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Light Water Reactor Sustainability Program

Technical and Economic Considerations for Uprate of Existing Nuclear Reactors with Cogeneration

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ABSTRACT

The United States nuclear reactor fleet consists of 63 pressurized water reactors and 31 boiling water reactors and is a pivotal component in the nation's energy infrastructure, supplying approximately 97 GW_e of clean power. With the country's commitment to decarbonization by 2050, these reactors are not only instrumental in decarbonizing the electricity grid but also play a critical role in decarbonizing industrial processes, producing clean fuels, and scaling up CO_2 removal. This report delves into the potential for power uprates in the existing fleet to contribute to these decarbonization efforts, focusing on the expansion of capacity for applications such as hydrogen production and carbon capture and sequestration. Building on previous research, the report explores regional market demands for hydrogen, oxygen, and carbon dioxide, financial implications of oxygen and CO_2 sales from high-temperature steam electrolysis systems, and the potential for direct air capture systems paired with uprated nuclear plants.

The current nuclear fleet has successfully completed a total of 172 power uprates, yielding a thermal power increase equivalent to about eight new large reactors. This report assesses the impact of these uprates and the Inflation Reduction Act of 2022 on the nuclear industry's transformation to support a decarbonized economy. Detailed market analysis reveals that opportunities for uprates exist in both regulated and merchant electricity markets, with potential disparities in demand and production capabilities across regions. Additionally, the report examines the financial viability of integrating direct air capture with uprated nuclear plants, considering the energy demands of direct air capture (DAC) systems and the potential revenue from carbon sales. The findings suggest that cogeneration of hydrogen, oxygen, or carbon via DAC may be economically feasible under certain regional market conditions and that strategic partnerships with hydrogen consumers could mitigate risks associated with regional demand variability.

The report further underscores the significance of regional market dynamics in the decision to uprate nuclear plants and pursue cogeneration. For instance, the Gulf Coast region, with its robust industrial base, has a high demand for hydrogen that may exceed the supply capabilities of uprated plants. Conversely, regions such as the Northeast exhibit less hydrogen demand, suggesting that strategic investment in uprate projects exclusively for hydrogen cogeneration should be informed by regional hydrogen consumption patterns. The potential for uprated nuclear plants to sell oxygen alongside hydrogen is also briefly examined. However, it is generally concluded that oxygen sales will make little impact on project economics due to relatively low oxygen prices and limited demand. Plants pursuing hydrogen cogeneration may have little motivative to also capture oxygen unless a strong regional demand is identified.

Moreover, the economic analysis of integrating DAC with nuclear power uprates presents a nuanced picture. While DAC systems can benefit from the low-carbon heat and power provided by nuclear plants, the profitability of such ventures is highly sensitive to the regional price of electricity and carbon. The report identifies conditions under which DAC integration could be more profitable than selling uprated power to the grid, particularly when high carbon prices are attainable through high-purity industrial applications or the voluntary

offset market. However, the uncertainties of CO_2 prices and the nascent stage of DAC technology suggest that nuclear plant operators should approach such investments cautiously. Ultimately, while uprates combined with hydrogen, oxygen, or DAC cogeneration can offer viable paths to profitability, they are contingent on specific regional market conditions, and careful evaluation of regional market conditions is necessary to determine if these options are viable from a financial standpoint.

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FIGURES

TABLES

ACRONYMS

BOP	balance of plant
CLTP	Current Licensed Thermal Power
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
DAC	direct air capture
DCF	discounted cashflow
DOE	Department of Energy
EOR	enhanced oil recovery
EPU	extended power uprate
FCEV	fuel cell electric vehicle
GHG	greenhouse gas
H_2	hydrogen
HP	high-pressure
HTE	high-temperature electrolysis
HTSE	high-temperature steam electrolysis
IRA	Inflation Reduction Act
IRR	internal rate of return
IEA	international energy agency
ITC	Investment Tax Credit
LTE	low-temperature electrolysis-
LWR	light water reactor
MMT	million metric tons
MW_{th}	megawatt thermal
MW_e	megawatt electric
NETL	National Energy Technology Laboratory
NPV	net present value
NSSS	nuclear steam supply system
NPP	nuclear power plants
O&M	operations and maintenance
O_2	oxygen

OLTP	Original Licensed Thermal Power
PEM	proton exchange membrane
PTC	Production Tax Credit
PWR	pressurized water reactor
SMR	steam methane reforming
SOEC	solid oxide electrolysis cells
SPU	stretch power uprate

1. INTRODUCTION

The nuclear reactor fleet of the United States (U.S.) has 63 pressurized water reactors (PWR) and 31 boiling water reactors (BWR) in operation. These reactors supply approximately 97 GWe of power in various regions and states in the U.S. These reactors have the capacity to continuously supply clean electricity and heat on a large scale. Traditionally, the most economically efficient mode of operation for NPPs has been as baseload units with constant power output at or near maximum capacity of the plant. In recent years increased variable electricity generation (e.g., solar and wind), low electrical load growth, and low natural gas prices have reduced the need for baseload nuclear power [1, 2]. While it is possible for NPPs to operate flexibly with changing grid demand, doing so will not reduce the plant's operating costs and may not always be the most desirable option [2]. Alternatively, at times of reduced grid demand, the heat and electricity could be used to produce an alternative product, such as hydrogen, oxygen, or carbon dioxide.

As the U.S. strives to achieve decarbonization by the year 2050, nuclear power plants (NPPs) can play a vital role in reaching the target by (1) decarbonizing the electricity grid, (2) decarbonizing industrial processes in need of heat or power, (3) playing a vital role in producing clean fuels, and (4) scaling up CO_2 removal. New nuclear reactors will play a vital role in achieving these targets, but existing nuclear fleet can expedite decarbonization goals by increasing clean power production, a process called power uprate. Expanding the existing capacity could provide a clean source of energy to the grid or other industrial applications such as hydrogen production or carbon capture and sequestration.

This report aims to expound upon previous Light Water Reactor Sustainability (LWRS) Program research found in the report titled "Assessing the Impact of the Inflation Reduction Act on Nuclear Plant Power Uprate and Hydrogen Cogeneration" (hereafter referred to as the "previous uprate" report). This report further explores the following areas: (1) regional market demand for hydrogen, oxygen, and carbon dioxide, (2) potential for direct air capture (DAC) systems, (3) the financial implications associated with the sale of oxygen from high-temperature steam electrolysis (HTSE) systems as well as the financial implications for the sale of CO_2 from DAC systems.

2. OPERATING FLEET UPRATE POTENTIAL AND IMPACT OF THE INFLATION REDUCTION ACT

2.1. Current Uprate Potential

The nuclear fleet has completed a combined total of 172 power uprates, which equates to an approximate increase of 24,090 MW_{th} or roughly 9% of total present nuclear reactor operating power. The power produced from these uprates is the generating capacity equivalent of approximately eight new reactors [3].

Figure 8Uprates included a range of different sizes which can be categorized as follows [4]:

- Measurement uncertainty recapture power uprate (MUR): Typically, power uprates up to 2% are also often referred to as 10 CFR 50.62 Appendix K uprates. These uprates account for uncertainty in measuring feedwater flow. MURs normally do not require significant component upgrades other than new feedwater flow measurement devices.
- Stretched Power Uprate (SPU): Typically, power uprates that increase power levels between 2 and 7% and are within the existing design margin of the plant. SPUs normally require changes to instrument setpoints but generally do not involve significant plant modifications beyond potentially the high-pressure (HP) turbine (and in some cases the main generator) depending on the existing margin.
- Extended Power Uprate (EPU): EPUs have been approved for power increases as high as 20% the original licensed thermal power (OLTP). EPUs typically require significant modifications to the balance of plant (BOP) equipment, such as HP turbines, condensate pumps and motors, main generators, and transformers.

The average current licensed thermal power (CLTP) and the percentage uprates beyond OLTP for BWRs and PWRs are shown in Table 1. The details of the CLTP and uprate for the individual BWRs and PWRs were provided in the previous uprate report [2].

Table 1. CLTP and percentage uprates beyond OLTP for current fleet of BWRs and PWRs.

Nuclear reactor type	**Average CLTP, MW_{th}**	**Total % uprate above OLTP for operating reactors**
Boiling Water Reactors (BWRs)	3,344	14%
Pressurized Water Reactors (PWRs)	3,104	6%

Some of the key takeaways from the previous uprate report on historical uprates include [4]:

- The average CLTP for operational BWRs is on average approximately 200 MW_{th} higher than for PWRs. For comparison, the average OLTP for BWRs is smaller than for PWRs (by approximately 30 MW_{th}).
- In total, BWRs have gained more than 13,000 MW_{th} through power uprates, despite having approximately half of the number of reactors when compared to PWRs [5].

When one accounts for the average maximum historical uprate potential by design, it is possible to estimate how much additional uprate potential exists in the existing fleet and measuring the delta between total potential uprate (based on historical maxima) and current uprate to date. The previous uprate report investigated this and determined that the total combined uprate potential for BWRs and PWRs is estimated to be ~16,500 MW_{th} [4].

Nuclear reactors in the U.S. operate in both regulated and merchant electrical markets, with 39 of the 94 operating reactors operating in the merchant market [4]. Retail electricity prices in regulated markets are set by state regulators to enable utilities to recover operating and investment costs and a competitive rate of return on investments such as an uprate in power generation. In merchant markets, customers have the option of selecting an electric supplier, rather than being required to purchase electricity from their local utility. This strategy introduces retail competition. In this case, the investment risk falls upon the electricity supplier, rather than the customer, unlike in the regulated markets. Subsequently, it is important to look at uprate data in two different markets to better understand if market structure has an impact on average uprate size. Figure 1 and Figure 2 show the percent uprate beyond OLTP for stations in merchant and regulated markets, respectively. The average percent uprate for stations in merchant markets is approximately 10%, compared to an average percent uprate of approximately 7% for stations in regulated markets. Based on this information, there appears to be uprate opportunities and capacity in the regulated and merchant markets.

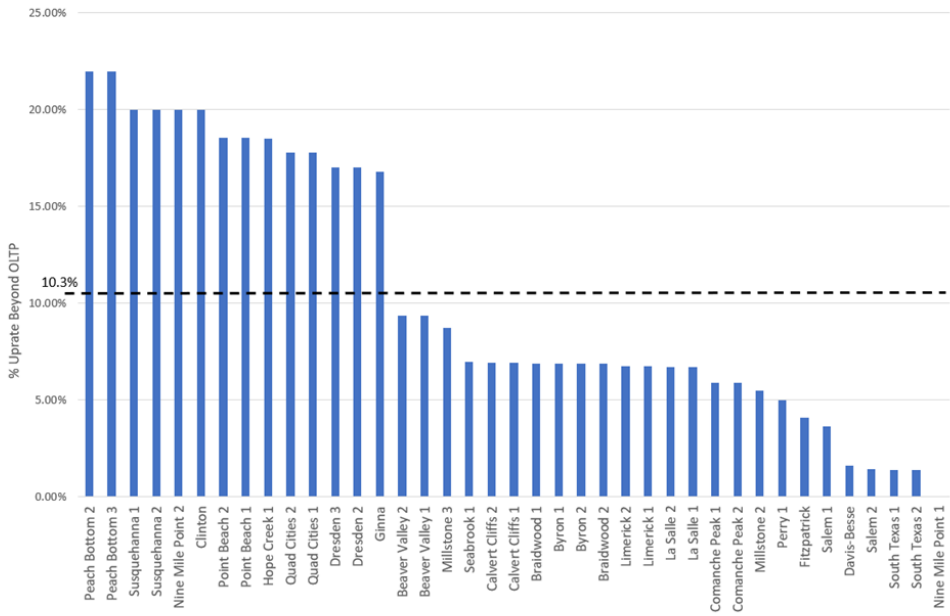

Figure 1. Total percent uprate for plants in merchant markets (dashed line represents average). Taken from [4].

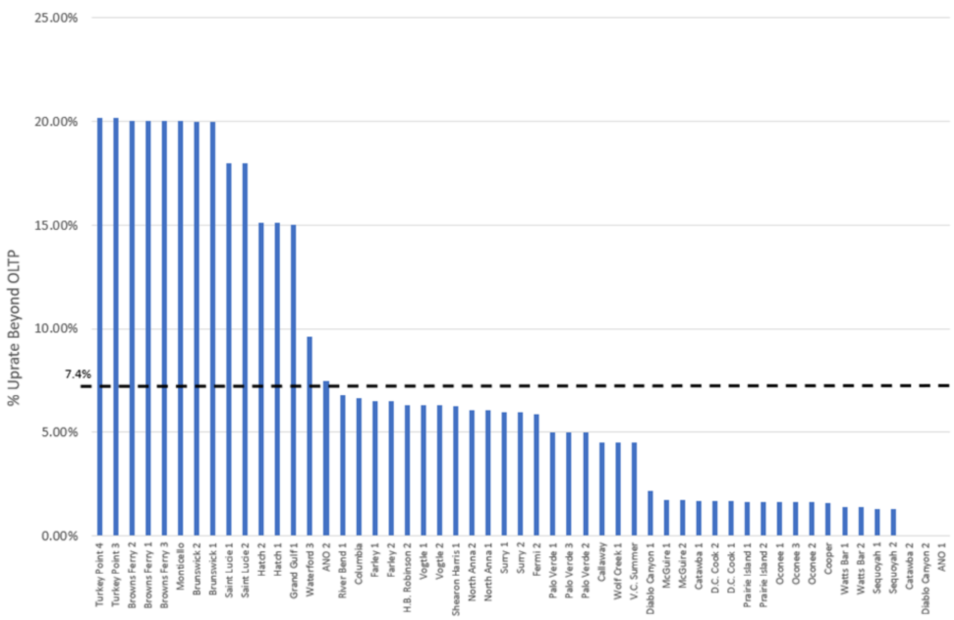

Figure 2. Total percent uprate for plants in regulated markets (dashed line represents average). Taken from [4].

2.2. Tax Incentives from the Inflation Reduction Act

The Inflation Reduction Act (IRA) of 2022 provides several tax credits that can be used for clean power generation from nuclear energy, investment in uprate to increase nuclear power generation, nuclear power integration with hydrogen generation from electrolysis, and carbon capture and sequestration [6]. The production tax credits (PTC) and investment tax credits (ITC) available based on the Internal Revenue Code Sections are shown in Table 2.

Table 2. IRA tax credits.

Tax Credit	Title	Description
45U PTC	Zero-Emission Nuclear Production Credit for Existing Reactors	Tax credit to use nuclear energy to produce electricity that was placed in service before August 6, 2022
45Y PTC	Clean Electricity Production Credit	New technology-neutral PTC for electric generation facilities that have zero GHG emissions and are placed in service after December 31, 2024
48E ITC	Clean Electricity Investment Tax Credit	Technology-neutral ITC for electric generation facilities that have zero GHG emissions
45V	Clean Hydrogen Production Credit	Tax credit for the production of qualified clean hydrogen beginning January 1, 2023
45Q	Carbon Capture and Sequestration Credit	Tax credit for carbon capture with geologic sequestration, utilization for enhanced oil recovery, and other qualified uses

2.2.1. Zero-Emission Nuclear Production Credit for Existing Reactors (Section 45U)

Zero-Emission Nuclear Production Credit 45U is applicable for existing reactors that use nuclear energy to produce electricity and were placed in service before August 6, 2022. The credit is available for electricity produced and sold after December 31, 2023, and before December 31, 2032. Section 45U is not applicable for an advanced nuclear power facility under Section 45J. The credit amount is calculated as shown in Figure 3.

