedstocks. These costs can vary widely, depending on the type, size, and geographic concentration of the feedstock, as well as the distance to the processing center. For example, municipal solid waste has significant sorting and preprocessing requirements to isolate organic feedstocks from recyclables and other waste products not compatible with upgrading to biofuels. In contrast, wet wastes such as manure and wastewater require less preprocessing but are impractical to transport due to

their high water content and are therefore often upgraded on-site. Biogas can be used for on-site power generation, upgraded on-site and directly injected into the pipeline network, or trucked in tube trailers to a centralized upgrading hub. Solid feedstocks for thermal gasification can be transported to centralized processing facilities via rail or waterway, where possible, but feedstock sources that are not near these transportation resources would need to be transported by truck. Moving low-energy-density materials by truck introduces costs and energy losses, so feedstock sources further from processing facilities would produce more expensive fuels.

Supply Chain

Supply chain constraints for power plants using RNG or RD would be minimal because the fuels are drop-in replacements for their fossil equivalents. Impacts to land use, workforce, and transmission could be minimized by repurposing existing plants and leveraging existing gas and fuel delivery networks. Constructing new plants, especially to replace existing aging units, could face supply chain challenges for major equipment. Gas turbines have a well-established manufacturing industry, but their supply and demand sometimes become temporarily misaligned, leading to long lead times. Manufactured equipment that currently has a smaller market, such as fuel cells and linear generators, may face these challenges more acutely if demand increases more rapidly than manufacturing capacity can scale up. Fuel cells also require critical minerals, platinum group metals for PEM fuel cells, and rare earth elements for solid oxide fuel cells, which could pose supply chain risks.

Fuel production also faces some supply chain risks. Biogas purification, syngas cleaning, and FT synthesis all require specific material inputs with some potential sourcing vulnerabilities, especially FT synthesis catalysts made of cobalt and ruthenium (Amin et al. 2024). Additionally, the supply chain of feedstocks, possibly the most significant constraint to the scalability of biofuels, would depend on improved efficiency in the logistics of collecting and transporting fragmented biomass sources, as well as the scale-up of preprocessing facilities (Aslani et al. 2024, El Zahab 2022).

3.3.4 Project Lead Times

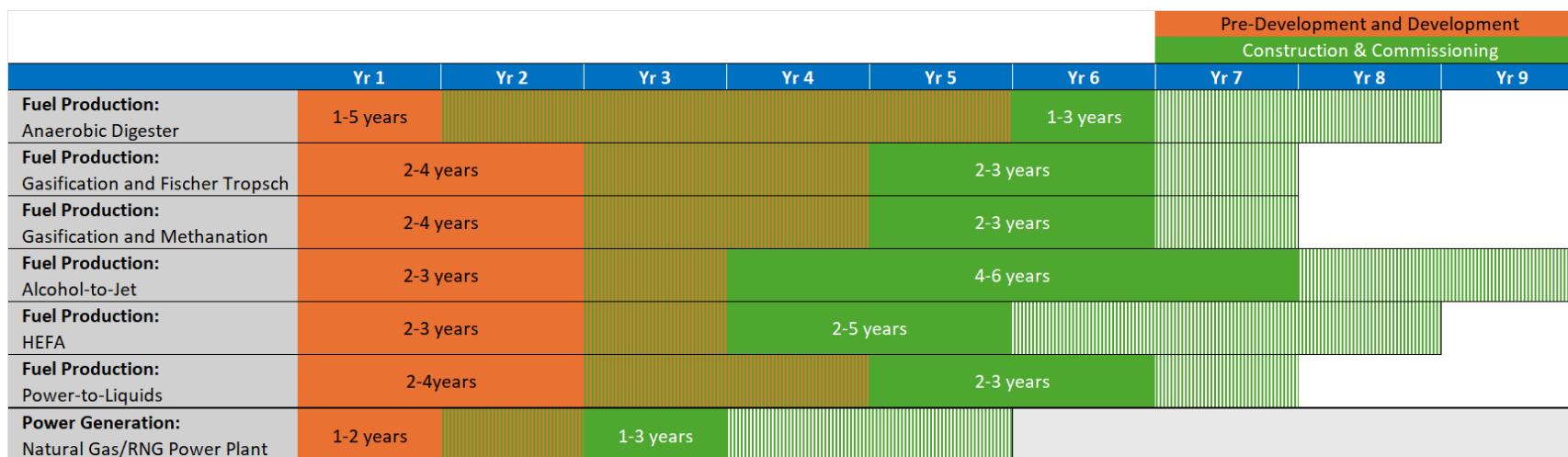
Figure 24 summarizes the estimated lead times for various fuel conversion and power generation technologies. Anaerobic digesters have the potential for short lead times (2–3 years), but their timelines are uncertain due to the wide variation in estimated preconstruction activities, which can be site-specific. Considering the uncertainties of the predevelopment and development (1–5 years) and the construction and commissioning phase (1–3 years), an anaerobic digester project could take 2–8 years.

Estimated lead times for RD conversion technologies range from 4 to 9 years. These current estimates may change if RD is more broadly adopted for decarbonization. Increased demand and subsequent capacity buildout could foster learning-by-doing, which would improve timelines, but if this happens rapidly, bottlenecks in workforces and supply chains could extend timelines.

An advantage of RNG or RD is their suitability for existing power generation assets, but in some cases, developers may need to build new capacity. Section 2.3.4 discusses the project lead times for new turbines, stationary fuel cells, and linear generators; timelines would be similar for new assets powered with biofuels. Figure 24 shows a nominal timeline for developing a new turbine power plant, which may also apply to stationary fuel cells. Linear generators could follow a shorter timeline due to the modularity of the units.

Developing sustainable, cost-effective feedstock supply systems to support the biofuel industry could further extend project development timelines.

Figure 24. Project Lead Times for Biofuel Technologies



3.3.5 Geographic Suitability and Constraints

Given the existing infrastructure in place in New York State for NG and distillate, RD and RNG do not face significant geographic constraints. If attribute tracking were implemented in New York State, RNG could be used statewide using the existing pipeline system, which already connects to existing power plants. Similarly, for RD, utilizing the existing on-site storage facilities currently used for fossil distillate at dual-fuel sites and distillate delivery infrastructure statewide minimizes geographic constraints for the peaking use cases assumed in this study. This makes RNG and RD particularly attractive for Downstate New York, where siting constraints for other resources are more severe.

Many feedstocks are regionally clustered either near large population centers (such as municipal solid waste, food waste, and wastewater) or agricultural regions (animal manure, agricultural waste). The placement of conversion and upgrading facilities near feedstock sources and pipeline injection sites will be critical to minimizing feedstock transport needs and leveraging existing infrastructure.

3.3.6 Readiness Summary

Because RNG and RD are drop-in fuels for existing NG- and distillate-fired plants, the technologies needed to generate electricity from renewable fuels are readily available for use. However, the adoption of RNG and RD as a fuel in the NYS electric sector will depend on the availability of feedstocks, the readiness of conversion technologies, and competition with other sectors, as illustrated in Figure 21. Advancing the maturity and economic competitiveness of thermal gasification could have a considerable impact on the amount of fuel available for use, both within the power sector and other sectors of the economy. The utilization of renewable fuels will also depend heavily on the coordination and development of infrastructure to collect, transport, and convert feedstocks into renewable fuels, likely from a multistate network. Finally, competition with other hard-to-decarbonize sectors could limit the availability of renewable fuels for use in the power sector.

3.4 Emissions and Other Considerations

3.4.1 Emissions

3.4.1.1 Greenhouse Gas Emissions

This report evaluates GHG emissions associated with RD and RNG used in the power sector, using the NYS GHG accounting framework as laid out in the DEC's Statewide GHG Inventory and the Climate Act. The following three emissions categories are relevant to this exercise:

1. **Upstream and midstream:** For fossil fuels, includes emissions from drilling, oil and gas production, gathering, trucking, transmission pipeline leaks, and compressor station leaks. Biofuels include feedstock sourcing, transport, and refining, as well as leaks from transmission pipelines and compressor stations.
2. **Downstream:** Includes emissions from leaks in distribution pipelines, industrial/commercial/residential meters, and within commercial and residential buildings.
3. **Combustion/power production:** Includes emissions from burning the fuel or converting it into electricity.

When evaluating electric sector emissions, the Climate Act accounting attributes the upstream emissions of both in-state and out-of-state produced fossil fuels, as well as the emissions associated with combustion of the fuel, to the power sector. While gross emissions are incurred when consuming fossil fuels and biofuels, the Climate Act accounting methodology also evaluates fuels on a net basis and, in the net case, excludes CO₂ emissions from biofuels in the sector where they are consumed, such that combustion emissions only include nonbiogenic GHG emissions, such as methane (CH₄) and nitrous oxide (N₂O). For fossil fuels, CO₂ emissions from the combustion of fuels are also included in the net emissions. The CO₂-equivalence of CH₄ and N₂O are evaluated based on a 20-year global warming potential (GWP20), which is 84 lb CO₂e/lb CH₄ and 264 lb CO₂e/lb N₂O.

Several other categories, such as downstream fugitive emissions from the gas distribution network, in-state upstream emissions from biofuel production, and transport emissions, are accounted for in other sectors within the *Statewide Greenhouse Gas Emissions Report*, and, therefore, are not included in the emissions accounting for power generation. Furthermore, out-of-state upstream emissions associated with biofuels are not accounted for under the Climate Act accounting framework. While these emissions are not accounted for in the power generation emissions, they are still important to reduce when considering economywide emissions, global climate change mitigation, and local impacts.

Table 11. Comparison of Fuel Types by Statewide Greenhouse Gas Accounting Categories

Fuel Type	Categorization	Upstream Out of State	Upstream In State	Midstream/Downstream	Combustion/Power Production
Natural Gas	Gross	Included in power sector of <i>Statewide Greenhouse Gas Emissions Report</i>	Minimal, almost no in-state NG production	Attributed to other sectors in <i>Statewide Greenhouse Gas Emissions Report</i>	Included in power sector of <i>Statewide Greenhouse Gas Emissions Report</i>
Natural Gas	Net	Included in power sector of <i>Statewide Greenhouse Gas Emissions Report</i>	Minimal, almost no in-state NG production	Attributed to other sectors in <i>Statewide Greenhouse Gas Emissions Report</i>	Included in power sector of <i>Statewide Greenhouse Gas Emissions Report</i>
Fossil Distillate	Gross	Included in power sector of <i>Statewide Greenhouse Gas Emissions Report</i>	Minimal, almost no in-state distillate production	Attributed to other sectors in <i>Statewide Greenhouse Gas Emissions Report</i>	Included in power sector of <i>Statewide Greenhouse Gas Emissions Report</i>
Fossil Distillate	Net	Included in power sector of <i>Statewide Greenhouse Gas Emissions Report</i>	Minimal, almost no in-state distillate production	Attributed to other sectors in <i>Statewide Greenhouse Gas Emissions Report</i>	Included in power sector of <i>Statewide Greenhouse Gas Emissions Report</i>
Renewable Natural Gas	Gross	Not included in <i>Statewide Greenhouse Gas Emissions Report</i>	Attributed to other sectors in <i>Statewide Greenhouse Gas Emissions Report</i>	Attributed to other sectors in <i>Statewide Greenhouse Gas Emissions Report</i>	Included in power sector of <i>Statewide Greenhouse Gas Emissions Report</i>
Renewable Natural Gas	Net	Not included in <i>Statewide Greenhouse Gas Emissions Report</i>	Attributed to other sectors in <i>Statewide Greenhouse Gas Emissions Report</i>	Attributed to other sectors in <i>Statewide Greenhouse Gas Emissions Report</i>	Only non-CO ₂ emissions included in power sector of <i>Statewide Greenhouse Gas Emissions Report</i>
Renewable Diesel	Gross	Not included in <i>Statewide Greenhouse Gas Emissions Report</i>	Attributed to other sectors in <i>Statewide Greenhouse Gas Emissions Report</i>	Attributed to other sectors in <i>Statewide Greenhouse Gas Emissions Report</i>	Included in Power Sector of <i>Statewide Greenhouse Gas Emissions Report</i>
Renewable Diesel	Net	Not included in <i>Statewide Greenhouse Gas Emissions Report</i>	Attributed to other sectors in <i>Statewide Greenhouse Gas Emissions Report</i>	Attributed to other sectors in <i>Statewide Greenhouse Gas Emissions Report</i>	Only non-CO ₂ emissions included in power sector of <i>Statewide Greenhouse Gas Emissions Report</i>

Note on Emissions Accounting

New York has adopted a unique approach to greenhouse gas accounting pursuant to its 2019 Climate Act that differs from practices used by other jurisdictions. Most other jurisdictions use accounting practices developed by the United Nations Framework Convention on Climate Change (UNFCCC).

Adjusting the power sector emissions in this report to accounting practices more typically applied by other jurisdictions requires three adjustments. The first requires removing the upstream emissions associated with fossil fuels, as out-of-jurisdiction emissions are not considered and in-state upstream emissions are accounted for in other sectors. The second requires removing gross biogenic CO₂ emissions, which are considered carbon neutral under those frameworks. The third requires adjustment of non-CO₂ emissions to 100 year GWP; however, in the absence of upstream emissions, those pollutants are not major drivers of results reported in this analysis.

To find emissions factors consistent with New York's accounting practices and a description of differences between New York's approach and practices adopted under the UNFCCC, see NYSERDA's "Fossil and Biogenic Fuel Greenhouse Gas Emission Factors" white paper (NYSERDA 2022d).

Figure 25 shows the gross equivalent CO₂ emissions for each fuel consumed in the power sector on a per-MMBtu basis. While the gross CO₂e emissions associated with combustion of RNG and RD in the power sector are equivalent to those of NG and fossil diesel, the total gross CO₂e emissions in the power sector per MMBtu are lower for RNG and RD than for NG and fossil diesel because upstream fossil fuel extraction, production, and delivery emissions are included in the power sector but upstream biogenic emissions (and sequestration) for biofuels are not (NYSERDA 2023a, 2025d).

Figure 25. Gross Carbon Dioxide Equivalent Emissions in the Power Sector

Expressed in pounds of CO₂e per MMBtu of fuel.

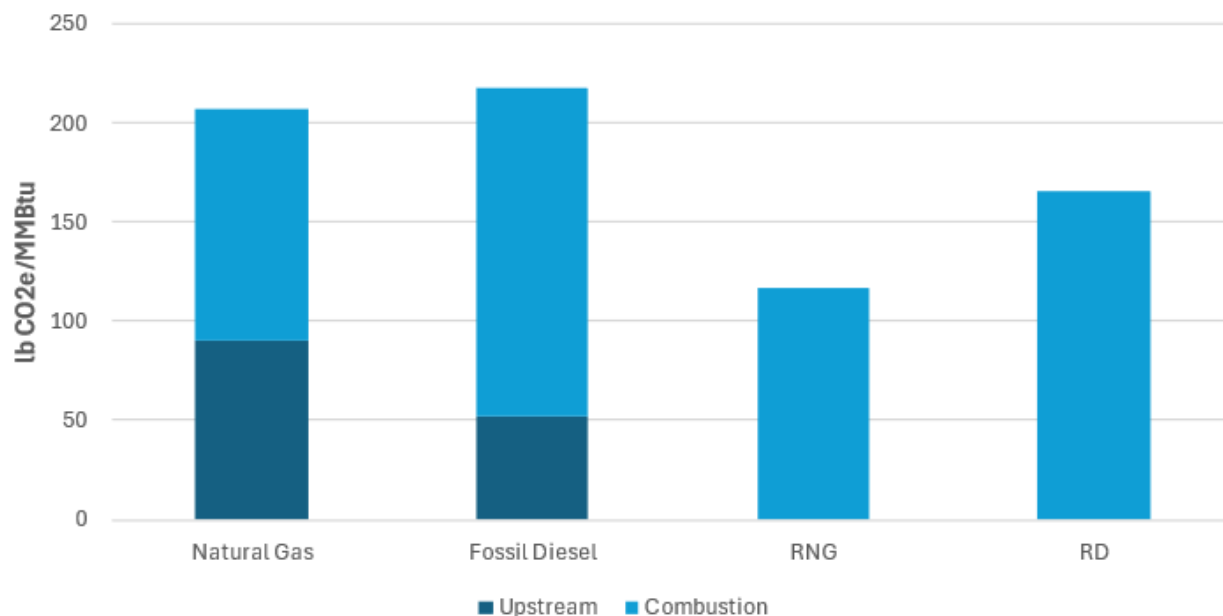
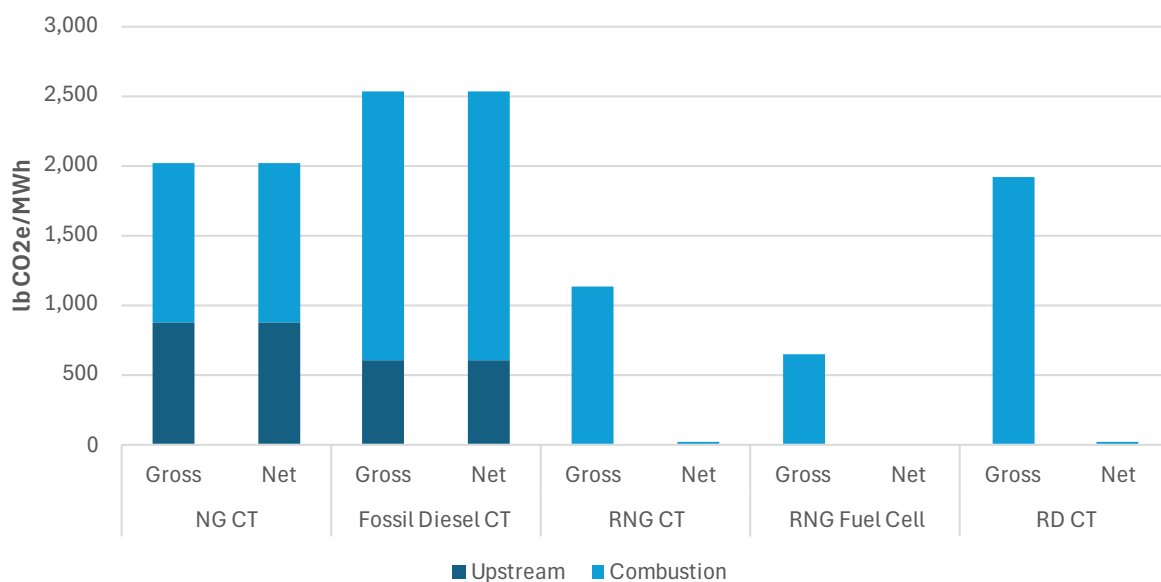


Figure 26 shows how the equivalent CO₂ emissions vary based on power generation technology and also displays both gross and net emissions. Emissions per MWh are calculated based on a typical heat rate (efficiency) of each technology. While a CT operating on NG or RNG is expected to have the same heat rate, the lack of upstream emissions for the RNG CT results in lower gross CO₂e emissions than the NG CT. An RNG fuel cell has a lower heat rate and, therefore, has lower gross CO₂e emissions per MWh. A CT operating on fossil distillate or RD is expected to have a higher heat rate and, therefore, an RD CT has gross CO₂e emissions approaching those of the NG CT plant. However, when evaluated on a net basis, the CO₂e emissions are low for all three biofuel technologies and, in the case of the RNG fuel cell, zero due to a lack of N₂O production during operation.

Figure 26. Gross Carbon Dioxide Equivalent Emissions by Power Generation Technology

Expressed in pounds of CO₂e per MWh of electricity produced.

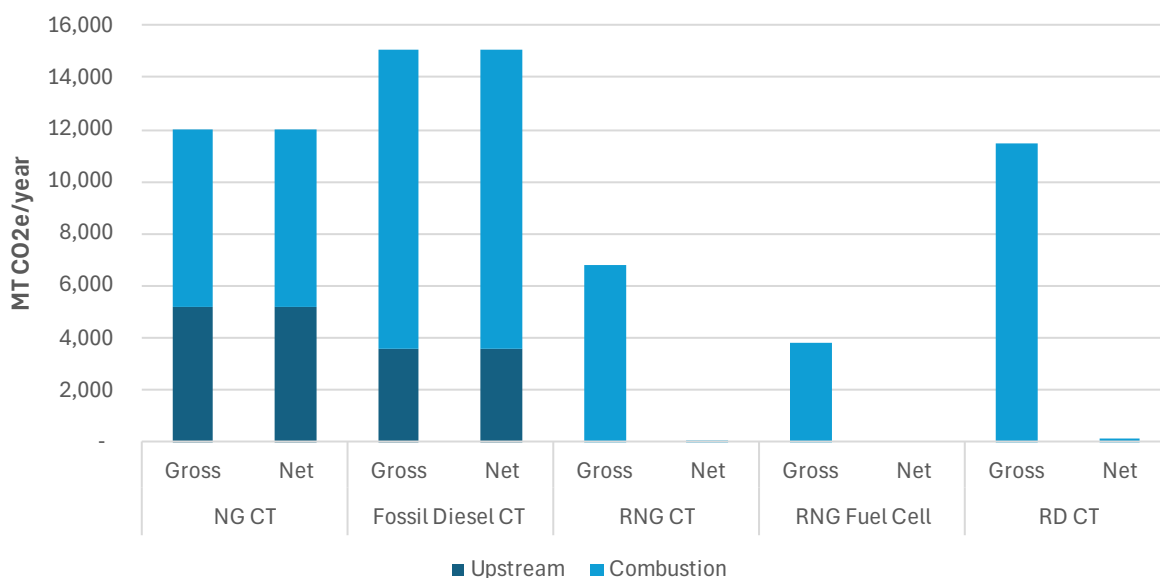


3.4.1.2 Annual Power Sector Emissions from Peaker Plants and Scalability Analysis

This report primarily assumes that RNG and RD will be used solely in peaking applications due to the availability of feedstocks, costs, and competition with other sectors. Figure 27 illustrates the CO₂e emissions per fuel type and technology annually for a single plant, assuming a 50 MW peaker plant with a 3% capacity factor, or 13,140 MWh per year.

Figure 27. Gross Carbon Dioxide Equivalent from a Peaker Plant

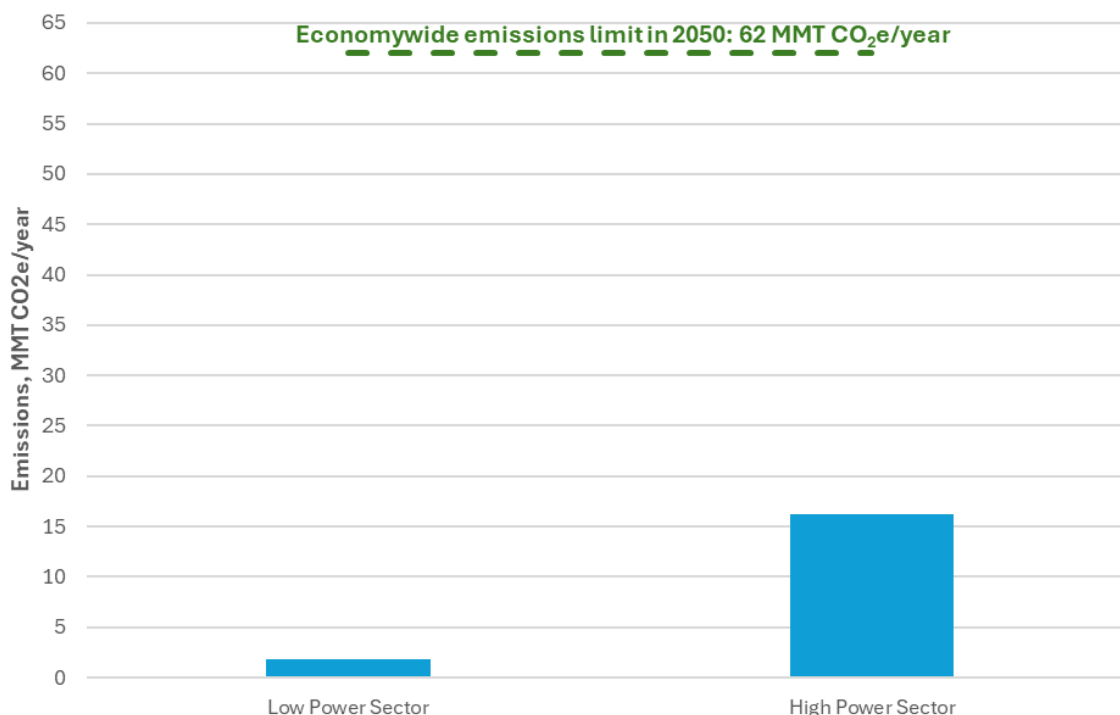
Expressed in metric tonnes of CO₂e produced per year.



While RNG and RD are primarily assumed to be used in peaking applications, this report also considers the supply and demand implications of if RNG were used to meet all 2040 power sector load requirements beyond that met by existing nuclear and renewable generation (assumed to be a minimum of 70% of total generation by 2040), as Figure 28 illustrates. This illustrative bookend is derived from the *2025 Draft State Energy Plan*, Net Zero A scenario, and would require nearly 50,337 GWh of electricity per year to be generated from RNG plants. Assuming this higher electricity generation is achieved using baseload combined cycle plants instead of peaking CT plants, which would leverage the greater efficiency of a combined cycle plant, this would result in approximately 16.2 MMT of CO₂e emissions per year. This would require significant emission reductions from other sectors to meet the 2050 emission target. Any further emissions reductions from other sectors would be challenging because residual 2050 emissions are reserved for the most difficult-to-decarbonize end uses. For example, modeling based on the *Draft SEP* suggests that 38 MMT would be needed for nonenergy sectors, like waste and agriculture. On the other hand, meeting the Low Power Sector scenario demand of approximately 3,621 GWh per year, derived from the modeled hydrogen demand in the *2025 Draft State Energy Plan*, Net Zero A scenario, would result in approximately 1.9 MMT of CO₂e emissions per year.

Figure 28. Annual Carbon Dioxide Equivalent from the Power Sector under Low- and High-Demand Scenarios

Expressed in metric tonnes of CO₂e produced per year.



3.4.1.3 Upstream Greenhouse Gas Emissions

Ultimately, the upstream emissions of RD or RNG will depend on the feedstock type, the collection and processing practices, and the production pathway. According to NYSERDA (2022c), the feedstocks with the lowest carbon intensities are those that reduce methane emissions, which have a 20-year global warming potential of 84 lb CO₂e/lb CH₄, that would otherwise come from uncaptured anaerobic decomposition of organic wastes. These include the collection and processing of waste-based feedstocks such as manure from cows and pigs, the diversion of food waste from landfills, and the beneficial use of gas from WWTPs. Agricultural residues, energy crops, forestry products, forestry residues, and municipal solid waste all have similar carbon intensity ranges due to the energy-intensive thermal gasification process required to produce biogas from biomass. However, incorporating renewable energy sources and on-site co-produced electricity can help reduce the emissions impact of gas production.

While Climate Act accounting treats the net emissions of biofuels as zero or near-zero for the power sector, biofuels can contribute meaningfully to GHG emissions reductions in other sectors. Different feedstocks have different avoided-emissions potential. For example, avoided emissions from RNG

production are greater for AD of animal manure, where the business-as-usual treatment of the feedstock is a manure storage facility that releases significant amounts of methane, as compared to landfill gas, which is often already flared. Generally, RNG has a higher avoided-emissions potential than RD. A more detailed discussion of life-cycle emissions can be found in the Alternative Fuels section of the *2025 Draft State Energy Plan*.

While upstream GHG emissions from biofuel production are not accounted for in the power sector emissions, they are still important when considering economywide emissions. While CH₄ is the desired product in biogas production, with raw biogas generally comprising 50%–70% CH₄, some leaks can occur even in controlled environments, especially if digesters are not sealed well or if piping and storage systems leak (Bakkaloglu 2022). Furthermore, CH₄ leaks can occur during the transport of RNG through transmission pipelines and compressor stations. CO₂ is also a significant byproduct of AD, often comprising around 40%–50% of raw biogas from landfill gas (NYSERDA 2022c). This biogenic CO₂ is removed from the biogas during upgrading and typically released into the atmosphere, though research is underway on opportunities for utilization or sequestration of this CO₂ (Cordova 2023).

3.4.1.4 Co-Pollutant Combustion Emissions

Beyond GHG emissions, other co-pollutant emissions are associated with the combustion of RNG and RD in CTs, such as PM, NO_x, and sulfur oxides (SO_x). PM is a primary pollutant of concern, resulting from direct PM emissions as well as secondary formation from NO_x and SO_x. Ozone is formed from NO_x combined with volatile organic compounds (VOCs) in sunlight. PM emissions from RNG and RD are expected to be similar to those of their fossil counterparts. PM emissions from distillate or RD are generally higher than from NG or RNG, making emissions dependent on the balance of fuels used. SO_x emissions are expected to be similar for RNG and RD to those of the equivalent fossil fuel. They are not a substantial pollutant of concern today, given the very low emissions from NG, emission controls, and the phase-out of coal in New York State. NO_x emissions from RNG and RD are also expected to be similar to those of the equivalent fossil fuel, but may vary if fuel switching occurs. Because fuel cells operate without combustion, the use of RNG in a fuel cell rather than a CT minimizes PM and NO_x production to near zero. Section 3.4.2 discusses the implications of these non-GHG emissions.

3.4.2 Other Considerations

3.4.2.1 Air Quality

Unlike other technologies evaluated in this report, shifting from using NG or distillate to RNG or RD in CT peaking units is not expected to improve local air quality, given the similar emission characteristics between the fuels, all else equal. While PM, NO_x, and SO_x emissions may be controlled, they are not zero, and a transition to RNG or RD would result in fewer health benefits than other zero-emission technologies. Generally, replacing a fossil fuel with a renewable counterpart would not substantially reduce co-pollutant emissions and associated air quality impacts in the power sector. Furthermore, if fuel switching occurs such that RD is used more frequently than fossil distillate today, negative impacts on air quality could occur. However, if units are relied on at a lower rate after switching to RNG, due to high prices and availability of other renewable resources, air quality would improve. Moreover, using a fuel cell for power production instead of a CT could further reduce local emissions of PM, NO_x, and SO_x.

In addition to air quality considerations from combustion at power generation facilities, air quality must also be considered at the fuel production sites. The upstream emissions associated with the production facilities could impact air quality and the local environment if not properly accounted for and controlled.

3.4.2.2 Safety and Environmental Considerations

Handling energy-dense materials such as gaseous or liquid fuels can be inherently dangerous, but the well-established safety protocols for NG and fossil distillate should apply to RNG and RD.

A pipeline leak or liquid fuel spill would pose similar risks of environmental contamination, whether the fuel was of fossil or biogenic origin, but the infrastructure and protocols in place to prevent leaks and spills of fossil fuels would also apply to biofuels.

3.4.2.3 Land Use

The land-use impact of RNG and RD is highly dependent on the feedstock. When fuels are derived from waste resources such as landfill gas, wastewater, animal waste, or agricultural waste, land-use impact is minimal. However, if bioenergy crops are grown for feedstock sourcing, considerable concerns arise about the use of arable land for RNG and RD feedstock production and the increased shift of natural lands to agricultural use globally, with consequences for global GHG emissions. These concerns can be moderated by limiting the use of energy crops and focusing on waste products and crops that do not shift land use. As discussed in the supply and demand dynamics (Figure 22), necessary tradeoffs emerge

between the supply available if RNG and RD production focuses only on waste streams versus including purpose-grown crops, which increase supply but also associated environmental and land-use concerns, potentially resulting in uncertain GHG emission reductions or even increases.

3.4.2.4 Workforce

The adoption of biofuels in the electric power sector presents significant workforce opportunities, particularly for workers transitioning from retiring fossil fuel industries. Many roles in biofuels production—such as plant operations, engineering, maintenance, and feedstock logistics—require skills that closely align with those found in fossil fuel sectors, potentially enabling a transfer of expertise. Targeted training and workforce development programs would be beneficial in addressing differences in process technologies and ensuring that displaced fossil fuel workers are equipped for the biofuels industry.

3.5 Cost

3.5.1 Fuel Costs

Power generation with renewable natural gas or renewable diesel is characterized by low capital costs and high operating costs. Fuel expenses primarily drive the operating costs.

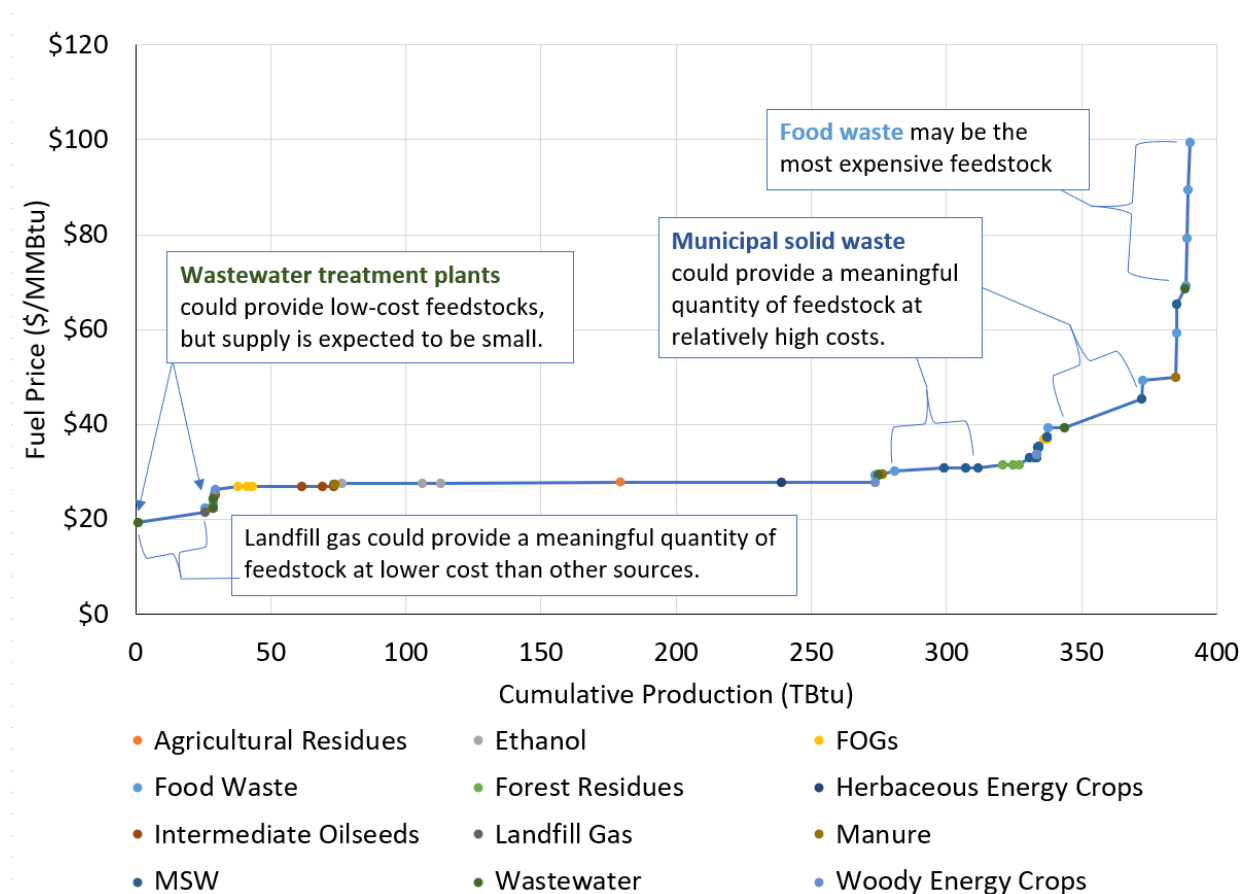
E3 developed a biofuel supply curve optimization tool for the *2025 Draft State Energy Plan*. The tool projects costs of biogenic fuels in New York State, given specific demand assumptions. Power sector and other sector demand are derived from the *2025 Draft State Energy Plan*, Net Zero A scenario. Two power sector bookends were considered as discussed in Section 3.1.2. The Low Power Sector Demand scenario assumes that RNG and RD are used only for peaking, based on the *2025 Draft State Energy Plan* modeling, which assumed hydrogen as a proxy for DEFR and saw these units operating at 2% capacity factors in 2040 in the Net Zero A scenario. The High Power Sector Demand scenario explores a hypothetical upper bookend of renewable fuel demand, using RNG to meet all 2040 Net Zero A scenario power sector load requirements beyond that met by existing nuclear and renewable generation (assumed to be a minimum of 70% of total generation by 2040).

Fuel costs will depend on which feedstock and process are used to produce the fuel. An illustrative supply curve for New York State in 2040 is shown in Figure 29 below, assuming statewide demand from the *Draft SEP* Net Zero A scenario with high power sector demand consistent with the scenario described in the feedstock availability (Section 3.1.2). Power generation demand for biofuels is assumed to be

10% distillate (RD) and 90% RNG based on the high range of historical data for New York State peaking capacity. Data points for different feedstocks and fuel products are arranged along the curve from least expensive to most expensive. A data point's vertical position on the plot represents its cost, and the distance from the previous point represents its quantity. Text boxes highlight some illustrative examples.

Figure 29. E3 Biofuel Supply Curve Modeled for the High Power Sector Demand Scenario in New York State, 2040

Prices reported in 2023 USD.



The marginal and average prices calculated by E3 SEP tool for three scenarios are presented in Table 12, with the ranges in marginal prices visualized in Figure 30. The low, base, and high cases are based on different fuel demand scenarios informed by the SEP economywide demand and two power sector bookends:

- The Economywide + High Power Sector Demand scenario has a total 2040 demand of 543 TBtu and also includes demand from all sectors.

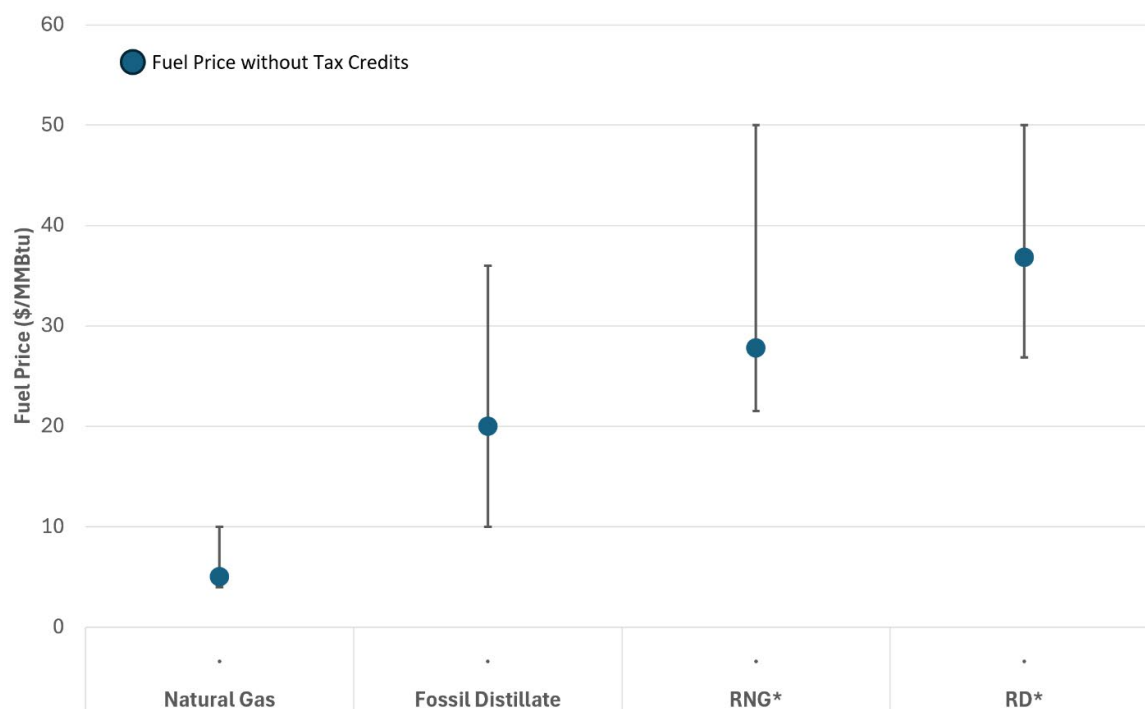
- The Economywide + Low Power Sector Demand scenario has a total 2040 demand of 221 TBtu and also includes demand from all sectors.
- The Low Power Sector Only scenario shows how demand from only the power sector (25 TBtu) would result in lower prices.

The analysis in this section assumes that the marginal price will drive the market-clearing price, but depending on how these markets evolve, some generators may be able to access lower costs through direct transactions with fuel producers.

The values used for the LCOE analysis conducted in Section 3.5.4 are shown in bold in Table 12. The RNG and RD marginal cost for the Economywide + High Power Sector Demand scenario is hypothetical due to insufficient feedstocks to meet that level of demand. A value of \$50/MMBTu was chosen, representing the cost of the last meaningful quantity of feedstock before the marginal cost undergoes an asymptotic price spike, as shown in Figure 30. The reference NG and fossil distillate costs are derived from historical and projected fuel prices.

Figure 30. Projected Prices for Renewable Natural Gas, Renewable Diesel, and Their Fossil Counterparts, 2040

Prices reported in 2023 USD.



* Supply is insufficient to meet the Economywide + High Power Sector Demand scenario. The prices shown reflect the last meaningful quantity of feedstock before the marginal cost undergoes an asymptotic price spike.

Table 12. Marginal and Average Prices for Renewable Natural Gas, Renewable Diesel, and Their Fossil Counterparts across Different Model Scenarios

Bolded values indicate those used in LCOE calculations. Prices reported in 2023 USD/MMBtu.

Case	Demand Scenario	RNG Marginal Price	RD Marginal Price	RNG Average Price	RD Average Price	Natural Gas	Distillate
High	Economywide + High Power Sector	\$50a	\$50a	\$32	\$29	\$4–\$10	\$10–\$36
Base	Economywide + Low Power Sector	\$28	\$37	\$24	\$31		
Low	Low Power Sector Only	\$22	\$27	\$21	\$27		

^a Supply is insufficient to meet the Economywide + High Power Sector Demand scenario. The prices shown reflect the last meaningful quantity of feedstock before the marginal cost undergoes an asymptotic price spike.

3.5.1.1 Biofuels Tax Credits

The federal Clean Fuel Credit (Section 45Z), established under the Inflation Reduction Act, is a technology-neutral incentive for the production of clean transportation fuels—including biofuels—that is effective for fuels produced and sold between January 1, 2025, and December 31, 2027. This timeline was recently extended through December 31, 2028. The base credit is \$0.20/gallon for transportation fuels, which can increase up to \$1.00/gallon if the PWA requirements are met. The credit amount is further adjusted based on the fuel’s life-cycle GHG emissions, with higher credits awarded to fuels with lower carbon intensity. The analysis in this section does not include the Clean Fuel Credit because it is not expected to be available to fuels produced in 2040.

3.5.2 Capital and Operating Costs

3.5.2.1 Capital Costs

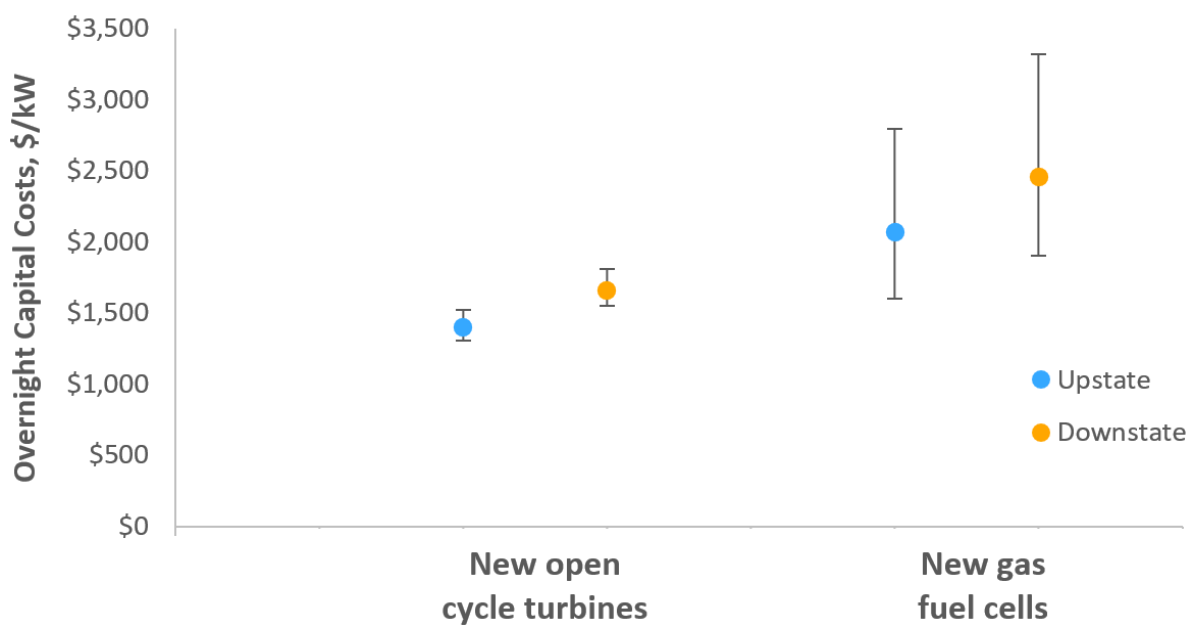
To combust biofuels in existing turbines, no additional capital expense is expected to be necessary. Depending on the age of the plant and its capital recovery, some capital components may be included, but this study assumed no capital components for existing asset cases. This is a simplification because existing assets will eventually become obsolete, and capital cost savings would not be permanent.

The capital cost assumptions for new turbines are derived from the input assumptions from the *2025 Draft State Energy Plan* (SEP) and benchmarked against the NYISO Demand Curve Reset process. Capital costs for new fuel cells are based on estimates for an NG SOFC (NREL 2024a). These fuel cell costs from the NREL ATB are scaled by a factor derived from the ratio of SEP turbine costs to ATB

turbine costs, reflecting local market conditions that affect power plant components and skilled labor. Figure 31 presents a range of overnight capital costs for deploying biofuels power generation technologies for 2040.

Figure 31. Estimated Overnight Capital Costs: Deployment of New Biofuels Power Generation in New York State, 2040

Prices reported in 2023 USD.



3.5.2.2 Operating and Maintenance Costs

Operating costs are derived from the 2024 NREL ATB cases for open-cycle turbines and SOFC (NREL 2024a). The fixed O&M costs are adjusted for NYS labor rates. Variable O&M costs for liquid fuel operation are increased by 5% for additional fouling, corrosion, and deposits inside the turbine, which increases maintenance frequency. Table 13 presents the O&M costs used in this study.

Table 13. Estimated Operating and Maintenance Costs of Biofuel Power Plants in Upstate New York State, 2040

Prices reported in 2023 USD.

Cost Category	RD Turbine	RNG Turbine	RNG Fuel Cell
Fixed O&M (\$/kW/year)	\$25.43	\$25.43	\$44.47
Variable O&M (\$/MWh)	\$7.55	\$7.19	\$7.92

3.5.3 Funding and Subsidies Available to Biofuels Projects

Eligibility for the technology-neutral Clean Electricity ITC and Clean Electricity PTC tax credits for new or existing CTs using biofuels depends on the emissions profile of the feedstock. Facilities using RNG must demonstrate net-zero GHG emissions through a life-cycle assessment (LCA), which must consider all stages of the fuel's life cycle. As a result, the eligibility of RNG and RD power generation projects is project-specific and uncertain, depending on project configuration. Neither the Clean Electricity ITC nor the Clean Electricity PTC is included in the LCOE analyses for CTs. In contrast, under H.R. 1, fuel cell property qualifies for a 30% ITC regardless of emissions or PWA requirements, provided construction starts before 2033 to qualify for the full credit.

3.5.4 Levelized Cost of Electricity

An important advantage of biofuels is their ability to replace fossil fuels without additional capital investment in generating assets. However, existing assets would eventually need to be replaced as they age, so these savings are not permanent. Figure 32 presents datasets for each generator type: one including a capital component and another excluding capital costs in 2040. This analysis assumes a 3% capacity factor, based on the *2025 Draft State Energy Plan* modeling adjusted for uncertainty. As discussed below, the capacity factor will vary annually due to the weather and other factors. Error bars represent the ranges for capital expenses (where applicable), operating expenses, and fuel. The purple dot represents the Clean Electricity ITC for new fuel cells, although project construction must start before 2033 to qualify for the full credit. A counterfactual set of LCOE values using fossil fuel is also calculated and included on the graph as black squares, illustrating that at low capacity factors, the fossil counterfactuals are also quite high. Appendix A provides additional details on LCOE calculation assumptions.

Figure 32. Calculated Levelized Cost of Electricity of Renewable Natural Gas and Renewable Diesel Power Generation Technology

Full tax credit eligibility requires construction to start before the credit phaseout date. Prices reported in 2023 USD.

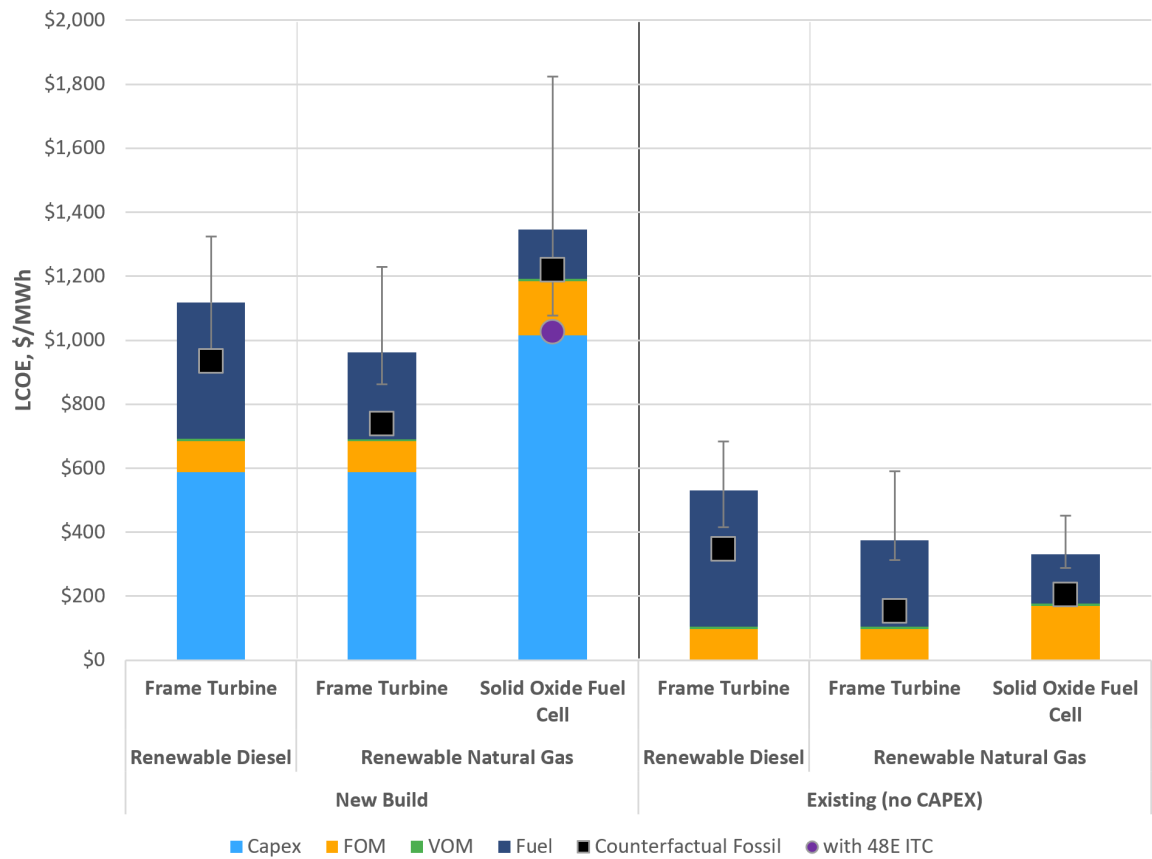
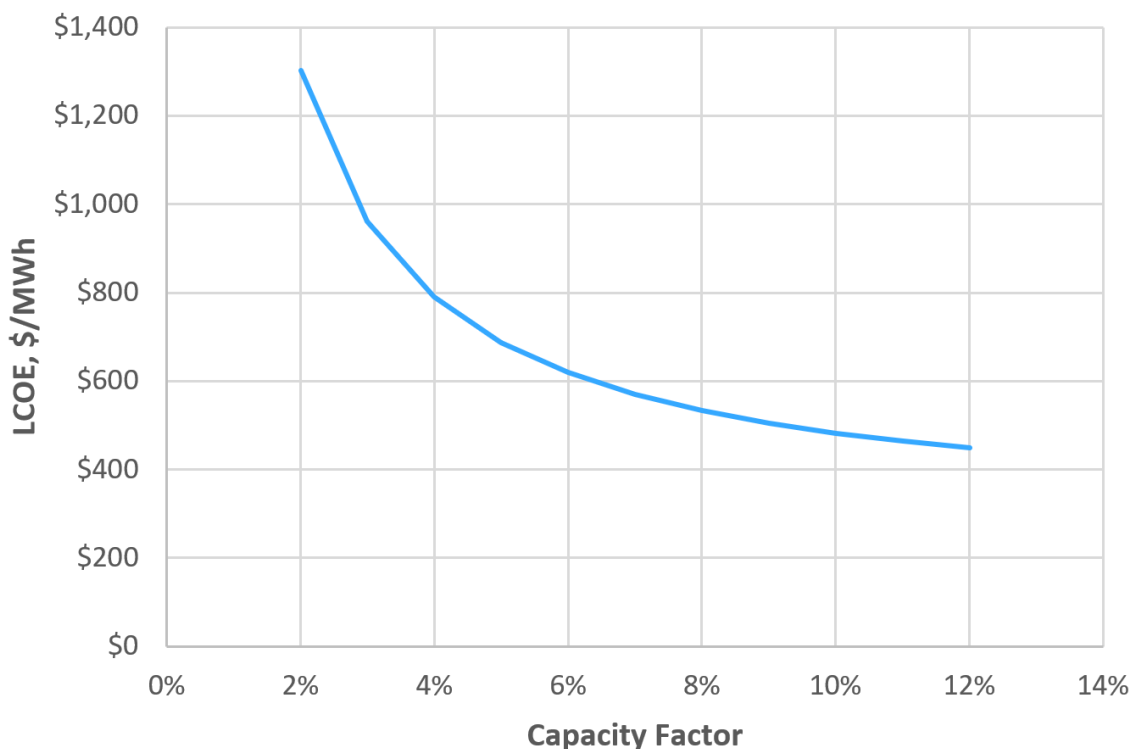


Table 12 presents the biofuel prices used for the LCOE calculations, with values shown in bold.

Peaking unit capacity factors will vary annually depending on the weather and availability of baseload and renewable resources. To demonstrate how LCOE changes with the capacity factor of the generator, Figure 33 shows the LCOE of a new turbine firing RNG at a capacity factor ranging from 2% to 12%.

Figure 33. Levelized Cost of Electricity for a New Renewable Natural Gas-fired Turbine by Annual Capacity Factor

Prices reported in 2023 USD.



3.6 Scalability for 2040

Based on the feedstock availability and supply and demand dynamics discussed in Section 3.1.2, three scenarios are generated to describe the potential for Conservative Deployment, Moderate Deployment, and Aggressive Deployment of RNG- and RD-fired technologies for power generation. Ultimately, the scale of biofuel deployment for power generation will depend on the availability of feedstocks, the availability of production technologies, competing demand from other sectors, and economywide emission limits.

3.6.1 Conservative Scenario

In a Conservative Deployment scenario, thermal gasification is not available as an RNG or RD conversion technology, either due to commercial barriers or because it is focused on generating high-value fuels for other sectors, such as SAF for decarbonizing aviation. In this case, only AD feedstocks and conversion pathways are available for supplying RNG and RD. This would result in only about

20% of the total estimated RNG supply being available for use in any sector and almost no RD. While some of this RNG supply could be used for power generation, it will compete with the demand from other sectors, as shown in Figure 22, significantly limiting the availability of biofuels for use in power sector generation. The use of these limited feedstocks would be focused on regions where other options are limited, such as Zones J and K.

3.6.2 Moderate Scenario

In a Moderate Deployment scenario, thermal gasification has overcome commercial barriers, and all conversion pathway technologies are available for biofuel production. Regional feedstock coordination enables a portion of feedstocks to be available from the surrounding region, such that the 250–320 TBtus of biofuels are available for use economywide, as illustrated in Figure 22. While the majority of biofuel produced is used to meet demand from other sectors, the supply is sufficient to meet power sector demand in peaking applications throughout the State. In this scenario, gross annual CO₂e emissions from biofuels in the power sector are approximately 1.9 MMT (see Section 3.4.1), which would require a moderate reduction in other sector emissions to avoid risking the economywide emissions cap of 62 MMT CO₂e.

3.6.3 Aggressive Scenario

In an Aggressive Deployment scenario, additional biofuel supply may be available for power sector generation in a limited way beyond just critical hours if demand from other sectors lags or if a higher share of available feedstocks from the surrounding region is available for use in New York State. However, use of RNG beyond a peaking application could increase gross emissions to as high as 16.2 MMT of CO₂e (see Section 3.4.1), or 25% of the 2050 economywide gross CO₂e emission limit of ~62 MMT. Because most residual 2050 emissions are expected to be used in the hardest-to-decarbonize sectors (e.g., waste, agriculture, aviation), use of RNG and RD in the power sector would need to be scaled back by 2050 to avoid risking the economywide limit.

3.6.4 Beyond 2040

If the power sector continues adopting biofuels beyond 2040, the developments described in the Moderate Deployment and Aggressive Deployment scenarios may be achieved or continue in the 2040s and beyond, depending on industry progress by 2040. Thermal gasification and methanation technologies could further mature and overcome commercial barriers, making additional feedstock pathways available, potentially expanding the supply. Advancements in logistics systems for feedstock collection, transport,

and preprocessing could reduce costs and improve the economics of biofuel production. The extent of biofuel use in the power sector beyond 2040 will also depend on advances in decarbonization technology affecting harder-to-decarbonize sectors and their effect on the economywide CO₂e emission limit.

3.6.5 Scalability Summary

Regardless of the scenario, available feedstocks are insufficient for biofuels to serve as more than a peaking resource. Other energy resources, such as intermittent renewables and high capacity factor resource DEFs, would therefore be needed. However, the scenarios described earlier would have varying degrees of impact on a 2040 grid.

The Conservative Deployment scenario would fall short of meeting 0x40 reliability needs during challenging weeks statewide but could provide key peaking support, especially Downstate, where other options are limited.

In the Moderate Deployment scenario, RNG and RD could play a key role in meeting the reliability needs of a 0x40 grid as peaking resources, especially in Downstate New York, where other options are limited. However, limited feedstocks, high fuel costs, and gross emissions implications of these fuels would prevent their expansion beyond peaking applications. Technologies with lower GHG footprints and fewer supply constraints would be required to provide additional support. Given the uncertainty around supply, RNG should not be considered a universal solution, because lower-cost alternatives may exist in certain parts of the State, such as low-cost hydrogen from curtailed renewables or in areas where high capacity factor resources are needed to meet additional energy needs.

While the aggressive scenario could expand RNG and RD applications beyond peaking roles, the emissions implications would be significant, and available feedstocks for these fuels alone cannot meet the energy and reliability needs of a 0x40 grid.

3.7 Conclusions

Based on the previous assessment, the following key observations are offered to inform future consideration of biofuel deployment in New York State.

Biofuels are carbon-based fuels derived from renewable feedstocks that produce fewer net emissions relative to fossil fuels. These fuels are expected to be critical to the decarbonization of many hard-to-electrify sectors, including transportation, supplemental heating, and industry, but could also be useful for the power sector.

The biofuels most relevant to the power sector are RNG and RD because they are drop-in replacements for NG and fossil distillate.

RNG and RD can be produced from a variety of feedstocks that have different fuel production pathways, emissions implications, land-use implications, and infrastructure requirements.

Candidate feedstocks include waste-based feedstocks, such as landfill gas, wastewater, manure, food waste, and municipal solid waste (MSW), as well as plant-based feedstocks, including agricultural or forest residues and purpose-grown energy crops or trees. Each feedstock will require the development of aggregation mechanisms to collect them for upgrading to fuel.

RNG has relatively few infrastructure hurdles, but it is sourced from limited feedstocks that are also required for the decarbonization of other sectors. RNG is a drop-in alternative to NG and can

therefore use existing NG pipelines and generators without retrofit. RNG is particularly appealing for Downstate New York deployment, where building new infrastructure is complex and space is limited. RNG can be produced from both anaerobic digestion (AD) and thermal gasification/methanation.

Thermal gasification/methanation is currently at a lower readiness level than AD, requiring both technological and commercial advancement for market readiness before 2040. Based on an assessment of available feedstocks, both of these RNG production pathways, as well as access to non-NYS-based regional feedstock supplies, would be required to generate enough RNG to meet both peaking power sector demand and other sector demand. As shown in Figure 22, based on the feedstock supply assumptions in this study, RNG is most likely to serve as a peaking resource due to limitations of current feedstock sources.

The use of RNG in the power sector has both local and statewide emissions consequences. Under the Climate Act's gross accounting methodology, the point-of-use emissions per unit of electricity of NG and RNG are similar. Due to high costs and feedstock constraints as well as the increased renewable deployment underway, these plants are expected to operate at lower capacity factors than today, which would lead to reduced emissions and improved air quality. Under the NYS gross emissions accounting framework, using RNG as a peaking-only asset could result in approximately 1.9 million metric

tons (MMT) of gross carbon dioxide equivalent (CO₂e) emissions in 2040, which is small relative to the 2050 limit of 62 MMT. If the role of RNG were to grow to be more of a baseload resource, gross emissions would total a more significant 16.2 MMT of gross CO₂e emissions, which is likely not viable under the 2050 economywide gross emission limit, given emissions from other difficult-to-decarbonize sectors. If fuel cells were used instead of CTs, these gross emissions would be meaningfully lower due to their higher efficiencies. In contrast, under the NYS net accounting framework and under IPCC accounting conventions, RNG has zero or close to zero net emissions. If RNG is blended with NG to leverage existing gas infrastructure, an attribute tracking mechanism would be required to appropriately account for emissions.

RD is a drop-in replacement for fossil distillate that is promising as a backup fuel for reliability needs, similar to the use of distillate in dual-fuel generating units today. RD holds an advantage of high energy density and existing transport and storage infrastructure. RD may be particularly important as the electric system eventually becomes winter-peaking with expected heating load electrification. Developing RD supply chains would also benefit other sectors that require renewable liquids. However, RD use in a CT has more than 65% higher gross GHG emissions on a per-megawatt-hour (MWh) basis than RNG, due to its lower heating value and resultant reduced plant efficiency. RD also has increased co-pollutant emissions compared to RNG, but is similar to fossil distillate.

The cost of RNG and RD will depend on the type of feedstock used to produce the fuel. Low-cost feedstocks for biofuel production include landfill gas and wastewater, while higher-cost feedstocks include municipal solid waste, energy crops, and agricultural residues. RNG cost will depend on the feedstock, but is expected to be significantly more expensive than NG. Similarly, the cost of RD depends on the feedstock and is expected to be significantly more expensive than fossil distillate. As lower-cost feedstocks are fully expended with demand from the power sector and other uses, biofuel prices may increase as production shifts to higher-cost feedstocks.

4 Nuclear

4.1 Technology Overview

Nuclear power is a mature technology currently representing approximately 20% of the electricity generated in the U.S. annually. Typically, nuclear power is generated through sustained fission (splitting) of uranium atoms. Most reactors use a moderator (typically water, graphite, or beryllium) to sustain the chain reaction. The heat produced during fission is transferred to a coolant (e.g., water, gas, liquid metal, molten salt) that is used to produce steam, which is then expanded through a steam turbine generator to generate electricity.

The current operating fleet in the U.S. is made up of light water reactors. “Light water” refers to the lightest and most common isotope of water. “Heavy water” reactors use a heavier isotope of water (deuterium oxide) as a moderator. Currently, no heavy water reactors are operating in the U.S. The U.S. fleet comprises two primary types of light water reactors (LWRs): pressurized-water reactors (PWRs) and boiling-water reactors (BWRs). PWRs use pressurized water as a coolant, with separate cooling loops to drive the steam turbine. In contrast, BWRs allow the water in the cooling loop to boil, and the resulting steam directly drives the steam turbine. PWRs and BWRs were widely deployed starting in the mid-1950s. Today, they comprise the vast majority of operational reactors worldwide. These reactors use low-enriched uranium (LEU) fuel, where the proportion of a specific uranium isotope is increased through physical processes.

This report examines three main reactor categories, distinguished by size, coolant type, and maturity:

- **Large light water reactors (LLWRs):** Large reactors (>600 megawatts electric [MWe]), mostly PWRs and BWRs, using LEU fuel and water as the coolant and moderator. Advanced LLWRs incorporate evolutionary safety features and improved performance compared to earlier generations.
- **Light water small modular reactors (lwSMRs):**^{4, 5} Small reactors (50–300 MWe) derived from LLWR designs, often with an integrated reactor and steam generator in a single containment vessel.
- **Non-water-cooled reactors:** Reactors, both small and large, using a coolant and moderator other than water and often a high-assay low-enriched uranium (HALEU) fuel.

The scope of this report is limited to advanced reactors (ARs). The term “advanced reactor” refers to any fission reactor concept or design that offers features and attributes that depart from those of the traditional light water reactors (LWRs) that comprise most of the currently operating nuclear fleet in terms of fuel

forms, coolants, structural materials, size, safety margins, deployment models, and other important design and operational aspects (EPRI 2022a).⁶ For this research, advanced LLWRs are considered under the umbrella of ARs due to passive safety features and deployment models.

Table 14 provides an overview of the most notable nuclear fission technologies, categorized by coolant. It introduces selected reactor designs, their methods of energy production, key components, and their respective advantages and challenges. Table 15 provides more details on selected designs, including their market and regulatory status. It summarizes the major nuclear technologies (excluding heavy water reactors, fission microreactors, and fusion reactors, which are not the focus of this report), notable corresponding designs, and their current statuses. Table 15 focuses on designs relevant to the U.S. market and does not list test reactors.

Overview of Nuclear Fusion Technologies

While nuclear fusion represents a promising source of clean energy, its maturity level is comparatively low. Unlike fission, which splits heavy atomic nuclei, fusion combines lighter nuclei (e.g., hydrogen isotopes) to form heavier elements, releasing energy. Using the same reaction that powers the sun, fusion promises abundant, clean energy with minimal waste and no meltdown risk (EPRI 2020a). However, sustaining the extreme conditions required remains a major challenge. Fusion approaches include:

- Magnetic confinement fusion (MCF): Uses strong magnetic fields to confine plasma (e.g., tokamaks, stellarators)
- Inertial confinement fusion (ICF): Uses high-energy lasers to compress fuel
- Magneto-inertial fusion: A hybrid of MCF and ICF

The International Thermonuclear Experimental Reactor (ITER) is the largest fusion project, backed by global partners. First fusion is now expected in 2035, with energy-producing reactions by 2039 (Clery 2024, ITER 2024). Meanwhile, private ventures, such as the Massachusetts Institute of Technology's Soonest/Smallest Private-Funded Affordable Robust Compact (SPARC), in partnership with Commonwealth Fusion Systems, are developing smaller, modular designs with the goal of net-positive energy by 2026. Helion Energy signed an agreement with Microsoft to pursue development of the world's first commercial fusion power plant, aiming to deliver 50 MWe of electricity by 2028 (Cuthrell 2024). Elsewhere, the Commonwealth of Virginia announced that Commonwealth Fusion Systems will invest billions to build the world's first grid-scale commercial fusion power plant in the State, aiming for 400 MWe of electricity (Governor of Virginia 2024).

Despite its promise and recent headlines, fusion faces fundamental technical hurdles—including energy breakeven, material degradation, fuel supply challenges, and unresolved regulatory frameworks.

Table 14. Overview of Nuclear Fission Technologies

Technology	How It Produces Energy	Fuel, Coolant, and Moderator	Plant Capacity (MWe)	Relative Advantages	Challenges
LLWR	Uses water to generate steam, either directly in the reactor core or in a secondary circuit, for use in a steam turbine generator.	Fuel: LEU Coolant: Water Moderator: Water	>600–1,000+	- Proven technology - Lower level of cost uncertainty/risk - Demonstrated strong safety and performance record - Established supply chains	- Large capital investment and complex projects - Recent high-profile project overruns in other jurisdictions - Require large amounts of cooling water (unless using alternative heat rejection systems)
lwSMR	Same as LLWRs, but with scaled-down designs.	Same as LLWRs, but with scaled-down designs.	60–300	- Derivatives of regulated and proven technologies and designs (in some cases) - Higher cost reduction potential than LLWR (assuming standardization and series construction) - Expected greater siting flexibility	- Unproven track record at commercial scale in the U.S. - High upfront costs despite modular potential; high cost uncertainty - Require large amounts of cooling water (unless using alternative heat rejection systems)
Gas-Cooled Reactor	Uses helium gas to transfer heat from the reactor core to generate steam for use in a steam turbine generator. Includes both High Temperature Gas Reactor (HTGR) and Gas Fast Reactor (GFR).	Fuel: HALEU Coolant: Helium Moderator: Graphite or none	80–300+	- High operating temperature enables industrial applications - Inherent safety features (e.g., meltdown-resistant fuel) - Higher cost reduction potential than LLWR (assuming standardization and series construction)	- Unproven track record at commercial scale in the U.S. - High cost of TRI-structural ISOtropic particle fuel (TRISO) fuel - High cost uncertainty - Complex fuel handling - Lack of recent licensing and operational experience at commercial scales (if any) - Nascent fuel (e.g., HALEU) and commercial-grade component supply chains
MSR	Uses molten salt as coolant and, in some designs, as fuel. Heat from fission is transferred to the salt, which then generates steam for use in a steam turbine generator.	Fuel: HALEU Coolant: Molten fluoride or chloride salts Moderator: Graphite or none	200–1,000	- High efficiency - Operation at atmospheric pressure simplifies design and enhances safety - Inherent safety features (e.g., meltdown-resistant fuel) - High technical potential to recycle nuclear waste - Higher cost reduction potential than LLWR (assuming standardization and series construction)	- Unproven track record at commercial scale in the U.S. - Materials challenges - Limited commercial-scale operational experience - High cost uncertainty - Lack of recent licensing and operational experience at commercial scales (if any) - Nascent fuel (e.g., HALEU) and commercial-grade component supply chains - High cost TRISO fuel (some designs)
Liquid Metal-Cooled Fast Reactor	Uses liquid sodium or lead as a coolant to transfer heat from the reactor core, typically through an intermediate loop, before generating steam for use in a steam turbine generator.	Fuel: HALEU, Mixed oxide fuel (MO _x) Coolant: Liquid sodium or lead Moderator: None	>300–1,200	- Demonstrated ability to recycle nuclear waste (though limited economic potential to date) - Inherent safety features (e.g., meltdown-resistant fuel) - High operating temperatures allow for advanced heat applications - Operation at atmospheric pressure simplifies design and enhances safety - Higher cost reduction potential than LLWR (assuming standardization and series construction)	- Unproven track record at commercial scale in the U.S. - High cost uncertainty - Sodium coolant reacts violently with water and air, requiring special isolation measures - Lack of recent licensing and operational experience at commercial scales (if any) - Nascent fuel (e.g., HALEU) and commercial-grade component supply chains

Table 15. Overview of Select U.S.-Relevant Nuclear Energy Technologies and Designs

Technology	Coolant	Designs (Developer)	Description	Status
LLWR	Light water	AP1000 (Westinghouse)	Advanced PWR with active and passive safety systems.	Operational: U.S., China Commercial agreements: Poland, Ukraine
LLWR	Light water	ABWR (GE Hitachi)	Advanced BWR with active and passive safety systems.	Operational: Japan, China Licensed: U.S.
LLWR	Light water	APR1400 [Korea Hydro & Nuclear Power (KHNP)]	South Korean advanced PWR designed for enhanced safety and economic efficiency.	Operational: South Korea, UAE Design Certification approved: U.S.
lwSMR	Light water	NuScale SMR (NuScale)	Integral PWR with fully passive safety systems and scalable design for flexible deployment.	Design Certification for two designs: U.S. Commercial agreements: U.S., Romania
lwSMR	Light water	BWRX-300 (GE Hitachi)	Integral BWR designed for modular construction with passive safety features.	Preapplication and CP submitted: U.S. Under licensing: Canada Commercial agreements: U.S., Canada
lwSMR	Light water	SMR-300 (HOLTEC)	Integral PWR designed for modular construction with passive safety features.	Preapplication: U.S. Commercial agreements: U.S., Canada
lwSMR	Light water	AP300 (Westinghouse)	Scaled-down version of AP1000 designed for highly modular and flexible deployment.	Preapplication: U.S. Commercial agreements: U.S.
HTGR	Helium	Xe-100 (X-energy)	High-temperature gas-cooled SMR using TRISO fuel.	Preapplication and CP submitted: U.S. Commercial agreement: U.S.
GFR	Helium	EM2 (General Atomics)	GFR using TRISO fuel for high efficiency.	Preapplication: U.S.
Liquid Metal-Cooled Fast Reactor	Sodium (SFR)	Natrium (TerraPower & GE Hitachi)	SFR paired with molten salt energy storage	Preapplication, CP submitted: U.S.
Liquid Metal-Cooled Fast Reactor	Sodium (SFR)	PRISM (GE Hitachi)	SFR for waste reduction and advanced fuel cycles.	Under development: U.S.
Liquid Metal-Cooled Fast Reactor	Lead (LFR)	Lead Fast Reactor (Westinghouse)	Lead-cooled fast reactor design.	Under development: U.S.
Liquid Metal-Cooled Fast Reactor	Lead (LFR)	Lead-Bismuth Fast Reactor (Columbia Basin)	Lead-cooled reactor concept.	Under development: U.S.
MSR ^a Liquid Salt Fueled	Liquid Salt	IMSR (Terrestrial Energy)	MSR using fluoride salts and designed for modularity and high safety standards.	Under development: Canada
MSR ^a Liquid Salt Fueled	Liquid Salt	MCFR (TerraPower)	Molten salt fast reactor with a focus on research and validation of molten salt technology.	Under development: U.S.
MSR ^a Liquid Salt Cooled (FHR)	Liquid Salt	KP-FHR (Kairos Power)	High-temperature reactor using fluoride salt for cooling, combining features of HTGR and MSR.	Preapplication: U.S.

^a Different formulations of molten salts exist, with choices depending on the neutron energy design, whether the fuel is solid or liquid, and whether the salt serves as a primary or secondary coolant.

4.2 Technology Performance Attributes

The performance attributes of nuclear technologies extend beyond power generation to include their ability to integrate with the grid, support reliability, and adapt to evolving system conditions. Understanding these attributes, particularly in the context of grid services, can help evaluate the role of different reactor designs in modern energy systems. The ability of different nuclear technologies to provide various grid services depends on their design, deployment model, and grid integration approach, as well as prevailing market design and grid operations paradigms (EPRI 2025g). LLWRs have well-documented capabilities based on decades of commercial operation globally. At the same time, lwSMRs and non-water-cooled reactors introduce new design features that could impact their ability to provide flexibility and services at commercial scales.

Table 16 describes how each technology can provide key grid attributes, using qualitative ratings that reflect both technical potential and real-world deployment experience based on current market and operational paradigms.

Many technologies can be specifically designed to provide selected grid services if system needs are known and mechanisms are in place to allow a given technology to participate in relevant markets. Therefore, these qualitative categorizations are not intended to be exhaustive. For LLWRs, the only nuclear technology to have been commercially deployed to date in the U.S., the categorization is based on fundamental technical capability and frequency of deployment in the real world. For lwSMRs, the categorizations rely on reasonable projections from the current fleet of LLWRs. Non-water-cooled reactors present much greater uncertainty due to diverse designs, lack of maturity, and plans for alternative deployment models (e.g., cogeneration).

