THE ECONOMICS OF CARBON CAPTURE AND SEQUESTRATION

THE NATIONAL REGULATORY RESEARCH INSTITUTE

February 1, 2022

DOE/NETL-2021/3215

Disclaimer

Acknowledgements

This work was funded under DOE Contract DE-FE0025912.

Authors

The report was researched and written by NRRI Staff: Dr. Carl Pechman (Director), Kathryn Kline, Dr. Sherry Lichtenberg, Jeffrey Loiter, Dr. Bernie Neenan, Elliott Nethercutt, and Thomas Stanton.

TABLE OF CONTENTS

LIST OF EXHIBITS

ACRONYMS AND ABBREVIATIONS

ACCESS	Accelerating Carbon Capture and Extending Secure Storage
AFUDC	Allowance of Funds Used During Construction
AGC	Automatic generation control
ASU	Air separation unit
BC	British Columbia
Bcf/d	Billion cubic feet per day
C&T	Cap-and-trade
CAISO	California ISO
CATCH	Carbon Oxide Sequestration Credit
CCS	Carbon capture and storage
CDM	Clean Development Mechanism
CDR	Carbon dioxide removal
CEPS	Clean energy portfolio standards
CF	Capacity factor
CFB	Circulating fluidized-bed
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
CONE	Cost of New Entry
CO-OP	Rural Electric Cooperative
COP	Conference of Parties
COx	Carbon oxides
CT	Combustion Turbine
CWIP	Construction Work in Progress
DER	Distributed energy resource
DOE	Department of Energy
EGR	Enhanced (natural) gas recovery
ELCC	Electric Load Carrying Capacity
ELL	Entergy Louisiana
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERS	Essential reliability services
EU	European Union
EWG	Electric wholesale generator
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse gas
GW	Gigawatt
H_2	Hydrogen
HCL	Hydrochloric acid
HP	High pressure
hrs	Hour
HRSG	Heat recovery steam generator
ICAP	Installed capacity
IEA	International Energy Agency
IGCC	integrated gasification combined cycle
IOU	Investor-owned utility
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
ISO	Independent system operator
ISO-NE	ISO-New England
ITC	Investment Tax Credit
KO	Knockout
Kt	Kiloton
kV	Kilovolt
kW, kWe	Kilowatt electric
kWh	Kilowatt-hour
LCOE	Levelized cost of electricity
LMP	Location Marginal Price
LPO	Loan Programs Office
LSE	Load-serving entity
LTHR	Low-Temperature Heat Rate
MBbl/d	Million barrels per day
MISO	Midcontinent ISO
MM	Million
Mt, MT	Metric ton
MMT	Million metric tons
muni	Municipal utility company
MW	Megawatt
MWh	Megawatt-hour
N/A	Not applicable/available

N_2	Nitrogen
NaOH	Sodium hydroxide
NDC	Nationally Determined Contributions
NERC	North American Electric Reliability Corporation
NETL	National Energy Technology Laboratory
NG	Natural gas
NGCC	Natural gas combined cycle
NOx	Nitrogen oxides
NRRI	National Regulatory Research Institute
NYISO	New York ISO
O_2	Oxygen
PJM	PJM Interconnection
PPA	Purchase power agreements
PTC	Production tax credit
PUC	Public utility commission
PURPA	Public Utilities Policy Act of 1978
PV	Photovoltaics
R&D	Research and development
REC	Renewable energy certificate
RGGI	Regional Green House Gas Initiative
RPS	Renewable portfolio standards
RTO	Regional transmission organization
SCALE	Storing CO_2 and Lowering Emissions
SDM	Sustainable Development Mechanism
SDG	Sustainable Development Goals
SPP	Southwest Power Pool
SWS	Sour water stripper
t	Ton
T&S	Transport and storage
TSVCR	Taskforce on Scaling Voluntary Carbon Markets
U.S., USA	United States
UNFCCC	United Nations Framework Convention on Climate Change
USD	U.S. dollar
USEA	United States Energy Association
V	Volt
VoLL	Value of lost load
yr, YR	Year
ZLD	Zero-liquid discharge
°C	Degrees Celsius

1 INTRODUCTION

1.1 PURPOSE OF THIS REPORT

Preventing the release of carbon dioxide (CO_2) from the combustion of fossil fuels is likely to be an important component of decarbonizing all sectors of the economy. The purpose of this report is to explain the economic and regulatory treatment of carbon capture and storage (CCS), or carbon capture, utilization, and storage, as applied to the generation of electricity.[1] For ease of reading, "CCS" is used throughout this document, although utilization is included as one of the many economic factors in CCS investment. This report examines a wide range of strategies, markets, policies, and regulatory constructs that affect the economics of CCS plants and carbon storage.