Base Amount 0.3 cents × KWh of electricity produced by taxpayer and sold to an unrelated person

Less: "reduction amount"

Equals: Amount of section 45U Credit

The "reduction amount" is calculated as follows:

16% x (Gross receipts from electricity produced by facility (including electricity service or products provided in conjunction therewith) and sold to unrelated person (plus certain zero emission credit payments)

Less: 2.5 cents * KWh energy produced and sold to unrelated person)

Equals: Reduction Amount

Figure 3. Section 45U tax credit amount. Taken from [4].

If the "reduction amount" (as calculated above) would cause the Section 45U credit amount to go below zero, the amount of the credit is zero. The amount of the credit calculated above is multiplied by five if prevailing wage requirements [7] are satisfied. Both the 0.3 cents per kWh and 2.5 cents per kWh amounts in the formula shown in Figure 1 are indexed for inflation using the gross domestic product (GDP) implicit price deflator and Calendar Year 2023 as the base year.

Based on the above formula, if prevailing wage requirements are met, Section 45U provides a $15/MWh, per reactor, credit when gross receipts are up to $25/MWh in 2023 dollars. As illustrated in Figure 4, the credit is reduced when the reactor's gross receipts exceed $25/MWh such that the credit is completely phased out if the reactor receives $43.75/MWh or more in gross receipts. Gross receipts include any amount received with respect to the qualified nuclear power facility from a zero-emission credit (ZEC) program. However, amounts received from a ZEC program are excluded from the gross receipts amount if the full amount of the credit is used to reduce payments from such a ZEC program.

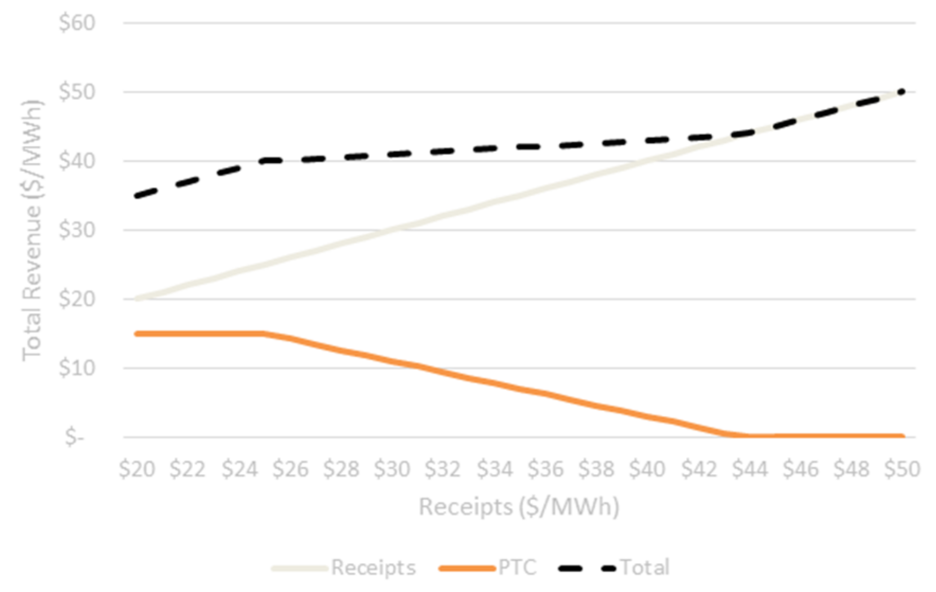

Figure 4. Section 45U gross receipts. Taken from [4].

2.2.2. Clean Electricity Production Credit (Section 45Y)

The Clean Electricity Production Credit (Section 45Y) establishes a new technology-neutral PTC for electric generation facilities that have zero GHG emissions and are placed in service after December 31, 2024. The credit phases down over 3 years to zero beginning with the second calendar year after, whichever is the latest, 1) the year the treasury secretary determines the annual U.S. GHG emissions from electricity production is equal to or less than 25% of GHG emissions in 2022 or 2) 2032. Assuming the applicable year is 2032, the full credit amount would be available for 2033, the credit would be reduced to 75% in 2034, 50% in 2035, and 0% in 2036.

The facilities are eligible for Section 45Y credit for the first 10 years after the facility is placed in service after December 31, 2024. The facility must have a zero GHG emissions rate. A qualified facility does not include any facility for which a credit determined under Section 45J, 45U, 48E, or 45Q was allowed (i.e., claimed) for the taxable year or any prior taxable year. As a result, the generation facility has the option to choose between the clean electricity PTC or ITC (Section 48E) but cannot choose both for the same facility.

Incremental production from an uprated facility is eligible for Section 45Y credits, even if the existing capacity from the facility has claimed Section 45U or 45J credit.

The credit amount equals 0.3 cents per kWh ($3/MWh) (indexed for inflation using the GDP implicit price deflator from 1992) for electricity produced and sold to an unrelated person. The amount of the credit calculated above is multiplied by five if prevailing wage and apprenticeship requirements [7] are satisfied. The value of Section 45Y credit is expected to be about $30/MWh in 2025, which is 0.3 cents per kWh ratioed by GDP implicit price deflator from 1992 to 2025 times five for meeting wage and apprenticeship requirements.

The Section 45Y credit is increased by 10% if the facility is in an "energy community," and by another 10% if "domestic content" requirements are met. Thus, if the requirements of the energy community and domestic content were met (along with prevailing wage and apprenticeship requirements), the value of Section 45Y credit would be about $36/MWh in 2025.

However, Section 45Y credit has provisions that apply rules similar to those of Section 45(b)(3). Those rules require a 15% reduction of the credit if tax-exempt bonds are used to finance the facility.

2.2.3. Clean Electricity Investment Credit (Section 48E)

The Clean Electricity Investment Credit (Section 48E of the IRA) establishes a new technology-neutral ITC for electric generation facilities that have zero GHG emissions and are placed in service after December 31, 2024. The Section 48E ITC declines to zero over 3 years beginning with the second calendar year after the year the Treasury Secretary determines the annual U.S. GHG emissions from electricity production is equal to or less than 25% of GHG emissions in 2022 or 2032. Therefore, if the applicable year is 2032, the full credit amount would be available for 2033, then the credit would be reduced to 75% in 2034, 50% in 2035, and 0% in 2036.

Qualified facilities are eligible for Section 48E ITC the year that the facility is placed in service. To be considered a qualified facility, it must be owned by the taxpayer, used for electricity generation, have been placed into service after Dec. 31, 2024, and have a GHG emissions rate that is less than zero. For a facility to qualify for the tax credit, the facility cannot include tax credits of Section 45J, 45U, 45Y, or 45Q. A facility can select the clean electricity PTC or ITC but cannot choose both.

With the 48E tax credit, a qualified facility includes additions associated with a facility uprate placed in service before January 1, 2025. A facility can combine the ITC associated with Section 48 for uprate investment along with the production tax credits of Sections 45U or 45J (advanced reactor PTC).

The Section 48E credit is equal to 6% of a qualified investment in any qualified facility and is increased to 30% if prevailing wage and apprenticeship requirements are met. The Section 48E credit may be increased by 10% if the facility is in an energy community and by another 10% if the domestic content standard is met. If the requirements for both bonuses were met (along with prevailing wage and apprenticeship requirements), the credit would be 50% of the qualified investment. Credits can be carried forward for up to 22 years

As with Section 45Y credit, the Section 48E credit will be reduced if the facility used tax-exempt bonds to finance the facility uprate. The reduction is 15% or the fraction of the proceeds of the tax-exempt bond used to provide financing for the facility over the aggregate number of additions to the capital account for the qualified facility, whichever is less.

2.2.4. Credit for Production of Clean Hydrogen (Section 45V)

Section 45V provides a tax credit for the production of qualified clean hydrogen beginning January 1, 2023. A clean hydrogen production facility must be owned by the taxpayer, produce qualified clean hydrogen, and start construction of the facility before January 1, 2033. The credit is available for the first 10 years after a facility is placed in service. The hydrogen must be for sale or for use as verified by an unrelated third party.

The availability and value of the credit depends upon the life-cycle GHG emissions rate that results from the facility's hydrogen production process. More stringent emission rates correspond to higher credit values. Qualified clean hydrogen is produced through a process that results in a life-cycle GHG emission of 4 kilograms or less of CO_2e[a] per kilogram of hydrogen (as defined by the Argonne National Laboratory GREET life-cycle model, "Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation" model.) Assuming the prevailing

a. CO_2e is defined as the number of metric tons of CO_2 emissions with the same global warming potential as one metric ton of another greenhouse gas.

wage and apprenticeship requirements are met, the credit amount equals $3.00 per kilogram of hydrogen multiplied by:

- 20% if the facility produces hydrogen that results in life-cycle GHG emissions between 2.5 and 4 kilograms of CO_2e per kilogram of hydrogen
- 25% if the facility produces hydrogen that results in life-cycle GHG emissions between 1.5 and 2.5 kilograms of CO_2e per kilogram of hydrogen
- 33.4% if the facility produces hydrogen that results in life-cycle GHG gas emissions between 0.45 and 1.5 kilograms of CO_2e per kilogram of hydrogen
- 100% if the facility produces hydrogen that results in life-cycle GHG gas emissions under 0.45 kilograms of CO_2e per kilogram of hydrogen.

Hydrogen produced using energy from a nuclear plant would result in a life-cycle GHG emission of less than 0.45 kg of CO_2e per kilogram of hydrogen, thus qualifying for the full $3.00/kg [8]. However, it should be noted that guidance issued by the U.S. Department of the Treasury in December 2023 clarified that existing clean energy sources that divert power for hydrogen production are not eligible for the 45V tax credit [9]. Rather, the energy for hydrogen production should be provided from a newly built clean energy source, or power gained from an uprate to an existing clean power source. Thus, hydrogen produced using the existing generating capacity of the current fleet of NPPs does not qualify for the tax credit; however, if an NPP were to undergo a power uprate, hydrogen produced using the plant's increased capacity could qualify.

The Section 45U zero-emission nuclear PTC provides that existing nuclear plants are eligible to receive a credit under both Section 45U (for production of electricity) and Section 45V (for production of hydrogen) where electricity from the qualified nuclear facility is used at a qualified clean hydrogen production facility. Also, existing nuclear plants may combine the credit under Section 45Y (for production of additional capacity electricity) with Section 45V. However, a facility cannot claim both the 45V and 45Q tax credits.

As discussed with other tax credits, the Section 45V credit would decline if tax-exempt bonds were used to finance the facility. The reduction is 15% or the fraction of the proceeds of the tax-exempt bond used to provide financing for the facility over the aggregate number of additions to the capital account for the qualified facility, whichever is less.

2.2.5. Carbon Capture and Sequestration Credit (Section 45Q)

The IRA included updates to the Section 45Q tax credit for carbon capture and sequestration to incentivize further investment in this area. Most notably, the updates include an increase in the value of the tax credit, an extension to the start-of-construction window, and a decrease in the minimum capture rate required to qualify for the credit.

The value of the tax credit varies depending on the end use of the CO_2, which is separated into three groups: geological sequestration, geological sequestration via enhanced oil recovery (EOR), and other qualified uses. Geological storage is the process of injecting CO_2 deep underground where it will be trapped in porous rock formations. EOR is the process of injecting CO_2 into oil fields to increase the amount of oil that can be extracted from a reservoir. Some of this injected CO_2 becomes trapped underground, while the rest resurfaces with the oil. However, the resurfaced CO_2 is typically re-injected, which can lead to over 99% of the CO_2 used throughout the project being permanently stored underground [10].

The credit value and requirements for qualification vary depending on the capture method. The credits available for capture via DAC are shown in Table 3. These credits are available for facilities that are placed into service after December 31, 2022, and that start construction prior to January 1, 2033, and annually capture at least 1,000 metric tons. The credit can be claimed for 12 years after the facility begins operation, unless the credit is transferred to another entity, in which case it can be claimed for 5 years. In contrast to the 45V, 45Q cannot be stacked with 45E or 45Y. This means facilities uprating will only be able to claim a clean power tax credit or the CO2 capture tax credit, not both. Additionally, a facility that claims the 45Q credit is not eligible to claim the 45V clean hydrogen tax credit.

Table 3. Carbon capture and sequestration credits for DAC as presented in Section 45Q of the IRA (assuming prevailing wage requirements are met).

Application	45Q Tax Credit Amont
Geological Sequestration	\$180/tonne
Geological Sequestration with EOR	\$130/tonne
Other Qualified Uses	\$130/tonne

3. INTEGRATED HYDROGEN PRODUCTION SUMMARY

3.1. Electrolysis Overview

Pure hydrogen (H_2) can be produced by splitting water (H_2O) with electricity through electrolysis. By integrating low-CO_2 electricity generated by an NPP with an electrolyzer, clean hydrogen can be produced at a carbon emission rate of less than 0.45 kg of CO_2 per kg of H_2 produced (on a life-cycle basis). This clean hydrogen has the potential to replace carbon-intensive H_2 produced from fossil-fuel-based steam methane reforming (SMR) of natural gas. SMR-based H_2 without carbon capture has an associated carbon content between 9 kg and 12 kg of CO_2 per kg of H_2 [11]. Currently, 95% of the H_2 produced in the U.S. is sourced via SMR [11], [12]. In addition to thermochemical processes like SMR, there are three primary hydrogen production types. Each type is briefly explained below along with some specific processes associated with it:

- Thermochemical processes utilize heat and chemical reactions to extract hydrogen from various materials. These processes include SMR, autothermal reforming, coal gasification, biomass gasification, biomass-derived liquid reforming, and solar thermochemical hydrogen.
- Electrolytic processes break down water molecules into hydrogen and oxygen. Low-temperature electrolysis (LTE) requires only electricity while the more efficient high-temperature electrolysis (HTE) needs both steam and electricity.
- Direct solar water-splitting processes involve separating hydrogen and oxygen from water using solar power, such as photoelectrochemical and photobiological processes.
- Biological processes involve the use of microorganisms to generate hydrogen, such as microbial biomass conversion and photobiological processes.

With the immense CO_2 output of SMR, the integration of an NPP with a clean hydrogen production source presents an opportunity to decarbonize the present and future hydrogen supply chain. Currently, there are multiple electrolyzer technologies that can be used for H_2 production. This includes LTE and HTE technologies, which will be the focus of this report.