Table 16. Comparison of Nuclear Reactor Technologies by Grid Services and Attributes

Italicized entries indicate a lack of real-world U.S. demonstration.

Attribute	LLWRs	lwSMRs	Non-Water-Cooled Reactors
Inertial Response (Rotational)	Typically provides attribute uses large rotating steam turbines	Typically provides attribute <i>similar to LLWRs, but smaller units, resulting in less inherent inertia per reactor; multimodule plants may compensate</i>	Typically provides attribute <i>cooling methods may differ, but most designs still use large rotating machinery, storing large amounts of kinetic energy, like LWRs; similar to lwSMRs, some designs may be smaller units</i>
Primary Frequency Response	May sometimes provide attribute can adjust steam flow to turbines to increase or decrease power; provision may be limited by physics, economics, and regulatory factors (FERC 2018)	May sometimes provide attribute <i>similar to LLWRs but multimodule plants may allow a staged response</i>	May sometimes provide attribute <i>similar to LWRs, though some technologies may integrate energy storage, enabling quick injection or absorption of power (Bragg-Sitton 2022), and avoidance of direct, unplanned maneuvering of the reactor</i>
Voltage & Reactive Power	Typically provides attribute synchronous generators provide reactive power and voltage regulation	Typically provides attribute <i>similar to LLWRs but smaller scale.</i>	Typically provides attribute <i>dependent on power conversion principles; if a steam turbine with a synchronous generator is used, the resource behaves like a traditional LLWR</i>
Ramping	May sometimes provide attribute state-of-the-art designs can ramp at ~5% power/min, but have been limited (in the U.S.) due to market design, economics, and operational constraints	May sometimes provide attribute <i>some designs are expected to offer significant capability (e.g., NuScale, 10% power/min), while others are more comparable to the best-in-class LLWRs</i>	May sometimes provide attribute <i>some ARs may integrate energy storage, enabling high ramp rates (e.g., Sodium, 12% power/min); others are comparable to lwSMRs and best-in-class LLWRs; many designs in development have not been assessed</i>
Cycling Capability	May sometimes provide attribute long warm-up and cooldown times, and high fixed costs discourage frequent start-stop cycles; regulatory/operational restrictions also prevent frequent or deep cycling (NREL 2020)	May sometimes provide attribute <i>Some smaller units may be better candidates for cycling than LLWRs but still face disincentives (NREL 2020)</i>	May sometimes provide attribute <i>similar to lwSMRs</i>
Short Minimum Run Time	Does not provide attribute require long startup/shutdown times	May sometimes provide attribute <i>smaller cores, fewer systems, and lower thermal inertia than LLWRs likely allow shorter start times; modular plants could allow staggered unit starts</i>	May sometimes provide attribute <i>some designs with energy storage or gas cycles could have shorter startup/shutdown times</i>
Black Start	Does not provide attribute typically requires external power to restart and synchronize with the grid; regulatory requirements necessitate external power, like on-site distillate generators	Does not provide attribute <i>designs would likely still require external power to restart (Wald 2024); NRC regulations requiring two separate power sources may still prohibit black start (O'Brien et al. 2022)</i>	Does not provide attribute <i>similar to lwSMRs, though some designs with thermal energy storage (and proper power electronics) may provide greater black-start potential</i>
Capacity Factor	High designed for continuous operation with long fuel cycles; has exceeded 90% in the U.S.	High <i>modular refueling can reduce downtime and improve capacity factor; some developers are aiming for 90%–95%, though a learning curve may occur before higher values are achieved, as was observed for LLWRs in the U.S.</i>	High <i>MSRs and selected HTGRs may be refueled while online, increasing overall availability; similar to lwSMRs, early plants may have lower availability/capacity factors</i>
Minimum Stable Output	May sometimes provide attribute ~50% of rated power; state-of-the-art designs can reduce output up to 50% while maintaining reactor operation	May sometimes provide attribute <i>Varies; multiunit designs can take units offline or ramp individual units to stagger output; single-unit SMRs must adjust reactor power directly via steam turbine bypass or other mechanisms</i>	May sometimes provide attribute <i>Varies; possibly similar approach to lwSMRs, though some designs integrated with energy storage may shift output differently</i>

The following summarizes the key takeaways from Table 16.

- The large rotating machinery associated with a nuclear plant’s steam turbine-generator system inherently provides valuable grid services, including rotational inertia for frequency stability, reactive power support, and voltage regulation—capabilities that will be critical to supporting grid reliability in a decarbonized 2040 grid.
- Although some nuclear technologies may be capable of flexible operation, most are expected to run steadily at high capacity factors to align with existing economic, market, and regulatory structures.
- Most nuclear power plants require external power for startup and auxiliary systems, so they are not typically capable of providing black-start services. Some emerging designs that integrate energy storage or alternative on-site power sources could potentially offer limited black-start capability, but this remains undemonstrated.

The following offers additional details on key nuclear attributes.

4.2.1 Ramping

Ramping is a key factor in load following. Many lwSMRs and non-water-cooled reactors are being designed for load-following operation, either through planned schedules or real-time grid signals, with capabilities influenced by reactor design, component size, auxiliary systems, and coolant choice (Zhang and Jiang 2024). Load following can be achieved directly (e.g., control rods or turbine bypass) or indirectly (e.g., diverting power to hydrogen production or energy storage instead of ramping the reactor itself). Indirect methods reduce thermal stress and reactor wear, improving long-term performance. However, business models and operational frameworks for these approaches are still evolving. LLWRs can ramp at ~5% power per minute (Marcinkiewicz 2017), though market design, economics, and operational constraints have limited the use of this capability in the U.S. Some lwSMR designs may offer improved ramping, while others may perform similarly to advanced LLWRs. Some non-water-cooled reactors integrate energy storage, enabling even higher ramp rates and the ability to load-follow without reducing the overall output of the plant (e.g., Natrium, 12% power per minute), though many designs remain unassessed for their ramping performance. Table 17 lists ramp rates for ARs found in the literature.

Table 17. Ramp Rates for Selected Nuclear Reactor Designs

Source: Marcinkiewicz (2017), Detering (2023), and Abou-Jaoude et al. (2024).

Developer	Design	Unit-Capacity (MWe)	Ramp Rate (% power/min)	Notes
Westinghouse	AP1000	1,110	5%	5%/min between 25% and 100% of full capacity.
KEPCO	APR1400	1,400	5%	Similar ramping capability to AP1000, from 50% to 100% of full capacity.
X-energy	Xe-100	80	5%	Rate per module; typically deployed in 320 MWe configurations.
GE Hitachi	BWRX-300	300	1%	Typical ramp rate; a higher rate is possible with turbine bypass.
NuScale	VOYGR	77	10%	Per module rate from using turbine bypass; can change power output via dispatchable modules (take one or more reactors offline), power maneuverability (adjust reactor power for one or more modules), turbine bypass (bypass turbine steam to the condenser; only for short time frames).
TerraPower	Natrium	345	12%	Rate obtained by molten salt thermal energy storage system

4.2.2 Grid Application

Historically, LLWRs have typically performed the role of providing reliable, grid-tied, baseload power rather than load-following due to high capital-to-operating cost ratios and current market and regulatory paradigms (Ingersoll et al. 2020). While emerging lwSMRs and non-water-cooled reactors could offer greater potential for load-following and provide select other grid services, regulatory and market changes would be needed to fully realize these capabilities. The primary drivers for deploying grid-tied ARs are replacing fossil-fuel baseload generation with clean, firm power and meeting load growth. Rising power demand from large industrial loads, including data centers, presents an additional opportunity for customers who may be willing to pay a premium for carbon-free electricity, although uncertainties remain regarding interconnection, grid integration, and actual power needs (EPRI 2024j).

4.2.3 Nongrid Applications

Advanced nuclear could also support nonpower applications. Buildings, transportation, and industry consume a significant amount of thermal energy. Non-water-cooled reactors, capable of reaching 800°C, could support industrial process heat, petrochemicals, and low-carbon hydrogen production (NASEM 2023a). The suitability of reactors for these applications depends on required temperatures and co-location feasibility, as heat cannot be transported efficiently and cost-effectively over long

distances. Siting near industrial facilities poses safety and regulatory challenges, particularly when hazardous materials are involved (NASEM 2023a). These factors create additional hurdles related to siting, emergency planning, and regulatory approvals. While nonpower applications present additional revenue and deployment opportunities, they are not the focus of this report.

4.3 Readiness for 2040

4.3.1 Latest Deployment Trends

The global nuclear landscape is evolving rapidly, with a range of technologies under development. The following sections highlight recent developments⁷ in technology and design, as well as recent regulatory activity. Table 18 summarizes these developments in a matrix-style status tracker, covering technical development, licensing, commercial agreements, and construction (if applicable). The latest deployment trends are not exhaustive, capturing only major developments for designs most relevant to the U.S. market as of July 2025.

4.3.1.1 Large Light Water Reactors

Westinghouse, AP1000: Westinghouse Electric Company is actively marketing and deploying its AP1000 reactor, with significant progress in several regions. Westinghouse is expanding into emerging nuclear markets to meet climate and energy security goals. Currently, six AP1000 reactors are operating globally, with eight more Chinese variations (CAP1000) under construction⁸ (Business Wire 2024). In the U.S., the Vogtle Electric Generating Plant in Georgia recently completed two AP1000 units, joining two existing earlier-generation reactors on site, making it the largest nuclear power plant in the country (Southern Company 2025). In July 2025, Westinghouse announced plans to deploy 10 AP1000 reactors in the U.S. (WNN 2025e). Poland selected Westinghouse to deploy six AP1000 units and develop its nuclear workforce as part of its modernization and decarbonization strategy. As of 2024, the U.S. International Development Finance Corporation expressed interest in providing partial financing for the project (Reuters 2024). Additionally, Westinghouse is working with Ukraine to deploy nine AP1000 units, as the country seeks to transition away from Russian technology (*Vodo-Vodyanoi Energeticheskoy Reaktor*, or VVER, design) and promote energy security (WNN 2024a). Some of this work may be partly financed by the U.S. Export-Import Bank (Dalton 2024).

Korea Hydro & Nuclear Power (KHNP), APR-1400: KHNP is actively seeking to expand its global footprint using both its APR-1400 design and APR-1400–based export designs (e.g., APR-1000). In 2022, Polish energy company ZE PAK signed a letter of intent with KHNP to deploy two 1400 MWe

units based on APR1400 technology at Pątnów in central Poland. This proposal was approved via a decision-in-principle and would be the second nuclear power project in Poland, following the AP1000 planned project. The KHNP project faces challenges, however, as the Polish government stated it would seek financial partners (rather than finance entirely on its own) to support this second project (Rogers 2024). Also, the European Commission could challenge or block the project if it does not comply with European Union (EU) competition procedures (WNA 2025b). KHNP is pursuing additional discussions in several countries to deploy its export designs. In the Czech Republic, KHNP was selected as the preferred bidder, over Westinghouse and Électricité de France (EDF), for the construction of up to four APR-1400–based units at the Dukovany and Temelín sites (Kim and Lee 2024). KHNP has sought to differentiate its offer by highlighting local content and a strong construction record (KHNP 2023).

The AP1000 and APR-1400 are currently the most actively marketed and internationally pursued LLWRs, supported by recent project wins, operating units, and strong government backing. Their export momentum reflects a combination of proven performance, regulatory approvals, and alignment with the energy strategies of countries seeking to expand or establish civilian nuclear programs.

4.3.1.2 *Light Water Small Modular Reactors*

NuScale, VOYGR: NuScale’s US600 (12 50 MWe units) and US460 (6 77 MWe units) remain the only certified American SMR designs, and the US600 is the second SMR design with Standard Design Certification (SDC) globally after the Korean System-integrated Modular Advanced Reactor (SMART). NuScale obtained certification for its updated, higher-capacity 77 MWe design (six US460 units) in May 2025 (NRC 2025). In 2023, the Utah Associated Municipal Power Systems (UAMPS) Carbon Free Power Project, which sought to build six 77 MWe modules at an Idaho National Laboratory site, was cancelled, citing insufficient subscription (Pearl 2023). Still, the company is attracting significant interest in eastern and central Europe, supported by European nuclear regulators’ familiarity with PWR technology. The U.S., Japan, South Korea, and the United Arab Emirates have agreed to provide up to \$275 million to advance the deployment of NuScale’s VOYGR in Romania (Power Magazine 2023).

GE Hitachi, BWRX-300: GE Hitachi’s BWRX-300 received a construction license for a pilot plant at Ontario Power Generation’s (OPG) Darlington site, with completion planned by 2030. The Tennessee Valley Authority (TVA) is collaborating with OPG and conducting its own early site work for potential BWRX-300 reactors (Patel 2025a). TVA received an ESP in 2022 for its Clinch River site and applied for a construction permit (CP) in May 2025 (Larson 2025). The vendor and operator plan for the first unit to be operational by 2029 (Power Magazine 2023). GE Hitachi and TVA have also teamed up with

Bechtel, BWX Technologies (BWXT), Duke Energy, EPRI, American Electric Power, Oak Ridge Associated Universities, Sargent and Lundy, Scot Forge, and North American Forgemasters to apply for an \$800 million grant from the DOE to accelerate deployment (TVA 2025). Internationally, GE Hitachi is nearing approval for 6 BWRX-300 power plants (24 units total, 7.2 gigawatts electric, or GWe, capacity) in Poland, despite the country's lack of experience with PWR technology.

HOLTEC, SMR-300: HOLTEC, a nuclear power plant equipment supplier and decommissioning firm, has entered the AR market and is in preclicensing discussions with the U.S. Nuclear Regulatory Commission (NRC) for its 300 MW SMR-300 design. In 2023, HOLTEC began pre-planning for a multiunit project at the former Palisades Nuclear Power Plant in Michigan, which it purchased and plans to restart to deploy its SMR designs (Dalton 2023). The company recently signed an agreement with Hyundai Engineering and Construction (Reuters 2025). HOLTEC intends to submit a CP application to the NRC in 2026 (Dalton 2023a). Additionally, HOLTEC received financing from the UK government to support the deployment of SMR-300 and is seeking a project site, along with agreements to establish component manufacturing facilities in Ukraine (Shaw 2024b, WNN 2024b). Most recently, DOE authorized HOLTEC to provide SMR-300 reactors to India, with the concurrence of the Indian government, allowing the company to share technical information and collaborate with Indian companies on SMR-300 deployment (Nuclear Engineering 2025).

Westinghouse, AP300: Westinghouse is actively working to deploy its AP300 design, a scaled-down version of its AP1000. Several notable developments have occurred in Canada and the UK. In Canada, Westinghouse signed a memorandum of understanding with Curtiss-Wright Corporation, a global components manufacturer with experience in the nuclear industry, to support the AP1000 and AP300 projects. They also signed a memorandum of understanding with SaskPower and Cameco to evaluate the potential of Westinghouse's reactor technology and the associated nuclear fuel supply chain for Saskatchewan's energy strategy (Westinghouse 2024b). The company anticipates design certification for the AP300 in Canada by 2027, with site-specific licensing and construction of the first unit expected to be completed by 2030 (Wolfe 2024a). Westinghouse highlights the established AP1000 supply chain as a key advantage for AP300 deployment.

In the UK, Westinghouse signed an agreement with Community Nuclear Power to build four AP300 SMRs in northeast England (Wolfe 2024a). The company filed its licensing application with the UK regulator in August 2024 (Nuclear Newswire 2024b). Additionally, Westinghouse signed an agreement with Chemetics Inc., a producer of nuclear-grade equipment, to support new-build nuclear projects in

Canada and globally. Chemetics will design and fabricate alloy and carbon steel vessels and heat exchangers for AP1000 and AP300 reactors (Westinghouse 2025).

4.3.1.3 Non-Water-Cooled Reactors

High-Temperature Gas Reactor

X-energy, Xe-100: X-energy is engaged in prelicensing activities with the NRC, submitting topical reports. As part of DOE's Advanced Reactor Demonstration Program (ARDP),⁹ X-energy is developing the Xe-100 project in Seadrift, TX, in partnership with Dow Inc. The company submitted its CP application to the NRC (X-energy 2025) and has updated its plans to begin construction later this decade, with operations expected in the early 2030s (Dalton 2025).

X-energy is also building a TRISO fuel facility in Oak Ridge, TN, with cost-sharing support from the U.S. government. Although the facility was initially expected to begin operations in 2027, the timeline has been delayed due to a change in the end customer (Dassow 2024, Yurman 2024). In early 2024, Xenergy and TransAlta agreed to explore the deployment of the Xe-100 in Alberta, Canada, with a target of the early 2030s. The Canadian Nuclear Safety Commission found no fundamental barriers to licensing the Xe-100 (Nuclear Engineering 2024, Wolfe 2024b).

In April 2025, DOE allocated HALEU to X-energy for fuel fabrication at its future Oak Ridge facility, a first in the nation designed to manufacture TRISO fuel for the commercial market, X-energy also amended its special nuclear material license application to the NRC to reflect the required installation of additional equipment to receive the HALEU allocation (Business Wire 2025).

Gas-Cooled Fast Reactors

General Atomics, Fast Modular Reactor: General Atomics Electromagnetic Systems (GA-EMS), in partnership with Framatome, is designing its fast modular reactor under the DOE's Advanced Reactor Concepts-20 (ARC-20) program. General Atomics is engaging in prelicensing activities with the NRC and plans to develop the reactor, power conversion, and instrumentation and control systems over the next few years. The company will also conduct cost analysis, aiming to demonstrate the reactor by 2030 and deploy it commercially by the mid-2030s (General Atomics 2021).

Fluoride Salt-Cooled Reactors

Kairos Power, Hermes/KP-FHR: Kairos Power is working to commercialize its KP-FHR design. The company received a CP for Hermes 1, a 35 megawatt thermal (MWt) nonpower demonstration reactor supported by DOE's ARDP. The NRC approved the permit in less than 2 years (NRC 2023), providing important momentum for licensing non-light-water reactors. Hermes became the first non-water-cooled reactor to receive an NRC CP in more than 50 years and is expected to begin operations by 2026. Kairos Power poured the first nuclear-related concrete in May 2025 (Kairos Power 2025).

The company also received a CP for Hermes 2, a follow-on test facility featuring two reactors driving a shared turbine generator (with potential to produce ~20 MWe), in just 18 months. Kairos Power plans to install power generation equipment later, pending approval of a future operating license. If testing succeeds, the company intends to commission a larger demonstration unit, KP-X, by 2030. Its full commercial version will be called KP-FHR.

In October 2024, Google agreed to support Kairos Power's commercialization and committed to purchasing power from its SMRs, targeting the first unit by 2030 and up to 500 MWe by 2035. Microsoft and Google are also exploring the KP-FHR design, reflecting growing interest in clean, firm energy for data centers. While they have not disclosed full details, their involvement signals rising confidence in nuclear energy (Terrell 2024).

Sodium-Cooled Fast Reactor

TerraPower, Natrium Reactor: In 2024, TerraPower announced plans to build a Natrium reactor at a former coal-fired power plant in Kemmerer, WY. The project has secured about \$1 billion in private funding and \$2 billion from the U.S. government through the ARDP. TerraPower submitted its CP application to the NRC in March 2024, marking the first submission for a commercial non-water-cooled reactor (Patel 2024b).

The NRC has issued a Limited Work Authorization (LWA) while it reviews the application. TerraPower has already begun nonnuclear construction (e.g., site preparation) and aims to begin operations by 2030 (Patel 2024b). The company also signed a memorandum of understanding with Sabey Data Centers, a Seattle, WA-based developer, owner, and operator, to explore the deployment in Texas and the Rocky Mountain region to meet Sabey's data center energy needs (Nuclear Newswire 2025).

Additionally, TerraPower has partnered with a clean energy developer, nVision Energy, to establish a repeatable deployment model for Sodium facilities across the U.S. (TerraPower 2025). The company has awarded contracts for major long-lead items for its first reactor, including a training simulator, control systems, and radiation monitoring systems (Curtiss-Wright 2025).

Overview of U.S. Nuclear Plant Licensing Pathways

This report does not discuss nuclear regulation in detail, but the U.S. Nuclear Regulatory Commission (NRC) oversees nuclear plant licensing in the U.S. through two primary pathways: 10 CFR 50 (Part 50), a two-step process allowing design flexibility but increasing risk, and 10 CFR 52 (Part 52), a one-step process that streamlines approval but restricts design changes.

Part 50 requires a Construction Permit (CP) followed by an Operating License (OL). This pathway allows design modifications during construction, but the absence of guaranteed final approval increases regulatory and financial risk. Most U.S. reactors have used this approach, often facing delays and cost overruns. A Limited Work Authorization (LWA) enables early site preparation before receiving a CP, but major construction needs full approval.

Part 52 combines the CP and OL into a Combined Operating License (COL) to reduce licensing uncertainty by resolving design and siting issues in advance through Standard Design Certification (SDC) or Early Site Permit (ESP). This process can shorten project timelines, but restricts postapproval design changes, which may cause delays. Vogtle Units 3 and 4 remains the only U.S. project to use Part 52. Future strategies may involve using Part 50 for the first-of-a-kind (FOAK) reactor and transitioning to Part 52 for subsequent units based on standardized design.

Applicants can pursue optional ancillary regulatory actions and authorizations to address siting and safety issues early. For example, an ESP approves a site based on environmental impacts, alternative site evaluations, and site-specific factors such as emergency preparedness and security. Applicants may seek an ESP before selecting a specific reactor design or committing to site development. Both Part 50 or 52 allow the use of an ESP.

The Nuclear Energy Innovation and Modernization Act requires the NRC to develop a more efficient licensing pathway for advanced reactors. The NRC expects to finalize the new rule no later than by the end of 2027. The proposed Part 53 rule—technology-inclusive and performance-based—offers a potential alternative for licensing new reactors more efficiently.

Beyond NRC licensing, developers must obtain additional permits for siting, construction, and operation based on the project's specifics. Common permits include environmental, air, and water rights permits; grid interconnection agreements; aviation and radio-frequency approvals; hazardous waste and storage permits; and building, fire, and historic preservation permits (EPRI 2023b).

Table 18. U.S. Nuclear Technology Status

Deployment progress and regulatory milestones for selected nuclear technologies based on developments in the U.S.

Technology		Design [Fuel/Form]	Developer	NRC Pre-Application	Standard Design Certification		Federal Permitting				Nuclear Licensing				Govt. Support	Commercial Agreements (U.S.)		Construction		Deployment	
							Early Site Permit		Part 50—Construct. Permit		Part 50—Operating License		Part 52—Combined License								
					Submitted	Approved	Submitted	Approved	Submitted	Approved	Submitted	Approved	Submitted	Approved	Submitted	Approved	Deployment Funding	Non-Binding/ Exploratory	Binding/ Financial Backing	Site Preparation	Full Construction
LWR	LLWR	AP1000 [LEU/Pellets]	Westinghouse	✓	✓	✓	✓	✓	N/A	N/A	N/A	N/A	✓	✓	x	✓	✓	✓	✓	✓	✓
	LLWR	APR1400 [LEU/Pellets]	KEPCO	✓	✓	✓	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
	lwSMR	US600 [LEU/Pellets]	NuScale	✓	✓	✓	x	x	N/A	N/A	N/A	N/A	x	x	x	x	x	x	x	x	x
	lwSMR	BWRX-300 [LEU/Pellets]	GE Hitachi	~	x	x	✓	✓	✓	~	x	x	N/A	N/A	x	✓	✓	~	x	x	x
	lwSMR	SMR-300 [LEU/Pellets]	HOLTEC	~	x	x	x	x	x	x	x	x	N/A	N/A	x	~	x	x	x	x	x
	lwSMR	AP300 [LEU/Pellets]	Westinghouse	~	x	x	x	x	N/A	N/A	N/A	N/A	x	x	x	x	x	x	x	x	x
Non-Water-Cooled	HTGR	Xe-100 [HALEU/TRISO]	X-energy	~	x	x	x	x	✓	~	x	x	N/A	N/A	✓	✓	✓	x	x	x	x
	GFR	FMR [HALEU/TRISO]	General Atomics	~	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
	FHR	KP-FHR [HALEU/TRISO]	Kairos Power	~	x	x	x	x	x	x	x	x	N/A	N/A	x	✓	x	x	x	x	x
	SFR	Sodium [HALEU/ Metallic]	TerraPower/ GE Hitachi	~	x	x	x	x	✓	~	x	x	N/A	N/A	✓	x	✓	~	x	x	x

Legend
 ✓ Completed
 ~ In Progress
 x No formal developments yet
 □ Not mandated/required for deployment, but improves the probability of success
 N/A Not applicable

The following summarizes key considerations for Table 18:

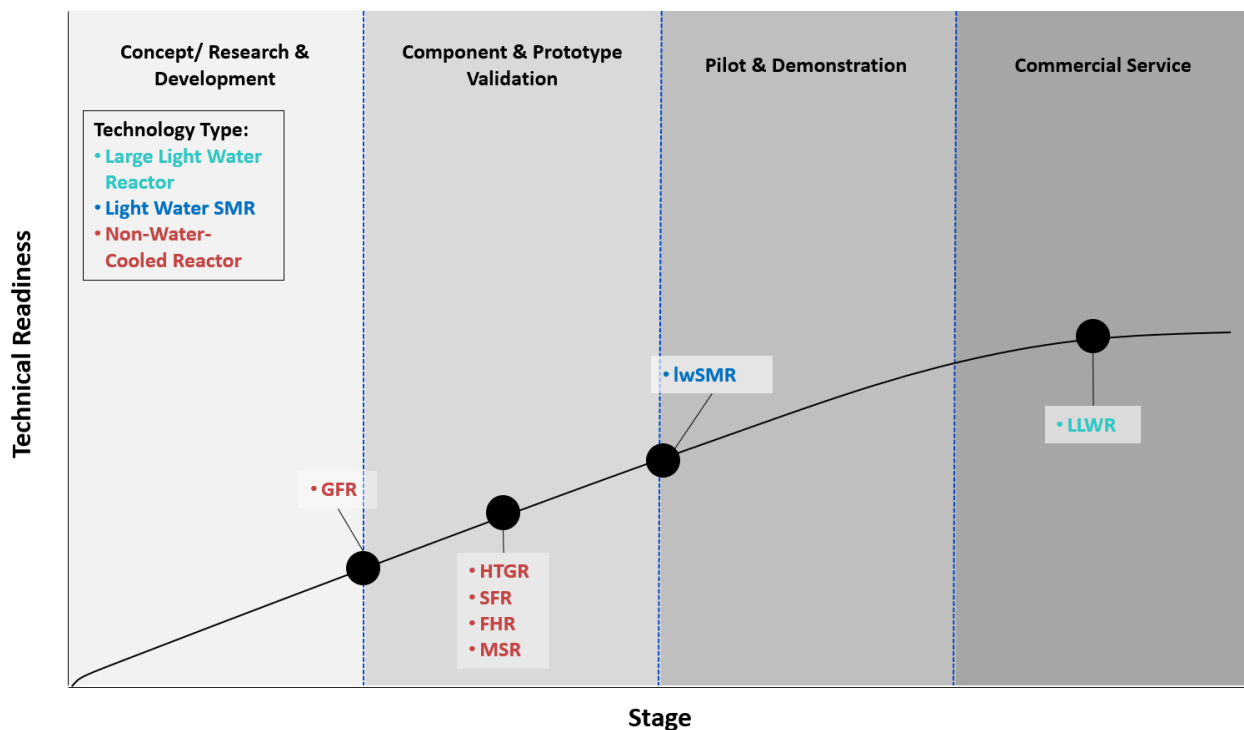
- Public information on these projects is typically limited, so the assessments presented here are subject to uncertainty and change.
- The status categories should not be considered mutually exclusive or linear; projects may occupy multiple stages simultaneously.
- Progress within each category can vary. For example, “Site Preparation” may be marked as “In Progress” if limited excavation has begun, even though substantial work may still be required. These categorizations do not indicate the amount of time remaining to complete a phase.
- “Preapplication” includes preparation for a permit and/or licensing application; the table does not distinguish between types of preparation.
- An Early Site Permit (ESP) is not specific to a given reactor design, although developers often pursue an ESP with a specific design in mind to streamline future licensing steps.
- Licensing status reflects the regulatory pathways developers plan to follow, based on publicly available sources, such as GAO (2023). “Not applicable” indicates that a company or design is not currently planning to take that pathway.
- A company may engage in both “Nonbinding/Exploratory” and “Binding/Financial Backing” project discussions.
- This table includes only designs most relevant to the U.S. market and only commercial or project developments occurring in the U.S.

4.3.2 Technology Readiness

The current readiness of AR technologies ranges from the early concept/research and development phase for nuclear fusion and gas-cooled fast reactors (GFR) to commercial service in many countries for LLWRs. Figure 34 depicts the current status of major AR technologies discussed in this report.

Figure 34. Current Technology Readiness of Major Nuclear Technologies

A technology remains in its current readiness phase until it completes all activities in that phase. A technology on the line between two readiness phases indicates that it has completed all activities in one phase but has not started activities in the next. The figure provides a high-level comparison of nuclear technologies but does not reflect the variation in technological maturity within a category.



Generally, the readiness gaps for more mature nuclear technologies (e.g., lwSMRs) are related to validation and regulatory qualification of unique systems and extension to new performance regimes (e.g., develop and qualify unique reactor components, qualify improved fuels and materials). In contrast, technologies with lower maturity are related to fundamental viability and performance confirmation of key reactor features, such as materials compatibility, materials durability, and performance of passive safety systems (NASEM 2023a).

Concept/Research and Development

GFRs are the least mature technologies. These reactors would operate with a fast neutron spectrum and a helium coolant to achieve high temperatures and efficiencies.

Component and Prototype Validation

These technologies are in the predemonstration phase, though their maturity varies. Fluoride-salt-cooled high-temperature reactors (FHRs) are a unique thermal-spectrum reactor concept that uses a mixture of elements with varying readiness (e.g., limited operational experience with the chosen fuel), which lowers overall maturity. However, prototype-scale demonstrations are underway (e.g., Kairos Power’s Hermes) as part of a broader commercialization vision. Fast-spectrum molten salt reactors (MSRs), such as TerraPower’s molten chloride fast reactor (MCFR), also have a lower maturity. While designers have proposed various conceptual designs, these reactors require further R&D before demonstrating a plant, particularly to address issues related to materials compatibility (NASEM 2023a). Developers are pursuing thermal-spectrum MSRs,¹⁰ but are not yet ready for technology demonstration because they continue to validate selected physics and other fundamental aspects.

lwSMRs are the most mature SMR technology, leveraging widely deployed LWR technology.¹¹ Developers could commission reference plants by 2030 (NASEM 2023a). NuScale’s VOYGR and GE Hitachi’s BWRX-300 may lead early commercialization, followed by X-energy’s Xe-100 HTGR (NASEM, NNWI 2023). HOLTEC’s SMR-300 and Westinghouse’s AP-300 may follow in 2030–2035 as “later evolutionary” deployments (NNWI). Less mature reactors requiring fuel or materials qualification likely will not complete demonstration until post-2030, possibly 2035–2040 (NASEM, NNWI).

Despite their relative maturity, no lwSMRs, HTGRs, or sodium-cooled fast reactors (SFRs) have completed all necessary activities to transition beyond Component and Prototype Validation in the U.S.

Pilot and Demonstration

Historically, LWR technologies have followed a structured development process before commercialization, progressing from scientific feasibility research to engineering and performance demonstrations (to validate system scale-up) and finally to commercial demonstrations leading to market deployment (NASEM 2023a). For non-water-cooled reactors and lwSMRs, the successful completion of recently launched or upcoming precommercial projects—BWRX-300 at Clinch River (lwSMR), Xe-100 at Seadrift (HTGR), and Natrium at Kemmerer (SFR)—could help transition these designs into Pilot and Demonstration. For lwSMRs that can leverage extensive LWR validation data, developers may compress the technology development process and reduce or eliminate the need for additional dedicated pilot plants if these projects successfully demonstrate reliability, safety, and economic feasibility. Instead, FOAK units, like the BWRX-300 at Clinch River, may function both as pilot projects—validating performance and generating operational data—and as early commercial plants.

Commercial Service

LLWRs dominate commercial nuclear deployment, with multiple designs operating globally.

International interest in advanced LLWRs, such as the AP1000, continues to grow, with deployments in China and Poland and planned projects in Ukraine. However, challenges, including long construction timelines and financing hurdles, continue to slow deployment.

Given regulatory and investment hurdles for ARs—particularly lwSMRs and non-water-cooled reactors—initial commercialization may not immediately lead to widespread deployment. Technologies with limited operating experience may require extended operational testing after initial projects to validate performance and refine designs (NASEM 2023a). Nontraditional investment in nuclear could help overcome financing hurdles and facilitate the deployment of multiple reactors.

4.3.3 Infrastructure and Supply Chain Readiness Dynamics

The readiness of enabling infrastructure is a crucial consideration for energy technology. This includes the fundamental physical structures, facilities, and tools, along with their associated processes. The readiness of infrastructure in New York State can vary significantly based on geography and site-specific factors. Table 19 summarizes the infrastructure readiness of nuclear technologies with a focus on New York State's dynamics, followed by notes on state-specific considerations for each category.

Table 19. Infrastructure Readiness of Key Nuclear Energy Technologies in New York State

Technology	Transmission & Grid Integration	Fuel Supply Chain & Waste Management	Cooling Water & Thermal Management	Siting & Land Use	Supply Chain
LLWRs	Highly site-specific.	No significant buildout required LEU fuel supply chains are established.	Short lead time Thermal management needed for cooling. Dry cooling is possible, but wet cooling is more efficient.	Long lead time Footprint is very energy-dense. Identifying feasible sites is a challenge, but several communities are interested.	Short lead time Component supply chains are established.
lwSMRs	Highly site-specific.	No significant buildout required LEU fuel supply chains are established.	Short lead time Thermal management needed for cooling. Dry cooling is possible, but wet cooling is more efficient.	Long lead time Footprint is very energy-dense. Identifying feasible sites is a challenge, but several communities are interested.	Short lead time May leverage LLWR supply chains.
Non-water-cooled reactors	Highly site-specific.	Long lead time HALEU fuel supply chains needed.	Short lead time Thermal management needed for cooling. Dry cooling is possible, but wet cooling is more efficient.	Long lead time Footprint is very energy-dense. Identifying feasible sites is a challenge, but several communities are interested.	Long lead time Component supply chains needed.

Transmission and Grid Integration

Siting plants, especially those with large capacity, farther from load centers may require expanding high-voltage transmission lines and substations. SMR grid impacts will vary based on single-unit or multimodule configuration (e.g., phased interconnection of units or modules). Siting new reactors at existing nuclear facilities or repurposed industrial and retired fossil sites may offer advantages such as existing infrastructure and grid access, although the feasibility and benefits are highly site-specific.

Fuel Supply Chain

LLWR and lwSMR fuel cycles are well-established, but rely heavily on imports. According to DOE (2022a), six primary suppliers currently provide LEU (<5% enrichment), with only one based in the U.S. Large-scale expansion could strain supply chains. Most non-water-cooled reactors require new supply chains to produce HALEU (5%–20% enrichment) fuels and advanced fuel forms (e.g., TRISO, metallic, or molten salt-based fuels). The U.S. currently lacks HALEU enrichment capabilities; only Russia and China possess them. Most non-water-cooled ARs require HALEU for optimal performance, though a few emerging designs not discussed in this report are fuel-flexible. As noted earlier, several AR technology developers have received HALEU allocations from the DOE to support deployment until longer-term fuel supply solutions become available.

Waste Management

While the absence of a federal long-term repository for shared high-level waste remains an important consideration, existing on-site fuel storage infrastructure and well-established waste management practices ensure safe operations. These allow continued buildout of nuclear capacity ahead of federal disposal facilities. Non-water-cooled reactors produce similar waste to LWRs but may generate novel waste streams requiring different disposal and management. Section 4.4.2 provides a fuller discussion of nuclear waste.

Cooling Water and Thermal Management

All nuclear reactors, including non-water-cooled designs, require some cooling water for the Rankine steam cycle. Availability of cooling water is site-specific. Cooling water is most readily available in Upstate New York, where several nuclear plants already operate. Using air-cooled condensers could provide greater siting flexibility, allowing for installation in areas distant from major water bodies. However, air-cooled reactors lose efficiency by approximately 5%–7% (Wald 2023).

Siting and Land Use

Identifying sites with sufficient space and appropriate characteristics to host nuclear facilities can be a challenge. All potential sites must undergo rigorous safety and environmental assessments. Public acceptance may also affect siting decisions. As of 2023, 55% of Americans favor nuclear energy for electricity, the highest approval rating in a decade, while 44% oppose it (Brenan 2023). Acceptance of nuclear power is generally higher among those near nuclear plants, such as in Upstate New York and Western New York, where communities have witnessed the safety and benefits of nuclear plants

(NASEM 2023a). There are several prospective communities in New York that have expressed interest in new nuclear. Many developers of lwSMRs and non-water-cooled reactors are interested in siting their reactors near industrial facilities or other large electricity customers. However, this co-location adds complexity, requiring careful assessment of safety, emergency planning, and mutual risks between the nuclear plant and nearby facilities. Sections 4.3.5 and 4.4.2 provide additional discussion of siting considerations.

Component Supply Chain

LLWRs have established component supply chains, though a robust nuclear expansion could strain production capacities. Some lwSMR designs may benefit from the ability to use the same LLWR supply chains. LLWRs use large amounts of bulk materials but present relatively low concern over the use of “critical materials” (those raw materials essential for economic and national security, with high supply chain risks due to geopolitical, economic, or geological factors). Key materials include cadmium, chromium, and nickel (DOE 2022a). Non-water-cooled reactors have unique requirements, potentially requiring specialized materials and components (e.g., liquid metal, molten salt coolants).

All U.S. grid-scale LWRs require specialized components manufactured in certified facilities (Hoggett 2014). Only four global manufacturers in three countries (Japan, China, and Russia) produce key components such as reactor pressure vessels (RPVs), steam turbines, and generators, creating potential supply chain bottlenecks (Hoggett, DOE 2024c). New provisions introduced in the H.R. 1 require projects to limit material assistance from Prohibited Foreign Entities (PFEs) to qualify for key energy tax credits, introducing further supply chain uncertainty.

Although new forging capacity is emerging, ARs are expected to rely less on large forgings by shifting to smaller, factory-built vessels (DOE 2022a). The U.S. can produce smaller forgings, piping, and general equipment, but the ASME N-stamp certification, which verifies that a manufacturer of nuclear components meets specific quality standards, limits domestic suppliers, necessitating imports (DOE 2022a). The NRC permits commercial-grade dedication, a process by which an item is designated for use as a component in nuclear construction, as an alternative, but expanding domestic production requires policy support.

While LLWR supply chains are well-established, novel AR components need stronger commitments to justify the development of new manufacturing capabilities (DOE 2024c). ARs, particularly SMRs, aim to shift key construction activities—such as reactor fabrication and assembly—from project sites to off-site factories to reduce costs and timelines. However, no centralized AR facilities exist, and developers will need firm project commitments to establish them (DOE 2022a).

4.3.4 Project Lead Times

Nuclear plants are large and highly complex construction projects with long lead times. Deploying a reactor by 2040 will require early planning and coordination. According to DOE (2024c), building a nuclear power plant, regardless of reactor type or size, includes five major steps:

- Design: Develop plant plans and layouts.
- Site selection/Early Site Permit (ESP): Evaluate site suitability.
- Construction: Build the plant.
- Supply chain: Manufacture and deliver components.
- Licensing: Coordinate with the NRC and other regulators to ensure safety and quality.

In the nuclear industry, FOAK, between first- and Nth-of-a-kind (BOAK), and NOAK describe different stages of technology deployment, with each stage representing a step toward commercial maturity and efficiency:

- **FOAK projects** involve the same key steps for delivering a nuclear project, but are the first implementations of a new design. These early projects are more likely to face higher costs, delays, and uncertainties due to a lack of experience and expertise. FOAK-specific costs arise from the need for more extensive licensing engagement (e.g., due to the absence of precedent), supply chain gaps, workforce development needs, and elevated financing risks. While FOAK projects are more expensive and time-consuming, they generate critical data and lessons that can inform future builds.
- **BOAK projects** reflect the “next” commercial offering (Abou-Jaoude et al. 2024).
- **NOAK projects** represent the desired end state after multiple deployments of the same design, benefiting from efficiencies, cost reductions, and shorter timelines. However, the transition from FOAK to NOAK is not always clearly defined. Each design matures at its own pace. The ultimate goal is to standardize and optimize processes, making subsequent deployments more predictable and commercially viable—a crucial factor in scaling nuclear power amid high capital costs and stringent safety requirements.

The project lead time estimates presented in the following section account for potential FOAK-BOAK-NOAK dynamics.

4.3.4.1 Large Light Water Reactor Lead Times

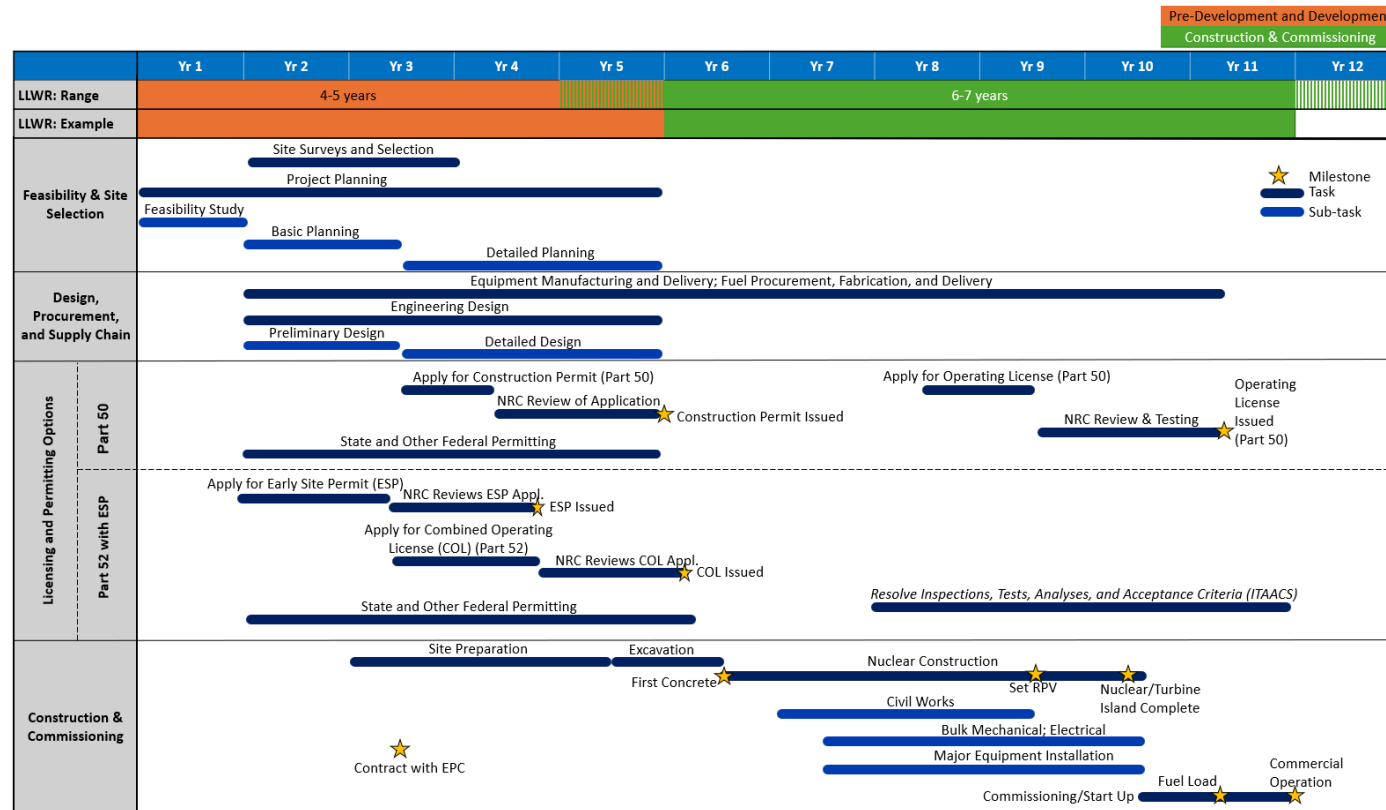
Project delivery timelines for LLWRs are widely debated due to significant global variation. This report estimates that a BOAK well-planned and executed LLWR project may take 10–12 years to complete in New York State (EPRI 2023o, NEI 2023, Stewart and Shirvan 2023, Shirvan 2024, IEA 2025, Zane and Zane 2025), including 4–5 years for planning and 6–7 years for construction and commissioning. This assumes using an already-licensed LLWR design such as the AP1000. In more pessimistic scenarios, based on past U.S. and Western nations’ nuclear experience, total project delivery duration of 15–20 years, including 5–10 years for planning and 8-10 years for construction and commissioning may also be possible (IEA 2025). Ultimately, actual timelines will depend on project-specific factors, offering opportunities to decrease time and increase efficiencies.

Figure 35 presents an illustrative timeline of key delivery phases for a BOAK LLWR project. According to Shirvan (2024), a NOAK LLWR could be constructed in as few as 4 years, from first nuclear concrete to commercial operation.

Figure 35. Representative Delivery Timeline for a Large Light Water Reactor

Both Part 50 and Part 52 licensing pathways are shown; however, only one of these pathways would be used for a given project. The ESP is optional and can be used with either licensing pathway. In this example, Part 50 is shown without an ESP, and Part 52 includes one.¹² The application steps do not include preapplication engagement with the NRC, which can help increase project success. While federal actions aim to accelerate permitting timelines, their effectiveness is unproven.

Source: Adapted from DOE (2024c).



Future LLWR deployments may benefit from lessons learned and the precedent set by recent projects like Vogtle, making their timelines more predictable and potentially shorter (Shirvan 2024). Vogtle Units 3 and 4, which entered commercial operation in July 2023 and April 2024, respectively, 10 and 11 years after project construction began (Wingfield 2023), overcame significant challenges. These issues included an incomplete design, limited constructability review for a reactor new to the U.S. market, project management challenges, high levels of attrition and absenteeism, and a shortage of experienced labor, partly due to the COVID-19 pandemic (DOE 2024c). Addressing these and other root causes is an opportunity to reduce project lead times for LLWRs and ARs because most of these root causes are human-driven rather than technology-driven. Notably, NASEM (2023a) asserts that nuclear project cost and schedule overruns in the U.S. and Europe have not necessarily been driven by failures in constructing the nuclear island, but from the civil works (e.g., concrete or steel structures and balance of plant).

4.3.4.2 Small Modular Reactors (Water and Non-Water-Cooled) Lead Times

SMRs could achieve shorter lead times than LLWRs due to streamlined designs, smaller physical footprints, and modular construction. Additionally, the NRC has prioritized licensing for these technologies, establishing expedited milestones for SMR approvals. However, while SMRs have the potential for shorter lead times, significant uncertainties remain, particularly for non-water-cooled designs, which lack recent commercial-scale deployment and regulatory precedent in the U.S.

The lack of observed data on SMRs makes it especially important to characterize uncertainty. This analysis uses “typical” Part 52 licensing lead times from NEI (2023)—including ESPs and COLs—along with plausible construction and commissioning durations drawn from a review of literature (Stewart et al. 2022, X-energy 2022, Duke Energy 2023c, Enerdata 2024, EY 2024, Shirvan 2024, GE Vernova Hitachi 2025, Nuclear AMRC 2025). Simple probabilistic SMR FOAK project delivery durations were estimated based on assumed variability.¹³ An additional 2 years were included to account for preapplication and other NRC engagements, resulting in a total FOAK duration of 9–15 years, with 5–9 years of planning and 3.5–5.5 years of construction and commissioning time.

The Optimistic scenario (9 years total) captures 95% of the variability below the mean and lies within the idealized project lead time range presented in EPRI (2023o), 7–10 years total. That estimate also aligns with the FOAK range from EY (2024). The Average scenario (12 years total) reflects a projected timeline slightly longer than the range presented by EPRI (2023o). It may be more applicable to New York State, where new nuclear has not been deployed in over 45 years. The Conservative scenario (15 years total) represents a worst-case assumption, where licensing durations extend beyond NRC milestone estimates

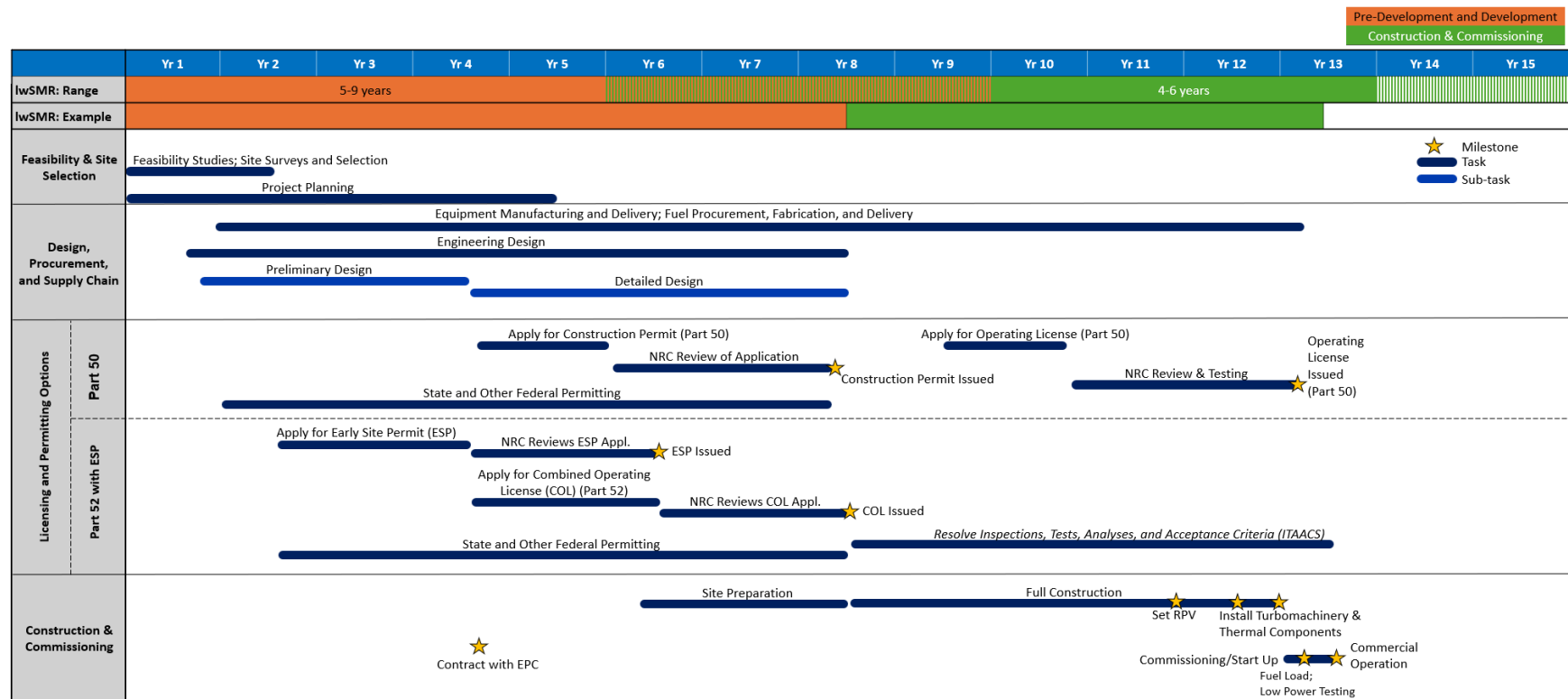
(NEI 2023), reflecting lengthy timelines observed in recent U.S. nuclear projects. While exceeding values commonly found in the literature, this scenario provides a cautious benchmark for planning. Figure 36 depicts an illustrative example of a FOAK project for a single unit, as adapted from Duke Energy (2023a, 2023b, 2023c). SMRs may achieve construction (from first nuclear concrete to commercial operation) durations as short as 3–4 years at NOAK (Stewart and Shirvan 2022, Enerdata 2024, EY 2024, GE Hitachi 2025).

Figure 36 is likely more applicable to lwSMR projects, as the project delivery process and schedule for non-water-cooled reactors could differ significantly, particularly in licensing—especially for FOAK deployments—and in procurement and construction, given the need for specialized equipment for fuel and coolant handling, alternative containment structures, and distinct supply chain requirements. Timelines will vary based on project-specific circumstances.

Figure 36. Illustrative Delivery Timeline for a Single Small Modular Reactor

For simplicity, the delivery of a single SMR unit is shown. Both Part 50 and Part 52 licensing pathways are included; however, only one would be used for a given project. ESP is optional and compatible with either licensing pathway. In this example, Part 50 is shown without an ESP, and Part 52 includes one. The application steps do not include preapplication engagement with the NRC, which can help increase project success. These illustrative next-deployment SMR project development timelines are longer than those for LLWR projects, reflecting the lack of pre-certified SMR reactor designs and lack of real-world SMR development experience. With increased deployment, SMR timelines could eventually become shorter than LLWR timelines. While federal efforts aim to accelerate permitting timelines, their effectiveness is unproven.

Source: Adapted from Duke Energy (2023a, 2023b, 2023c).



4.3.4.3 **Potential Strategies to Shorten Project Delivery Times**

Several proactive strategies and activities could help reduce project lead times for nuclear projects in New York State and elsewhere (NEA 2021, Wrigley et al. 2021, Stewart and Shirvan 2022, Asuega et al. 2023, Jain Family Institute 2024, Bolisetti et al. 2024, DOE 2024c). These include:

- **Consult original equipment manufacturers (OEMs) and engineering, procurement, and construction (EPCs) entities:** Collaborate to understand timelines, potential constraints, and project complexities to support effective planning.
- **Engage early with NRC:** Engage early to identify regulatory requirements, streamline licensing, and adjust designs to align with regulatory expectations.
- **Conduct constructability review:** Bring experts into the design process to identify and resolve potential issues before construction begins. This serves as a critical bridge between engineering design and field execution, enhancing planning and reducing costs and schedule overruns.
- **Select a certified design:** Reduces regulatory approval time, lowers risks, and improves project planning.
- **Complete design before construction:** Avoid starting construction with an incomplete design, which can lead to rework, licensing amendments, delays, and cost increases. (FOAK plants have historically started construction with an incomplete design).
- **Capitalize on experience and learning effects:** Leverage workforce and management experience from prior projects to reduce inefficiencies and mitigate risks.
- **Leverage series and staggered construction:** Build multiple reactors of the same design on overlapping timelines to maximize learning effects and reduce delays between projects.
- **Leverage existing nuclear facilities and retired coal generation sites when practical:** Share infrastructure and labor across multiple units to reduce costs, shorten schedules, and streamline permitting.
- **Use experienced vendors:** Work with reliable vendors with prior project experience in nuclear projects to improve schedule reliability, budget adherence, and compliance.
- **Procure long-lead items early:** Secure critical components early to avoid delays tied to manufacturing and delivery lead times.
- **Use modularization and off-the-shelf components:** Adopt factory-built modular systems and readily available components to accelerate construction and reduce on-site labor.

Recent federal actions have introduced opportunities to accelerate permitting timelines, but the effectiveness of these actions remains unknown.

Details on Series and Staggered Construction

Series and staggered construction could enhance nuclear project efficiency by leveraging experience, optimizing supply chains, and maintaining workforce continuity. Series construction—building multiple units of the same design in succession—incorporates lessons learned to improve cost and schedule

predictability. Staggered construction—starting construction on new units before previous ones are completed—can accelerate project delivery timelines by keeping projects in continuous development (i.e., maximizing resource utilization) while also incorporating some lessons learned from previous deployments.

The degree of staggering between deployments affects cost and timeline efficiency. Bolisetti et al. (2024) suggest that a 25% stagger between subsequent reactor builds—starting construction on a new unit when construction on the previous one is 25% complete, and so on—can optimize experience and learning. This approach is particularly suitable for scenarios involving rapid capacity expansion. Staggers shorter than 25% may require parallel workforces and could reduce total project lead times but increase financial risk due to concurrent capital expenditures, supply chain demands, and workforce requirements. Longer staggers may ease financial strain and allow for greater flexibility in adapting to market conditions, but could extend deployment timelines. Duke Energy implements a stagger of approximately 33% in its SMR strategy, starting construction on each subsequent unit one year after the previous unit’s 36-month construction period. This approach enables a continuous construction workflow and facilitates knowledge transfer between projects (Duke Energy 2023a, 2023b, 2023c). Generally, long gaps risk losing skilled workers, disrupting supply chains, and requiring reengagement with regulators, which limits learning benefits.

While staggered construction could help smooth the transition from FOAK to NOAK deployments if successfully executed, it also introduces potential cascading risks, where delays in earlier units could disrupt the overall deployment schedule. No one-size-fits-all approach or proven overlap percentage exists. Projects must balance schedules to optimize benefits, cost, risk, and efficiency.

Details on Nuclear Site Expansion and Repurposing Coal Generation Sites

Interest is growing in using previously industrialized sites for new energy projects, including nuclear, due to the ability to reuse existing infrastructure like grid connections, water access, and transportation routes. This reuse simplifies and speeds up construction, addresses environmental and land-use concerns, and eases the approval process with local communities. However, repurposing sites also introduces challenges, including aging infrastructure and potential existing hazards. Some of the most promising sites include existing nuclear or nonnuclear generation and sites contiguous to nuclear generation because these may offer beneficial existing infrastructure, such as transmission and cooling water access. They

also reduce permitting and community acceptance hurdles, potentially lowering project cost and/or schedule. Generally, greenfield sites (undeveloped locations) require more extensive site preparation, new grid infrastructure, and lengthy permitting, which potentially lead to longer project delivery durations.

4.3.5 Geographic Suitability and Constraints

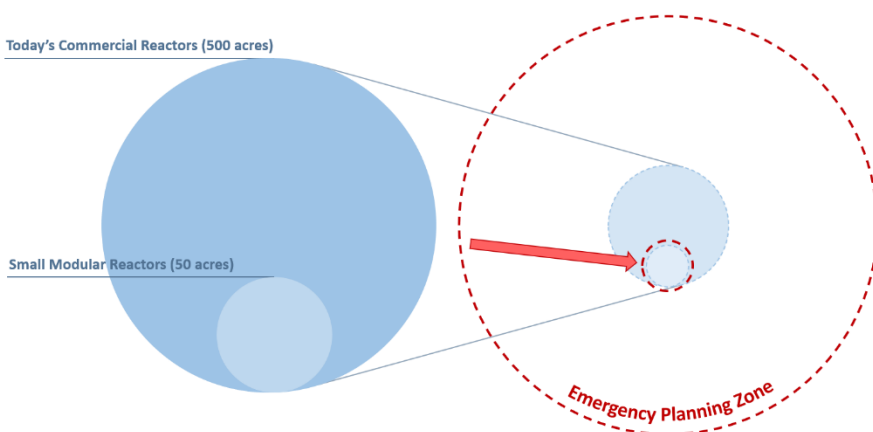
Infrastructure readiness throughout New York State varies significantly based on geography and site-specific factors. Several factors impact a site's suitability for nuclear deployment, including safety and buffer zones, existing nuclear and retired coal sites, and environmental and regulatory constraints.

4.3.5.1 Emergency Planning Zones

Emergency Planning Zones (EPZs) are designated areas around a nuclear facility where emergency response plans are developed to protect public health and safety in the event of an incident, which directly influence site selection and plant operations. Traditional LLWRs have a 10-mile EPZ for plume exposure (e.g., evacuation planning) and a 50-mile EPZ for ingestion exposure (e.g., monitoring food and water safety). However, the NRC has adopted a more flexible, performance-based approach to EPZs for lwSMRs and non-water-cooled reactors, recognizing their enhanced safety features and lower off-site risk potential. The new rule (10 CFR § 50.160) moves away from fixed-distance EPZs. Instead, it scales them based on actual off-site dose consequences, considering factors such as accident likelihood, source term, and meteorology (Penella et al. 2023). This risk-informed, consequence-oriented approach enables smaller EPZs, including site-boundary EPZs where justified, reducing regulatory burdens while maintaining public safety and potentially introducing more siting flexibility in some NYS regions. The NuScale design has an NRC-approved EPZ limited to the site boundary (Kim 2024). Figure 37 shows a generalized comparison of LLWR and SMR footprints and EPZs from EPRI (2022e).

Figure 37. Comparison of Estimated Reactor Footprints and Emergency Planning Zones

Source: Modified from EPRI (2022e).



Population density affects siting because NRC regulations discourage placing large reactors near dense urban areas unless risk can be mitigated. As a result, the Downstate New York regions, including New York City (Zone J) and Long Island (Zone K), present the most stringent land constraints. Moving significant amounts of nuclear power from Upstate New York to Downstate would likely require additional transmission investments to mitigate congestion. This impacts both financial investment and lead times for planning and construction.

Designers can configure nuclear plants with air cooling, minimizing water use and opening up more siting options, although with reduced efficiency and vastly increased land area needs.

4.3.5.2 Existing Nuclear Site Expansion and Repurposed Coal Sites

Table 20 summarizes commercial nuclear sites in New York State. All plants have established EPZs to protect the safety of nearby communities during emergencies. These include a 10-mile plume exposure pathway EPZ and a 50-mile ingestion exposure pathway EPZ. Many of these plants are located near population centers, such as Oswego and the greater Rochester region, although not all cities fall within the 10-mile EPZ. For example, Rochester lies outside the EPZ for the Ginna plant. Within each designated EPZ, detailed emergency plans exist, including evacuation routes, public alert systems, and coordination with local and State authorities.

Table 20. Operational Nuclear Power Plants in New York State

Attribute	Nine Mile Point Nuclear Generating Station	James A. FitzPatrick Nuclear Power Plant	R.E. Ginna Nuclear Power Plant
Technology	BWR Unit 1: 644 MWe Unit 2: 1,375 MWe	PWR 813 MWe	BWR 576 MWe
Commercial Operation Date	Unit 1: 1969 Unit 2: 1988	1974	1970
Land Area (Acres)	900 acres (same site as Fitzpatrick)	900 acres (same site as Nine Mile Point)	426

In a study analyzing the potential to use existing nuclear sites for new nuclear capacity, Nine Mile Point, FitzPatrick, and Ginna were identified as potential sites for a new AP1000, with Nine Mile Point being the most promising (Williams et al. 2024). Constellation, which owns all active nuclear plants in New York State, is exploring the possibility of building SMRs at Nine Mile Point and is seeking federal funding and an ESP from the NRC (Proctor 2025). Constellation has also considered releasing land for unrestricted use at Ginna, and the Wayne County Board of Supervisors has expressed its support for both the continued operation of the plant and for the development of new nuclear projects (Buchiére 2024).

Retired coal-fired power plant sites in New York State could support early nuclear adoption by reusing site infrastructure, such as transmission connections. Omitaomu et al. (2024) identified two retired coal sites in New York State that could collectively host an additional 1.2 GWe of new nuclear capacity.

4.3.6 Readiness Summary

AR technologies' readiness ranges from the early concept/R&D phase to commercial service. LLWRs hold higher readiness levels than lwSMRs and non-water-cooled reactors. All ARs face relatively few infrastructure readiness hurdles, although siting constraints could require siting plants far from load centers, necessitating expansion of high-voltage transmission lines and substations.

Advanced nuclear deployment in New York State's 2040 electric power sector faces lead time constraints. LLWRs, the most mature nuclear technology, may require 10–12 years for well-executed projects, including 4–5 years for planning and 6–7 years for construction and commissioning. lwSMRs and non-water-cooled reactors may require timelines of 9–15 years for FOAK deployments, but could improve efficiencies with experience. These reactor types present greater uncertainty due to limited U.S. commercial deployment experience. Deploying new nuclear units at or near existing nuclear sites or retired coal sites may accelerate project timelines.

Supply chain readiness varies significantly by technology. LLWRs and lwSMRs can leverage established LEU fuel cycles and component supply chains, although large-scale nuclear fleet expansion could strain production capacities. Non-water-cooled reactors face more fundamental gaps because these technologies require new supply chains for HALEU fuel and specialized nuclear-grade components. The U.S. lacks sufficient domestic HALEU enrichment capability to support a fleet of non-water-cooled reactors, creating potential supply dependencies that could delay deployment.

Recent regulatory developments create opportunities for new nuclear deployments, although uncertainties remain. The NRC has prioritized licensing for advanced reactors and adopted flexible EPZs for SMRs. However, no lwSMRs or non-water-cooled reactors have completed all necessary U.S. regulatory activities. Recent federal actions may accelerate permitting timelines, although their real-world implications remain unclear.

4.4 Emissions and Other Considerations

4.4.1 Emissions

Nuclear does not produce any GHG emissions or co-pollutants during power production.

4.4.2 Other Considerations

4.4.2.1 *Air Quality*

Unlike fossil fuel-based generation, nuclear power does not emit localized air pollutants such as NO_x, SO₂, or PM, which contribute to respiratory and environmental issues. Even with backup fossil generation during downtime, emissions remain marginal compared to conventional fossil-based generation. As a firm, dispatchable zero-air-pollution source, nuclear stands apart from other baseload resources that emit significant GHG emissions and co-pollutants. Nuclear power also has minimal life-cycle emissions, comparable to or lower than renewables (WNA 2025a). These emissions stem primarily from uranium mining, fuel processing, construction, and decommissioning, rather than from plant operation itself, which produces no direct CO₂ or co-pollutants.

4.4.2.2 *Safety*

All nuclear reactors must include safety systems that control (stop) the fission reaction, ensure adequate cooling of fuel, and prevent radioactive release during abnormal conditions. Radiation, energy emitted as particles or electromagnetic waves, naturally occurs in cosmic rays, radon gas, and elements in the earth's

crust. In nuclear power, radiation primarily results from the fission process, where atomic nuclei split and release energy, neutrons, and radioactive fission products. Effective radiation management ensures exposure remains within limits to protect workers, the public, and the environment (NRC 2022).

To ensure safety, nuclear power plants employ a principle known as defense-in-depth (DiD), which uses multiple protective layers to prevent, mitigate, and contain radiation exposure, as shown in Table 21. DiD protects plant staff, the public, and the environment by preventing uncontrolled release of radioactivity (IAEA 2024). DiD incorporates multiple physical barriers between the source of radioactivity (the fission products) and the environment, starting with the fuel itself because approximately 98% of all fission products stay within the fuel pellet unless it melts. Ceramic uranium oxide pellets, used in LWRs, and other fuel forms are designed to retain fission products. Metal cladding encloses these pellets, which are housed within a reactor vessel. Containment structures surrounding the vessel provide additional protection to limit radiation release under both normal and accident conditions.

Table 21. Defense-in-Depth Levels

Source: Adapted from Kim (2024).

Level	Objective	Mechanisms	Radiological Consequences/Impact
1	Prevent abnormal operations, breakdowns, and failures	Conservative design and high-quality construction and operations; control of main plant parameters within defined boundaries	No off-site impacts
2	Control abnormal operations, breakdowns, and failures	Control, regulation, and surveillance systems	No off-site impacts
3	Manage accidents to limit radiological emissions	Reactor protection systems, safety protocols, accident procedures	None to minor off-site impacts
4	Contain core melt accidents to limit off-site releases	Safety features to control core melt, accident management	Temporary, localized off-site impacts
5	Mitigate radiological consequences from material release	Emergency response beyond site	Protective measures needed off-site

Beyond physical barriers, nuclear power plants incorporate engineered safety systems designed to prevent fuel overheating and the release of fission products. These systems fall into two categories: active and passive safety systems, although many plants use elements of both. Active safety systems require external power or human intervention to operate, such as pumps and control systems. Passive safety systems, conversely, rely on natural forces like gravity, natural circulation, and convection, requiring no external power or human intervention. These safety systems operate in tandem with radiation monitoring systems, emergency cooling systems, and operational protocols to detect and respond to any irregularities.

Advanced LLWRs and lwSMRs use passive safety systems, including gravity-fed water tanks and natural convection cooling (Hussain 2020). A fundamental safety-enhancing characteristic of SMRs is their smaller power output per unit. All else being equal, lower power implies a smaller radioactive inventory in the core and less energy available for release during an accident (Ramana and Mian 2014). NuScale markets its design as “walk-away safe,” meaning it can shut down and cool itself indefinitely without operator intervention, power, or additional water. This relies on an Emergency Core Cooling System (ECCS) with passive valves that automatically open during emergencies to allow heat dissipation via natural convection (NASEM 2023a)

Non-water-cooled reactors adopt different inherent safety approaches, using advanced fuels and coolants:

- HTGRs: Use TRISO fuel that withstands extreme temperatures, preventing core damage even under a total cooling failure
- MSRs: Some use liquid fuel that retains fission products, reducing the risk of large radioactive releases
- SFRs and LFRs: Rely on passive heat removal and low-pressure operation, eliminating high-pressure coolant ejection risks

However, these reactors introduce new challenges. For example, sodium coolant in SFRs reacts with air and water, and molten salts cause material degradation over time (EPRI 2023a, Gao et al. 2024). Regulatory frameworks and safety assessments must be adapted to these new designs. Concerns exist about the NRC’s ability to regulate and ensure safety across the diverse emerging reactor designs (NYSERDA 2025a). The federal Accelerating Deployment of Versatile, Advanced Nuclear for Clean Energy (ADVANCE Act) aims to address these concerns by supporting NRC resource flexibility. International collaboration among U.S., Canadian, and UK regulators is also expected to accelerate AR licensing.

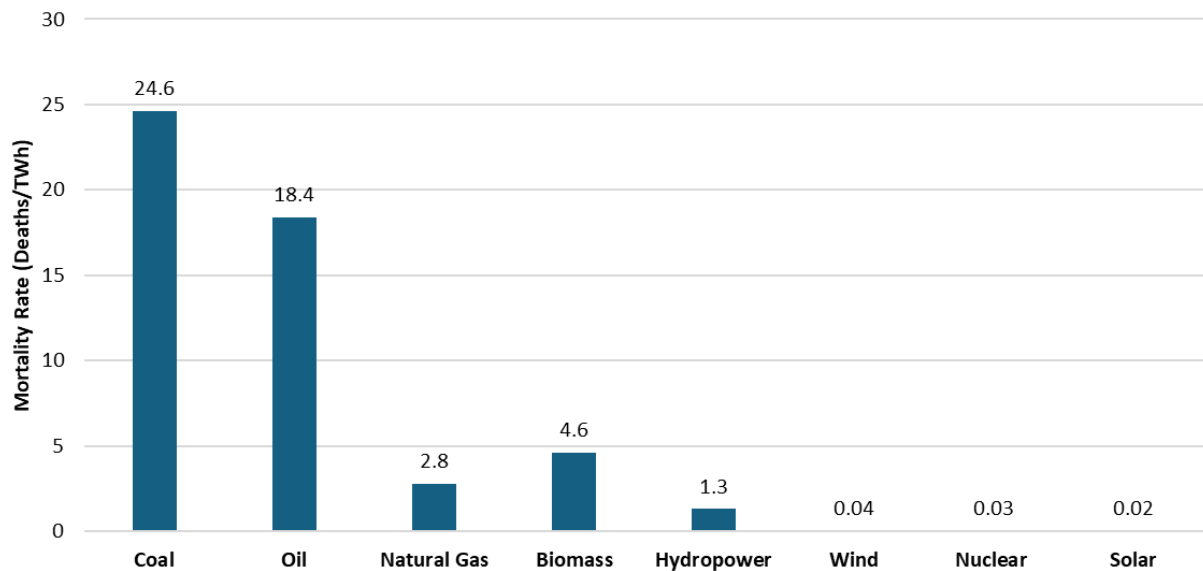
Passive safety represents a shift in nuclear safety philosophy but does not guarantee absolute safety. It must fit within a broader DiD framework, which also includes active backups and emergency response planning. Ensuring that regulatory, operational, and human readiness keep pace with technological advancements is critical for integrating these new designs into the energy sector. Nuclear safety depends heavily on oversight by independent authorities responsible for the design, construction, and operation of commercial nuclear plants. While the NRC is the primary regulatory body in the U.S., industry organizations like the Institute of Nuclear Power Operations (INPO) complement its role by setting performance guidelines, conducting evaluations, and overseeing training to maintain the highest standards of safety and operational performance.

Observed data show that radiation exposure from nuclear power plants is relatively low compared to natural background radiation and other common sources. In the U.S., the average annual dose from natural sources is about 6 millisieverts (mSv) per person, depending on location and lifestyle. Individuals living near a nuclear power plant typically receive less than 0.01 mSv per year from the plant, lower than the exposure from a single chest X-ray (0.1 mSv) or a cross-country flight (0.04 mSv) (NRC 2022). Even in severe accidents, modern plant designs and emergency response measures aim to limit public exposure.

The risks associated with radiation from nuclear power are often considered in comparison to other energy sources. Studies from organizations such as the World Health Organization (WHO) and the International Atomic Energy Agency (IAEA) assess the health impacts of various energy technologies. Fossil fuel combustion, for example, releases pollutants linked to respiratory illnesses and other health concerns, while nuclear power’s radiation-related risks are primarily managed through containment and regulatory oversight. Data from 2023 identify nuclear energy as having the second-lowest mortality rate (from accidents and air pollution) among major energy sources, as illustrated in Figure 38.

Figure 38. Annual Mortality Rate from Accidents and Air Pollution among Energy Sources

Source: Based on data from Mathisen (2023).



Experience from past incidents has shaped ongoing improvements in reactor designs to enhance safety and emergency preparedness. ARs offer the promise of safer designs through engineered safety systems and/or advanced fuels that could reduce both the likelihood and consequences of core damage events (NYSERDA 2025a). Ultimately, nuclear safety relies on extensive engineering, regulatory frameworks,

operational controls, and emergency response mechanisms. The DiD strategy ensures that multiple safeguards are in place, reducing the likelihood and consequences of radiation exposure to the public and the environment.

4.4.2.3 Nuclear Waste

The LEU fuel used by the current fleet of commercial nuclear reactors and many developing lwSMRs requires replacement and management. Nuclear waste falls into two broad categories: high-level waste (HLW) or low-level radioactive waste (LLRW). HLW primarily consists of fuel removed from reactors, whereas LLRW includes nonnuclear materials contaminated through routine reactor operations. (Additional radioactive waste also comes from medical, industrial, and research applications.) While HLW loses most of its radioactivity within a few decades, a small portion (~3%) remains highly radioactive for thousands of years and requires long-term isolation. Used fuel presents both near-term hazards from fission products like cesium-137 and strontium-90 and long-term hazards from plutonium and uranium (Werner 2011).

In the U.S., the NRC regulates the storage and disposal of commercial HLW through on-site wet pool and dry cask storage, ensuring compliance with regulations under the Atomic Energy Act (Larson 2020). Individual states are responsible for LLRW.

Used fuel from power plants is initially stored in pools, where circulating water cools and shields the radioactive material. After 5-10 years, operators transfer it to dry cask storage, which does not require active cooling. Facilities store dry casks on concrete pads or within engineered bunkers within a secured perimeter at nuclear plant sites or independent spent fuel storage installations (ISFSIs). The NRC considers both storage methods safe and sees no immediate need to accelerate transfers from pools to casks (NRC 2024).

Geologic repositories are the internationally recognized solution for long-term disposal and are technically feasible, as demonstrated by Finland's current construction and Sweden's planned project. However, no country, including the U.S., operates a permanent geologic repository for commercial HLW (Larson 2020). Most countries, like the U.S., store waste at reactor sites or interim facilities while they develop long-term disposal solutions. While on-site storage has proven safe for decades, it remains politically and legally contested (NYSERDA 2025a).

Many AR designs incorporate increased fuel efficiency and waste reduction (NYSERDA 2025a). For example, fast neutron reactors (e.g., SFRs) can produce or “breed” more fuel than they consume while also reducing some of the waste in conventional used fuel. Researchers continue to explore the recycling of waste fuel from advanced reactors, recognizing that spent nuclear fuel (SNF) retains more than 90% of its original energy (DOE 2022b). While the nuclear sector must overcome significant economic and cost barriers, some technologies aim to increase the circularity of the nuclear fuel cycle.