CCS can play a unique role in the path to decarbonization by

- Improving the resilience of a network with high renewable penetration
- Supporting the beneficial use of carbon
- Providing services that enhance the reliability of the electric grid

Each of these aspects of CCS has complex economic and regulatory dimensions. This report explains how these aspects of CCS work together to determine the economic cost and benefits of CCS and, therefore, the value of CCS to decarbonization.

1.2 THE IMPETUS TO DECARBONIZE

The Paris Agreement is the current international treaty governing climate change. It was adopted by 196 countries in December 2015[2] and became effective in November 2016, after ratification by 189 countries.[3] The objectives of the agreement include:

> …strengthen[ing] the global response to the threat of climate change, in the context of sustainable development and efforts to eradicate poverty, including by: (a) Holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels…; (b) Increasing the ability to adapt to the adverse impacts of climate change and foster climate resilience and low greenhouse gas emissions development…; and (c) Making finance flows consistent with a pathway towards low greenhouse gas emissions and climate-resilient development.[4]

[1] These terms may also be applied to industrial processes that release large amounts of carbon, the largest being the production of cement, steel, ammonia, and ethylene. See for example Pee, Pinner et. al. "Decarbonization of industrial sectors: the next frontier," *McKinsey & Company (June* 2018). CCS for industrial sources of carbon emissions is beyond the scope of this report.

[2] *The Paris Agreement* [Web page], *United Nations Framework Convention on Climate Change* (2016) [retrieved June 2021] https://unfccc.int/process-and-meetings/the-paris-agreement/the-paris-agreement.

[3] "*Paris climate agreement to enter into force on 4 November," United Nations Sustainable Development Goals*, (October 15, 2016) [Web page, retrieved June 2021], https://www.un.org/sustainabledevelopment/blog/2016/10/paris-climate-agreement-to-enter-into-force-on-4-november/.

[4] Op cit., note 1.

The economic costs associated with global decarbonization are significant. Morgan Stanley estimates that getting to net zero by 2050 will cost $50 trillion. It further estimates that "the potential of CCS under the Paris Agreement would require capital investment of approximately $2.5 trillion by 2050."[5]

The United States commitment to reducing greenhouse gas (GHG) emissions under the Paris Agreement will require transformation across all sectors of the economy.[6] In the United States (U.S.), electricity generation is responsible for 25 percent of GHG emissions.[7] No single technology or reduction strategy will be sufficient to reduce emissions by the amounts necessary to meet overall targets; even with the continued shift to non-emitting renewable sources, fossil-fuel based generation is likely to continue. Analyses of decarbonization pathways reach differing conclusions on its trajectory over the next few decades, but modelers generally agree that preventing the release of CO_2 from the combustion of fossil fuels for power generation will be an important component of U.S. climate strategy.

The United States initially joined the Paris Agreement in September 2016, opted out of the agreement in 2019, and rejoined under the Biden Administration in 2021.[8] This on-again, off-again U.S. approach to decarbonization has limited the development of a comprehensive carbon policy. The result has been a decarbonization strategy that is currently being implemented in a largely ad hoc manner and is not based upon a national plan that lays out the optimal mix of decarbonization options. As a consequence, the factors that will determine the value of CCS are driven nationally (both in compliance with international agreements and to meet current federal policy), regionally, statewide, and locally. Many policy mechanisms and market factors will determine the value of CCS. Policy mechanisms include direct subsidies, such as the 45Q tax incentive program, carbon pricing and taxes, and the regulatory treatment of CCS. Market factors that will determine the financial feasibility of CCS include capital and operating costs (including fuel) and revenues from the sale of electricity and carbon capture In order to meet carbon targets, many existing conventional fossil units will be retired, thereby increasing the value of CCS as a baseload resource. A recently published report by the Council on Environmental Quality demonstrates the current administration's commitment to CCS:

> To reach the President's ambitious domestic climate goal of net-zero emissions economy-wide by 2050, the United States will likely have to capture, transport, and permanently [store] significant quantities of carbon dioxide (CO_2). In addition, there is growing scientific consensus that carbon capture, utilization, and sequestration (CCUS) and carbon dioxide removal (CDR) will likely play an important role in decarbonization efforts globally; action in the United States can drive down technology costs, accelerating CCS deployment around the world.[9]