Electrolysis technologies vary in the configuration and stage of development and commercialization. LTE and HTE use electricity to split water into H_2 and O_2. However, solid oxide electrolysis cells (SOEC) are classified as a type of HTE that uses steam to improve process efficiency. Proton Exchange Membrane (PEM) electrolysis is classified as a type of LTE, which has moved from a demonstration phase to commercialization. Characteristics of the PEM and SOEC electrolysis technologies considered in this analysis are summarized in Table 4, and the operating principles and operating conditions for PEM and SOECs are described in the following sections.

Table 4. Electrolysis technologies considered.

Technology	Operating Temperature	Operating Pressure	Specific Energy Requirements	Direct Capital Costs	Maturity
LTE (PEM)	Low-Temperature (<100°C)	20 bar	~55 kWh_e/kg H_2	~\$407/kWe (100 tonne H_2 per day)	Commercial

HTE (SOEC)	High-Temperature (700–800 °C)	5 bar	~37 $kWh_e/kg\ H_2$ ~6 $kWh_t/kg\ H_2$	~$535/kWe (100 tonne H_2 per day)	Demonstration

3.1.1. Low-Temperature Electrolysis – Proton Exchange Membrane Electrolysis

PEM electrolysis is a commercial technology that uses a polymer electrolyte membrane with acidic characteristics that enable the exchange of H^+ ions (protons). These units operate at (~90°C). The proton exchange membrane electrolysis cell configuration is illustrated in Figure 5.

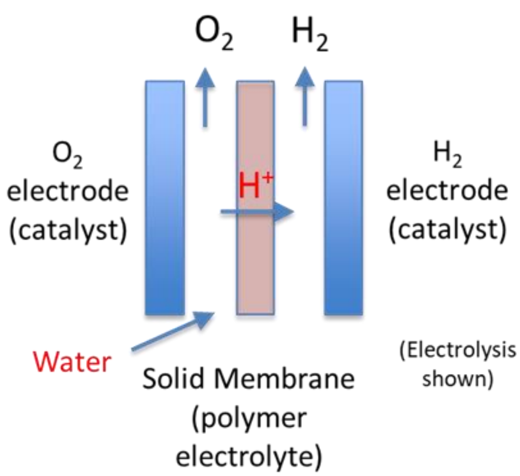

Figure 5. PEM electrochemical cell configuration. Taken from [13].

LTE technologies require only electricity to drive the reaction, allowing for quick startup and shutdown. This offers an advantage for incorporation into integrated energy systems that may demand dynamic operation.

3.1.2. High-Temperature Electrolysis – Solid Oxide Electrolysis

SOECs operate at high temperatures (700–800°C) to increase the efficiency of the electrolysis process [13]. In addition to electric power, SOECs require thermal energy input to vaporize the feedwater stream and to achieve the required stack operating temperature. The SOEC configuration is illustrated in Figure 6.

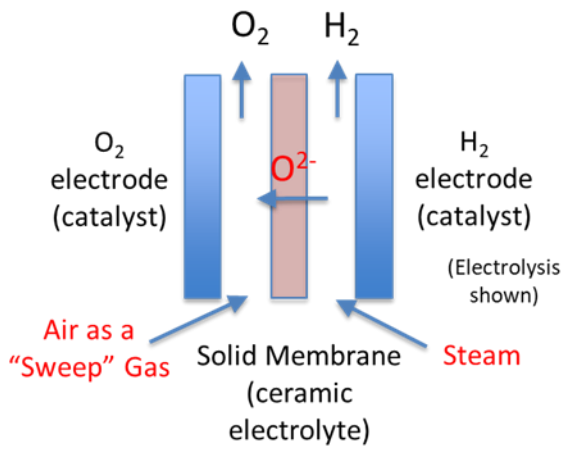

Figure 6. Electrolysis cell configurations. Taken from [13].

To operate the SOEC stack at elevated temperatures, the process requires a configuration with a feedwater steam generator, recuperating heat exchangers, topping heaters, as well as compressors and blowers to pressurize and circulate the vapor phase reactants and products (and the sweep gas used to balance the pressure between the cathode and anode sides of the cells). A schematic of the electrical and thermal integration of an NPP with an HTE electrolysis facility is shown in Figure 7. Detailed assessment of a NPP integration with a hydrogen generation facility can be found in [14]. Heat from the PWR secondary loop can be sent to the HTE process using a thermal energy delivery loop. The thermal energy delivery loop is a system that transfers heat from the NPP to the HTE site using a tertiary loop filled with heat transfer fluid as shown.

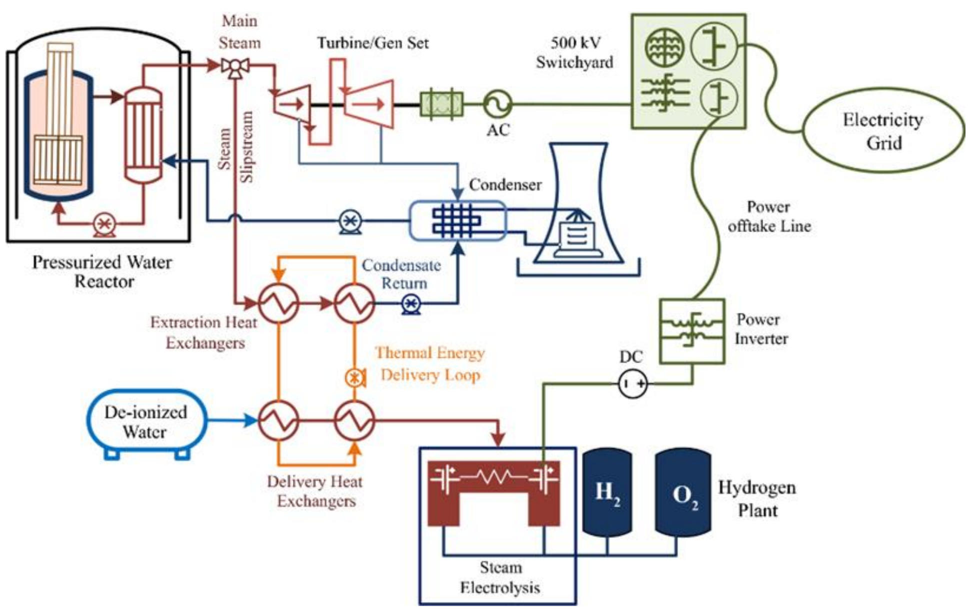

Figure 7. Heat and electricity delivery from a LWR NPP to a high-temperature SOEC electrolysis plant. Taken from [15].

The extensive BOP configuration required for HTE introduces complications for performing rapid startup and shutdown operations. However, the use of a hot standby mode with low energy consumption during time periods when the SOEC plant is not producing H_2 could minimize the ramp times to enable system operation as a dispatchable load in support of grid-balancing operations [15].

4. Hydrogen and Oxygen Market Analysis

4.1. Hydrogen Market

As mentioned, the SMR-produced hydrogen dominates the existing hydrogen market, creating substantial opportunity for market disruption from clean hydrogen providers. Not only can clean carbon hydrogen replace SMR-produced hydrogen, it can also provide an alternative energy carrier to displace fossil fuels for applications that are difficult or near-impossible to electrify. Hydrogen can also be a cost-effective solution for bulk long-term energy storage. Neither the direct combustion of hydrogen nor the extraction of electrons in a hydrogen fuel cell generate carbon emissions. However, SMR results in 8–12 kg of carbon dioxide emitted for every kilogram of hydrogen produced, clearly negating the zero-carbon benefit [11], [16]. Hydrogen generated from either HTE or LTE using energy from nuclear plants can be used to replace the carbon-intensive hydrogen from SMR.

The push for increased low-carbon hydrogen production, utilization, and infrastructure in the U.S. has been accelerated by DOE's "1 1 1" plan (i.e., the Hydrogen Shot Initiative). A goal of the Hydrogen Shot Initiative is to reduce the price of low-carbon hydrogen by 80% to $1 per kilogram over the next decade [17]. The IRA offers expansive federal subsidization of clean energy production and investment as part of the national energy security strategy to transition to a clean energy economy. PTCs for clean hydrogen production, among others, are provided under the IRA as discussed in Section 2.2. This legislation incentivizes NPP operators or owners to produce low-carbon hydrogen alongside electricity. While the cogeneration of hydrogen entails a major shift in the operation and business model of an NPP, it provides an opportunity to diversify a utility's revenue streams and enter a market that is projected to grow significantly.

*4.1.1. **Incentive for Generating Hydrogen with a Nuclear Plant***

Hydrogen production via electrolysis that is powered by nuclear energy (electricity and steam) is particularly appealing due to the emerging hydrogen economy and significant subsidization from the federal government (i.e., the IRA hydrogen tax credit). There is an additional incentive for the production of hydrogen for NPPs that have undergone power uprate. As discussed in Section 2.2.4 the 45V clean hydrogen production tax credit is available for hydrogen produced with uprate power, but not existing generating capacity. Therefore, there is greater financial incentive for an NPP planning to undergo uprate to cogenerate hydrogen than an NPP not undergoing uprate.

*4.1.2. **Market Status***

Hydrogen primarily fulfills industrial purposes. Petroleum refining makes up most of the hydrogen consumption in the U.S., followed by ammonia production and methanol production, making up 93% of total hydrogen consumption. The remaining 7% is used in transportation, electronics, metallurgy, and other chemical production.

Figure 8 shows the breakout of demand in the U.S. The estimated hydrogen consumption of the U.S. was approximately 12 million metric tons (MMT) in 2023 [18].

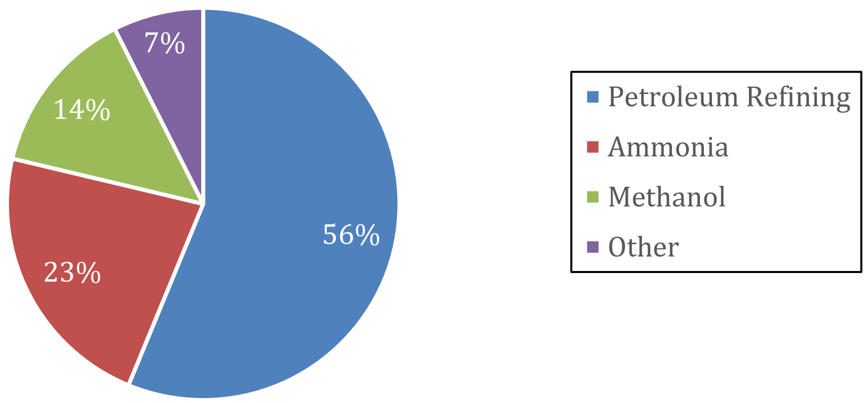

Figure 8. Hydrogen consumption breakout in the U.S. in 2023 by sector [18].

As previously stated, approximately 95% of the 12 MMT of hydrogen consumed annually in the U.S. is generated through SMR, emitting up to 144 MMT of CO_2 during production [16]. The predominant low-carbon hydrogen production method is electrolysis, given the energy supply is low-carbon. A NPP can provide the electricity for LTE or steam and electricity for HTE, rendering both processes clean hydrogen producers. To demonstrate the feasibility of hydrogen production integration with NPPs, multiple small-scale pilot projects are underway with existing NPPs [19], [20], [21].

The previous uprate report projected that current demand would grow from 12 MMT per year to an upper bound of 106 MMT per year by 2050. Figure 9 breaks this future growth out by industries projected to expand, including fuel cell electric vehicles (FCEVs) [22]. Keep in mind that total future demand projections are variable upon the price of clean hydrogen. The lower the price, the higher the projected demand. The National Renewable Energy Laboratory (NREL) published an extensive report that investigated price and demand with potential to be disrupted by clean, low-cost hydrogen [22]. The report presents threshold prices (i.e., the maximum price an industry is willing to pay before it selects an alternative) for the nine industries seen in Figure 9. To further illustrate the relationship between price and demand, a variation of a demand curve is created by mapping total demand with change in threshold price as shown in Figure 10. In the figure, current hydrogen demand (12 MMT/year) is overlaid for context (For further detail see the previous uprate report [4]). Suppliers can view this demand-to-price mapping as the price targets necessary for future demand growth. In practice, actual adoption by industries will depend on numerous factors, such as technological capability, the pressure to meet specific climate change targets, and impacts on a firm's profit margins. Nevertheless, by integrating the insights from Figure 9 and Figure 10, the potential of a hydrogen-driven economy becomes more evident. Clean hydrogen is set to play a crucial role in the decarbonization of multiple industries, and producers must start building capacity now to meet future demands.

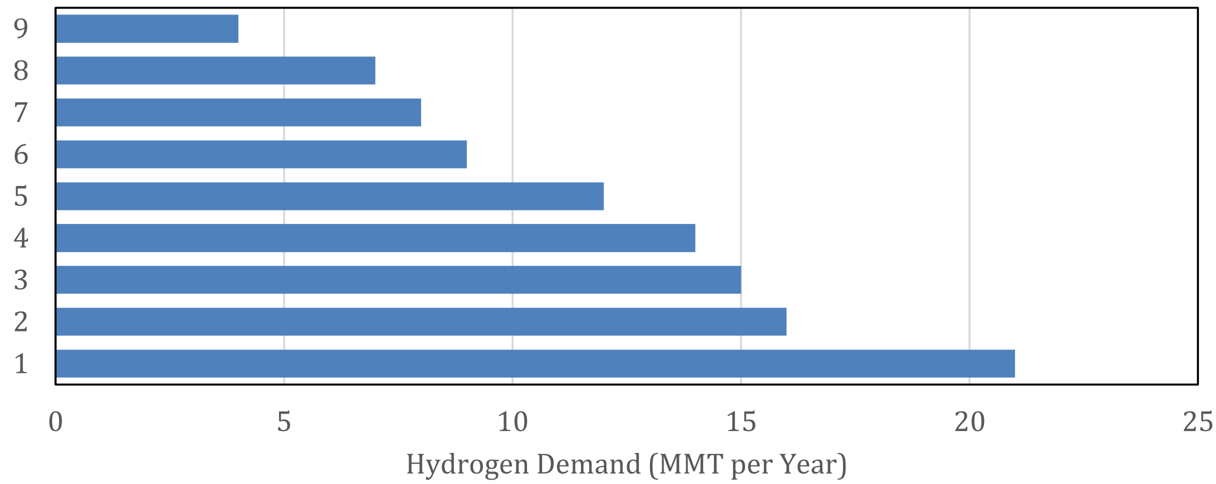

Figure 9. Potential U.S. clean hydrogen consumption by sector in 2050.