The use of HALEU and advanced fuel forms (e.g., TRISO) in many non-water-cooled reactors yields waste with various volumes, compositions, and disposal challenges (NASEM 2023b). These characteristics introduce unique waste management considerations, given limited experience handling diverse waste streams and the potential need for new processing and disposal methods.

Nuclear waste volumes are small compared to waste from other industries:

- Nuclear power contributes less than 0.5% of the total hazardous waste shipped annually in the U.S. (WNA 2024)
- The U.S. generates 2,000 metric tons of SNF per year, less than half the volume of an Olympic-sized swimming pool (DOE 2022b)
- Since the 1950s, the U.S. has accumulated 90,000 metric tons of SNF, which could fit on a football field at a depth of less than 10 yards (DOE 2022b)
- A 1,000 MWe nuclear reactor produces about 3 cubic meters of HLW annually, whereas a similarly sized coal plant produces 300,000 metric tons of hazardous coal ash each year (Kim 2024, WNA 2021)

Despite its high radioactivity, nuclear waste is well-managed, with traceability and disposal systems that ensure accountability and safety, which would be carefully planned for at all future nuclear power generation facilities in New York.

4.4.2.4 Water Use

Nuclear plants use a thermodynamic power cycle to produce electricity from heat. These power cycles require the removal of waste heat after the steam passes through the steam turbine generator. Many plants operate in closed-loop systems where cooling water recirculates, minimizing consumption. Some water is lost or consumed through evaporation in cooling towers, which release visible steam, but do not introduce pollutants or radiation.

In once-through cooling systems, water drawn from natural sources (e.g., lakes) absorbs heat and is discharged back at a higher temperature, potentially affecting local ecosystems. However, thermal discharge from thermal power plants is strictly regulated to protect aquatic ecosystems. Under the Clean Water Act (CWA), the EPA and State agencies set site-specific temperature limits to prevent ecological harm. Section 316(a) requires plants to prove their discharges do not significantly impact fish and aquatic life, while Section 316(b) mandates protective measures for water intake systems.

Closed-loop cooling reduces water withdrawals and thermal pollution. Some facilities must reduce output during hot weather to stay within permitted temperature limits. New nuclear projects undergo environmental impact assessments to ensure compliance and mitigate risks. These regulations help balance nuclear power's cooling needs with environmental protection.

Stein et al. (2022) estimate water consumption (i.e., water not returned to its source, including due to evaporation) for various reactor types, as follows:

- LLWR: 1.514 L/kWh
- lwSMR: 1.512 L/kWh
- HTGR: 0.908 L/kWh
- Liquid metal and molten salt-cooled reactors: 1.030 L/kWh

4.4.2.5 Land Use

Nuclear power has the lowest land use intensity of any electricity production source, generating the most electricity per year per acre (DOE 2024c); see Figure 39. Table 22 summarizes land-use needs by reactor size. The “overall site” value provides the best estimate for the land needed for long-term operation.

At the same time, while the “additional construction” area represents a temporary footprint, it is only relevant for planning permanent expansion. If a cooling water reservoir is required, up to 4,000 additional acres may be needed beyond the listed values.

Data from Table 22 suggests that the total land required to construct 1,000 MWe of capacity using multiple SMRs is comparable to that needed for a single advanced large reactor (e.g., AP1000).¹⁴

Specific land use depends on design. Beyond land area requirements, other factors should be considered when comparing deployment options. SMRs may offer greater siting flexibility, particularly if smaller EPZs and lower population criteria are approved, potentially allowing placement in locations unsuitable

for LLWRs. LLWRs, however, consolidate power generation into a single unit, which can simplify project planning, operational management, and transmission planning.

Figure 39. Land-use Efficiency (Direct and Indirect) of Various Power Generation Sources

Source: Adapted from DOE (2024c).¹⁵

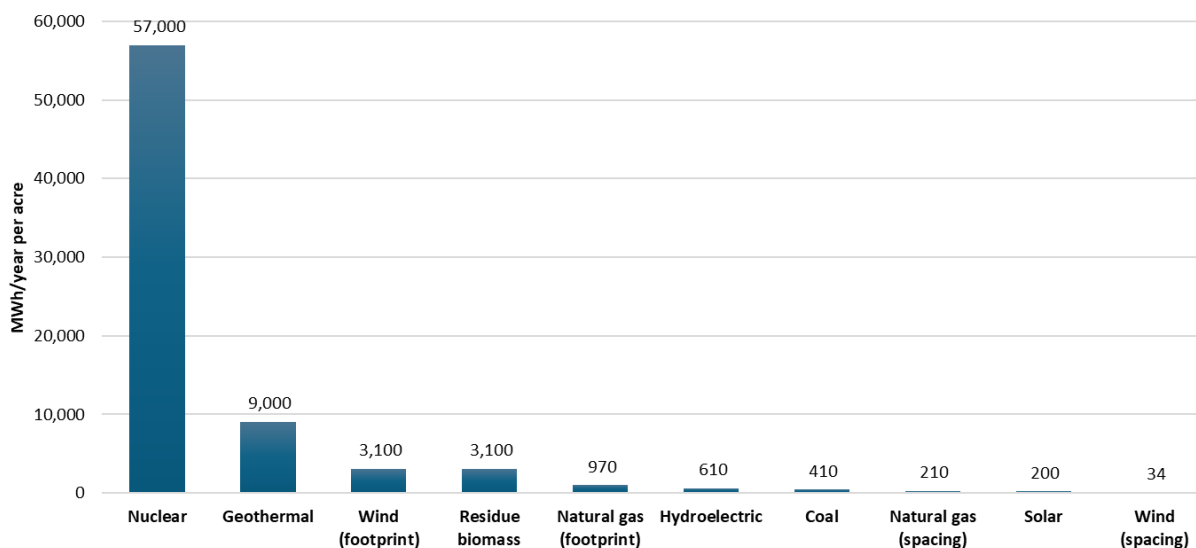


Table 22. Land-use Requirements for Nuclear Reactors by Reactor Output

Source: Adapted from EPRI (2022b).

Size ^a	Output (MWe)	Plant Footprint (Acres) ^{b, c}	Overall Site (Acres) ^{b, c}	Additional Construction (Acres) ^{b, c}
Micro	≤50	0.1 to 4	1 to 8	2 to 10
Small (SMR)	50 ≤ 300	25 to 200	50 to 500	50 to 100
Medium	300 ≤ 600	60 to 250	250 to 800	75 to 200
Large	>600	100 to 400	500 to 2,000	100 to 500

^a Each value represents a single unit. Consult an OEM and AE to obtain accurate values.

^b These values reflect typical ranges based on consolidated data from several literature sources and select recent COL and ESP applications.

^c As of publication, the NRC's draft Generic Environmental Impact Statement assumes proposed plant sites are no larger than 100 acres, or 40.5 hectares (ha), with no more than 30 acres, or 12 ha, permanently disturbed and 20 acres, or 8.1 ha, temporarily.

4.4.2.6 Workforce and Economic Benefits

Nuclear technologies offer significant direct and indirect economic benefits, including through supply chains that could expand in New York State. The State is currently home to 32 nuclear industry companies and leading nuclear education programs (NYSERDA 2025a). A new wave of nuclear buildout

could create hundreds of ongoing, high-quality jobs and reinforce the State’s broader nuclear ecosystem. These jobs may span manufacturing of reactor components and equipment, workforce training for new operators and technicians, and specialized support services such as engineering, maintenance, and regulatory compliance. This growth could also drive community revitalization, particularly in regions transitioning away from coal-based generation (Hansen et al. 2022, NYSERDA 2025a). The less developed nature of supply chains for non-water-cooled reactors compared to LWRs offers New York State an opportunity to become a hub for emerging advanced nuclear supply chains, with sufficient interest and investment. For example, X-energy (2021) expects to create 4,500 permanent jobs in Canada by building a four-unit/module Xe-100 plant valued at approximately \$6.1 billion (USD).

The number of long-term jobs¹⁶ created by nuclear power projects varies depending on plant size and the host community. Smaller reactors (100 MWe) support 121–178 long-term jobs, while larger ones (900 MWe) can sustain 573–998 jobs, particularly in more populous areas where secondary employment is higher (Hansen et al. 2024). Annual revenue follows a similar trend, ranging from \$57.4M–\$74.1M for 100 MWe plants to \$501.1million–\$634.3 million for 900 MWe plants (Hansen et al.). These figures underscore the localized economic benefits of nuclear projects—through direct jobs, supply chain activity, and regional spending—across a range of plant sizes.

SMRs will likely have a smaller on-site workforce (Hildebrandt et al. 2023). DOE estimates that SMRs could provide nearly 240 permanent jobs per gigawatt, while traditional large-scale reactors currently employ around 500 per gigawatt (GW) (DOE 2024c). Emsley (2020) provides a comparison of employment in nuclear power to wind, finding that the former generates roughly 25% more employment per unit of electricity, based on data from France and the U.S. Furthermore, WNA finds that nuclear power jobs pay considerably more than wind and solar jobs. Traditional LLWRs employ hundreds of workers for operations, security, and maintenance. Notably, at the plant level, some lwSMRs and non-water-cooled reactors aim for higher levels of automation and autonomous operation (Hildebrandt et al. 2023, DOE 2024c). This may generate socioeconomic issues, including around transparency, workload, and deskilling.

Notwithstanding, workforce challenges may arise if nuclear is scaled up, as the current national shortage of mechanical and electrical engineers and skilled tradespeople (e.g., welding, machining, electronics) could constrain deployment and operation (NASEM 2023a). At the national level, the DOE projects that the U.S. will need 375,000 workers by 2050 to manufacture, construct, and operate ARs (NEI 2024).

4.5 Technology Cost

4.5.1 Base Case Capital Costs

Given that the technologies discussed here have either been deployed only in limited areas in the U.S. or have not yet been fully implemented, the cost of constructing new nuclear power plants in New York State remains uncertain. This study developed capital cost estimates based on an extensive literature review and recent real-world experience. The sources that informed the study most heavily include:

- **Meta-Analysis of Advanced Nuclear Reactor Cost Estimations**
Abou-Jaoude et al. (2024) provide a thorough dataset covering parameters relevant to assessing new nuclear capacity in energy system models. The authors aggregated and standardized data from numerous previous studies dating from 1980 to 2023. This approach delivers comprehensive and balanced results because the larger dataset offsets missing or anomalous data from any individual study. However, some older studies may be less relevant to the capital costs of new nuclear plants than those focusing on recent deployments.
- **2024 Total Cost Projection of Next AP1000**
Shirvan (2024) estimates the cost of the next AP1000 deployment based on experience from Vogtle 3 and 4. This source provides a grounded and focused capital cost projection for near-term LLWR projects, although detailed analysis of other relevant parameters is outside the scope. For comparison, the report also develops SMR costs from a combination of top-down and bottom-up cost estimates.
- **Developer Estimates for FOAK Technologies**
For technologies that have not yet been deployed in the U.S., cost estimates are generally derived from the technology developers. These developers have the most detailed understanding of their technology, but FOAK deployments have historically cost more than the developers forecasted (see Table 23).

4.5.2 Deployment Type Impact on Costs

The type of deployment—whether a greenfield site, as an addition to an existing nuclear plant facility, or at or near a retired coal plant—affects project costs. While highly variable and site-specific, discussing key cost drivers can be useful for illustrative and high-level planning.

4.5.2.1 *New Nuclear Power Plant at or near a Retired Coal Plant*

Siting a new nuclear reactor at or adjacent to a retired coal plant could reduce capital costs by repurposing the transmission interconnection and possibly some associated electrical equipment. (Hansen et al. 2022) However, repurposing turbine plant equipment, condensers, heat rejection systems, or structures and buildings like offices is unlikely. These components would likely need to be demolished and reconstructed for the nuclear plant. These potential savings and costs are highly site-specific and could

vary significantly between projects. The level of required environmental remediation at the retired coal plant site can also impact capital costs because it would incur additional expenses not necessary for greenfield deployment and could partially offset savings from repurposing infrastructure. Because savings vary widely, this report does not provide a specific estimate.

4.5.2.2 Additional Reactors at Existing Nuclear Power Plants

Locating new reactors at an operating nuclear power plant is expected to offer greater savings than building at or near a retired coal plant. This approach leverages existing interconnection rights-of-way and access to cooling water. Additionally, an operating nuclear plant offers licensing advantages and benefits from the experienced nuclear staff. Beyond capital savings, siting a new reactor at an existing plant offers operational efficiencies through the shared use of resources. If multiple reactors are built at the same site, further cost savings are expected due to the direct spillover of experience and learning among units.

Shirvan (2024) suggests that building the next AP1000 at an existing nuclear site, instead of a greenfield site, could reduce costs by \$1,000–\$1,250/kW. The author attributes these savings to leveraging existing knowledge and infrastructure, which could shorten timelines (80–96 months at Vogtle versus 90–100 months at a new site) and result in material infrastructure cost savings.

4.5.3 Capital Cost Uncertainty

Cost uncertainty stems from several key factors, including site preparation and development, engineering design, licensing, commissioning, fuel loading, and financing. Material costs fluctuate based on supply chain shocks, including tariffs and other constraints, as well as fluctuations in commodity pricing. Workforce availability and specialized nuclear construction experience directly impact labor costs and schedules. Design and management experience introduce uncertainty as engineering challenges are resolved during construction. Regulatory and permitting processes increase timeline uncertainty, which in turn translates into higher financing costs. Accurately developing cost estimates requires understanding these factors and applying appropriate uncertainty ranges to account for them.

Future nuclear cost estimates must incorporate structured cost ranges to account for these uncertainties. For LLWRs, this report bases these ranges on the Vogtle experience and estimates that the next AP1000 could have a capital cost of \$9,700–\$15,100/kW, with a base case estimate of \$12,100/kW. The base case for LLWRs in New York State is based on the high range of Shirvan’s (2024) estimates, while the

optimistic case reflects the low end. The conservative case represents a scenario in which New York State could face new challenges that might offset additional learning gains, making the first LLWR in the State cost the same as Vogtle 4, the second AP1000 at the plant.

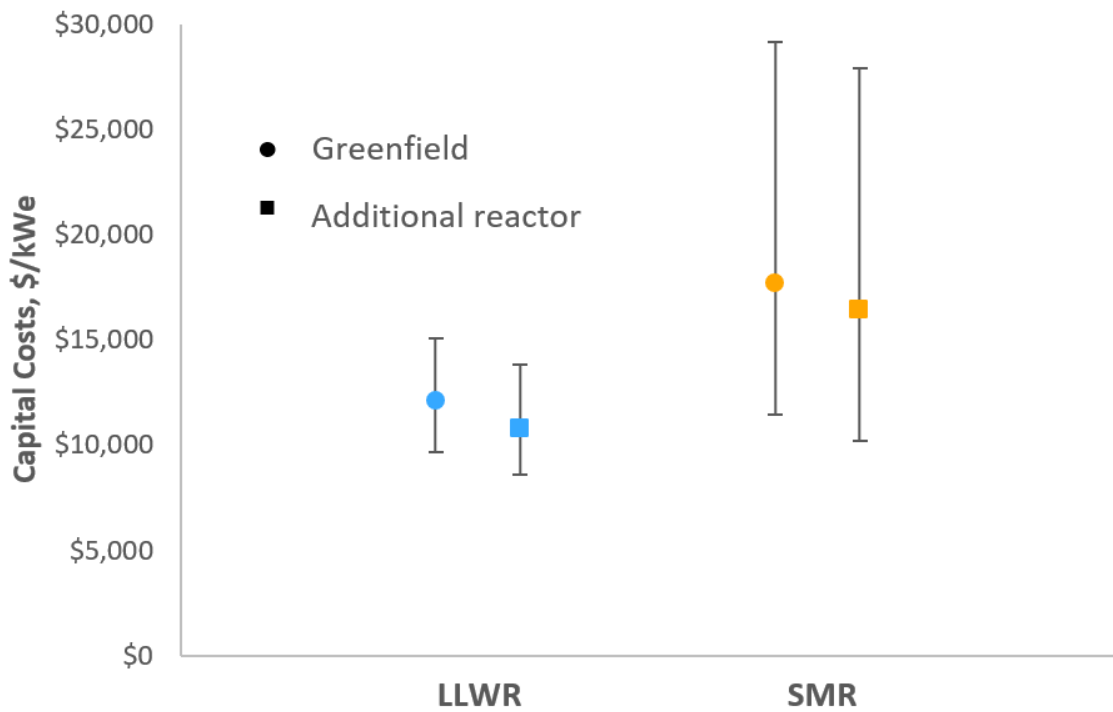
The uncertainty range for SMRs is larger than for LLWRs because no SMR power plant has been completed in the U.S. This report estimates that the next SMR could have a capital cost of \$11,500–\$29,100/kW, with a base case estimate of \$17,700/kW. The base case is based on Shirvan’s (2024) estimate for a FOAK SMR deployment. Given the lack of real-world SMR cost data, this study uses standard uncertainty ranges derived from AACE cost estimate classes, based on technology maturity rather than project definition. SMRs are assumed to have the highest uncertainty, with bands of +65%/-35%.

4.5.4 Next Deployment Costs

Figure 40 presents the estimated capital costs for the next deployment of nuclear power in New York State at both greenfield and existing nuclear sites. The next LLWR in New York State would be BOAK because Vogtle 3 and 4 have been completed. If the next nuclear reactor in the State is an SMR, the costs could be closer to FOAK if no other SMR projects are completed early enough for New York State to benefit from the learning.

Figure 40. Estimated Overnight Capital Cost of the Next Deployment of Nuclear Power Generation in New York State

Prices reported in 2023 USD.



For comparison, Table 23 presents the costs of recent or ongoing nuclear projects. The difference in the two NuScale cost estimates reflects FOAK-specific cost risks.

Table 23. Cost of Recent or Ongoing Nuclear Projects

Project	Specific cost (2023\$/kW)	Source
Vogtle final cost	\$15,000	DOE (2024c)
NuScale 2020 estimate	\$5,000	Patel (2020)
NuScale estimate at time of cancellation	\$20,100	Schlissel (2023)
TerraPower estimate	\$12,900	Powers and Rubin (2021)

4.5.5 Cost Reduction Opportunities

4.5.5.1 *Learning Curves in Nuclear Energy: Overview and Application*

Experience and learning curves are linked to cumulative deployment costs. For power generation technologies, learning rates reflect the percentage reduction in unit costs for every doubling of capacity or units deployed. For nuclear learning, it implicitly assumes continuous (e.g., series) construction without major periods of deployment gaps, such as seen over the prior decades (Abou-Jaoude et al. 2024).

Observed system-level (i.e., not component-level) learning rates for nuclear vary widely, depending on the time period and geography. The largest cost declines have occurred outside the U.S., for projects constructed in series by the same firm (Stein et al. 2022). Abou-Jaoude et al. (2024) found nominal system-level learning rates of 8% and 9.5% for LLWR and SMRs. Observed nuclear learning rates vary widely, from cost increases (-49%) for national nuclear programs, to cost declines (+11%) for projects constructed in series by the same firm (Stein et al.). Beyond series construction of standardized designs, SMRs may offer increased learning potential due to simpler designs, greater off-site fabrication and assembly, and smaller unit sizes, allowing more frequent learning cycles within a single project (Stewart et al. 2022, Abou-Jaoude et al. 2024).

This study uses a range of learning rates, with the base case learning rates based on those reported in Abou-Jaoude et al. (2024). Conservative and optimistic learning rates reflecting an approximately +/-35% uncertainty in learning rate. To achieve the broadest uncertainty range, the conservative learning rate is applied to the conservative starting cost, the base learning rate is applied to the base starting cost, and the optimistic learning rate is applied to the optimistic starting cost. As in Abou-Jaoude et al., this study assumes that the full learning occurs only for deployments of the same design, and that deployments of other technologies create spillover learning, which is one-third the learning rate of deployments of the same technology. The model assigns the market share of a given technology as 10% for the conservative case, 25% for the base case, and 40% for the optimistic case. This study uses nuclear deployment scenarios estimated in Abou-Jaoude et al. (2024) for these calculations. For the base and optimistic cases, the model introduces a 5-year lag for the learnings from deployments to translate to cost reductions. The model does not use a 5-year lag for the conservative case because deployment proceeds more slowly and learning is more likely to transfer from project to project. Table 24 presents the learning rate assumptions.

Table 24. Learning Rate Assumptions for Nuclear Technologies

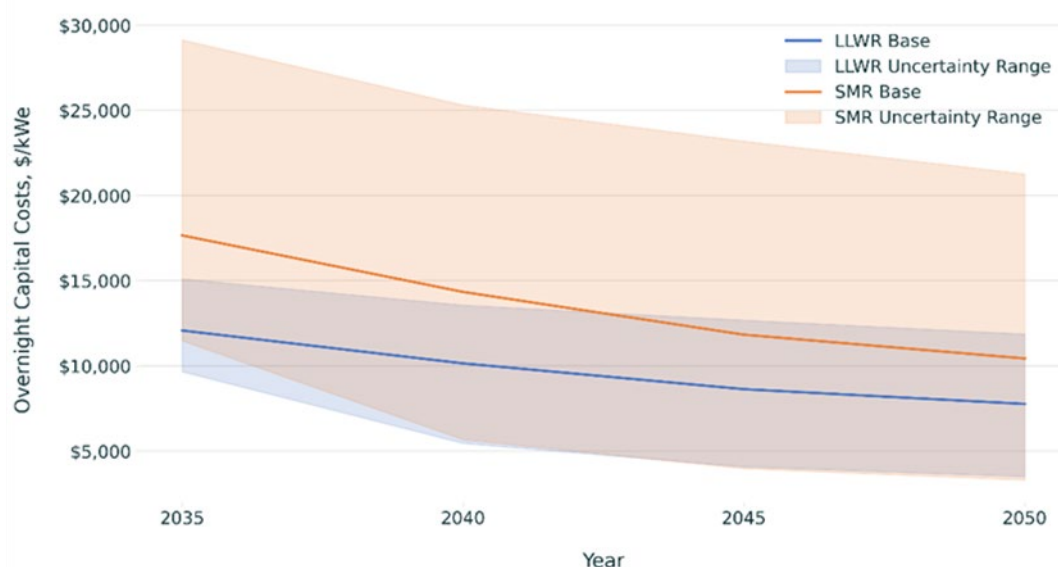
Metric	Conservative LLWR	Base LLWR	Optimistic LLWR	Conservative SMR	Base SMR	Optimistic SMR
Learning Rate	5%	8%	11%	6.5%	9.5%	13.5%
Market share	10%	25%	40%	10%	25%	40%

4.5.5.2 Possible Capital Cost Trajectories for Nuclear Power Plants

Figure 41 presents a possible trajectory of nuclear power plant capital costs in New York State based on the assumptions stated earlier. For consistency, the model uses greenfield costs for all deployments. Dates shown represent completion dates. The findings that Section 4.3.4 presents indicate that a well-planned and executed nuclear project could come online in New York State in the second half of the 2030s.

Figure 41. Potential Capital Cost Trajectories for Nuclear Projects in New York State

Prices reported in 2023 USD.



4.5.5.3 Other Cost Saving Opportunities

Between FOAK and second-of-a-kind deployments, considerable cost reductions are expected due to one-time savings from having a complete design, finalized regulatory approvals, and repeatable construction experience (Shirvan 2024). FOAK plants cost much more, but project stakeholders can share risk through a consortium approach, where multiple entities agree to build reactors of a new design in the first tranche. This approach enables the technology developer to achieve scale and

efficiencies in manufacturing. Similar efficiencies can be achieved locally by establishing a project pipeline and deploying multiple reactors of the same type with the same workforce in a serial fashion, especially when deploying multiple reactors at the same site. The construction of Vogtle 4 materialized 20% cheaper than that of Vogtle 3 (DOE 2024c).

4.5.6 Ongoing Costs

Nuclear power’s capital costs are the most impactful component when considering the overall cost of nuclear energy, but O&M and fuel costs also require consideration.

4.5.6.1 Operating and Maintenance Costs

Table 25 presents O&M costs for Upstate New York based on adjustments to data from Abou-Jaoude et al. (2024). Fixed O&M costs include staff salaries, nonlabor regular maintenance expenses, regulatory compliance costs, property taxes, annualized decommissioning costs, and ongoing capital plant expenditures. Variable O&M costs include consumable materials, as well as SNF management and disposal.

Table 25. Estimated Operating and Maintenance Costs of Greenfield Nuclear Power Plants in Upstate New York, 2040

Prices reported in 2023 USD.

Cost Category	Unit	Scenario	LLWR	SMR
Fixed O&M	\$/kW-year	Optimistic	\$136	\$128
Fixed O&M	\$/kW-year	Base	\$190	\$147
Fixed O&M	\$/kW-year	Conservative	\$221	\$234
Variable O&M	\$/MWh	Optimistic	\$2.13	\$2.47
Variable O&M	\$/MWh	Base	\$3.14	\$2.92
Variable O&M	\$/MWh	Conservative	\$3.81	\$3.14

4.5.6.2 Fuel Costs

The cost of LEU, the fuel used in LLWRs, can range between \$9/MWh and \$12/MWh (NREL 2024a). These values do not include costs associated with SNF, which the model includes in the O&M costs. The cost of HALEU fuel is uncertain, but it is expected to be more expensive than LEU due to the increased enrichment required. Manufacturing advanced forms like TRISO would further increase the cost. The cost of HALEU may range from \$10/MWh to more than \$20/MWh (White and Cothron 2023, Sorensen 2024).

4.5.7 Funding and Subsidies Available to Nuclear Projects

New nuclear projects have considerable opportunity to receive funding from the federal government. Such support could alter project and system-level economics. H.R. 1 maintains the eligibility of new nuclear projects for the 48E Clean Electricity ITC and the 45Y Clean Electricity PTC, with phase out occurring for projects that start construction between 2033 and 2036. However, H.R. 1 introduces new provisions that limit project eligibility for these credits based on the project's interaction with Federal Entities of Concern. H.R. 1 also introduced a new nuclear energy community bonus credit to the Clean Electricity PTC for advanced nuclear facilities located in a metropolitan statistical area that has (or, at any time after December 31, 2029, had) 0.17% or greater direct employment related to the advancement of nuclear power. The full consequences of these additional provisions are not yet fully understood.

4.5.7.1 Federal Tax Credits

Table 26 shows the key Inflation Reduction Act tax credits that H.R. 1 maintained for nuclear.¹⁷ Project construction must start before 2033 to be eligible for full credit.

Table 26. Major Provisions of the Inflation Reduction Act Maintained in H.R. 1

Prices reported in 2023 USD.

Source: Based on Nuclear Innovation Alliance (2023b).

Provision	Value without Satisfying the PWA Requirements	Value with Satisfying the PWA Requirements	Additional Bonuses
Clean Electricity PTC	~\$6/MWh	~\$28/MWh	10% bonus if project is located within an energy community 10% domestic content bonus
Clean Electricity ITC	6% of Initial Capital Cost	30% of Initial Capital Cost	10% bonus if project is located within an energy community 10% domestic content bonus

The Clean Electricity PTC is adjusted annually for inflation. Due to the high capital costs of nuclear power plants, the ITC is expected to be more advantageous than the PTC for near-term deployments.

4.5.7.2 Other Federal Assistance Opportunities

Beyond the Inflation Reduction Act tax credits, other federal assistance programs available for advanced nuclear projects include loan guarantees, direct assistance, and debt finance. Loan guarantees support projects by guaranteeing loans from private lenders, thereby reducing the perceived risk and helping projects secure financing at favorable terms. This helps lower the overall cost of capital for the project. Debt finance can offer terms that private sector funders may not readily provide, especially for FOAK projects (e.g., longer debt terms). Direct assistance includes grants and other financial support that the government provides directly to cover specific project costs, such as R&D, construction, or operational expenses. This direct funding reduces the financial burden on project developers and accelerates the deployment of advanced nuclear technologies.

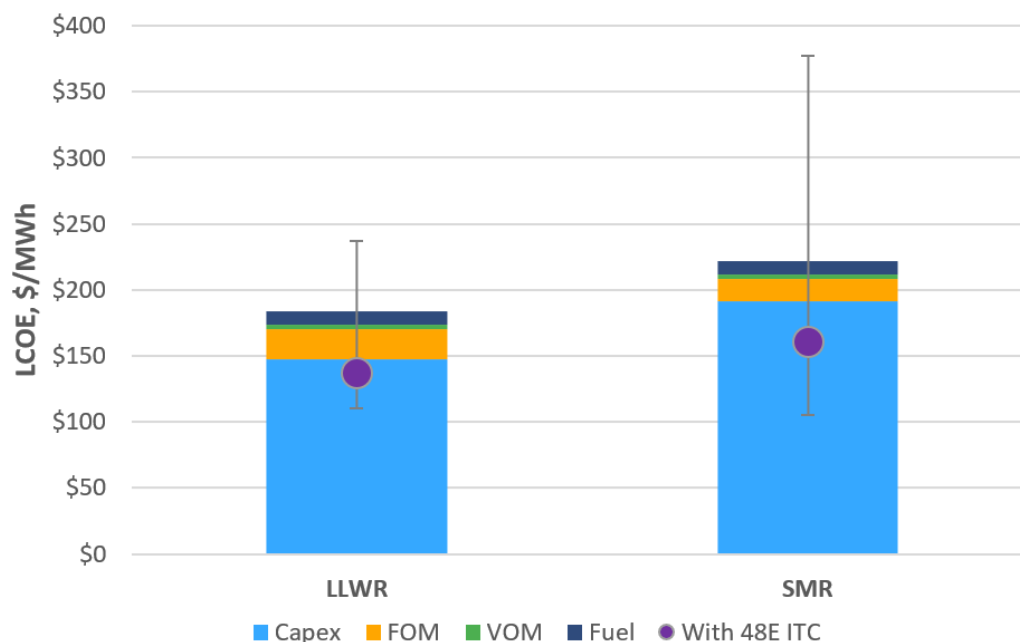
4.5.8 Levelized Cost of Electricity

Figure 42 presents the calculated levelized cost of electricity from LLWRs and SMRs deployed in Upstate New York in 2040, including sensitivities for ITC effects. The LCOE analysis assumes a capacity factor of 95% and a plant life of 40 years. The ITC scenarios assume the project satisfies the PWA requirements. Project construction must start before 2033 to be eligible for full credit. The error bars represent high and low cases for capital costs, fixed O&M, variable O&M, and fuel. Appendix A provides additional details on assumptions used in the LCOE calculation.

LCOE is an imperfect analysis because it does not reflect total system costs and, for nuclear, it does not capture the value of 60- to 80-year asset lifetimes. The LCOE for nuclear may be >\$100/MWh during the capital cost recovery period, but once the capital cost has been paid off (typically within 30 years), the generating cost will drop dramatically.

Figure 42. Calculated Levelized Cost of Electricity of Nuclear Technology

Full tax credit eligibility requires construction to start before the credit phaseout date. Prices reported in 2023 USD.



4.6 Scalability for 2040

Stakeholder goals and risk tolerance will determine the scale of nuclear capacity deployed in New York State by 2040. The illustrative scenarios presented here explore the potential deployment of new nuclear assets by 2040, considering overall technology readiness, project delivery lead times, and deployment strategies described in this report. They highlight the key decisions and conditions necessary for success and should be viewed as exploratory rather than prescriptive guidance.

Regardless of the deployment approach, several foundational strategies and activities are necessary to ensure project success. As the ambition of a scenario increases, so does the importance of these efforts:

- Conduct preapplication engagement with NRC, State and local agencies, technology developers, nuclear operators, communities, labor (e.g., unions), industry organizations, and large electric customers
- Identify sufficient viable sites
- Invest in transmission to deliver power from new units
- Invest in workforce development activities
- Cooperate with relevant other projects if any (e.g., sharing of information, lessons)

- For emerging designs (e.g., lwSMRs, non-water-cooled reactors), New York State may need to undertake additional work (e.g., regulatory, supply chain, and workforce preparations) before FOAK projects are completed elsewhere to enable deployment by 2040.

Unless otherwise noted, all the following scenarios assume a total project delivery duration for a well-planned and executed BOAK LLWR (10–12 years), and the average estimate for a FOAK SMR (12 years) presented earlier.

4.6.1 Conservative Deployment Scenarios

Conservative deployment scenarios focus on leveraging existing technologies, industry practices, and known sites to maximize the likelihood of success. This strategy prioritizes risk reduction over deployment speed and volume, ensuring financial exposure and cost uncertainty are managed carefully. Deployment could include, for instance, a single LLWR or a single lwSMR. Deploying an LLWR could require a higher total investment but offers greater cost predictability, benefiting from mature designs, established supply chains, and experience, including lessons learned from recent projects. Deploying an lwSMR could have lower overall capital costs due to a smaller overall project size and potentially shorter construction duration, but carries higher uncertainty due to less mature designs and limited deployment experience. A single SMR would also provide less capacity to support a zero-emissions 2040 grid than a single LLWR.

While this scenario limits deployment to a single reactor before 2040, a deployment pipeline extending beyond 2040 could mitigate cost risks associated with the FOAK project.

Existing nuclear sites and retired coal plants in New York State could reduce siting challenges. Planning and regulatory engagement must begin within the next few years to stay on track for 2040 deployment, with project construction starting no later than 2034 for an LLWR and 2035 for an lwSMR.

Rather than radically transforming New York State’s energy mix, this measured approach would moderately expand nuclear capacity by 2040 while laying the groundwork for future deployments beyond 2040. By committing to a smaller buildout, this approach would limit upfront capital exposure and reduce the risk of workforce shortages that might result if multiple projects were pursued simultaneously. However, such pressures might still arise where out-of-state projects might compete with those in New York State for the same workforce, and less visibility on future pipeline might reduce the attractiveness of workforce training programs and the ability to build a sustainable workforce.

4.6.2 Moderate Deployment Scenarios

A moderate approach to deploying new nuclear in New York State by 2040 could involve deploying multiple LLWRs, multiple lwSMRs of the same design, deploying a single non-water-cooled reactor, or deploying both an LLWR and an lwSMR. Depending on the configuration, the previously identified nuclear sites and repurposed coal sites could potentially still accommodate most of these new plants to facilitate siting.

Deployment of multiple reactors by 2040 would require a staggered approach to construction, with the second unit's construction starting before completing the first unit. If deploying two LLWRs with a 25% stagger, as Bolisetti et al. (2024) suggest, construction on the first unit must start no later than 2032 for the second unit to start construction no later than 2034, requiring early planning and regulatory engagement. Planning must start no later than 2028 and 2030 for the first and second reactors, respectively. For two lwSMRs, the first unit must start construction by 2033 for the second unit to start construction by 2035 to stay on schedule,¹⁸ requiring planning to start by 2028 and 2030 for the first and second deployment, respectively. Pairing an LLWR with a direct-derivative lwSMR may streamline licensing, supply chain coordination, and workforce training by leveraging design similarities. Maintaining reactor standardization—such as deploying a consistent LLWR or lwSMR series—could reduce supply chain risks and improve construction efficiency. Notably, pairing an LLWR with a non-water-cooled reactor could reduce the value of staggering since the two technologies would likely draw from different supply chains, specialized labor pools, and licensing pathways. This divergence may justify a parallel construction approach instead—allowing New York State to pursue complementary deployment tracks while preserving flexibility in its long-term nuclear strategy.

A large workforce with multiple project demands would need to be managed, for example, through staggered work schedules, to avoid shortages of skilled labor. Early and proactive engagement with labor unions, local communities, and plant operators will prove crucial to securing public and political support.

This scenario could transform New York State's energy landscape and lay the foundation for a long-term nuclear fleet. However, managing multiple large projects simultaneously introduces risks of cost overruns, workforce shortages, and supply chain bottlenecks. Success depends on careful execution, strong policy support, and the ability to adapt to unforeseen challenges.

4.6.3 Aggressive Deployment Scenarios

An aggressive approach to deploying new nuclear in New York State would prioritize deployment speed, considering economic development opportunities and nuclear energy's potential contribution toward the 0x40 target. This approach would reduce the ability to minimize financial and technological risk and to use learning effects from one project for the next. It would likely involve parallel series construction and advancing multiple technologies rather than selecting a single design from the start. New York State could deploy one or more non-water-cooled reactors in addition to deploying a small fleet of multiple LLWRs or multiple lwSMRs of the same design. Siting needs would likely exceed availability at existing nuclear and coal sites and would involve greenfield sites.

This scenario requires close NRC and technology developer engagement to address readiness gaps, particularly for non-water-cooled designs. Developers must also strengthen relationships with non-water-cooled technology developers and supply chain partners to secure specialized components and fuels, such as HALEU. LLWR and non-water-cooled projects could proceed in parallel, leveraging distinct supply chains. Early and proactive engagement with labor unions, local communities, and plant operators is crucial. The scenario requires a robust construction workforce capable of supporting multiple projects and considerable out-of-state labor.

This scenario would transform New York State's nuclear landscape, offering significant decarbonization potential and positioning the State as a leader in advanced nuclear technology deployment. However, it also carries the highest risk, requiring navigation of a complex regulatory pathway and rapid progress in closing technology and supply chain readiness gaps. Success depends on aggressive coordination across industry, policymakers, and investors to derisk deployment and ensure timely execution.

4.6.4 Beyond 2040

While 2040 marks a key milestone, nuclear holds even greater potential to shape New York State's energy future beyond 2040. Projects pursued for deployment by 2040 would not only expand capacity but also build essential experience, supply chains, and regulatory pathways, laying the groundwork for a larger-scale expansion in the following decade. A 2050 outlook for achieving nuclear scale may offer a more achievable timeline to reach greater scale, but addressing the critical gaps for 2040 deployment remains crucial to position nuclear as a cornerstone of the State's long-term energy strategy.

4.6.5 Scalability Summary

Even in the advanced deployment scenario, nuclear alone cannot meet the energy and reliability needs of a 0x40 grid due to performance limitations such as ramping, as well as siting and transmission congestion constraints. However, the three scenarios described earlier would affect a 2040 grid very differently.

The conservative scenario becomes achievable if the State promptly coordinates the successful deployment of a single project by 2040, but this scenario would only mildly increase the nuclear capacity by 2040 and would require support from a mix of other technologies to meet remaining grid needs.

The moderate scenario would require more significant upfront investment and faster, more rigorous State action to coordinate the staggered deployment of multiple projects. If this scenario involves two LLWR projects built before 2040, it could achieve over 2 GW of firm baseload capacity, which would reduce the need to rely on intermittent resources while still requiring supplemental energy and flexibility inputs from other technologies. Importantly, this scenario would position New York State well to continue expanding nuclear capacity post-2040 to meet growing energy needs.

The advanced scenario would result in a transformative shift in the NYS energy landscape, but it would require substantial investment, coordination, and risk management strategies to deploy a fleet of reactors before 2040. Overreliance on any one technology could compromise the 0x40 target if project delays occur.

4.7 Conclusions

Based on the previous assessment, the following key observations are offered to inform future consideration of advanced nuclear technology deployment in New York State:

Nuclear is a zero-emissions, low-footprint technology that has reliably provided firm power in the U.S. for decades. Nuclear has the highest energy density compared to other DEFR technologies and renewables, capable of producing over 1,600× more electricity per acre than wind, 200× more than solar, and 60× more than NG turbine plants, without directly emitting carbon dioxide (CO₂), NO_x, sulfur dioxide (SO₂), or PM. “Advanced” nuclear refers to reactors that differ from today’s conventional fleet in coolant type, fuel form, safety features, and deployment approach.

Advanced reactors come in a variety of designs and can address different demand requirement scenarios. Current advanced nuclear technology options include large light water reactors (LLWRs), light water small modular reactors (lwSMRs), and non-water-cooled reactors. lwSMRs are smaller (50–300 megawatt electric [MWe] per unit) derivatives of LLWR designs. Non-water-cooled reactors can vary in size and use alternative coolants such as gases or liquid metals/salts and alternative fuels, including high-assay low-enriched uranium (HALEU).

Advanced reactors are capable of more flexible operation than conventional reactors, but baseload power remains more economical. The high capital-to-operating cost ratio of nuclear reactors makes high capacity factor use more cost-effective. Other use cases for nuclear power include leveraging the significant thermal energy generated to support industrial process heat and hydrogen production. These applications are at a lower readiness than standard baseload power generation.

LLWRs are at a higher readiness level than lwSMRs and non-water-cooled reactors. LLWRs have a long history of successful commercial deployment in the U.S. and globally, while lwSMRs and non-water-cooled reactors have only been deployed in limited examples outside of the U.S. lwSMRs are more mature than non-water-cooled reactors as they leverage widely deployed light water technologies, established supply chains, and a domestic regulatory framework with extensive experience. lwSMRs are beginning to enter the Pilot and Demonstration phase in the U.S. and other relevant markets. lwSMRs and some non-water-cooled designs are deployable before 2040, but they require attention to development strategies to ensure timely deployment. However, these reactors may offer greater siting flexibility, along with potential long-term cost reductions enabled by modular deployment models that shift more construction off-site, streamline workflows, and enhance learning from more frequent builds of smaller units.

Deploying new nuclear in New York State before 2040 requires early planning. The next well-planned and executed LLWR project could take 10–12 years to deploy, including 4–5 years for planning and 6–7 years for construction and commissioning. However, federal intervention to streamline permitting could shorten these timelines. Additionally, as the industry matures, future builds could benefit from lessons learned in earlier projects, and Nth-of-a-kind (NOAK) timelines could approach 8–9 years. Some lwSMRs and non-water-cooled reactors may have shorter project lead times due to factory fabrication and design simplification, but significant uncertainty remains in these timelines. Deploying new reactors at or near existing nuclear sites could reduce near-term project timelines.

The cost of the next nuclear plant in New York State will depend on a number of factors. lwSMR and non-water-cooled reactor costs are currently more uncertain than LLWR costs due to a lack of deployments. LLWRs are expected to be cheaper per kilowatt (kW) for the near future, but lwSMRs and non-water-cooled reactors have lower overall investment costs due to their smaller project sizes. lwSMRs and non-water-cooled reactors also have increased learning potential due to simpler designs, greater offsite fabrication and assembly, and smaller unit sizes. Coordinated market building could result in faster declines in per-kW capital costs relative to LLWRs. Cost reduction opportunities include selecting designs that have already been completed and standardized, establishing a project pipeline by deploying multiple reactors of the same design with the same workforce, building multiple reactors at a single site, and building at or near existing nuclear sites.

Careful planning for safety and waste management has underpinned past deployments and would continue for any future deployment. Nuclear power plants have been safely operated around the world, including New York State, for decades and have one of the lowest mortality rates of any power generation source. A defense-in-depth safety approach combined with adherence to regulatory standards and guidance from nuclear safety oversight organizations reduces risk to workers and communities. New advanced reactors are designed to include enhanced passive safety features. Nuclear waste has been safely stored at reactor sites in the U.S. in the absence of a national centralized repository. Continued careful planning for safety and waste management will be critical for future deployment.

5 Carbon Capture and Storage

5.1 Technology Overview

CCS is a technology for capturing and storing CO₂ from flue gas produced by different sources, such as point sources like power generation and industrial processes, or dilute sources like atmospheric air. This section focuses on CCS for fossil-fuel-fired power plants. Fossil fuels, such as coal and NG, generate about 60% of power in the U.S. power sector, and nearly all of the existing CCS projects in the power sector capture CO₂ from coal-fired turbines. Technology to capture from NG-fired turbines exists but has not been deployed at the same commercial scale as coal-fired plants.

This section examines the potential for CCS to be integrated into New York State's existing or new power generators. Because coal is no longer used in the NYS power sector, this assessment focuses on NG applications.

Although capture technologies can operate flexibly, they operate best as a high capacity factor resource because it is currently impractical for the technology to load-follow and ramp up and down quickly. Doing so incurs higher operating costs, degrades system performance, and lowers capture rates. Thus, capture technologies are not currently suitable for peaking-only power generation resources. The current performance of the technology would incur higher costs during flexible operation. In addition, transporting and storing or using an intermittent CO₂ supply of this scale would be technically challenging.

Amine-based chemical absorption is the most mature type of capture technology for commercial deployment. Other technologies that capture CO₂ from flue gas exist, but are not yet commercially developed, including advanced solvents, water-lean solvents, solid sorbents, membranes, cryogenic techniques, oxy-combustion, and the Allam-Fetvedt cycle. Section 5.1.1 describes these further.

Bioenergy with Carbon Capture and Storage

Bioenergy with carbon capture and storage (BECCS) captures CO₂ from flue gas generated by combusting alternative biomass-based fuels. This assessment considers biofuels only for peaking resources due to the limited scale of available feedstock for fuel production, as discussed in the biofuels section of this report. Because CO₂ capture technologies are best suited for baseload-only resources, BECCS may pose deployment challenges at commercial scale in the power sector.

However, smaller-scale deployments may offer viable use cases of BECCS. For example, the Klemetsrud waste-to-energy facility in Oslo, Norway, has a total capacity of 114 MW and has tested Aker's capture technology in a demonstration project to capture 2,000 metric tons (t) of CO₂ per year from the facility (World Kinect 2023). The New York State Energy Research and Development Authority (NYSERDA) is funding other early-stage projects that develop capture technologies from municipal waste and biomass combustion, primarily through the Carbontech Development Initiative (Columbia University, 2025).

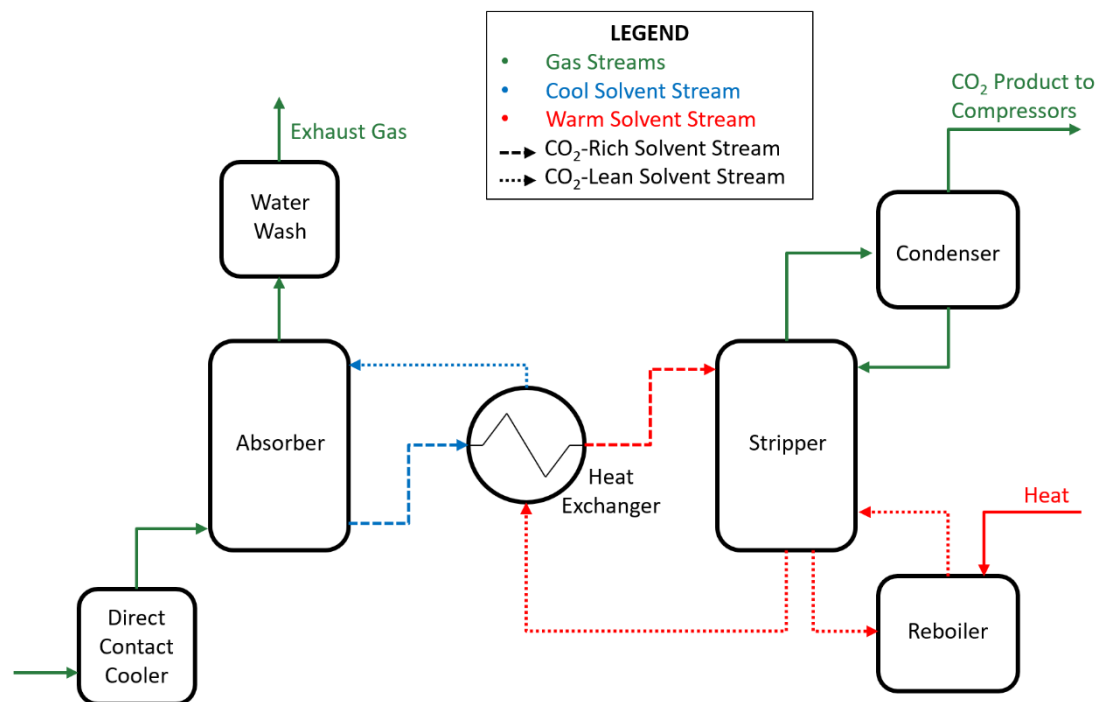
This assessment considers CCS only for natural-gas-based resources, not for alternative fuels and feedstock such as waste-to-energy plants, biomass incineration, or fuel cells with capture, largely because these technologies are currently being deployed at scales smaller than natural-gas-based power generation.

5.1.1 Capture

5.1.1.1 *Amine-based Solvent Capture*

Aqueous-amine solvents for postcombustion capture are the most commercially advanced capture technology. Figure 43 illustrates a simplified process flow diagram of a conventional amine-based solvent capture process used for capturing CO₂ from flue gas from power generation (adapted from Du et al. 2021). The diagram does not show the fossil-based power plant that generates the flue gas or the compression and transportation network where the captured CO₂ is treated to meet storage or utilization specifications.

Figure 43. Process Flow Diagram of a Conventional Amine Scrubbing Process



An aqueous amine-based capture process uses a water-based (aqueous) solution of a nitrogen-containing class of organic molecules called amines to capture gaseous CO₂ from flue gas and purify and compress it to pipeline specifications for transport to a storage or utilization end use. The capture process cycles through phases of chemical absorption and desorption of CO₂ with the amine-based solvent. During absorption, the “lean,” or “without CO₂,” solvent enters an absorber column, encounters flue gas exiting the power plant stack, and absorbs the gaseous CO₂. The solvent, now rich with CO₂, passes through a heat exchanger network to be heated in preparation for entering a stripper column. In the stripper column, the hot, CO₂-rich solvent releases CO₂, which is vented out of the top of the column. The solvent, now lean from CO₂, passes through a heat exchanger network to be cooled prior to returning to the absorber column. The CO₂ exiting the stripper column passes through the final stages of dehydration and compression to reach pipeline pressure and purity specifications.

Throughout the process, the amine-based solvent cycles between CO₂-lean and CO₂-rich states and is recycled during operation until it reaches the end of its lifetime. Solvent materials endure thousands of regeneration cycles, which bring the material’s temperature between 20°C and 120°C per cycle, until they degrade and require replacement. Commercial solvent lifetimes can range from 10 to 30 years, depending on their thermal stability. The capture process uses direct or indirect steam and generally conserves it in

the heat exchange network that the process uses. For an NG combined cycle (NGCC) power plant retrofitted with capture, the process draws energy from the plant. As such, the plant experiences a power derate in the total energy exported. Section 5.2.2 discusses power derating further.

5.1.1.2 *Alternative Capture Technologies*

Although aqueous-amine solvents are the most advanced postcombustion capture technology, other technologies are in development to remove CO₂ from combustion flue gas, including:

- **Advanced solvents** use different aqueous chemistries for capture, including carbonates and bicarbonates, phase-change materials, and other chemical solvents. These chemistries often blend more than one component, typically a primary reaction material and a promoter to increase the uptake rate of the primary component. Advanced solvents are designed to reversibly react to absorb CO₂ at low concentrations and release CO₂ at low temperatures. Advantages include heating less liquid during regeneration and lower energy consumption. Challenges include maintaining material stability, controlling solvent composition during cycling between absorption and desorption phases, and solids handling and overall operability. The University of Kentucky is conducting lab- and bench-scale testing on absorber components, including solvent materials, solvent packing, and solvent wetting for their NGCC power plant (NETL 2025a).
- **Water-lean solvents** contain less than 25% moisture by weight compared to aqueous amine solvents, which typically contain 70%–80% water. Nonaqueous solvents can have even lower water content, below 5%. Water-lean solvents may be single-component or a blend of reactive and nonreactive materials. Their advantages include heating less liquid during regeneration and lowering energy consumption as a result. Challenges include higher viscosity, which can slow adsorption rates and hinder heat transfer capabilities, and potential compatibility issues with the sealing materials used in the capture process. Pacific Northwest National Laboratory, Research Triangle Institute, and EPRI are conducting pilot-scale testing of a water-lean, single-amine solvent on simulated coal- and NG-fired flue gas at the National Carbon Capture Center (NETL 2025b).
- **Solid sorbents** in development for capture applications include amines grafted onto porous silicas, activated carbon, metal-organic frameworks, and alkalized alumina. In these processes, the sorbent is arranged in a packed bed or monolith to contact flue gas and is regenerated through direct steam injection or indirect heating under a vacuum to produce CO₂. Advantages include higher loading of CO₂ per mass of material and less liquid to be heated up during regeneration. Challenges include the difficulty of solid-solid heat exchange, longer cycle times for indirect heating, managing moisture during direct steam injection, lower product purity or recovery, solids handling, and material stability. Example work on this technology is being done by TDA Research and Membrane Technology and Research, Inc., with bench-scale testing of a structured sorbent in their microwave-assisted thermal swing adsorption process using simulated NG-fired flue gas (NETL 2025c).

- **Membranes** capture CO₂ in high-pressure, high-CO₂ gas processing systems. These systems use a thin active layer to preferentially transport CO₂ from a region of high to low partial pressure. Vacuum pumps drive CO₂ permeation and enable regeneration. Advantages include relying only on electrical energy to capture CO₂ and having no moving parts for easier operation. Challenges include lower selectivity than chemically-driven separations and requiring a cryogenic CO₂ purification step to meet pipeline purity. GTI Energy is conducting lab-scale testing of an ionic liquid membrane capture process on simulated NG-fired flue gas (NETL 2025d).
- **Cryogenic capture** physically separates CO₂ from other components by cooling to induce phase-change in the CO₂. Capture from NG-based flue gas occurs closer to atmospheric pressure, resulting in a solid CO₂ product separated from the gaseous nitrogen and oxygen stream. Systems collect the solid product either by cycling the heat exchange surface onto which the solid CO₂ condenses, or by using liquid heat exchange material to collect the solid product as a slurry. Advantages include no material stability issues by not using a chemical separation agent and using only electrical energy to drive refrigeration to extreme temperatures and to power rotating machinery for the process. Challenges include longer start-up times to reach operating temperatures and the need for near steady-state operation to minimize thermal loss. Carbon America is conducting pilot-scale testing of its FrostCC cryogenic capture process on simulated NG-fired flue gas at the National Carbon Capture Center (NCCC 2024).

Oxy-Combustion and the Allam-Fetvedt Cycle

Oxy-combustion is the combustion of a carbon-based fuel with oxygen to produce heat and a stream of primarily CO₂ and water. The process either uses produced heat directly in a gas turbine or removes it for use in a steam turbine, supercritical CO₂ turbine, or other Brayton cycle component. The Allam-Fetvedt cycle is a variation of oxy-combustion that uses flue gas recirculation to moderate the flame temperature and produces CO₂ as a working fluid for the power cycle in a supercritical CO₂ turbine. The NET Power cycle is the natural-gas-based version of the Allam-Fetvedt cycle.

These alternative combustion technologies produce a higher concentration waste stream of CO₂ than conventional combustion, making them well-suited to be paired with CCS. NET Power has developed the most recent demonstration of a capture process based on oxy-combustion at the 50 MW thermal scale in La Porte, TX (Patel 2024c).

In oxy-combustion processes, temperature moderation is important due to the extremely high adiabatic flame temperatures that occur when combusting fuel with oxygen. The NET Power cycle operates as a highly recuperated system with high efficiency at high temperatures and pressures, which requires heat exchangers made from expensive, high-temperature nickel-metal alloys to prevent material failure.

Conventional amine-based capture is not used with the oxy-combustion process because the process already achieves a high CO₂ concentration. However, oxy-combustion processes require additional contaminant handling, an air separation unit to provide a nearly pure oxygen stream, and cleanup procedures to meet the CO₂ pipeline specifications.

Current oxy-combustion processes have a lower readiness level than amine-based capture and must overcome barriers to become competitive. As a highly recuperated system, the NET Power cycle experiences thermal lag and reduced performance during ramping. Long startup times for the overall process are expected due to long startup times for the air separation unit and the need to pressurize the CO₂ working fluid, as well as building up the temperature profiles required for recuperation in heat exchangers. These startup times are expected to be comparable to—or longer than—those of conventional capture systems. Oxy-combustion plants can only be new builds; they cannot be retrofitted to any existing power generator because they do not use conventional capture equipment and require different temperature and pressure specifications.

5.1.2 Transport, Storage, and Utilization

5.1.2.1 Transport

CO₂ transportation involves moving CO₂ from sources to locations for storage or use. In the U.S. today, most CO₂ is captured from stationary sources, compressed, and then transported to designated sites for long-term underground storage, enhanced oil recovery (EOR), or future industrial applications. Pipelines are the dominant method of CO₂ transport and operate under specific pressure conditions that maintain CO₂ in a dense, supercritical state, which optimizes both transport and storage injection due to its high solubility and flow characteristics.

In the U.S., over 5,000 miles of pipelines operate across Gulf Coast states, Colorado, Wyoming, and North Dakota to move CO₂ from natural and industrial sources to geologic storage sites, particularly for EOR. Offshore pipelines are less common, but Norway's Snøhvit project has successfully transported CO₂ offshore via pipeline since 2008. The U.S. currently lacks offshore CO₂ pipelines.

While pipelines remain the primary method, alternative transport options include ships, trains, barges, and trucks. Northern Europe commonly uses ships to transport food-grade CO₂ with vessels capable of carrying up to 45,000 metric tons. This method often provides a cost-effective solution for long-distance transport, but terminal locations require careful planning due to potential safety hazards and supply intermittency. Rail transport, widely used in the U.S. and Canada, moved over 713,000 metric tons of refrigerated CO₂ in 2017. Specialized insulated tank cars transport CO₂ at low temperatures and moderate pressures. Researchers are exploring ways to repurpose tank cars to increase CO₂ transport capacity. Trucks transport CO₂ mainly over short distances and play a key role in supplying CO₂ for industrial applications such as the beverage industry. While not economical for long-distance transport, trucks offer a viable option for pilot-stage carbon storage projects due to lower capital investment requirements.

5.1.2.2 Storage

New York State has three key regional geologic storage options for captured CO₂: the Appalachian Basin, the Newark Basin, and offshore Long Island (specifically, the Baltimore Canyon Trough, George Bank Basin) along the Atlantic Continental Shelf. Section 5.3.3 discusses these in detail.

5.1.2.3 Utilization

In addition to permanent geologic storage, several utilization pathways offer economic and environmental benefits. The primary utilization pathways in commercial use today include EOR and conversion into products such as beverages. Other utilization pathways, early in the technology readiness, include industrial applications, mineralization, and building materials.

- **EOR:** One of the largest uses of captured CO₂ is injecting it into depleted oil reservoirs for EOR production. The CO₂ pushes oil to the surface, while a portion remains trapped underground, contributing to carbon sequestration. New York State has minimal EOR opportunity, so this application is not a significant option for the State.
- **Industrial applications:** Industries widely use CO₂ in food and beverage carbonation, water treatment, and chemical manufacturing. It is also used in metal fabrication for welding and cooling processes.
- **Conversion into products:** Captured CO₂ can be transformed into fuels, chemicals, and plastics. Emerging technologies explore ways to use CO₂ to make synthetic fuels, commodity chemicals and solvents, and polymers, reducing reliance on fossil-based feedstocks.
- **Mineralization and building materials:** CO₂ reacts with minerals to form stable carbonates used in cement and concrete production. This not only stores CO₂ permanently but also reduces emissions from traditional cement manufacturing.

The permanence of CO₂ sequestering varies widely across utilization pathways. EOR offers moderate to low permanence since only part of the CO₂ remains stored underground unless specifically optimized for sequestration. Industrial use, such as in food and beverage or refrigeration, results in low permanence since the CO₂ is quickly released back into the atmosphere. Converting CO₂ into fuels, chemicals, or plastics offers low to moderate permanence, depending on the product lifespan and end-of-life treatment. In contrast, mineralization and incorporation into building materials provide high permanence. The CO₂ becomes chemically bound in stable forms that can remain sequestered for decades to centuries.

CO₂ utilization is not currently viable downstream of the power generation sector because the volume of CO₂ produced far exceeds the current demand for existing utilization pathways. While some industries use captured CO₂ for products like synthetic fuels, chemicals, or concrete, these markets are relatively small compared to the vast emissions from power plants. Additionally, most CO₂ utilization processes require further technological development and are not yet cost-competitive on a large scale. As a result, the power sector is expected to primarily rely on geologic storage rather than utilization to manage captured CO₂ effectively in 2040.

5.2 Performance Attributes

Table 27 describes how amine-based capture technologies can provide key grid attributes using the qualitative ratings developed for this report. Many technologies can be specifically designed to provide selected grid services if system needs are known and mechanisms are in place to allow participation in relevant markets. These qualitative categorizations are not exhaustive and reflect fundamental technical capability and real-world frequency of deployment in the real world.

Table 27. Comparison of Amine-based Postcombustion Capture Technologies by Grid Services and Attributes

Italicized entries indicate a lack of real-world U.S. demonstration.

Attribute	Natural Gas Combined Cycle with Amine-Based Postcombustion Carbon Capture
Inertial Response (Rotational)	<i>Typically provides attribute</i> <i>large rotating turbomachinery in the NGCC plant provides strong inertia, which the addition of capture equipment does not impact</i>
Primary Frequency Response	<i>Typically provides attribute</i> <i>the heat exchanger network and main capture equipment respond adequately to frequency variations, so the NGCC plant's ability to provide this service is not impacted by the addition of capture equipment</i>
Voltage & Reactive Power	<i>Typically provides attribute</i> <i>the heat exchanger network and main capture equipment tend to operate at steady state, requiring an expected amount of reactive power that can be provided and controlled suitably by the NGCC plant; the capabilities of the NGCC plant are not impacted</i>
Ramping	<i>May sometimes provide attribute</i> <i>capture equipment may feasibly ramp up and down but overall performance and capture efficiency may be reduced during steep ramps; the capture technology has no impact on base NGCC ramping capabilities</i>
Cycling Capability	<i>May sometimes provide attribute</i> <i>capture equipment may take several hours to startup and shutdown, and capture efficiency may be reduced during initial startup; the capture technology has no impact on base NGCC cycling capabilities</i>
Short Minimum Run Time	<i>May sometimes provide attribute</i> <i>capture equipment may take several hours to startup and shutdown, and capture efficiency may be reduced during initial startup, which may impact the minimum run time of the full plant</i>
Black Start	<i>May sometimes provide attribute</i> <i>capture processes generally do not have their own auxiliary power and instead rely on the NGCC plant's distillate generator or other auxiliary power to operate off of grid power</i>
Capacity Factor	<i>High</i> <i>capture technologies are designed to perform optimally at high capacity factors to recoup capital cost, but may feasibly operate lower while incurring additional operating costs</i>
Minimum Stable Output	<i>May sometimes provide attribute</i> <i>capture technologies with steam extraction are expected to have a minimum stable output of ~50% while others could achieve lower than that, depending on heat integration with the NGCC plant</i>

The following summarizes key takeaways from Table 27:

- The performance of CCS technologies in providing various grid services depends on how individual process components rely on integration with grid power. NGCC power plants without CCS provide base ramping, cycling, and black-start capabilities. Capture technologies have performance attributes that either coincide with the base capabilities of the power plant or perform independently from the power plant. For example, the inertial response, primary frequency response, and voltage power of a capture technology depend on the NGCC power plant's ability to provide these attributes. Other attributes—such as ramping, cycling capability, minimum run time, and black-start capabilities—are inherent to the capture technology and do not positively or negatively impact these attributes for the power plant.
- Amine-based capture technologies for postcombustion capture have well-documented capabilities based on existing coal commercial projects. In contrast, emerging capture technologies, such as membrane-based, cryogenic, or the NET Power cycle, face uncertainties in performance at commercial scales.

The following provides additional details on key CCS attributes.

5.2.1 Ramp Rates, Flexibility, and Expected-Capacity Factors

In existing commercial CCS projects, the capture technology does not impact the ramping capabilities of the NGCC power plant. Instead, it has its own limitations in providing a quick ramping. As such, CCS is best suited for baseload power sources rather than peaking power sources. While many capture technologies target a capture rate between 90% and 95% during steady-state operations, capture rates during startup and shutdown may be lower based on the availability of steam to heat the reboiler and the quantity of CO₂ available to run through the CO₂ compressors. During ramping and load-following, rapid changes in flue gas quantity and composition reduce the efficiency of the capture unit. Typically, ramping forces the capture technology to operate outside steady-state conditions for 15–30 minutes. During this time, the actual capture rate can fall by 5%–10% below the design capture rate. This can be overcome by temporarily increasing steam supply to the reboiler to enable faster ramping of the capture technology and shorten the time that it operates outside of steady-state design conditions, but this incurs an energy penalty.

There is more economic and practical value in producing CO₂ at a constant rate from baseload energy supply rather than intermittently from peaking resources. Carbon offtakers that use CO₂ will likely require a continuous, steady supply of CO₂ for their end uses. Additionally, intermittent flow can compromise pipeline and wellbore integrity. Pressure fluctuations may cause deleterious CO₂ phase

changes, including gas segregation and increased corrosivity (EPRI 2023q). A continuous CO₂ supply from capture technologies at baseload NGCC power plants reduces the likelihood of these outcomes, compared to peaking-only applications where 2040 generation might be limited to a few days per year.

To improve flexibility and enable peaking applications, capture technologies can benefit from optimized heat integration with the NGCC steam cycle, aligning the capture technology with the consistent performance attributes of the power plant, such as ramping, cycling capability, and minimum run time. Solvent storage can enable some flexibility by allowing the capture process to continue during transient operation (IEA 2020). While capture technologies offer some operational flexibility for daily and seasonal unit operation and capacity factor variations, they do not guarantee sufficient flexibility to follow drastic operational changes while maintaining steady-state performance.

5.2.2 Capture Rates and Power Derate

Amine-based solvent capture technologies aim to achieve a 90% capture benchmark. Theoretically, these technologies can reach higher capture rates by either (1) increasing the exposure of flue gas to the capture solvent by increasing the surface area for gas contact, resulting in a higher capital cost, or (2) using more extreme conditions to strip CO₂ from the amine-rich solvent during regeneration, which requires increased energy consumption (EPRI 2023q). To achieve deep decarbonization of 99% capture or higher, systems typically require both increased gas contacting surface area and more extreme regeneration conditions. Du et al. (2021) estimate that increasing the capture rate from 90% to over 99% can increase the LCOE and cost of CO₂ captured by 7%–8%. While 99% capture is theoretically possible, recent CCS deployments have failed to reach even 90%, possibly due to economic choices rather than poor performance. Section 5.3.1 further discusses the latest deployment trends.

Retrofitting an NGCC power plant with 90–99% capture results in a power derate of 10%–12%. Power derate directly reflects the net heat rate of the system, which is the amount of fuel consumed per net power output. As the capture rate increases, the heat requirements for CO₂ desorption also increases, raising the net heat rate. The derate can be calculated as the difference between the net heat rate of the system without capture and the net heat rate of the system with capture at a particular capture rate. Table 28 reports net heat rate values and derate percentages for four capture rates.

Table 28. Net Heat Rate Values and Percent Derate at Four Capture Rates from Natural-Gas-fired Flue Gas

Capture Rate	0%	90%	95%	99%
Net Heat Rate (MMBtu/MWh)	6.075	6.692	6.740	6.784
Derate (%)	—	10.1	10.9	11.6

As capture rate increases, both the system’s net heat rate and percent derate increase. As a result, costs rise due to reduced plant power output and increased cost of regeneration equipment to handle higher heat desorption. Systems may lower derate and improve efficiency by using a larger heat exchanger, which increases capital cost (EPRI 2023q).

Once a system achieves 90%–95% capture, upstream emissions from producing and transporting NG-based fuel for the power plant significantly outweigh the amount of CO₂ captured downstream of the stack. Section 5.4.1 provides additional emissions analysis for capture at rates of 90%, 95%, and 99%.

Alternative capture technologies, including chemical absorption with advanced solvents, oxy-combustion, membranes, and supercritical CO₂ cycles (cryogenic), could reach higher stream capture rates and lower energy penalties (IEA 2023a). However, significant uncertainty remains regarding whether these performance and cost benefits will scale commercially by 2040.

5.2.3 Greenfield and Retrofit Applications

The performance impacts of retrofitting postcombustion capture technologies to an existing NGCC power plant largely depend on the plant’s performance attributes before the capture retrofit (NREL 2024a). DOE case studies show that the performance of greenfield and retrofit applications is nearly identical except for the addition of a low-pressure steam turbine off-design efficiency penalty for retrofit cases (NETL 2023). In retrofit cases, engineers throttle and extract steam upstream of the existing plant LP turbine stage and redirect it to the capture process. As such, this significantly reduces steam flow from the full design flow and lowers overall turbine efficiency for the plant’s power production. In real-world projects, engineers must consider that this efficiency penalty varies greatly depending on the plant’s specific turbine performance. In some cases, a complex turbine configuration may make steam extraction infeasible or uneconomical (Du et al. 2021).

5.3 Readiness for 2040

5.3.1 Latest Deployment Trends

5.3.1.1 Commercial Deployments

Only amine-based chemical absorption technologies have reached commercial deployment, primarily in coal-fired flue gas. Successfully deployed projects have reported capture rates below the 90% target. Currently, the U.S. has one commercially operating CCS plant, Petra Nova, which was designed to capture at least 90% of the CO₂ emissions from the 650 MW coal-fired boiler at the W.A. Parish Unit 8 in Texas. Petra Nova shut down temporarily in 2020 due to low oil and power prices during the COVID pandemic, but the project restarted operations in September 2023 (Patel 2024a). Before the shutdown, the Institute for Energy Economics and Financial Analysis (IEEFA) found that the project had missed its carbon sequestration goal by 17% and may have captured only 65%–70% of CO₂ (Robertson and Mousavian 2022).

Boundary Dam 3 in Canada, the world's first coal-fired power facility to implement carbon capture, began operation in 2014 and remains operational. However, its capture efficiency remains below its 90% target, with estimates ranging from 50% to 68% (Vaughan 2022). A report by project owner SaskPower states that some flue gas bypasses the capture unit for both technical and economic reasons, resulting in lower capture rates (Jacobs et al. 2022). The capture unit can achieve 90% capture efficiency on this partial diversion mode, but this does not account for the unabated stream of diverted flue gas. Overall, while high capture rates are theoretically possible, recent deployments demonstrate that both technical and economic barriers still prevent achieving them.

5.3.1.2 Latest Trends on NGCC Plants

The latest deployments of amine-based capture technologies for NGCC power plants have been at the front-end engineering design (FEED) or pilot demonstration level because capture from NG-fired flue gas remains in the early stages of development. Table 29 summarizes the solvent technology, capture performance, energy, and project status for selected notable projects. All data in Table 29 are sourced from publicly available sources, discussions with technology providers, or direct EPRI involvement in related projects (EPRI 2024e). Several carbon capture projects that recently received DOE support have lost funding, which can affect market development (Patel 2025b).

Table 29. Ongoing Activities of Selected Amine-based Capture Technologies

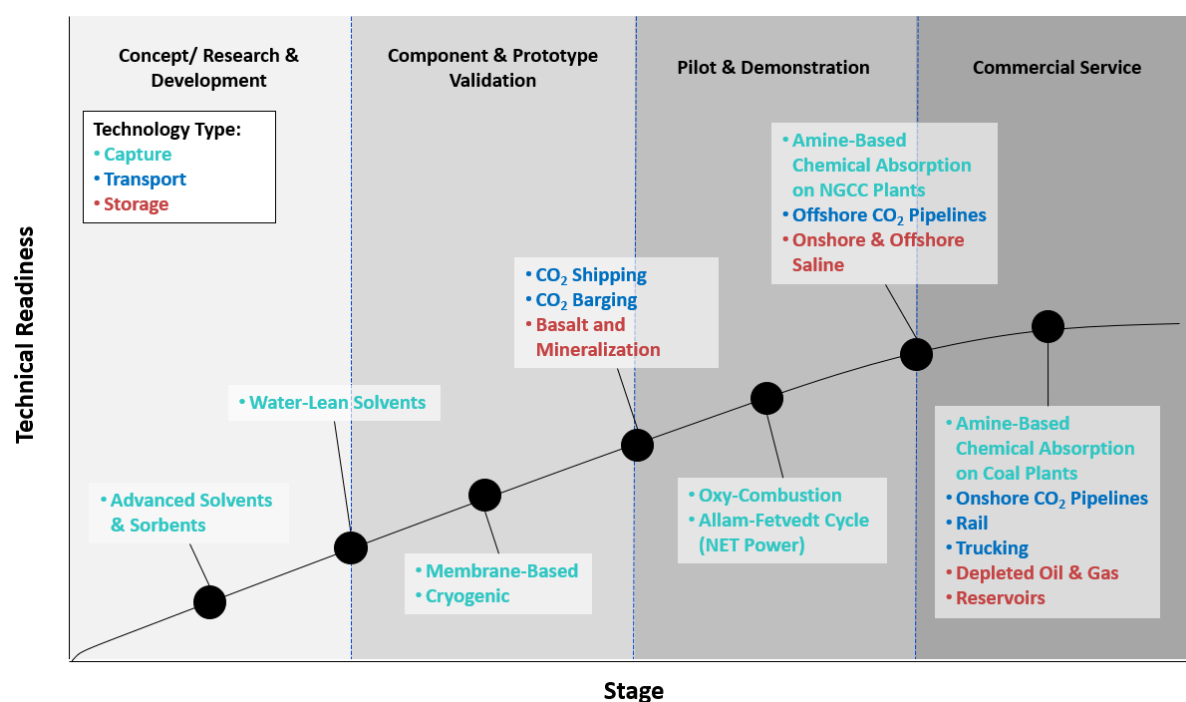
Amine-based Solvent Technology	Proprietary	Developer	Target Capture Rate (%)	Target Regeneration Energy (GJ/t CO₂)	CCS Project Status at Power Production or Industrial Sites
Cansolv DC-103 and DC-203	yes	Shell	90	2	FEED study (2022) of 6.5 million t CO ₂ /year at Calpine Deer Park Energy Center in Texas (NGCC)
KM CDR KS-1 and KS-21	yes	Mitsubishi	90–95	3	Demonstration of 2.5 million t CO ₂ /year at Lake Charles Power Station in Louisiana (NGCC)
Aqueous amine	yes	University of Kentucky	95	2.42	FEED study (2025) of 640 MW (~1 million t CO ₂ /year) at Cane Run Unit 7 in Kentucky (NGCC)
Econoamine FG+	yes	Fluor	90	2.76	FEED study (2022) of 4,000 t CO ₂ /day (~1 million t CO ₂ /year) at Elk Hills Power Plant in California (NGCC)
ICE-31	yes	ION Clean Energy	90	2.7–2.8	Demonstration of 3.7 million t CO ₂ /year at Polk Power Station in Florida (NGCC)
Just Catch	yes	Aker Advanced Carbon Capture	90	2	Demonstration of 400,000 t CO ₂ /year at Heidelberg Materials in Brevik, Norway (Cement)
OASE blue	yes	Linde-BASF	90	2.8	FEED study (2023) of 1,000 MWe (~2 million t CO ₂ /year) at James M. Barry Plant in Alabama (NGCC)
CDRMax (amine-promoted buffer salts)	yes	Carbon Clean	90	2.8	Pre-FEED (2018) of 1,633 t CO ₂ /day (~500,000 t CO ₂ /year) at Klemetsrud AS Plant in Oslo, Norway (Waste-to-energy)
DeltaSolv	yes	DeltaClean Tech	85	2.4	Demonstration of 860 MWe (~1.5 million t CO ₂ /year) at Enmax Shepard Energy Centre in Calgary, Canada (NGCC)
Piperazine	no	UT Austin and UOP	90	2.1–2.4	FEED study (2022) of 460 MWe (~900,000 t CO ₂ /year) at Mustang Station of Golden Spread Electric Cooperative in Texas (NGCC)
CESAR 1 (amino methyl propanol and piperazine)	no	TNO and SINTEF	90	2.5–3	Testing at 119 t CO ₂ /day (~40,000 t CO ₂ /year) at Technology Centre Mongstad in Norway (flue gas at 5 vol% CO ₂)

5.3.2 Technology Readiness

Figure 44 shows the technical readiness of different capture, transport, and storage systems based on their stages of technical development.

Figure 44. Current Technology Readiness of Capture, Transport, and Storage Technologies

A technology remains in its current readiness phase until it completes all activities in that phase. A technology on the line between two readiness phases indicates that it has completed all activities in one phase but has not started activities in the next. The figure provides a high-level comparison of capture, transport, and storage technologies, but does not reflect the variation in technological maturity within a category.