---

[5] "Decarbonization: The Race to Zero Emissions," Morgan Stanley, (November 25, 2019). Retrieved from: https://www.morganstanley.com/ideas/investing-in-decarbonization/

[6] United Nations Framework Convention on Climate Change, "Paris Agreement"

[7] Percentage based on CO_2 equivalents, 2019 data from the "U.S. EPA Greenhouse Gas Inventory Data Explorer," *Environmental Protection Agency,* accessed 6 May 2021, https://cfpub.epa.gov/ghgdata/inventoryexplorer/

[8] Somanader, Tonya, "President Obama: The United States Formally Enters the Paris Agreement," *The White House*, September 3, 2016, accessed June 2021, https://obamawhitehouse.archives.gov/blog/2016/09/03/president-Obama-United-states-formally-enters-Paris-agreement

[9] Larson, et. al., "Net-Zero America: Potential Pathways, Infrastructure, and Impacts, interim report," *Princeton University*, (December 15, 2020) https://netzeroamerica.princeton.edu/the-report and "Net Zero by 2050," International Energy Agency. (May 2021). https://www.iea.org/reports/net-zero-by-2050, quoted in *Council on Environmental Quality Report*

1.3 STRUCTURE OF THIS REPORT

This report is composed of four major sections. After the general introduction, Section 2 describes both the policy contexts in which CCS exists and the technical aspects of CCS as a decarbonization strategy. Section 3 presents an analysis of the many factors that affect the economics and competitiveness of CCS generating facilities in the U.S. electric system. Section 4 presents recommendations for policies and strategies that may improve the prospects for CCS, based on the findings in Section 3.

to Congress on Carbon Capture, Utilization, and Sequestration, delivered to the Committee on Environment and Public Works of the Senate and the Committee on Energy and Commerce, the Committee on Natural Resources, and the Committee on Transportation and Infrastructure of the House of Representatives, as directed in Section 102 of Division S of the Consolidated Appropriations Act, 2021.

2 CCS POLICY AND TECHNOLOGY

2.1 THE POLICY CONTEXT

2.1.1 The Governance of Carbon Reductions

The governance of carbon reductions represents a complex and fluid interaction among various levels of jurisdiction, from local governments to the international community. This governance falls into a number of broad categories, including goal setting, financial subsidies, regulation of market prices, planning, and cost recovery of CCS investments. Exhibit 2-1 provides an overview of the different governance levels and the authority exercised at each of those levels. A key theme of this report is identifying and assessing the importance of the levers at the federal, state, and regional levels of governance that affect the economic viability of CCS.

Exhibit 2-1. Governance of carbon reductions

The development of effective carbon goals demonstrates the inter-connectedness of the various levels of governance. At the highest level, international agreements have established the basis for national goals. The United States filed its first Nationally Determined Contributions (NDC) report in March 2016, proposing to achieve an economy-wide target for reducing its GHG emissions by 26–28 percent below its 2005 level by 2025 and making its best efforts to reduce its emissions by 28 percent.[10] The NDC proposed several regulatory actions, the most relevant of which for the purposes of this report was an effort to finalize regulations to reduce carbon pollution from new and existing power plants. An updated NDC, announced in April 2021, proposed an economy-wide target of reducing net GHG emissions by 50–52 percent below 2005

[10] "United States of America First NDC," *United Nations Framework Convention on Climate Change*, February 9, 2016, https://www4.unfccc.int/sites/ndcstaging/Pages/Party.aspx?party=USA&prototype=1

levels by 2030.[11] It includes a goal of 100 percent carbon pollution-free electricity by 2035. Among the strategies used to achieve this goal will be leveraging "the carbon pollution-free energy potential of power plants retrofitted with carbon capture."[12]

Other entities have taken individual actions to reduce carbon emissions. As discussed in Section 3.5.3, at least 30 states have implemented renewable portfolio standards (RPS), clean energy portfolio standards (CEPS), or other requirements for low- or zero-emissions resources to be used in energy production.[13] Cities and local municipalities have taken steps to decarbonize, for example, Berkeley, California has banned the installation of natural gas in new buildings.[14] The scope of local decarbonization efforts is limited by a municipality's authority to implement broad ranging carbon policies. In the case of Berkeley, it is able to ban new gas installations in the city but is not able to create statewide policy with respect to the use of natural gas. Decarbonization efforts even extend to individual corporations that have made commitments to reduce their climate footprints. Nearly 35 percent of European and U.S. Fortune Global 500 companies have made a public commitment that they are, or will be, carbon neutral by 2030 by using 100 percent renewable power or meeting another science-based target.[15]