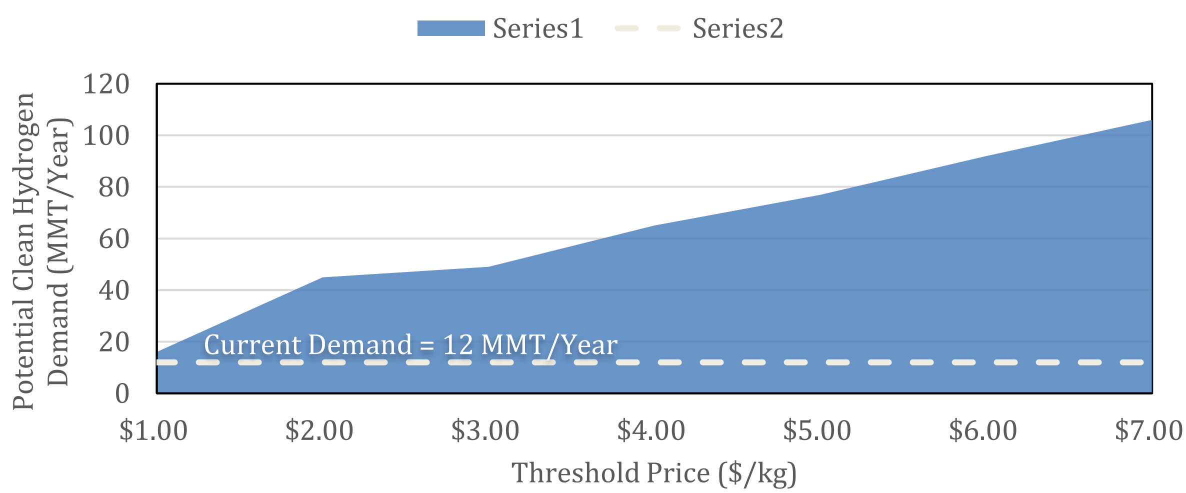

Figure 10. Clean hydrogen 2050 demand curve.

The previous uprate report focused on the prospective developments within the clean hydrogen market sector, contemplating the future landscape and the technological advancements that may shape its evolution. This report expands upon that contemplation by focusing on the immediate opportunities emerging today within the regional hydrogen markets. To provide a backdrop for this discussion, Figure 11 presents the existing landscape of U.S. NPPs and hydrogen hubs across states, grouped by region. For explicit region definitions, see Table 5. This segmentation is pivotal in understanding the regional dynamics influencing hydrogen production, as the usage of hydrogen as an energy carrier and industrial feedstock exhibits significant variation from one region to another.

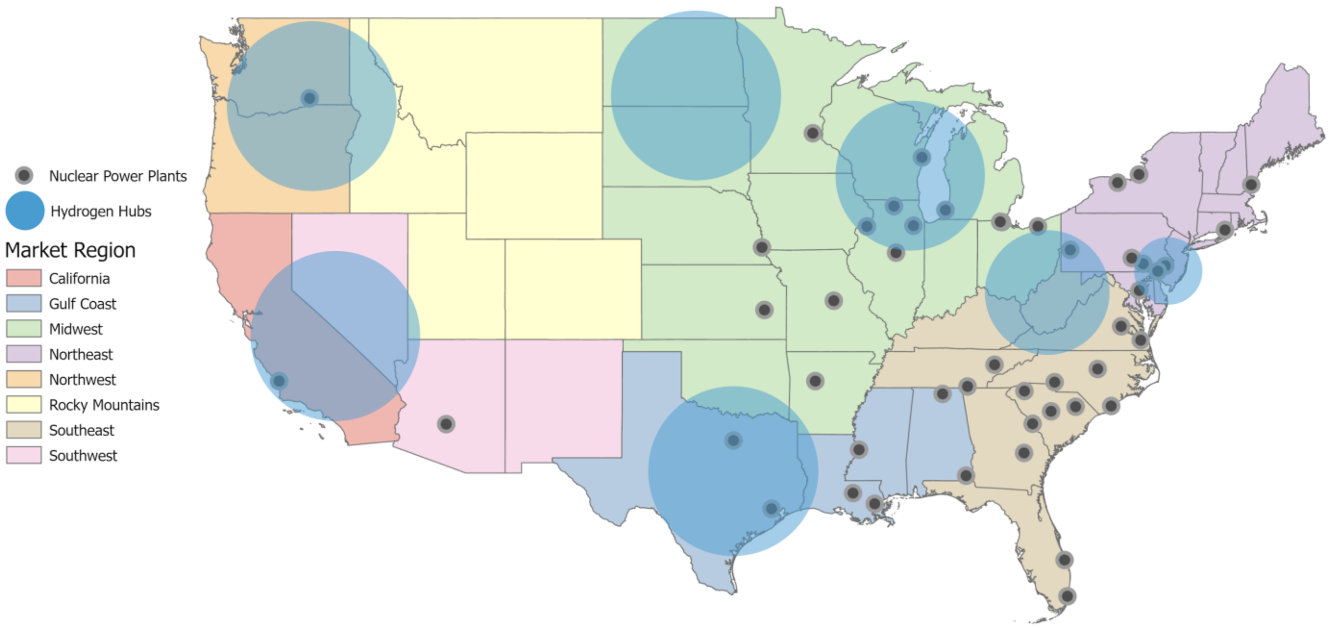

Figure 11. U.S. regions with current nuclear fleet plant locations [23], [24].

Table 5. U.S. region definitions.

Northeast	Southeast	Midwest	Rocky Mountains
New York	Florida	Illinois	Colorado
Pennsylvania	Georgia	Indiana	Wyoming
New Jersey	South Carolina	Ohio	Montana
Massachusetts	North Carolina	Michigan	Idaho
Connecticut	Virginia	Wisconsin	Utah
Rhode Island	West Virginia	Minnesota	
New Hampshire	Kentucky	Iowa	
Vermont	Tennessee	Missouri	
Maine		Kansas	
Maryland		Nebraska	
Delaware		North Dakota	
		South Dakota	
		Oklahoma	
		Arkansas	
Gulf Coast	**California**	**Southwest**	**Northwest**
Texas	California	Arizona	Washington
Louisiana		New Mexico	Oregon
Mississippi		Nevada	
Alabama			

Figure 12 shows a visual representation of the estimated annual hydrogen demand distribution, stratifying the data across the various regions of the continental U.S. Within this distribution, the Gulf Coast region emerges as the predominant consumer of hydrogen, with its demand constituting approximately 59% of the national total. This pronounced demand can be attributed to the region's extensive industrial base and the integration of hydrogen in the various processes shown. Following the Gulf Coast, the state of California represents another significant market, with its hydrogen demand accounting for 18% of the UUU.S.' total requirement. The Midwest follows, contributing 12% to the overall U.S. hydrogen demand. This analysis of the current hydrogen regional markets can provide a foundation for stakeholders to identify and capitalize on the opportunities that are present today within their own regions. For a state-level breakdown of hydrogen demand, see Table 14 in APPENDIX D.

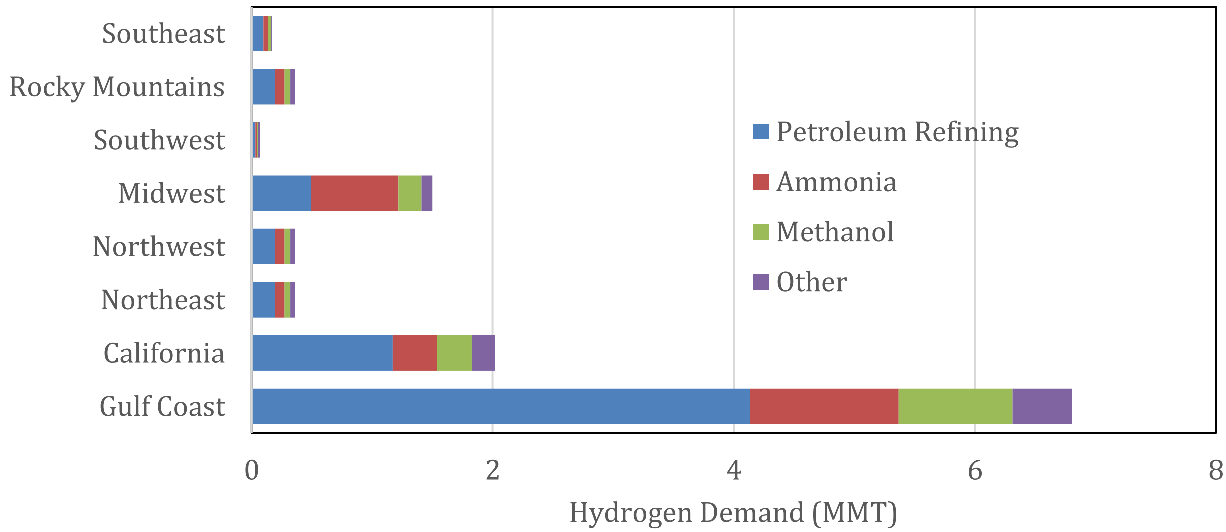

Figure 12. Hydrogen sector demand in MMT by U.S. region in 2023 [18].

The bar chart in Figure 13 presents a comparative analysis of hydrogen demand across various regions of the U.S., shown side-by-side with the potential hydrogen production capacity if each NPP in the respective regions dedicated all their uprate potential to hydrogen production. The regions are depicted along the horizontal axis, while the vertical axis quantifies the mass of hydrogen in MMT. It is evident from the chart that the Gulf Coast region of the U.S. exhibits the highest demand for hydrogen, but interestingly, its potential hydrogen-cogeneration production capacity does not reach this demand, showcasing a significant lack in clean hydrogen supply via nuclear. On the contrary, the Southeast has a lower demand, yet its production potential is significantly above the required level. The Midwest and the Northeast also show an imbalanced relationship between demand and potential supply, with production potential exceeding demand. The Southwest and Rocky Mountain regions lack NPPs but have small demand relative to the other regions. Overall, the chart suggests that, while some regions could be ideal for hydrogen cogeneration, others may need to rely on inter-regional hydrogen transportation or alternative production methods to meet their demands.

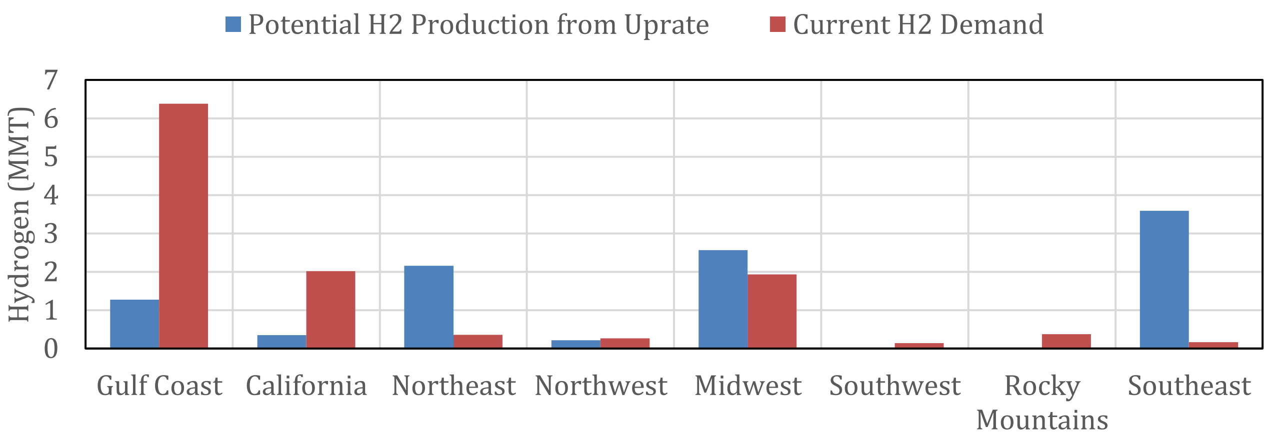

Figure 13. Potential hydrogen production supported by power uprates versus hydrogen demand by region.

The prevalence of carbon-emitting hydrogen production through SMR underscores the opportunity for cleaner methods of production, like electrolysis integrated with NPPs. The regional analysis highlights the uneven distribution of hydrogen demand across the U.S., with the Gulf Coast region leading consumption due to its heavy industrial activities. Although some regions, like the Southeast, show a surplus in potential hydrogen production capacity, the overall picture indicates a mismatch between regional demand and production capabilities. This disparity suggests a need for strategic planning in infrastructure development, inter-regional hydrogen transport solutions, and investment in alternative production methods to equilibrate the supply-demand balance.

4.2. Oxygen Market

The chemical process of electrolysis splits water molecules into their constituent hydrogen (H_2) and oxygen (O_2) gases. With the mounting interest in generating clean hydrogen through HTE or LTE, there arises potential commercial opportunity not just for the hydrogen produced, but also for the oxygen byproduct that is generated in the process. In fact, oxygen (O_2) is produced at a ratio of ~8 kg of O_2 per kilogram of produced H_2. Typically, O_2 is treated as a byproduct and vented to the atmosphere. However, O_2 could be recovered for industrial applications such as steel, refining, and medical purposes. Currently, the majority of O_2 is produced from the cryogenic separation of O_2 from air (which is 79% nitrogen and 21% O_2), which utilizes large quantities of power.

4.2.1. Market Status

Oxygen gas manufactured for industrial applications comes in varying purity levels, typically between 90% and 99.995%. Some industries, such as the electronics and healthcare sectors, require high-purity oxygen, while other uses, such as combustion or cutting applications, can use lower purity oxygen. Meanwhile, a moderate level of purity is sufficient for a wide array of industrial activities, including chemical manufacturing and metalworking [25]. Table 6 lists some of the oxygen applications by the required purity. For steelmaking, refining, water treatment, metal fabrication, pulp and paper manufacturing, and food and beverage production, most needs are satisfied by the standard, cost-effective 90–95% purity oxygen. Instances requiring the highest purity levels (≥ 99.5%) are rarer either because they are only required in infrequent cases (i.e., specialized steelmaking, chemicals production for semiconductors and electronics, glass production for semiconductors, high-quality optical components, or fiber optics), or because the added benefit of fewer impurities fails to justify the high cost. The exception is medical oxygen, which must be of ≥ 97% purity.

Table 6. Oxygen Purity by Industry [25].

Oxygen Purity	**Application**
Greater than 99.995%	• Semiconductor manufacturing • Laser cutting • Pharmaceutical production • Medical oxygen • Aerospace applications
99.9–99.99%	• Gas and oil operations • Laser cutting/welding • Laboratory/analytical uses • Gas mixtures
99.5–99.9%	• Health care • Glass manufacturing • Electronics manufacturing • Metal fabrication • Steel heat treatment • Ozone generation
99–99.5%	• Chemical and petrochemical processes • Metal fabrication • Food processing • Secondary steelmaking • Glass manufacturing
Less than 99%	• Combustion/smelting/welding • Wastewater treatment • Food freezing and packaging • Oxy-fuel cutting

In the U.S., industrial oxygen plays a pivotal role across various sectors. Its largest application is in the steel industry, where it is utilized to increase furnace temperature and efficiency, thereby facilitating the production of high-quality steel. The chemical manufacturing sector also relies heavily on oxygen, using it in oxidation processes to create a plethora of chemical compounds. Additionally, oxygen is employed in the healthcare industry for respiratory assistance and in water treatment facilities to enhance aerobic digestion. The utilization of medical oxygen, which constitutes a portion of the overall oxygen consumption within the healthcare sector, represents approximately 6% of the demand and is on an upward trajectory. The glass and paper industries use oxygen to improve combustion in furnaces and kilns, leading to more energy-efficient and environmentally friendly production. Figure 14 shows a pie chart illustrating the current oxygen usage by U.S. industry and Figure 15 gives the regional breakdown. For a state-level breakdown of oxygen demand see Table 14 in APPENDIX D. Currently, the main techniques for generating industrial oxygen include cryogenic distillation of air and non-cryogenic methods such as vacuum swing adsorption (VSA) and pressure swing adsorption (PSA).