5.3.2.1 Capture

Amine-based chemical absorption processes are the most common and mature capture technology today for coal-fired flue gas. They are currently the most suitable option for fast commercial deployment for NG-fired flue gas. Other methods of capture include chemical absorption with advanced solvents, oxy-combustion, membrane-based capture, and supercritical CO₂ cycles with cryogenic heat integration methods. The process optimization and capture performance of these alternative capture technologies for NGCC power plants remain to be demonstrated.

The most advanced capture projects currently perform at commercial-scale capture from coal-fired flue gas. From the existing selection of amine-based chemical absorption processes, Shell and Mitsubishi Heavy Industries (MHI) provide the leading technologies for capturing from coal-fired flue gas at a commercial scale of millions of metric tons of CO₂ per year. These projects include Shell's capture technology deployed at SaskPower's Boundary Dam and Mitsubishi's capture technology deployed at NRG Energy's Petra Nova, both with a design capture rate of 1 MMT CO₂/year.

Shell and Mitsubishi are also demonstrating their technologies on NG-fired power plants. Shell achieved 90% capture using the DC-201 solvent during testing at the National Carbon Capture Center (NCCC) for simulated NG-based flue gas in 2014 (NCCC 2015). MHI achieved 95%–98% capture using the KS-21 solvent during testing at Technology Centre Mongstad for NG-based flue gas in 2021 (MHI 2021). As such, Shell and Mitsubishi are in the best position to tailor their capture technologies to capture from NG-fired flue gas at commercial scales; however, this development has only occurred in design and pilot testing and has not yet been achieved in a real-world commercial demonstration. The work done to achieve capture at commercial scales from coal-fired flue gas will inform the development of technologies to achieve capture at the same scales from NG-fired flue gas.

Other notable technology developers that have begun designing and testing their capture technologies for NG-based flue gas at commercial scales include Fluor and ION Clean Energy. Readiness gaps for more mature capture technologies from developers such as Fluor and ION Clean Energy are related to the lack of demonstrated performance at commercial scale. Readiness gaps for capture technologies with lower maturity, such as cryogenic and membrane-based technologies, are related to the fundamental viability of capture performance in a component validation setting.

Coal versus Natural Gas Capture

Capturing CO₂ from coal-fired flue gas has become the leading standard for CCS projects due to the dominating presence of coal power in the past. Regions of the U.S. have begun transitioning to an electricity grid primarily served by NGCC power plants, making the need for deployment of CCS projects designed to capture from NG-fired flue gas more evident. Due to the higher CO₂ concentration in coal-fired flue gas, it is one of the easier point sources to capture from in a power generation setting. Coal-fired flue gas has a CO₂ concentration of ~12 mol% and NG-fired flue gas has a CO₂ concentration of ~4 mol%. As such, capturing from NG-fired flue gas requires additional absorption and desorption energy and costs compared to coal-fired flue gas.

CCS projects for NGCC power plants can counter some energy cost challenges with a makeup in plant efficiency compared to coal power plants. The energy consumption per amount of CO₂ captured is similar when capturing from either coal or NG power plants. However, the carbon intensity of electricity from NGCC (~0.45 t CO₂/MWh) is less than half of the carbon intensity of electricity from coal (~1 t CO₂/MWh), which means that NGCC produces fewer CO₂ emissions for the same amount of energy supplied than coal. As such, the draw of parasitic power from the plant is less for NGCC than for coal, and NGCC experiences less reduction in overall plant efficiency. Overall, deploying capture technology on NG-fired flue gas versus coal-fired flue gas presents both benefits and challenges. Exact magnitudes of tradeoffs are best understood on a site-specific basis.

5.3.2.2 *Transport and Storage*

CO₂ transport and storage technologies vary in readiness, with onshore pipelines and storage in depleted oil and gas reservoirs or EOR operations being the most commercially mature. The Cortez Pipeline, which delivers CO₂ from Colorado to the Permian Basin in Texas and New Mexico, exemplifies established onshore transport, while offshore pipelines, although less developed, are operational in projects like Sleipner and Snøhvit in Norway. CO₂ shipping is in early demonstration, and rail and truck transport are limited to small-scale applications and last-mile delivery.

For storage, onshore saline aquifers and depleted reservoirs offer promising near-term options. Offshore storage and CO₂ mineralization remain in earlier stages of development and require further demonstration and investment.

5.3.3 Infrastructure and Supply Chain Readiness

The readiness of enabling infrastructure is a crucial consideration for energy technology. This includes the fundamental physical structures, facilities, and tools, along with their associated processes. The next three sections describe the infrastructure and supply chain readiness of the capture, transport, and storage components of CCS.

5.3.3.1 *Capture*

The readiness of infrastructure in New York State varies significantly based on geography and site-specific factors. Table 30 summarizes the infrastructure and supply chain readiness of the main capture processes with a focus on New York State's dynamics, followed by notes on state-specific considerations for each category.

Table 30. Infrastructure Readiness of Main Capture Processes in New York State

Technology	Grid Integration	Fuel Supply Chain & Waste Management	Thermal Management	Siting & Land Use	Supply Chain
NGCC with amine-based solvent capture	No significant buildout required Retrofits need no new interconnection; new plants have geographic flexibility to be near existing transmission and load	No significant buildout required Existing NG network in NYS is sufficient	Short lead time Cooling needed for power plant and carbon capture process	Short lead time Retrofits may be easier to site than new builds	Short lead time Scale-up of carbon capture equipment manufacturing needed

Thermal Management

Techniques for thermal integration between the capture process and power plant can reduce the need to extensively upgrade the thermal network when integrating CCS.

Siting and Land Use

Capture projects can be retrofitted onto an existing plant or designed for a greenfield plant. Projects that can leverage existing thermal plant sites and associated interconnections will have limited infrastructure impacts. Section 5.4.2 discusses land use and environmental considerations of CCS.

Supply Chain

Most fuels, materials, and processes required for a capture technology are well-understood and commonly available in existing supply chains in the power sector. Common amine-based capture materials used for point source capture have robust supply chains that could enable scale-up toward commercial availability (DOE 2023b). Emerging capture technologies, as an alternative to amine-based solvent technologies, may require different supply chains, but most technologies rely on common materials and process components that are already widely produced both in the U.S. and globally.

The following sections detail the unique infrastructure considerations associated with the statewide deployment of CCS.

5.3.3.2 Transport

The successful deployment of CCS relies on efficient and scalable CO₂ transport infrastructure to move captured emissions from power plants and industrial sources to storage sites. Various transport modes—including pipelines, rail, trucks, and ships—offer different advantages based on cost, capacity, and geographic considerations. Table 31 summarizes the infrastructure readiness of each transport mode with a focus on New York State and state-specific considerations for implementation.

Table 31. Infrastructure Readiness of Carbon Dioxide Transport Modes in New York State

Transport Mode	Network & Supporting Infrastructure	Siting, Permitting & Land Use	Workforce & Supply Chain
Pipeline	Infrastructure not ready CO ₂ pipelines often require long, unpredictable timelines	Long lead time Projects often face right-of-way and permitting challenges	Long lead time Pipeline projects require equipment and skilled labor
Rail	Long lead time Operators must upgrade or add terminals and lines, depending on volume and route	Long lead time Projects may require new permitting, equipment, and skilled labor, depending on volume and route	Long lead time Projects may require new equipment and skilled labor, depending on volume and route
Truck	No significant buildout required Operators can use existing infrastructure	No significant buildout required Operators can use existing infrastructure	Short lead time Project requires additional truck drivers
Shipping	Long lead time Operators must upgrade ports	Long lead time Port projects require land and permitting	Long lead time Port projects require equipment and skilled labor

Network and Supporting Infrastructure

Developing a CO₂ transport network in New York State could include a combination of pipeline development, rail infrastructure upgrades, truck transport logistics, and maritime transport development to connect emission sources with storage sites. Pipelines offer the most efficient large-scale solution, but they require new compression stations, monitoring systems, and rights-of-way. Currently, this network does not exist on the U.S. East Coast nor within New York State. Rail transport can leverage existing networks and is readily available locally, but it will need CO₂-specific terminals and specialized tank cars. Truck transport provides short-distance flexibility for pilot projects and can use existing road networks. Maritime transport via barges and ships could be used in coastal ports around the New York Metropolitan Area, Long Island, and Lake Ontario, but it will require modifications to ports and compliance with safety regulations.

To evaluate the feasibility of CO₂ transport in New York State, it is essential to quantify the infrastructure requirements for moving captured emissions from power plants to potential storage sites. Table 32 presents two hypothetical scenarios. The first scenario examines one 500 MWe NG-fired power generation facility operating at a 65% capacity factor with a 95% capture rate, capturing 0.88 MMT of CO₂ per year, or 2,411 metric tons per day. The second scenario examines a hypothetical upper bookend to the total electricity demand in 2040 that NG-based power could meet. This hypothetical bookend reflects the total demand projected in the *2025 Draft SEP*, Net Zero A scenario, minus the amount met by a 70% renewable grid and the current nuclear fleet. Assuming a 95% CO₂ capture rate at all NG-based fossil fuel power generation stations, this scenario would generate 17.25 MMT of captured CO₂ per year, or 47,260 metric tons per day. Both scenarios align with the emissions scenarios explored in Section 5.4.1. Table 32 depicts how this volume could be transported using different modes including pipelines, rail, trucking, and maritime shipping (capacities sourced from NPC 2019). By estimating the number of transport units required per day, this analysis highlights the scalability and practicality of each option and offers insight into the most viable pathways for CO₂ movement within the State.

Table 32. Example Scenarios of Carbon Dioxide Transport Infrastructure Daily Requirements by Mode

Transport Mode	Capacity per Unit	Single 500 MWe NG-fired plant (65% capacity factor, 95% capture rate) 2,411 t per day	Upper bookend (2040 demand, 70% renewable, existing nuclear) 47,260 t per day
Pipeline	1,000–100,000+ t per day (varies by size and pressure)	Single pipeline (ample capacity)	Single pipeline (ample capacity)
Rail	~83 t per tank car	29 railcars	569 railcars
Truck	~18 t per tanker truck	134 trucks	2,626 trucks
Ship (barge or tanker)	~1,000–50,000 t per voyage	1 ship every 3–5 days or 2–3 smaller barges per day	1–2 ships every day or 24–47 smaller barges per day

Pipelines transport 1.5 MMT of CO₂ per year, making them the most efficient and scalable option. Maritime transport could handle these hypothetical volumes, but this would only apply to sources near navigable waterways and would require investment in port infrastructure and CO₂ handling facilities. Additionally, although one or two ships per day could theoretically accommodate the upper bookend scenario, the distributed footprint of CO₂ sources would require an alternative transport method to

gather the CO₂ for shipping. Rail and truck transport are impractical at this scale, but could serve as an alternative if the source captures a significantly lower volume of CO₂. For example, a small pilot project capturing 50,000 metric tons of CO₂ annually would need fewer than two railcars per day.

Siting, Permitting, and Land Use

Developers must plan for siting, permitting, and land use when building CO₂ transport infrastructure. Unlike states with well-established oil and gas infrastructure, New York State has limited experience with CO₂ pipelines. Developers must navigate State and federal regulations that were not originally designed for CCS infrastructure. This regulatory framework can lead to lengthy approval timelines and potential legal challenges, which increase investor uncertainty and delay project implementation. Additionally, zoning laws, land use restrictions, and ecological concerns, particularly in densely populated areas or regions with protected lands, can complicate the acquisition of rights-of-way.

Public acceptance is another notable risk. Communities may oppose CO₂ pipelines due to concerns about safety, environmental risks, and property rights issues. In other states, CO₂ pipeline projects have faced resistance from landowners concerned about potential leaks, emergency response capabilities, setback distances, and the impact on property values (CRS 2023). Unlike oil and gas pipelines, which often benefit from eminent domain powers, CO₂ pipelines in New York State lack the same legal authority. This means developers must negotiate land access agreements with individual landowners, a process that can be time-consuming and costly. Without eminent domain, opposition from even a small number of landowners could delay or block projects entirely.

To address these challenges, developers must engage in extensive public outreach and communicate transparently about safety protocols, environmental benefits, and the economic opportunities associated with CCS deployment. However, they must also overcome public skepticism and regulatory barriers to establish a viable CO₂ transport network in New York State.

Rail and truck transport offer flexibility by leveraging existing infrastructure, but they would likely require additional buildout to reach individual CO₂ sources. As noted earlier, these modes are not scalable to the needs of the power sector. Barge and ship transport could provide a viable alternative for transporting CO₂ via waterways to storage, particularly along the Hudson River and Long Island coast, but would require specialized port infrastructure and maritime permitting.

Supply Chain

The supply chain could experience bottlenecks, such as shortages of specialized materials like high-grade steel for pipelines and well casings, or a limited availability of skilled labor for pipeline construction and well drilling. Infrastructure limitations, regulatory hurdles, and competition with other industries for supply chain resources could also impact logistics for equipment and materials. Beyond infrastructure, the supply chain must also support ongoing CO₂ handling and operational needs, such as the production and maintenance of compressors, monitoring sensors, and leak detection technologies. If manufacturers cannot supply these components in sufficient quantity or time, transport and storage expansion could face delays. Ensuring supply chain resilience will be critical to securing parts and equipment reliably despite market fluctuations, global trade disruptions, or increased demand from other carbon management projects across the U.S.

5.3.3.3 Storage

New York State has three primary geographic regions for CO₂ storage: the Appalachian Basin, the Newark Basin, and offshore Long Island within the Baltimore Canyon Trough or Georges Bank Basin (Table 33). Each basin presents unique characteristics that influence its potential for long-term CO₂ storage, including rock composition, depth, permeability, and proximity to emission sources.

- **Appalachian Basin:** This large basin spans significant portions of Ohio, West Virginia, Pennsylvania, and Western New York. It holds potential for CO₂ storage in deep saline reservoirs, depleted oil and gas reservoirs, shale, and through EOR. Within New York State, the basin could theoretically store up to 4.4 billion metric tons (gigatonnes, or Gt) of CO₂ (NYSERDA 2020). However, not all reservoir types are found in New York State, and the highest storage potential exists in neighboring states.
- **Newark Basin:** Mostly located in New Jersey and minor portions of southern New York and eastern Pennsylvania, the basin contains at least 1.9 Gt of theoretical CO₂ storage capacity in onshore saline reservoirs (Collins 2017). Its complex geology, interbedded sandstone, siltstone, shale, and volcanic intrusions, requires further research and geologic characterization to determine its suitability for large-scale CO₂ sequestration. Similar to the Appalachian Basin, most of the storage potential exists in neighboring states.
- **Offshore Long Island (Baltimore Canyon Trough and Georges Bank Basin):** The Atlantic Continental Shelf near Long Island offers substantial offshore CO₂ storage potential in deep offshore saline reservoirs in both the Baltimore Canyon Trough and Georges Bank Basin. Regional-scale estimates suggest theoretical capacity ranges from 9.3 to 403 Gt of CO₂, depending on storage efficiencies ranging from 1% to 13% (Battelle 2019). All storage potential lies in U.S. federal waters outside New York State's jurisdiction. Similar to the Newark Basin, these offshore areas require further geological characterization and data acquisition to determine CO₂ storage viability.

Table 33. Theoretical Capacities for Carbon Dioxide Storage in Regional Geologic Basins near or within New York State

Geologic Basin	Occurs within NYS	Type(s) of Geologic Storage	Theoretical-Capacity (Gt of CO ₂)	Notes
Appalachian Basin	Partially	Onshore saline, EOR, depleted oil and gas, shale	4.4 (756+ available in broader region) (NYSERDA 2020, Yildirim et al. 2025)	Specified capacity is within NYS (NYSERDA 2020)
Newark Basin	Partially	Onshore saline	1.9 to 30.2 (Collins 2017)	Significant majority of capacity exists outside of NYS
Baltimore Canyon Trough, Georges Bank Basin	No	Offshore saline	9.3 to 403 (Battelle 2019)	All capacity exists outside NYS

As an illustrative example, in 2022, New York State generated 376 MMT of CO₂e emissions, of which 22 MMT were sourced from power generation (DEC 2022). Although these emissions are expected to decline, this equates to 200 years of CO₂ storage capacity if capturing only power generation emissions and assuming storage occurring only in New York State (4.4 Gt). Alternatively, if all CO₂e emissions were to be captured economywide and stored within New York State, theoretical capacity would be reached at 11.7 years. However, the transition to renewables will significantly extend the theoretical timeline by reducing overall emissions.

New York's capacity for large-scale CO₂ storage is limited compared to other regions with well-established geologic formations for sequestration. The Appalachian Basin, while promising, has limited well-characterized saline formations within New York State. The Newark Basin, which predominantly lies outside New York State, requires further geological assessment to determine its suitability. Offshore storage options in the Baltimore Canyon Trough and Georges Bank Basin, entirely outside New York State waters, offer significant capacity but require substantial infrastructure investment and regulatory approvals.

Given these constraints, New York State would likely need to collaborate with neighboring states or participate in regional and federal initiatives to secure sufficient storage capacity for captured emissions if carbon capture becomes a significant strategy for decarbonization.

Interstate collaboration could involve transporting CO₂ via pipelines to larger geologic storage sites in nearby states such as Pennsylvania, Ohio, or West Virginia, where deep saline aquifers and depleted oil and gas reservoirs offer substantial sequestration potential. This approach would require agreements on

regulatory frameworks, pipeline infrastructure development, and potential revenue-sharing mechanisms. Federal support through initiatives like the DOE's CarbonSAFE program and regional carbon storage hubs could further facilitate cross-state CO₂ transport and storage. New York State could integrate into a broader carbon management network to ensure safe, efficient storage of its captured emissions, even if stored in out-of-state locations.

Implementing geologic CO₂ storage in New York State presents several risks, uncertainties, and hurdles that must be addressed for successful deployment. One of the primary challenges is injection well permitting, which involves navigating a complex regulatory framework. Class VI wells, designated for CO₂ sequestration under the EPA, require extensive site characterization, monitoring plans, and financial assurances to ensure long-term storage integrity. New York State currently lacks primacy for Class VI well permitting, meaning operators must seek approval directly from the EPA. This can be a time-consuming process and add uncertainty to project timelines. As of March 2025, the EPA had issued eight Class VI permit decisions amongst a backlog of 165 permit applications with an average processing time of 2.5 years (EPA 2025b).

Concerns regarding induced seismicity, well integrity, and potential groundwater contamination may further complicate permitting efforts, requiring extensive geological studies and risk mitigation strategies.

Land ownership and pore space rights also pose significant challenges. CO₂ storage projects must address long-term liability because operators need to ensure that injected CO₂ remains securely trapped for centuries. Liability for potential leaks, seismic events, or contamination of groundwater could pose financial and legal risks for operators beyond the typical 30-year operational timeline of a storage project.

While some states, such as Texas, Montana, and North Dakota, have implemented long-term stewardship funds or state-managed postclosure programs, New York State has not yet developed a clear framework for managing long-term liability post site closure (GCCSI 2019). Without these mechanisms, private operators may be hesitant to invest in CO₂ storage due to the prospect of indefinite responsibility for monitoring and remediation. Addressing these legal and regulatory uncertainties will be critical to realize large-scale geologic CO₂ storage in New York State.

While this section focuses on carbon storage options within or adjacent to New York State, other U.S. regions, particularly the Gulf Coast and Midwest, have geology that likely holds potential for more storage capacity at lower costs than the Northeast. If a pipeline network were developed to transport CO₂

to wells in these regions, New York State could take advantage of these high-quality sequestration resources, potentially at a lower overall transport and storage cost on a per tonne basis than using storage within or near New York State (EPRI 2023d).

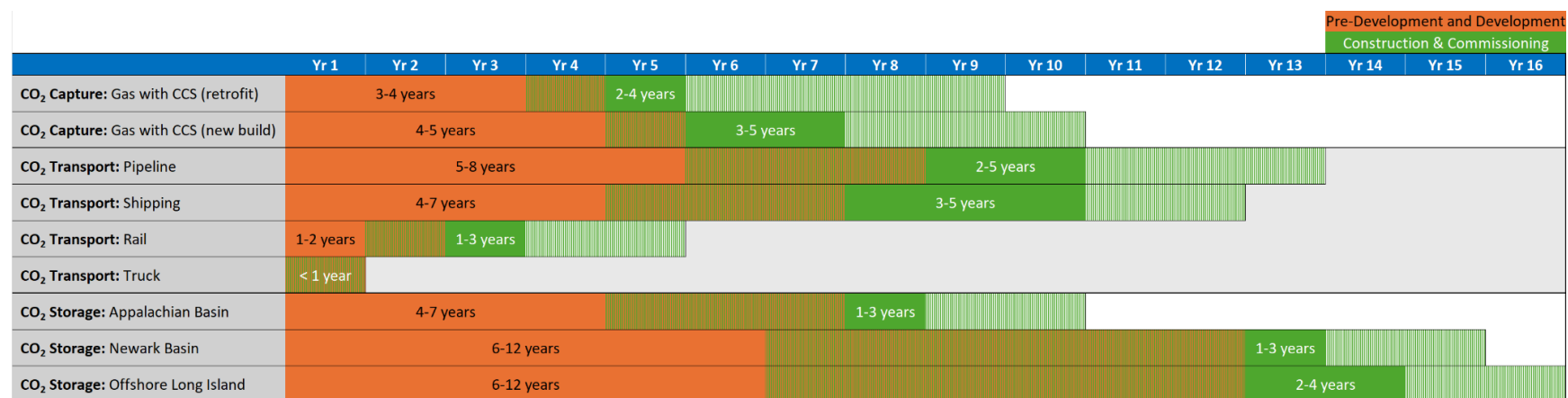
5.3.4 Project Lead Times

Understanding what happens to the CO₂ after capture is essential for estimating project lead times. Projects that involve CO₂ utilization tend to have shorter lead times than projects involved in geological sequestration due to the yearslong timeframe it takes to develop the resources for a new CO₂ storage site (IEA 2023a). However, as discussed earlier, the scale of CO₂ from a power plant is likely to exceed demand from utilization, with the exception of EOR, which is not a significant option for the State.

Other major factors affecting project lead time include project complexity, regulatory approvals for siting, material procurement, and financing. Preliminary work to conduct siting and permitting can affect project developers' relationships with stakeholders in communities surrounding the project, such as public utilities and community engagement groups. Building these relationships can help facilitate CCS project success.

Figure 45 summarizes estimated project lead times for CO₂ capture, transport, and storage technologies.

Figure 45. Estimated Project Lead Times for Capture, Transport, and Storage Projects and Technologies



5.3.4.1 Capture Lead Times

A retrofit capture project typically takes 5–8 years from the start of the design to an operational project. Designing and conducting a FEED study for a specific project site can take 1–2 years (IEA 2023a). Project developers then spend up to 2 years producing outlined specifications and securing regulatory approval. After reaching the final investment decision, the project proceeds through detailed engineering, procurement, construction, and commissioning during the next 2–4 years. Installing a capture process at a greenfield NGCC plant can take an additional 1–2 years due to the need to optimize the steam turbine design for integration with the capture process and potential siting and permitting constraints for the overall plant (S&L 2024). As such, greenfield capture projects may require 7–10 years, consistent with the project timeline expected for a new-build NGCC plant.

5.3.4.2 Transport Lead Times

In New York State, permitting hurdles, public acceptance challenges, and the lack of existing CO₂ pipeline infrastructure mean that developing a large-scale CO₂ pipeline network could take 7 to 13 years from planning to operation. Obtaining regulatory approval alone can take several years. After permitting, pipeline construction takes 2–5 years, depending on the scale, route complexity, and extent of stakeholder negotiations. Marine transport of CO₂ from NYS ports to offshore or out-of-state storage sites could be an alternative, but it also requires significant infrastructure development. Retrofitting existing ports or constructing new CO₂ handling terminals could take 7–12 years, including environmental assessments, regulatory approvals, and terminal construction. While shipping has fewer land-use conflicts than pipelines, developers must still navigate maritime regulations, secure vessel supply, and build safe CO₂ loading/unloading facilities, all of which could extend project timelines.

5.3.4.3 Storage Lead Times

In or near New York State, the three primary storage regions are in different stages of geological assessment, and none currently has permitted Class VI injection wells for commercial-scale CO₂ sequestration. The Appalachian Basin is the most studied of the three storage options. However, site assessments, including data acquisition, extensive geologic characterization, permitting of test wells and Class VI wells, could take 4–7 years (IEA 2023a). Although CO₂ utilization for EOR has significantly shorter project lead times due to known geology, EOR is not a significant option for New York State. The Newark Basin remains less characterized for CO₂ storage, with uncertainties in rock permeability and storage integrity. It requires significant geological assessments and pilot testing, making full-scale development by 2040 unlikely without changes in federal and/or State initiatives and funding.

Predevelopment timelines for the Newark Basin may take 6–12 years. Constructing and commissioning an onshore storage site takes an additional 1–3 years. Offshore CO₂ storage offers greater capacity, but it faces the longest lead time, possibly 8–16 years total, due to the need for subsea pipeline construction, marine permitting, and regulatory uncertainty. Establishing a legal framework for offshore storage in federal or State waters is still in progress, so this option is unlikely to be available until after 2040 unless federal policy incentives significantly accelerate development.

5.3.5 Geographic Suitability and Constraints

The additional space required for a capture retrofit is usually project-specific. For an NGCC plant rated at 543 MWe net with 95% capture, the new-build plant itself would require approximately 30 acres and the new-build plant installed with a capture technology would require approximately 60 acres of land (EIA 2024a). Thus, adding a capture process effectively doubles the NGCC plant's expected footprint. This much additional land may not be feasible at existing NGCC power plants in New York State, especially in densely populated areas in Downstate New York.

Developing a CO₂ pipeline network that traverses the densely populated areas of Downstate New York requires complicated land acquisition, while water crossings and existing transit corridors further increase complexity. Given these obstacles, alternative transport methods, such as shipping or rail, may be more practical for moving CO₂ from the New York Metropolitan Area to offshore or out-of-state storage sites. Facilities near the Pennsylvania/New Jersey border or on Long Island have greater feasibility for pipeline connections due to their proximity to potential CO₂ storage sites. Southern and Western New York plants could connect to Pennsylvania's Appalachian Basin storage sites with shorter pipeline routes, while Long Island facilities could utilize offshore saline aquifers. However, both scenarios still require substantial infrastructure investment and coordination with neighboring states and federal agencies.

Regulatory standards affect pipeline routing and right-of-way considerations. For instance, the Code of Federal Regulations (49 CFR § 195.210) requires pipelines to avoid, as much as practicable, areas with private dwellings, industrial buildings, and public assembly locations. Specifically, no pipeline may be located within 50 feet of such structures unless it has at least 12 inches of cover in addition to the standard requirements.

Siting a CCS project in Western New York near identified storage potential could increase project viability by reducing the need for extensive transportation infrastructure.

5.3.6 Readiness Summary

Deploying CCS technology in the NYS electric power sector requires addressing infrastructure and geographic constraints that could limit its viability as a decarbonization strategy by 2040. Amine-based capture technologies have reached commercial scale on coal-fired power plants, although their application to NGCC plants has been primarily at the pilot and demonstration stage.

CCS deployment requires CO₂ transport and storage infrastructure, which is currently in early stages in the eastern U.S. Building a CO₂ pipeline network requires permitting, siting, and regulatory frameworks that have yet to be developed. Although New York State has limited theoretical CO₂ storage capacity, nearby states and other regions are expected to offer sufficient capacity, accessible through a pipeline network. The lack of Class VI injection well permits in New York State, along with the EPA's long processing time and application backlog, creates permitting uncertainties.

Geographic constraints further limit CCS feasibility, particularly in Downstate New York regions, where retrofitting capture equipment, potentially doubling existing plant footprints, would be challenging in densely populated areas. Potentially long project lead times for pipeline and storage site development mean New York State must act in the near term to enable comprehensive CCS deployment by 2040.

5.4 Emissions and Other Considerations

5.4.1 Emissions

The GHG emissions expected from a baseload NGCC plant with carbon capture depend on its rated output, the carbon intensity of its fuel, and other plant assumptions such as capacity factor and capture rate. While adding CCS to an NG-based plant can significantly reduce combustion emissions, it does not mitigate associated upstream emissions.

This report uses emissions factors expressed as mass of CO₂e per unit of energy, based on the Climate Act accounting framework. The framework uses a 20-year global warming potential and incorporates upstream fossil emissions (NYSERDA 2022a). Climate Act emissions factors were applied with net high heat value (HHV) heat rates, in MMBtu/MWh, to account for the power derate associated with capture and calculate emissions factors for each capture rate scenario in units of lb CO₂e/MWh (Table 34). Emissions factors were determined for NG-based fuel under four capture rate scenarios:

no capture, 90% capture, 95% capture, and 99% capture. These emissions factors exclude fugitive gas system emissions, which depend on gas grid size and are accounted for in other sectors in the DEC inventory. They also exclude potential fugitive emissions from CO₂ transport and storage infrastructure, although such emissions are typically considered small relative to upstream NG emissions (IPCC 2006).

Table 34. Emissions Factors and Heat Rate Values for Natural-Gas-based Fuel in Four Capture Rate Scenarios

Attribute	Unit	NG (No capture)	NG + CCS 90%	NG + CCS 95%	NG + CCS 99%
Heat Rate	MMBtu/MWh	6.075	6.692	6.740	6.784
Upstream Emissions Factor (per MMBtu)	lb CO ₂ e/MMBtu	90	90	90	90
Combustion Emissions Factor (per MMBtu)	lb CO ₂ e/MMBtu	117	12.8	6.8	0
Total Emissions Factor (per MMBtu)	lb CO ₂ e/MMBtu	207	102.8	96.8	90
Upstream Emissions Factor (per MWh)	lb CO ₂ e/MWh	547	602	607	611
Combustion Emissions Factor (per MWh)	lb CO ₂ e/MWh	711	86	46	0
Total Emissions Factor (per MWh)	lb CO ₂ e/MWh	1258	688	652	611

Adding carbon capture to a system increases power requirements for inlet gas flow processing and solvent regeneration. As capture rates increase, the system consumes more fuel per net MWh of electricity produced. Thus, upstream emissions (in lb CO₂e/MWh) increase with a higher capture rate (Table 34).

While CCS significantly reduces combustion emissions, it increases upstream fossil emissions relative to a plant without capture, leaving considerable residual emissions.

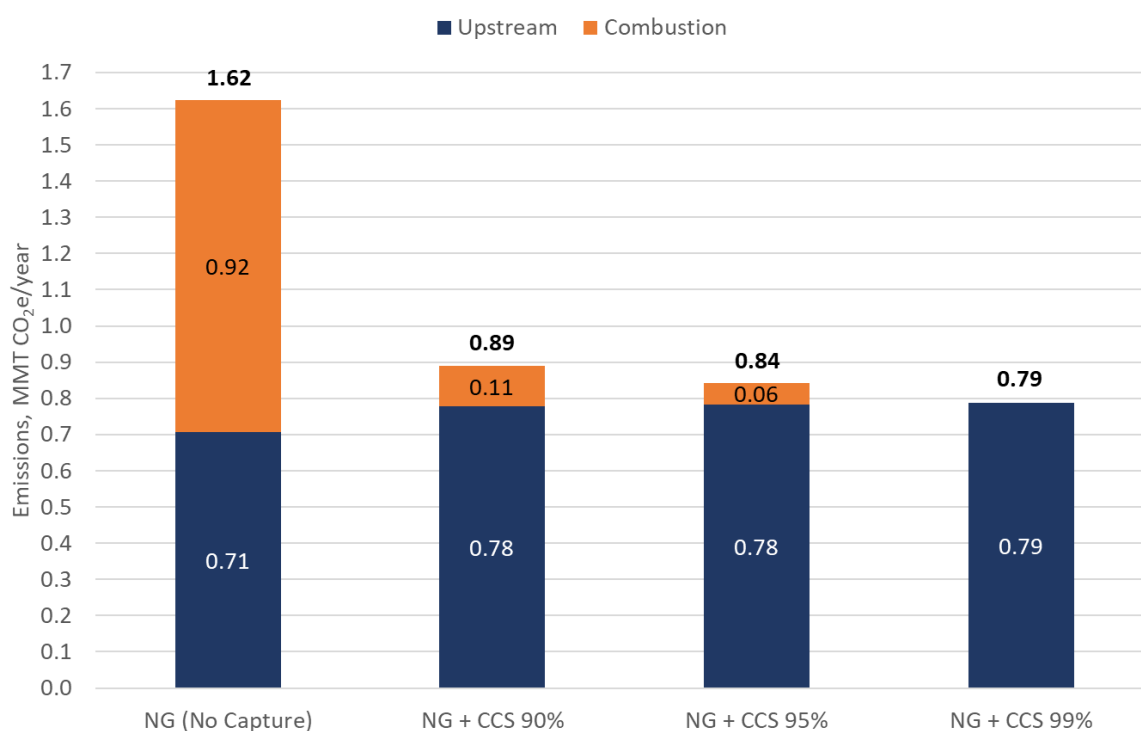
5.4.1.1 Emissions from Baseload Plant

To estimate annual emissions for a typical baseload plant, this assessment assumed a gross baseload plant size of 500 MWe and a 65% capacity factor, generating 2,847,000 MWh/year. The total amount of CO₂e emissions from this plant was calculated using the emissions values in lb CO₂e/MWh from Table 34.

Figure 46 shows the total CO₂e emissions with breakdowns for the amount attributed to upstream activities and combustion activities.

Figure 46. Carbon Dioxide Equivalent Emissions by Capture Rate Scenario

For a 500 MWe gross NGCC plant under four carbon capture rate scenarios.



An NGCC power plant without capture generates 1.62 MMT of CO₂e per year, with 0.71 MMT CO₂e/year attributed to upstream and 0.92 MMT CO₂e/year attributed to combustion. Plants with 90%, 95%, and 99% capture achieve 45%, 48%, and 51% reductions in total gross emissions or 0.89 MMT, 0.84 MMT, and 0.79 MMT CO₂e/year, respectively. While combustion emissions decrease as capture rate increases, there continue to be gross emissions due to remaining upstream emissions, even when considering 99% capture and nearly complete removal of combustion emissions.

5.4.1.2 Aggregate Emissions in 2040

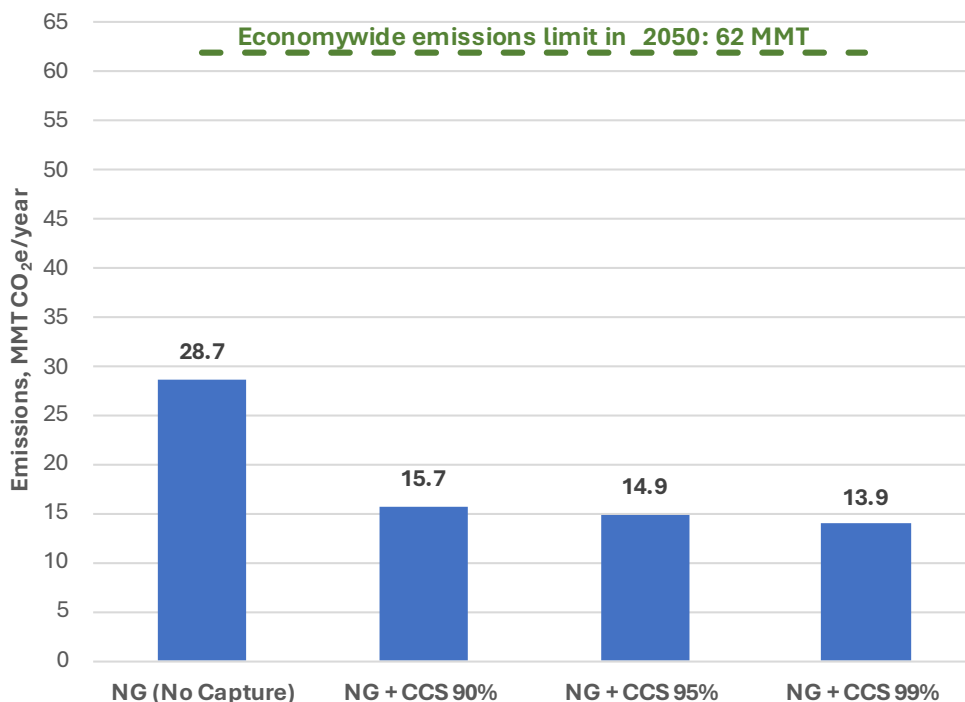
The Climate Act requires New York State to reduce economywide GHG emissions 85% by 2050 relative to 1990 levels (CAC 2022). This requirement results in an economywide emissions cap of 62 MMT CO₂e/year.

The *2025 Draft State Energy Plan* (SEP) analysis assumed the power sector would have zero gross emissions by 2040. The remaining 2050 emissions were reserved in that analysis for the hardest to decarbonize end uses, e.g., waste, agriculture, and aviation. As a result, any gross emissions generated by the NGCC with CCS must be compensated for by further reductions in other sectors, which may not be feasible. This section estimates the total annual emissions that would be produced if NG-based power with CCS were a more central component of 2040 power generation in New York State and compares those estimates to the 2050 economywide limit of 62 MMT CO₂e/year.

To estimate the GHG emissions associated with such a scenario, the emissions factors in Table 34 were applied to a portion of the total 2040 projected demand. An upper bookend to the total electricity demand in 2040 that could be met with NG-based power is estimated as the total demand as projected by the *2025 Draft SEP*, Net Zero A scenario, minus the amount that will be met by a 70% renewable grid and the current nuclear fleet: 50,337 GWh. This simplified estimate does not account for the shape of the residual electric sector demand. Figure 47 shows the resulting estimated emissions from supplying 50,337 GWh of electricity from an NGCC fleet under four capture rate scenarios.

Figure 47. Carbon Dioxide Equivalent Emissions of Natural Gas Combined Cycle with Carbon Capture and Storage

For NGCC generation under four carbon capture rate scenarios.



Deploying an NG-based fossil fleet without capture to meet this electricity demand would generate a total of 28.7 MMT CO₂e/year. Deploying an NG-based fossil fleet with capture would result in lower emissions, with implementation of 90% capture generating 15.7 MMT CO₂e/year, 95% capture generating 14.9 MMT CO₂e/year, and 99% capture generating 13.9 MMT CO₂e/year. These emissions are significant (22%–25%) relative to the economywide limit of 62 MMT CO₂e/year by 2050. Other sectors are unlikely to achieve reductions of this magnitude in emissions. Thus, deploying NG-fired power generation with CCS at a large scale would either require innovations that facilitate a significant reduction in upstream emissions or necessitate a transition toward a lower-carbon firm energy alternative before 2050.

This accounting also excludes emissions from potential petroleum combustion in dual-fuel NG power plants in New York State. Additional emissions reduction would be required either by capturing distillate-based emissions or by substituting lower-carbon alternative fuels.

5.4.1.3 Non-Greenhouse Gas Emissions

NGCC power plants emit non-GHG air pollutant emissions, including NO_x, SO_x, and PM. To meet required emissions limits, today's power plants are equipped with emissions control systems that reduce these airborne pollutants. Postcombustion capture technologies, together with existing or additional emission controls, may further reduce non-GHG emissions.

Typically, dry low NO_x (DLN) burners and selective catalytic removal systems work together to remove 75%–90% of NO_x before the flue gas is emitted by the plant (Schmitt et al. 2022). These emissions control systems are used before flue gas enters the capture process. In the subsequent capture process, an amine-based solvent is used to absorb CO₂, and this solvent can also absorb 80%–95% of the remaining NO₂ in the flue gas, leading to an additional 9% reduction of NO_x. NO₂ comprises about 10% of total NO_x in flue gas. (Schmitt et al.). While the capture process may also further reduce emissions of primary PM_{2.5} (Schmitt et al.), the use of the amine solvent is also expected to emit ammonia, which would oxidize in the atmosphere to form ammonium and contribute to secondary PM_{2.5} formation. The increase in ammonia could be mitigated by implementing additional emission controls, such as an acid wash (Rochelle 2024, Waxman et al. 2024).

NGCC power plants typically produce little to no sulfur emissions. The capture process can essentially remove and effectively eliminate any SO_x from the flue gas. Similarly, a direct contact cooler (DCC) within the capture process can also effectively eliminate any PM emissions from flue gas emitted by the plant.

Overall, adding a capture unit can decrease some co-pollutant emissions, but it may also introduce new co-pollutant emissions from ammonia. Further research is needed to identify solvents that are most effective for separating CO₂ from the flue gas while also reducing non-GHG air pollutant emissions throughout the capture process.

5.4.2 Other Considerations

5.4.2.1 Air Quality

Natural gas power plants equipped with postcombustion capture technologies can reduce SO₂, NO_x, and primary PM_{2.5} emissions that would otherwise be present in flue gas and emitted from the plant stack, thereby reducing air pollution concentrations and having health benefits. However, amine solvents could increase ammonia emissions and may contribute to the formation of secondary PM_{2.5}. Additionally,

degradation of amine or other solvents during operation of the capture process could occur and present risks to any exposed population if unmanaged (IEA 2023a). Most capture processes are developed to minimize solvent degradation after extensive solvent material lifetime testing and water washing, which captures ammonia emissions before CO₂ depleted flue gas exits the absorber column.

5.4.2.2 Safety and Environmental Considerations

CO₂ pipelines, although generally safe, can pose specific risks due to CO₂ properties. CO₂ pipelines operate under high pressure, and ruptures can lead to the sudden release of dense CO₂ clouds, which can displace oxygen and pose an asphyxiation risk to operators or local populations (IEA 2023a). Storing CO₂ underground in deep saline aquifers or depleted reservoirs is safe when properly managed. Well integrity and proper site selection are essential to prevent CO₂ migration and groundwater contamination.

Induced Seismicity

Excessive reservoir pressure from injection could theoretically reactivate faults and induce seismic activity. This learning is derived from analogous saltwater disposal wells associated with oil and gas activities, where induced seismic activity was detected with a magnitude greater than 5.0. Currently, geologic storage of CO₂ has been found to cause only microseismic events of a magnitude insufficient to be felt (IEA 2023a).

Groundwater and Wastewater Management

For capture processes, considering the water source that will be used for raw water withdrawal is critical because this dictates the type of water used by the process and, ultimately, as process discharge. Makeup water for the plant can be supplied from a local publicly owned treatment works (POTW) or groundwater. Water used in a capture process comes into contact with equipment surfaces and is collected and treated for a permitted discharge back to local municipal sources. Cooling water blowdown is also treated for chloride and metals before being discharged (Schmitt et al. 2022).

The EPA regulates CO₂ injection under the Underground Injection Control (UIC) program, specifically through Class VI wells designated for the geologic CO₂ sequestration. This regulatory program ensures that injection sites include proper well construction, monitoring, and containment measures to prevent groundwater contamination. Additionally, New York State addresses the regulatory status of CO₂ as a waste and provides legal clarification that compliant CO₂ streams are not subject to hazardous waste

regulation, which is not inherently covered in the general Class VI permitting framework (DEC 2025, Federal Register 2014).

CO₂ storage can pose risks to groundwater quality if not carefully managed due to the potential migration of CO₂ or brine from deep storage formations into shallower aquifers. This migration may occur through faulty wellbores, fractures, or geologic faults, potentially altering water chemistry and making it unsuitable for drinking or agriculture. When CO₂ dissolves in water, it can form carbonic acid, which may lower pH and mobilize heavy metals. Additionally, overpressurization of a storage reservoir may require operators to extract formation brine to maintain integrity and generate a wastewater that must be properly handled. Disposal options for this brine include reinjection into deep wells, use of evaporation ponds, or treatment methods such as desalination if the brine quality permits beneficial reuse.

5.4.2.3 Water Use

The steam turbine output of an NGCC power plant affects overall condenser duties, cooling water flows, and the required amount of cooling water makeup. Capture processes have significant cooling water demand due to greater cooling tower blowdown and evaporative losses, generally met by increased raw water consumption. Raw water consumption equals the difference between the raw water withdrawal demand for the process and the process discharge returned to a water source. Raw water consumption can increase by 51%–53% for capture from an NGCC plant that uses H-class turbines (Schmitt et al. 2022). For a 992 MWe net NGCC plant without capture, raw water consumption is 2.8 gallons per minute per megawatt (gpm/MW) net. With a 90% capture, the same plant uses 4.2 gpm/MW net (Schmitt et al.). As a result, the cooling water and raw water demands for a plant increase as the capture rate increases. The plant's cooling water and raw water demands can be reduced if the capture process uses steam from the host plant rather than an auxiliary boiler, thereby decreasing the steam cycle condenser duty (Homsy et al. 2023). Other less mature capture methods, such as those paired with oxycombustion, have the potential for lower water use.

5.4.2.4 Land Use

When retrofitting a capture technology to an NGCC power plant, it is important to consider the amount of additional equipment required for the capture process and evaluate how much of the existing plant equipment can be integrated into the capture process, such as for electricity or thermal loads. As discussed earlier, the additional space required for the capture retrofit may double the expected footprint of the NGCC plant where the capture process is installed.

The right-of-way requirements for pipelines are influenced by factors such as pipeline diameter, construction practices, and regulatory standards. Right-of-way widths are designed to accommodate safe and efficient construction activities, including excavation, material storage, and the movement of equipment. Specific conditions such as soil type, terrain, and construction techniques may require adjustments. Narrower rights-of-way might be necessary in environmentally sensitive areas, sites with cultural or historic significance, and densely populated regions.

According to a study by the Interstate Natural Gas Association of America (INGAA 1999), the baseline construction right-of-way widths for pipelines of various diameters are:

- 8–16 inches: 80 feet
- 18–24 inches: 95 feet
- 30–36 inches: 110 feet
- 40–42 inches: 125 feet

An 18-inch CO₂ pipeline requiring a 95-foot right-of-way uses approximately 11.5 acres per mile of pipeline length. Additional land is needed for compressor stations, which have a footprint of 5–10 acres and are typically located every 50–100 miles along a pipeline. Valve sites, placed approximately every 20 miles, occupy 0.5 to 1 acre each (INGAA 1999). Note that these estimates are based on operating NG pipelines. CO₂ pipelines require more compressor stations due to higher operating transport pressures.

A CO₂ injection site with one injection well and one monitoring well typically requires 3–10 acres of land, depending on site layout and infrastructure needs. The well pad itself generally occupies 2–5 acres. Additional space may be needed for a separate monitoring well if it is not co-located. Surface infrastructure, including compression, processing, storage, and utilities, requires an extra 1–2 acres. Access roads and regulatory buffer zones further expand the total footprint. Co-locating both wells minimizes land use, while separate placement could increase the overall area needed. Additional land may also be necessary for seismic monitoring and pipeline connections, especially at sites intended for long-term storage.

5.4.2.5 Workforce

CCS projects will likely leverage the existing NG pipeline and generator workforce. Workforce training will need to focus on engineering, construction, logistics, and safety compliance. Pipelines will require welders, engineers, and safety inspectors. Rail transport will require logistics managers and hazardous

materials specialists trained in CO₂ handling. Trucking will depend on hazardous materials (HAZMAT)-certified drivers and maintenance technicians. Maritime transport will require marine engineers and port operators.

5.5 Cost

5.5.1 Capture

5.5.1.1 Capital Costs

The estimated costs of combined-cycle NG power plants in New York State, considering current market conditions, have been estimated for the *2025 Draft State Energy Plan* (SEP) analysis and are leveraged for this study. Organizations such as the National Energy Technology Laboratory (NETL) have conducted cost and performance studies of NGCC plants with carbon capture across various configurations and assumptions. NETL's report, *Cost and Performance of Retrofitting NGCC Units for Carbon Capture—Revision 3*, provides a detailed analysis (2023). The data from this report are leveraged here via the NREL ATB workbook (NREL 2024a). To estimate current costs for new NGCC plants with CCS in New York State, this study multiplies the SEP NGCC cost by the ratio of the ATB new-build NGCC with CCS case to the ATB unabated NGCC case. To estimate current costs for retrofit CCS on NGCC plants in New York, that cost estimate for new NGCC plants with CCS in New York was multiplied by a ratio of the ATB NGCC CCS retrofit case to the ATB new-build NGCC with CCS case.

For consistency with other technologies, this study uses standard ranges inspired by AACE cost estimate classes, based on technology maturity rather than project definition. CCS technology is assumed to have moderately high uncertainty, with bands of +35% to -23% for the capture component of the project. NGCC plants are assumed to have low uncertainty, with bands of +9% to -7%. New NGCC plants with CCS are given uncertainty bands of +19% to -13% based on a weighted average of the capital costs of the NGCC and CCS components.

Figure 48 shows capital cost projections for power generation and/or capture, assuming a 95% capture rate. Sections 5.5.2. and 5.5.3 discuss transport and storage costs.

Figure 48. Estimated Overnight Capital Cost of Natural Gas Combined Cycle with Carbon Capture and Storage Technology with a 95% Capture Rate in Upstate New York

Prices reported in 2023 USD.

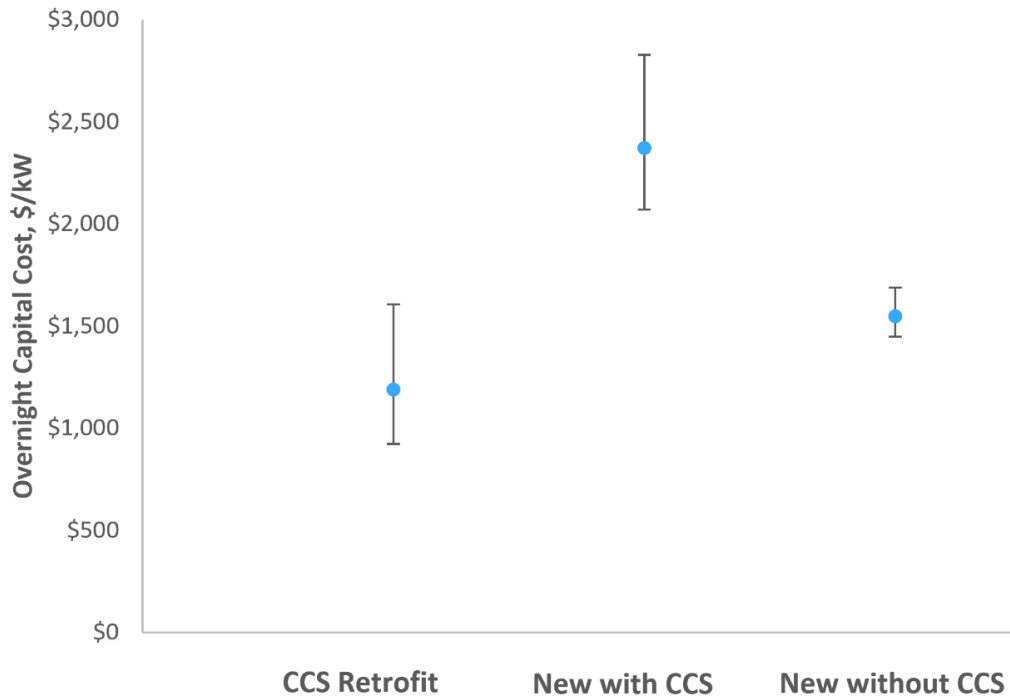
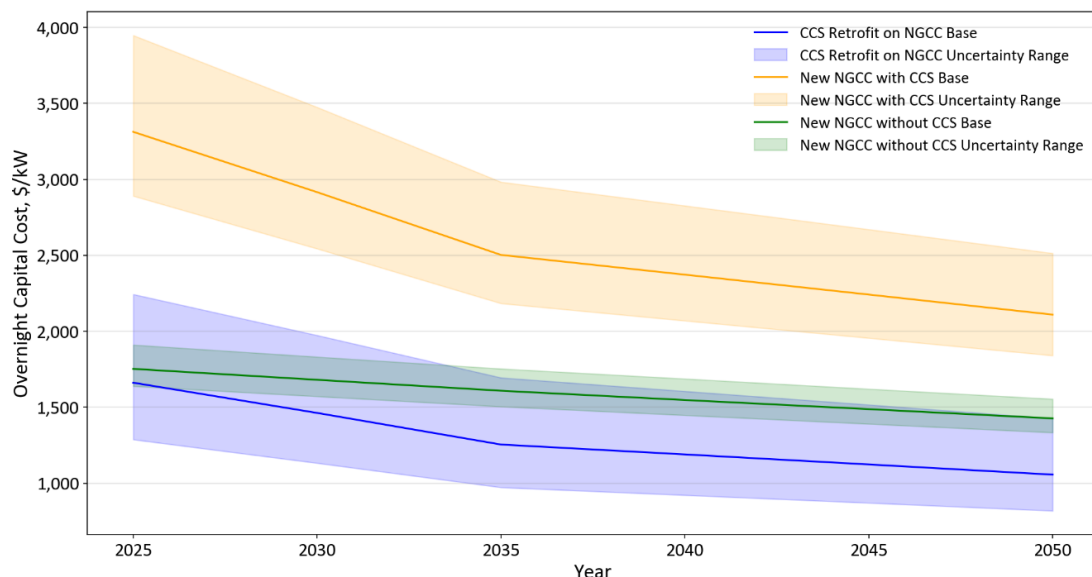


Figure 48 depicts the cost projections for CCS retrofits and new build NGCC with CCS plants in Upstate New York, based on data from the NREL ATB and the 2025 *Draft SEP*.

Figure 49. Potential Capital Cost Trajectories for Natural Gas Combined Cycle with Carbon Capture and Storage New Build and Retrofit Projects with a Capture Rate of 95% in Upstate New York

Prices reported in 2023 USD.



Costs generally increase as the capture rate increases. Du et al (2021) found that increasing the capture rate from 90% to 99% at an NG plant with CCS increased the capital cost of CO₂ capture equipment by 23% and the LCOE increased by 8.5%.

5.5.1.2 Ongoing Costs

Operating and Maintenance Costs

Table 35 presents O&M costs for Upstate New York based on adjusted data from the NREL ATB.

Table 35. Estimated Operating and Maintenance Costs of Natural Gas Combined Cycle Power Plants with Carbon Capture and Storage with a 95% Capture Rate in Upstate New York, 2040

Prices reported in 2023 USD.

Cost Category	Unit	Scenario	NGCC with CCS
Fixed O&M	\$/kW-year	Optimistic	\$44
Fixed O&M	\$/kW-year	Base	\$52
Fixed O&M	\$/kW-year	Conservative	\$61
Variable O&M	\$/MWh	Optimistic	\$3.49
Variable O&M	\$/MWh	Base	\$3.98
Variable O&M	\$/MWh	Conservative	\$4.47

Fuel Costs

This analysis assumes a fuel cost of \$5/MMBtu of NG, with low and high sensitivities of \$2/MMBtu and \$7/MMBtu based on historical and projected fuel costs for baseload operation.

5.5.2 Transport

Transport distance, CO₂ volume, and capital cost assumptions, particularly for pipeline construction, strongly influence CO₂ transport costs. Several studies have evaluated onshore CO₂ pipelines costs in the U.S. Smith et al. (2021) summarized three cost ranges from Heddle et al. (2003), the NETL CO₂ Transport Cost Model (DOE 2018), and NPC (2019). A recent EPRI study (2023d) also assessed the cost of transport and storage options along the Eastern Seaboard (New York State to Florida). The study evaluated trade-offs between storing CO₂ in a geologically constrained region versus transporting it to regions with favorable geology. EPRI found onshore transport costs ranging from \$8.08 to \$11.27 per tonne of CO₂ across several onshore scenarios analyzed. Table 36 presents the assumptions that this study used, based on the EPRI results.

Table 36. Levelized Carbon Dioxide Onshore Transport Costs

Costs are expressed in 2023 USD per tonne of CO₂ transported.

Scenario	Levelized Cost of CO ₂ Transport (\$/tonne CO ₂)
Low	\$8
Medium	\$10
High	\$12

This analysis assumes a relatively high pipeline capacity factor, consistent with baseload CCS applications. It also assumes variable pipeline diameters, inclusive of smaller gathering (4–12 inches) and larger transmission lines (12–36 inches), with 16 inches being the most common diameter in the network.

To explore the effect of low capacity factor resource (5%) pipeline use on levelized transport costs, an analysis using the NETL CO₂ Transport Cost Model (DOE 2018) was conducted using a 200-mile, single-diameter hypothetical pipeline as a test case. The analysis found that CO₂ transport costs increase significantly at low capacity factors, with costs increasing from \$3–\$9/tCO₂ for an 85% capacity factor to \$30–\$36/tCO₂ for a 5% capacity factor, depending on the volume of CO₂ transported.

Offshore CO₂ pipelines share similar cost components and variability with onshore pipelines, but typically cost more to construct and maintain. To estimate offshore pipeline costs and the cost reductions from pipeline networks, cost multipliers based on literature sources are applied. Research suggests that offshore pipelines may be 50%–100% more than onshore pipelines (Zapantis et al. 2019).

Pipeline networks shared by multiple sectors, which enable shared infrastructure and economies of scale, are generally considered most cost-effective.

5.5.3 Storage

Storage costs vary significantly based on site-specific geological conditions as well as regional differences in drilling, labor, capital, and operational expenses. In regions with high-quality sequestration resources, such as the Mt. Simon formation beneath several midwestern states, including Ohio, Indiana, Michigan, Illinois, and Iowa (Leetaru et al. 2009), the FECM/NETL CO₂ Saline Storage Cost Model estimates the cost of storage for a site with a nominal average injection rate of 17.25 million tonnes per year to be approximately \$7.4/tonne CO₂ (NETL 2024). Conversely, the EPRI Eastern Seaboard study estimates that costs in the Appalachian Basin range from \$25 to \$40+/tonne CO₂ (EPRI 2023d). Table 37 shows the assumptions this study applies based on these EPRI results.

Table 37. Levelized Carbon Dioxide Storage Costs Assumptions

Costs reported in 2023 USD.

Scenario	Levelized Cost of CO ₂ Storage (\$/tonne CO ₂)
Low	\$25
Medium	\$32.5
High	\$40

A significant portion of the costs associated with saline aquifer storage comes from drilling various wells—such as exploration, injection, and monitoring wells—whose number depends on project scale and key geological factors. Additionally, many CO₂ storage cost estimates in saline aquifers fail to fully account for the expenses of extracting, treating, and disposing of formation fluids, which can pose a critical issue in closed onshore saline formations (Jahediesfanjani et al. 2019). These closed formations require active pressure management, creating a tradeoff between maximizing storage capacity and managing costs.

Similar to offshore pipelines, offshore CO₂ storage typically incurs higher costs than onshore storage.

5.5.4 Funding and Subsidies Available to Carbon Capture and Storage Projects

The Carbon Capture 45Q tax Credit provides financial incentives for carbon capture, utilization, and storage at power plants or industrial sources. Established under the Internal Revenue Code and enhanced by the Inflation Reduction Act, the tax credit originally offered \$85 per metric ton for geological storage of qualified carbon oxide and \$60 per metric ton for utilization. Under H.R. 1, the provision equalizes the credit amount for CCS, whether the carbon is permanently stored or used in products or for EOR. H.R. 1 also adds FEOC requirements to the eligibility for the Carbon Capture Credit.

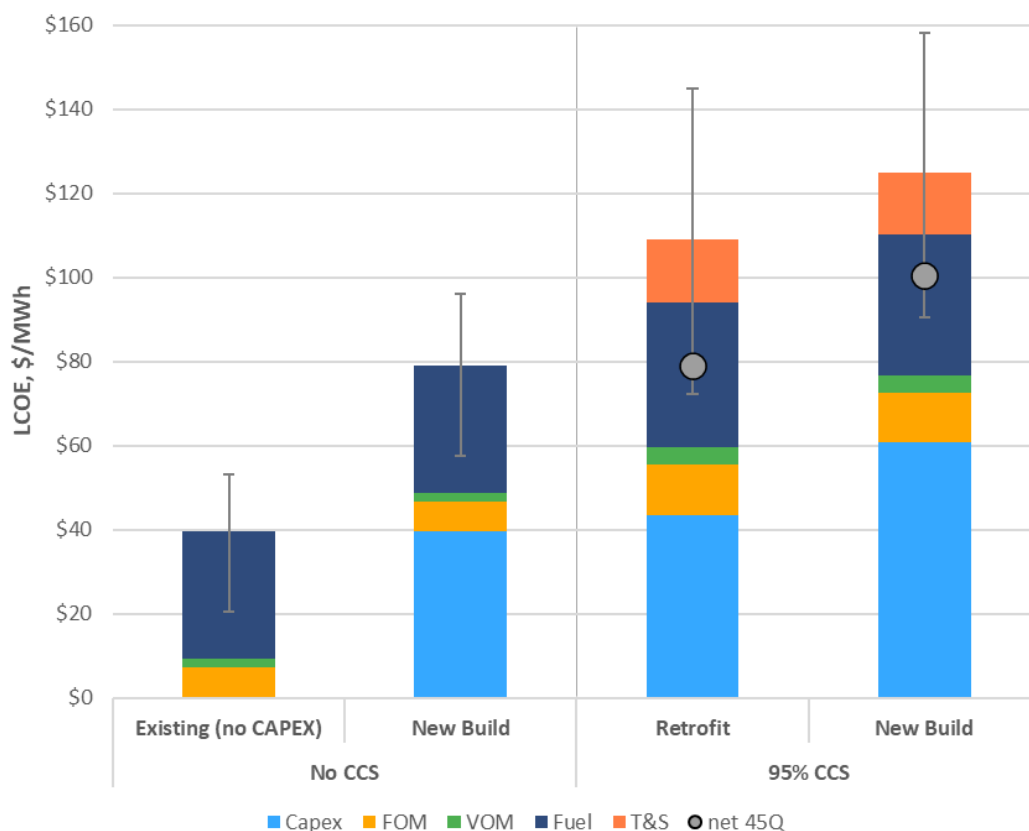
The credit remains available for 12 years after the capture equipment becomes operational. Projects must comply with PWA standards during construction to qualify for the full credit. Construction must begin on the project before 2033 to be eligible for full credit.

5.5.5 Levelized Cost of Electricity

Figure 50 shows the calculated LCOE for an NGCC plant with CCS, compared to counterfactual cases without capture. Figure 50 also illustrates the impact of the Carbon Capture Credit levelized over the project's lifetime. To qualify for the full credit, construction must start before 2033. The LCOE assumes an NG price of \$5/MMBtu, a 50% capacity factor, and the base CO₂ transport and storage cost assumptions described earlier. Error bars reflect high and low scenarios for capital costs, fixed and variable O&M, fuel costs, and CO₂ transport and storage costs (where applicable). A 12-year life is assumed for retrofits, reflecting the shorter lifespan of existing equipment. Appendix A provides additional details on the assumptions used in the study's LCOE calculation.

Figure 50. Calculated Levelized Cost of Electricity of Natural Gas Combined Cycle Technology

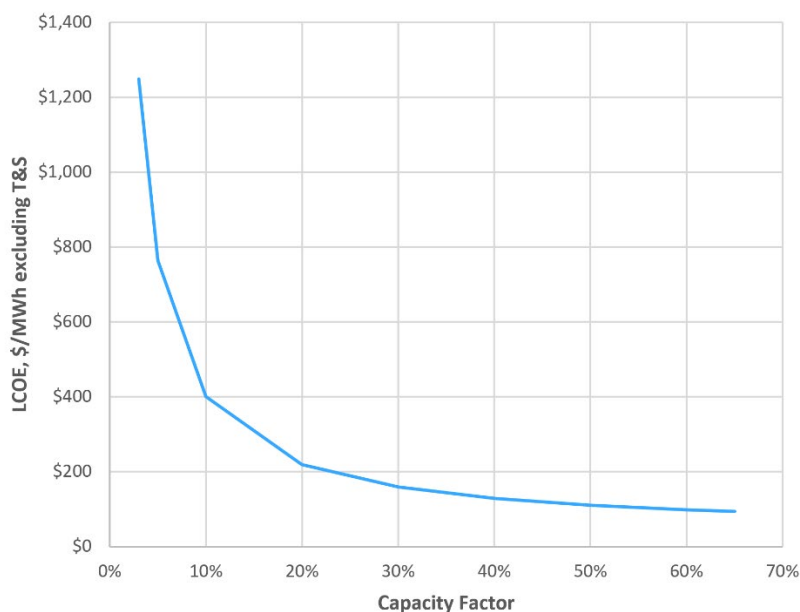
Full tax credit eligibility requires construction to start before the credit phaseout date. Prices reported in 2023 USD, with and without CCS.



In addition to the technical barriers discussed earlier regarding the intermittent supply of CO₂ for pipeline injection, underground sequestration, or industrial utilization at low capacity factor (nonbaseload), operating an NG plant with carbon capture at reduced capacity can create economic challenges. As the capacity factor decreases, the LCOE increases asymptotically, as Figure 51 demonstrates.

Figure 51. Levelized Cost of Electricity for a New Natural Gas Combined Cycle Plant with Carbon Capture and Storage

LCOE by annual capacity factor, expressed in 2023 USD.



5.6 Scalability for 2040

This section outlines potential 2040 scenarios for CCS deployment and key conditions required to meet these scenarios. These scenarios are not prescriptive or guidance; they represent viable possibilities based on technology readiness, infrastructure availability, project delivery lead times, and potential deployment strategies.

As Section 5.4.1 discusses, the Climate Act targets a statewide 85% reduction in economywide GHG emissions by 2050, relative to 1990 levels (CAC 2022). This goal results in a statewide emissions cap of 62 MMT CO₂e/year by 2050. Residual emissions in 2050 are assumed to primarily come from the hardest-to-decarbonize end uses, such as waste, agriculture, and aviation. CCS-related emissions from the power sector would require offsetting reductions in the hardest-to-decarbonize end uses to remain within the economywide emissions cap, which may not be feasible at a larger scale.

A retrofit capture project typically requires a total lead time of 5–8 years from design initiation to operational status. Greenfield capture projects typically require more time, 7–10 years. During the lead time for a capture project, project developers must complete the process design, secure regulatory

approvals, and commission the plant. Regulatory barriers or funding constraints can delay any of these steps. Transport and storage infrastructure projects typically require 10–15 years due to permitting hurdles and limited existing network infrastructure.

Given the expectation that CCS will primarily serve as a baseload-only application, expected emissions reduction performance by 2040, and anticipated lead times, this report outlines three deployment scenarios: conservative, moderate, and aggressive.

5.6.1 Conservative Scenario

In the Conservative Deployment scenario, CCS technologies are deployed at a highly limited number of sites (if any at all). Projects are restricted to specialized use cases, such as sites with biogas production facilities, and are sufficiently small to minimize infrastructure buildout.

5.6.2 Moderate Scenario

In a Moderate Deployment scenario, CCS technologies are deployed at a minimal number of NGCC power plants (if any at all). These projects would be co-located with or in proximity to identified storage sites or near a major CO₂ offtaker, minimizing pipeline buildout. To be on track to contribute to economywide emissions reductions by 2040, planning and regulatory engagement should begin by 2032 for capture technologies (near the maximum expected lead time) and by 2028 for transport and storage technologies (2 years before the minimum expected lead time). To comply with economywide emissions goals in New York State, emissions from other sectors outside the electricity sector need to be reduced further by 2050, and upstream gas emissions must also be significantly reduced. A Moderate Deployment scenario would likely lead to renewed interest and further characterization of all onshore storage options, including the Appalachian Basin and Newark Basin, to enhance understanding of storage capacity and geologic heterogeneity. Additional CCS demonstration and pilot projects could provide critical insights and sectorwide learnings.

5.6.3 Aggressive Deployment Scenario

In an Aggressive Deployment scenario, breakthroughs in operational flexibility could enable the incorporation of CCS into peaking power applications. In this scenario, NGCC with CCS would only be used during times of the most extreme demand. A pipeline network or barging infrastructure would be needed, but could benefit from shared use by other sectors looking to decarbonize with CCS.

Alternatively, significant improvements in the market for utilization could render a complex infrastructure buildout unnecessary.

This scenario requires more units with installed CCS than the Moderate Deployment scenario, but with significantly lower capacity factors, introducing higher levelized costs. However, their infrequent use would produce lower emissions than a baseload configuration, reducing strain on the economywide 2050 limit.

5.6.4 Beyond 2040

Estimates of NG availability and geologic sequestration potential indicate no technical barriers to operating baseload power generation assets with CCS in New York State beyond 2040. However, residual emissions from these plants could make economywide targets more difficult. If carbon capture technologies more suitable for smaller and more intermittent sources of CO₂ emissions become commercially available, these technologies could be applied to sectors beyond peaking power generation to decarbonize other sectors. If CO₂ transport and sequestration infrastructure were built for power generation, these could be utilized for carbon-negative sources of CO₂, such as biofuel production and direct air capture, beyond 2040.

5.6.5 Scalability Summary

CCS paired with NG-fired combustion alone will not be able to meet the energy and reliability needs of a 2040 grid due to the emissions implications and lack of ramping compatibility. The three scenarios described earlier would have varying degrees of impact on a 2040 grid.

The Conservative Deployment and Moderate Deployment scenarios could be achieved with State action to support pilot and demonstration products in niche use cases. However, this degree of deployment would not meaningfully close the 0x40 energy and reliability gap. These initial pilot applications could facilitate the development of shared storage infrastructure and utilization use cases that can be beneficial to other sectors of the economy.

The Aggressive Deployment scenario would require breakthroughs in technology cost and performance, as well as a demand for shared infrastructure in other sectors, which makes this scenario challenging to implement before 2040.

5.7 Conclusion

Based on the previous assessment, the following key observations are offered to inform future consideration of CCS deployment on NG power plants in New York State.

CCS is a mature technology in other industries that could leverage existing NG power plant sites.

The most mature capture technology is amine-based capture, which is already in commercial deployment on coal plants but is less mature on NG-fired plants. Other technologies, such as oxycombustion with CCS, membranes, advanced solvents, and cryogenic capture, are less mature but may offer advantages in the future.

CCS on NG-fired power plants is technically capable of operating flexibly but is best suited as a baseload resource. CCS can ramp quickly, but this results in either lower capture rates or a decrease in the plant's power output. Additionally, the high capital-to-operating ratio of CCS makes a high capacity factor the most economical use case.

Existing NG plants can be retrofitted to perform amine-based carbon capture. Retrofitting existing plants is estimated to be approximately 45%–50% cheaper and has a lead time that is approximately 25% shorter than building a new plant, but it can be expected to roughly double the existing plant's footprint, which could limit applicability, especially in urban settings.

NG-fired power generation paired with CSS would require significant buildout of carbon transport and storage infrastructure. Pipelines are the most practical and economic transport option for the amount of captured carbon dioxide (CO₂) that an NG power plant would generate. New York State does not have any CO₂ pipelines, and building a new CO₂ pipeline system faces challenges in regulation, permitting, and public acceptance. Building out a CO₂ pipeline could benefit other hard-to-decarbonize end uses, such as industrial applications. Siting plants near potential storage locations could help mitigate the permitting and construction complexities associated with new pipeline projects.

New York State has limited opportunities for carbon storage. The Appalachian Basin has approximately 4.4 gigatons of carbon dioxide (Gt-CO₂) of theoretical capacity in New York State, which is sufficient to store the current power sector's emissions for 200 years. Other storage options include the Newark Basin, which is primarily located outside of New York, and offshore saline storage,

which has a lower readiness level and would require substantial infrastructure investment. New York State would likely need to collaborate with neighboring states or rely on regional and federal initiatives to ensure adequate storage capacity. CO₂ utilization for biofuel production, metal fabrication, and other applications is promising but not yet at a scale that can accommodate power sector quantities of CO₂.

Even with capture rates exceeding 99%, CCS on NG-fired plants would not significantly reduce upstream emissions under NYS GHG accounting. Current CCS projects aim for 90%–95% capture rates, but these rates have not yet been demonstrated for long-term operation. Higher capture rates are possible, but they come with increased cost. The upstream emissions associated with fuel production and transportation account for nearly half of the GHG emissions of an NG-fired plant without capture under the NYS emissions accounting methodology, and the incorporation of CCS on combustion plants does not mitigate these upstream emissions.

6 Next-Generation Geothermal

6.1 Overview and Subcategorization of Geothermal Technologies

Geothermal energy originates from the earth's interior, primarily generated by the radioactive decay of long-lasting isotopes. This substantial reservoir of geothermal energy beneath the earth's surface can be harnessed through various methods for several key applications, including power generation.

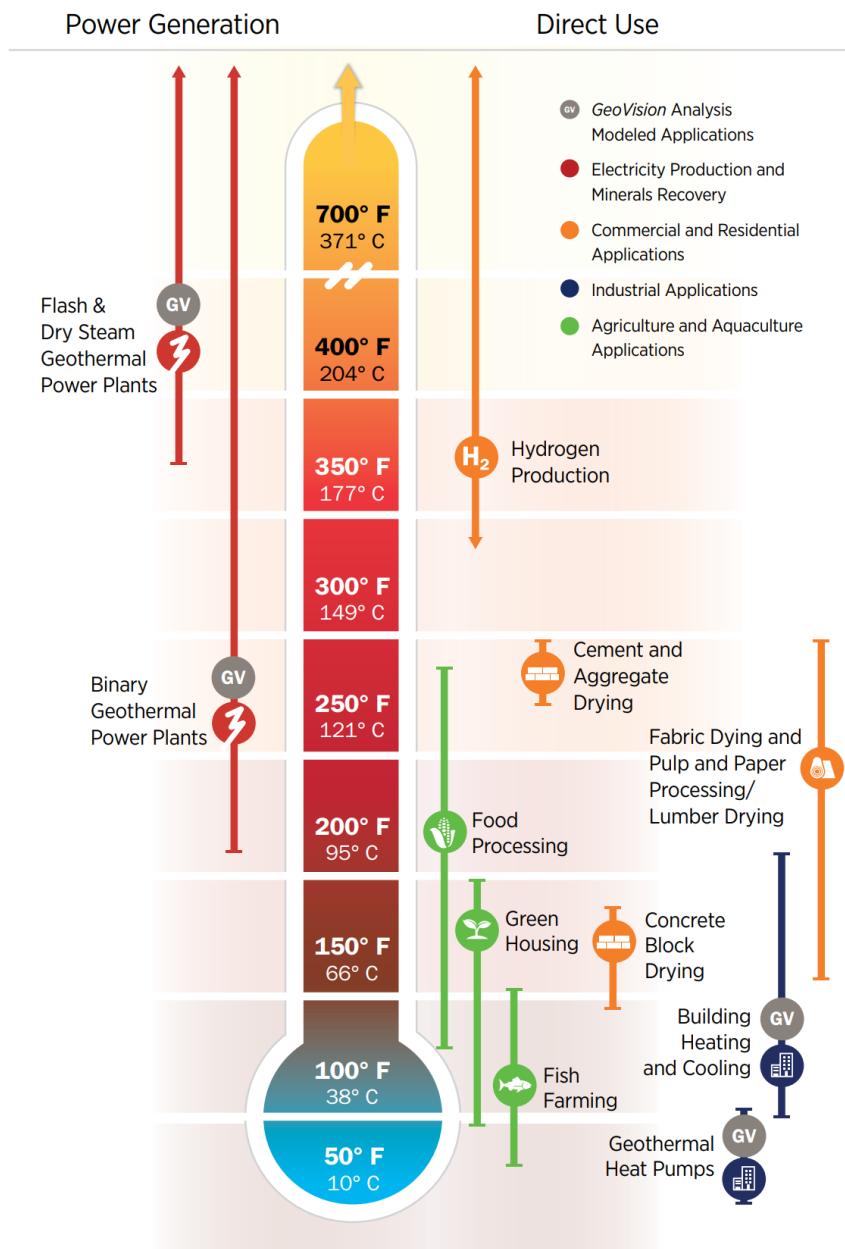
Temperature typically increases with depth at an average rate of 25°C–30°C per kilometer, or 15 degrees Fahrenheit (°F) per 1,000 feet, known as the geothermal gradient (EPRI 2012, Quick 2010). However, geothermal heat flows and temperature gradients vary significantly. They are closely associated with tectonically active areas, which can result in locally elevated temperatures within the crust closer to the surface. Having higher temperatures closer to the surface increases the economic viability of all geothermal technologies because it reduces drilling costs to reach the necessary temperature for power generation.

Based on existing data, the required drilling depths to reach geothermal temperatures suitable for geothermal power generation in New York State are expected to be about 8 km, which presents significant technical and financial challenges. Active advanced geothermal projects are currently operating 2–5 km deep.

This energy is primarily extracted by drilling into the ground and transporting it to the surface using fluids. At the surface, the energy is either converted to electricity or used directly as heat. Temperatures above 150°C are generally required for electricity generation, although temperatures as low as 120°C can be used. Lower temperatures are used in various direct heat applications. Low-temperature heat from depths of less than 100 meters can be used for heating and cooling applications through ground source heat pumps, also known as geothermal heat pumps, which are not the focus of this report. Figure 52 illustrates the range of temperature and geothermal technology applications.

Figure 52. Continuum of Geothermal Energy Technology Applications and Uses

Source: DOE (2019).



Until recently, geothermal energy was considered a niche technology, relying on three fundamental elements—heat, fluid, and permeability—to generate electricity from hydrothermal or conventional geothermal systems (see Figure 53). These systems, consisting of reservoir rocks with in situ fluids and natural permeability, are typically located near tectonically active areas with high temperature gradients, making them geographically limited. However, in recent years, next-generation geothermal technology

has gained momentum. This new approach focuses on harnessing subsurface heat in locations lacking fluids and/or natural permeability. Enhanced geothermal systems (EGS) achieve this by injecting fluid to engineer a geothermal reservoir, while closed-loop geothermal systems (CLGS) extract heat without direct contact with the reservoir/rock (Figure 53).

6.1.1 Geothermal Energy Technologies

Conventional geothermal or Hydrothermal power generation uses well-established geothermal resources and power conversion technology, backed by decades of practical experience. Hydrothermal power plants have been a commercial reality in Italy, Japan, the U.S., Iceland, New Zealand, and Mexico for many decades. The use of geothermal steam for electricity production began in the early 20th century, with the first experimental installation built in Larderello, Italy, in 1904. Hydrothermal systems (Figure 53, left) are natural reservoirs of steam or hot water formed where magma nears the surface, heating groundwater trapped in fractured or porous rocks, or where water circulates deeply along faults. The high temperatures of the rocks heat the fluids, which can then emerge as hot water or steam if the temperature is sufficiently high. This fluid or steam carries heat that can be used on the surface for heating or, when the temperature exceeds 120°C–150°C, power generation. These systems are typically found near tectonic plate boundaries and are often associated with volcanoes and seismic activity, which fracture the crust and increase permeability for subsurface fluids (geofluids). New York State is not located in such geologic environments and therefore does not have hydrothermal resources.

More recent technologies, known as next-generation geothermal, have the potential to engineer effective geothermal resources where permeability and/or fluid might be absent, considerably expanding resource availability and potential commercial adoption. Although it is still an emerging industry, next-generation geothermal presents several starting advantages, including transferable technology, supply chains, and workforces from the oil and gas sector that are expected to help achieve rapid scale-up.

EGS generates electricity from hot dry rock, a resource that is virtually unlimited around the world. However, EGS is currently viable only at shallower depths (up to 5 km or 3 miles), due to limitations in drilling technology and economic constraints. While current drilling technology can reach depths of ~8 km (the expected depth needed in New York State), improvements in reservoir engineering technologies will be needed to enable viable development at such depths.

Extracting heat from these formations involves artificially fracturing the formation and establishing a fluid circulation system to facilitate the extraction of heat. EGS technologies span a spectrum of approaches to enhance fluid connectivity. Hot dry rock lies on one extreme of the EGS spectrum where there is an absence of natural geothermal potential without artificial pumping of fluids at depth. On the other end, EGS can involve relatively minor enhancements to conventional geothermal systems, for example, by flushing extra fluid through a hydrothermal system along with naturally available groundwater. EGS may be feasible anywhere in the world, depending on the economic limits of drill depth. The process of stimulating wells for EGS is similar to hydrofracturing, which is often referred to as “fracking” in the context of oil and gas extraction. EGS could someday be viable in New York State, but it will require both technological advancements and significant cost reductions in order to achieve commercial deployment.

CLGS refers to a new generation of systems in which no fluids are introduced to or extracted from the earth. Instead, a series of pipes is constructed in the ground and filled with a heat transfer fluid such as water or a mixture of water and antifreeze. The fluid, which is never in direct contact with the rock, absorbs heat from the earth and carries it to a heat exchanger, where the heat is used to generate steam to power a turbine and generate electricity. In New York State, the economic proposition of CLGS, as with EGS, depends on either finding appropriately high temperatures at the shallower depths or achieving significant technological advancements and cost reductions to enable economic power generation at NYS-relevant depths.

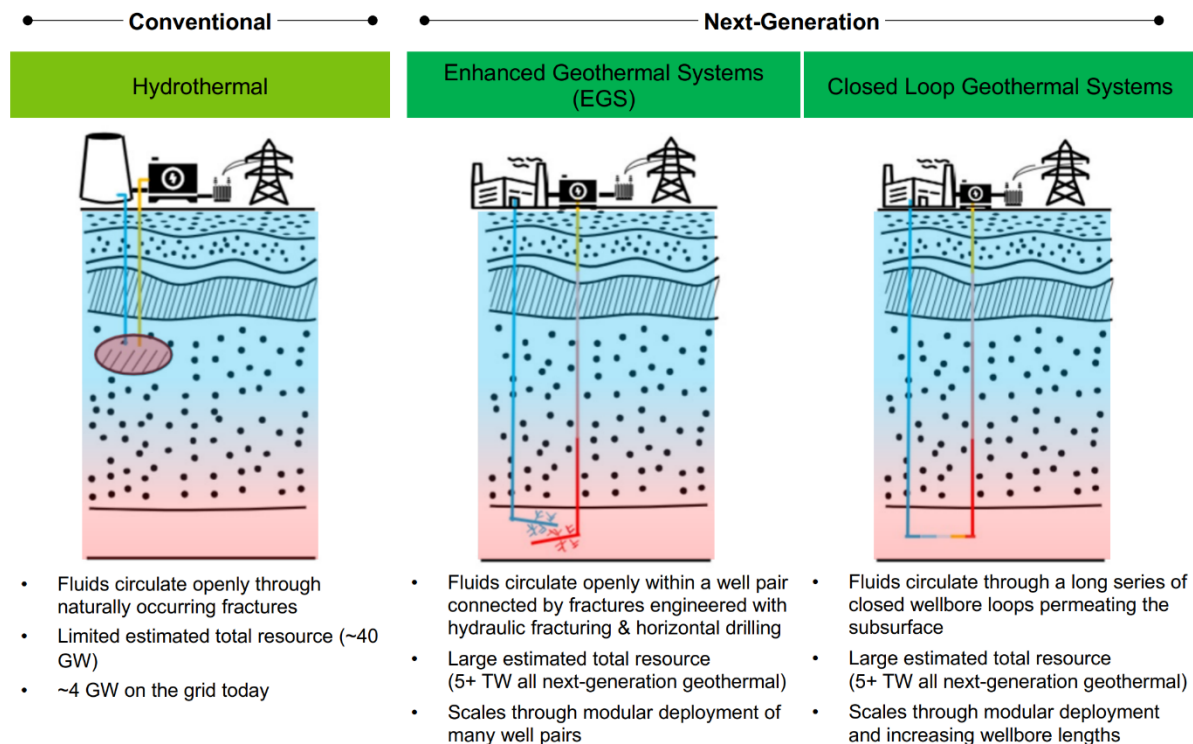
Superhot rock geothermal (SHR) targets deeper formations with temperatures exceeding 450°C, potentially increasing power output per well five- to tenfold. SHR geothermal leverages existing and advanced technologies from the oil and gas, as well as electric power industries, offering high energy density. CLGS developments are also targeting SHR resources.

Developing SHR reservoirs presents significant technical challenges, including drilling to great depths (~7–10 km in the central/eastern U.S. and >15 km in the eastern U.S.), managing high temperatures and pressures, and ensuring well integrity. Resistant casing materials and reliable downhole power supply and monitoring technologies are essential. Induced seismicity during reservoir development and operation is a higher risk for SHR than EGS or CLGS at shallower depths. Proof-of-concept demonstrations are crucial for advancing SHR geothermal, progressing from sites with relatively shallow hot dry rock formations to locations that require next-generation drilling methods.

Despite its low readiness and challenges, SHR geothermal has the potential to be disruptive as a vast and ubiquitous resource. Continued investment and innovation could enable commercial deployment within 10–15 years, providing clean, reliable, and cost-effective energy with zero carbon emissions (EPRI 2023I).

Figure 53. Geothermal Technology Overview across Conventional and Next-Generation Designs

Source: DOE (2024d).



6.1.2 Geothermal Electricity Generation

Once the hot fluid reaches the surface, its thermal energy must be converted to electricity to be useful for power generation. Three main types of technologies are used to convert geothermal energy into electricity (Figure 54): dry/direct steam, flash steam, and binary cycle. Flash steam plants are the most common worldwide, but the choice of power conversion technology to use in a geothermal power plant depends on the characteristics of the geothermal resource. Power output and plant economics are strongly correlated with resource temperature; for example, as geofluid temperature increases, power output increases and cost per unit of capacity decreases, although not linearly (NREL 2024b).

Dry steam power plants inject geothermal steam, which is above the saturation point of water, directly into the turbine to generate electricity without separating liquid water from steam. Flash steam plants are available in two forms—one stage and two stage—but generally involve pumping hot geofluids extracted from a geothermal reservoir under high pressure to a low-pressure aboveground tank, causing some of the geofluid to rapidly transform (“flash”) into steam vapor, which is used to drive a steam turbine generator. Binary-cycle power plants use a heat exchanger to transfer heat from the geothermal fluid to a secondary fluid, which vaporizes and flows through the turbine to generate electricity, typically using a closed-loop Rankine cycle. Binary plants can operate with lower-temperature fluids (around 95°C) compared to flash and dry steam plants (above 180°C), but they generally have lower conversion efficiencies and higher investment costs. (IRENA 2023, IEA 2023b)

The type of geothermal power plant used depends on the enthalpy (heat content) of the geothermal resource (Table 38). Dry steam power plants are used for high enthalpy resources, whereas flash steam and binary power plants are used for medium and low enthalpy resources, respectively. EGSs are typically compatible with flash or binary power plants due to their ability to handle a range of temperatures and pressures. CLGs are better suited for binary power plants, which efficiently use lower-temperature resources. New York State is likely to have low-enthalpy geothermal resources, making binary power plants the most viable option for power generation. However, selection of the power plant technology will be site- and project-specific.

Figure 54. Geothermal Power Plant Technologies

Source: IRENA (2023).

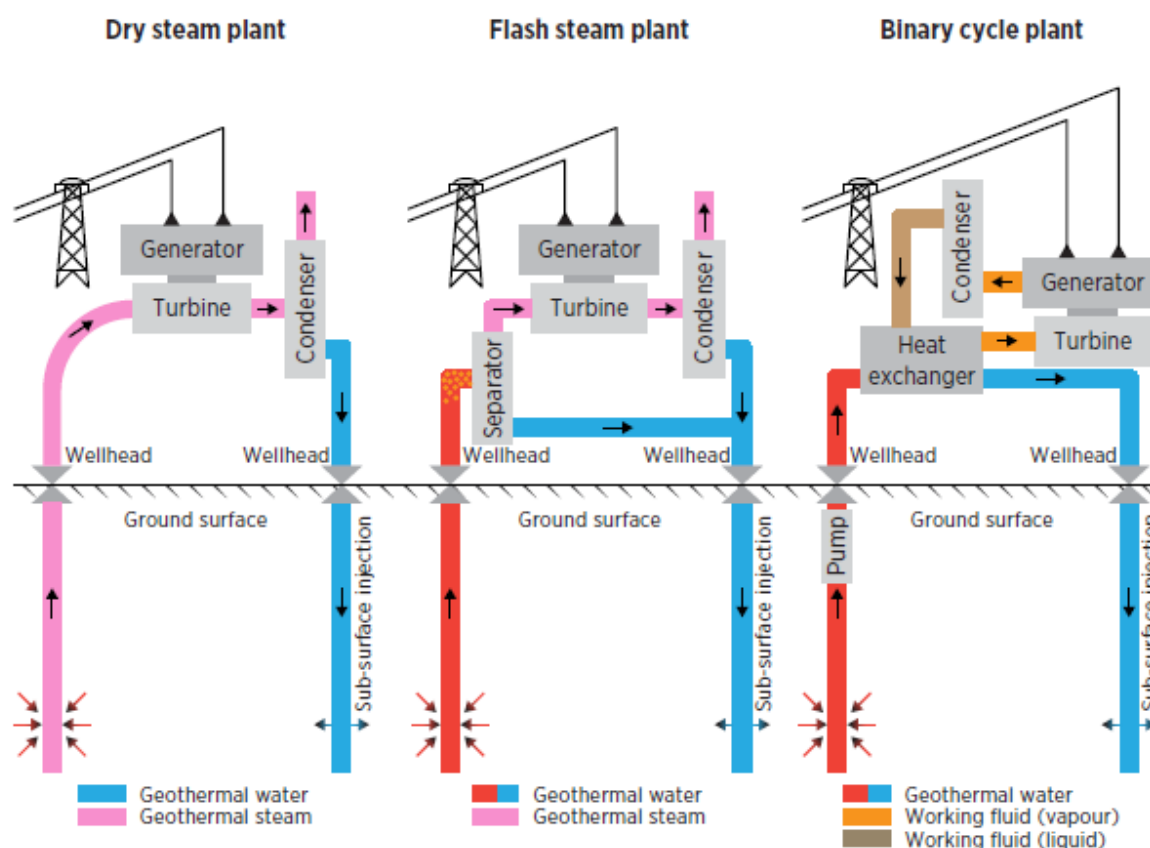


Table 38. Geothermal Power Plant Technologies Related to the Resource Temperature

See also Figure 54.

Technology	Resource Temperature	Typical Use Case	Efficiency	Notes
Dry Steam	>235°C	High-temp fields	High	Rare (e.g., The Geysers, CA)
Flash Steam	180°C–235°C	Volcanic or tectonic regions, moderate-temperature fields	Moderate to High	Most common globally
Binary Cycle	95°C–180°C	Low- to moderate-temperature fields	Moderate	More applicable for NYS temperature gradients

Ground Source Heat Pumps for Heating and Cooling

Ground source heat pumps (GSHPs), also known as geothermal heat pumps, are highly efficient systems for heating and cooling buildings. They use the relatively constant temperatures found 10s to 100 meters deep to transfer heat to or from the ground. This technology can operate in any climate, providing year-round comfort by leveraging the earth's natural thermal properties. GSHPs consist of a network of pipes buried either horizontally or vertically, through which a fluid circulates to absorb or release heat. This fluid then transfers the heat to a heat pump inside the building, which warms or cools the indoor air.

One of the significant advantages of GSHPs is their energy efficiency. They can reduce energy consumption by up to 65% compared to traditional heating, ventilation, and air conditioning HVAC systems. The initial setup costs for GSHPs can be higher due to the need for extensive ground loops or boreholes, however the long-term savings on energy bills and the system's durability make them a worthwhile investment.

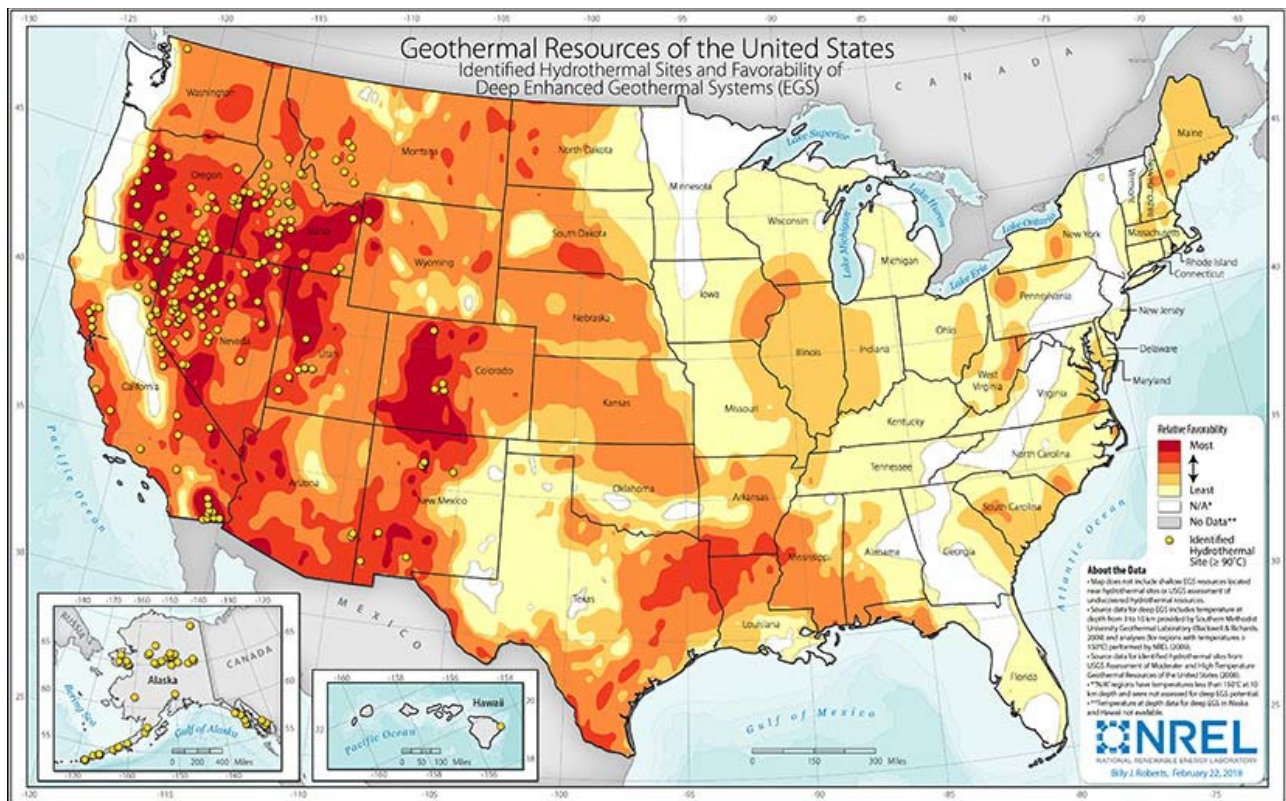
While GSHPs do not directly contribute to power generation, they do have a significant impact on overall load reduction. By efficiently managing heating and cooling demands, they reduce the peak load on the electrical grid. This is particularly beneficial during extreme weather conditions when traditional HVAC systems would otherwise place a high demand on the grid. The consistent and efficient operation of GSHPs helps stabilize energy consumption, resulting in lower overall energy usage and reduced strain on power infrastructure. Additionally, GSHPs contribute to reducing greenhouse gas (GHG) emissions by lowering reliance on fossil fuels for heating and cooling (DOE 2017, 2025c).

6.1.3 New York State Resource Availability

As Figure 55 illustrates, most geothermal resources in the U.S. lie in the western states. In New York State, estimates suggest the most promising availability may be in Western New York. However, localized potential is largely unknown due to a lack of test drilling to date.

Even in regions with higher estimated potential, achieving the necessary temperatures for power generation may require deeper drilling than most existing geothermal projects. Limited data suggest depths of up to 8 km may be necessary, compared to the 2–5 km depths of current projects.

Figure 55. Map of Relative Geothermal Resource Potential in the U.S.



6.2 Performance Attributes

Performance attributes vary among the three generations of technologies: dry steam, single and double flash, and binary. While binary is the most likely power generation technology to be paired with a next-generation geothermal deployment in New York State, flash or dry steam could be paired with a future SHR deployment.

Table 39. Comparison of Geothermal Technologies by Grid Services and Attributes

Italicized entries indicate a lack of real-world U.S. demonstration.

Attribute	Flash	Dry	Binary
Inertial Response (Rotational)	Typically provides attribute large synchronous generators, similar to fossil fuel, nuclear, and hydroelectric plants, provide strong inertia	Typically provides attribute large synchronous generators, similar to fossil fuel, nuclear, and hydroelectric plants, provide strong inertia	Typically provides attribute large synchronous generators, similar to fossil fuel, nuclear, and hydroelectric plants, provide strong inertia
Primary Frequency Response	Typically provides attribute uses synchronous generators, providing a strong primary frequency response	Typically provides attribute uses synchronous generators, providing a strong primary frequency response	May sometimes provide attribute uses synchronous generators, but primary frequency response might be slightly less robust due to heat exchange steps and lower working fluid temperature, affecting power adjustment speed and efficiency
Voltage & Reactive Power	Typically provides attribute synchronous generators adjust reactive power output to manage voltage fluctuations, and they can both generate and absorb reactive power, which is essential for maintaining voltage stability and supporting the grid during disturbances	May sometimes provide attribute typically stable voltage levels, but may require additional equipment to manage reactive power due to the direct steam use	May sometimes provide attribute binary cycle plants often require more complex systems for voltage and reactive power management
Ramping	Typically provides attribute can ramp flexibly by venting steam or bypassing the turbine	May sometimes provide attribute relatively stable ramping due to the direct steam use	May sometimes provide attribute moderate ramping capabilities due to the heat exchange process
Cycling Capability	Typically provides attribute more flexible than dry steam plants with the ability to adjust output by venting steam or bypassing the turbine (site-specific feasibility)	Does not provide attribute limited due to the design using direct steam from the reservoir	May sometimes provide attribute moderate cycling capability due to the heat exchange process involved
Short Minimum Run Time	Typically provides attribute ~20–30 min	Typically provides attribute ~30 min	Typically provides attribute ~30–45 min
Black Start	Typically provides attribute can often start independently, but may need some external power initially	May sometimes provide attribute <i>typically requires external power to initiate steam extraction</i>	Does not provide attribute usually requires external power to start the heat exchange system
Capacity Factor	High ~90%	High ~90%	High ~90%
Minimum Stable Output	May sometimes provide attribute ~20%–30% of nominal capacity	May sometimes provide attribute ~25%–35% of nominal capacity	May sometimes provide attribute ~30%–40% of nominal capacity

The following summarizes key takeaways from Table 39:

- All geothermal power generation options provide inertia.
- Geothermal power plants using flash technology can provide most of the attributes and grid services offered by flexible legacy resources. Conversely, binary cycle geothermal plants, the type of plant most applicable to the heat resources in New York State, may only provide key attributes such as primary frequency response, voltage and reactive power, ramping, and cycling in limited circumstances and with added complexity.

The following offers additional details on key geothermal attributes:

6.2.1 Capacity Factor

Geothermal operates largely as a baseload resource rather than a load-following resource due to high capital costs and low marginal operating expenses because it does not require fuel. This economic model favors continuous operation at a high capacity factor to ensure the recovery of the substantial initial investment. Operating geothermal plants as baseload resources maximizes their efficiency and reliability.

While geothermal plants can technically adjust their output to follow load demands, the required infrastructure and technology are less developed and less cost-effective than those used in other load-following resources like combustion or hydroelectric power. However, driven by the increasing need for flexible generation, stakeholders are exploring options to utilize geothermal more flexibly, for example, by storing excess energy underground when electricity is abundant and inexpensive, then releasing it when demand and prices rise. This approach allows geothermal plants to shift output to match daily and seasonal demand changes, effectively functioning as both a power source and an LDES system.

6.2.2 Useful Life

The useful life of a geothermal power plant varies. An assumed useful life of 30 years is commonly used for analyses, but many plants have exceeded that span. The Geysers geothermal power plant in California, with units installed in 1975 and 1976, continues to operate, having undergone some retrofits for blades and lower-pressure operations. Bjarnarflag, near Krafla in Iceland, has generated power since its commissioning in 1966.

6.2.3 Ramp Rates

Geothermal power plants have estimated ramp rates of 20% per minute for flash and dry steam turbines and 15% per minute for binary systems. These estimates exclude the need to heat the gathering lines to prevent water hammer or inadvertent flashing of residual water.

6.3 Readiness for 2040

6.3.1 Latest Deployment Trends

The global geothermal landscape is evolving rapidly, with diverse technologies under development, most of which are centered in the U.S. The following sections describe recent project developments by technology and design.

Most current geothermal developments (hydrothermal and EGS) are in the western U.S., where high-temperature geothermal resources are closer to the surface than in New York State. Planned next-generation geothermal activity is also concentrated in the western U.S. This section does not cover deployment trends in conventional hydrothermal geothermal because hydrothermal is not viable in New York State.

6.3.1.1 *Enhanced Geothermal Systems*

In 2023, Fervo completed construction and validated its technology at commercially relevant operating conditions at its 3.5 MW Blue Mountain project site in Nevada, with wells reaching depths of 2.5 km. The site now provides power to a 115 MW Google data center. Google, Fervo, and Nevada Energy (NVE) submitted a new Clean Transition Tariff to the Nevada Public Service Commission for approval. The tariff includes an executed energy supply agreement with NVE to bring 115 MW of enhanced geothermal power online in Nevada in 2030, which Fervo will provide.

Fervo is also constructing Cape Station, a 400 MW project in Beaver Mountain, Utah, and has signed a power purchase agreement with Southern California Edison to sell a portion of its power to the utility. Fervo has drilled several deep wells at its Project Cape site in Utah, including a vertical observation well to 3 km and several horizontal wells with a total measured depth of over 3 km with laterals extending 1.5 km (Fercho et al. 2024).

DOE's Frontier Observatory for Research in Geothermal Energy (FORGE) project in Utah has drilled highly deviated wells with true vertical depths of 2.5–2.6 km and total measured depth of 3.3 km.

6.3.1.2 Closed-Loop Geothermal Systems

Eavor Technologies has demonstrated its closed-loop technology, Eavor Lite, for thermal energy at a pilot facility in Alberta, Canada, producing 20 GWh of thermal energy since 2019 from a depth of 2.4 km (Cariaga 2024). Eavor is currently building a commercial-scale version of its Eavor-Loop technology in Geretsried, Germany, designed to generate 65 MW of thermal power and 9 MW of electric power. As of late 2024, a well in Geretsried has reached a depth of 4.5 km, although limited progress updates are available (Cariaga 2025).

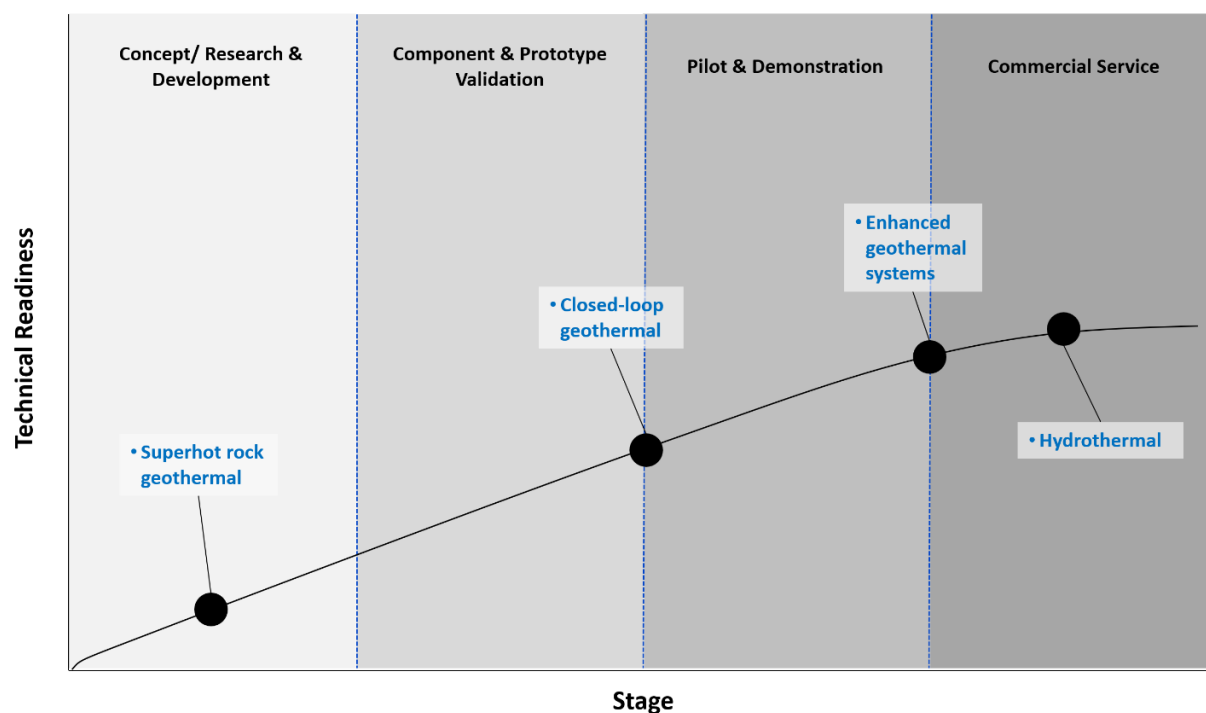
6.3.1.3 Superhot Rock

Recent SHR developments include drilling into natural reservoirs with supercritical fluids at sites in California, Iceland, and New Zealand, enabling higher-efficiency power cycles. Global research efforts are exploring SHR geothermal projects, supported by funding from the European Union, Japan, China, Mexico, and New Zealand. DOE also supports deep EGS research through the FORGE project in Utah. AltaRock Energy plans to demonstrate geothermal energy extraction from a manufactured SHR reservoir in Oregon.

6.3.2 Technology Readiness

Figure 56 presents the various stages of technology readiness across geothermal technologies. The subsequent sections discuss the readiness of each technology except for hydrothermal, which is not viable in New York State. Notably, these readiness assessments apply to typical depths of 2–5 km because few projects to date have reached the 8 km depths relevant for New York State.

Figure 56. Current Technology Readiness of Geothermal Technologies



6.3.2.1 Enhanced Geothermal Systems

EGS currently lie between the demonstration phase and commercial service.

The main technical challenge in developing EGS is engineering the subsurface to economically extract heat for power generation or direct-use applications. This is particularly difficult for deep-resources EGS (typically >4 km deep), which may contain heat but lack practical extraction methods.

EGS development shares similarities with unconventional oil and gas projects because they both require creating and maintaining a functional resource using reservoir stimulation technologies. However, EGS has unique goals. In unconventional oil and gas, the high energy density of hydrocarbons allows for cost-effective creation of limited reservoir volumes and extraction of relatively low volumes of oil or gas near the wellbore, with rapid production declines after the initial high output.

In contrast, EGS requires sustained circulation of high water flow rates over long periods, necessitating large reservoir volumes. The economic conditions for EGS differ due to the lower energy density of hot water, which requires payback periods of about a decade. This drives the need for large reservoirs with distributed fractures to ensure efficient, long-term heat exchange.

Developing EGS may require new reservoir stimulation technologies, including a combination of high-pressure stimulation with chemical treatments from the oil and gas industry, and low-pressure techniques proven effective in DOE’s EGS demonstration projects (DOE 2019).

The readiness barriers described earlier are for current EGS projects that target depths of 2–5 km. Deploying EGS at New York–relevant depths introduces additional readiness challenges, including drilling technologies, reservoir stimulation techniques suited for deeper and hotter conditions, sustainable long-term fracture networks, and materials capable of withstanding extreme pressures, temperatures, and chemical environments.

6.3.2.2 Closed-Loop Geothermal Systems

CLGS currently ranges from the technology component validation and unit prototyping stage to the technology demonstration phase.

The primary challenge for closed-loop heat exchanger designs lies in their reliance on conduction and, sometimes, free convection, to transfer energy into the well. These processes are inherently slower than forced convection, which drives energy transport in conventional geothermal wells, resulting in slower energy transport, lower revenue, and weaker project economics.

In recent years, many innovators have proposed variations of closed-loop heat exchangers for geothermal energy production, often acknowledging the inherent challenges and introducing modifications to address them. Despite these efforts, significant technical hurdles remain for the widespread deployment of deep CLGS (McClure 2023).

The Closed-loop Geothermal Working Group Study has identified several key behaviors, or technical barriers, to CLGS (White 2023). In Closed-Loop Geothermal Systems (CLGS), the outlet temperature exhibits a distinct thermal response, marked by an initial sharp decline followed by a slower, steady decrease. This pattern reflects the system’s reliance on conductive heat transfer from the surrounding rock, which is inherently slower than convective mechanisms. The early temperature drop occurs as the system rapidly extracts heat from the rock near the borehole, while the gradual decline indicates a transition to a quasi-steady state where heat replenishment is limited by conduction. This thermal behavior directly impacts system efficiency, influencing both short-term energy output and long-term performance expectations.

Although the thermal behavior of CLGS is well understood, options to enhance energy output are limited. The most effective strategy is to increase the borehole surface area in contact with the reservoir rock, typically by extending its length or enlarging its diameter. However, both approaches involve substantial increases in capital costs. Even under ideal conditions, CLGS generally yields energy outputs that are comparable to—or lower than—those of traditional hydrothermal wells. As a result, the economic viability of CLGS projects hinges largely on drilling and completion costs and whether the expected energy production can justify those investments (White 2023).

6.3.2.3 Superhot Rock

SHR geothermal power generation is currently in the R&D phase, with no field demonstrations planned to date.

SHR systems face considerable technical challenges associated with developing and extracting heat from SHR reservoirs. Wells must be drilled to significant depths, at high temperatures and pressures, in hard crystalline rocks, while keeping costs reasonable. Resistant casing materials (metals and cements) are needed to avoid well failures. Deep reservoirs with sufficient size and hydraulic conductivity must be created to allow for sustained extraction of geothermal fluid. Downhole power supply and monitoring technologies that can withstand extreme conditions are needed, and above-ground systems must support reliable long-term power generation using highly corrosive geothermal fluid.

According to a 2021 Clean Air Task Force report, SHR development challenges involve engineering rather than scientific breakthroughs (CATF 2021). Induced seismicity during SHR reservoir development and operation remains a key risk.

Research into SHR drilling and well construction at depths greater than 5 km and temperatures above 374°C is steadily advancing. Improvements in polycrystalline diamond carbide (PDC) drill bits have improved rates of penetration (ROP) into hard rock. Developers have also made progress on insulated drill pipes. These advancements suggest that deep drilling for SHR geothermal projects is approaching feasibility.

However, several key technology gaps remain, hindering deep drilling in challenging subsurface geological environments. The industry needs rapid advancements in drilling rigs, bit technology, high-temperature downhole tools, and temperature management equipment. Currently, these drilling

systems and the time required to access deep, hard rock formations result in significant project costs. To achieve commercial viability for SHR geothermal, technology companies and research laboratories must rapidly develop, test, and deploy new technologies.

Overall, SHR geothermal wells can be drilled using a combination of existing technologies. The technological challenges are solvable, but economic barriers persist due to the limited availability and testing of these drilling systems. These barriers should lessen as the SHR geothermal industry grows. A significant gap is the lack of access to SHR conditions in both field and laboratory settings. Without open-access experimental facilities and pilot sites, these technologies cannot undergo the iterative improvements necessary to derisk SHR drilling and scale development to advance the industry (Pearce 2024).

In New York State, SHR temperatures are expected at depths greater than 10–15 km. This makes deployment by 2040 highly unlikely, in addition to the substantial challenges already associated with SHR.

6.3.3 Infrastructure and Supply Chain Readiness

Enabling infrastructure is crucial for the development of energy technology. This includes the fundamental physical structures, facilities, and tools, along with their associated processes and procedures. Table 40 summarizes key infrastructure and supply chain readiness considerations for geothermal in New York State.

Table 40. Infrastructure and Supply Chain Readiness of Geothermal Technologies in New York State

Technology	Transmission & Grid Integration	Fuel Supply Chain & Waste Management	Cooling Water & Thermal Management	Siting & Land Use	Supply Chain
Geothermal	Long lead time Location depends on geographic resource potential, cannot always be sited near an optimal interconnection point.	No significant buildout required	No significant buildout required	Long lead time Location depends on geographic resource potential	Short lead time Can leverage some oil and gas supply chains

Transmission and Grid Integration

Because geothermal power plants are typically smaller than other baseload technologies, they may be easier to connect to transmission systems than large nuclear or combined-cycle gas plants. However, geothermal's dependence on geographic resource potential could result in optimal sites being far from transmission lines, necessitating the construction of major additional interconnection infrastructure.

Supply Chain

The geothermal supply chain benefits significantly from leveraging the existing fossil energy supply chains. However, major delays and uncertainties persist for key components such as organic Rankine cycle equipment, pumping equipment with pressures and rates required for deep geothermal projects, ultra-heavy rigs or custom rigs designed to be more efficient in geothermal environments, and turbines. Accessing and derisking geothermal resources requires specialized equipment, advanced drilling technologies, and extensive subsurface exploration.

6.3.4 Project Lead Times

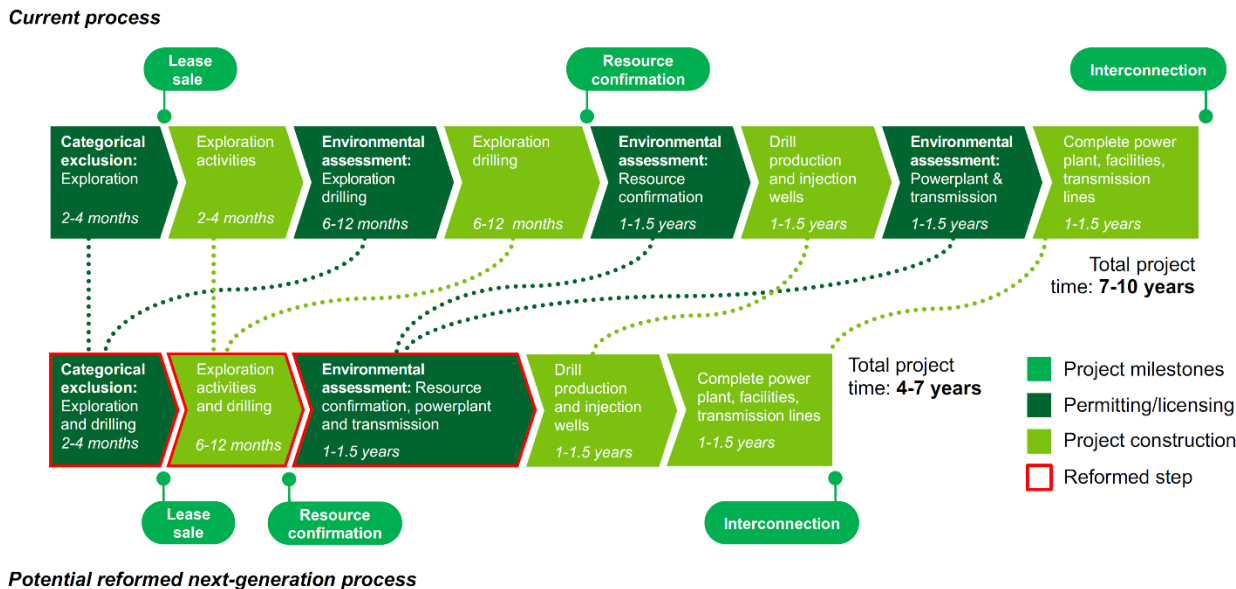
Lengthy and complex permitting processes are one of the major challenges preventing the acceleration of geothermal deployment. Long lead times increase project and financing costs. In many countries, geothermal projects require 5–10 years for full permitting (IEA 2023b).

DOE's Liftoff report (DOE 2024d) estimates that, under current permitting practices, total geothermal project timelines, including permitting and construction, range from 7 to 10 years (Figure 57). A potential reformed, next-generation permitting process could shorten this to 4–7 years (DOE 2024d). In New York State, deeper geothermal drilling will likely require more comprehensive environmental reviews and assessments. These requirements could further lengthen permitting lead times and construction times, adding to project complexity and cost.

Figure 57. Geothermal Project Timelines Process Flow Diagram: Current versus Streamlined Scenario

Comparing permitting and development timelines for geothermal projects on public land.

Source: DOE (2024d).

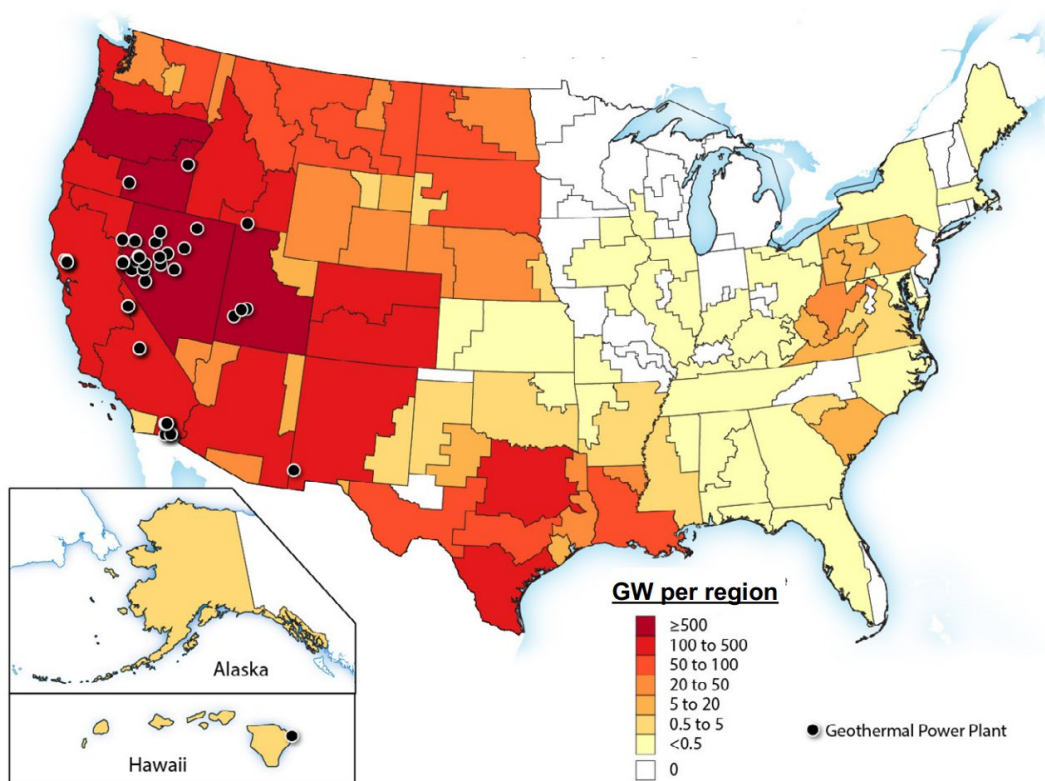


6.3.5 Geographic Suitability and Constraints

Next-generation technologies significantly enhance geothermal’s geographic suitability for power generation compared to conventional geothermal. However, as discussed in Section 6.1.3, the western U.S. still offers the most favorable areas. The DOE map in Figure 58 estimates less than 0.5 GW of near-term potential in New York State based on currently available technology. Improved technology likely increases New York State’s total, long-term technical potential beyond 0.5 GW, but the exact amount remains unknown. Within the State, Western New York may have the greatest potential (Figure 58), but better understanding of localized geothermal potential in New York State will require significant test drilling at depths relevant to power generation.

Figure 58. Map of Next Generation and Conventional Geothermal Resource Estimates in the U.S.

Source: DOE (2024d).



6.3.6 Readiness Summary

New York State's deeper geothermal potential, compared to other regions, poses the most significant readiness barrier. EGS, CLGS, and SHR are relatively new technologies that have not yet reached commercial deployment, even in regions with more accessible potential. These technologies must mature in regions with easier access before being deployed in harder-to-reach regions such as New York State. However, overlap with the oil and gas sector in supply chains, workforce, and technology should expedite learning in next-generation geothermal technologies and advance readiness.

6.4 Emissions and Other Considerations

6.4.1 Emissions

Geothermal power plants are widely recognized as a clean and renewable energy source, but they are not entirely emission-free. Operational emissions from geothermal systems primarily originate from the geothermal fluid extracted from the earth's subsurface. This fluid often contains dissolved gases that can

be released during the energy conversion process, particularly in open-loop systems such as flash and dry steam plants. These emissions can include GHG like carbon dioxide and trace amounts of CH₄, as well as non-GHG pollutants such as hydrogen sulfide (H₂S), sulfur dioxide (SO₂), and trace amounts of other pollutants such as NH₃, NO_x, PM, and heavy metals such as arsenic, mercury, and boron. However, these emissions are extremely small when compared to fossil fuels. The type and quantity of emissions depend on the geological characteristics of the resource, the technology used, and whether the system is open-loop or closed-loop. Open-loop systems in tectonically active regions may release significant quantities of noncondensable gases, but binary systems, the technology expected for New York State's suboptimal geothermal resource, typically emit very little directly due to their closed-loop design.

6.4.1.1 Greenhouse Gas Emissions

Compared to fossil fuel power generation, geothermal power plants produce very low GHG emissions during operation. Binary EGS systems emit significantly less CO₂ than conventional geothermal systems. Closed-loop geothermal systems, which do not bring geothermal fluids to the surface, have even lower emissions potential. Because they operate as sealed systems, they virtually eliminate the release of noncondensable gases and other subsurface pollutants, resulting in life-cycle CO₂e emissions that are often negligible—frequently reported as close to 0.0 g/kWh.

6.4.1.2 Co-Pollutants

Other pollutants can also be present in the geothermal fluid, but these emissions are expected to be minor. Geothermal H₂S emissions are estimated to be 0.1 g/kWh, SO₂ emissions about 0.001 g/kWh, and NO_x, PM, and mercury are negligible (UNEP 2016). Next-generation binary geothermal power plants have effectively zero emissions (DOE 2024d).

6.4.2 Other Considerations

6.4.2.1 Air Quality

As discussed in Section 6.4.1, EGS binary power plants may release some emissions, but they remain very low compared to other technologies, so local air quality is not expected to be a major concern.

6.4.2.2 Safety and Environmental Considerations

Chemical Spills and Habitat Disruption

Potential spills could occur during the drilling and extraction processes, where geothermal fluids can contain various chemicals such as heavy metals (e.g., arsenic, mercury, lead) and hydrogen sulfide or corrosive chemicals. To prevent environmental contamination during geothermal drilling and extraction, especially from fluids that may contain heavy metals or hydrogen sulfide, strict safety protocols are necessary. These include multilayered well casing and cementing to isolate fluids from groundwater, closed-loop systems that reinject fluids back into the reservoir, and surface containment measures to manage accidental spills. Continuous monitoring, emergency response plans, and the use of nontoxic or treated fluids further reduce risks. These safeguards are modeled on best practices from both geothermal and oil and gas industries and are enforced through regulatory oversight and permitting processes.

Geothermal development may disrupt sensitive ecosystems due to construction activities, noise pollution, and potential spills of geothermal fluids. However, geothermal projects require less land than other renewable technologies; they generally cause less habitat disruption than wind, solar, or hydropower. Geothermal also typically disrupts habitats less than fossil fuel power generation due to its minimal air emissions and no fuel needs.

Water Quality and Groundwater Contamination Risks

Ground contamination is a potential risk if precautions are not properly taken. Although EGS shares some technical similarities with hydraulic fracturing in the oil and gas industry, many of the water-related risks from fracking do not apply to modern EGS projects. This is largely due to key differences in design and operation: Geothermal fluids are typically nontoxic and carefully managed. Wells use multiple casing and cement layers to protect groundwater, and operations occur at much greater depths—often thousands of feet below aquifers.

Induced Seismicity

Stimulating a geothermal reservoir (by creating fractures or enhancing preexisting fractures) or injecting fluid to replenish a geothermal reservoir may cause induced seismicity (IS). The level of potential risk depends on the extent and magnitude of that activity and its proximity to property and people. Previous experience with geothermal-related IS, such as Basel, Switzerland, led to the development of thorough

protocols, including the International Energy Agency (IEA) IS 2008 Protocol and the 2012 DOE update to prevent and mitigate IS. These protocols guide geothermal developers in managing IS safely and gaining public acceptance, particularly for EGS projects (Levine 2017). While these protocols are guidelines, permits often require adherence to them.

IS risk affects both conventional and closed-loop systems to some degree due to the prolonged cooling of the reservoir or rocks during their operation. For EGS, reservoir stimulation adds another risk factor for IS, potentially causing earthquakes that could harm local infrastructure and facilities. Any seismic events in populated areas are likely to trigger opposition, potentially delaying or halting project development (IEA 2023b).

The vast experience with IS following shale gas developments (during fracking and wastewater injection) has greatly contributed to real-time IS monitoring techniques and the development of a sophisticated traffic light system (TLS) to mitigate the risk of potential induced seismicity associated with geothermal projects (Norbeck and Latimer 2024). The geothermal IS risk is lower than in wastewater injection in oil and gas operations because of constant fluid recirculation (fluid is produced, not only injected), which considerably limits the pressure buildup in the subsurface.

Waste

The primary waste associated with geothermal projects is brine, a salty water extracted from geothermal reservoirs often containing various dissolved minerals and chemicals, including heavy metals such as arsenic and mercury. Plants typically reinject the brine back into the geothermal reservoirs to maintain the system balance and minimize environmental contamination.

6.4.2.3 Water Use

Water use varies in geothermal power generation, but most water is not consumed; it is recirculated and reinjected into the same underground reservoir. Both conventional and EGS plants typically consume between 0.3 and 0.73 gallons per kilowatt-hour. For example, a 30 MW EGS facility might use 2–6 million gallons of water annually, significantly less than the average water demand of coal, NG, nuclear, or biomass power plants. Moreover, even if geothermal energy were scaled to supply 8.5% of the nation's electricity, it would account for only about 1.1% of total water withdrawals in the power sector. Importantly, geothermal systems often use nonfreshwater sources such as municipal wastewater or brackish water, thereby minimizing freshwater demand (DOE 2024d).

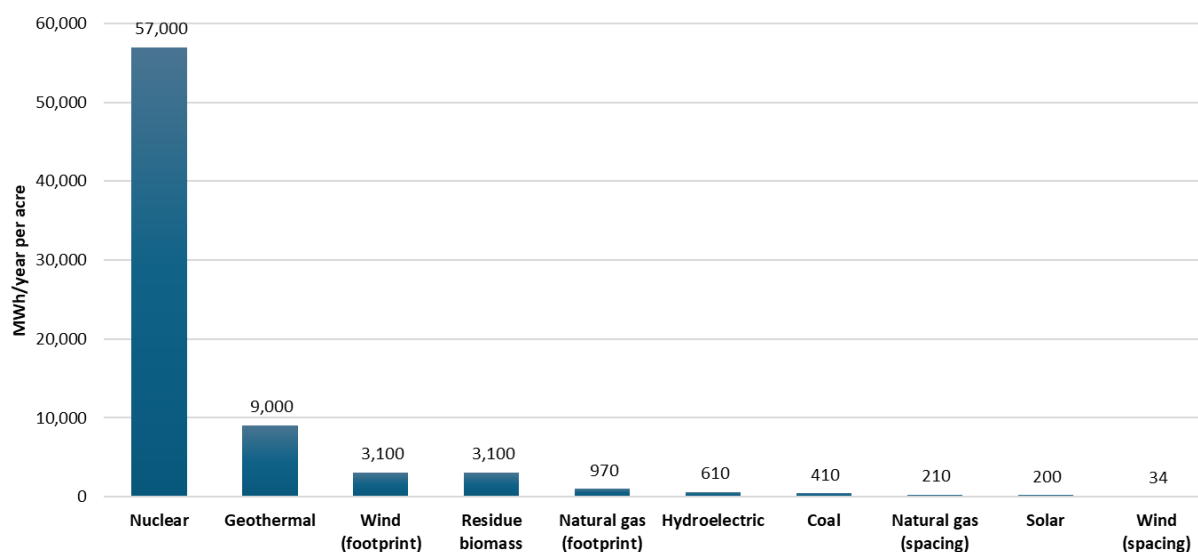
6.4.2.4 Land Use

Geothermal power plants are compact and produce more energy per acre than any other technology except nuclear. Figure 59 compares the land-use efficiency of power sector technologies.

Figure 59. Land-use Efficiency by Power Sources

This figure compares the direct and indirect land-use efficiency of various power generation technologies. “Direct land use” includes land occupied by the electricity-producing facility (direct) and, when applicable, the land needed to source fuel for plant operations (indirect). “Footprint” includes the direct land area physically occupied by energy infrastructure, such as solar panels, wind turbine bases, power plants, access roads, and supporting structures, and “spacing” includes the land in between physical components in an electricity generation or fuel extraction site (e.g., areas between wind turbines or NG extraction pads).

Source: Adapted from DOE (2024c).¹⁹



6.4.2.5 Workforce and Economic Benefits

The geothermal industry requires a workforce with skills that significantly overlap with those in the oil and gas sector. Employment opportunities span geoscientists, engineers, tradespeople, and functional workers in health, safety, supply chain, and research. There is therefore significant potential for a workforce transition from fossil fuel industries to geothermal energy. However, this transition will require supplementary training to address the different health, safety, and environmental risk profiles associated with geothermal operations (IEA 2023b).

6.5 Cost

Next-generation geothermal power generation is characterized by high capital costs and low operating costs, but the capital costs associated with deploying this technology in New York State are uncertain. Geothermal power generation in regions with high heat at shallow depths is economically viable, but due to New York State’s relatively low-quality geothermal resources, a geothermal well for power generation in the region may need to drill to depths of 7–8 km based on extrapolations from oil and gas well data. The deepest enhanced geothermal project in the U.S. is likely at the FORGE site, which has reached depths of about 3 km. As a result, estimating the cost of achieving similar heat profiles in New York State is difficult.

The NREL 2024 ATB provides cost estimates for EGS using a bottom-up modeling approach through the Geothermal Electricity Technology Evaluation Model (GETEM). This framework integrates drilling performance metrics, reservoir stimulation success rates, and power plant specifications to project capital expenditures across technology innovation scenarios. The model assumes a baseline depth of 3 km for deep EGS projects, with costs calibrated to field data from initiatives such as FORGE and commercial demonstrations. It yields a projected cost range of \$13,000–\$34,000/kW, with an average of about \$22,000/kW for resources of 150°F–200°F (NREL 2024b). Less information is available for CLGS, but due to its lower technical readiness, CLGS is expected to be more expensive than EGS.

The EGS industry has observed high learning rates, based on data from FORGE and other developments, with project development costs declining by almost 50% between 2021 and 2023. Improvements in geothermal drilling, well field stimulation, and economies of scale enabled by improved flow rates, have driven these reductions (DOE 2024d). Continued rapid improvements could increase the viability of next-generation geothermal for power generation in New York State.

6.5.1 Funding and Subsidies Available to Geothermal Projects

Geothermal remains eligible for the two key Inflation Reduction Act technology-neutral tax credits, the Clean Electricity ITC and the Clean Electricity PTC. Credits begin to phase out between 2033 and 2036. (The ITC cannot be combined with the PTC for the same facility.)

6.6 Scalability for 2040

The findings from each of the above sections were taken together to produce three scalability scenarios for geothermal power generation in New York State. The Moderate Deployment scenario represents an achievable base case if ambitious action were taken toward technology deployment. The Conservative Deployment and Advanced Deployment scenarios capture lower and higher degrees of progress in technology readiness and deployment, respectively.

The potential scalability of geothermal power generation in New York State by 2040 is relatively low due to several key factors. New York State lacks hydrothermal resources and has limited data on heat flow or geothermal gradients, largely because few measurements exist and no wells have been drilled to relevant depths. Existing data suggest that wells would need to reach depths of about 8 km to access geothermal temperatures suitable for geothermal power generation, which presents significant technical and financial challenges. No existing geothermal projects currently operate at these depths. The DOE estimates that New York State's achievable geothermal power generation potential by 2040 is less than 0.5 GW (DOE 2024d). Although the theoretical potential is quite high, current technology and infrastructure make it largely inaccessible. However, because this is a rapidly advancing field, monitoring future technology developments will be essential.

6.6.1 Conservative Deployment Scenario

In a Conservative Deployment scenario, geothermal power generation may not occur due to the lack of hydrothermal resources, and the technical and economic barriers associated with drilling and stimulating at such depths. However, geothermal energy still holds promise for direct-use applications—particularly for heating and cooling. Projects like Cornell University's campus heating initiative demonstrate how geothermal can reduce peak electricity demand and support decarbonization goals, even without electricity generation.

Under this scenario, deploying direct-use applications could increase knowledge of localized resource potential through additional test drilling. Gaining experience in permitting geothermal heating projects could also streamline future permitting processes. These developments could help enable the deployment of geothermal power after 2040 if technical and economic improvements materialize over a longer timeline.

6.6.2 Moderate Deployment Scenario

A Moderate Deployment scenario could involve establishing a pilot geothermal power plant, which would demonstrate the feasibility of geothermal power generation in the State. Achieving this by 2040 would require significant reductions in drilling costs, improvements in drilling technologies, and the development of stimulation technologies to withstand the conditions at such depths.

6.6.3 Aggressive Deployment Scenario

An Aggressive Deployment scenario would require significant advancements in drilling technology to unlock more geothermal potential at competitive costs, leading to larger-scale projects. DOE’s 2023 “Enhanced Geothermal Shot Analysis” concludes that, with aggressive technology improvements in key EGS areas, geothermal electricity generation could provide close to 0.5 GW in New York State by 2040 (Augustine et al. 2023).

As mentioned earlier, SHR temperatures are likely found only at depths greater than 10–15 km in New York State. This, combined with the numerous challenges associated with producing power from SHR conditions, makes deployment before 2040 unlikely, even in an aggressive scenario.

6.6.4 Beyond 2040

The feasibility of geothermal power generation in New York State depends on the highly uncertain timelines of technological improvements. Extending the time horizon beyond 2040 increases the likelihood of achieving the necessary advancements for EGS, CLGS, and potentially even SHR.

To make geothermal energy a viable and scalable solution in New York State, the industry must advance several key technologies. These include advanced drilling technologies, durable well materials, and efficient systems for extracting and converting heat into electricity. Innovations in power conversion are also essential. Finally, reducing costs through modular designs, public-private partnerships, and supportive policy frameworks will be critical to accelerating deployment.

6.6.5 Scalability Summary

Advanced geothermal is not expected to significantly impact the 2040 electricity grid due to its low readiness and high cost uncertainty at the depths required for New York State. The Conservative Deployment and Moderate Deployment scenarios could be achieved with State support for test drilling and pilot projects, but they would have minor impacts on a 2040 grid. However, these efforts

could better position New York State for deployments as the technology continues to mature. The Aggressive Deployment scenario could see more deployments if significant advancements in drilling and reservoir engineering are made or if localized potential is higher than expected, but the overall contribution to the 2040 grid is still expected to be <1 GW.

6.7 Conclusions

Based on the previous assessment, the following key observations are offered to inform future consideration of next-generation geothermal power deployment in New York State.

Geothermal power generation is a low-emissions and low-land footprint technology that is highly geographically dependent. Conventional geothermal relies on naturally occurring hydrothermal resources, while next-generation geothermal uses human-engineered reservoirs. Geothermal suitability in New York State depends on the geological landscape, which is largely unexplored. Given the more promising geology in other U.S. regions and current technology limitations, potential deployment in New York State through 2040 is likely <1 gigawatt (GW). However, with further innovation in drilling and stimulation techniques, high theoretical potential exists across the State for next-generation geothermal technologies in the long term.

Although conventional hydrothermal geothermal power generation is not available in New York, advanced technologies may be possible with further innovation. Most geothermal deployments are in the western U.S., where temperatures required for power generation can be reached at relatively shallow depths, approximately 2–5 kilometers (km). Next-generation geothermal technologies, such as enhanced geothermal systems (EGS) or closed-loop geothermal systems (CLGS), are possible in New York State, but they may require depths of approximately 8 km. No U.S. projects are currently pursuing these depths.

The most promising region for geothermal deployment is likely western New York, but significant test drilling is still required to fully understand the localized potential. Current depth estimates for potential geothermal resources are based on data from oil and gas wells. More testing will be required to determine the regions with the highest potential.

Costs for geothermal power generation at NYS-relevant depths are highly uncertain. Significant advancements in drilling technology will be required to economically access the depths relevant to NYS geology. However, advancements in drilling techniques already underway may help to lower costs quickly.

Induced seismicity and groundwater contamination are at considerably reduced risk for next-generation geothermal. While groundwater contamination has been associated with oil and gas hydraulic fracturing, similar contamination is a significantly reduced risk with geothermal power generation systems, as appropriate prevention measures can be applied. Similarly, because the fluid injected into the subsurface is also removed, induced seismicity is lower with geothermal systems than in the oil and gas extraction processes.

7 Long-duration Energy Storage

7.1 Technology Overview

LDES encompasses a diverse set of technologies that share the goal of storing energy for dispatch at a later time. While no universally accepted definition exists, the DOE defines LDES as systems with dispatch durations of at least 10 hours (DOE 2023c), whereas the LDES Council prefers a threshold of 8 hours (LDES Council 2024). This report adopts the DOE’s definition: systems capable of delivering stored energy for 10 hours or more.

Table 41 presents a segmentation of energy storage technologies based on their dispatch duration.

Table 41. Codifying the Technology in the Context of Discharge Duration

Source: DOE (2023c).

Technology	Duration (hours)
Short Duration	0–10
Interday LDES	10–36
Multiday LDES	36–160
Seasonal Shifting	160+

7.1.1 Technology Types

Energy storage technologies can be broadly categorized by the energy storage medium (EPRI 2024d):

- Chemical: chemical reaction resulting in a product that can be used to generate heat or power
- Electrochemical: reversible chemical reactions that generate an electric potential difference
- Mechanical: energy storage as potential or kinetic energy via compression, gravity, or rotation
- Thermal: energy storage by heating bulk media

This LDES assessment excludes chemical storage technologies (i.e., hydrogen, ammonia), which are addressed in other sections. The technologies included in this assessment represent a subset of technologies under development, selected based on specific criteria (Table 42) to narrow the broader set of energy storage technologies tracked by EPRI.

Table 42. Criteria Used to Narrow the Set of Energy Storage Technologies

Criteria	Value	Units	Notes
Technology Readiness Level	>4	TRL	Indicates potential for technical readiness within 5–10 years
Commercial Readiness Level	Medium or higher	—	Reflects some achieved commercial capability
Demonstrated Scale	>100	kWe	Minimum scale demonstrated in a pilot plant
Duration	>10	Hours	Minimum required discharge duration
Commercial Scale	>1	MWe	Must deliver at least this scale
Energy Density/Footprint	>1	MWhe/acre	Ensures suitability by excluding technologies with very low energy density
Fossil Fuel Consumption	0	—	Must not rely on fossil fuel combustion; zero-emissions only

7.1.1.1 *Electrochemical*

Electrochemical storage technologies use a reversible chemical reaction to generate an electrical potential difference. A battery cell enables ionic exchange between anolyte and catholyte through a porous membrane. When charging the batteries, electricity causes the ions to flow to a higher energy state; during discharge, the ions return to a lower energy state, generating electricity.

Electrochemical storage technologies for long-duration applications generally feature high costs but also tend to achieve high RTE. These technologies have a lower expected lifetime compared to other LDES technologies. Most electrochemical storage systems can be deployed and tested in smaller pilot sizes, which comparatively allows for rapid iteration and innovation.

Electrochemical storage technologies include various types. Lithium-ion batteries (LIBs) currently dominate the market, particularly targeting short-duration applications. Developers are advancing other electrochemical storage technologies for long-duration applications. This assessment focuses on the alternative electrochemical storage technologies detailed in Table 43.

Table 43. Overview of Select Electrochemical Long-duration Energy Storage Technologies

Technology Type	Description
Advanced Lithium-ion Batteries	Commercial LIBs have been around since the 1990s and have enabled a range of technologies from consumer electronics and EVs to stationary energy storage. Developers are advancing new LIB technologies to enhance performance, safety, and longevity while also reducing manufacturing costs.
Flow Batteries	Flow batteries are a type of rechargeable battery that stores energy in reactants dissolved in liquid electrolytes. External tanks store the liquid electrolytes, which are pumped into positive and negative sides of an electrochemical cell where the electrochemical reactions occur. The volume of reactants in the external tanks determines the system's energy capacity, and the active electrode surface area in the combined electrochemical cells determines system power. Different types of flow batteries include redox flow, hybrid flow, and organic flow batteries.
Lead-acid Batteries	Lead-acid batteries operate through electrochemical reactions between lead, lead dioxide, and sulfuric acid to store and release electrical energy. While lead-acid batteries have been used for many decades, recent innovations, such as the use of gelled electrolyte, fiberglass mat, and bipolar cell architecture, have been introduced to improve the system performance, lifespan, and efficiency.
Metal-air Batteries	Metal-air batteries use a metal electrode (such as iron, zinc, or aluminum), an electrolyte, and a gas diffusion electrode (GDE). The GDE supplies the active oxygen component from the surrounding air or an oxygen tank. A chemical reaction between the metal and oxygen generates electricity, and the cell capacity primarily depends on the type of metal used.
Sodium-ion Batteries	Sodium ion batteries (SIB) use mobile sodium ions that move between the anode and the cathode during charging and discharging. SIBs operate using the same principle as LIBs, and the basic design of the electrochemical cell is the same in both types of batteries.
Sodium-sulfur Batteries	Sodium-sulfur (NaS) batteries consist of solid electrodes made of sodium and sulfur separated by a solid electrolyte. Traditional NaS batteries are heated internally to about 570°F (299°C) because sodium and sulfur are solid and unreactive at room temperature. Recent developments in NaS battery technology aim to address challenges such as sealing, dendrite formation, and electrolyte degradation by targeting a low- to moderate-temperature version.

Additional novel electrochemical storage technologies do not fall into the common categories listed in Table 43. These include metal-hydrogen batteries, zinc hybrid cathode batteries, and nonflow zinc-bromide (ZnBr) batteries. These technologies vary in readiness levels and, while not analyzed in this report, they remain potential candidates for LDES applications.

7.1.1.2 Mechanical

Mechanical energy storage technologies store energy by applying force to a medium to cause acceleration, compression, or displacement (against gravity). The resultant potential energy can be stored then recovered by reversing the process to produce power.

These technologies are well suited to LDES applications and generally experience minimal standby losses. They offer high reliability and typically are not limited by storage capacity degradation or depth of discharge. Additionally, some mechanical energy storage systems provide real system inertia, crucial for integration with variable renewable energy sources. However, some mechanical storage systems face inherent siting constraints due to specific geological requirements.

This assessment focuses on the mechanical energy storage technologies detailed in Table 44.

Table 44. Overview of Select Mechanical Energy Storage Technologies

Technology Type	Description
Compressed Air Energy Storage	Compressed air energy storage (CAES) compresses air during charging and stores it in pressurized form, either in underground reservoirs (for larger-scale CAES) or in aboveground containers (for smaller-scale CAES). During discharge, the pressurized air is heated and allowed to expand through a turbine to drive a generator and produce electricity. CAES types include: • Diabatic CAES: Uses external heat sources, usually from fossil-fuel combustion, to heat the high-pressure air before expansion. • Adiabatic CAES: Uses thermal energy storage (TES) to capture the heat generated during the compression process, and reuses it to preheat the air before expansion, avoiding external heat. • Isothermal CAES: Injects all heat released during compression into the expansion process at the same pressure and temperatures. Collectively, adiabatic and isothermal CAES are referred to as Advanced-CAES in this report.
Compressed Carbon Dioxide Energy Storage	Compressed CO₂ energy storage technology is akin to closed-loop, adiabatic CAES but uses CO₂ as the storage medium. CO₂ has favorable physical and thermodynamic properties. Systems can use either near-atmospheric CO₂ stored aboveground as a gas, or supercritical CO₂, which allows for a more compact system, but requires storing CO₂ at higher pressures.
Liquid Air Energy Storage	Liquid air energy storage (LAES) is a CAES variant that liquefies air by compressing and cooling it to low temperatures, then storing it in insulated aboveground tanks. The system stores the heat of compression in an in-situ TES system. During discharge, the liquid air is heated by the TES system and expanded back into a gas, driving the turbine.
Pumped Storage Hydropower	Pumped storage hydropower (PSH) stores and generates electricity by moving water between two reservoirs at different elevations. During charging, water is pumped from a lower to an upper reservoir, and during discharge, it is released to drive a turbine and generate electricity.
Geomechanical Energy Storage	Geomechanical energy storage systems are largely built upon the mature PSH components using subsurface geological formations to store and release energy from pressurized water, thus aiming to expand siting flexibility.
Gravity-based Energy Storage	Gravity energy storage elevates a mass mechanically to store potential energy. During discharge, it releases the mass to descend by gravity, typically at a controlled rate, with the resulting force from descent driving a generator to produce electricity. Some systems use a working fluid denser than water, allowing them to operate at lower elevations than is required for a similarly sized PSH.

7.1.1.3 Thermal Energy Storage

TES technologies use electrical or direct heat sources to store heat in a storage medium. These technologies often employ high-temperature reservoirs that hold storage media such as ceramics, concrete, gravel, graphite, metals, molten salt, sand, or materials with high latent energies of phase change. These thermal reservoirs can be discharged to provide heat for various applications, including industrial processes, building use, or electricity generation through a turbine (or via radiation absorbed by thermophotovoltaic cells).

TES technologies typically have long life cycles, low material costs, and can offer high energy density compared to other LDES alternatives. Most TES systems can also provide system inertia and bulk energy services and have the potential to repurpose retiring power plant infrastructure to minimize costs. However, most TES technologies are relatively less mature compared to other LDES technologies (EPRI 2022i) and offer lower alternating current (AC)-to-AC RTE.

This assessment focuses on the thermal energy storage technologies detailed in Table 45.

Table 45. Overview of Select Thermal Energy Storage Technologies

Technology Type	Description
Molten Salt	Molten salt TES stores thermal energy by heating a mixture of salts to high temperatures. This type of sensible heat TES is commonly used in concentrated solar power plants. This assessment classifies molten salt separately due to its higher readiness level compared to other emerging sensible TES systems.
Phase-change Material	Phase-change material (PCM) TES stores and releases thermal energy through changes in physical state, such as solid to liquid or vice versa. For example, PCMs absorb heat during melting and release it during solidification, maintaining a nearly constant temperature during these phase changes.
Pumped Heat	Pumped heat TES systems use heat pumps to transfer thermal energy between two thermal stores, typically by cycling a working fluid between high and low temperatures. During charging, the system stores heat from compression in a hot TES and stores cold from expansion in a cold TES. During discharge, the cycle reverses and operates as a heat engine, generating power from the heat flow between the hot and cold TES.
Sensible Heat	Sensible heat TES involves storing energy by raising the temperature of a medium without changing its phase. The amount of heat stored is directly proportional to the density, volume, specific heat, and temperature variation of the storage material. Common materials include sand, gravel, and concrete. The system extracts stored heat by reversing the process. This assessment further divides sensible heat storage technologies into two categories: • Maximum temperatures >1,832°F (1,000°C) • Temperatures <1,832°F (1,000°C)
Thermochemical	Thermochemical TES stores heat through reversible chemical reactions. When heat is added, it drives an endothermic reaction that stores energy in chemical bonds. The reverse exothermic reaction releases the stored energy. Thermochemical TES systems vary in temperature based on the reaction used. For example, salt hydrates can generate steam at 1,110°F (600°C), while metal oxides can generate air at 2,730°F (1,500°C).
Thermophotovoltaic	Thermophotovoltaic (TPV) systems convert thermal energy into electrical energy using TPV cells. These systems typically use high-temperature storage media such as carbon blocks or solid graphite and TPV cells for energy recovery. Developers are also designing TPV systems to deliver heat as a service.

Iron Fuel Energy Storage

While this report addresses chemical energy storage technologies such as hydrogen and other alternative fuels in separate chapters, this note focuses specifically on iron powder-based chemical energy storage technology. This technology uses metallic iron powder as a recyclable energy carrier. It stores energy by reducing iron oxide into elemental iron, currently achieved primarily using hydrogen fuel. However, research is ongoing to enable electrochemical recharging with renewable energy instead of hydrogen.

To discharge, the system combusts iron to release high-temperature heat, producing iron oxide, which is then captured and reused—creating a closed-loop system. The thermal output can be used directly or converted to electricity through a steam cycle, delivering approximately 2 MWh per cubic meter for iron powder. This makes the technology suitable for both industrial heat and power generation (Berger 2024).

This technology offers some advantages for grid-scale deployment. Iron is abundant, stable in its solid form, and has a high volumetric energy density and long shelf life. It also poses fewer safety concerns than gaseous fuels, liquid fuels, and lithium-ion batteries (LIBs). It can be transported and stored in its charged or discharged state using existing infrastructure, which makes it cost-effective to develop sites that have high renewable energy potential but lack economic access to grid interconnections. The technology does not require specific geological conditions and can be retrofitted with existing infrastructure.

However, iron fuel energy storage technology faces certain challenges. Regenerating the fuel with hydrogen reduction requires a reliable supply of low-cost hydrogen and high-throughput reduction systems. The RTE is relatively low compared to other energy storage options due to cumulative losses during hydrogen production, iron oxide reduction, iron combustion, and heat-to-electricity conversion. Electrochemical recharging could reduce costs and improve RTE, but this recharging technology is not yet mature for iron powder. Additionally, retrofitting existing thermal power plants presents integration challenges, including the need for specialized combustion and ash-handling systems.

Iron fuel technology presents a potential LDES option for Zone J, where land availability is limited and safety and siting flexibility are critical. Its compact footprint, stable form, and transportable fuel cycle make it attractive for deployment on or near former industrial sites, urban brownfields, or for repurposing retiring fossil infrastructure. However, scaling the technology will require advancements in regeneration efficiency, combustion system design, and technology demonstration projects to validate cost and performance at scale. Similar metal-based chemistries, such as those using aluminum, are also under development but are still in the R&D phase.

7.1.2 Technology Use Cases and Value Streams

LDES technologies can provide various energy services, including electrical energy, capacity, balancing and reserves, resiliency, transmission and distribution deferral, and low-carbon heat (EPRI 2024d).

While not exhaustive, this list sufficiently covers the relevant use cases for utility customers in the power sector. These use cases also offer significant opportunities for revenue generation through multiple market mechanisms.

1. **Electrical Energy**

LDES can generate value through energy shifting, for example, by moving solar energy from daytime hours to evening peak load hours. This results in peak shaving, as customers use energy delivered by LDES systems to reduce the generation needed to meet peak loads. LDES technologies can capitalize on energy price differentials by buying electricity when demand and prices are low, storing it, and selling it during periods of high demand and high prices, generating revenue through arbitrage.

2. **Capacity**

LDES technologies can supply additional electricity when the grid is under the most stress and can serve as alternatives to traditional peaking plants because they can supply power over long durations. These systems participate in capacity markets by offering reliable peak capacity. Most regions now approve capacity ratings for energy storage based on the number of hours of discharge that can be sustained, ensuring compliance with resource adequacy requirements (EPRI 2024d).

3. **Balancing and Reserves**

LDES can also provide various balancing and reserve services, including frequency regulation, spinning reserves, and other constructs developed by the grid operator to minimize service interruptions to customers. Some LDES systems offer additional features, such as synchronous inertia, short-circuit current capability, and black-start capability, among other aspects that may also be beneficial for reliability. As both a demand response (DR) asset and generator, LDES can bid into ancillary service markets across a range of charging and discharging capacities. However, this market typically represents a small portion of the economic activity in electricity markets.

4. **System Resilience**

LDES can play a role in preparing for extreme events which threaten power system reliability. Whether integrated into microgrids or bulk power systems, LDES can provide extended-duration backup power during outages caused by extreme weather events.

5. **Transmission and Distribution Deferral**

LDES can mitigate or delay the need for new transmission and distribution infrastructure by providing localized energy storage in constrained areas, thus avoiding costly long-term asset upgrades. A typical LDES asset, with a lifespan of about 10–20 years represents a lower-risk investment compared to a transmission line with a lifespan of 40 or more years. LDES systems can also inject and absorb power quickly, helping to stabilize power flows and reduce the need for more costly adjustments to the system (EPRI 2024i).