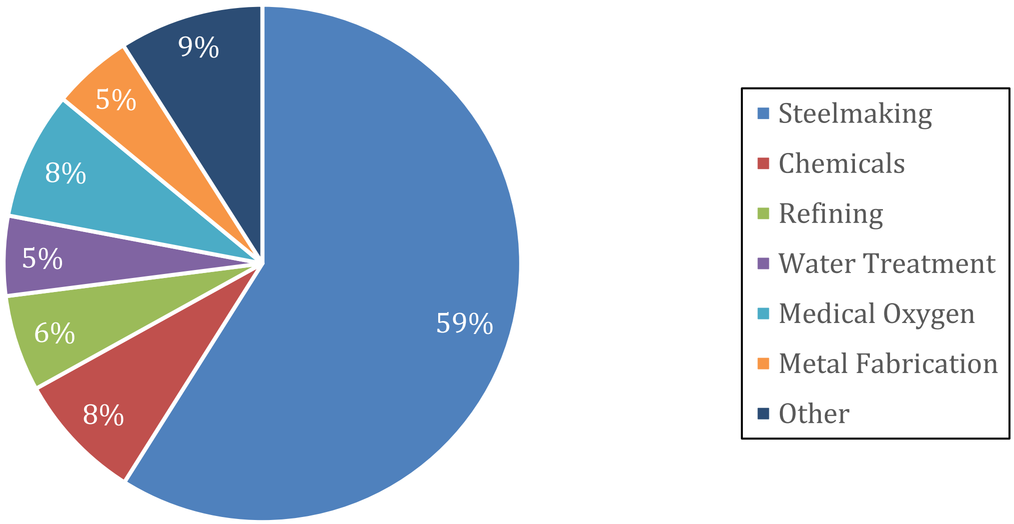

Figure 14. Oxygen consumption breakout in the United Sates in 2023 by sector [25].

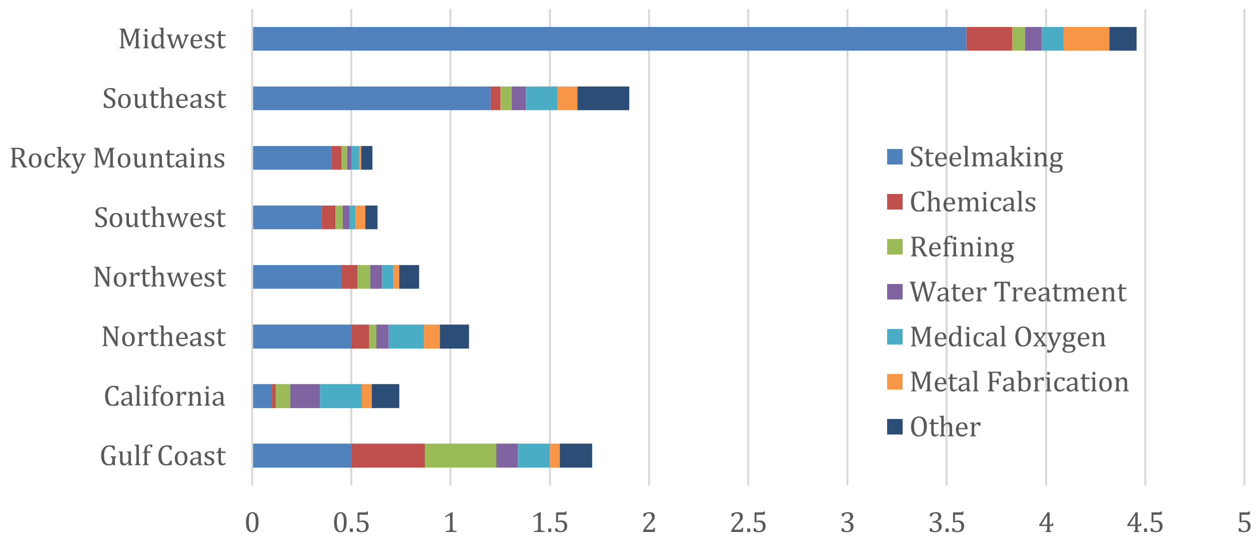

Figure 15. Oxygen sector demand in MMT by U.S. region in 2023 [25].

In 2023, the U.S. consumed around 12 million metric tons of industrial oxygen per year, marking a significant increase from the approximate 10.3 MMT recorded in 2019 [25]. This upward trend is projected to continue. The bar chart in Figure 16 illustrates a clear upward trajectory in the demand for industrial oxygen, starting from a baseline of 10.3 MMT in 2019. Each bar represents a progressive increase over the years, culminating in a projected demand of 15.5 MMT by 2030.

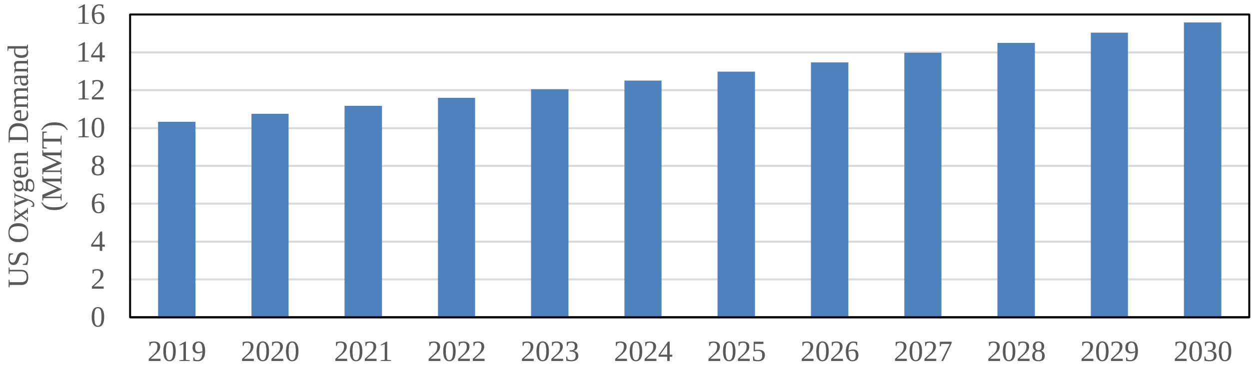

Figure 16. U.S. oxygen demand (in MMT) projections from 2019–2030.

The growth in industrial oxygen demand is driven by several market factors. In steelmaking and metals, there has been an increase in production using electric arc furnaces (EAF), which consumes more oxygen and therefore contributes to increased demand. Additionally, challenges in scrap availability are driving the adoption of oxygen-enriched processes to work with lower quality raw materials. The shift toward continuous casting and production of specialty steel grades, particularly for use in renewable energy and electric vehicles, requires higher purity oxygen. In the chemical sector, the trend toward methanol production, the development of second-generation biofuels, and the innovation in specialty chemicals are all oxygen intensive. Process intensification and custom synthesis models in chemical manufacturing further heighten oxygen demand. Refining is experiencing a surge in oxygen demand due to stricter sulfur and carbon specifications, the use of heavier crude oil, biofuels co-processing, the creation of high-octane fuels, and water recycling initiatives. Glass and ceramics production are being propelled by emerging market demand, the push for lightweight materials, the surge in solar glass production, technical glass innovation, and furnace efficiency pursuits, all of which rely on oxygen. Water treatment is another area where oxygen is increasingly important, driven by stringent effluent regulations, the need for water reuse, nutrient removal mandates, indirect potable reuse, and energy efficiency efforts. Medical oxygen demand is growing due to aging populations, healthcare modernization, a shift toward home healthcare, diagnostic growth, and emergency preparedness following the COVID-19 pandemic [25].

Figure 17 displays a bar chart that provides a comparison of the current demand for industrial oxygen with the potential production capacity from electrolysis powered by nuclear energy across U.S. regions. Displayed on the vertical axis is the mass of oxygen in MMT. The horizontal axis categorizes this data by U.S. regions. For each region, a pair of side-by-side bars demonstrates the contrast in demand and potential supply from electrolysis powered by energy from NPP uprate. Notably, the data reveal that the potential for oxygen production using NPP uprate energy far exceeds the current industrial demand in nearly every region. The exceptions are the Southwest and Rocky Mountain regions, which currently contain no potential for nuclear energy powered electrolysis. The implications of this potential oxygen production are considerable, suggesting a capacity for NPPs to become major suppliers of near-zero carbon oxygen in the industrial oxygen market and potentially influence market dynamics through the introduction of a substantial new source of this vital industrial gas.

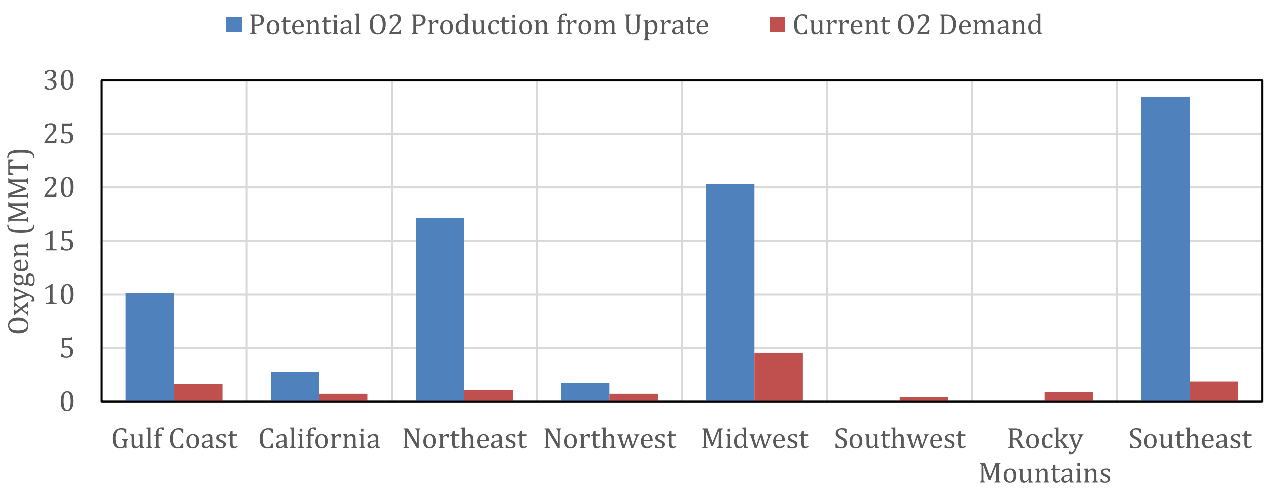

Figure 17. Potential oxygen production versus oxygen demand by region.

The industrial applications for oxygen are diverse and critical, ranging from steelmaking to healthcare, and the demand is on an upward trajectory. The growth in industrial oxygen consumption is anticipated to continue, with projections reaching 15.5 MMT by 2030. This increasing demand, coupled with the substantial potential oxygen output from electrolysis-based hydrogen generation could not only satisfy existing market needs but could also stimulate new uses and applications, further expanding the oxygen market. As industry looks toward a future of clean energy and sustainable practices, the role of NPPs could extend beyond electricity generation, making them integral players in the broader scope of industrial production and environmental stewardship.

5. Impacts of Oxygen Sales on Integrated Hydrogen Economics

The modeling in the previous uprate report assumed that oxygen was vented from the hydrogen system and not captured. However, capturing and selling the oxygen could result in improved financial outcomes. To measure the potential impact of oxygen capture, the discounted cashflow (DCF) model from the previous uprate report was adjusted to include revenues from oxygen sales. While additional revenues from oxygen sales were accounted for in this instance, note that additional costs that might be incurred from the system were not. It is likely that capturing the oxygen would require additional capital costs and potentially even additional operations and maintenance (O&M); however, the aim for this modeling iteration was simply to see the delta in returns from added revenue. This would help contextualize how lucrative oxygen sales would be compared to hydrogen.

The range of pricing for bulk oxygen sales[b] across all purity levels is reported to be as low as \$0.004/kg to as high as \$0.019/kg [25]. Additionally, for every kilogram of hydrogen produced, it is expected that 7.93 kilograms of oxygen could be captured [15]. Subsequently, this means that for every kilogram of hydrogen produced, an additional \$0.03 to \$0.15 is generated from the oxygen sale revenues. When considering the hydrogen price targets shown in Figure 10, which range as high as \$3/kg, this number becomes relatively small. However, instances where hydrogen is sold at much lower price point, it could make a larger relative impact on profitability.

Table 7 shows the results of adding both the lower and upper oxygen price and points to two cases where hydrogen is sold for \$1.00/kg H_2 and \$3.00/kg H_2. These results highlight the impact oxygen sales can make on the project's internal rate of return (IRR). In both the \$1.00/kg H_2 and the \$3.00/kg H_2 scenarios adding oxygen

[b] The report provides two different sale prices—one for small cylinder delivery, which would be like a small consumer purchase, and one for bulk liquid delivery. The bulk delivery numbers were assumed as the oxygen produced would be sold to larger firms with high demand rather than sold to individual consumers.

sales only increased the IRR by ~1%, for both LTE and HTE models. In some instances, the positive impact varied, but adding oxygen sales never increased the IRR by more than 1%. Recall again that this modeling assumes no additional costs associated with these systems.

Table 7. Impacts of oxygen sales on internal rate of return of uprate with hydrogen cogeneration projects.

		LTE Produced H_2		**HTE Produced H_2**	
H_2 Sales Price	**O_2 Sales Price**	**Power ITC + H_2 PTCs**	**Power PTCs + H_2 PTCs**	**Power ITC + H_2 PTCs**	**Power PTCs + H_2 PTCs**
$1.00/kg H_2	***Base Case: No O_2 Sales***	**15.3%**	**12.6%**	**18.3%**	**15.3%**
	$0.03/kg O_2	15.5% (+.2%)	12.7% (+.1%)	18.5% (+.2%)	15.4% (+.1%)
	$0.15/kg O_2	16.2% (+.9%)	13.3% (+.7%)	19.1% (+.8%)	16.0% (+.7%)
$3.00/kg H_2	***Base Case: No O_2 Sales***	**22.9%**	**19.3%**	**25.9%**	**22.2%**
	$0.03/kg O_2	23.0% (+.1%)	19.4% (+.1%)	26.0% (+.1%)	22.3% (+.1%)
	$0.15/kg O_2	23.4% (+.5%)	19.7% (+.4%)	26.3% (+.4%)	22.6% (+.4%)

A general conclusion from this IRR comparison is that oxygen sales will not drastically change the economics of these projects. In some instances, it may be enough to push returns to a desired range, but it generally appears that the sale of oxygen would be most beneficial if hydrogen prices are depressed, as highlighted by the lower H_2 sales point scenario. Also, if near-zero oxygen commands a premium, the oxygen from the electrolysis/NPP production scheme could increase in demand. In that sense, co-integration of oxygen and hydrogen capture should be considered if there is ample demand in the region, and the cost of including oxygen capture is reasonably small.