6. **Low-Carbon Heat**

Some LDES technologies, particularly thermal LDES, may offer a pathway to store electrical energy as heat and deliver it on demand for various applications, such as industrial processes and building heat.

7.2 Performance Attributes

LDES technologies vary in their ability to provide essential grid services. Table 46 shows the relative strengths and weaknesses of the three categories of LDES technologies.

Table 46. Comparison of Long-Duration Energy Storage Technologies by Grid Services and Attributes

Italicized entries indicate a lack of real-world U.S. demonstration.

Attribute	Electrochemical	Mechanical	Thermal
Inertial Response	May sometimes provide attribute most systems are inverter-based and lack inherent inertia, but new inverters can provide synthetic inertia	Typically provides attribute most systems are coupled with synchronous generators that offer rotating inertia	Typically provides attribute most systems couple with synchronous generators that offer rotating inertia
Primary Frequency Response	Typically provides attribute electrochemical systems, through power electronics, enable frequency response	May sometimes provide attribute most systems can deliver frequency response when operated in grid-support mode, although slower than inverter-based systems	May sometimes provide attribute most systems can deliver frequency response when operated in grid-support mode, although slower than inverter-based systems
Voltage & Reactive Power	Typically provides attribute inverter-based battery systems offer flexible reactive power control and voltage regulation	Typically provides attribute integrated synchronous machines supply voltage support and reactive power	Typically provides attribute integrated synchronous machines supply voltage support and reactive power
Ramping	Typically provides attribute inverter-based systems provide rapid ramping, responding within seconds due to fast electronic control	May sometimes provide attribute most mechanical storage systems can adjust output but at slower ramp rates than inverter-based systems	May sometimes provide attribute ramping constrained by thermal inertia and turbine dynamics
Cycling Capability^a	Typically provides attribute modern electrochemical systems are engineered for high cycle counts, though cycle life varies with technology	May sometimes provide attribute <i>frequent cycling possible, although mechanical wear may limit cycles</i>	May sometimes provide attribute <i>frequent cycling possible, limited turbine-generator operational constraints</i>
Short Minimum Run Time	Typically provides attribute can deliver power over very short runtime, suited for rapid response applications	May sometimes provide attribute <i>capable of short runs (2 hours), although better suited for longer durations</i>	May sometimes provide attribute <i>some can operate for short runs, but thermal inertia and turbine stability limit very short run times (<2 hours)</i>
Black Start	Typically provides attribute can be designed and controlled for black-start capability	May sometimes provide attribute some configured with auxiliary power for black start; PSH has demonstrated black start	Does not provide attribute most stand-alone thermal systems lack black-start capability, although TPV systems can provide it
Minimum Stable Output	May sometimes provide attribute can maintain a stable minimum output depending on design and operational strategy	May sometimes provide attribute <i>can maintain a stable minimum output (as low as 10%), depending on design and operational strategy</i>	May sometimes provide attribute <i>can maintain a stable minimum output (as low as 20%) depending on design and operational strategy</i>

^a Cycling capability in the context of LDES refers to how frequently a storage system can cycle. While electrochemical systems may have shorter overall cycle life, they offer higher cycling frequency. In contrast, mechanical and thermal systems—often coupled with synchronous generators—typically cannot start and stop or cycle as frequently.

The following summarizes key takeaways from Table 46:

- Mechanical energy storage systems typically support grid stability by providing rotational inertia, voltage control, ramping and black-start capability. However, they often have slower response times and limited operational flexibility.
- Electrochemical energy storage with an inverter-based system can deliver fast frequency response, high cycling capability, and short minimum run times, making them well-suited for dynamic grid support. These systems also provide voltage regulation through power electronics.
- Thermal energy storage can provide inertia, voltage support, and contribute to ramping when integrated with power generation systems, although it generally lacks fast response capabilities.

The suitability of LDES technologies for a particular application depends on key attributes such as RTE, duration, energy density, and standby losses. These factors influence the cost-effectiveness and feasibility of various energy storage technologies for various applications. These attributes for each technology are shown in Table 47. Key takeaways for each attribute are summarized below.

7.2.1 Round-trip Efficiency

Electrochemical storage technologies generally offer high RTE compared to other LDES technologies, making them efficient for frequent charge-discharge cycles. Conversely, thermal energy storage systems typically have lower RTE in AC-to-AC applications due to inefficiencies in the power generation cycle but perform well in AC-to-heat applications.

7.2.2 Duration

Most electrochemical systems are designed for interday storage, except for metal-air batteries, which are more suited for multiday applications. Mechanical storage can provide interday to multiday storage. Thermal energy storage systems, particularly those with lower-cost energy components, can be a cost-effective solution for longer-duration applications.

7.2.3 Energy Density and Standby Losses

Energy density is another crucial factor, with thermal energy storage technologies generally exhibiting high density due to their ability to store large amounts of heat in a compact space. LAES systems also offer high energy density because the storage medium—liquid air—can be compressed into a small volume. Standby losses vary across technologies, with electrochemical storage experiencing self-discharge over time, mechanical energy storage having low losses when not actively cycling, and thermal energy storage subject to gradual heat dissipation.

Table 47. Performance Characteristics of Long-duration Energy Storage Technologies

Source: Data derived from EPRI's Energy Storage Technology Database entries (2025d).

Technology Class	Technology Type	Duration ^a	RTE ^b	Energy Density (MWh/acre)	Standby Losses, %/day
Electrochemical	Advanced Lithium-ion	Short to Interday	High	28–350	<1%
Electrochemical	Flow Battery	Short to Interday	Medium	50–200	0%–4%
Electrochemical	Lead Acid	Short to Interday	Medium	30–100	<1%
Electrochemical	Metal Air	Interday to multiday	Low	200–250	1%–10%
Electrochemical	Sodium Ion	Short to Interday	High	50–294	<1%
Electrochemical	Sodium Sulfur	Short to Interday	Medium	30–572	<2%
Mechanical	Advanced Compressed Air	Short to Interday	Medium	12–760	<1%
Mechanical	Compressed CO ₂	Interday to multi-day	Medium	17–135	<1%
Mechanical	Geo-mechanical	Short to Interday	Medium	8–80	<1%
Mechanical	Gravity	Short to Interday	High	1–220	<1%
Mechanical	Liquid Air	Short to Interday	Medium	160–1,200	1%–2%
Mechanical	Pumped Hydro	Interday	Medium	20–50	<1%
Thermal	Molten Salt	Interday	Low	420–540	1%–2%
Thermal	Phase-Change Material	Interday	Low	150–790	1%–5%
Thermal	Pumped Heat	Interday to multiday	Medium	83–580	1%–2%
Thermal	Sensible (<1,000°C)	Interday to multiday	Low	250–1,900	1%–2%
Thermal	Sensible (>1,000°C)	Interday	Medium	500–12,000	1%–3%
Thermal	Thermochemical	Interday to multiday	Low	1,800–8,000	1%–2%
Thermal	Thermophotovoltaic	Interday to multiday	Low	1,000–5,800	1%–3%

^a This table categorizes LDES into short, interday, and multiday durations based on currently available data from technology vendors. However, many technologies are scalable and can operate across multiple duration categories. Treat this classification as indicative, not definitive.

^b LDES technologies exhibit a range of RTEs, which may overlap across the defined categories: low (<60%), medium (60%–85%), and high (>85%). This table reports RTEs based on the higher observed values for each technology.

7.3 Readiness for 2040

7.3.1 Latest Deployment Trends

North America currently maintains substantial pumped hydropower storage capacity, with numerous projects exceeding 100 MW. The additional deployment of new LDES technologies has been primarily driven by procurement targets in states such as California and New York. This momentum is expected to continue growing in the future, driven by the increasing penetration of renewable energy and the push toward decarbonization. About 50% of projected LDES capacity additions in North America are expected to be mechanical technology. LDES growth is anticipated in other regions as well, driven by the increase in renewable energy penetration and the push toward decarbonization (LDES Council 2024).

This section discusses various LDES procurement initiatives in New York State and California, as well as selected developments in Australia, the UK, and Italy.

7.3.1.1 Long-duration Energy Storage Deployment in New York State

To support the development and demonstration of LDES technologies in New York State, NYSERDA has awarded funding for several LDES projects (NYSERDA 2022b, 2023b). Table 48 summarizes select projects.

Table 48. NYSERDA-funded Long-duration Energy Storage Projects

Developer	Capacity	Technology Type	NYSERDA Funding
Form Energy	10 MW/10,00 MWh (100 hrs)	Iron-air	\$12 M
PolyJoule, Inc.	167 kW/2 MWh (12 hrs)	Conductive polymer battery	\$1.03 M
Urban Electric Power	100 kW/1 MWh (10 hrs)	Zinc alkaline battery	\$0.7 M
Sperra (previously RCAM)	—	Marine pumped hydro	\$1.2 M
Quidnet Energy	100 kW/1 MWh (10 hrs)	Geomechanical	\$2.5 M

7.3.1.2 Long-duration Energy Storage Deployment in California

California’s LDES program has received more than \$270 million in funding to support demonstration and deployment of non-lithium-ion LDES technologies across the state. Table 49 summarizes some of the key LDES projects under development in California (CEC n.d.).

Table 49. Long-duration Energy Storage Projects under Development in California

Project	Capacity	Technology Type	Expected COD	CEC Funding
Viejas Band of Kumeyaay Indians	7 MW/70 MWh (10 hrs)	Vanadium flow and zinc hybrid battery	2025	\$43 M
Paskenta Band of Nomlaki Indians	15 MWh	Zinc-Br flow battery	2026	\$32.7 M
Form Energy	5 MW/500 MWh (100 hrs)	Iron-air	2025	\$30 M
Sacramento Municipal Utility District	3.6 MW/28.8 MWh (8 hrs)	Iron-flow battery	2027	\$10 M
University of California, San Diego	10 MWh thermal	Thermochemical	2027	\$8.9 M
Noon Energy	100 kW/10 MWh (100 hrs)	Chemical	2028	\$8.8 M

California has attracted proposals for larger LDES developments, with Hydrostor leading a notable development: a 500 MW/4,000 MWh adiabatic compressed air energy storage (A-CAES) Willow Rock Energy Storage Center in Kern County, which can deliver continuous power for at least 8 hours (Hydrostor 2024).

In August 2024, the California Public Utilities Commission (CPUC) announced a centralized framework for procuring long lead-time clean energy resources, including 2 GW LDES (CPUC 2024). Beginning in 2026, solicitations will be issued for up to 1 GW of LDES resources with a duration of at least 12 hours as well as 1 GW of LDES multiday storage resources. Projects are expected to come online between 2031 and 2037.

7.3.1.3 Federal Programs Supporting Long-duration Energy Storage

Several federal programs have supported LDES through funding, research, and loan guarantees. DOE’s LDES portfolio includes the following programs (DOE 2024b):

- **LDES Demonstration Program:** Demonstrates the commercial viability of LDES technologies and promotes wider commercial adoption.

- DOE/U.S. Department of Defense (DOD) LDES Joint Program: Supports demonstration of LDES technologies at government facilities through collaboration between DOE and DOD.
- LDES Pilot Program: Advances a diverse set of LDES technologies toward commercial viability and utility-scale demonstrations.

The DOE Loan Programs Office (LPO) has provided financial support through the Title 17 Energy Financing Program, which offers loan guarantees for innovative energy storage projects (DOE LPO 2024). DOE’s Energy Storage Grand Challenge further supports R&D, focusing on advancing energy storage technologies (DOE n.d.b). The ARPA-E DAYS Program funds LDES technologies capable of storing energy for 10–100 hours (APRA-E 2024). Ongoing funding of these efforts remains uncertain.

7.3.1.4 *Long-duration Energy Storage Deployment in Other Countries*

LDES deployment continues to expand internationally, with several countries establishing market mechanisms and policy frameworks to encourage investment. Table 50 highlights several examples.

Table 50. Examples of Long-duration Energy Storage Deployment in Australia, Italy, and the United Kingdom

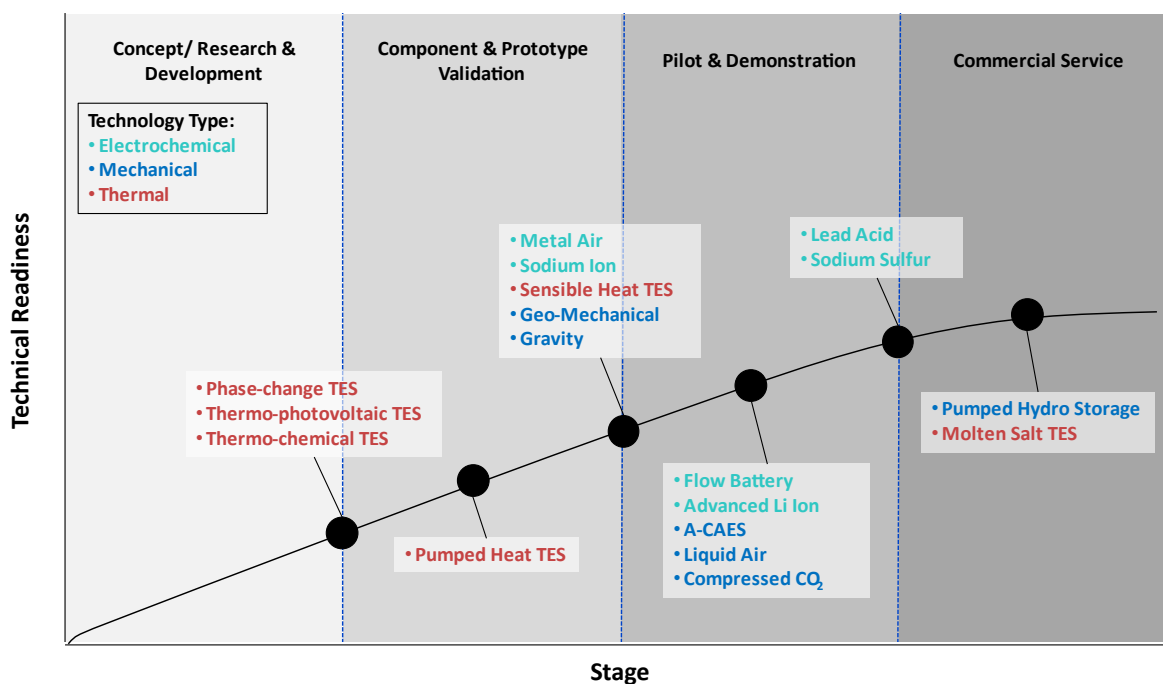
Country	LDES Deployment
Australia	Under the Electricity Infrastructure Roadmap, the New South Wales (NSW) government aims to deliver at least 12 GW of renewable energy generation and 2 GW/16 GWh of LDES by 2030 (NSW Climate and Energy Action 2020). Under the Roadmap, Australian Electric Market Operator (AEMO) Services conducts competitive tenders for Long-term Energy Service Agreements (LTESA). These tenders support investment, construction, and operation of renewable generation, LDES, and firming infrastructure. As part of its 10-year Tender Plan, AEMO Services conducts annual LDES tenders and biannual generation tenders to meet Roadmap objectives cost-effectively. To date, NSW has released four Roadmap Tender Rounds, with Rounds 1, 2, and 3 having announced their results. Rounds 1 and 3 awarded LTESAs to four LDES projects, collectively adding 574 MW/4,592 MWh of energy storage capacity, including several battery projects and one A-CAES project. Each awarded project has an 8-hour dispatch duration. In addition to these rounds, the NSW government has supported six pumped hydro projects with a combined 2.5 GW capacity for preinvestment activities and feasibility assessments through its \$50 million Pumped Hydro Recoverable Grants Program (PHRGP). In 2024, the NSW government consulted stakeholders on improving how it assesses LDES LTESAs (NSW DCCEE 2024). Based on the feedback, the NSW Government now mandates that LDES LTESA assessments consider the financial values of benefits provided by LDES infrastructure, including: • System resilience to low-probability, high-impact unserved energy events • System security services, such as inertia and system strength • Network investment deferrals, particularly through well-sited energy storage that reduces curtailment and unlocks hosting capacity
Italy	Italy has introduced direct tenders for large-scale energy storage capacity under long-term contracts (12–14 years). System operator Terna predominantly offers these contracts for battery energy storage systems, PSH, and other qualifying technologies. These long-term contracts provide stability and certainty for investors and developers, reducing the cost of capital and ultimately lowering costs to consumers (Terna Energy 2023).
UK	In 2021, the UK government launched the Longer-Duration Energy Storage Demonstration (LDES) competition as part of its £1 billion Net Zero Innovation Portfolio. This initiative allocated over £69 million in capital funding to accelerate the commercialization of FOAK LDES technologies. LDES supports various technologies through two funding streams, Stream 1 and Stream 2. To date, the government has funded 6 projects under Stream 1, and 26 projects have been funded in Stream 2 (DESNZ 2023). Recognizing key deployment barriers including high upfront capital costs, revenue uncertainty, insufficient market signals, and long build times, the UK government assessed various policy options, including a Regulated Asset Base (RAB) model, a cap-and-floor mechanism, Contracts for Difference (CfD), and a reformed capacity market. Based on this analysis, the government recommended implementing a cap-and-floor mechanism to support LDES deployment. This approach attracts private investment by guaranteeing a minimum return (floor) and capping excess profits (cap). It also helps reduce the weighted average cost of capital (WACC) by mitigating investment risk, which is essential given the high upfront costs. In 2024, the government consulted stakeholders on the proposed cap-and-floor mechanism. Following consultation, it confirmed the cap-and-floor scheme as the most viable option (DESNZ 2024b).

7.3.2 Technology Readiness

The readiness of LDES technologies varies widely across the various technologies being pursued, as shown in Figure 60. Significant uncertainty remains regarding which technologies will achieve large-scale deployment. While some technologies are well-established, others are still in early development or experimental phases, with the potential for breakthroughs that could reshape the energy storage landscape.

Figure 60. Current Technology Readiness of Long-duration Energy Storage Technologies

A technology remains in its current readiness phase until it completes all activities in that phase. A technology on the line between two readiness phases indicates that it has completed all activities in one phase but has not started activities in the next. The figure provides a high-level comparison of LDES technologies but does not reflect the variation in technological maturity within each category.



Mature technologies, such as PHS and molten salt TES, have been deployed commercially for years and provide reliable, large-scale energy storage. Similarly, electrochemical systems such as lead-acid and sodium-sulfur batteries have been in operation for decades. However, many emerging technologies are still in the early stages of commercialization. A-CAES, redox flow batteries, liquid air, and compressed CO₂ energy storage are gaining traction but have yet to reach widespread deployment. Meanwhile, thermochemical, TPV, and phase-change TES systems remain in early-stage development, with ongoing research aimed at improving efficiency, cost, and scalability.

Given the diversity of technologies and their varying levels of maturity, large-scale adoption will depend on continued technological advancements, cost reductions, and supportive policy and market frameworks. The evolving energy landscape may favor specific technologies based on application needs, grid requirements, and market dynamics.

7.3.2.1 Key Barriers to Long-duration Energy Storage Deployment

Historically, 1–4-hour energy storage systems, alongside thermal generators, have effectively met capacity needs during peak demand periods in many regions. In several wholesale markets, including NYISO, systems with a duration of at least 4 hours receive substantial capacity credit. For example, 6-hour systems in NYISO qualify for a 100% capacity credit, while 4-hour systems receive a 90% credit. Additional duration beyond this threshold typically does not result in higher capacity credit. However, as renewable penetration increases, the highest-value energy shifts may extend beyond 4–6 hours, which favors LDES. Increased renewable penetration will deepen diurnal demand spreads and increase the likelihood of seasonal supply shortfalls, requiring additional energy supply beyond the 4-hour duration mark (Denholm et al. 2023).

The addition of solar photovoltaic (PV) power and the electrification of building heating may shift net demand peaks toward winter. In cold climates such as those in New York State, electrification is expected to lead to future winter system peaks that often exceed the capabilities of short-duration energy storage systems. As winter peaks rise and solar PV generation increases, LDES becomes more critical.

Most experts recognize that changes to current market and regulatory frameworks are necessary to promote market-based deployment of large-scale LDES. New market products must provide appropriate compensation for the attributes of LDES technologies, including the duration, reliability contributions, and decarbonization benefits. Lack of adequate compensation and revenue certainty are key barriers to LDES deployment, as observed across various markets studied for this assessment. Moreover, LDES technologies are capital-intensive, have longer lead times, and face extended payback periods, which pose financing and deployment challenges.

Appropriate revenue mechanisms and market participation models can provide the appropriate pricing of energy attributes that LDES can deliver to electric systems. Well-designed market and regulatory frameworks can help reveal valuable use cases and applications of LDES in New York State. Reforms can ensure that LDES technologies are compensated for the benefits they provide to the system, offer

long-term revenue stability, and align with broader decarbonization goals. Market mechanisms such as cap-and-floor systems and long-term energy supply agreements are being exercised in other markets to provide long-term revenue certainty for LDES (see Section 7.3.1).

The following summarizes several potential reforms highlighted during discussions with experts:

- **Duration-based Compensation:** Assign appropriate capacity credits to LDES based on long discharge duration, not just power rating, to accurately reflect value in grid reliability.
- **Carbon Reduction Credits:** Compensate LDES owners for CO₂ reductions achieved by charging during low-carbon electricity periods and discharging during high-carbon electricity periods.
- **Indexed Storage Credit for LDES:** Build on New York State's indexed storage credit for shorter-duration energy storage by introducing an analogous mechanism tailored to LDES, which could provide revenue stability. This would tie compensation to a capacity hedge price, fostering investor confidence. Introducing new LDES-specific market products without undermining existing capacity markets is critical to maintaining economic viability and avoiding missed revenue opportunities in existing capacity markets.
- **Functional Valuation Framework:** Evaluate LDES based on location-specific metrics such as System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI).²⁰ LDES should also be valued for its potential to contribute critical services, particularly in pairing with renewables or grid infrastructure, to account for services beyond capacity.
- **Revenue Stacking Opportunities:** Enable LDES to participate in multiple market segments, such as frequency regulation, capacity services, and grid reliability support. This multistream revenue approach increases economic viability.
- **Energy Storage as a Transmission Alternative:** Despite limited success in most regions, refining tariffs for energy storage as transmission can unlock new opportunities.

7.3.3 Infrastructure and Supply Chain Readiness

Table 51 summarizes the current status of infrastructure and supply chain readiness for various LDES technologies. Notes on key impacts and considerations for each category are provided below the table.

Table 51. Infrastructure Readiness of Long-duration Energy Storage Technologies in New York State

Technology	Transmission & Grid Integration	Fuel Supply Chain & Waste Management	Cooling Water & Thermal Management	Siting & Land Use	Supply Chain
Electrochemical	Site-specific	No significant buildout required No fuel required; some EOL considerations required	No significant buildout required	No significant buildout required Energy-dense, small footprint	Infrastructure not ready Potential raw material supply chain constraints
Mechanical	Site-specific	No significant buildout required No fuel required; some EOL considerations required	No significant buildout required	Infrastructure not ready Large footprint or underground infrastructure required	Infrastructure not ready Manufactured component supply chain buildout required
Thermal	Site-specific	No significant buildout required No fuel required; some EOL considerations required	No significant buildout required	No significant buildout required Energy-dense, small footprint	Infrastructure not ready Manufactured component supply chain buildout required

Transmission and Grid Integration

Most LDES technologies do not require significant grid expansion because they are modular and can be deployed close to load centers. However, large-scale energy storage deployment might require upgrades in grid interconnection, especially in urban areas, or significant transmission buildout if sited in remote areas. LDES systems can utilize established grid connections when paired with an existing asset such as a retiring thermal plant. LDES technologies can be deployed as transmission assets and can help avoid or defer transmission investment.

Fuel Supply Chain and Waste Management

Most LDES technologies do not require fuel sources to operate and do not produce significant waste, avoiding any fuel supply chains and waste management concerns. However, end-of-life (EOL) disposal and recycling of storage media require consideration to mitigate environmental impacts.

Cooling Water and Thermal Management

Cooling water and thermal management strategies vary significantly across LDES technologies. Mechanical and thermal energy storage systems require heat dissipation mechanisms, while electrochemical storage systems rely more on controlled cooling to prevent overheating. Water consumption depends on the specific cooling method employed, with some systems favoring air or phase-change cooling to reduce reliance on water resources. Liquid cooling systems may involve water consumption. However, these LDES systems do not require a significant buildout of cooling water supply.

Siting and Land Use

Most electrochemical technologies are generally compact and modular, requiring little land, making them suitable for urban or distributed applications. Flow, lead-acid, and metal-air batteries may have slightly higher land requirements for larger installations compared to other electrochemical technologies due to lower energy density. Mechanical energy storage technologies, especially geomechanical and gravity storage, may require a large land area due to relatively low energy density, which poses siting challenges. A-CAES may need purpose-built underground caverns, which adds to the siting and permitting complexity. LAES has high energy density and requires a relatively smaller footprint. Compressed CO₂ can be installed aboveground and is not significantly complex to build. PSH requires substantial infrastructure, including reservoir build, which can lead to siting, permitting, and environmental concerns. However, some mechanical energy storage technologies, such as gravity energy storage, can be deployed by repurposing existing infrastructure, such as abandoned mineshafts or oil wells, thereby reducing complexity and costs. Thermal energy storage technologies are generally energy dense and can be deployed for both heat and power applications at existing thermal units, industrial sites, or land-constrained areas. All LDES technologies have safety considerations that can impact siting potential. Section 7.4.2 discusses safety issues.

Supply Chain

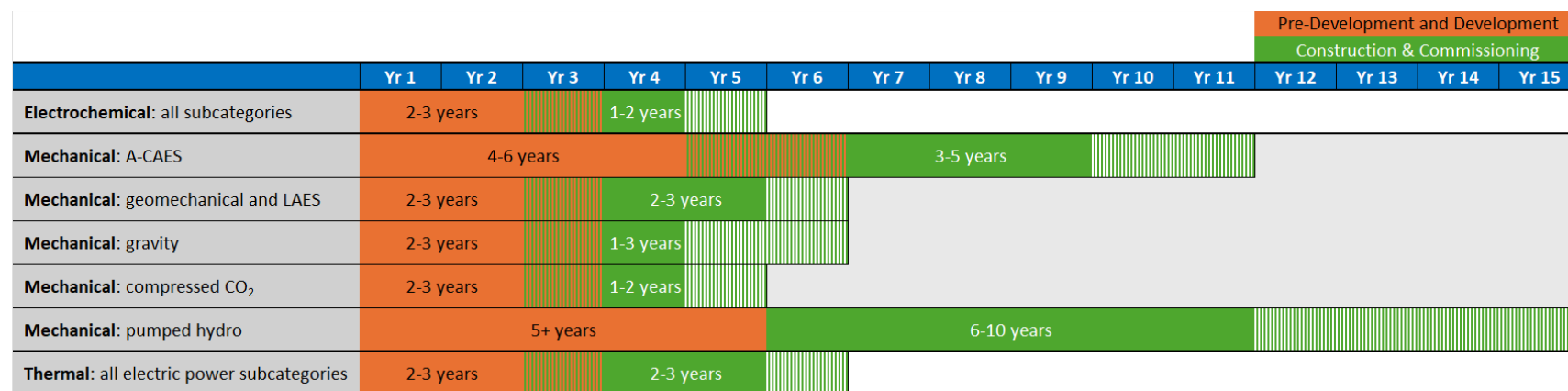
Electrochemical energy storage technologies, including advanced lithium-ion and flow batteries, face raw material supply chain constraints (lithium, nickel, vanadium), which could make large-scale deployment challenging. Lead-acid, metal-air, sodium-ion, and sodium-sulfur batteries rely on raw materials that are either abundant or fully recyclable, but like all LDES technologies, they require manufacturing expansion.

Mechanical and thermal energy storage technologies generally do not rely on rare raw materials or subcomponents. However, A-CAES and LAES face the highest risks in scaling manufacturing and assembling facilities. Significant interventions must build adequate facilities and know-how to scale these technologies (DOE 2023c).

7.3.4 Project Lead Times

The deployment of energy system technologies, including LDES, typically progresses through four key phases (EPRI 2023n). In predevelopment, developers identify sites, assess viability, and create conceptual designs. Project development involves engineering, securing property and access rights, finalizing power agreements, obtaining grid interconnection approvals, permitting, financing, contracting, and procuring technology. Construction covers site preparation, executing construction plans, and building the facility. Commissioning completes the process by system testing, validating the system, and initiating commercial operations. Project lead times for LDES technologies vary significantly based on technology type, infrastructure requirements, site-specific conditions, and deployment complexity. Permitting and construction activities are generally the most time-intensive stages of the deployment timeline. Figure 61 shows the estimated project lead times for select technologies.

Figure 61. Project Timelines for Long-duration Energy Storage Technologies



7.3.4.1 *Electrochemical Lead Times*

Electrochemical systems generally have shorter permitting timelines compared to mechanical and thermal technologies because developers typically design them to be modular, containerized, and compact. Construction times for electrochemical energy storage systems are generally short (<2 years) due to their modular nature and relatively straightforward installation. Containerized battery systems can be manufactured in a factory and transported to the site for installation.

7.3.4.2 *Mechanical Lead Times*

Mechanical energy storage technologies typically require longer permitting timelines than electrochemical systems. Given the limited number of mechanical LDES projects worldwide to date (outside PSH), permitting timelines for newer mechanical technologies remain highly uncertain. Large-scale A-CAES projects, such as Hydrostor's 500 MW/4,000 MWh Willow Rock Energy Storage Center facility in Kern County, California, have experienced multiyear permitting. Hydrostor submitted its initial permit application in December 2021 and anticipates that the review process will be completed in 2025 (Carbon Capture Credits 2025). Gravity-based and geomechanical systems may achieve faster permitting, particularly when utilizing brownfield sites or existing industrial infrastructure, although they can still encounter challenges such as height restrictions (for gravity systems) and subsurface risk assessments (for geomechanical storage). These technologies typically avoid the extended permitting timelines of PSH, which often require 5 years or more due to complex regulatory reviews and stakeholder engagement.

Construction times for mechanical energy storage technologies can vary more. Liquid air and compressed CO₂ energy storage systems have short construction times because they leverage existing industrial processes and infrastructure, allowing for adaptability. A-CAES with purpose-built caverns requires extensive infrastructure, resulting in longer construction timelines of up to 5 years. Geomechanical and gravity-based energy storage systems take 1–3 years to construct, depending on geological or structural considerations, but generally do not need extensive site development. PSH, requiring large-scale civil works and water reservoirs, has the longest construction timeline among LDES technologies (6–10 years).

7.3.4.3 Thermal Lead Times

Thermal energy storage technologies have uncertain permitting timelines due to limited deployment experience. Large-scale molten salt systems integrated with concentrated solar power (CSP) have historically required 2–3 years of permitting, primarily driven by concerns over land use, wildlife habitat, and water usage. TES itself (the salt tanks) does not add much unique delay—the overall CSP plant infrastructure and environmental footprint typically drive the permitting timeline. Retrofitting retiring thermal plants with TES can shorten permitting timelines, particularly when existing infrastructure is utilized and sites are already industrialized.

Thermal energy storage technologies typically require 2–3 years for construction, influenced by the need for specialized materials, integration with heat exchange systems, and site-specific engineering considerations.

7.3.4.4 Siting Considerations

A key determinant across all LDES technologies is whether the project is sited on a brownfield or greenfield site. Brownfield sites can offer significant advantages, including shorter permitting timelines, fewer environmental assessments, and better community acceptance due to their familiarity with energy infrastructure (EPRI 2023k). In contrast, greenfield projects face longer permitting due to environmental surveys, interconnection challenges, and new land-use approvals, especially in jurisdictions with more stringent environmental and local governance standards.

7.3.5 Geographic Suitability and Constraints

New York State faces distinct challenges for LDES scalability in Upstate (Zones A-E) and Downstate (Zones J and K) due to differences in land availability, proximity to load centers, and other deployment constraints. Upstate New York, with its more abundant land and existing renewable generation from hydro, solar, and wind, offers greater potential for large-scale LDES deployment. The key bottlenecks for Upstate deployment include longer lead times for technologies such as A-CAES, material supply chain constraints, and the readiness of some technologies. Additionally, transmission bottlenecks might limit the ability to deploy large-scale LDES and transmit stored energy to high-demand Downstate areas.

Downstate New York, particularly the New York Metropolitan Area and Long Island, faces greater challenges due to space constraints, high land costs, and dense population. Large-scale LDES options like geomechanical or gravity energy storage are challenging in urban areas, necessitating compact and

modular solutions. Locating LDES near communities requires additional consideration of the safety risks associated with these technologies. Thermal energy storage technologies (sensible, phase-change) have high energy density, can serve heat and power needs, and could be installed at existing fossil plants in urban regions. Their use of non-flammable materials might make them suitable for densely populated areas.

Downstate New York regions with greater penetration of variable renewable energy are expected to experience an increase in diurnal energy spread. LDES technologies with high cycling capabilities and high RTEs are well-suited to meet these needs. Electrochemical energy storage systems, such as flow batteries, are particularly effective at demonstrating high cycling capabilities and offer lower thermal runaway risks compared to LIBs. Many LDES technologies are inherently modular, making them well-suited for deployment in land-constrained regions. Manufacturers are increasingly offering smaller units, enhancing versatility for urban deployments. Table 52 outlines the minimum project sizes based on current product offerings and land requirements for select technologies, as announced by vendors, reinforcing the modularity of LDES and scalability potential in regions such as Downstate New York, where distributed, compact energy storage solutions are essential.

Table 52. Minimum Deployment Size Based on Vendor Announced Product

Storage Technology	Size ^a	Area Required (acres)	Technology Developer
Flow Battery	75 kW/900 kWh	<1	Invinity
Sodium-Ion Battery	45 kW/540 kWh	<1	Adena Power
Sodium-Sulfur Battery	1 MW/5.9 MWh	<1	NGK
Carbon Dioxide Battery	20 MW/200 MWh	12–15	Energy Dome
Sensible Heat (power-to-heat)	7 MWt/100 MWh	1–2	Rondo Energy

^a The listed minimum project sizes reflect current product offerings, not the inherent limitations of the technologies. Future advancements may allow smaller, more flexible configurations, so these figures should be viewed as indicative rather than absolute constraints on scalability or deployment potential.

In urban areas like the New York City, developers can integrate modular LDES systems into vacant lots and commercial buildings, reducing land-use conflicts. Thermal energy storage systems might be suitable for repurposing existing steam power plant sites and gas turbine sites and could reuse existing infrastructure, including electrical infrastructure and turbine generators.

The New York City Mayor’s Office of Climate and Environmental Justice conducted a study under PowerUp NYC to explore opportunities for replacing fossil fuel power plants in New York City with battery energy storage, aligning with New York State’s climate goals (PowerUp NYC 2023). A geospatial screening analysis using public datasets identified viable sites for energy storage deployment.²¹

The analysis identified specific land types for energy storage deployment, including:

- City-owned land and parking lots: The city identified 27 acres of city-owned vacant land and municipal parking lots (assuming 15% availability), providing an opportunity for energy storage installation.
- Privately-owned land: Privately-owned vacant land offers greater potential (~240 acres), but it faces significant competition for other land uses.
- Fossil fuel plant sites: 14 fossil fuel plants were analyzed (total capacity ~7,500 MW), and approximately 100 acres of land were identified. However, energy storage may not be a suitable replacement at all sites, depending on each plant’s operational patterns and the lag time between decommissioning and new development.

In addition to the land identified above, Long Island also has opportunities for LDES deployment. The region hosts several fossil fuel plants, whose output has declined in recent years and is projected to continue declining as more renewable energy sources are added to the electric grid. Repurposing retiring units by installing thermal energy storage could be a viable option. Solar farms in the region also present a compelling opportunity for pairing with LDES technologies, supporting grid stability, maximizing renewable energy utilization, and providing firm, clean energy to the region.

7.3.6 Readiness Summary

LDES deployment readiness varies widely across technologies. Some technologies, such as PHS, molten salt TES, lead-acid batteries, and sodium-sulfur batteries, are mature technologies that have operated commercially for decades. Conversely, many other emerging technologies are in the early stages of commercialization. Geographic suitability and scalability also vary across technologies. Upstate New York offers greater potential for deployment of large-scale LDES, while Downstate New York faces greater challenges due to space constraints, high land costs, and dense population, necessitating compact and modular solutions. Given the diversity of technologies and their varying levels of maturity, future large-scale adoption will depend on continued advancements, cost reductions, and supportive policy frameworks. The evolving energy landscape may favor specific technologies based on application needs, regional grid requirements, and market dynamics. Market and regulatory changes recognizing the value of LDES attributes can support LDES deployment across the State.

7.4 Emissions and Other Considerations

7.4.1 Emissions

LDES technologies do not directly emit GHGs during their operation. However, the GHG emissions associated with the operations of LDES technologies depend on both the source of electricity used for charging and the technology's efficiency. Because all energy storage systems experience RTE losses, a portion of the energy input is wasted as heat or other losses. If the charging electricity is derived from fossil fuel-based sources, these losses result in additional emissions, increasing the carbon footprint of the energy storage system. Conversely, when LDES is charged primarily with renewable energy, its contribution to operational emissions is minimal. This dependency underscores the importance of grid decarbonization in determining the true environmental benefits of energy storage (EPRI 2020b).

7.4.2 Other Considerations

7.4.2.1 *Air Quality*

LDES technologies are not expected to significantly impact air quality.

7.4.2.2 *Safety and Environmental Considerations*

Each LDES technology presents distinct safety and environmental challenges. The diversity of LDES technologies, combined with limited operational experience for emerging technologies, complicates the development of a standardized approach to safety and environmental risk management. The following section summarizes the key safety considerations of LDES technologies, as well as their potential for recycling.

Electrochemical

Electrochemical LDES technologies share some common safety risks across all types. These include arc flash and electrical shock hazards from high-voltage systems, as well as residual energy left after shutdowns or damage, which can pose dangers to operators and maintenance personnel. Chemical spills and leaks resulting from corrosion also present safety and environmental concerns. Additionally, the large and heavy modules used in these systems can pose physical strain risks to installation personnel during installation, maintenance, or in the event of mechanical failure. Rapid or unexpected shutdowns can lead to electrical and physical instability, underscoring the importance of a comprehensive understanding of these risks.

In 2023, New York State convened an interagency fire safety working group to enhance the safety of energy storage systems statewide. The group collaborated with national labs and other subject matter experts to evaluate current fire codes and testing standards pertinent to the development and electrification of battery energy storage systems. The group produced a Fire Code Recommendations Report that informed the code development process in New York State (NYSERDA 2025e).

From an environmental perspective, electrochemical systems raise concerns regarding the extraction of raw materials. Safe and commercially viable recycling methods exist today. These methods are generally cost-effective, particularly for modules with high nickel or cobalt content. Recycling offers key environmental benefits by recovering critical materials, reducing the need for new extraction, and supporting domestic supply control (EPRI 2024g). Table 53 summarizes the safety risks and EOL management considerations for these technologies.

Table 53. Safety and End-of-Life Management Considerations for Selected Energy Storage Technologies

Technology	Safety Considerations	EOL Management
Advanced Lithium-ion Batteries	The principal safety concern for LIBs is thermal runaway. Although all prevalent lithium-ion chemistries contain flammable electrolytes and can exhibit propagating thermal runaway, the propensities and intensities vary across different chemistries (EPRI 2023p). Despite continued incidents, the failure rate of utility-scale BESS has dropped significantly from 2018 to 2024, even as global deployment surged—reflecting improvements from lessons learned and better design practices (EPRI 2025a). Advanced lithium-ion technologies, such as ASSBs, hold promise for advancements in safety. In ASSBs, the liquid electrolyte and polymer separator are replaced with a solid electrolyte, eliminating the need for the flammable solvents typically found in liquid electrolytes. While solid electrolytes significantly reduce the likelihood of inciting combustion, failures in other system components, such as electrical subsystems, can still ignite the battery (EPRI 2020b). If metallic lithium is involved, response procedures may differ from those for lithium-ion systems, which typically rely on large volumes of water.	Due to the use of metallic lithium, current lithium-ion recycling protocols may not apply to ASSBs. Modified protocols will need to be developed.
Flow Batteries	Flow batteries use nonflammable liquids, reducing fire risks. However, gas generation—particularly hydrogen and oxygen—can occur when operating close to the voltage limits where electrolysis can produce gases. The high heat capacity of the aqueous electrolyte usually limits temperature rise, but off-nominal conditions may still cause temperatures to rise and gas release. The toxicity or flammability of the gases released and the degradation and changes that occur to the flow battery components under off-nominal conditions have not been fully investigated (Jeevarajan et al. 2023). Engineered exhaust systems typically recombine or vent H ₂ and O ₂ gases. For other gases, such as bromine, which is highly corrosive and toxic, additional mitigation measures may be needed to address potential hazards. Flow battery electrolytes are often highly acidic or basic and contain concentrated metal ions, posing risks to humans and the environment if spilled. Mitigation designs include secondary containment systems to manage any electrolyte leakage from the primary containment.	Recycling flow batteries is anticipated to be less complex compared to lithium-ion technologies, with reported efficiencies of up to 95% for recovering metals from stack and system components, and up to 97% for vanadium extraction from the vanadium redox flow battery electrolyte, as demonstrated in a test by U.S. Vanadium (U.S. Vanadium, 2021).

Table 53. (continued)

Technology	Safety Considerations	EOL Management
Lead-acid Batteries	VRLA batteries face thermal runaway risk, where uncontrolled recombination of hydrogen and oxygen during charging can increase internal pressure, potentially deforming the casing and, in rare cases, causing fires. However, these incidents are generally less severe than those in LIBs. Mitigation strategies include temperature-compensated charging and the use of catalysts to reduce gas buildup. Thermal runaway risk can increase with age in VRLA cells (EPRI 2023e). In VLA batteries, safety measures focus on regular electrolyte maintenance and spill containment.	Lead-acid batteries have well-established recycling practices, with >98% recycling rates in developed countries and improving rates globally. This makes them one of the most recycled energy storage technologies, contributing to a near-circular economy in certain regions.
Metal-air Batteries	Metal-air batteries utilize various metals, with Li, Zn, Fe receiving significant R&D attention due to their advantages. Li-air batteries, leveraging the high energy density of Li, are suitable for nonaqueous electrolyte systems as Li is highly reactive with water. However, Li-air batteries face safety challenges due to the formation of dendrites on the lithium metal anode, which can lead to short circuits and thermal events. Zn-air batteries, in contrast, use a nontoxic, nonflammable aqueous electrolyte, enhancing safety and reducing negative environmental impacts. However, charging can lead to hydrogen evolution at the anode, requiring appropriate safety precautions to mitigate potential hazards (Salado and Lizundia 2022). The aqueous electrolyte used in Zn-air batteries is typically alkaline KOH, which is corrosive and can cause irritation or severe injury if it comes into contact with personnel. Iron-air batteries also use aqueous electrolytes and face the challenge of hydrogen evolution as a byproduct of operation.	Metal-air batteries, including zinc-air, aluminum-air, and iron-air variants, rely on abundant and inexpensive raw materials. Established recycling routes for these metals are readily applicable and can support the broader adoption of this technology.
Sodium-ion Batteries	SIBs offer improved safety relative to LIBs during handling and transport, as they can be safely discharged to 0 volts, largely due to the use of aluminum current collectors on both the anode and cathode. This capability provides logistical advantages for safer energy storage and installation (Li 2023). However, SIBs encompass various electrochemistries, and most use hard carbon anodes with a variety of cathode materials. The electrolytes in many designs are based on organic carbonates, which share similar thermal runaway risks with LIBs. Like LIBs, SIBs with organic electrolytes form a solid-electrolyte interphase (SEI) on the anode, and the breakdown of this SEI layer can trigger thermal runaway under certain conditions, posing additional safety risks. While non-flammable ionic liquid electrolytes can be used to enhance safety, their lower ionic conductivity may limit applicability in certain designs.	Recycling SIBs is technically feasible, given their similarity to LIBs, but economic challenges may arise due to the low value and cost of materials used. No established recycling markets exist yet.
Sodium-sulfur Batteries	NaS high-temperature batteries operate with molten sodium and sulfur, which pose inherent safety concerns due to the risk of a highly exothermic fire if these materials combine. Sodium and sulfur are flammable and can release toxic SO ₂ gas during a fire. Modern NaS batteries incorporate several safety measures: sand filling to absorb and extinguish leaked materials, thermal fuses to prevent short circuits, hermetic cell seals, and thermal enclosures to isolate against external impacts and internal leakage.	EOL management for NaS batteries poses challenges, primarily due to safety concerns about exothermic reactions. Methods for recycling and disposal, along with their associated safety protocols, are still under development, requiring further refinement to address these risks effectively (Fraunhofer ISI 2022).

Mechanical

Mechanical energy storage technologies present safety challenges due to high-pressure systems, moving components, and potential structural failures. Most systems using turbomachinery and heat exchangers, similar to those found in commercial gas turbine plants, necessitate comparable safety considerations. Environmental impacts for these technologies typically do not involve gaseous emissions, but may include water quality impacts, water usage, temperature, or physical risks.

Table 54 summarizes some of the key risks associated with these technologies.

Table 54. Key Safety and Environmental Concerns of Long-duration Energy Storage Technologies

Technology	Key Safety and Environmental Considerations
A-CAES	Key safety concerns include maintaining pressure vessel integrity and safely managing heat during compression. Robust pressure vessels with active monitoring and relief systems ensure this. Leaking underground geological energy storage may contaminate groundwater with pH, trace metals, or dissolved substances. Pressure fluctuations may potentially lead to ground subsidence or geological deformation, particularly when using underground caverns or porous rock formations for air storage.
Compressed CO ₂	CO ₂ leaks pose safety and environmental risks, which can be hazardous to health due to asphyxiation risks and the environment due to climate impacts.
Geomechanical	Subsurface water management and potential groundwater contamination raise environmental concerns. Operators must carefully select sites, assess structural integrity, and conduct monitoring to ensure safe and effective operation.
Gravity	Gravity systems move large masses to store and release energy. Uncontrolled descent due to system failure, or even standard installation and deinstallation procedures, can pose significant risks to nearby people and property.
LAES	LAES systems liquefy air by cooling it to cryogenic temperatures. Safety considerations include handling cryogenic temperatures.
PSH	PSH technology is well-established and has been operational for decades. Dams require long-term maintenance since structural damage can lead to catastrophic flooding downstream. Depending on the extent of ecosystem modification required for their construction, PSH systems can lead to significant GHG emissions and habitat disruption.

Thermal

Thermal energy storage technologies pose safety risks, including containment failures, material degradation, and accidental spillage, which can harm workers or contaminate the environment. These technologies are still in the early stages of development, so researchers have limited empirical data available on long-term safety risks, degradation mechanisms, and failure modes under diverse operational and environmental conditions.

Table 55. Key Safety Considerations for Thermal Energy Storage Technologies

Technology	Key Safety and Environmental Considerations
Molten Salt	Molten salt storage requires consideration of the toxicity of materials. Common nitrate-based salts, such as sodium and potassium nitrate, have low toxicity but are oxidizers so they must be handled properly when near potential fuel sources (Ho 2017). Chloride-based salts, used in higher-temperature systems, are more corrosive and present moderate toxicity (Ding et al. 2018). Other risks include handling corrosive fluids and managing potential leaks, spills, and infrastructure damage at high operating temperatures.
Phase Change	Public information on the long-term safety risks, failure mechanisms, and operational reliability of phase change TES remains limited.
Pumped Heat	Pumped heat storage uses thermodynamic cycles with compressed gases or other working fluids, which can pose risks associated with high-pressure systems and mechanical failure. Systems require robust design and operational safeguards, such as the use of a pressure relief system.
Sensible	Sensible heat storage materials with high thermal inertia can pose structural risks under extreme temperature variations, especially when the thermal storage medium is subjected to pressure.
Thermochemical	Thermochemical storage involves chemical reactions at elevated temperature or pressure, posing risks to worker safety and the environment.
Thermophotovoltaic	Thermophotovoltaic systems, while innovative, may raise life-cycle toxicity concerns, such as waste generated during semiconductor production.

Developing a standardized safety framework for LDES is inherently complex due to the diverse operational principles, materials, and risks associated with each technology. Emerging energy storage system technologies require unique safety assessments. In the absence of comprehensive safety data for new technologies, standards development organizations face significant challenges. Researchers must investigate aging mechanisms and failure modes in emerging storage technologies to assess potential hazards and implement appropriate safety management strategies.

Ensuring the safety of emerging energy technologies requires a proactive approach to address novel risks and failure modes associated with their deployment and operations. Revising qualification standards to account for new failure mechanisms and incorporate advanced testing methodologies often lags behind the initial market introduction of these technologies. Consequently, adopting a defense-in-depth strategy, which involves implementing multiple layers of safeguards to prevent and mitigate risks effectively, should extend beyond compliance with existing codes and standards in any given jurisdiction, incorporating leading safety practices (EPRI 2023p).

7.4.2.3 Land Use

As discussed in Section 7.3.5, the land-use requirements of LDES technologies vary by technology. Most electrochemical technologies are compact and modular, requiring relatively little land. Mechanical energy storage technologies, especially geomechanical and gravity storage, often require more land due to their relatively low energy density. Technologies such as A-CAES and PSH may require large infrastructure buildouts in underground caverns and water reservoirs, respectively, introducing complexity in siting and permitting.

Thermal energy storage technologies tend to be energy dense, reducing land requirements. Projects that leverage existing sites could lower land-use impacts.

7.4.2.4 Workforce

Workforce considerations differ by LDES technology. Most LDES technologies require a minimal workforce to operate the storage site, and many sites may be operated from a control center without staff on-site full-time, but rather for regular inspection and maintenance. For mechanical and thermal energy storage technologies, maintenance skills will likely translate from thermal fossil plants, offering an opportunity for workers transitioning from retiring fossil fuel plants. Electrochemical energy storage technologies may require more training of maintenance staff. Workforce constraints for LDES technologies are expected to arise primarily during manufacturing and deployment rather than operations. As deployment scales, the availability of skilled labor could become a limiting factor. This challenge may be compounded if wages and benefits are not competitive with other industries (DOE 2023c).

7.5 Cost

The capital cost of LDES technologies varies based on technology type, project size, duration, and specific site conditions. It is also important to distinguish between the capital cost of the energy storage system and the overall cost-effectiveness of stored electricity. Metrics such as RTEs, O&M expenses, and system lifetime all contribute to system cost-effectiveness. The levelized cost of storage (LCOS) is commonly used for cost comparisons across different energy storage technologies. However, LCOS is inherently biased toward high-cycling technologies because CAPEX and fixed operating costs are spread over a greater number of kilowatt-hours discharged compared to low-cycling technologies. For LDES technologies designed for infrequent, multiday operation, their LCOS values may appear significantly higher compared to short-duration systems, despite their potential to provide superior value in grid applications requiring extended-duration energy storage (EPRI 2023j).

Figures 62 through 64 show the capital cost of next-of-a-kind deployments of various energy storage technologies in \$/kWh for 10-hour, 24-hour, and 100-hour durations. These figures encompass all-inclusive project costs covering equipment, materials, labor, engineering, and contingencies, and are drawn from multiple sources, including studies by PNNL and EPRI, as well as vendor-provided data.

Cost estimates for multiday storage in this analysis are extrapolated from shorter-duration systems, assuming that capital costs scale predictably with increasing energy storage duration. However, actual costs for LDES solutions may vary significantly due to nonlinear scaling effects, diminishing economies of scale, and technology-specific constraints. These costs represent present-day, next-of-a-kind estimates. Section 7.5.1 discusses future cost reduction potential.

While the cost estimates are presented side by side, they are based on systems of varying scales and configurations, based on typical product offerings for the respective technologies. Differences in system size, design, and integration approach can influence unit costs, limiting the precision of direct comparisons. Geographic conditions, site-specific requirements, and construction timelines introduce additional variability. Moreover, some energy storage systems are designed with asymmetric charge and discharge rates, which can impact cost calculations.

Accurately estimating costs for long-duration storage systems requires a detailed feasibility study that encompasses site-specific engineering assessments, supply chain considerations, and system performance evaluations. Such an analysis falls beyond the scope of this assessment. Additionally, not all energy storage technologies are inherently suited for long-duration applications due to technological, economic, or operational limitations. Factors such as efficiency losses, degradation mechanisms, land requirement, thermal management challenges, and infrastructure and safety requirements can influence the feasibility and cost-effectiveness of deploying certain technologies for extended durations. Therefore, while the extrapolated cost estimates provide a general indication of potential trends, they should not be interpreted as definitive.

Figure 62. Capital Costs of Select Electrochemical Technologies for Various Storage Durations

Costs reported in 2023 USD.

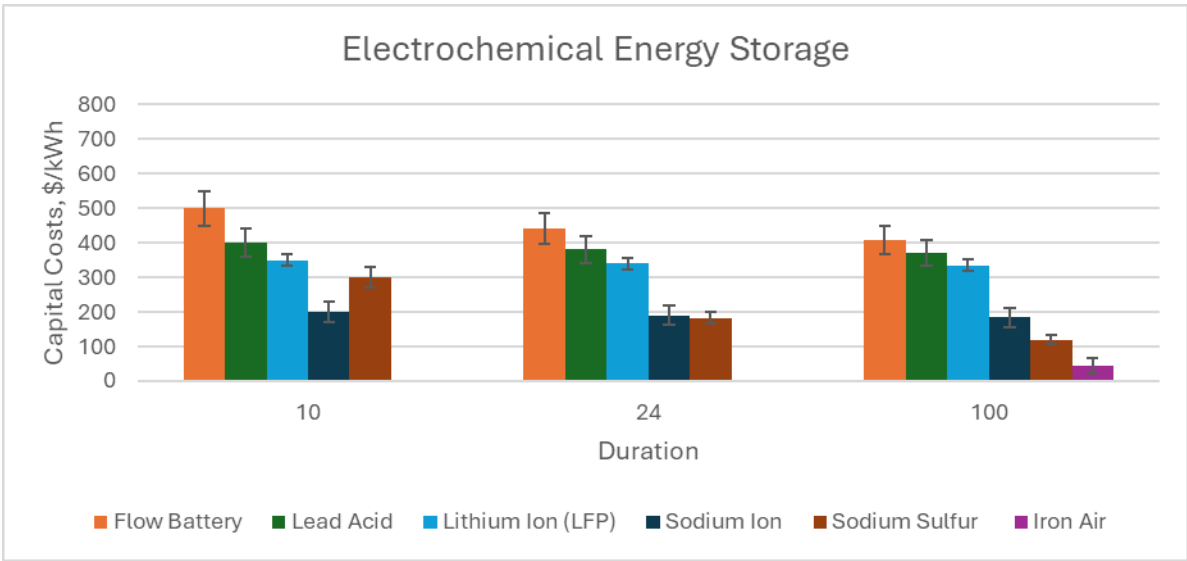


Figure 63. Capital Costs of Select Mechanical Technologies for Various Storage Durations

Costs reported in 2023 USD.

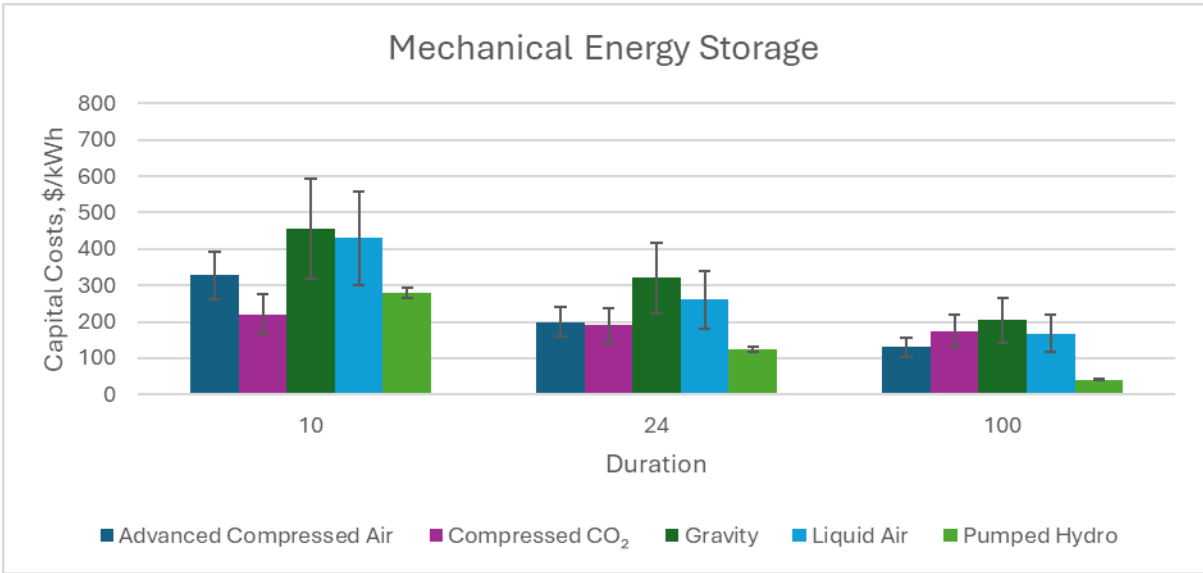
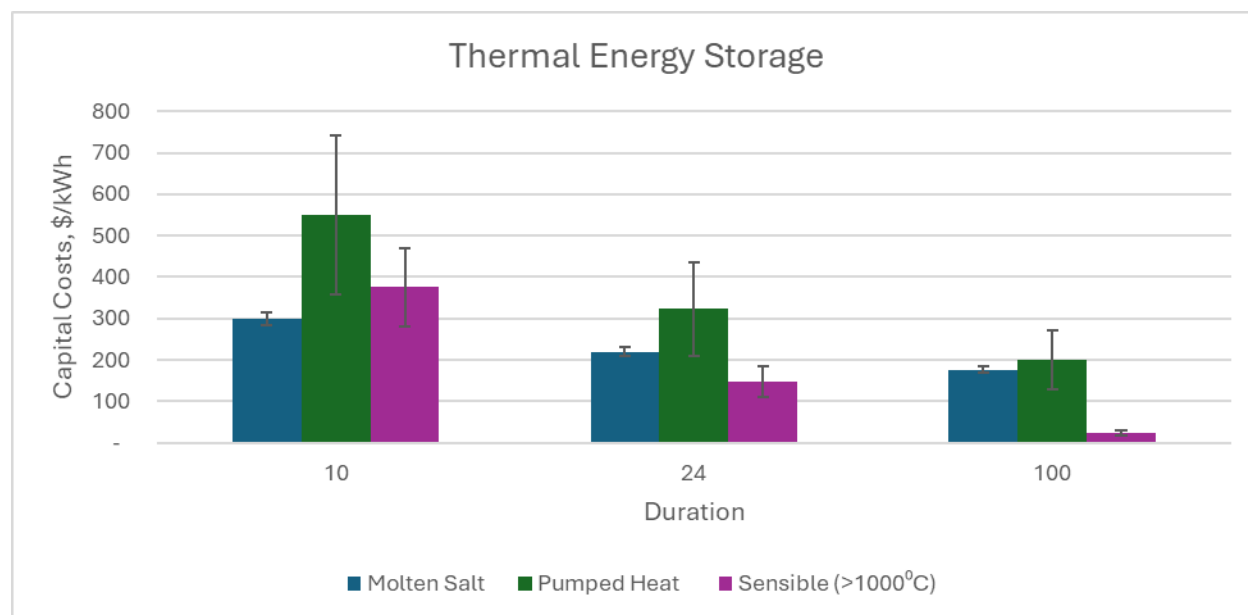


Figure 64. Capital Costs of Select Thermal Technologies for Various Storage Durations

The capital costs for molten salt and sensible TES systems are based on retrofitted or integrated configurations using an existing steam-Rankine cycle. In contrast, the cost estimates for pumped heat storage systems are based on stand-alone installations. Costs reported in 2023 USD.



The cost of the energy storage system can be divided into two components: energy-related costs and power-related costs. LDES with low energy-related costs tend to be more capital-efficient, particularly for longer durations. LIBs, the dominant short-duration energy storage solution, have high energy-related costs because they store energy within individual battery cells. Scaling up duration requires adding more cells, which form the bulk of the system’s cost. This results in a nearly linear increase in cost with duration, making LIBs economically unfavorable for LDES applications. In contrast, technologies such as flow batteries allow decoupling of energy-related components (e.g., electrolyte storage tanks) from power-related components. This separation enables a more cost-effective scaling of energy capacity, as increasing storage duration primarily requires larger electrolyte tanks rather than additional power equipment. However, Vanadium Redox flow batteries, one of the most commercially advanced types of flow batteries, rely on vanadium—a costly and supply-sensitive material—which limits their cost advantage for long-duration applications. Other flow battery chemistries, such as iron flow batteries, may offer lower costs but are at an earlier stage of commercialization.

SIBs are estimated to have a cost advantage over LIBs due to the abundance and lower price of sodium. Additionally, SIBs can eliminate the use of expensive metals like cobalt and possibly nickel for cathodes, further reducing costs. However, the use of hard carbon for anodes, which is currently more expensive

than graphite, offsets some of these savings (Fraunhofer ISI 2022). While overall material costs for sodium-ion cells are estimated to be lower than those of lithium-ion cells, the actual cost reduction depends on large-scale production efficiencies and continued material advancements. Similarly, sodium-sulfur batteries benefit from low-cost raw materials because both sodium and sulfur are abundant and inexpensive. However, sodium-sulfur batteries require high operating temperatures, leading to additional costs for thermal management and safety. While these factors impact overall system costs, sodium-sulfur batteries still present a cost advantage over LIBs for large-scale stationary energy storage applications.

Mechanical energy storage technologies vary widely in cost, depending on the infrastructure requirements. Gravity-based systems and LAES are estimated to have the highest capital cost. Gravity-based energy storage, which involves lifting and lowering heavy masses, requires significant material use, involves moving parts, and has a large physical footprint, driving up capital costs. LAES, which operates at cryogenic temperatures, incurs high capital costs due to specialized insulation and infrastructure requirements.

Thermal energy storage technologies tend to have relatively lower energy-related costs compared to electrochemical solutions, particularly for longer durations. Since most thermal energy storage can scale energy capacity by simply increasing the volume of storage material, their cost structure is generally more favorable for longer durations.

7.5.1 Cost Reduction Potential of Long-duration Energy Storage Technologies

LDES technologies are poised for substantial cost and performance improvements, driven by innovations in materials, manufacturing techniques, and system design. Key insights from the LDES Council's survey (LDES Council 2024) and the DOE's *Long-Duration Storage Shot Technology Strategy Assessments* (DOE 2023d) provide a forward-looking perspective on the cost reduction potential of electrochemical, mechanical, and thermal energy storage systems.

According to the LDES Council survey, installation costs for electrochemical and mechanical energy storage technologies could decline by up to 60%. In comparison, thermal energy storage systems may see cost reductions of up to 50% between 2025 and 2030. O&M costs, which typically account for less than 2% of annualized project costs, are expected to remain relatively stable (LDES Council 2024).

DOE's *Long-Duration Storage Shot Technology Strategy Assessments* (DOE 2023d) use stakeholder engagement and modeling to identify key innovation pathways that can significantly reduce the LCOS relative to 2030 projected baseline costs. The potential LCOS improvements for various LDES technologies compared to the 2030 baseline estimates discussed later are based on the DOE's strategy assessments of implementing the most promising 10% of innovation portfolios for 10-hour duration applications (DOE Office of Electricity 2024).

7.5.1.1 Electrochemical Energy Storage Technologies

Flow Batteries

Cost reduction opportunities for flow batteries include the development of novel electrolytes, scalable manufacturing processes, accelerated material discovery cycles, and enhanced system design (e.g., bipolar plates). The DOE estimates that a \$330 million incremental investment over current funding could yield a 66% reduction in LCOS over 8–12 years.

Lead-acid Batteries

Improvements such as redesigned current collectors, advanced manufacturing methods, and the incorporation of novel active materials could significantly reduce LCOS. DOE projects that an additional \$180 million investment over 5–9 years could lead to a 77% LCOS reduction.

Lithium-ion Batteries

Innovations, including rapid battery health diagnostics, enhanced cycle life control, impurity reduction in materials, and improved electrode/electrolyte designs, could reduce LCOS by 51%. Achieving this would require an additional \$1 billion investment over 8–13 years.

Sodium-ion Batteries

SIBs show potential through innovations such as cathode–electrolyte interface optimization, anode-less battery configurations, electrolyte development, and scaled grid deployment. DOE estimates that a \$240 million additional investment could yield a 54% LCOS reduction over 9–13 years.

7.5.1.2 Mechanical Energy Storage Technologies

Compressed Air Energy Storage

System modeling, demonstration projects, improved mechanical compression and expansion technologies, advanced manufacturing, and the development of low-temperature turbines and heat exchangers could all help reduce costs. DOE assessments project that these innovations could reduce LCOS by 60% with an additional \$750 million investment over 5–10 years.

Pumped Storage Hydropower

Hybrid project deployments, the use of advanced materials and 3D printing, and improved geotechnical characterization methods could reduce LCOS by up to 85%, according to DOE strategy assessments. Achieving this would require an incremental investment of \$570 million over 6–10 years.

7.5.1.3 Thermal Energy Storage Technologies

Molten Salt Thermal Energy Storage

Innovations such as single-tank systems, automated manufacturing, standardized components, multiple-scale demonstrations, and improved heat-to-electricity conversion could reduce LCOS by 17% LCOS within 6–8 years. DOE strategy assessments estimate this would require an additional investment of \$760 million.

Although similar assessments are not available for all LDES technologies—such as metal-air, sodium-sulfur, gravity-based systems, geomechanical energy storage, LAES, compressed CO₂, phase-change materials, sensible energy storage, Pumped Hydroelectric Energy Storage (PHES), thermochemical, and TPV storage—existing analyses indicate a broad and promising landscape for cost reductions across the LDES spectrum.

7.5.1.4 Federal Incentives for Long-duration Energy Storage

The Inflation Reduction Act expanded federal support for energy storage by making stand-alone energy storage systems eligible for the Clean Electricity ITC and the Clean Electricity PTC. Energy storage technologies—including electrochemical, mechanical, and thermal systems—qualify if they have a minimum capacity of 5 kWh. Under H.R. 1, energy storage technologies remain eligible for the ITC and PTC, which will phase out beginning in 2033. The base ITC is 6%, increasing to 30% if PWA

requirements are met. The base PTC is ~0.56 cents/kWh, increasing to ~2.8 cents/kWh if prevailing wage and apprenticeship requirements are met. Additional 10% bonus credits are available for projects that meet domestic content requirements or are located in energy communities, potentially raising the total ITC to 50% (IRS 2025a).

H.R. 1 adjusts the domestic content thresholds from 40% to 55% between 2025 and the end of 2026. Energy storage facilities are also subject to the new FEOC provisions under H.R. 1, which may introduce market uncertainties and supply chain constraints. LDES technology faces more stringent FEOC provisions than other technologies, with 75% non-FEOC requirements in 2030, compared to 60% for other qualifying technologies. The full consequences of these new provisions are not yet fully understood.

7.6 Scalability for 2040

The scalability of LDES in New York State will depend on several factors, including technology readiness, land and infrastructure availability, State energy targets, market and regulatory mechanisms, supply chain, and workforce availability. This section explores potential 2040 deployment scenarios and outlines the key conditions required for their realization. These scenarios are not prescriptive but serve as a framework for understanding different levels of ambition in LDES deployment.

Regardless of the scenario, certain strategies will be critical to success. Market reforms that improve revenue mechanisms for LDES can help ensure a sustainable financial model for investment. Demonstration and pilot projects must accelerate progress in manufacturing, assembly, and system integration. Expanding transmission infrastructure, particularly upgrading high-voltage lines to facilitate power transfers from Upstate New York storage to major load centers, will be essential. Workforce development initiatives must build a skilled labor force capable of supporting LDES deployment. Incentives such as tax credits, direct funding, and subsidies can help expand domestic manufacturing and supply chain capacity, thereby promoting private sector development.

7.6.1 Conservative Deployment Scenario

In the Conservative Deployment scenario, LDES deployment in New York State remains limited, focusing on mature, modular technologies such as electrochemical battery energy storage technologies in Upstate New York. These technologies are selected for their high readiness levels and minimal siting constraints. Downstate New York integration remains minimal, largely constrained by fixed and highly

competitive land availability and lack of policy incentives. Retiring thermal plants in Zones J and K are repurposed for other firm generation options like hydrogen, RNG, or carbon capture. Short-duration energy storage continues to dominate the market, outcompeting LDES due to its lower cost, standardization, and market familiarity. LDES remains largely unstandardized and limited to pilot-scale demonstrations. This scenario would not achieve large-scale LDES deployment by 2040 but lays the foundation for broader adoption beyond 2040.

7.6.2 Moderate Deployment Scenario

The Moderate Deployment scenario extends LDES deployment in both Upstate New York and Downstate New York. In the Upstate area, site-specific technologies, such as A-CAES with purpose-built caverns, are deployed where available land and favorable geology permit. However, interconnection constraints limit broader deployment because much of the interconnection capacity is allocated to firm generation resources and near-term additions like short-duration energy storage. Downstate deployment would include modular, safer, and cost-effective technologies such as flow batteries and thermal energy storage systems in urban or constrained areas. However, land availability remains a key limiting factor. Short-duration lithium-ion energy storage, already better established and supported by immediate grid needs, often claims the limited space before other LDES technology options can compete. This scenario assumes mid-level maturity of emerging LDES technologies and partial standardization, which improves investor confidence. This scenario requires multiple pilot and demonstration projects to test large-scale deployment in Upstate areas and smaller, modular systems in Downstate areas. Long-term market signals, including LDES procurement targets and mandates, will also be necessary to provide investment certainty and reduce stakeholder uncertainty. Timely permitting and interconnection will also be essential for the successful execution of projects. Success in this scenario depends on policy support, careful execution, and the ability to adapt to evolving market and regulatory conditions.

7.6.3 Aggressive Deployment Scenario

An Aggressive Deployment scenario envisions widespread LDES deployment across both Upstate New York and Downstate New York, driven by technological breakthroughs in modularity, energy density, and cost, and supported by strong policy and market signals. Upstate areas deploy multiple site-specific technology projects supported by standardized components and improved permitting. However, available interconnection capacity limits expansion, requiring strategic transmission upgrades and LDES-dedicated procurement mechanisms to unlock further scale. Downstate sees broader adoption of modular LDES systems supported by favorable incentives, streamlined permitting processes, improved modular

deployment strategies, and integration into urban energy planning. Nevertheless, available land remains highly competitive, and early occupation by short-duration energy storage systems can limit opportunities of LDES in the short term. Retiring fossil fuel power plants in New York City and Long Island are selected for both LDES and other firm generation options. These alternatives absorb much of the available retiring thermal plant sites and policy focus, resulting in only a subset of sites available for repurposing with LDES. Large-scale renewable energy projects, particularly solar and wind farms, could be paired with LDES to enhance grid stability and firm up intermittent generation.

Under this scenario, LDES is largely standardized, cost-competitive, and supported by market products tailored for longer-duration capacity and reliability mandates aligned with the State’s decarbonization goals. However, deployment must navigate and coordinate with a broader ecosystem of clean energy technologies. This scenario succeeds by targeting early, integrated planning of land use, policy incentives, streamlined interconnection, and permitting process for LDES, ensuring that LDES technologies gain a foothold in the evolving resource mix. Furthermore, to support aggressive deployment, workforce development plays a crucial role in this transition, with targeted training programs, including those aimed at retraining fossil fuel workers for careers in LDES and related clean energy sectors.

7.6.4 Beyond 2040

LDES technologies are expected to have an important role in supporting a grid increasingly dependent on variable renewables in 2040 and beyond. Early pilot projects and demonstrations will accelerate learning in manufacturing, assembly, and system integration, increasing market familiarity with these technologies, laying the foundation for continued broader adoption of LDES technologies beyond 2040.

7.6.5 Scalability Summary

LDES cannot meet the grid’s full 2040 reliability needs alone due to duration constraints and recharging requirements. However, large-scale deployment could reduce the need for expensive peaking units by shifting supply availability to times of greatest need.

The Conservative Deployment scenario described earlier primarily focuses on Upstate New York applications due to competition with short-duration energy storage and limited land availability in Downstate New York, although it would lay the groundwork for higher impacts beyond 2040 by helping to develop energy storage solutions.

The deployment of modular LDES technologies downstate in the Moderate Deployment scenario could have increased impacts on the 2040 grid, but would still require the support of other 0x40 technologies, especially during times of extreme need.

The Aggressive Deployment scenario would have a more transformative effect on the balance of the statewide electric supply and demand, but would still require the deployment of generation units to support energy storage at that scale.

7.7 Conclusions

Based on the previous assessment, the following key observations are offered to inform future consideration of LDES deployment in New York State.

LDES can provide avoided infrastructure benefits today and will become more important as the prevalence of intermittent renewables in the grid increases. LDES can provide grid benefits today, including avoided transmission and distribution infrastructure investment. While short-duration energy storage (<10 hours) alongside existing thermal generators meets most of the current grid's balancing needs, higher renewable penetration will introduce longer peak challenges that will require longer-duration energy storage (>10 hours) to manage, along with larger capacities.

Different energy storage technologies are better suited for different durations. This report examines 18 electrochemical, mechanical, and thermal energy storage technologies capable of operating for durations greater than 10 hours. Electrochemical and mechanical storage technologies are typically most suitable for short- to interday applications. Thermal storage technologies tend to be better suited for interday to multiday applications. However, optimal durations will depend on the specific use case for each project.

The LDES technologies with the highest technology readiness are pumped hydro, molten salt thermal energy storage, lead-acid batteries, and sodium-sulfur batteries. Generally, electrochemical and mechanical energy storage technologies are at a higher readiness level than thermal energy storage technologies.

Electrochemical storage technologies are more modular and can provide more grid services than mechanical or thermal energy storage technologies, but they currently require additional safety considerations and have higher costs and shorter lifetimes. These technologies also require inverters for grid interconnection, which limits contributions for certain ancillary services, such as inertia.

Thermal energy storage technologies can also help decarbonize industrial processes that require heat, typically provided by a fossil-fired boiler, including cement, steel, brewing, and a host of other processes. Multiple thermal energy storage technologies are being installed for commercial use for these types of applications, which can help accelerate this technology for power use by maturing the core technology.

LDES deployment potential can be limited due to space constraints and safety considerations. High-population-density areas have limited land availability, which competes with other energy technologies such as short-duration energy storage and thermal generation. Potential siting opportunities may include municipal-owned and privately owned land, as well as retiring fossil plant sites and integration with renewable energy projects. Upstate New York LDES potential is larger due to fewer space and population density constraints.

Emerging energy storage technologies are in the early stages of development, necessitating ongoing assessments to mitigate risks. Safety considerations are unique to each technology, creating challenges in standardization and efficient permitting processes. However, New York is a national leader in this area, having convened an interagency fire safety working group to ensure the safety of lithium ion battery energy storage systems across the State. The group produced a Fire Code Recommendations Report that informed the code development process in New York State.

Electricity market design changes will be needed to support market-based deployment of LDES. Targeted market and regulatory reforms, incentivizing longer durations, are needed to support deployment and technological advancement.

8 Virtual Power Plants and Demand Response

8.1 Overview and Subcategorization of Virtual Power Plants and Demand Response

8.1.1 Demand Response

Demand response is a grid management strategy that enables utilities to work with consumers to reduce consumption rather than focusing solely on supply-side solutions. For decades, demand response (DR) programs have successfully engaged large commercial and industrial customers to reduce their electricity usage during critical periods. These programs initially focused on emergency scenarios but have expanded to address peak demand challenges across the system.

Traditional DR typically involves large facilities, such as manufacturing plants, commercial buildings, or institutional campuses, which can significantly reduce their electricity consumption in response to utility signals. Participants receive financial incentives in exchange for their willingness to curtail load when needed, creating a cost-effective alternative to building additional generation capacity that might only operate during peak demand periods.