6. INTEGRATED DIRECT AIR CAPTURE OVERVIEW

Carbon capture technologies will be needed to meet decarbonization goals, which include both point source capture and DAC. Point source capture refers to the processes of capturing CO_2 from large generating sources, such as power plants and industrial facilities, before the CO_2 is released to the atmosphere. Conversely, DAC captures CO_2 after it has been released to the atmosphere. DAC is more energy intensive and therefore tends to be more expensive than point source capture due to the low concentration of CO_2 in the air (~400ppm). However, these technologies are not meant to compete with each other, but rather complement one another. While point source capture can reduce the amount of CO_2 released into the atmosphere, DAC can help to offset emissions from distributed sources and hard-to-decarbonize sectors, such as the transportation sector.

One of the major challenges with DAC is the high energy demand. DAC is an energy-intensive process, and the source of this energy will play a role in the system's overall performance and cost. It is important that a DAC system is supplied with low-carbon energy, which presents an opportunity for nuclear power.

A recent study by Stauff et al. investigated coupling DAC systems with three different advanced reactor designs [26]. For each of the scenarios considered, it was shown that the integrated system resulted in a decreased cost of capture when compared to the non-nuclear baseline cases. The current report expands upon this work by investigating if retrofitting the DAC system to an existing LWR could be profitable. Specifically, if an LWR undergoes uprate, are there conditions under which it is more profitable to install and operate a DAC system rather than simply selling the additional electricity?

6.1. Direct Air Capture Integration with Nuclear

The two most prominent DAC technologies are liquid solvent DAC (L-DAC) and solid sorbent DAC (S-DAC). L-DAC consists of two chemical loops, the first being the contactor loop where CO_2 is separated from air by exposing it to a chemical solution, such as potassium hydroxide. The second loop is the calciner loop, which separates the CO_2 from the solution using a high-temperature process, leaving a pure CO_2 stream. The calciner operates at around 900°C, which is typically supplied by natural gas combustion.

The electricity required for L-DAC could be supplied by an NPP, however, the heat demand cannot be directly met with LWR steam due to the high-temperature requirements. Supplying heat for L-DAC with an LWR would require modification to the conventional L-DAC system, such as the using an electric calciner, and is therefore not considered in this work.

S-DAC is a cyclic process that utilizes a solid material that binds with CO_2 to separate the CO_2 from the air. First, air passes through the adsorber bed; the CO_2 in the air binds with the sorbent and is removed from the air stream. Next, the CO_2 is separated from the sorbent in a process known as regeneration. The regeneration process requires the sorbent to be heated to around 100°C. The heat and electricity will need to be provided by a low-carbon source in order for the S-DAC process to be net-negative,

LWRs are low-carbon sources of energy that could provide both electricity and heat for an S-DAC system [26]. The regeneration temperature for the S-DAC system is low enough that the heat can be supplied through steam extraction from an LWR. While both PWRs and BWRs operate at high enough temperatures to supply heat to an S-DAC system, this report will only consider an S-DAC system integrated with a PWR since there are additional safety-related considerations associated with steam extraction from a BWR due to it being radioactive.

6.2. Direct Air Capture Model Description

The DAC system energy requirements and cost information used throughout this work are based on a DAC model developed by National Energy Technical Laboratory (NETL), specifically, the 0B-EB case in report DOE/NETL-2021/2865 [27]. This report provides a highly detailed description of both the energy requirements and cost assumptions for a generic S-DAC system. This model was selected as the basis for this work because it provides a highly detailed description of the energy requirements and cost assumptions used throughout the report.

NETL's 0B-EB case represents a generic solid sorbent DAC system that captures 100,000 tonnes of CO_2 per year. An electric boiler supplies the necessary steam to the DAC system and all electricity requirements are met by purchased electricity. The purchased electricity is assumed to be carbon free, meaning that the DAC system's gross capture rate is equal to its net capture rate.

The 0B-EB model is modified to represent a DAC system supplied with heat and electricity from an NPP. A detailed description of the energy requirements and cost estimates for the modified system are provided in APPENDIX A. The most significant change to the system is that the electric boiler is no longer needed because the steam can be directly supplied by the NPP. The steam and electricity powering the DAC system are carbon free so, once again, the gross capture rate is the same as the net capture rate. The size of the DAC system remains the same; however, the capacity factor is increased from 85 to 93%, allowing for 109,412 t/year to be captured using the same system. As discussed in APPENDIX A, in order for the DAC system's energy demands to be entirely met with uprate power, an uprate of 108 MW_{th} is required. The majority of NPPs could achieve an uprate of this size. Additionally, it should be noted that the DAC system discussed throughout this work is substantially larger than any DAC system currently deployed. For context, Mammoth, the S-DAC system currently being constructed by Climeworks is designed to have an annual gross capture rate of 36,000 tons [28].

The S-DAC system costs, which will be used as inputs to the financial model, are discussed in detail in APPENDIX B and summarized below in Table 8. Note that each of the system costs are presented as the cost per tonne of CO_2 captured annually.

Table 8. S-DAC system costs (shown in 2019 USD) presented as dollar per net-tonne of CO_2 captured annually.

	0B-EB	**0B-NPP**	**Explanation for change**
Direct Cost ($/tonne)	1,406	1,255	Omit cost of electric boiler and increased capacity factor
Owner's Cost ($/tonne)	341	291	Increased capacity factor
Fixed O&M ($/tonne-yr)	85	78	Increased capacity factor
Variable O&M ($/tonne)	245	22	Omit the cost of electricity

6.3. Carbon Dioxide Market Analysis

The carbon dioxide market is made up of several major applications that drive demand. This includes geological storage, EOR, high-purity, and industrial applications. Additionally, there is demand for captured carbon to be sold in the voluntary offset market as a carbon credit, which can generate revenue for firms capturing the carbon. Section 6.4 details the difference in price point for each of these groups. Depending on the purity, CO_2 is used in urea production, medical, rubber, firefighting, and food and beverage applications, among others.

Determining the exact demand for CO_2 in the U.S. is difficult but estimates place annual global demand for CO_2 at 230 million tonnes (Mt) with North America making up roughly 33%, or 76Mt [10] of the market. Globally, urea production consumes roughly 130Mt per year, followed by the second largest global consumer, which is the oil sector at 70–80Mt per year [29].

Between 2022 to 2030 the industry is expected to grow at a compounded annual growth rate of 8.4% [30]. This growth is expected to be driven by demand growth in the consuming industries. Anecdotally, a potentially significant shift in future CO_2 supply could come from the selection away from SMR-produced hydrogen. For urea, a derivative of ammonia and a substantial source of hydrogen demand, the CO_2 produced from the SMR process is used to create urea. In processes where SMRs are replaced by LTE- and HTE-sourced hydrogen, additional CO_2 will need to be sourced for urea production[c].

The future of CO_2 demand is difficult to predict and somewhat dependent upon how decarbonization efforts evolve globally. As more DAC and carbon capture sequestration technologies come online in the coming years, the market is likely to experience sharp increases in supply which, assuming CO_2 is sold and not all stored, could push prices downward as supply increases. However, International Energy Agency (IEA) projections expect more CO_2 to be stored rather than used unless storage capabilities fail to materialize [31]. Additional factors that could impact future CO_2 demand include the potential for CO_2-derived products and services to replace existing options. The IEA also considers these impacts and Figure 18 highlights different CO_2-derived products' potential future demand as well as the climate benefits associated with replacing existing sources. This addition of these CO_2-derived products could drastically change demand in the future but is highly dependent on the prices of existing solutions and technological advances.

[c.] To create urea, the CO_2 is reacted with ammonia under high pressure to form ammonium carbamate, which is then dehydrated to urea and water. The chemical reaction is as follows: $2\ NH_3 + CO_2 \rightarrow NH_2COONH_4$ (ammonium carbamate) $NH_2COONH_4 \rightarrow (NH_2)2CO$ (urea) + H_2O. Many urea production facilities are integrated with ammonia plants to directly utilize the CO_2 byproduct, making the supply chain more efficient and reducing the need to transport CO_2.

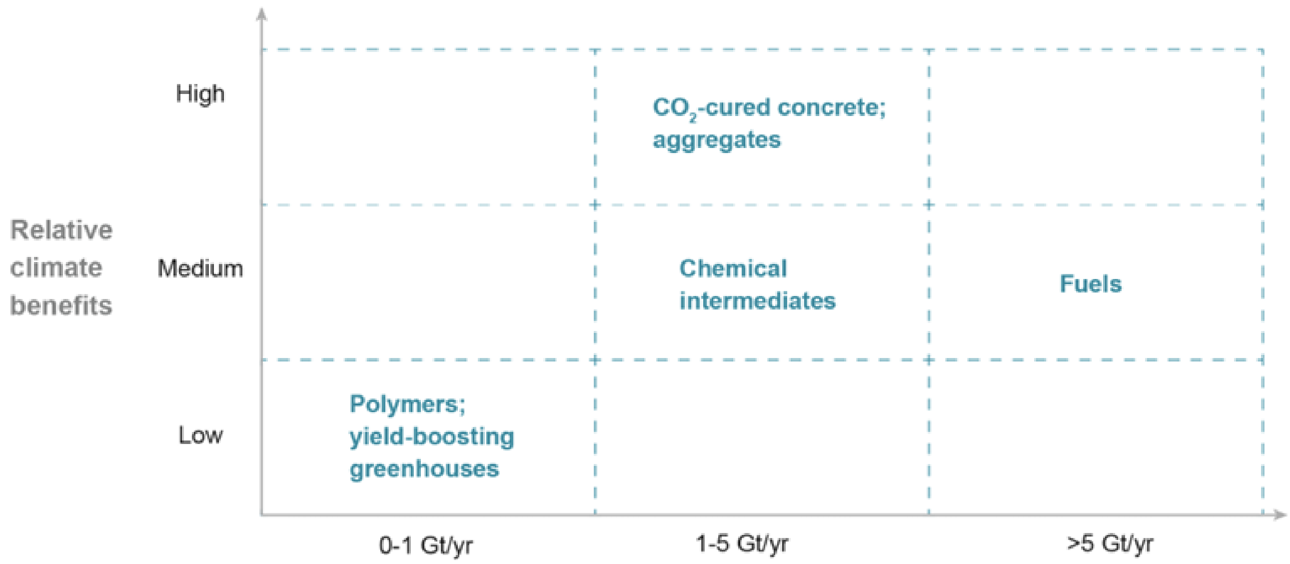

Figure 18. Theoretical potential and climate benefits of CO_2-derived products and services. Figure from [10].

6.4. Revenue Sources from CO_2 Capture

There are two potential revenue sources for entities that capture CO_2: the tax credits outlined in Section 45Q of the IRA and the sale of CO_2. As discussed in Section 2.2.5, the tax credits vary depending on the end use of the CO_2. Additionally, the market price for CO_2 varies greatly depending on the customer. The recent report by Stauff et al. discussed several revenue streams for captured carbon, including geological storage, EOR, high-purity applications, and the voluntary offset market [26]. Table 9 shows the market price for different CO2 applications (as provided by Stauff et al.) along with the value of the applicable IRA tax credit. These prices should not be treated as absolute price points for given applications, but as single references for how prices may change by application. For example, Stauff et al. report that $775/tonne was the highest observed price in the voluntary offset market, but significantly lower prices were also observed. To account for this, the model done herein leverages a wide range of CO_2 prices.

Table 9. Carbon market prices and tax credits by application [26].

Market Application	**Market Price by Market Application ($/tonne)**	**Tax Credit Amount by Market Application ($/tonne)**
Geological Storage	$0	$180
Enhanced Oil Recovery	$40	$130
High-Purity Industrial Applications	$400	$130
Max. Voluntary Offset Market	$775	$180

It should be noted that the market price for CO_2 can vary greatly depending on factors such as location, industry, and time of year [10]. Neither the supply nor the demand for CO_2 is constant throughout the year, which leads to a variation in price. For example, much of the CO_2 produced today is a result of ammonia production for the fertilizer industry, which peaks in the fall and winter months; however, the demand for high-purity CO_2 for the food and beverage industry peaks during the summer months [10]. Additionally, the price of CO_2 in the voluntary offset market can vary greatly. The price provided in Table 9 is the maximum publicly reported price for CO_2 in the voluntary offset market, but it should be noted that this price was for a small quantity of CO_2, and it is expected that this price decreases as the cost of CO_2 capture decreases [32]. Realistically, the price for CO_2 in the offset market will likely be lower than this; an assessment by S&P Global Platts shows that in 2021 the price for tech-based removal (such as DAC) could be as high as $300/tonne of CO_2 captured [33]. The values provided in Table 9 are used as inputs to the economic model discussed in the following section; however, to truly determine the economic viability of deploying a DAC system at an NPP it would be important to have a better understanding of the CO_2 market in that specific area.

7. Impacts of Carbon Sales on Integrated Direct Air Capture Economics

A simplified, DCF model was also developed to determine the profitability of uprate with DAC cogeneration. The methodology of discounted cashflow modeling allows comparison of different projects with different cost and cashflow structures by discounting everything into a single-year term. This methodology is detailed in the previous report where extensive modeling was done, but the discounted cashflow methodology can be expressed mathematically as follows in 1.

Net present value equation: $NPV = \sum_t^T \frac{CashFlow_t}{(1+DR)^t}$ (1)

Where:

- NPV represents the net present value of a project
- t represents a given year within the project lifetime T
- $CashFlow_t$represents a cashflow for a given year
- DR represents the discount rate for a project.

This approach flattens multiyear projects into a single metric, net present value (NPV). This equation can also be used to calculate the IRR by setting NPV equal to zero and solving for the required discount rate to result in NPV = 0, or the point at which the project breaks even where all the cashflows cover the costs. The previous uprate report developed more a complex model, with an accompanying Excel tool (NuH2, which can be requested from INL), which accounted for a myriad of factors that could impact cashflows each year. For the DAC cogeneration, a more simplistic modeling approach was used that focused on major factors to provide a first look into the potential for nuclear DAC integration profitability. For a full list of assumptions associated with the DAC DCF model, see APPENDIX B.

An important assumption in the model is that the DAC system is owned by the nuclear operator, so the CO_2 PTC, 45Q, cannot be claimed at the same time as either of the energy tax credits. Subsequently, in both the uprate only and the uprate plus DAC cases the same incremental cost of generation is assumed. To account for this, the additional cost of fuel associated with uprating the plant was calculated using assumptions from APPENDIX B. Nuclear O&M costs (both fixed and variable) were assumed to remain unchanged to match the assumptions made in the previous uprate report's hydrogen modeling. However, it is possible that more substantial uprates result in material changes to O&M costs. For a full list of costs and revenues assumed in these models see APPENDIX B.

The modeling measured the NPV of "Uprate + DAC" versus "Uprate-Only" projects. Figure 19 highlights the results of this modeling by showing three different uprate-only NPV outcomes with an associated power price. These NPV outcomes for uprate only, shown as dotted lines in various shades of red, illustrate that as the power price increases, the utility achieves a higher NPV. The solid blue lines of various shades show the NPV outcomes of uprate + DAC projects. As the price of carbon rises, these projects increase in profitability. Additionally, the higher the PTC amount that is claimed ($180/tonne verse $130/tonne), the better the NPV outcome.