Extending these DR capabilities to smaller, distributed resources presents greater complexity. Individual residential and small commercial customers lack the scale, expertise, or motivation to participate directly in traditional DR programs. Enrolling thousands of small customers, verifying participation, and managing settlements would be prohibitively expensive using conventional approaches. Additionally, many smaller customers hesitate to accept the potential inconvenience of manual intervention when DR events are called.

8.1.2 Virtual Power Plants

Virtual power plants (VPPs) offer a solution to these challenges by aggregating distributed energy resources (DERs) into coordinated systems that can provide grid services. A VPP can be defined as a network of decentralized power-generating units, flexible loads, and storage systems aggregated to operate as a unified resource. VPPs lower barriers to entry for smaller loads to participate in grid services. For these small-scale assets, individual participation in a conventional DR program would not be justified due to the expense and logistics involved. VPP technology creates economies of scale by pooling these resources.

Because VPPs can incorporate advanced automation, they enable smaller customers to more effectively respond to time-varying electricity rates, while also supporting the delivery of grid services. Time-varying or dynamic rates provide economic incentives for customers to shift their consumption patterns, but many individual consumers lack the time, expertise, or interest to actively manage their electricity usage in response to changing prices, as facility managers have done for legacy DR programs. VPPs bridge this gap by automating responses to price signals or direct utility control signals. The combination of time-varying rates and VPP technology creates a more robust demand-side management approach.

The New York Grid of the Future study aims to assess and plan for the integration of flexible resources, including VPPs, into the State’s evolving electric grid. Initiated in April 2024, the study seeks to “unlock innovation and investment to deploy flexible resources—such as distributed energy resources (DERs) and VPPs—to achieve our clean energy goals at a manageable cost and at the highest levels of reliability.” The study models the cost-effective, achievable potential for grid flexibility in 2030 and 2040, evaluates barriers to scaling these resources, and provides actionable recommendations for utility planning, regulatory reform, and customer engagement. Its initial findings are reported in *New York’s Grid Flexibility Potential, Volume I: Summary Report*, which informed the research for this Zero by 2040 study (Brattle 2025a). Additional detail of the study is reported in *New York’s Grid Flexibility Potential, Volume II: Technical Appendix* (Brattle 2025b).

8.1.3 Types of Distributed Energy Resources

Different types of DERs offer unique primary functions and operating characteristics that facilitate their integration into VPPs. The following list includes technologies expected to be the most important VPP participants in New York State by 2040. The list is not exhaustive, and other technologies could also develop to play significant roles.

Behind-the-meter (BTM) batteries, whether with or without solar, can store excess energy and discharge it during peak periods, providing both load reduction and power injection capabilities (Brattle 2025a).

Electric vehicle (EV) charging infrastructure enables controlled shifting of when vehicles charge, creating flexible loads that can be ramped down during peak demand, increased during periods of renewable abundance, or possibly run in reverse to send power back to the grid (vehicle-to-grid or V2G). New York State currently has around 200,000 EVs (Brattle 2025a).

Smart thermostats enable subtle temperature adjustments in buildings to precool or preheat spaces, shifting heating, ventilation, and air conditioning (HVAC) load without significantly impacting occupant comfort.

Electric water heaters function as thermal storage devices, heating water during off-peak hours to avoid energy consumption during high-demand periods while maintaining hot water availability.

All of these technologies are already being adopted to decarbonize New York State's broader energy system. VPPs can harness their flexibility to support the electric sector at a potentially lower cost than building new generation or storage assets. The system cost is expected to be lower for VPPs than for new traditional assets because customers make these investments independently, requiring little to no additional capital expense.

Home Energy Management Systems (HEMS) manage a group of DER assets (e.g., PV, battery storage, flexible loads) at the home level. Homes can be further aggregated into a VPP. In this scenario, HEMS systems communicate with the distributed energy resources management systems (DERMS) of the VPP operator. If a third-party aggregator manages the VPP, the DERMS communicates with the service-requesting entity (distribution utility and/or ISO). Alternatively, if meeting the service requirements (including minimum size, if applicable), the HEMS could potentially communicate directly with the service-requesting entity. From this perspective, HEMS are not an alternative to VPPs, but simply an intermediate level of aggregation and control within the overall hierarchical control structure. Importantly, depending on the grid services considered, VPPs aggregating multiple homes may reduce costs by spreading fixed participation costs across multiple end customers.

8.1.4 Distributed Energy Resources Management Systems

DERMS platforms enable utilities, third-party aggregators, or other VPP operators to monitor, forecast, optimize, and control distributed energy resources in real-time. For aggregated DERs seeking to provide grid services through a VPP structure, the DERMS establishes a hierarchical control architecture where it receives service requests from entities (such as distribution utilities or ISOs), translates these requests into operational commands, and then dispatches these commands to the appropriate DERs based on their capabilities and availability. DERMS also support the verification of service delivery and the collection of performance data necessary for settlement processes.

8.1.5 Technology Use Cases and Value Streams

VPPs can deliver multiple value streams across different levels of the electricity system.

8.1.5.1 *Reducing Load/Peak Shaving*

At the bulk system level, VPPs contribute value by reducing peak load. By decreasing demand during critical periods when the system experiences its highest load, VPPs help reduce the need for peaking generation assets that might otherwise operate only a few hours per year at a relatively high cost. More generally, the VPPs' peak shaving capacity can provide value across multiple grid domains, including generation, transmission, and distribution, by lowering the required infrastructure buildout and maximizing infrastructure utilization.

Traditional DR has primarily focused on helping with energy balancing at the bulk system level. VPPs extend this capability by enabling smaller loads to participate. Some VPP-connected resources shift their consumption to times of higher renewable energy production or lower system demand, while others reduce consumption during peak hours. Both strategies help create a flatter, more cost-efficient demand profile.

8.1.5.2 *Localized Distribution Services*

In addition to bulk system balancing, certain VPPs provide targeted services to distribution utilities, addressing localized distribution needs. VPPs may defer traditional distribution upgrades that would otherwise be required to maintain normal system operations, generating value for ratepayers in the form of avoided upgrade costs. Example services include reducing the load on specific feeders or substations that are approaching thermal capacity limits or prone to voltage violations. The concepts of distribution services and nonwires solutions (NWS) are closely related. The technical requirements for NWS can be decomposed and packaged into one or several distribution services. NWS refers to a suite of strategies that use DERs to defer or avoid traditional utility investments in transmission and distribution infrastructure, like new substations or power lines. Instead of building or upgrading “wires,” utilities can deploy these flexible, customer- or community-based resources to address grid constraints, manage peak demand, and enhance reliability.

8.1.5.3 Ancillary Services

Certain VPPs can provide various ancillary services at the bulk system level, including frequency regulation, ramping support, and operating reserves. These services help maintain grid stability and reliability, particularly as the share of variable renewable generation increases.

VPPs' ability to provide ancillary services depends on the characteristics of their constituent DERs. For example, battery storage systems and EV chargers with vehicle-to-grid functionality can respond rapidly to regulation signals, adjusting power output or consumption within seconds. Other DERs, such as water heaters or HVAC systems, may be better suited to services with less stringent response-time requirements.

In response to Federal Energy Regulatory Commission (FERC) Order No. 2222 (FERC 2020), independent system operators (ISOs), including NYISO, have been working with distribution utilities to implement new technologies and processes that enable VPPs to participate in wholesale electricity markets, including ancillary services.

8.2 Performance Attributes

VPPs serve some of the same functions as traditional grid assets, but they differ in many ways. For example, VPPs have limited durations, whereas a fuel-based asset can run as long as fuel is available. Table 56 assesses the ability of four of the most prominent VPP program types to provide a range of grid services.

Table 56. Comparison of Virtual Power Plant and Demand Response Technologies by Grid Services and Attributes

Italicized entries indicate a lack of real-world U.S. demonstration.

Attribute	Heating and Cooling	Water Heating	EV Charging	Battery storage
Inertial Response (Rotational)	Does not provide attribute no rotational inertia	Does not provide attribute no rotational inertia	<i>May sometimes provide attribute</i> <i>inverter-based DERs with GFM capability may be able to provide synthetic inertia</i>	<i>May sometimes provide attribute</i> <i>inverter-based DERs with GFM capability may be able to provide synthetic inertia</i>
Ramping	May sometimes provide attribute certain heating/cooling and water heating loads may be able to curtail energy imports within minutes of receiving a control signal for a given duration, but are typically not able to follow rapidly changing ramp-up and -down commands	May sometimes provide attribute certain heating/cooling and water heating loads may be able to curtail energy imports within minutes of receiving a control signal for a given duration, but are typically not able to follow rapidly changing ramp-up and -down commands	Typically provides attribute inverter-based DERs are technically capable of ramping within seconds, however, several operational factors, including SOC for storage-type resources, may constrain actual ramp-up and -down capabilities	Typically provides attribute inverter-based DERs are technically capable of ramping within seconds, however, several operational factors, including SOC for storage-type resources, may constrain actual ramp-up and -down capabilities
Cycling Capability	May sometimes provide attribute cycling capability is both resource- and customer-specific, and is largely determined by customer preferences, which then translate into minimum energy consumption requirements	May sometimes provide attribute cycling capability is both resource- and customer-specific, and is largely determined by customer preferences, which then translate into minimum energy consumption requirements	May sometimes provide attribute cycling capability is both resource- and customer-specific, and is largely determined by customer preferences, which then translate into minimum energy consumption requirements	May sometimes provide attribute cycling capability is both resource- and customer-specific, and is largely determined by customer preferences, which then translate into minimum energy consumption requirements
Short Minimum Run Time	May sometimes provide attribute minimum run times are both resource- and customer-specific, and are largely determined by customer preferences, which then translate into minimum energy consumption requirements	May sometimes provide attribute minimum run times are both resource- and customer-specific, and are largely determined by customer preferences, which then translate into minimum energy consumption requirements	May sometimes provide attribute minimum run times are both resource- and customer-specific, and are largely determined by customer preferences, which then translate into minimum energy consumption requirements	May sometimes provide attribute minimum run times are both resource- and customer-specific, and are largely determined by customer preferences, which then translate into minimum energy consumption requirements

Table 56. (continued)

Attribute	Heating and Cooling	Water Heating	EV Charging	Battery storage
Black Start	Does not provide attribute does not provide black-start support	Does not provide attribute does not provide black-start support	May sometimes provide attribute <i>inverter-based DERs with GFM capability may be able to provide black-start support</i>	May sometimes provide attribute <i>inverter-based DERs with GFM capability may be able to provide black-start support</i>
Capacity Factor	Low expected to function as a peaking-only resource	Low expected to function as a peaking-only resource	Low expected to function as a peaking-only resource	Low expected to function as a peaking-only resource
Minimum Stable Output	May sometimes provide attribute often binary levels, normal consumption, and no consumption	May sometimes provide attribute often binary levels, normal consumption, and no consumption	May sometimes provide attribute expected to be flexible up to resource nameplate, but may be subject to operational constraints	May sometimes provide attribute expected to be flexible up to resource nameplate, but may be subject to operational constraints

The following summarizes the key takeaways from Table 56:

- VPPs cannot provide rotational inertia, but VPP technologies that inject power back to the grid (batteries or V2G) may be able, in certain cases, to provide synthetic inertia.
- Depending on the underlying technologies, VPPs may ramp within minutes or seconds. Ramping also depends on the type of program or service offered.
- Cycling capability and run time vary by customer preferences and technology. See Table 57 for frequency and duration assumptions used in the *Grid of the Future* study.
- VPPs generally cannot provide black-start services. However, batteries or V2G resources could theoretically support a black-start in specific situations, such as a microgrid.
- VPP capacity factors are limited by the customer's willingness to tolerate disruption to the devices' functions. VPPs should be considered low capacity factor peaking assets.
- Some VPP devices operate on binary levels, while others offer more flexibility. However, minimum stable output is not directly comparable to traditional generation assets because VPPs are composed of many distributed resources.

The following offers additional details on key VPP attributes.

8.2.1 Performance Risks

Traditional DR has been primarily focused on system balancing. Conversely, VPPs may provide more localized distribution services (e.g., deferral of distribution upgrades), and/or bulk system services, including ancillary services such as frequency regulation and ramping. VPPs that pursue these emerging service applications typically face more participation and performance requirements than those applicable to traditional DR participants.

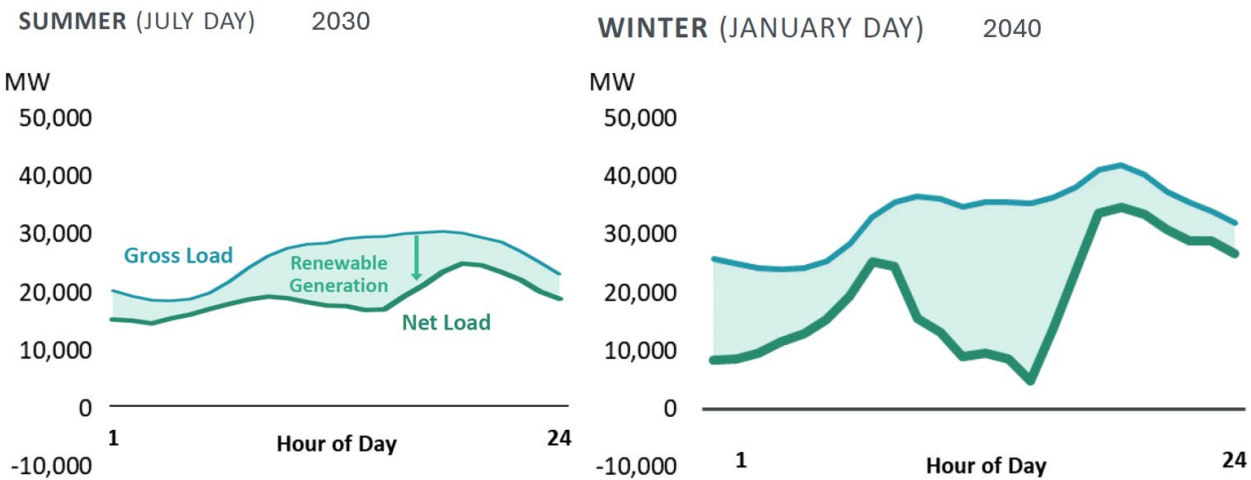
If traditional DR fails, system operators can usually balance at the system level by relying on reserve service products and/or real-time markets that enable other market participants to step in. In contrast, if a VPP fails to deliver a distribution service as expected, especially when this service intends to defer conventional distribution upgrades, the consequences may be more severe. The pool of alternative service providers available locally to meet the unmet needs may be very small or nonexistent. As a result, service-requesting entities are more likely to impose stricter performance requirements, including tighter measurement and verification (M&V) protocols and financial penalties for underperformance, similar to established practices in wholesale electricity markets.

VPPs also face significant challenges in maintaining long-term performance reliability and predictability compared to traditional generation assets. While conventional power plants are designed and rated to perform consistently over 20–30 years, VPPs operate with ongoing uncertainty and continuous changes

in the underlying asset base. Customers frequently upgrade appliances, modify participation preferences, or withdraw from programs altogether. Additionally, New York State’s grid environment continues to evolve, including a projected shift from summer peaking to winter peaking. This shift is expected to change the most important events from summer afternoons to dual peaks in winter mornings and afternoons. As a result, space heating will likely become a more important VPP asset over time than air conditioning (Figure 65).

Figure 65. System Load Shape by Season and Year in New York State

Source: Brattle (2025a).



Because grid flexibility programs are limited by their operational constraints (e.g., the number of events that can be called without creating undue interference with the devices’ primary functions and inconvenience for the customers), the total capacity of enrolled VPPs may not be able to respond to every event. The New York Grid of the Future study assumed 50% capacity credit across programs. The table below includes the frequency and duration of events by program type.

Table 57. Grid Flexibility Program Event Frequency and Duration as Modeled in the Grid of the Future Study

Source: Brattle (2025b).

Program	Event Frequency and Duration
Cooling (residential and small commercial)	15 events per year, 4-hour events
Space heating (residential and small commercial)	15 events per year, 3-hour events
Water heating (electric resistance and heat pump)	Daily shifting of water heating load, 4-hour events
EV managed charging (home and workplace)	Daily shifting of load, 4-hour events
EV TOU (home)	Daily shifting of load, 4-hour events
EV V2G (home)	100 events per year, 3-hour events
Time-varying rate (residential and small commercial)	Daily shifting of load, 4-hour events
Behavioral DR (residential)	10 events per year, 3-hour events
BTM battery (residential and commercial)	100 events per year, 3-hour events
Auto-DR (large C&I)	30 events per year, 4-hour events
Manual DR (large C&I)	30 events per year, 4-hour events

A device’s ability to contribute during the system’s peak load hour may have implications for the customer. For example, it may require reducing the air conditioning load on the hottest days of the year.

8.3 Readiness for 2040

8.3.1 Latest Deployment Trends

Building on decades of experience with DR, the industry has begun deploying VPPs across a range of geographies, device types, and program structures. The following sections describe recent developments related to VPPs.

8.3.1.1 Funding Opportunities

The Inflation Reduction Act included incentives like tax credits and rebates for Americans to purchase VPP-compatible technologies, including EVs and smart appliances, which would enable broad VPP deployment. However, under H.R. 1, the tax credits supporting EVs, including Clean Vehicle Tax Credit, Section 30D (Clean Vehicle Credit), Previously-Owned Clean Vehicle Tax Credit, Section 25E (Previously-Owned Vehicle Credit), Commercial Clean Vehicle Credit, Section 45W (Commercial Vehicle Credit), and Refueling Property Credit, Section 30C, as well as smart appliances (Energy Efficient Home Improvement Credit, Section 25C) and DERs (Residential Clean Energy Credit, 25D) are phased out by 2026, likely slowing adoption rates of these technologies.

8.3.1.2 *New York State Regulatory Mechanisms Favorable to Virtual Power Plants*

New York State has already enacted several regulatory programs that support VPP deployment.

Utility DR programs at the retail level increasingly allow dual participation with at least some NYISO programs and service products at the wholesale level. These include the Commercial System Relief Program and the Distribution Load Relief Program, two utility DR programs that compensate commercial customers for reducing their electricity usage during periods of high demand.

NYISO operates multiple load reduction programs that incorporate qualified behind-the-meter (BTM) DER aggregations, including the Special Case Resources Program and the Demand-Side Ancillary Services Program.

The PSC implemented the Value of Distributed Energy Resources Value Stack, which compensates and incentivizes DERs based on the cumulative (stacked) value they provide. This includes compensation for energy, capacity, environmental benefit, demand reduction, locational system relief, and community credit. Compensation is location-specific, offering greater reward to those who alleviate distribution system constraints most effectively (NYSERDA 2025f).

New York State’s nonwires alternatives (NWA) regulatory mechanism requires utilities to prioritize DER solutions over traditional grid upgrades for load growth needs. This framework requires utilities to competitively solicit DERs before approving conventional infrastructure projects.

8.3.1.3 *New York State Pilot with Sunrun and Orange & Rockland Utilities, Inc.*

In 2024, Orange & Rockland Utilities, Inc. (O&R), partnered with solar provider Sunrun to offer new solar customers a free LG Chem battery pack or a heavily discounted Tesla Powerwall. To qualify, customers had to enroll in a 10-year program allowing the batteries to discharge power during critical demand hours. The demonstration is expected to contribute 2 MW of aggregated capacity. About half of the installations are located in areas the State has designated as disadvantaged communities.

8.3.1.4 *Other Noteworthy Virtual Power Plant Deployments*

Utilities across the U.S. have launched various VPP initiatives in recent years. Table 58 shows a selection of other notable programs (DOE 2025b).

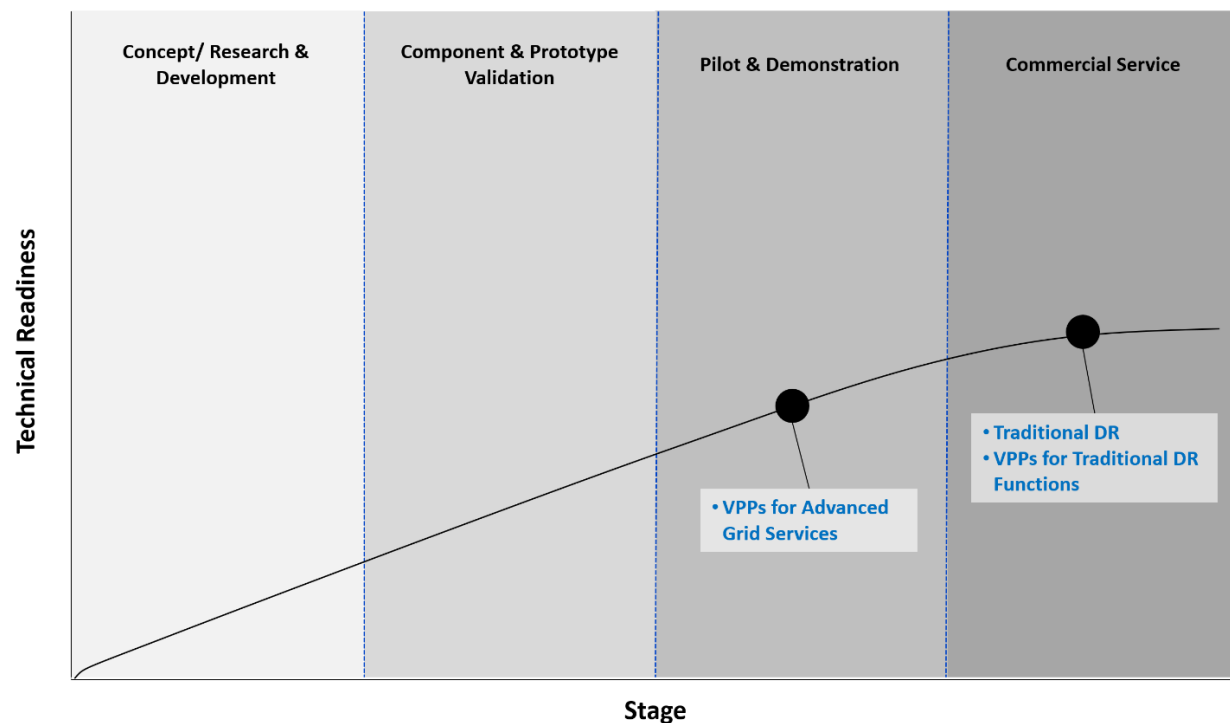
Table 58. Examples of Virtual Power Plant Programs in the U.S.

Utility	Program Name	DER Types	Size	Source
Roanoke Cooperative (North Carolina)	Upgrade to \$ave	Water heater control switch, smart thermostat, efficiency	1.75 MW (with plans to double, 2.5–3% of system peak)	Roanoke Cooperative (2025)
San Diego Community Power (California)	Solar Battery Savings	Solar, BTM battery	7.3 MW (0.4% of system peak)	San Diego Community Power (2025)
Arizona Public Service (Arizona)	Cool Rewards	Smart thermostat	160 MW (2% of system peak)	APS (2025)
National Grid (Massachusetts and New York)	Connected Solutions	Smart thermostats, batteries, HVAC, manufacturing loads, EV chargers, water heaters, thermal storage.	250 MW (2% of system peak)	National Grid (2025)

8.3.2 Technology Readiness

Figure 66 shows the current readiness of VPP and DR technologies in New York State.

Figure 66. Current Technology Readiness of Virtual Power Plant and Demand Response Technologies



8.3.2.1 Demand Response

Traditional DR has reached the stage of commercial service. Utilities and grid operators have economically and effectively deployed these programs for decades, primarily engaging large commercial and industrial customers who can significantly reduce their electricity consumption during critical periods. The technology, protocols, and business models for traditional DR are well-established, with utilities and grid operators routinely including these resources in their planning and operations. Stakeholders have standardized and refined performance verification, compensation structures, and enrollment processes for large-scale DR participants through years of operational experience.

8.3.2.2 Virtual Power Plants

The technology readiness of VPPs spans a spectrum depending on the specific application:

Virtual Power Plants for Traditional Demand Response Functions

VPP applications focused on basic load reduction and peak shaving have reached the commercial service stage. Companies have successfully deployed solutions that aggregate residential and small commercial assets to provide peak reduction services comparable to traditional DR, but with greater automation and less customer inconvenience.

Virtual Power Plants for Advanced Grid Services

Applications that provide more sophisticated grid services, such as frequency regulation, voltage support, and distribution-level services, remain primarily in the technology demonstration phase. Several pilot projects have demonstrated technical feasibility, but widespread commercial deployment with enforceable performance guarantees for these advanced services is still emerging.

Developers have demonstrated the hardware and software needed to adjust the load of customers' assets at scale for basic functions. Commercial deployments in California, such as those operated by OhmConnect, have successfully helped avert system emergencies by coordinating responses across thousands of residential customers (Kobayashi-Solomon 2022). Examples like this show that VPP technology can already deliver meaningful grid benefits in real-world conditions.

8.3.2.3 *Key Barriers to Widespread Adoption*

Metering and Telemetry

Advanced VPP applications generate value through “pay-for-performance” service products, which makes reliable performance verification critical to industry success. Current metering and telemetry hardware, while mature for large DR customers at the wholesale level, is too expensive for smaller participants.

Telemetry

Service-requesting entities need real-time data streaming to verify service delivery and make operational decisions. This demands a communication infrastructure that can reliably transmit data from numerous small assets.

Metering

Revenue-grade meters provide after-the-fact verification for settlement purposes, ensuring accurate compensation for services rendered.

Beyond M&V capabilities, distribution utilities more generally lack the visibility, communication, and control capabilities required to utilize DERs most effectively for grid services (Brattle 2025a). Current research focuses on identifying cost-saving opportunities by designing hardware specifically for smaller loads, such as lower voltage and single-phase systems, and by increasing manufacturing volumes to achieve economies of scale. For example, DERs above 10 kW often face prohibitive costs to implement the telemetry capabilities required by NYISO. As a result, many DER owners either find other channels to participate or decide not to provide flexibility (Brattle 2025a). Researchers are also exploring internet-based communications, rather than dedicated machine-to-machine phone lines traditionally used by wholesale market participants, as a more cost-effective alternative for smaller-scale DERs.

8.3.2.4 *Behind-the-Meter Asset Integration*

BTM assets present additional integration challenges for VPPs.

Primary Function Conflicts

Many BTM assets, such as EVs, water heaters, and thermostats, primarily serve customer needs rather than grid services. This creates tension for VPPs, which must balance customer-centric functionality with grid-responsive flexibility. For example:

- EVs require charging to meet driver schedules, but discharging to support grid peaks could deplete batteries needed for commuting.
- Water heaters must maintain temperature thresholds, limiting their ability to shift load during DR events without risking customer dissatisfaction.
- Smart thermostats face trade-offs between maintaining preferred indoor temperatures and adjusting HVAC usage to alleviate grid stress.

These conflicts are magnified by the asymmetry of risk: a single failure to meet customer expectations (e.g., a cold shower due to overaggressive water heater cycling) can erode trust and participation in VPP programs. Meanwhile, the grid benefits of these assets depend on reliable, sustained engagement. To address this challenge, VPP operators implement mitigation strategies such as adaptive load-shaping algorithms that precool or preheat homes within comfort buffers, dynamic customer override options, and transparent compensation structures that incentivize flexibility without undermining primary use cases. Resolving these conflicts is essential to scaling VPPs because customer opt-out rates directly correlate with the perceived intrusiveness of grid-directed control.

Submetering Requirements

Assessing compliance of individual BTM assets may require submetering, which adds expense and complexity. This is particularly challenging in residential settings where stakeholders must justify the cost of additional metering by the value of the services provided.

HEMS offers a potential intermediate layer of aggregation that helps address some of these challenges by managing multiple assets within a single home and optimizing their collective response to grid signals.

Standardization Requirements

VPPs require standardized interaction between aggregators and service-requesting entities (such as NYISO) to efficiently submit bids for services, receive confirmation of bid acceptance, process dispatch signals, and exchange messages regarding resource status. The lack of standardization among these interfaces slows VPP deployment by increasing integration costs for third-party aggregators and complicating participation across multiple service territories or markets (Brattle 2025a).

One prominent example of a standard used for DER communications protocols is IEEE 2030.5 (Smart Energy Profile 2.0), which facilitates interactions between the smart grid and consumers. It enables utilities to manage various aspects of the energy environment, including DR, load control, time-of-day pricing, and the integration of DERs. California’s Rule 21 mandates the use of IEEE 2030.5 for communication between DERs and the grid. An impact assessment of Rule 21 Phase 3 found that advanced inverter functionality can be deployed feasibly, safely, and predictably via standardization, and grid penetration levels of DERs like PV solar can be increased by 25% or more using the advanced control functions (CEC 2021).

8.3.2.5 *Commercial Readiness of Business Models*

The business case for VPPs depends on their ability to sell services to utilities or participate in wholesale markets at prices that cover costs and provide reasonable returns. Current VPP operations face several challenges.

Market Barriers

Low margins, high barriers to market entry, uncertainty regarding the frequency of peak events, and market-clearing energy prices during these events pose significant challenges to new companies. The recent closure of Swell Energy, a VPP company, in August 2024 illustrates these ongoing business model challenges (Allsup 2024).

Regulatory Hurdles

In New York State, NYISO’s 10 kW minimum threshold for individual DERs in aggregations, combined with its FERC Order 2222 phased compliance timeline extending to 2026, can create near-term barriers for residential-focused VPPs (NYISO 2024b).

While VPP techniques involving load reduction and shifting have been effectively deployed economically in some contexts, more advanced VPP technologies, such as V2G applications, remain primarily in the technology demonstration phase from both technical and business model perspectives.

8.3.2.6 *U.S. Department of Energy Imperatives for Accelerating Virtual Power Plants*

The DOE has identified five key imperatives for accelerating VPPs to their full potential, along with specific potential solutions for each (DOE 2025b).

1. **Expand DER Adoption with Equitable Benefits**

This imperative focuses on increasing the pool of potential VPP resources while ensuring benefits are widely distributed. Potential solutions include providing financial assistance for DER adoption and developing the workforce needed for DER installation and maintenance.

2. **Simplify VPP Enrollment**

Reducing friction in the customer acquisition process is critical for scaling VPP participation. Solutions include consumer education about VPP benefits, implementing automatic enrollment with opt-out options, and integrating VPP enablement directly into DER manufacturing.

3. **Increase Standardization in VPP Operations**

Standardization reduces integration costs and improves interoperability. Key solutions include developing common modeling tools and datasets for performance forecasting and measurement, standardizing service agreement contracts, creating industry- and regulator-aligned distribution system reliability standards, narrowing the set of DER interconnection and data standards, and implementing nationally recognized cybersecurity measures.

4. **Integrate into Utility Planning and Incentives**

Aligning VPPs with utility business models and planning processes is essential for widespread adoption. Solutions include comprehensive valuation of VPP benefits, integrating VPPs into distribution system planning requirements, aligning utility compensation and rate design with VPP deployment, and encouraging proactive VPP planning among utilities.

5. **Integrate into Wholesale Markets**

Enabling VPPs to access wholesale market revenue streams improves their economic viability. A key solution involves supporting ISOs and regional transmission operators (RTOs) to overcome region-specific barriers to FERC Order 2222 implementation, which aims to remove barriers preventing DERs from competing in wholesale electricity markets.

Progress across these imperatives would address many of the current barriers limiting the widespread deployment of VPPs and help move more advanced VPP applications from the technology demonstration stage to commercial service with economic deployment.

8.3.3 Infrastructure and Supply Chain Readiness

The infrastructure and supply chain readiness for VPPs in New York State presents relatively few barriers compared to other zero-emissions technologies. Table 59 illustrates key infrastructure and supply chain considerations, and the discussion following the table describes some of the key advantages of VPPs.

Table 59. Infrastructure Readiness of Virtual Power Plants in New York State

Technology	Transmission & Grid Integration	Fuel Supply Chain & Waste Management	Cooling Water & Thermal Management	Siting & Land Use	Supply Chain
VPPs	No significant buildout required	No significant buildout required No fuel needed or marginal waste produced	No significant buildout required No central heat source needing cooling	No significant buildout required No additional land needed	No significant buildout required VPP devices are already produced at scale

Transmission and Grid Integration

A benefit of VPPs is their potential to reduce or defer infrastructure buildout. By providing peak load reduction, VPPs can help avoid or delay transmission and distribution upgrades. This lack of significant physical buildout requirements gives VPPs an advantage in terms of siting and deploying compared to other DEFRs considered in this study.

Metering and Telemetry

As discussed in Section 8.3.2, the primary infrastructure hurdle for VPP implementation lies in metering and data systems rather than physical grid assets. The current metering infrastructure used for wholesale market participants is prohibitively expensive for smaller DERs. Conversely, existing advanced metering infrastructure (AMI) may lack the temporal resolution or communication capabilities needed for certain grid services.

Supply Chain

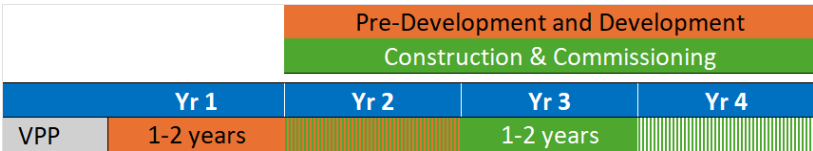
VPPs do not require entirely new manufacturing capabilities or rare materials. Instead, they primarily leverage existing DER technologies already in commercial-scale production. The primary supply chain challenge involves scaling up deployment of grid-interactive DERs.

8.3.4 Project Lead Times

Because VPPs aggregate already deployed DERs, they do not require large-scale construction or infrastructure buildout. As a result, their deployment timeline is expected to be shorter than of most power sector assets. The VPP pilot with Sunrun and O&R took about 4 years to implement. The PSC approved it in 2020, and operations began in 2024 (Sunrun 2020, 2025). This timeline (Figure 67) may

serve as a conservative estimate because it involved an early deployment of the technology, took place during the COVID-19 pandemic, and involved deploying physical hardware (batteries and solar panels), whereas other VPPs could leverage existing assets. Future VPPs could likely be deployed more quickly.

Figure 67. Project Lead Times for Virtual Power Plants



8.3.5 Geographic Suitability and Constraints

VPPs are suitable throughout the entire State. Unlike other technologies that can only be implemented in some regions or face serious technical challenges in Downstate New York deployment, VPPs can operate anywhere customers use electricity in ways that can be flexible.

8.3.6 Readiness Summary

VPPs hold promise for reducing peak load on New York State’s grid by 2040, as they face relatively few technology, infrastructure, or supply chain readiness hurdles, feature short lead times, and are geographically unconstrained. However, several challenges must be addressed to realize their full potential. Customer participation is a key variable, highlighting the need for simplified enrollment processes, consumer education, and program designs that facilitate enrollment. Metering and telemetry infrastructure present a potential technical barrier. Current wholesale-grade systems are prohibitively expensive for smaller DERs, while less costly alternatives may lack the reliability or capabilities required for certain grid services. Internet-based communications and purpose-designed hardware for smaller loads show promise for reducing these costs. Communication protocol standardization across utilities and markets remains incomplete.

Despite these challenges, pilot projects have successfully demonstrated VPP capabilities at a meaningful scale. With appropriate policy support, technological advancement, and business model innovation, VPPs could help manage a significant portion of New York State’s summer and winter peaks.

8.4 Emissions and Other Considerations

8.4.1 Emissions

Because VPPs compete directly with peaking generation assets, usually gas turbines, every additional megawatt hour averted by VPP services prevents the pollution associated with running the peaker plant. The actual emissions reduction of any VPP event depends on the carbon intensity of the grid at that time.

8.4.2 Other Considerations

8.4.2.1 *Air Quality and Safety*

In New York State, many peaking gas-fired assets are located near disadvantaged communities, so reducing local air pollution from these plants could improve the health of those neighborhoods. Additionally, because VPPs do not involve new grid-scale infrastructure, they do not carry the safety risks inherent to other technologies with concentrated energy densities.

8.4.2.2 *Land Use*

Unlike traditional power plants that require large, dedicated facilities, VPPs do not need a central physical facility, thus minimizing land use compared to conventional power plants. Instead, VPPs leverage existing infrastructure and small-footprint technologies that are already being adopted.

8.4.2.3 *Workforce and Economic Benefits*

Operating VPPs creates workforce opportunities in technical roles such as engineering and software development, as well as sales and business development roles.

In contrast to other power sector technologies, VPP investments distribute money to participants rather than toward capital projects for traditional peaking generation assets. VPP technology also offers an opportunity to directly assist low- to moderate-income consumers through potential arrangements in which they receive financial assistance for smart appliances when their existing appliances reach the end of their life, provided that the replacement can serve as a flexible grid asset. This arrangement benefits all parties: the consumer saves on the replacement cost, and the utility or grid operator gains increased demand flexibility.

8.5 Cost

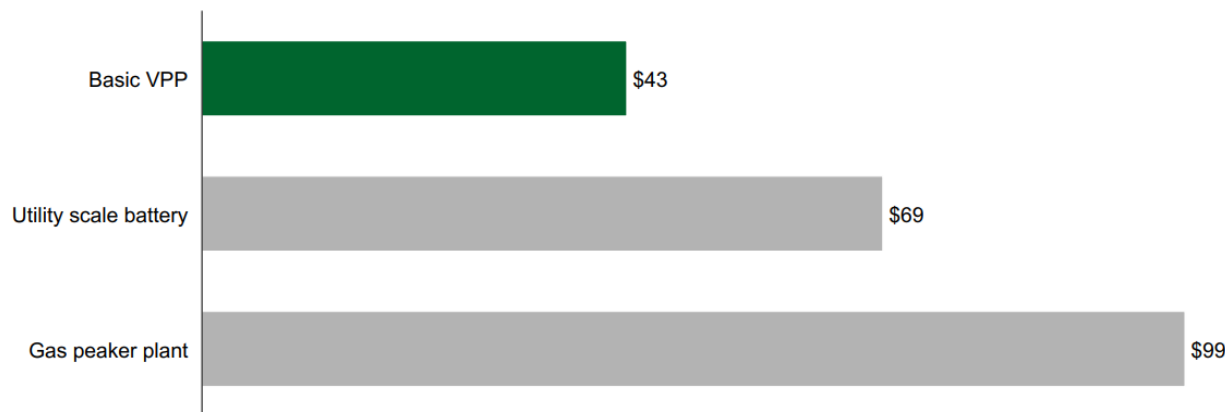
8.5.1 Solution Maturity and Prior Analysis

Unlike more established technologies with well-documented cost benchmarks, VPPs are still emerging, and few publicly available cost references exist. Moreover, VPP costs can vary significantly depending on the scope of services provided—whether limited to traditional DR or including more advanced grid services. The latter, which are newer and subject to more stringent technical requirements, tend to be more costly.

Prior analyses of VPP implementation costs typically focus on traditional DR participation and rely on observed costs from such programs. One example is the Brattle Group’s *Real Reliability: The Value of Virtual Power* report (Hledik and Peters 2023), cited in the DOE’s 2025 *VPP Liftoff Report* (DOE 2025b). It compares the cost of procuring 400 MW to address resource adequacy needs over 63 peak hours spanning 7 months, for 7 consecutive hours at a time. The VPP option is estimated to cost \$43/kW-year, compared to \$69/kW-year for utility-scale storage, and \$99/kW-year for a gas peaker plant (Figure 68).

Figure 68. Net Cost per Killowatt-year Comparison of Resource Adequacy Options

Source: DOE (2025b).



Note: Values for 400 MW of peaking capacity are shown in \$/kW-yr. The VPP analyzed consists of smart thermostats, smart water heating, home EV managed charging, and BTM battery demand response. Modeled equipment subsidy costs to utility are \$75 for smart thermostats, \$315 for smart water heaters, and \$0 for EV charging and BTM batteries. Marketing costs assumed at \$50 per device. Utility studied is assumed to have 50% renewable generation mix, with resource adequacy needs in summer and winter. 8760 hours were considered, and resources must be able to operate in 63 peak hours (when top 400 MW are needed) spanning 7 months, for 7 consecutive hours at a time. Benefits of emissions reduction and resilience are not shown; when included, VPP net cost is lower, though actual emissions impact will vary by local grid mix.^{xliv}

Source: Brattle Group’s *Real Reliability: The Value of Virtual Power Report*

Importantly, VPP applications involving more advanced grid services may require more complex equipment to support communications, control requirements, and M&V, which can substantially increase costs.

8.5.2 Key Cost Drivers

New York's Grid Flexibility Potential, Volume II: Technical Appendix (Brattle, 2025b) developed cost assumptions to facilitate a bottom-up approach to estimating VPP costs.

When a utility manages the VPP, upfront (i.e., one-time) costs include:

- Start-up costs to initiate a new VPP program
- VPP portfolio development, including marketing efforts to recruit customers
- Aggregation studies conducted by the distribution system operator (DSO) to ensure that managing the assets constituting the VPP as a group would not negatively impact the grid
- Any upgrades required on the customer-owned DER to enable their participation in the VPP
- Any integration costs, including metering, telemetry, and communications.
- Ongoing costs, including staffing, and the cost to maintain two-way communications with the VPP assets.

In addition, some aspects would incur both upfront and ongoing costs. This includes DERMS setup and maintenance to manage the VPP. When the VPP intends to provide wholesale services, stakeholders may incur additional upfront and ongoing costs to enable market participation in NYISO.

If a third-party aggregator manages the VPP, both the aggregator and the utility may share responsibility for startup costs, staffing, DERMS, communications, and integration.

In addition to the categories listed above, stakeholders must also account for the financial compensation of VPPs providing services. This includes payment to the DER asset owners and, where applicable, compensation to the third-party VPP aggregator (i.e., business margin). Compensation levels depend on the grid services offered and the price formation mechanisms in place (e.g., market-based, auction-based, administrative pricing). For distribution services, the utility's willingness to pay is set by the cost of the traditional upgrades avoided. For bulk system services, prices are typically set through competitive bidding.

8.5.3 Potential Opportunities for Cost Savings

Telemetry and communications are among the most commonly cited barriers to scaling VPPs, especially for distribution-connected resources seeking to participate in wholesale electricity markets. These barriers can be broken down into two categories: hardware (metering and telemetry) and the ongoing communication costs.

Hardware solutions used by traditional wholesale market participants may be too costly for smaller-scale DER, whose smaller service capacity limits expected revenue. Stakeholders can explore several strategies to mitigate these costs, including:

- **Instrument transformers:** Most wholesale market participants are currently connected at the transmission level, but new DER participating in wholesale markets would be connected to the distribution grid at lower voltage levels. This may allow the use of simpler and less costly instrument transformers.
- **Single-phase vs. polyphase meters:** While 3-phase measurements are required for transmission-connected participants, many residential customers have single-phase connections. Therefore, the more expensive polyphase meters used by large-scale participants may not be necessary for certain DER, especially residential customers. Single-phase metering is generally less expensive and can reduce overall hardware costs. Another option involves using existing retail meters or installing new submeters behind a retail meter to track individual DERs seeking to provide wholesale services. However, these approaches may require significant AMI system upgrades to support meter reconciliation.
- **New metering products and economies of scale:** Another dimension to consider is the likely emergence of new commercial products combining revenue-grade metering and real-time telemetry capabilities into a single hardware product. Similar trends have appeared in other market segments, such as integrating revenue-grade meters into solar inverters. In addition, as more DER customers adopt products that combine metering and telemetry, mass-market demand could generate significant economies of scale, further reducing the cost of hardware.
- **DER aggregation:** Aggregating DERs into groups for market participation may create opportunities to lower telemetry-related access costs. Several ISOs have specifically proposed that aggregators meet telemetry requirements at the aggregation level. This approach allows aggregators to specify their own requirements for the DER-to-aggregator metering and communication structures. While individual DERs would still need to report performance to the aggregator at short intervals, aggregators could use alternative, less expensive solutions compared to the ISO-grade RTUs and secure network connections otherwise required by individual large-scale market participants.

Regarding communications, ongoing costs for traditional wholesale market participants typically relate to the monthly charges to access communication networks enabling RTUs to transmit real-time data to the ISO. Private networks often utilize the Distributed Network Protocol version 3 (DNP3) connections

between RTUs and control centers, with encrypted Inter-Control Center Communications Protocol (ICCP) connections between control centers. Dedicated machine-to-machine phone lines offer higher reliability than internet connections. However, DER customers with access to fiber internet may reduce telemetry costs by transmitting data to the ISO over fiber-optic cabling, particularly relevant for electric utilities that also provide fiber internet services to their customers. More generally, internet-based communications represent a major cost-saving opportunity for smaller-scale DERs.

Another potential area for cost savings lies in integration between DER assets, aggregators, and distribution utilities. Currently, each jurisdiction maintains its own, and often evolving, set of integration requirements. This forces aggregators to tailor solutions for each area, increasing costs. As integration processes become more standardized across jurisdictions, VPP solutions will become more cost-effective by reducing the need for custom implementations.

8.6 Scalability for 2040

Flexible consumer energy technologies are expected to grow in adoption as New York State pursues its decarbonization goals. As Figure 69 illustrates, the Grid of the Future study estimated both current and future adoption of technologies that could support VPPs.

Figure 69. Estimated Current and Future Adoption of Flexible Energy Technologies in New York State

Source: Brattle (2025a).

	CURRENT	2040 EST.	Increase (approx.)
Smart Meters	68%	100%	+0.5x
Electric Vehicles	0.2 million	6.4 million	+30x
Electric Heating	19%	>60%	+2x
BTM Batteries	~90 MW	>2 GW	+20x

Several interconnected factors influence the adoption of VPP-compatible devices:

- For electric heating systems and water heaters, adoption depends on building electrification policies, equipment replacement cycles, and financial incentives to offset the higher upfront costs compared to fossil fuel alternatives.
- For EVs, adoption depends on vehicle availability, charging infrastructure deployment, purchase incentives, and consumer perceptions around range and performance.
- For BTM battery systems, high capital costs, permitting complexities, and interconnection complexities present adoption barriers, although declining prices and increasing interest in grid resilience could drive growth.

Across all technologies, consumer awareness remains a significant limiting factor because many potential adopters do not understand how their assets could support grid services while still meeting their primary energy needs.

The Grid of the Future study also estimated the cost-effective participation rates for different technologies, presented in Table 60. These rates are based on market research studies that evaluated customer willingness to participate in grid flexibility programs at various incentive levels, as well as a review of a subsequent study analyzing U.S. DR program and incentive data (Brattle 2025b).

Table 60. Cost-effective Participation Rates, Statewide Percent of Eligible Customers

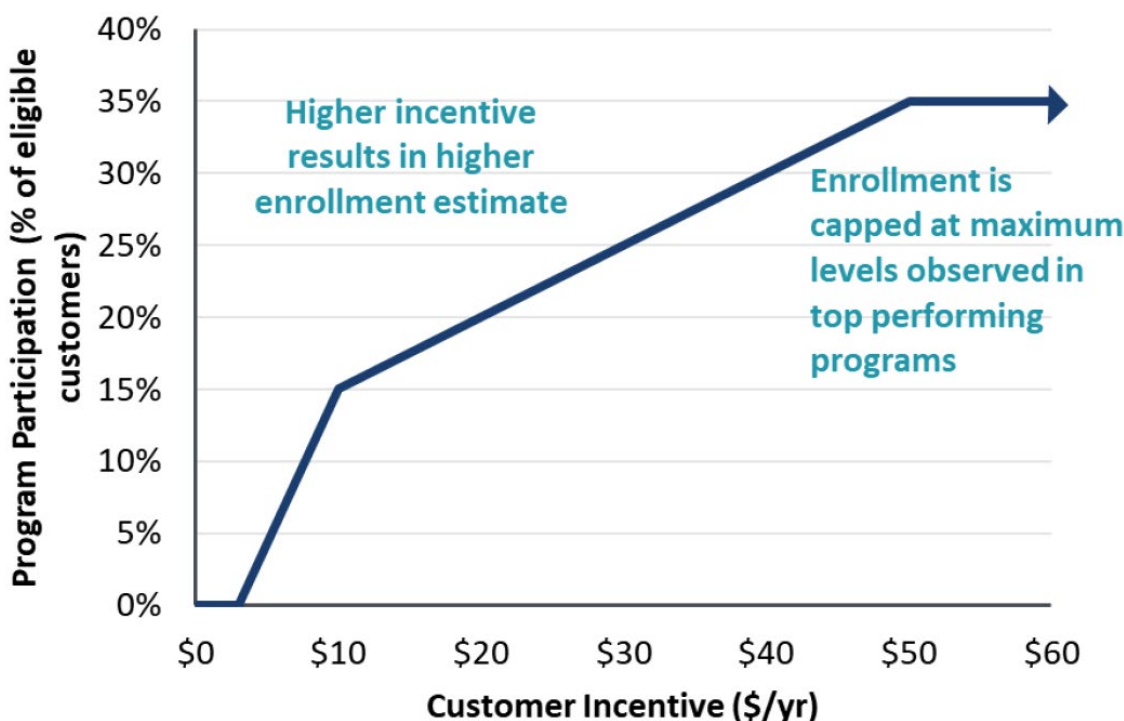
Source: Brattle (2025b).

Class	Grid Flex Option	2030 ³⁹	2040
Residential	Cooling	18%	34%
	Heating	23%	32%
	Heat pump water heating	20%	31%
	Electric resistance water heating	18%	39%
	Time-varying rate (opt-out)	80%	80%
	Time-varying rate (opt-in)	10%	20%
	Behavioral DR	80%	80%
	EV time-of-use (TOU)	40%	40%
	EV managed charging—home	32%	32%
	EV vehicle-to-grid (V2G)	N/A ⁴⁰	10%
	EV managed charging—workplace	--	1%
	BTM battery storage	~290 MW (0.5% of class)	~1.3 GW (2% of class)
Small C&I	Cooling	6%	10%
	Heating	3%	16%
	Time-varying rate (opt-out)	80%	80%
	Time-varying rate (opt-in)	5%	10%
Large C&I	Manual DR	33%	37%
	Auto DR	25%	25%
All C&I	BTM battery storage ⁴¹	~53 MW	~240 MW

The Grid of the Future study projects VPP participation based on empirical evidence from successful DR programs, using multiple methodologies, including customer surveys and reviews of existing program performance. The study differentiates participation growth trajectories by technology maturity, with newer technologies like EVs expected to achieve faster adoption rates than mature technologies that require retrofits. It models program participation as a function of incentive levels, showing a linear increase in participation with higher incentives, up to a cap based on maximum observed levels in top-performing programs, illustrated in Figure 70.

Figure 70. Depiction of Residential Enrollment as a Function of Incentive

Source: Brattle (2025b).

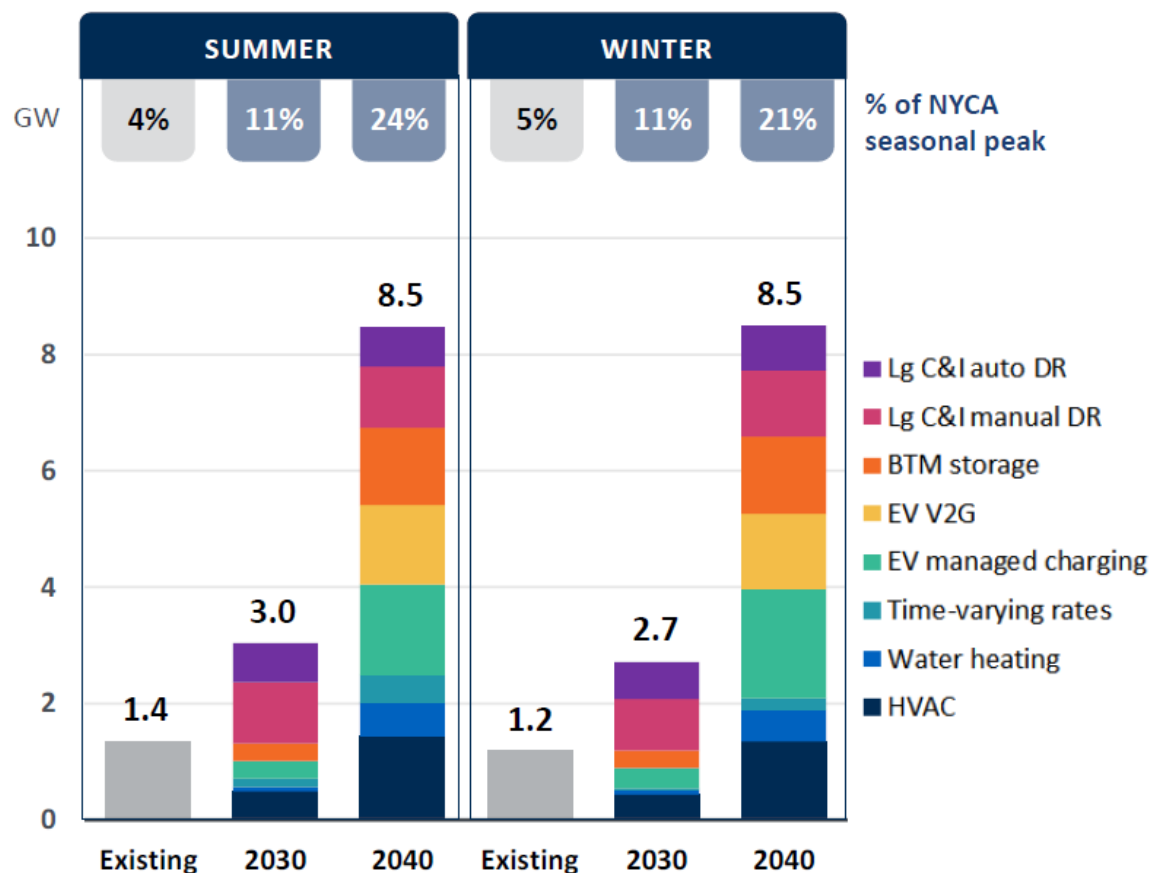


In addition to the incentives illustrated earlier, enrollment depends on user experience. A key factor influencing enrollment rates is whether a program uses an opt-in or opt-out structure. Programs with automatic enrollment are expected to achieve higher participation rates. Another factor for both enrollment and retention is the extent to which participation affects device usage. Programs that operate seamlessly, so that participants barely notice any changes, are more likely to attract and retain customers than those that cause noticeable inconvenience.

The Grid of the Future study estimated the potential of VPPs in New York State both in gigawatts and as a percentage of grid flexibility relative to the New York Control Area (NYCA) seasonal peak. As Figure 71 shows, by 2040, VPPs could provide 8.5 GW, meeting 24% of summer peak and 21% of winter peak (Brattle 2025a). The study derives its participation assumptions empirically from successful programs, so these values should be interpreted as optimistic estimates, assuming that efforts to implement grid flexibility measures are successful.

Figure 71. Potential of Virtual Power Plants in New York State

Source: Brattle (2025a).



The scenario modeled in the Grid of the Future study represents a high-end estimate if VPP deployment is broadly successful. Under less favorable scenarios, actual VPP capacity could be lower if deployment progresses more slowly than modeled if barriers persist (e.g., storage siting), or if customer willingness to participate lags behind expectations.

8.6.1 Beyond 2040

A significant portion of the technical potential flexibility that VPPs offer is expected to be capturable by 2040, but as business models, technologies, and customer acceptance continue to evolve, new opportunities for cost-effective VPPs may emerge. For example, increased automation and improved grid communication could enable smaller and more numerous devices to operate at times most favorable to the bulk power system without interfering with their primary functions.

8.6.2 Scalability Summary

While VPPs alone cannot meet the reliability needs of a 2040 grid because they do not generate energy, they could significantly impact the load shape of a 2040 grid to reduce the reliance on expensive peaking units.

The potential of 8.5 GW of VPP capacity described in the New York “Grid of the Future” study represents a significant contribution to New York State’s 2040 grid needs. However, a mix of other 2040 technologies will still be required to meet energy and reliability demands that VPPs cannot fulfill on their own.

8.7 Conclusion

Based on the above assessment, the following key observations are offered to inform future consideration of VPP deployment in New York State:

Demand response is a grid management strategy that enables consumers to reduce consumption during critical periods of demand. Demand response programs have been successfully reducing the electricity consumption of large-scale consumers for decades. VPPs coordinate the response of distributed energy resources (DERs) to enable smaller-scale customers to participate in grid operations.

VPPs could serve a critical role in harnessing the inherent flexibility of DERs and load-flexible appliances already being deployed. These aggregated resources can provide economic value to consumers and services across multiple grid domains, from bulk system balancing to localized distribution support.

Recent studies show that VPPs could provide 8.5 GW of flexibility potential in New York State in 2040. Achieving this estimated technical potential requires improving conditions for customer acquisition and participation, standardizing communications and market interfaces, and addressing metering and telemetry costs. Programs with easier enrollment and lower user interference are expected to have a greater impact.

VPPs offer a cost-effective approach to balancing energy supply and demand. Short lead times and low capital costs relative to other technologies make VPPs a cost-competitive option for bridging the gap to a zero-emissions power sector.

9 Resource Comparison

9.1 Overview

All of the DEFR technologies evaluated in this study have advantages and disadvantages. Understanding the trade-offs among technologies underscores the importance of maintaining a diverse technology portfolio for reducing GHG emissions while economically and reliably meeting electricity demand. When applied as part of an integrated portfolio, all technologies considered here can play useful roles that capitalize on their strengths.

This section compares technologies across the different attributes evaluated throughout this study. Most of the comparison focuses on comparing technologies within three resource groups: low capacity factor resources (hydrogen and biofuels), high capacity factor resources (advanced nuclear, carbon capture and storage, and next-generation geothermal), and gap-rightsizing resources (LDES and VPPs).²² Because technologies in different resource groups serve different functions, are expected to operate with very different profiles, and provide fundamentally different value to the grid, direct comparisons across resource groups are difficult and can be misleading. Ultimately, electric system modeling will be needed to understand the least-cost mix of resources and each of their potential unique contributions, which falls outside the scope of this study.

9.2 Low Capacity Factor Technologies

Low capacity factor resources offer high flexibility and responsiveness to grid needs. They can be deployed during periods of high demand and low renewable generation, offering reliability and fast-ramping capabilities without duration limitations, assuming fuel availability. These resources are expected to be critical in any future zero-emission grid. However, they are expected to operate for only a limited number of hours per year due to a high operating-to-capital cost ratio, primarily driven by the cost of fuel, as well as fuel availability constraints. The low capacity factor resources evaluated in this study are H₂, RNG, and RD.

The study evaluates several combinations of both fuel production and power generation technologies for low capacity factor resources. For hydrogen production, it considers both blue H₂ (hydrogen generated via SMR with carbon capture and storage) and green H₂ (hydrogen generated via an electrolyzer powered

by zero-emission renewable electricity).²³ For hydrogen power generation, the study evaluates an existing CT retrofitted to accommodate 100% hydrogen combustion, a new CT designed to operate on 100% H₂, and a H₂ fuel cell. For RNG, it evaluates power generation using an existing CT, a new CT, and an RNG fuel cell. For RD, the study evaluates power generation using both an existing and a new CT.

9.2.1 Readiness

The technologies and infrastructure needed to generate electricity from RNG and RD are more readily available than those needed for hydrogen-fueled power generation. RNG and RD are drop-in replacement fuels for existing NG- and distillate-fired plants, so the power plants, fuel transport, and storage infrastructure already exist. Additionally, some technologies and processes for biofuel production are already commercially available. However, scaling biofuels for power sector use beyond limited peaking applications may face challenges in the feedstock supply chain and technology maturity. Less mature technologies for fuel production, such as gasification combined with methanation, may be necessary to convert more readily available feedstocks, like cellulosic biomass, to RNG. Ultimately, building out the feedstock supply chain both in-state and in surrounding states will pose the biggest challenge for biofuel readiness.

The technologies to produce both blue and green H₂ are also commercially available, as are H₂ fuel cells, although these typically appear in smaller-scale, niche applications. Retrofit and new-build CTs designed for 100% H₂ combustion are less mature, but likely to reach commercial readiness by 2040. One of the most significant challenges for H₂ is the infrastructure needed to transport and store the fuel (and, in the case of blue H₂, to transport and store the captured CO₂). H₂ projects located near Upstate New York storage sites could be viable from an infrastructure perspective by 2040, but large-scale hydrogen power generation in other parts of New York State would likely require significant infrastructure development, including H₂ pipelines, underground storage, and possibly on-site storage, which would challenge large-scale deployment and introduce safety, environmental, and other risks. While blending H₂ into existing natural gas pipelines could lower initial deployment barriers by leveraging existing infrastructure to enable supply growth, the existing infrastructure is not designed to handle substantial quantities of hydrogen. Blending any meaningful amount of hydrogen would require a comprehensive compatibility assessment of safety, air quality, and reliability risks, as hydrogen is known to carry pipeline embrittlement risks. Further, GHG and co-pollutant emissions associated with combusting the blended fuel, while partially reduced depending on the blend rate, largely still remain. For these reasons, according to the *2025 Draft State Energy Plan*, New York State does not currently support the blending of hydrogen into the existing natural pipeline system.

Supply chain readiness is also less certain for H₂ production. Scaling up electrolyzer production and fuel cell manufacturing capabilities will be necessary to meet demand by 2040.

In general, most of the power generation and fuel production technologies evaluated have relatively short project lead times (<5 years), but required infrastructure buildout for H₂ pipelines (and CO₂ pipelines for blue H₂) could significantly extend the project lead time for the overall plant development and may not be achievable by 2040.

Figure 72 summarizes the technology, infrastructure, and supply chain readiness as well as the associated lead times of the low capacity factor technologies evaluated.

Figure 72. Summary of 2040 Readiness of Low Capacity Factor Resources for New York State

Fully green indicates an advantage for the technology, while fully yellow indicates a challenge for the technology, with partial shading indicating the technology falls in the middle.

2040 Readiness	Blue H ₂			Green H ₂			RNG			Renewable Diesel	
	Retrofit CT	New CT	Fuel Cell	Retrofit CT	New CT	Fuel Cell	Existing CT	New CT	Fuel Cell	Existing CT	New CT
Technology Readiness											
Infrastructure Readiness											
Supply Chain Readiness											
Project Lead Time											

9.2.2 Emissions

The emissions of blue H₂, green H₂, RNG, and RD, and their ability to reduce GHG and co-pollutants from the power sector, differ considerably, as Figure 73 and Table 61 illustrate, comparing emissions per MWh with those of reference NG and fossil distillate CTs using the NYS emissions inventory accounting methodology for the power sector (described in detail Section 3).

Green H₂ essentially eliminates all power sector emissions, except for moderate NO_x emissions during combustion in a turbine, which can be mitigated. Conversely, blue H₂ achieves a more moderate reduction in GHG emissions compared to NG emissions, due largely to the upstream emissions associated with the drilling, production, and transmission of the NG used for hydrogen production in the steam methane reformer, as well as the uncaptured GHG during hydrogen production. As with green H₂, the combustion of blue H₂ in a turbine produces moderate NO_x emissions. However, power production using an H₂ fuel cell does not produce NO_x emissions and, for blue H₂, results in lower GHG emissions per MWh than combustion in a turbine due to the higher efficiency of the fuel cell.

RNG and RD can significantly reduce net GHG emissions compared to NG and fossil distillate, respectively. However, gross GHG emissions from turbine combustion are still considerable. Life-cycle emissions from different feedstock-to-fuel pathways also vary. Although these emissions are not directly attributed to the power sector, they can impact emissions in other sectors and should be considered. RNG fuel cells produce over 40% lower gross GHG per MWh than RNG-fired turbines, and more than 65% lower than NG-fired turbines due to their higher efficiency.

PM and NO_x co-pollutants from fuel combustion in a turbine are comparable to those of a reference fossil fuel plant, although the anticipated lower run times, due to high fuel prices and the buildout of renewable generation technologies, would improve air quality. RD results in higher GHG and co-pollutant emissions per MWh than RNG, but co-pollutant emissions are slightly lower than those of fossil distillate due to the lower sulfur content in RD, which produces fewer or no SO_x emissions.

Figure 73. Power Sector Greenhouse Gas Emissions from Low Capacity Factor Resources

Emissions shown in gross and net terms, measured in lb of CO₂e per megawatt-hour (lb CO₂e/MWh).

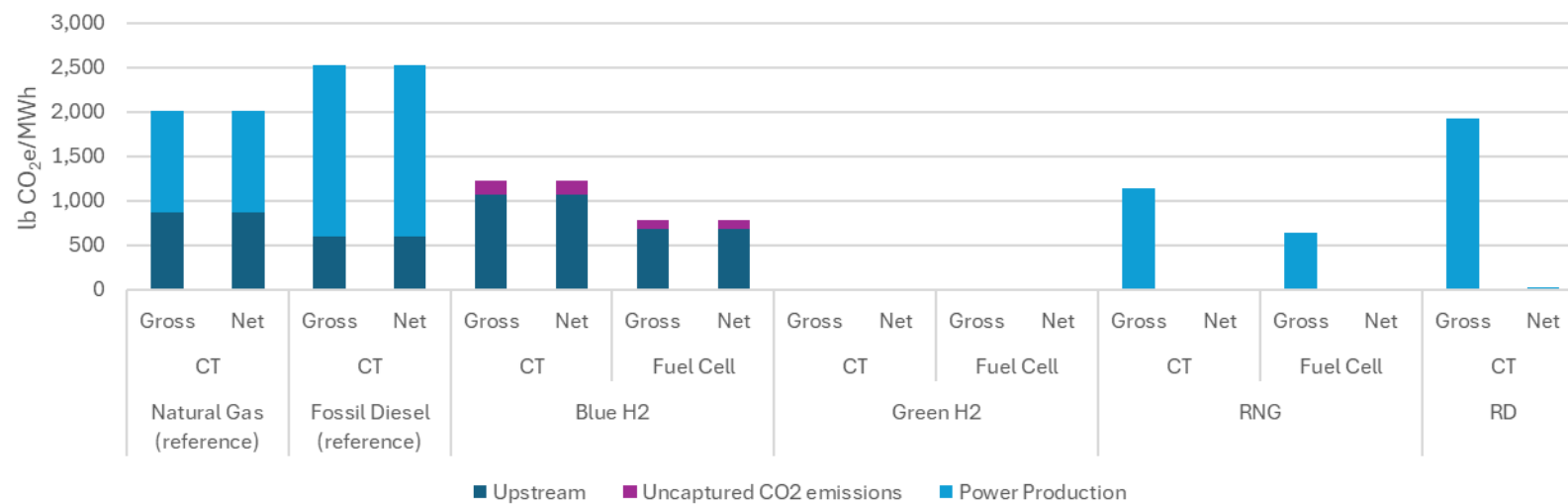


Table 61. Emissions Considerations for Low Capacity Factor Resources

Metric	Natural Gas (reference) CT	Fossil Diesel (reference) CT	Blue H ₂ CT	Blue H ₂ Fuel Cell	Green H ₂ CT	Green H ₂ Fuel Cell	RNG CT	RNG Fuel Cell	RD CT
Net GHG Emissions (lbCO₂e/MWh)	2012.0	2523.7	1225.2	785.9	0.0	0.0	10.1	0.0	26.7
Gross GHG Emissions (lbCO₂e/MWh)	2012.0	2523.7	1225.2	785.9	0.0	0.0	1137.2	644.8	1921.7
Fugitive Natural Gas System Emissions	Yes	No	Yes	Yes	No	No	Yes	Yes	No
Upstream Fossil Emissions	Yes	Yes	Yes	Yes	No	No	No	No	No
Co-pollutants^a	Reference (PM, NO _x , SO _x)	Very high (PM, NO _x , SO _x)	Low (NO _x)	None	Low (NO _x)	None	Similar to Reference (PM, NO _x , SO _x)	Very low	Very high (PM, NO _x)

^a Co-pollutant emission rankings of “very low” to “very high” are relative to the reference case of NG combustion, not to uncontrolled emissions. For all technologies evaluated, emissions controls would be utilized and plants would be in compliance with local regulations.

9.2.3 Other Considerations

Beyond the impacts on GHG and air quality from co-pollutant emissions discussed earlier, these technologies introduce additional important considerations. While water requirements for power generation are low in CTs and fuel cells, both blue H₂ and green H₂ consume significant amounts of freshwater as part of the H₂ production process. Land-use requirements for electrolyzers and H₂ power production facilities are relatively small, but the land use associated with the renewable generation required to power the electrolyzers can be significant. Hydrogen produced using nuclear electricity or via steam methane reforming with carbon capture results in lower land-use impacts compared to hydrogen produced with renewables.

For RNG and RD, the land use for some feedstocks, such as purpose-grown bioenergy crops, can cause concerns about the allocation of arable land for RNG and RD feedstock production, as well as the increased shift of natural lands to agricultural use. These concerns can be mitigated by limiting the use of energy crops and focusing on waste products and crops that do not require changes in land use. However, restricting available feedstocks to waste-only would cause a significant reduction in supply.

9.2.4 Cost

The cost of generating electricity using hydrogen or biofuels varies significantly depending on the power generation technology used and the details surrounding the fuel production and delivery.

9.2.4.1 Fuel Cost

For all fuel types, fuel prices are considerably higher on a dollar per MMBtu basis than the reference NG price, and most often higher than the reference fossil distillate price as shown in Figure 74.

Green H₂ is significantly more expensive than all other fuels due to the costs of electricity, infrastructure, and electrolyzers, which also operate with lower capacity factors given the availability of renewable energy. Lower-cost green H₂ could be unlocked by leveraging otherwise curtailed renewables, but this use case is limited by low energy availability and challenging electrolyzer economics due to even lower electrolyzer utilization. As highlighted in the earlier infrastructure readiness discussion, infrastructure requirements remain a key contributor to cost certainty. H₂ could require a sizable buildout of pipelines

and storage for statewide use, which drives increased costs. Figure 74 shows the base green hydrogen cost under the Power Sector Only with No Transport infrastructure scenario described in Section 2.5.1. The error bars represent the infrastructure uncertainty described in Figure 13 and uncertainty in electricity cost.

Blue H₂ has the potential to be significantly lower cost than green H₂ but faces similar transport and storage challenges and depends on the cost of NG, which remains uncertain in 2040. Figure 74 shows the base blue hydrogen cost under the Power Sector Only with No Transport infrastructure scenario described in Section 2.5.1. The error bars represent the infrastructure uncertainty described in Figure 15 and NG cost uncertainty. The price of blue H₂ could be similar to that of RNG, though still much more expensive than the reference NG price.

Notably, all the hydrogen costs in Figure 74 assume either pipeline transport or no transport is required. Absent a pipeline, the logistics and costs associated with serving statewide needs with H₂, especially for Downstate New York, are expected to be very challenging.

RNG and RD are less expensive than green H₂ because they do not depend on the cost of electricity. They also do not have the same infrastructure cost challenges as hydrogen because RNG and RD are drop-in replacements for NG and fossil distillate, respectively, and can thus leverage existing infrastructure for transport and storage. This makes biofuels especially advantageous for Downstate New York applications. In contrast, other technologies with siting constraints may require significant transmission upgrades or fuel transport infrastructure to serve the Downstate load.

The costs of biofuel production depend on the type of feedstock and the conversion technology required for fuel production. Because the quantity of feedstocks is limited, one of the key drivers of biofuel costs will be the volume of demand—as low-cost feedstocks are consumed, higher-cost feedstocks and more expensive conversion technologies will be required to meet demand. In Figure 74, the RNG and RD base costs reflect the Economywide + Low Power Sector Demand scenario described in Section 3.5.1, and the error bars represent the cost uncertainty associated with the higher and lower demand scenarios explored in Table 12.

Figure 74. Estimated 2040 Fuel Price Ranges for Low Capacity Factor Resources

Tax credits include the Clean Hydrogen Credit for green H₂ (\$3/kg) and the Carbon Capture Credit for blue H₂ (\$85/tonne). Full tax credit applicability depends on construction starting before credit phaseout. Prices reported in 2023 USD, with and without tax credits.

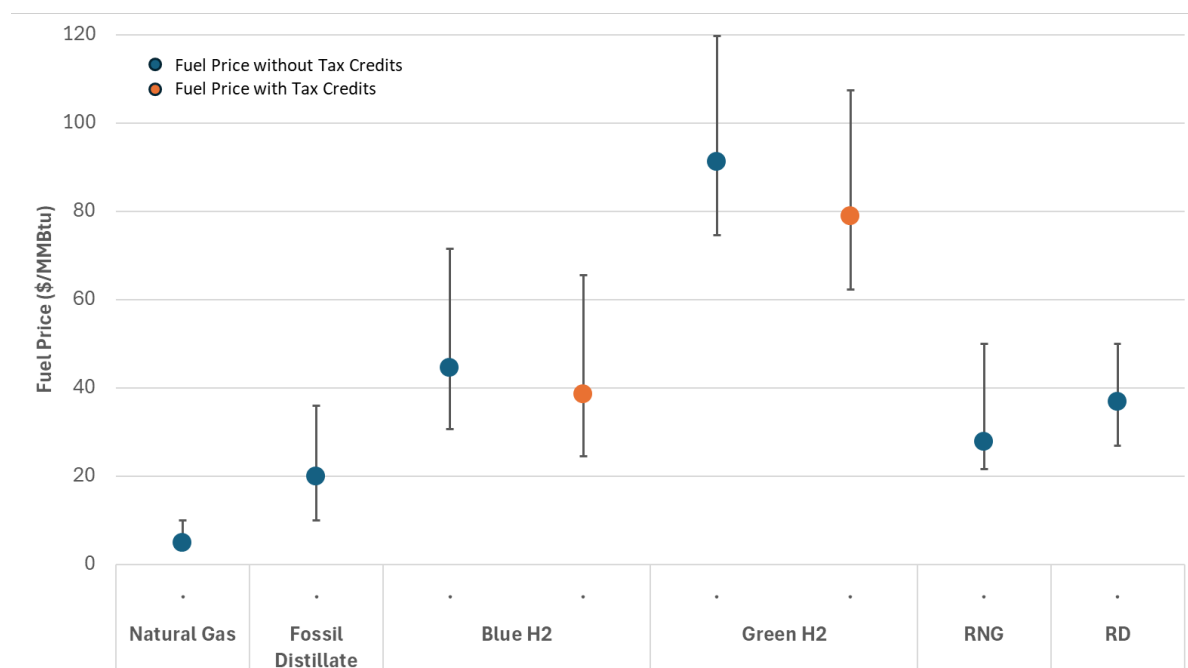


Figure 74 also illustrates the potential impact of tax credits on fuel prices. The different fuels qualify for different tax credits. Blue H₂ qualifies for the Carbon Capture Credit (\$85/tonne or approximately \$6/MMBtu), available for 12 years after the capture equipment becomes operational on a project that began construction prior to 2033. Green H₂ is assumed to be eligible for the maximum Clean Hydrogen Credit (\$3/kg or \$24.9/MMBtu) due to its zero life-cycle GHG emissions. However, recent federal policy changes require hydrogen production facilities to begin construction before January 1, 2028, for the Clean Hydrogen Credit, which presents a significant deployment challenge. The credit lasts for the first 10 years of a facility's lifetime. Assuming a project begins construction in 2027 and takes 2–4 years to build, the Clean Hydrogen Credits are unlikely to remain available long after 2040, and any qualifying projects must begin very quickly. Clean fuel credits for biofuels are expected to expire before 2030 and are not included in Figure 74.

9.2.4.2 Levelized Cost of Electricity

Figure 75 presents the 2040 LCOE²⁴ across new-build power plants for the low capacity factor resource technologies, assuming Upstate New York technology costs, compared with a reference case of a new

build NG-fired or fossil distillate CT. Table 62 details the capital, operating, and fuel costs used for the LCOE calculation. The error bars in Figure 75 reflect the ranges given in Table 62. Fuel cost ranges are based on the values shown in Figure 74.

Figure 75 shows that while the LCOEs are higher for H₂ and biofuel resources, all resources that operate at very low capacity factors incur high LCOEs as capital costs are spread over very few hours. This also applies to NG and oil peaker plants, as seen in the reference costs in Figure 75. It also holds true for peaker plants in use today: during periods of high demand and system stress, the grid activates older and less efficient resources to maintain reliability. The LCOE range for a fuel cell is wider than that of a CT due to increased uncertainty surrounding 2040 capital costs for large-scale fuel cell deployment beyond the niche applications where they are currently commercially deployed.