However, when the uprate only versus uprate plus DAC projects are compared, utilities are only better off electing uprate + DAC if there is a high certainty of elevated carbon prices. For example, as highlighted in Table

9, the applications that have lower CO_2 prices may not fetch a high enough market price to provide higher returns than selling power to the grid. In fact, in the lower price ranges such as those observed in enhanced oil recovery, the projects fail to return any profits and the utility loses money. This holds true even for the cases where tax credits are applied. When considering higher price ranges such as those found in high-purity industrial applications, it becomes possible for Uprate + DAC to produce NPV outcomes higher than uprate-only cases.

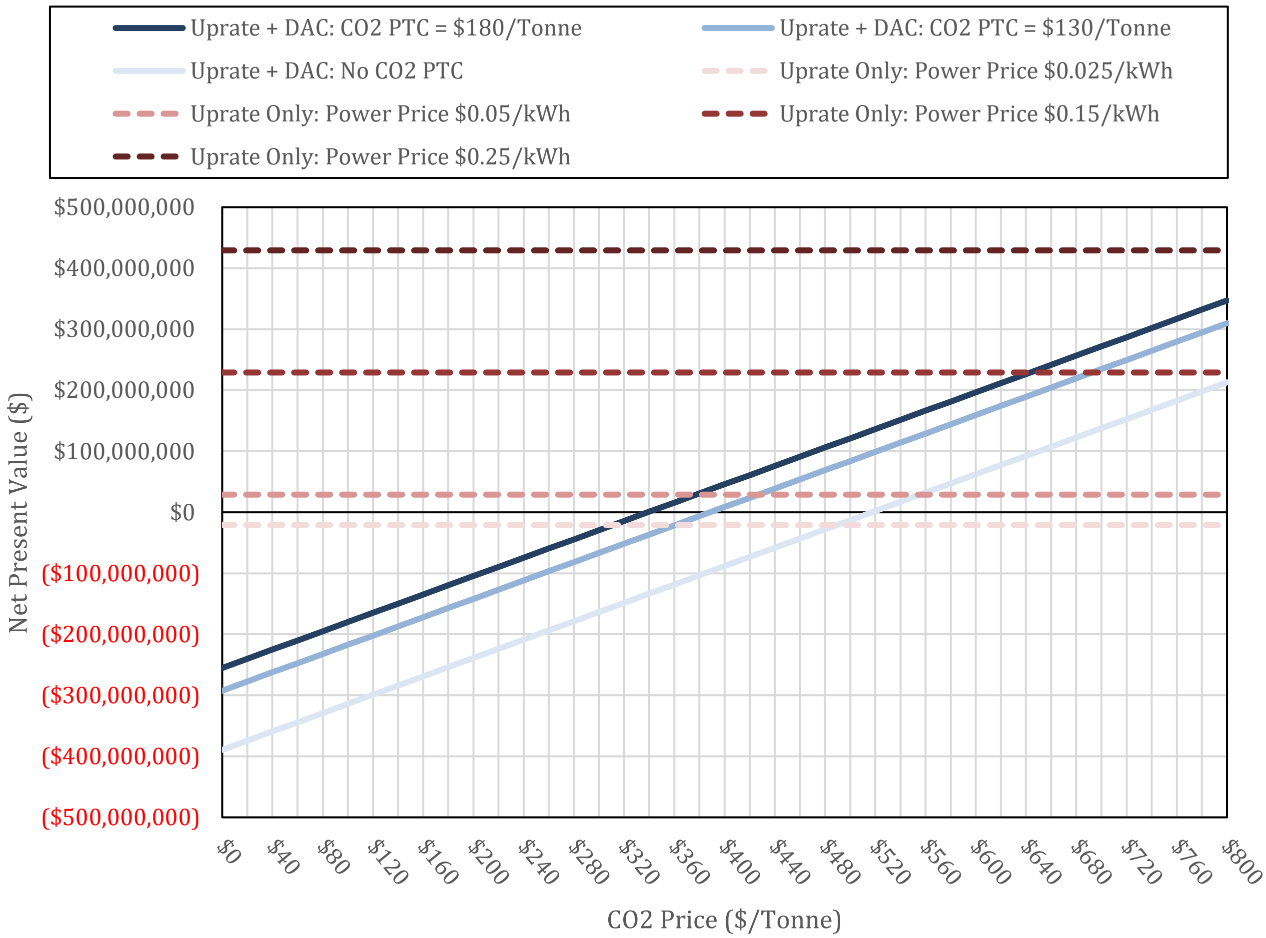

Figure 19. Comparison of profitability between uprate only and uprate + DAC integration.

Generally, utilities can expect uprate + DAC cogeneration to be a viable financial option if they have lower regional power prices, and higher CO_2 prices. Nevertheless, this decision should be made with caution as CO_2 demand in select regions may not be constant, and CO_2 prices may fluctuate more than energy prices. Utilities must seriously consider the characteristics of regional CO_2 markets from both a demand and price perspective to make informed decisions. Additionally, it should be noted that this analysis does not consider the price of transportation and storage. It is assumed that the carbon is consumed at plot edge (similar to what was assumed in the previous uprate report) and the impacts of transportation and storage costs are not represented in the model. If carbon is consumed farther away from the plant, it is possible that profitability could be eaten away by these additional costs. Future work in this area should consider the tradeoff between electing the clean power tax credits and carbon capture credits, to determine which yield a higher return when using power for DAC. This modeling provides a useful starting point for evaluating the economics of DAC cogeneration with uprates but is by no means all-encompassing and should be built upon in future work to better understand the financial implications of uprate + DAC cogitation.

8. SUMMARY

This report expanded upon the work done in the previous uprate report by further exploring regional market demand for hydrogen, oxygen, and carbon dioxide. The report found that, for some regions, an uprate with hydrogen cogeneration is unlikely to saturate regional demand, such as the Gulf Coast region, while in other regions very little demand exists at present to justify cogeneration, such as the Northeast region. Utilities considering uprates should pay close attention to regional demand and seek out partnerships with hydrogen consumers to hedge this risk. This could mean seeking out purchase agreements, similar to how SMR manufacturers operate, or by establishing relationships with consumers interested in decarbonizing processes that may already have solutions that use SMR-produced hydrogen.

Models from the previous uprate report were altered in these efforts to account for the potential revenues from oxygen sales. The results suggest that the added revenues will not create drastically different IRRs, but they may be financially advantageous in scenarios where hydrogen prices are low and additional revenues are needed to move a project's IRR small amounts. Oxygen, if it can be captured with relatively low additional costs, may be a useful addition for utilities. However, the regional demand analysis suggests that oxygen demand is far below the amount regions could produce if substantial amounts of uprates were to take place. In that sense, the decision to capture and sell oxygen should be made when there is high certainty of buyers as the market may become oversaturated quickly. In these instances, utilities may be unable to find buyers, or be forced to sell and lower prices which could impact the profitability of the added systems even more.

The viability of uprating with DAC cogeneration was also explored. The technical requirements of DAC cogeneration were analyzed and basic financial modeling was developed to produce a first look at project profitability. From an engineering standpoint, the power available from NPP uprate can support a substantially sized DAC system. The NPP can meet both the thermal and electrical requirements of the S-DAC system. Financially, uprate with DAC cogeneration may not always be the best option. It is clear that geological storage and EOR markets will not be profitable enough to justify the investment, but it is possible that high-purity industrial applications and the offset market produce large enough revenues to justify pursuing these projects, and doing so in place of selling power to the grid. Ultimately, the deciding factor will be the price utilities can receive for their power on the grid and if this creates too large of an opportunity cost.

The findings herein continue to support the conclusion of the previous uprate report—that utilities considering an uprate have very real options to reach profitability. The IRA tax credits have made selling power to the grid very likely to be profitable, and utilities may even be able to divert additional power to produce hydrogen, oxygen, or capture carbon via DAC. Each of these cogeneration options has variables that impact profitability and an uprate using any form of cogeneration should be considered on a case-by-case basis. This work has produced the foundational research needed to determine that profitability is possible, and that these unique cogeneration applications are worth additional consideration.

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APPENDIX A

The energy requirements and cost of the DAC system used throughout this work is based on the 0B-EB case in report DOE/NETL-2021/2865 [27]. The 0B-EB model is a generic solid sorbent system that is powered by clean electricity and an electric boiler. In this work the 0B-EB case is modified to represent a solid sorbent system integrated with an NPP for both heat and electricity. The "EB" in 0B-EB stands for electric boiler. However, since the heat for the modified system is supplied by an NPP rather than an electric boiler, the modified case will be referred to as the 0B-NPP case. The energy requirements and cost assumptions for the 0B-NPP system are discussed in the following sections.

A. ENERGY REQUIREMENTS AND OPERATING ASSUMPTIONS

Electricity Requirements

DAC systems require electricity for powering fans, pumps, and other auxiliary equipment. The total electricity demand for the 0B-EB case is 50 MW_e, which includes 19.5 MW_e to power the electric boiler. For the 0B-NPP case the electric boiler is not required since the steam is provided by the NPP, therefore the electricity requirement is reduced. Other than the electric boiler, all other electricity requirements remain the same, and the electricity demand for the 0B-NPP case is therefore assumed to be 30.5 MW_e.

Heat Requirement

Although the heat source is different, the heat requirements for the 0B-NPP case are unchanged from the 0B-EB case. For the 0B-NPP case, the electric boiler is replaced with a heat exchanger that provides heat from the NPP, as shown in Figure 20. To avoid modifying the operating conditions of the DAC system, the flow conditions at the inlet and outlet of the heat exchanger for the 0B-NPP case are assumed to be the same as the flow conditions at the inlet and outlet of the electric boiler in the 0B-EB case.

To supply heat to the DAC system, steam is extracted from the NPP BOP. For simplicity, it is assumed that main steam is used to heat the DAC working fluid. This assumption simplifies the analysis because the impact that main steam extraction has on electricity generation is straightforward. However, an optimized system design would likely extract steam from an alternate location that would have less of an impact on electricity generation, such as the location between the high-pressure turbine and the reheater. An alternate location for steam extraction is investigated in APPENDIX C to determine the impact of this simplifying assumption. It was shown that the location of steam extraction has a negligible impact on the results of the economic analysis since the amount of steam extracted to heat the DAC working fluid is a very small fraction of the overall flow.

The amount of steam extracted can be determined based on the extracted steam conditions and the amount of heat needed to the process heat exchanger in order to meet the DAC system requirements. Table 10 shows the steam conditions and flow rates on both sides of the process heat exchanger. The stream numbers correspond with the labels in Figure 20.

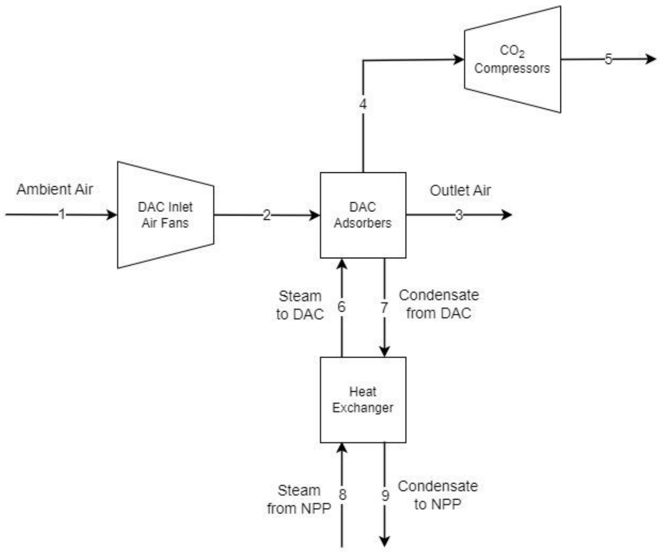

Figure 20. Representation of the 0B-NPP model where NPP heat is supplied to the S-DAC system via a heat exchanger.

Table 10. Steam flow conditions in the process heat exchanger for providing NPP heat to the S-DAC system.

	Temp (°C)	**Pressure (bar)**	**Enthalpy (kJ/kg)**	**Flow Rate (kg/s)**	**Note**
Stream 8: Extracted Steam	276	60.8	2779	8.90	Temperature and pressure of main steam; flow rate selected to meet DAC heat demand
Stream 9: NPP Condensate	231	60.8	995	8.90	Condensate return temperature is equal to final feedwater temperature. Assume to pressure drop.
Stream 6: Steam to DAC	153	5.1	2750	7.32	Matches 0B-EB Case
Stream 7: DAC Condensate	138	4.9	581	7.32	Matches 0B-EB Case

Uprate Size

Once the electricity demand and the amount of steam extraction required to meet the DAC thermal demand is determined, the uprate size required to meet these energy demands can be determined. Uprate size is determined such that all thermal and electrical energy for the DAC system is provided by uprate power. In other words, the amount of electricity available to sell to the grid before and after uprate should remain unchanged. The amount of thermal power removed from the NPP due to steam extraction can be calculated using the following equation:

$Q = m_{ext} (h_{ext}-h_{feed})$

Where:

- Q represents the amount of thermal power removed from the NPP and provided to the DAC system
- m_{ext} represents extracted steam mass flow rate
- h_{ext} represents the enthalpy of the extracted steam

- h_{feed} represents the enthalpy of the flow returned from the process heat exchanger, which returns at final feedwater conditions

This calculation shows that 16 MW_{th} is required to operate the DAC system. An additional 30.5 MW_e is required for operating the DAC system, which (assuming a 33% thermal efficiency) requires an additional 92.4 MW_{th} to produce. Therefore, the total uprate size required to supply energy to the DAC system is 108 MW_{th}.

Capacity Factor

The 0B-EB case used a capacity factor of 85%, which results in 100,000 tonnes of CO_2 captured per year. For the 0B-NPP case, the capacity factor is increased to 93%, which is a typical capacity factor for an NPP. This increase in capacity factor increases the amount of CO_2 that can be captured by the DAC system to 109,412 tonnes annually.

B. DIRECT AIR CAPTURE SYSTEM COST ASSUMPTIONS

Report DOE/NETL-2021/2865 provides detailed descriptions of the costs of building and operating the S-DAC system [27]. These costs are discussed here as well as any modifications made for the 0B-NPP model. One significant change that impacts all of these reported costs is the change in the capacity factor, which increases the system's annual capture rate. Each of the system costs are presented as the cost per tonne of CO_2 captured annually; therefore, the increased capacity factor for the 0B-NPP model will impact all of these reported costs.

Direct Cost

The direct cost includes the sorbent handling system, the sorbent preparation and feed system, the feedwater and miscellaneous BOP systems, the cooling water system, the spent sorbent handling system, the accessory electric plant, instrumentation and control, improvements to the site, buildings and structures, and the direct air capture system. For the 0B-EB case the direct cost was $1,406/tonne. For the 0B-NPP case the direct cost is modified to remove the cost of the electric boiler and the accessory electric plant, leading to a direct cost of $1,255/tonne.