Figure 75 also shows the potential impact of tax credits on LCOE for these technologies. The generation equipment for the green H₂ cases qualifies for the Clean Electricity ITC of 30% due to the zero-GHG electricity generated. While CTs firing blue H₂ do not qualify for the Clean Electricity ITC due to life-cycle GHG emissions, blue H₂ includes the Carbon Capture Credit for the H₂ CT. All fuel cells are expected to qualify for the Clean Electricity ITC, which, when combined with their higher fuel efficiency, can make these technologies competitive with their combustion turbine counterparts. Construction must begin prior to 2033 to be eligible for the full Clean Electricity ITC or Carbon Capture Credit. Figure 75 excludes the Clean Hydrogen Credit H₂ production incentive due to the deadline challenge discussed earlier.

In cases where the fuel can be used at an existing site, either by retrofitting a CT to fire H₂ or by using RNG or RD as a drop-in fuel at an existing CT, LCOE is considerably lower than for new builds, as shown in Figure 76. However, these savings are not permanent because the generating equipment will eventually need to be replaced. Figure 76 assumes the Clean Electricity ITC would be available for green hydrogen retrofit costs and Carbon Capture Credits for blue hydrogen, with construction required to begin before 2033 for full credit eligibility.

Overall, the high operating costs of these plants, driven primarily by their fuel costs, explain why they are expected to operate at low capacity factors and only at times when their contribution to the grid is most valuable.

Figure 75. Levelized Cost of Electricity of New Build Low Capacity Factor Resources, Upstate New York

Analysis assumes a 50 MW plant operating with a 3% capacity factor. Tax credits include Carbon Capture Credit (\$85/tonne CO₂) for blue H₂ fuel costs and Clean Electricity ITC (30%) for green H₂ power generation equipment and fuel cell projects. Full tax credit applicability depends on construction starting before the credit phaseout. Excludes Clean Hydrogen Credit, given limited availability window. Prices reported in 2023 USD, with and without tax credits, based on expected 2040 cost and performance ranges.

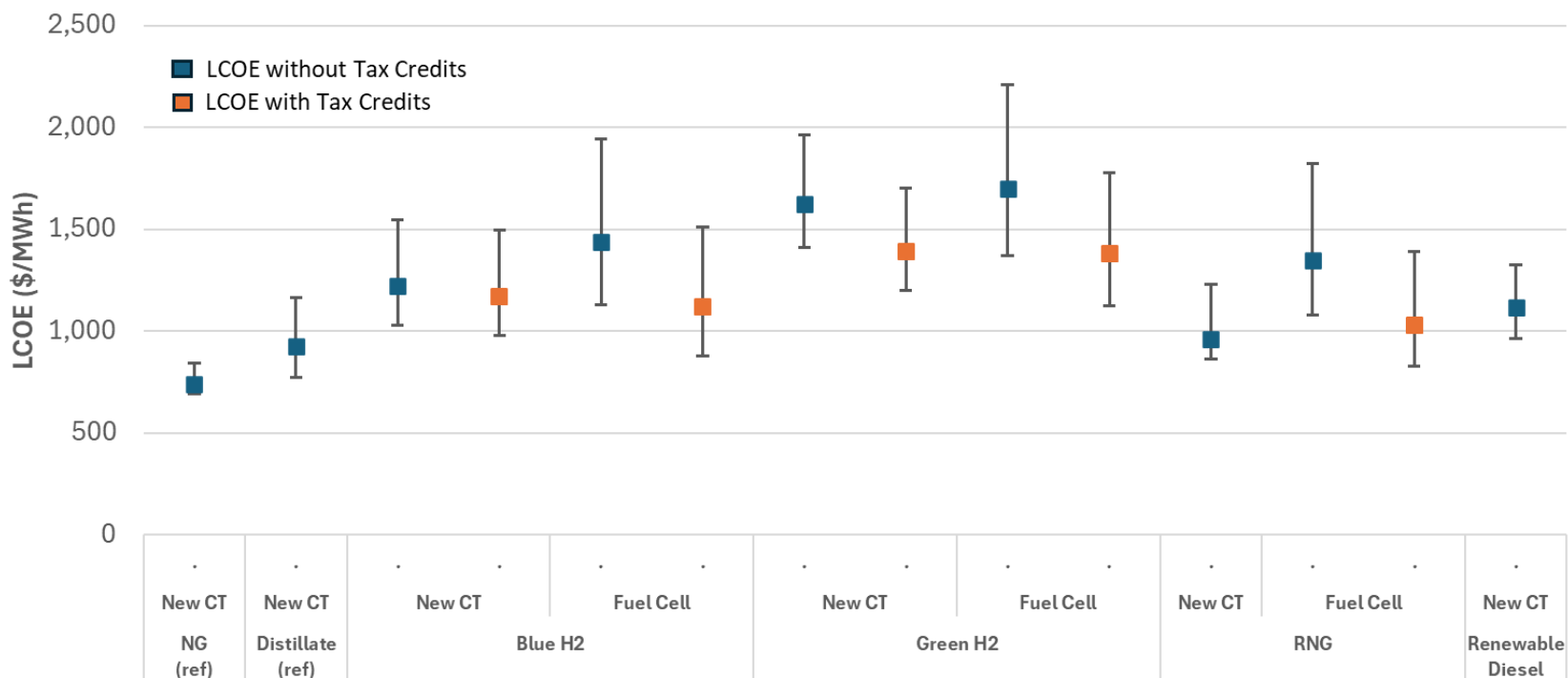


Table 62. 2040 Capital, Operating, and Fuel Costs for New Build Low Capacity Factor Resources

Prices reported in 2023 USD.

2040 Costs	NG (ref) New CT	Distillate (ref) New CT	Blue H₂ New CT	Blue H₂ Fuel Cell	Green H₂ New CT	Green H₂ Fuel Cell	RNG New CT	RNG Fuel Cell	RD New CT
Capital Cost Range (\$/kW)	1,311–1,528	1,311–1,528	1,577–1,972	1,606–2,798	1,577–1,972	1,606–2,798	1,311–1,528	1,606–2,798	1,311–1,528
Fixed OPEX Range (\$/kW-yr)	25	25	25	43–44	25	43–44	25	43–44	25
Variable OPEX Range (\$/MWh)	7.2	7.6	7.4	7.6–7.9	7.4	7.6–7.9	7.2	7.6–7.9	7.6
Fuel Cost without Tax Credits (\$/MMBtu)	4–10	10–36	30.6–71.6	30.6–71.6	74.6–119.7	74.6–119.7	21.5–50	21.5–50	26.9–50
Fuel Cost with Tax Credits (\$/MMBtu)	N/A	N/A	24.5–65.5	N/A	N/A	N/A	N/A	N/A	N/A

Figure 76. Levelized Cost of Electricity of Existing/Retrofit Low Capacity Factor Resources, Upstate New York

Analysis assumes a 50 MW plant operating with a 3% capacity factor. Tax credits include Carbon Capture Credit (\$85/tonne CO₂) for blue H₂ fuel costs and Clean Electricity ITC (30%) for green H₂ power generation equipment. Full tax credit applicability depends on construction starting before the credit phaseout. Excludes Clean Hydrogen Credit, due to its limited availability window. Prices reported in 2023 USD, with and without tax credits, based on expected 2040 cost and performance ranges.

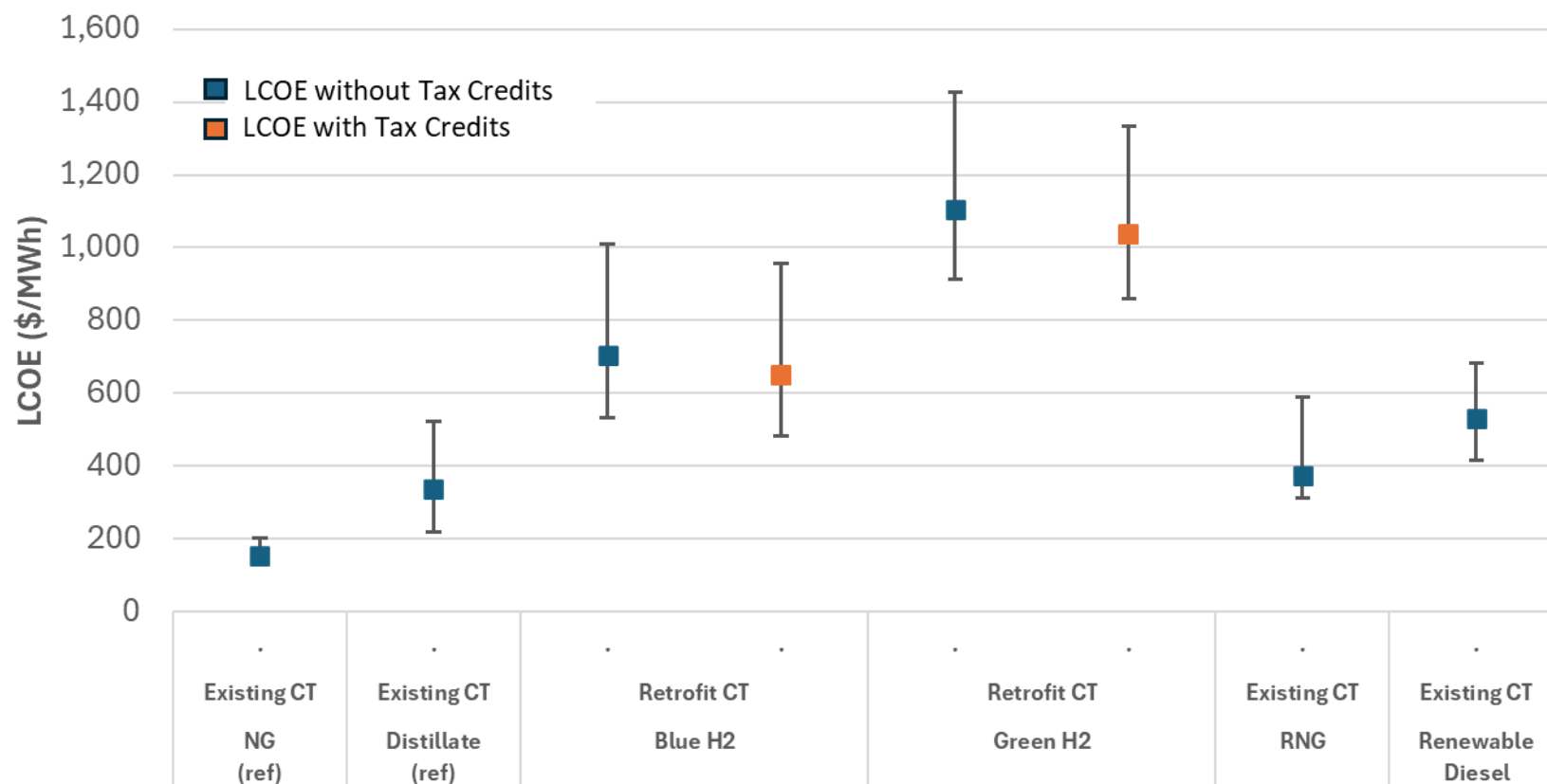


Table 63. 2040 Capital, Operating, and Fuel Costs for Existing/Retrofit Low Capacity Factor Resources

Prices reported in 2023 USD.

2040 Costs	NG (ref) Existing CT	Distillate (ref) Existing CT	Blue H₂ Retrofit CT	Green H₂ Retrofit CT	RNG Existing CT	RD Existing CT
Capital Cost Range (\$/kW)	0	0	272–473	272–473	0	0
Fixed OPEX Range (\$/kW-yr)	25	25	25	25	25	25
Variable OPEX Range (\$/MWh)	7.2	7.6	7.4	7.4	7.2	7.6
Fuel Cost without Tax Credits (\$/MMBtu)	4–10	10–36	30.6–71.6	74.6–119.7	21.5–50	26.9–50
Fuel Cost with Tax Credits (\$/MMBtu)	N/A	N/A	24.5–65.5	N/A	N/A	N/A

9.2.5 Summary

Low capacity factor resources are expected to be critical in any future zero-emission grid, offering reliability and fast-ramping capabilities on days with the most extreme system needs. Each technology evaluated has advantages and challenges. Infrastructure constraints and high costs may limit the widespread availability of H₂ in 2040, but low GHG emissions, especially for green H₂, will likely provide value across various industries in 2040 and beyond, making investments in pilot projects and eventual strategic infrastructure deployment important from an economywide perspective.

RNG and RD may be the most viable low capacity factor resources for 2040 deployment given their technology readiness, existing fuel transport infrastructure, and ability to serve as drop-in fuels in existing plants. However, the combination of feedstock limitations, competition for fuels from other sectors and states, and GHG considerations necessitates limiting their use to low capacity factor applications.

9.3 High Capacity Factor Technologies

High capacity factor resources operate the majority of the year, providing reliable baseload power. These technologies can meet existing and growing load, reducing the need for both high-cost low capacity factor DEFRs and some intermittent renewable deployment, often with a lower land footprint on a per-capacity basis. They also typically provide inertia and other ancillary grid services to support a grid increasingly dependent on variable renewables. While they have some ramping capabilities, they are less suitable for fast ramping or frequent starts and stops.

This analysis compares LLWRs, lwSMRs, non-water-cooled reactors, NG combined cycle plants with 95% carbon capture and storage (CCS), and next-generation geothermal systems.

9.3.1 Readiness

The readiness for 2040 deployment of the high capacity factor technologies evaluated in this study varies, with each having its own advantages and challenges, as summarized in Figure 77. LLWRs and CCS are the most technically mature technologies and do not face significant technical hurdles for deployment. lwSMRs and non-water-cooled reactors are less mature, with lwSMRs just entering the Pilot and Demonstration phase and non-water-cooled reactors still in the Component and Prototype Validation phase. Both, however, could achieve early commercial deployment by 2040.

While enhanced geothermal technologies have completed pilot projects and have begun to enter commercial deployment in some areas with more favorable thermal resources, the depths required for geothermal deployment in New York State are untested, and significant development is required before the technology approaches commercial deployment with New York State's available resources.

Although commercially available or approaching commercial availability, LLWRs and CCS face other hurdles for 2040 deployment readiness. LLWRs (as well as lwSMRs and non-water-cooled reactors) require significant project lead times, meaning deployment by 2040 requires that projects begin the development process within the next few years. Opportunities may exist to reduce these timelines if nuclear is built at existing sites, potentially reducing development activities and timeline.

For CCS projects, infrastructure buildout presents the most significant challenge because new pipelines must be sited, permitted, and built to transport CO₂ from the plant to its storage location, which also must be tested, permitted, and developed. Siting CCS projects near storage sites could mitigate the need for pipelines, but this introduces significant siting constraints due to the limited number of candidate storage locations in New York State. Siting constraints often require that these technologies be located far from load centers, which may necessitate substantial transmission in order to meaningfully contribute to resource adequacy needs in those load centers, especially in Downstate New York.

Overall, activities must begin soon in order to deploy any of the high capacity factor technologies.

Figure 77. Summary of 2040 Readiness of High Capacity Factor Resources for New York State

Fully green indicates an advantage for the technology, while fully yellow indicates a challenge for the technology, with partial shading indicating the technology falls in the middle.

2040 Readiness	Nuclear			CCS		Geothermal
	LLWR	lwSMR	Non-Water-Cooled SMR	Retrofit	New	
Technology Readiness						
Infrastructure Readiness						
Supply Chain Readiness						
Project Lead Time						

9.3.2 Emissions

The emissions of the high capacity factor technologies and their ability to reduce GHG and co-pollutants from the power sector differ, which Figure 78 and Table 64 illustrate, comparing emissions to those of a reference NG combined cycle baseload plant.

Nuclear plant operations produce no power sector emissions or associated co-pollutants or fugitive emissions. The binary enhanced geothermal technology most likely to be deployed in New York also has minimal emissions. Some studies show very low levels of GHG emissions, while others report zero emissions.

CCS, on the other hand, does have GHG emissions, primarily due to upstream emissions that cannot be avoided through capture at the plant. As a result, a CCS plant with 95% capture during power production only reduces overall GHG emissions by about 50% compared to a reference NGCC plant without CCS. Furthermore, while an NGCC plant with CCS reduces some co-pollutant emissions relative to a plant without capture, it still emits NO_x as well as associated fugitive emissions from the upstream fuel transport system and the downstream CO₂ transport system.

Figure 78. Power Sector Greenhouse Gas Emissions from High Capacity Factor Resources

Emissions shown in gross and net terms, measured in lb of CO₂e per megawatt-hour (lb CO₂e/MWh). Gross and net emissions are equivalent for all technologies and fuels evaluated here.

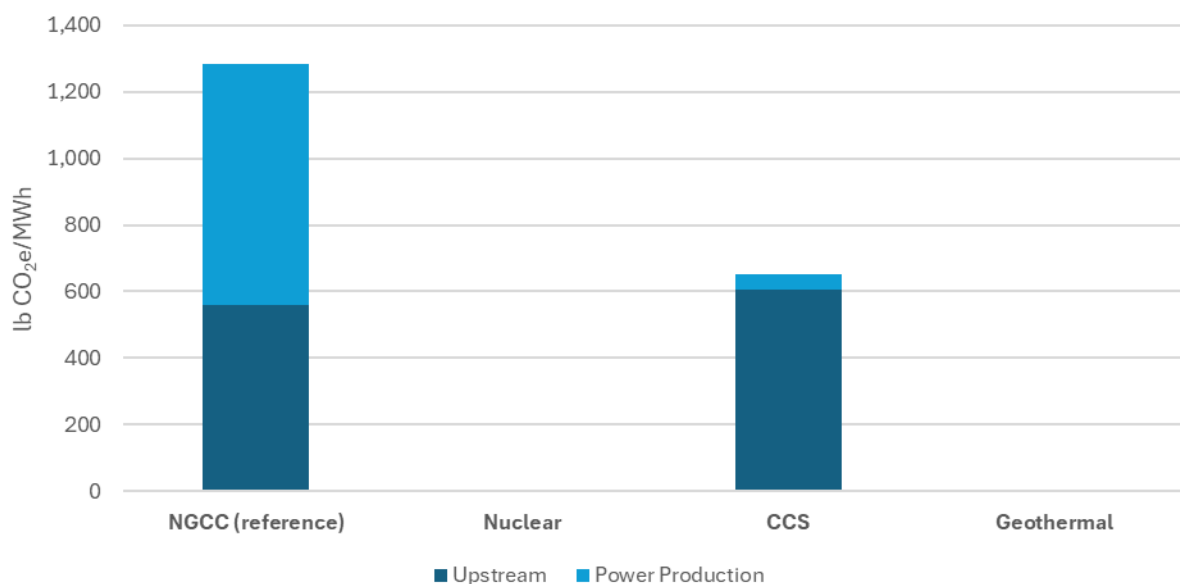


Table 64. Emissions Considerations for High Capacity Factor Resources

Performance Metrics	NGCC (Reference)	Nuclear	CCS	Geothermal
Net GHG Emissions (lbCO _{2e} /MWh)	1,282.6	0.0	652.4	5.5
Gross GHG Emissions (lbCO _{2e} /MWh)	1,282.6	0.0	652.4	5.5
Fugitive Gas System Emissions	Yes (upstream NG)	No	Yes (upstream NG and downstream CO ₂)	No
Upstream Fossil Emissions	Yes	No	Yes	No
Co-pollutants ^a	Reference (PM, NO _x , SO _x)	None	Low (NO _x)	Very Low (H ₂ S, SO ₂)

^a Co-pollutant emission rankings are relative to the reference case of NG combustion, not to uncontrolled emissions. For All technologies evaluated, emissions controls would be utilized, and plants would be in compliance with local regulations.

9.3.3 Other Considerations

Beyond GHG emissions and air quality impacts from co-pollutant emissions, additional important considerations influence the viability of these technologies. From a land-use perspective, all of these technologies have lower land-use impacts than other renewables. Nuclear also has a high job density and therefore also offers increased workforce and economic development opportunities compared to the other technologies.

Safety and waste management are significant considerations for nuclear. The nuclear fission process produces radioactive waste and materials, and extreme adverse operating conditions could pose radiation risks to workers and the public. As a result, nuclear power plants follow strict regulations and implement safety measures to mitigate these risks. New advanced reactors include enhanced passive safety features. As part of these regulations, nuclear power plants are typically not sited near high population densities, which limits siting potential.

For CCS, safety and environmental considerations include the air quality impacts, pipeline ruptures, induced seismicity, and groundwater contamination. Siting and constructing new pipelines could generate stakeholder impacts. While emissions impacts are difficult to mitigate, other CCS risks can be managed with thorough testing and careful execution.

For geothermal, risks such as groundwater contamination and induced seismicity during drilling and stimulation may arise if developers do not implement proper precautions. However, developers can significantly reduce these risks with careful planning and execution.

9.3.4 Cost

The cost of generating electricity from the high capacity factor resources evaluated in this study remains highly uncertain and varies significantly. Figure 79 shows the 2040 LCOE²⁵ across the technologies assuming Upstate New York technology costs, compared with reference cases of existing and new build NGCC plants. Table 65 details the capital, operating, and fuel costs used for the LCOE calculation. The error bars in Figure 79 reflect the ranges in Table 65, and, for CCS, a capacity factor uncertainty range of 40–65%.

Geothermal technology costs are extremely site- and resource-specific, heavily dependent on the drilling depth required to reach adequate temperatures. While geothermal development continues elsewhere in the U.S. and globally, applying those cost projections to New York State is challenging due to unproven depths. Therefore, specific cost data for New York State geothermal is not included. However, as geothermal activity at shallower depths grows, meaningful cost declines are expected, and these projects should be monitored for future cost estimate development.

Capital costs for future nuclear plants have a very wide uncertainty range, especially for lwSMRs and non-water-cooled reactors,²⁶ resulting in a broad LCOE range. The nuclear costs presented fall between FOAK and NOAK, representing the potential 2040 learning discussed in Section 4 on Nuclear energy. Learning-related cost reductions within this 2040 time horizon will only occur if initial projects start soon enough for subsequent projects to benefit.

NGCC + CCS is expected to offer a lower cost than nuclear, especially when CCS is retrofitted onto existing NGCC plants. However, given cost uncertainties, particularly around nuclear costs, some overlap exists between the cost estimates for nuclear and CCS technologies.

For all technologies, tax credits such as the Clean Electricity ITC for nuclear plants or the Carbon Capture Credit for CCS plants can significantly reduce LCOE. In the case of the CCS plants, LCOE could possibly compete with a new-build NGCC plant without capture. However, full credit applicability depends on construction starting before credit phaseout.

Figure 79. Levelized Cost of Electricity of High Capacity Factor Resources

Analysis assumes a 500 MW plant operating with a 40–65% capacity factor for NGCC and NGCC + CCS technologies and a 95% capacity factor for Nuclear technologies. Tax credits include Clean Electricity ITC (30%) for nuclear and Carbon Capture Credit (\$85/tonne) for CCS. Full tax credit applicability depends on construction starting before credit phaseout. Prices reported in 2023 USD, with and without tax credits, based on expected 2040 cost and performance ranges.

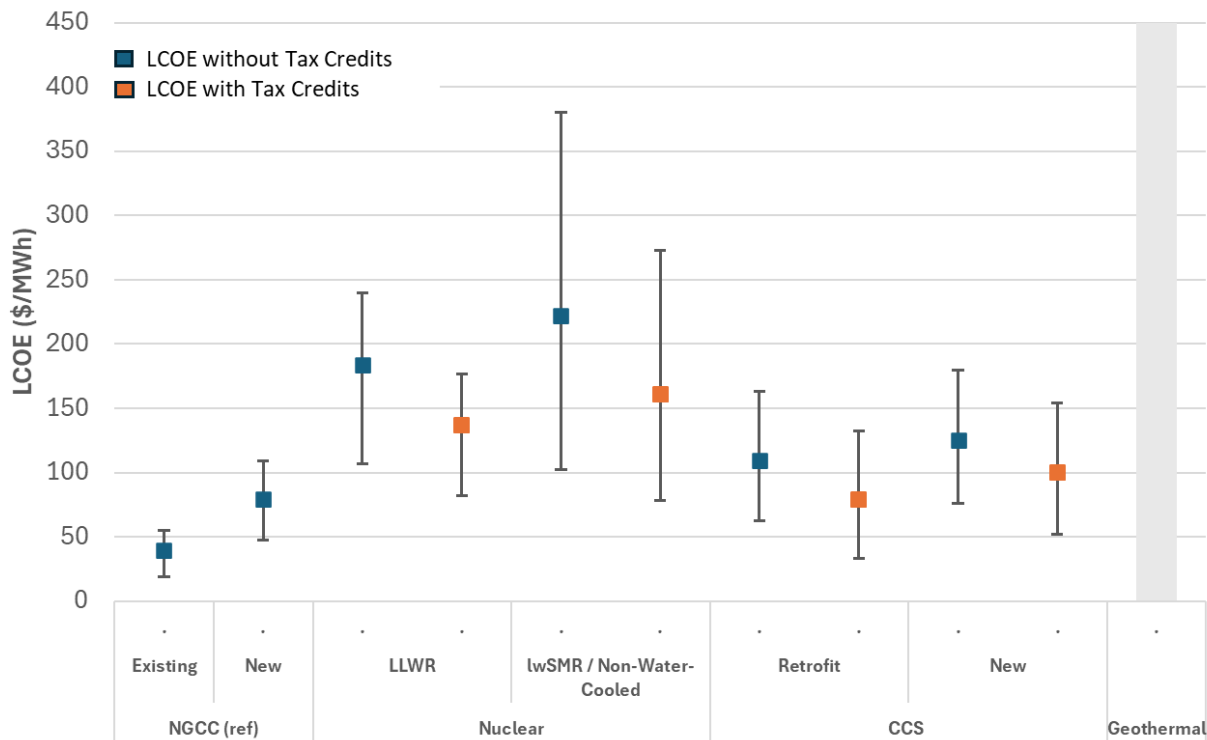


Table 65. 2040 Capital, Operating, and Fuel Costs for High Capacity Factor Resource Technologies

Prices reported in 2023 USD.

2040 Costs	Existing NGCC (Reference)	New NGCC (Reference)	Nuclear: LLWR	Nuclear: lwSMR/ Non-Water-Cooled	Retrofit NGCC + CCS	New CCS + CCS	Geothermal
Capital Cost Range (\$/kW)	0	1,448–1,688	5,459–13,559	5,674–25,311	922–1,606	2,070–2,827	Site- and resource-specific
Fixed OPEX Range (\$/kW-yr)	30–33	30–33	136–221	128–234	44–61	44–61	Site- and resource-specific
Variable OPEX Range (\$/MWh)	1.9–2	1.9–2	2.1–3.8	2.5–3.1	3.5–4.5	3.5–4.5	Site- and resource-specific
Fuel Cost (\$/MMBtu)	2–7	2–7	0.9–1.2	0.9–1.2	2–7	2–7	Site- and resource-specific
CO ₂ Transport and Storage Cost (\$/tonne)	N/A	N/A	N/A	N/A	33–52	33–52	Site- and resource-specific

9.3.5 Summary

High capacity factor resources are valuable for meeting existing load and expected load growth. While renewables are projected to supply most of the energy demand in 2040, high capacity factor resources can provide firm power and grid services that support reliability in a predominantly renewable grid. Their high energy density also helps mitigate potential land-use challenges associated with large-scale renewable deployment. High capacity factor resources could also reduce the need for low capacity factor resources, which are expensive and mostly idle. However, high capacity factor resource technologies require long lead times, often 10 years or more. To ensure they are operational by 2040, stakeholders must take early action.

Each technology offers unique advantages and faces specific challenges. From a deployment-readiness perspective, LLWRs and CCS are the most prepared for near-term implementation. However, lwSMRs and non-water-cooled reactors could also become commercially viable by 2040. Geothermal, while promising, has lower readiness and limited scalability in New York State.

In terms of cost, nuclear is expected to be more expensive than CCS in the near term, but it offers significant advantages in reducing GHG emissions and co-pollutants. Long-term nuclear cost reductions by 2040 are possible, but only if deployment begins soon. While CCS may be more affordable in the near term, it presents challenges in both the remaining upstream GHG emissions that are not mitigated with carbon capture, as well the infrastructure buildout that would be required for CO₂ transport and storage.

Both nuclear and CCS can reduce lead times and costs by selecting favorable sites, such as nuclear deployments at existing sites and CCS deployments near storage assets. Although geothermal may be limited in its scalability for 2040 deployment in New York State, ongoing advancements could make it a valuable long-term, zero-emission baseload option. Continued monitoring is important.

9.4 Gap-Rightsizing Resources

Gap-rightsizing resources help balance supply and demand, addressing the firm capacity gap. While these technologies do not generate electricity directly, they enhance the potential of other clean resources. They are expected to have significant value even today due to opportunities for energy arbitrage and infrastructure cost avoidance but will not be sufficient on their own to meet all grid needs due to duration limitations and because they do not generate electricity on their own.

This study considers two main categories of Gap-Rightsizing Resources: LDES and VPPs. LDES includes mechanical, electrochemical, and thermal storage technologies. Within each of these buckets are several technologies with a range of attributes.

9.4.1 Readiness

VPPs that deliver the advanced grid services needed in 2040 are largely ready for deployment. There is no physical infrastructure buildout required for VPPs, and their supply chains rely primarily on existing DERs already being deployed at commercial scale. The primary infrastructure and supply chain hurdles for VPPs are implementing the metering and data systems required to manage VPPs effectively and scaling up grid-interactive DERs. Several pilot projects have demonstrated the technical feasibility of both.

LDES technologies span a range of readiness levels within the mechanical, electrochemical, and thermal storage technology categories. Many technologies are already demonstrating success in pilot demonstrations and are nearing or achieving commercial deployment. Some supply chain buildout will be required across the LDES technologies as they achieve scale, with any supply chain risks around material constraints and manufacturing scalability depending on the final mix of technologies deployed.

VPPs require minimal physical footprint and can be sited anywhere that DERs are deployed. Conversely, LDES have unique siting considerations across technologies, including understanding safety, especially in urban environments, and possible land availability constraints, which can make siting in Downstate New York areas potentially more challenging. Project lead times for VPPs and most LDES technologies are generally shorter than those for low and high capacity factor technologies, although some mechanical storage technologies may take longer to deploy.

Figure 80 summarizes the 2040 readiness for deployment of these Gap-Rightsizing Resources.

Figure 80. Summary of 2040 Readiness of Gap-Rightsizing Resources for New York State

Fully green indicates an advantage for the technology, while fully yellow indicates a challenge for the technology, with partial shading indicating the technology falls in the middle.

2040 Readiness	LDES			VPP
	Mechanical	Electrochemical	Thermal	
Technology Readiness				
Infrastructure Readiness				
Supply Chain Readiness				
Project Lead Time				

9.4.2 Other Considerations

Neither LDES nor VPPs emit GHGs or co-pollutants during their operation. For LDES technologies, emissions may be associated with their operations depending on the source of electricity used to charge because RTE losses mean that more electricity is used for charging than is discharged. However, when LDES is charged with zero-emission electricity, as would be the case in a 0x40 grid, the emissions

associated with LDES operation would be zero. The emissions impact of VPPs on overall power sector emissions depends on the carbon intensity of the grid at the time of dispatch because VPPs generally reduce the operation of peaking generation assets and their associated emissions.

VPPs are generally expected to be lower-cost than LDES on a per-MWh basis, although actual costs are highly uncertain and can vary significantly depending on the scope and application. At the same time, VPPs face continuous changes in the underlying asset base as customers upgrade appliances, modify their participation preferences, or potentially withdraw from programs altogether.

The availability of VPPs and LDES technologies to provide services when needed varies. VPPs depend on customer participation, which may be unpredictable during peak events, such as winter peaks. LDES has the potential for longer discharge durations and higher operational certainty, but it is also a net load on the grid due to the need to recharge and RTE losses.

One of the most significant barriers for large-scale deployment by 2040 is the availability of compensation structures and market mechanisms that incentivize the attributes that these gap-rightsizing resources can offer to the grid. Targeted market and regulatory reforms could help to provide financial incentives that encourage investment and deployment.

10 Conclusions

A 2040 zero-emission grid will require a mix of attributes to maintain reliability requirements, and meeting these needs will require diverse resources. Most of the energy needs of a 0x40 grid could be met by renewables, such as solar and land-based, and offshore wind, as well as existing nuclear and hydro assets. Pairing these resources with complementary technologies such as short-duration storage and GFM inverters will maximize their potential benefits to the grid. The DEFRs studied in this report will play a critical and complementary role in supplying clean, firm power during extended periods of high demand and low renewable generation. Other technologies, such as regional and in-state transmission and dynamic line ratings, will play a critical role in reducing congestion.

A mix of DEFR technologies within and across resource categories will best meet statewide needs, maximize benefits, and minimize the risk associated with overreliance on any one resource. Each of the candidate DEFRs evaluated throughout this study could serve complementary roles in a 2040 grid. **Low capacity factor resources** with fast ramping capabilities will play a vital role on days with the most extreme system needs and will be needed throughout New York State. **High capacity factor resources** can help meet growing loads, reduce the need for buildout of some intermittent renewables and mostly idle peaking plants, diversify the energy mix, and provide inertia and other critical grid services to support a grid increasingly dependent on variable renewables. **Gap-rightsizing resources** can balance supply and demand, reduce the need for upgrades to transmission and distribution infrastructure, and provide benefits to consumers even today. Regional variability may require different solutions in different locations.

Low capacity factor resources such as hydrogen and biofuels are expected to be needed throughout the State to support the grid during peaking events, but each type of fuel faces distinct geographic limitations and cost challenges. H₂ is unlikely to be viable everywhere by 2040, with particular challenges in Downstate New York, due to infrastructure constraints and challenges with the availability of renewables. However, H₂ will likely be valuable in a variety of industries in 2040 and beyond, which justifies investments in pilot projects and deployment of a limited shared transport and storage infrastructure network from an economywide perspective. RNG and RD are the most viable resources for 2040 deployment because the technologies are proven and the fuels can be used as drop-in replacements in existing NG and dual fuel plants, especially for use Downstate where other resources face greater challenges. However, a combination of feedstock limitations, competition for fuels from other sectors and states, and GHG considerations will limit their use to low capacity factor applications. For all of the low capacity factor resources, the cost per MWh of electricity generated remains very high, due primarily

to high fuel costs, although this holds true for any resource with capital investments spread over a few hours. Therefore, these resources will likely be limited to peak system needs in an economically optimal resource mix, necessitating other resources. Importantly, these fuels will also play a critical role in decarbonizing other sectors, so developing these technologies is likely to provide benefits outside of the power sector.

High capacity factor resources such as nuclear, NG combustion paired with carbon capture, and geothermal can increase energy diversity while meeting load growth, but projects face geographic limitations, high and uncertain capital costs per project, and timeline challenges.

For nuclear, near-term investments and deployments, such as the recently announced NYPA nuclear project development and other projects at strategic locations like existing nuclear plants, can help meet growing energy needs while leading to learning and cost reductions that can pave the way for further scaling beyond 2040. While NGCC paired with CCS, especially in retrofit applications, can offer some of the lowest-cost DEFR electricity, the upstream GHGs that cannot be mitigated using carbon capture restrict long-term deployment potential. Additionally, the buildout of CO₂ transport and storage faces significant regulatory challenges. While geothermal may not achieve large-scale deployment in New York State by 2040, long-term potential and lessons learned from other projects and industries could result in deployment beyond 2040.

Gap-rightsizing resources such as VPPs and LDES can provide valuable support in balancing supply and demand and reducing infrastructure buildout needs, but they have inherent duration limitations. Furthermore, charging LDES during extreme weeks may not be possible. As such, the value of these Gap-Rightsizing technologies may differ from that of technologies that are not duration-limited. However, their modularity, lower upfront costs, and ability to reduce peak loads make them useful assets in any 2040 grid.

There are several actions that can facilitate the readiness of these resources to achieve the scale needed for 2040.

Pursue a diverse set of resources to minimize the risk of overreliance on individual technologies.

Each of these candidate technologies could serve complementary roles in a 2040 grid. Low capacity factor resources will be vital on days with the most extreme power needs. High capacity factor resources could significantly reduce the land needed by the power sector while also providing vital inertia and other ancillary grid services to support a grid with increasing intermittent renewables and growing load.

Gap-rightsizing resources can shift supply to times of greater need and reduce the need for upgrades to transmission and distribution infrastructure. Additionally, different resources are best suited to different geographic regions, making a mix necessary to best meet statewide needs.

Start early to increase the likelihood of readiness by 2040.

All resources considered here have deployment barriers that need to be addressed to meet the needs of a zero-emissions grid. Several have long lead times. Starting early can increase the likelihood of success of individual projects, while also increasing the opportunity for beneficial learning. Moreover, because federal tax incentives are only available for a limited duration, starting early can increase the likelihood of taking advantage of those incentives.

Invest in grid-enhancing technologies early to minimize the need for backstop resources.

VPPs, energy storage, and other technologies, such as GFM inverters and dynamic line ratings, will be valuable assets for any 2040 grid. Deploying these resources early could reduce the need to build capital- and time-intensive generation and transmission projects.

Invest in innovation to enhance resource viability.

Most DEFR candidates are not yet ready for commercial deployment. Furthermore, additional emerging versions of technologies that are earlier on the readiness scale and, therefore, not included in the current detailed analysis, may offer promising cost reductions or performance improvements that could be achieved through research and development (R&D) investments. Investing in innovation can help accelerate readiness for 2040.

Develop strategies across industries for unlocking key resources with infrastructure

hurdles. Clean fuels such as hydrogen and biofuels, as well as CCS, could serve crucial roles in the decarbonization of sectors outside of the power sector. Coordination among sectors to build transportation and storage infrastructure in strategic locations could lower costs and enable more rapid deployment.

Engage early with technology developers, end users, and other stakeholders.

Early engagement can help to understand and identify potential projects, siting locations, and demonstration opportunities. Coordinating with industry and federal and State governments can facilitate national markets and accelerate cost reductions.

Conduct grid modeling to understand tradeoffs of relying on different resources.

Electric system modeling will be necessary to understand the most economic suite of technologies to deploy. Given the high level of cost uncertainty, it will be important to model a range of costs and performance attributes to understand how breakthroughs could affect which technologies are selected.

Conduct a regular reassessment of options and remain flexible as new technology options come online. This is a rapidly evolving space as new technologies capable of providing clean, firm power and grid services are being developed. Regularly evaluating the progress of these technologies and embedding flexibility into resource planning are critical for benefiting from improvements in cost and performance.

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Appendix A. Levelized Cost of Electricity Calculation Assumptions

The calculated levelized cost of electricity (LCOE) of a technology depends on several assumptions, including financial assumptions around debt and equity percentages and financing costs, depreciation assumptions, lifetime assumptions, and construction duration assumptions. Project ownership, perceived technology risk, and the financial market at the time of deployment can influence financial assumptions. For this study, the analysis used the same financial assumptions across all LCOE calculations as a simplification, summarized in Table A-1. All analyses use 2023 USD, which corresponds to the start of this study.

Table A-2 shows technology-specific assumptions used in LCOE calculations, including the book life²⁷, Modified Accelerated Capital Recovery System (MACRS) depreciation assumptions, the construction financing factor,²⁸ and the baseline capacity factor assumption. “Capacity factor” is the ratio of expected generation divided by the maximum potential generation for an asset. In some cases throughout the report, analyses evaluated how capacity factor assumptions affect LCOE results, which are presented in figures within the individual technology sections.

Table A-3 shows the tax credit values used in analyses assessing the impact of potential tax credits on LCOE. The study assumes the project meets prevailing wage and apprenticeship (PWA) requirements and includes any compliance costs in the locational adjustment factors. The applicability of tax credits will depend on the project. Some technologies may not qualify for credits assumed in this study, while others may not be configured to take advantage of credits.

As noted throughout this study, although LCOE is a convenient metric for comparing generation technologies on a common basis and the utility industry frequently uses it as a high-level screening tool, several other project-specific considerations affect project value. These may include the plant’s ability to generate electricity when energy requirements are highest, the plant’s capacity value, the environmental benefits that certain technologies provide, the existing regional resource mix, the desire for portfolio diversification, and the plant’s ability to provide other necessary grid attributes. In addition, variability and uncertainty in the inputs used in LCOE calculations—such as fuel, capital, and operating costs, as well as capacity factors—can affect the results of LCOE comparisons among technologies. Resource

planners use a suite of planning tools to compare the full range of attributes of new generation technologies. Although LCOE provides one way to compare generation technologies, it will not be the sole factor in plant-specific decisions—and comparing technologies based on LCOE should be approached with caution.

While LCOE can be an incomplete and potentially misleading metric for comparing technologies with significantly different operating profiles and technology characteristics, it can provide a high-level comparison of resources within the same category in lieu of capacity expansion modeling.

Table A-1. Nontechnology-Specific Financial Assumptions

Inputs	Rate
Nominal WACC	10.0%
Real WACC (discount rate)	7.8%
Inflation Rate	2%
Tax Rate	21%

Table A-2. Technology-Specific Assumptions

Technology	MACRS Recovery Period in years	Book Life in years	Capacity Factor	CFF
Aeroderivative H ₂ CT	15	30	3%	1.11
Aeroderivative H ₂ CT Retrofit	10	12	3%	1.11
Fuel Cell	20	20	3%	1.11
CT	15	30	3%	1.11
Nuclear	15	40	95%	1.30
Small Modular Reactor	15	40	95%	1.19
NGCC	20	30	50% ^a	1.11
NGCC with CCS	20	30	50% ^a	1.11
NGCC CCS Retrofit	10	12	50% ^a	1.11

^a In the Resource Comparison, the analysis calculates NGCC and NGCC with CCS LCOEs using a capacity factor range of 40%–65%.

Table A-3. Tax Credit Assumptions

Tax Credit	Credit Value
Clean Electricity Investment Tax Credit (ITC), Section 48E	30%
Clean Electricity Production Tax Credit (PTC)(, Section 45Y	\$28/MWh
Carbon Capture and Sequestration Tax Credit, Section 45Q	\$85/tonne CO ₂
Clean Hydrogen Production Tax Credit, Section 45V	\$3/kg H ₂

Appendix B. Resource Costs

Table B-1. Resource Costs

Hydrogen						
Technology	Use Case	Attribute	Unit	Low	Base	High
Green Hydrogen	Fuel Production & Delivery	Fuel Cost	\$/MMBtu	74.59	91.25	119.70
Green Hydrogen	Fuel Production & Delivery	Fuel Cost with 45V	\$/MMBtu	62.25	78.91	107.36
Blue Hydrogen	Fuel Production & Delivery	Fuel Cost	\$/MMBtu	30.63	44.64	71.56
Blue Hydrogen	Fuel Production & Delivery	Fuel Cost with 45Q	\$/MMBtu	24.53	38.53	65.45
New Hydrogen Turbine	Upstate Power Generation	Capital Cost	\$/kW	1,577	1,753	1,972
New Hydrogen Turbine	Upstate Power Generation	Fixed O&M	\$/kW-yr	25.43	25.43	25.43
New Hydrogen Turbine	Upstate Power Generation	Variable O&M	\$/MWh	7.35	7.35	7.35
New Hydrogen Turbine	Upstate Power Generation	LCOE: Green Hydrogen	\$/MWh	1,409	1,626	1,964
New Hydrogen Turbine	Upstate Power Generation	LCOE: Green Hydrogen with ITC	\$/MWh	1,199	1,393	1,701
New Hydrogen Turbine	Upstate Power Generation	LCOE: Blue Hydrogen	\$/MWh	1,029	1,224	1,548
New Hydrogen Turbine	Upstate Power Generation	LCOE: Blue Hydrogen with 45Q	\$/MWh	977	1,171	1,495
New Hydrogen Turbine	Downstate Power Generation	Capital Cost	\$/kW	1,872	2,080	2,340
New Hydrogen Turbine	Downstate Power Generation	Fixed O&M	\$/kW-yr	33	33	33
New Hydrogen Turbine	Downstate Power Generation	Variable O&M	\$/MWh	7.35	7.35	7.35
New Hydrogen Turbine	Downstate Power Generation	LCOE: Green Hydrogen	\$/MWh	1,562	1,793	2,147
New Hydrogen Turbine	Downstate Power Generation	LCOE: Green Hydrogen with ITC	\$/MWh	1,312	1,515	1,835
New Hydrogen Turbine	Downstate Power Generation	LCOE: Blue Hydrogen	\$/MWh	1,182	1,390	1,731
New Hydrogen Turbine	Downstate Power Generation	LCOE: Blue Hydrogen with 45Q	\$/MWh	1,129	1,337	1,679
Retrofit Hydrogen Turbine	Upstate Power Generation	Capital Cost	\$/kW	272	351	473
Retrofit Hydrogen Turbine	Upstate Power Generation	Fixed O&M	\$/kW-yr	25.43	25.43	25.43
Retrofit Hydrogen Turbine	Upstate Power Generation	Variable O&M	\$/MWh	7.35	7.35	7.35
Retrofit Hydrogen Turbine	Upstate Power Generation	LCOE: Green Hydrogen	\$/MWh	914	1,106	1,427

Table B-1. (continued)

Hydrogen						
Technology	Use Case	Attribute	Unit	Low	Base	High
Retrofit Hydrogen Turbine	Upstate Power Generation	LCOE: Green Hydrogen with ITC	\$/MWh	861	1,037	1,333
Retrofit Hydrogen Turbine	Upstate Power Generation	LCOE: Blue Hydrogen	\$/MWh	534	703	1,011
Retrofit Hydrogen Turbine	Upstate Power Generation	LCOE: Blue Hydrogen with 45Q	\$/MWh	482	651	958
Retrofit Hydrogen Turbine	Downstate Power Generation	Capital Cost	\$/kW	322	416	562
Retrofit Hydrogen Turbine	Downstate Power Generation	Fixed O&M	\$/kW-yr	33	33	33
Retrofit Hydrogen Turbine	Downstate Power Generation	Variable O&M	\$/MWh	7.35	7.35	7.35
Retrofit Hydrogen Turbine	Downstate Power Generation	LCOE: Green Hydrogen	\$/MWh	974	1,175	1,510
Retrofit Hydrogen Turbine	Downstate Power Generation	LCOE: Green Hydrogen with ITC	\$/MWh	910	1,093	1,399
Retrofit Hydrogen Turbine	Downstate Power Generation	LCOE: Blue Hydrogen	\$/MWh	594	772	1,094
Retrofit Hydrogen Turbine	Downstate Power Generation	LCOE: Blue Hydrogen with 45Q	\$/MWh	541	720	1,041
Hydrogen Fuel Cell	Upstate Power Generation	Capital Cost	\$/kW	1,109	1,706	2,814
Hydrogen Fuel Cell	Upstate Power Generation	Fixed O&M	\$/kW-yr	42.1	43.7	43.7
Hydrogen Fuel Cell	Upstate Power Generation	Variable O&M	\$/MWh	7.93	8.25	8.25
Hydrogen Fuel Cell	Upstate Power Generation	LCOE: Green Hydrogen	\$/MWh	1,371	1,698	2,212
Hydrogen Fuel Cell	Upstate Power Generation	LCOE: Green Hydrogen with ITC	\$/MWh	1,123	1,378	1,779
Hydrogen Fuel Cell	Upstate Power Generation	LCOE: Blue Hydrogen	\$/MWh	1,127	1,440	1,945
Hydrogen Fuel Cell	Upstate Power Generation	LCOE: Blue Hydrogen with 45Q	\$/MWh	1,094	1,119	1,911
Hydrogen Fuel Cell	Downstate Power Generation	Capital Cost	\$/kW	1,373	2,113	3,486
Hydrogen Fuel Cell	Downstate Power Generation	Fixed O&M	\$/kW-yr	52.1	54.1	54.1
Hydrogen Fuel Cell	Downstate Power Generation	Variable O&M	\$/MWh	7.9	8.2	8.2
Hydrogen Fuel Cell	Downstate Power Generation	LCOE: Green Hydrogen	\$/MWh	1,582	1,954	2,535
Hydrogen Fuel Cell	Downstate Power Generation	LCOE: Green Hydrogen with ITC	\$/MWh	1,288	1,574	2,021
Hydrogen Fuel Cell	Downstate Power Generation	LCOE: Blue Hydrogen	\$/MWh	1,339	1,696	2,268

Table B-1. (continued)

Hydrogen						
Technology	Use Case	Attribute	Unit	Low	Base	High
Hydrogen Fuel Cell	Downstate Power Generation	LCOE: Blue Hydrogen with 45Q	\$/MWh	1,305	1,662	2,234
Biofuels						
Technology	Use Case	Attribute	Unit	Low	Base	High
RNG		Fuel Cost	\$/MMBtu	21.53	27.82	50.00
New RNG Turbine	Upstate Power Generation	Capital Cost	\$/kW	1,311	1,402	1,528
New RNG Turbine	Upstate Power Generation	Fixed O&M	\$/kW-yr	25	25	25
New RNG Turbine	Upstate Power Generation	Variable O&M	\$/MWh	7.19	7.19	7.19
New RNG Turbine	Upstate Power Generation	LCOE	\$/MWh	862	961	1,230
New RNG Turbine	Downstate Power Generation	Capital Cost	\$/kW	1,556	1,664	1,814
New RNG Turbine	Downstate Power Generation	Fixed O&M	\$/kW-yr	33	33	33
New RNG Turbine	Downstate Power Generation	Variable O&M	\$/MWh	7.19	7.19	7.19
New RNG Turbine	Downstate Power Generation	LCOE	\$/MWh	994	1,100	1,378
Existing RNG Turbine	Upstate Power Generation	Capital Cost	\$/kW	0	0	0
Existing RNG Turbine	Upstate Power Generation	Fixed O&M	\$/kW-yr	25	25	25
Existing RNG Turbine	Upstate Power Generation	Variable O&M	\$/MWh	7.19	7.19	7.19
Existing RNG Turbine	Upstate Power Generation	LCOE	\$/MWh	313	374	590
Existing RNG Turbine	Downstate Power Generation	Capital Cost	\$/kW	0	0	0
Existing RNG Turbine	Downstate Power Generation	Fixed O&M	\$/kW-yr	33	33	33
Existing RNG Turbine	Downstate Power Generation	Variable O&M	\$/MWh	7.19	7.19	7.19
Existing RNG Turbine	Downstate Power Generation	LCOE	\$/MWh	342	403	619
RNG Fuel Cell	Upstate Power Generation	Capital Cost	\$/kW	1,606	2,072	2,798
RNG Fuel Cell	Upstate Power Generation	Fixed O&M	\$/kW-yr	43	44	44
RNG Fuel Cell	Upstate Power Generation	Variable O&M	\$/MWh	7.62	7.92	7.92
RNG Fuel Cell	Upstate Power Generation	LCOE	\$/MWh	1,076	1,346	1,824
RNG Fuel Cell	Upstate Power Generation	LCOE with ITC	\$/MWh	863	1,026	1,269
RNG Fuel Cell	Downstate Power Generation	Capital Cost	\$/kW	1,906	2,460	3,321
RNG Fuel Cell	Downstate Power Generation	Fixed O&M	\$/kW-yr	60	62	62

Table B-1. (continued)

Biofuels						
Technology	Use Case	Attribute	Unit	Low	Base	High
RNG Fuel Cell	Downstate Power Generation	Variable O&M	\$/MWh	7.62	7.92	7.92
RNG Fuel Cell	Downstate Power Generation	LCOE	\$/MWh	1,287	1,602	2,147
RNG Fuel Cell	Downstate Power Generation	LCOE with ITC	\$/MWh	1,027	1,222	1,511
RD		Fuel Cost	\$/MMBtu	26.85	36.85	50.00
New RD Turbine	Upstate Power Generation	Capital Cost	\$/kW	1,311	1,402	1,528
New RD Turbine	Upstate Power Generation	Fixed O&M	\$/kW-yr	25	25	25
New RD Turbine	Upstate Power Generation	Variable O&M	\$/MWh	7.55	7.55	7.55
New RD Turbine	Upstate Power Generation	LCOE	\$/MWh	965	1,119	1,324
New RD Turbine	Downstate Power Generation	Capital Cost	\$/kW	1,556	1,664	1,814
New RD Turbine	Downstate Power Generation	Fixed O&M	\$/kW-yr	33	33	33
New RD Turbine	Downstate Power Generation	Variable O&M	\$/MWh	7.55	7.55	7.55
New RD Turbine	Downstate Power Generation	LCOE	\$/MWh	1,096	1,257	1,472
Existing RD Turbine	Upstate Power Generation	Capital Cost	\$/kW	0	0	0
Existing RD Turbine	Upstate Power Generation	Fixed O&M	\$/kW-yr	25	25	25
Existing RD Turbine	Upstate Power Generation	Variable O&M	\$/MWh	7.55	7.55	7.55
Existing RD Turbine	Upstate Power Generation	LCOE	\$/MWh	416	532	684
Existing RD Turbine	Downstate Power Generation	Capital Cost	\$/kW	0	0	0
Existing RD Turbine	Downstate Power Generation	Fixed O&M	\$/kW-yr	33	33	33
Existing RD Turbine	Downstate Power Generation	Variable O&M	\$/MWh	7.55	7.55	7.55
Existing RD Turbine	Downstate Power Generation	LCOE	\$/MWh	444	560	713
Nuclear						
Technology	Use Case	Attribute	Unit	Low	Base	High
Low Enriched Uranium		Fuel Cost	\$/MWh	9	10.5	12
High Assay Low Enriched Uranium		Fuel Cost	\$/MWh	10	15	20
Nuclear: LLWR	Greenfield	Capital Cost	\$/kW	5,459	10,144	13,559
Nuclear: LLWR	Greenfield	Fixed O&M	\$/kW-yr	136	190	221
Nuclear: LLWR	Greenfield	Variable O&M	\$/MWh	2.13	3.14	3.81
Nuclear: LLWR	Greenfield	LCOE	\$/MWh	110	184	237
Nuclear: LLWR	Greenfield	LCOE with ITC	\$/MWh	85	137	174
Nuclear: LLWR	Coal-to-Nuclear	Capital Cost	\$/kW	5,027	9,502	12,873

Table B-1. (continued)

Nuclear						
Technology	Use Case	Attribute	Unit	Low	Base	High
Nuclear: LLWR	Coal-to-Nuclear	Fixed O&M	\$/kW-yr	169	298	414
Nuclear: LLWR	Coal-to-Nuclear	Variable O&M	\$/MWh	2.13	3.59	4.82
Nuclear: LLWR	Coal-to-Nuclear	LCOE	\$/MWh	108	188	251
Nuclear: LLWR	Coal-to-Nuclear	LCOE with ITC	\$/MWh	84	144	191
Nuclear: LLWR	Expansion	Capital Cost	\$/kW	4,872	9,053	12,436
Nuclear: LLWR	Expansion	Fixed O&M	\$/kW-yr	136	190	221
Nuclear: LLWR	Expansion	Variable O&M	\$/MWh	2.13	3.14	3.81
Nuclear: LLWR	Expansion	LCOE	\$/MWh	101	168	220
Nuclear: LLWR	Expansion	LCOE with ITC	\$/MWh	79	126	163
Nuclear: SMR/Non-Water Cooled	Greenfield	Capital Cost	\$/kW	5,674	14,340	25,311
Nuclear: SMR/Non-Water Cooled	Greenfield	Fixed O&M	\$/kW-yr	128	147	234
Nuclear: SMR/Non-Water Cooled	Greenfield	Variable O&M	\$/MWh	2.47	2.92	3.14
Nuclear: SMR/Non-Water Cooled	Greenfield	LCOE	\$/MWh	105	222	377
Nuclear: SMR/Non-Water Cooled	Greenfield	LCOE with ITC	\$/MWh	81	130	230
Nuclear: SMR/Non-Water Cooled	Coal-to-Nuclear	Capital Cost	\$/kW	5,296	13,719	24,647
Nuclear: SMR/Non-Water Cooled	Coal-to-Nuclear	Fixed O&M	\$/kW-yr	123	158	290
Nuclear: SMR/Non-Water Cooled	Coal-to-Nuclear	Variable O&M	\$/MWh	2.47	3.25	3.92
Nuclear: SMR/Non-Water Cooled	Coal-to-Nuclear	LCOE	\$/MWh	100	215	376
Nuclear: SMR/Non-Water Cooled	Coal-to-Nuclear	LCOE with ITC	\$/MWh	77	157	272
Nuclear: SMR/Non-Water Cooled	Expansion	Capital Cost	\$/kW	5,056	13,325	24,225
Nuclear: SMR/Non-Water Cooled	Expansion	Fixed O&M	\$/kW-yr	128	147	234
Nuclear: SMR/Non-Water Cooled	Expansion	Variable O&M	\$/MWh	2.47	2.92	3.14
Nuclear: SMR/Non-Water Cooled	Expansion	LCOE	\$/MWh	97	209	363
Nuclear: SMR/Non-Water Cooled	Expansion	LCOE with ITC	\$/MWh	76	152	260
Carbon Capture and Storage						
Technology	Use Case	Attribute	Unit	Low	Base	High
Natural Gas		Fuel Cost	\$/MMBtu	2	5	7
NGCC + CCS Retrofit	Upstate Power Generation	Capital Cost	\$/kW	922	1,190	1,606
NGCC + CCS Retrofit	Upstate Power Generation	Fixed O&M	\$/kW-yr	44	52	61
NGCC + CCS Retrofit	Upstate Power Generation	Variable O&M	\$/MWh	3.49	3.98	4.47

Table B-1. (continued)

Carbon Capture and Storage						
Technology	Use Case	Attribute	Unit	Low	Base	High
NGCC + CCS Retrofit	Upstate Power Generation	LCOE	\$/MWh	72	109	145
NGCC + CCS Retrofit	Upstate Power Generation	LCOE with 45Q	\$/MWh	43	79	115
NGCC + CCS Retrofit	Downstate Power Generation	Capital Cost	\$/kW	1,094	1,412	1,906
NGCC + CCS Retrofit	Downstate Power Generation	Fixed O&M	\$/kW-yr	62	73	84
NGCC + CCS Retrofit	Downstate Power Generation	Variable O&M	\$/MWh	3.49	3.98	4.47
NGCC + CCS Retrofit	Downstate Power Generation	LCOE	\$/MWh	83	122	161
NGCC + CCS Retrofit	Downstate Power Generation	LCOE with 45Q	\$/MWh	53	92	131
New NGCC + CCS	Upstate Power Generation	Capital Cost	\$/kW	2,070	2,373	2,827
New NGCC + CCS	Upstate Power Generation	Fixed O&M	\$/kW-yr	44	52	61
New NGCC + CCS	Upstate Power Generation	Variable O&M	\$/MWh	3.49	3.98	4.47
New NGCC + CCS	Upstate Power Generation	LCOE	\$/MWh	90	125	158
New NGCC + CCS	Upstate Power Generation	LCOE with 45Q	\$/MWh	67	100	133
New NGCC + CCS	Downstate Power Generation	Capital Cost	\$/kW	2,457	2,816	3,356
New NGCC + CCS	Downstate Power Generation	Fixed O&M	\$/kW-yr	62	73	84
New NGCC + CCS	Downstate Power Generation	Variable O&M	\$/MWh	3.49	3.98	4.47
New NGCC + CCS	Downstate Power Generation	LCOE	\$/MWh	104	141	177
New NGCC + CCS	Downstate Power Generation	LCOE with 45Q	\$/MWh	81	116	152
Long Duration Energy Storage						
Technology	Use Case	Attribute	Unit	Low	Base	High
Flow Battery	10h Duration	Capital Cost	\$/kWh	450	500	550
Flow Battery	24h Duration	Capital Cost	\$/kWh	400	440	480
Flow Battery	100h Duration	Capital Cost	\$/kWh	370	410	450
Lead Acid Battery	10h Duration	Capital Cost	\$/kWh	360	400	440
Lead Acid Battery	24h Duration	Capital Cost	\$/kWh	340	380	420
Lead Acid Battery	100h Duration	Capital Cost	\$/kWh	330	370	410
Lithium Ion Battery (LFP)	10h Duration	Capital Cost	\$/kWh	330	350	370
Lithium Ion Battery (LFP)	24h Duration	Capital Cost	\$/kWh	320	340	360
Lithium Ion Battery (LFP)	100h Duration	Capital Cost	\$/kWh	320	335	350
Sodium Ion Battery	10h Duration	Capital Cost	\$/kWh	170	200	230
Sodium Ion Battery	24h Duration	Capital Cost	\$/kWh	160	190	220
Sodium Ion Battery	100h Duration	Capital Cost	\$/kWh	160	185	210

Table B-1. (continued)

Long Duration Energy Storage						
Technology	Use Case	Attribute	Unit	Low	Base	High
Sodium Sulfur Battery	10h Duration	Capital Cost	\$/kWh	270	300	330
Sodium Sulfur Battery	24h Duration	Capital Cost	\$/kWh	170	185	200
Sodium Sulfur Battery	100h Duration	Capital Cost	\$/kWh	110	120	130
Iron Air Battery	100h Duration	Capital Cost	\$/kWh	20	45	70
Advanced Compressed Air	10h Duration	Capital Cost	\$/kWh	260	330	400
Advanced Compressed Air	24h Duration	Capital Cost	\$/kWh	160	200	240
Advanced Compressed Air	100h Duration	Capital Cost	\$/kWh	100	130	160
Compressed CO ₂	10h Duration	Capital Cost	\$/kWh	170	220	280
Compressed CO ₂	24h Duration	Capital Cost	\$/kWh	140	190	240
Compressed CO ₂	100h Duration	Capital Cost	\$/kWh	130	175	220
Gravity	10h Duration	Capital Cost	\$/kWh	320	455	590
Gravity	24h Duration	Capital Cost	\$/kWh	220	320	420
Gravity	100h Duration	Capital Cost	\$/kWh	140	205	270
Liquid Air	10h Duration	Capital Cost	\$/kWh	300	430	560
Liquid Air	24h Duration	Capital Cost	\$/kWh	180	260	340
Liquid Air	100h Duration	Capital Cost	\$/kWh	120	170	220
Pumped Hydro	10h Duration	Capital Cost	\$/kWh	270	280	290
Pumped Hydro	24h Duration	Capital Cost	\$/kWh	120	125	130
Pumped Hydro	100h Duration	Capital Cost	\$/kWh	30	40	50
Molten Salt	10h Duration	Capital Cost	\$/kWh	290	300	320
Molten Salt	24h Duration	Capital Cost	\$/kWh	210	220	230
Molten Salt	100h Duration	Capital Cost	\$/kWh	170	180	190
Pumped Heat	10h Duration	Capital Cost	\$/kWh	360	550	740
Pumped Heat	24h Duration	Capital Cost	\$/kWh	210	320	430
Pumped Heat	100h Duration	Capital Cost	\$/kWh	130	200	270
Sensible Heat	10h Duration	Capital Cost	\$/kWh	280	375	470
Sensible Heat	24h Duration	Capital Cost	\$/kWh	110	150	190
Sensible Heat	100h Duration	Capital Cost	\$/kWh	20	25	30
Fossil Counterfactuals						
Technology	Use Case	Attribute	Unit	Low	Base	High
Natural Gas (peaking)		Fuel Cost	\$/MMBtu	4	5	10
Natural Gas (baseload)		Fuel Cost	\$/MMBtu	2	5	7
New NG Turbine	Upstate Power Generation	Capital Cost	\$/kW	1,311	1,402	1,528
New NG Turbine	Upstate Power Generation	Fixed O&M	\$/kW-yr	25	25	25
New NG Turbine	Upstate Power Generation	Variable O&M	\$/MWh	7.19	7.19	7.19

Table B-1. (continued)

Fossil Counterfactuals						
Technology	Use Case	Attribute	Unit	Low	Base	High
New NG Turbine	Upstate Power Generation	LCOE	\$/MWh	692	740	841
New NG Turbine	Downstate Power Generation	Capital Cost	\$/kW	1,556	1,664	1,814
New NG Turbine	Downstate Power Generation	Fixed O&M	\$/kW-yr	33	33	33
New NG Turbine	Downstate Power Generation	Variable O&M	\$/MWh	7.19	7.19	7.19
New NG Turbine	Downstate Power Generation	LCOE	\$/MWh	823	878	990
Existing NG Turbine	Upstate Power Generation	Capital Cost	\$/kW	0	0	0
Existing NG Turbine	Upstate Power Generation	Fixed O&M	\$/kW-yr	25	25	25
Existing NG Turbine	Upstate Power Generation	Variable O&M	\$/MWh	7.19	7.19	7.19
Existing NG Turbine	Upstate Power Generation	LCOE	\$/MWh	143	153	201
Existing NG Turbine	Downstate Power Generation	Capital Cost	\$/kW	0	0	0
Existing NG Turbine	Downstate Power Generation	Fixed O&M	\$/kW-yr	33	33	33
Existing NG Turbine	Downstate Power Generation	Variable O&M	\$/MWh	7.19	7.19	7.19
Existing NG Turbine	Downstate Power Generation	LCOE	\$/MWh	172	181	230
Fossil Distillate		Fuel Cost	\$/MMBtu	10	21	36
New Distillate Turbine	Upstate Power Generation	Capital Cost	\$/kW	1,311	1,402	1,528
New Distillate Turbine	Upstate Power Generation	Fixed O&M	\$/kW-yr	25	25	25
New Distillate Turbine	Upstate Power Generation	Variable O&M	\$/MWh	7.55	7.55	7.55
New Distillate Turbine	Upstate Power Generation	LCOE	\$/MWh	769	935	1162
New Distillate Turbine	Downstate Power Generation	Capital Cost	\$/kW	1,556	1,664	1,814
New Distillate Turbine	Downstate Power Generation	Fixed O&M	\$/kW-yr	33	33	33
New Distillate Turbine	Downstate Power Generation	Variable O&M	\$/MWh	8	8	8
New Distillate Turbine	Downstate Power Generation	LCOE	\$/MWh	901	1074	1310
Existing Distillate Turbine	Upstate Power Generation	Capital Cost	\$/kW	0	0	0
Existing Distillate Turbine	Upstate Power Generation	Fixed O&M	\$/kW-yr	25	25	25
Existing Distillate Turbine	Upstate Power Generation	Variable O&M	\$/MWh	7.55	7.55	7.55
Existing Distillate Turbine	Upstate Power Generation	LCOE	\$/MWh	220	348	522
Existing Distillate Turbine	Downstate Power Generation	Capital Cost	\$/kW	0	0	0

Table B-1. (continued)

Fossil Counterfactuals						
Technology	Use Case	Attribute	Unit	Low	Base	High
Existing Distillate Turbine	Downstate Power Generation	Fixed O&M	\$/kW-yr	33	33	33
Existing Distillate Turbine	Downstate Power Generation	Variable O&M	\$/MWh	8	8	8
Existing Distillate Turbine	Downstate Power Generation	LCOE	\$/MWh	249	377	551
New NGCC without CCS	Upstate Power Generation	Capital Cost	\$/kW	1,448	1,548	1,688
New NGCC without CCS	Upstate Power Generation	Fixed O&M	\$/kW-yr	30	32	33
New NGCC without CCS	Upstate Power Generation	Variable O&M	\$/MWh	1.90	1.97	2.04
New NGCC without CCS	Upstate Power Generation	LCOE	\$/MWh	58	79	96
New NGCC without CCS	Downstate Power Generation	Capital Cost	\$/kW	1718	1838	2003
New NGCC without CCS	Downstate Power Generation	Fixed O&M	\$/kW-yr	41	44	46
New NGCC without CCS	Downstate Power Generation	Variable O&M	\$/MWh	1.90	1.97	2.04
New NGCC without CCS	Downstate Power Generation	LCOE	\$/MWh	67	89	107
Existing NGCC without CCS	Upstate Power Generation	Capital Cost	\$/kW	0	0	0
Existing NGCC without CCS	Upstate Power Generation	Fixed O&M	\$/kW-yr	29.75	31.51	33.37
Existing NGCC without CCS	Upstate Power Generation	Variable O&M	\$/MWh	1.90	1.97	2.04
Existing NGCC without CCS	Upstate Power Generation	LCOE	\$/MWh	21	40	53
Existing NGCC without CCS	Downstate Power Generation	Capital Cost	\$/kW	0	0	0
Existing NGCC without CCS	Downstate Power Generation	Fixed O&M	\$/kW-yr	41	44	46
Existing NGCC without CCS	Downstate Power Generation	Variable O&M	\$/MWh	1.90	1.97	2.04
Existing NGCC without CCS	Downstate Power Generation	LCOE	\$/MWh	23	42	56

Endnotes

- ¹ Various terms are used to describe the technologies evaluated in this report, such as “clean, firm” resources. This report uses “dispatchable emission-free resources” (DEFERs) in alignment with terminology used by NYISO and the PSC’s May 2023 order.
- ² Capacity factors represent the extent to which a generator operates compared to its maximum potential output over a defined period (annually, here). This report assumes Low Capacity Factor Resources operate only during the most challenging hours. Most LCOE figures assume a 3% capacity factor for these resources based on *Draft SEP 2040* modeling of the power sector. In a given year, the capacity factors for these resources could be higher depending on grid dynamics, including weather and congestion. High Capacity Factor Resources operate at varying levels, typically greater than 50%, and up to 95% for nuclear. Appendix A provides additional information.
- ³ There is uncertainty on whether upstream natural gas emissions and uncaptured emissions from blue hydrogen would accrue to the power sector or another sector, but those emissions are included in this report considering blue hydrogen is a derivative of natural gas.
- ⁴ Industry often refers to small reactors as SMRs. SMRs are expected to use factory fabrication and assembly (versus on-site), though this production mode is not guaranteed. The NRC defines lwSMRs as LWR designs of ≤ 300 MWe.
- ⁵ A category of medium reactors, ranging from 300–600 MWe, also exist. While historically rare due to diseconomies of scale, these reactors are being reconsidered due to modern construction, operation technologies, and efficiency.
- ⁶ Other discussion of nuclear technologies has used “generations” of nuclear designs. Most of the current fleet of traditional U.S. LWRs are considered Gen II or Gen III. In this report, “advanced” reactors include state-of-the-art Gen III+ and Gen IV designs.
- ⁷ Note that agreements to “explore opportunities” or “evaluate deployment potential” differ from contracts involving financial commitments or binding obligations. Many project announcements aim to attract interest or funding but lack firm commitments in financing, permitting, or timelines. Deployment depends on regulatory approvals, secured funding, and enforceable contracts. MOUs and nonbinding agreements signal intent but do not guarantee execution.
- ⁸ Westinghouse does not participate in the deployment of CAP1000 reactors in China because the CAP1000 is an indigenous adaptation of the Westinghouse AP1000 technology.
- ⁹ The ARDP Program accelerates the development of advanced nuclear reactors through cost-shared partnerships, focusing on near-term demonstrations, risk reduction, and innovative reactor concepts.
- ¹⁰ Terrestrial Energy’s IMSR is the only major thermal spectrum MSR currently under development. However, this report does not cover microreactors.
- ¹¹ Notably, Indian Point Unit 1, which operated from 1962 to 1974, was a small LWR with a capacity of 275 MWe. It demonstrated early U.S. experience with smaller commercial reactors, although it was not designed as a “modular” unit by today’s standards.
- ¹² While ESPs can be used with either Part 50 or Part 52 licensing, they were introduced under Part 52 and have historically supported COL applications. No U.S. project to date has proceeded from an ESP to a Part 50 CP. Pursuing an ESP introduces a distinct phase of work following site selection—adding approximately 3–4 years to the schedule—which may not be offset by reduced review durations under the Part 50 framework.

- ¹³ Simple averages and statistical rules of thumb were used to construct probabilistic scenarios (assuming a normal distribution) to capture the mean and 95% of the variability around the mean of key SMR project development tasks.
- ¹⁴ This report assumes four 250 MWe reactors are needed to generate 1,000 MWe. It uses the upper end of the range for “Small (SMR).”
- ¹⁵ “Land use” includes land occupied by the electricity-producing facility (direct) and, when applicable, the land needed to source fuel for plant operations (indirect). “Footprint” includes the direct land area physically occupied by energy infrastructure, such as solar panels, wind turbine bases, power plants, access roads, and supporting structures while “Spacing” includes the land in between physical components in an electricity generation or fuel extraction site (e.g., areas between wind turbines or NG extraction pads).
- ¹⁶ “Long-term jobs created by nuclear power projects” include jobs at the power plant, jobs supporting the supply chain, and jobs in the community supported by additional plant employee spending. These exclude temporary jobs created during the construction or coal power plant remediation phases.
- ¹⁷ Federal tax-exempt entities, like municipally owned utilities and not-for-profit cooperatives, can receive “direct pay” from the government instead of a tax credit. Tax-paying private entities can transfer tax credits to others who can better utilize them. Projects must be in service as of January 1, 2025, to be eligible. The PTC applies only to electricity produced in the first 10 years of operation. Credits begin phasing out for new facilities starting construction after 2032 (Nuclear Innovation Alliance 2023b).
- ¹⁸ Multimodule SMRs, such as NuScale’s VOYGR plant design (available in 4-, 6-, or 12-module configurations), offer an additional dimension of deployment flexibility through the sequential installation of reactor modules at a single site. While conceptually similar to intersite staggering of entire reactor projects, coordinated intrasite deployment can further smooth construction timelines by reducing remobilization needs, enabling shared infrastructure and governance, and fostering stronger learning effects (assuming a continuous workforce and successful progression between units). Although the precise schedule advantage of intrasite modularity is difficult to quantify, these integrated efficiencies may support faster and more cost-effective deployment relative to staggered builds across separate sites.
- ¹⁹ “Land use” includes land occupied by the electricity-producing facility (direct) and, when applicable, the land needed to source fuel for plant operations (indirect). “Footprint” refers to the direct land area physically occupied by energy infrastructure, such as solar panels, wind turbine bases, power plants, access roads, and supporting structures. In contrast, “spacing” includes the land in between physical components in an electricity generation or fuel extraction site (e.g., areas between wind turbines or NG extraction pads).
- ²⁰ SAIDI and SAIFI are key reliability metrics in the electricity distribution sector, measuring the duration and frequency of outages.
- ²¹ NYPA-owned units were excluded from this PowerUp NYC analysis due to NYPA’s separate feasibility study.
- ²² “Capacity factor” refers to the ratio of expected generation divided by the maximum potential generation for an asset.
- ²³ While this discussion focuses on green hydrogen produced by renewable electricity, pink hydrogen produced with nuclear energy is another viable form of clean electrolytic hydrogen.
- ²⁴ While LCOE can be an incomplete and potentially misleading metric for comparing technologies with significantly different operating profiles and technology characteristics, it can provide a high-level comparison of resources within the same category. In this case, all technologies are assumed to operate as peaking units with a capacity factor of 3%. They should not be directly compared with the LCOEs for High Capacity Factor Resources, which are assumed to have very different operational profiles. Appendix A provides additional details around assumptions used in LCOE calculation.

- ²⁵ While LCOE can be an incomplete and potentially misleading metric for comparing technologies with significantly different operating profiles and technology characteristics, it can provide a high-level comparison of resources within the same category. In this case, all technologies are assumed to operate as baseload units with a capacity factor of 40%–65% for NGCC and NGCC + CCS and a capacity factor of 95% for nuclear. Appendix A provides additional details on the assumptions used in the LCOE calculation.
- ²⁶ The significant overlap in cost estimate uncertainty between lwSMRs and non-water-cooled reactors prevents clear separation into distinct estimates. While the cost of lwSMRs and non-water-cooled reactors likely will not be the same, they are both expected to fall within the range shown here and may be higher or lower than the other. Therefore, this reports includes lwSMRs and non-water-cooled reactors within the same LCOE and uncertainty range.
- ²⁷ “Book life” represents the period over which the initial capital investment to build a plant is recovered. The book life can differ from a plant’s technical life or service life, which refers to the duration the plant remains in operation and depends on factors such as plant maintenance and market dynamics.
- ²⁸ CFF represents the portion of the total capital cost allocated to financing during the construction period of a project. For this study, CFF uses values from the NREL’s 2024 Annual Technology Baseline study (2024a).

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