Owner's Cost

The owner's cost includes pre-production costs, inventory capital, and other miscellaneous costs. Other than the impact of the change in capacity factor, these costs remain unchanged between the 0B-EB and 0B-NPP models.

Fixed O&M

The fixed O&M includes the cost of operating labor, maintenance labor, administrative and support labor, and the property taxes and insurance. Other than the impact of the change in capacity factor, these costs are unchanged between the 0B-EB and 0B-NPP models.

Variable O&M

The variable O&M costs include maintenance materials, sorbent waste disposal, and consumables including water, makeup water and waste water treatment chemicals, auxiliary power, and the DAC sorbent. For the 0B-EB case it was assumed that electricity is being purchased at a wholesale price of $0.06/kWh. For the 0B-NPP case, the cost of electricity does not need to be included since the cost of an NPP uprate and operation is included.

APPENDIX B

The general equation used to calculate cashflow for the Uprate + DAC model used in 1 is as follows.

Cashflow equation used to calculate Uprate + DAC cashflow from Equation 81.

$$Cashflow_t = Revenue_t - AdditionalFuelCostsFromUprate_t - DACVariableO\&M_t - DACFixedO\&M_t - InterestExpense_t - Federal\&StateTaxes_t + TaxCredits_t - DebtPrinciplePayment_t \tag{2}$$

The general equation used to calculate cashflow for the Uprate only model used in 1 is as follows. Cashflow equation used to calculate Uprate Only cashflow from Equation 9.

$$Cashflow_t = Revenue_t - AdditionalFuelCostsFromUprate_t - InterestExpense_t - Federal\&StateTaxes_t + TaxCredits_t - DebtPrinciplePayment_t \tag{9}$$

Direct air capture model assumptions are shown in Table 11.

Table 11. Direct air capture financial modeling assumptions.

Input	Unit	Value	Notes
Remaining Nuclear Plant Life (Assuming the DAC system as the same lifetime or longer)	Years	30	
Weighted Average Cost of Capital	%	10%	
Capital Portion Financed with Debt	%	50%	
Capital Portion Financed with Equity	%	50%	
Cost of Debt	%	8%	
Debt Term	Years	20	
Power Price	\$/kWh	\$0.05, \$0.10, \$0.25	Varied to show sensitivity to power price.
Nuclear Plant Capacity Factor	%	93%	
Added Fuel Cost from Uprate	\$/MWh	\$5.50	Identical to what was assumed in [4].
Carbon PTC Amount	\$/tonne	\$0, \$130, \$180	Dependent upon application. See Table 9 for more info.
Carbon PTC Lifetime	Years	12	Maximum PTC lifetime as discussed in Section 2.2.5.
Uprate ITC Amount	%	50%	Maximum ITC amount available as discussed in Section 2.2.3.
Uprate Capital Costs	\$/kWe	\$5,000	Identical to what was assumed in [4].

Input	Unit	Value	Notes
Construction Period	Years	4	
Uprate Size	kWe	35,693	
Integration Costs	% Uprate Capital Costs	1%	Identical to what was assumed in [4]

APPENDIX C

The main goal of the DAC analysis was to conduct a preliminary economic analysis to evaluate the potential profitability of retrofitting an S-DAC system to an existing PWR that has undergone power uprate. Hence, this analysis focused on economic modeling and market analysis rather than process modeling or system optimization. Several assumptions were made throughout, including the assumption that the DAC working fluid is heated by steam extracted from the NPP before it passes through the high-pressure turbine (i.e., main steam). This assumption simplified the analysis because the relationship between the amount of main steam extracted and the amount of electricity produced is straightforward. However, extracting main steam will result in a larger decrease in electricity generation than steam extraction from other locations. Here, further analysis is conducted to investigate if this simplifying assumption had a large impact on the results of the analysis.

Steam extracted from the NPP is used to heat up the DAC working fluid (steam) via a process heat exchanger to a temperature of 153°C. The main steam temperature of a typical PWR is around 273°C [14], which is significantly higher than the steam temperature required for the DAC system. Therefore, it is likely that there is an alternative location for steam extraction that would have less of an impact on electricity generation. One possibility is to extract steam from the piping between the high-pressure turbine and the moisture separator reheaters, which is referred to as the cold reheat piping. A recent report, INL/RPT-23-71939, conducted an analysis on steam extraction from the cold reheat piping of a Westinghouse 4-loop plant, which can be used to inform the impact of steam extraction for the S-DAC system [14]. This analysis showed that steam extracted from the cold reheat piping of a Westinghouse 4-loop plant could be provided to a process heat exchanger at a temperature of 184°C (364°F), which is a sufficiently high temperature to heat the DAC working fluid to the required temperature of 153°C [14]. Figure 21 shows how steam extracted from the cold reheat piping can be used to heat the DAC working fluid.

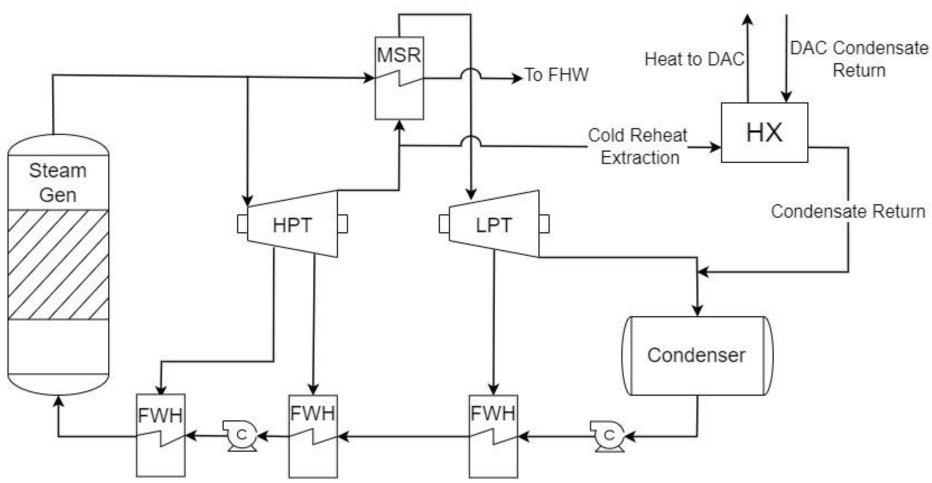

Figure 21. Representation of steam extraction from the cold reheat piping for supplying heat to an S-DAC system.

Whether main steam or steam from the cold reheat is used to provide heat to the DAC system, the amount of heat transferred to the DAC working fluid is the same. However, the amount of steam extraction required to provide this heat will differ since the temperature of the extracted steam is different. The amount of steam extraction is determined such that the appropriate amount of heat is transferred to the DAC working fluid. Table 12 shows the thermodynamic conditions of the streams entering and exiting the process heat exchanger. The inlet and outlet conditions on the DAC side of the heat exchanger are dictated by the heat requirements of the DAC system. The main steam and cold reheat steam thermodynamic conditions are based on the values provided in INL/RPT-23-71939 [14].

Table 12. Process heat exchanger conditions for main steam and cold reheat extraction.

	Temp (°C)	Pressure (bar)	Enthalpy (kJ/kg)	Flow Rate (kg/s)	Note
Main Steam					
Extracted Steam	276	60.8	2779	7.38	Temperature and pressure of cold reheat steam; flow rate selected to meet DAC heat demand
NPP Condensate	231	60.8	627	7.38	Condensate return temperature is equal to final feedwater temperature. Assume to pressure drop.
Cold Reheat					
Extracted Steam	184.5	11.1	2555	8.22	Temperature and pressure of cold reheat steam. Flow rate selected to meet DAC heat demand
NPP Condensate	148	11.1	624	8.22	Assume no pressure drop and minimum approach temperature of 10°C
DAC System					
Steam to DAC	153	5.1	2750	7.32	Matches 0B-EB Case
DAC Condensate	138	4.9	581	7.32	Matches 0B-EB Case

To compare the impact of main steam extraction and cold reheat extraction, the uprate size required to power the DAC system is calculated. In both cases the amount of additional uprate power required to operate the DAC system is determined such that all thermal and electrical energy for the DAC system is provided by uprate power. In other words, the amount of electricity available to sell to the grid before and after an uprate should remain unchanged.

In order to quantify the relationship between cold reheat steam extraction and electricity generation, the results of INL/RPT-23-71939 will be leveraged [14]. This work conducted detailed thermal extraction modeling for two different extraction mass flow rates; the results of this analysis are used here to quantify the relationship between steam extraction from the cold reheat piping for S-DAC and the resulting decrease in electricity generation. These results are shown in Figure 22. The amount of steam extracted and the decrease in electricity generation are presented as fractional amounts so that this relationship will hold true as the reactor thermal power is changed.

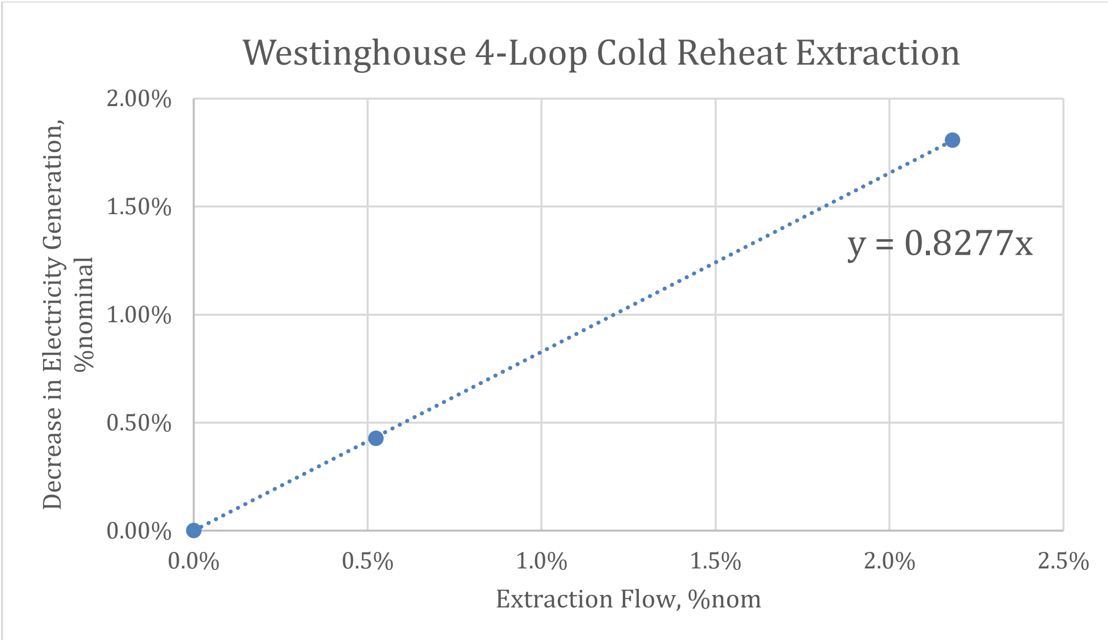

Figure 22. Relationship between cold reheat extraction and the resulting decrease in electricity generation.

Using this relationship, the amount of additional reactor thermal power required to supply energy to the DAC system can be determined. The results are presented in Table 13. The baseline reactor (no uprate) is based on INL/RPT-23-71939 [14].

Table 13. Thermal and electricity requirements for uprate only and uprate plus DAC scenarios

Baseline NPP	
Reactor Thermal Power	3659 MW_{th}
Main Steam Flow Rate	2051.6 kg/s
Electricity Generation / Available to Sell to Grid	1239.6 MW_e
Uprated NPP – No Extraction	
Percent Increase in Reactor Thermal Power	1.028%
Uprated Reactor Thermal Power	3761 MW_{th}
Thermal Power Added	102 MW_{th}
Main Steam Flow Rate	2109 kg/s
Electricity Generation	1274 MW_e
Additional Electricity Generation	34.6 MW_e
Uprate and Integration with DAC	
Decrease in Electricity Generation due to Extraction	4.11 MW_e
Electricity Supplied to DAC System	30.45 MW_e
Electricity reduction due to DAC	34.6 MW_e
Electricity Available to Sell to Grid	1239.6 MW_e

Assuming a baseline reactor thermal power (no uprate) of 3659 MW_{th}, an additional 102 MW_{th} is required to supply heat and electricity to the DAC system without reducing the amount of power available to sell to the grid. Alternatively, when main steam was used to provide heat to the DAC system, an additional 108 MW_{th} was required. Therefore, the supplying heat to the DAC system with main steam rather than cold reheat extraction requires an additional 6 MW_{th} of uprate power, which (assuming a thermal efficiency of 33%), can be restated as 1.1 MW_e. The economic modeling assumed that the cost of uprating is $5,000/kWe, therefore, the additional 1.1 MW_e of uprate power required when using main steam increases the cost of uprating by $5.6 million. However, the total capital cost of the system is approximately $408 million, meaning that by using main steam extraction rather than cold reheat extraction, the capital cost of the system is increased 1.4%. While this analysis shows that optimizing the steam extraction location will have an impact on the cost of the system, it is determined that this change is relatively small and will not have a significant impact on the overall results of the economic analysis.

APPENDIX D

Table 14. Demand for oxygen and hydrogen by U.S. state [18], [25].

State	Hydrogen Demand MMT/year	Oxygen Demand MMT/year
Arkansas	0.1915	0.06
Oklahoma	0.24	0.04
Texas	6.07	1.11
Louisiana	0.23	0.3
Mississippi	0.04	0.2
Alabama	0.04	0.034
Illinois	0.34	0.4
Indiana	0.14	2.1
Ohio	0.2	0.3
Michigan	0.2	0.4
Wisconsin	0.03	0.2
Minnesota	0.04	0.3
Iowa	0.15	0.2
Missouri	0.14	0.21
Kansas	0.2	0.14
Nebraska	0.03	0.1
North Dakota	0.02	0.054
South Dakota	0.01	0.05
California	2.016	0.742
New York	0.1285	0.37
Pennsylvania	0.042	0.1
New Jersey	0.02	0.1
Massachusetts	0.01	0.09
Connecticut	0.02	0.06
Rhode Island	0.0104	0.05
New Hampshire	0.02	0.043
Vermont	0.02	0.036
Maine	0.0204	0.05
Maryland	0.0204	0.1
Delaware	0.048	0.1
Arizona	0.060	0.22
New Mexico	0.0405	0.21
Colorado	0.1986	0.24
Wyoming	0.04	0.24
Montana	0.05	0.12
Idaho	0.044	0.1
Utah	0.04	0.2
Nevada	0.04	0.005

State	Hydrogen Demand MMT/year	Oxygen Demand MMT/year
Washington	0.22	0.54
Oregon	0.045	0.2
Florida	0.045	0.42
Georgia	0.04	0.3
South Carolina	0.01	0.3
North Carolina	0.01	0.3
Virginia	0.01	0.25
West Virginia	0.005	0.1
Kentucky	0.03	0.1
Tennessee	0.015	0.1