Planning will take on an increasingly important role in meeting not just the NDC goal, or any other federal goal, but in rethinking and retooling the entire electric system to reduce carbon emissions. Planning will be the cornerstone of decarbonizing in a coordinated and successful manner. Moreover, given the changing nature of emission abatement technology, the nature of planning itself will also need to evolve to meet these goals. States will play an important role in the planning process by either developing a state energy plan for the decarbonized electric system, such as California's "Integrated Energy Policies Report,"[16] or exercising public utility commission (PUC) oversight of the development of utility Integrated Resource Plans (IRPs). IRPs provide analyses of alternative mixes of resource options designed to meet customer load. Constraints and reduction goals can be explicitly incorporated into IRPs to develop least-cost solutions to achieve carbon reduction goals. It is likely that new products will evolve to support the investment required to implement IRPs.

The elements of carbon governance that affect the economics of CCS will be discussed in depth throughout this report.

---

[11] "The United States of American Nationally Determined Contribution," *United Nations Framework Convention on Climate Change, April 22, 20221,* 1. https://www4.unfccc.int/sites/ndcstaging/PublishedDocuments/United%20States%20of%20America%20First/United%20States%20NDC%20April%2021%202021%20Final.pdf

[12] UNFCCC, NDC, 2021, 3.

[13] "NRRI Clean Energy Policy Tracker," [Web page], *National Regulatory Research* Institute, accessed March 2021, https://www.naruc.org/nrri/nrri-activities/clean-energy-tracker/. The NRRI Clean Energy Policy Tracker provides the current status of formally adopted state GHG targets, RPS, CEPS, and energy efficiency portfolio standards.

[14] PROHIBITION OF NATURAL GAS INFRASTRUCTURE IN NEW BUILDINGS, ORDINANCE NO. 7,672–N.S., City of Berkeley, California, July 16, 2019 2019-07-23 Item C Prohibiting Natural Gas Infrastructure.pdf (cityofberkeley.info)

[15] *Farmer, A, Mahoney, M. and Donna Ni* "Making and Keeping Corporate Climate Commitments: Part 1," *Kirkland* & Ellis, August 11, 2020. https://www.kirkland.com/publications/article/2020/08/making-keeping-corporate-climate-commitments_pt-1

[16] "Final 2019 Integrated Energy Policy Report," *California Energy Commission,* 2019. https://efiling.energy.ca.gov/getdocument.aspx?tn=232922

2.1.2 Factors of Success for CCS

Identifying the factors that contribute to the success or failure of CCS projects will be valuable for designing and implementing policies aimed at improving the economics and competitiveness of CCS. A recent study by Abdulla and others examined over 50 U.S. proposed or already constructed CCS projects across four categories and identified 12 attributes that might affect success and could be quantitatively evaluated. [17] These attributes are shown in Exhibit 2-2.

Exhibit 2-2. CCS project attributes

Category	Project attribute	Hypothesis statement
Engineering economics	Plant siting	Locating on brownfield sites entails less site preparation, less extensive development of new infrastructure, and reduces regulatory burden.
	Capture technology readiness level	Deploying technologies already demonstrated at scale reduces technical, system integration, and project execution risks.
	Capital cost	Cheaper projects are easier to finance and overall carry less risk.
Financial credibility	Employment impact	Projects that improve local or regional economies through employment are more likely to form coalitions in their favor.
	Credibility of revenues	Projects that can demonstrate credible revenue streams or reduce their uncertainty are more likely to succeed.
	Credibility of incentives	Projects that secure a greater share of their cost are more likely to succeed. Incentives that are unconditional and upfront are more credible.
Local political features	Population proximity	Projects in sparsely populated locales are more likely to succeed because they encroach on fewer people and organized interests.
	Institutional setting	Projects benefit from jurisdictions with a legacy of supporting fossil infrastructure and attendant institutional memory in applying policy and regulatory frameworks.
	Burden of CO_2 disposal	Projects requiring less onerous arrangements for capture, storage, monitoring, and verification entail less risk.
Broader political features	Regulatory challenges	Projects that encounter neither legal difficulties nor regulatory delays are more likely to succeed.
	Public opposition	Projects that enjoy support from environmental or civil society groups are more likely to succeed.
	Industrial stakeholder opposition	Projects where concentrated industrial stakeholders align strategically with the developer are more likely to succeed.

Source: Abdulla et al., 2021

Assigning a quantitative and qualitative value to each attribute to reflect its importance reveals three key variables that are significant across all statistical models. These are:

- **Capital cost:** projects with larger capital costs are more likely to fail
- **Technology:** a high level of technological readiness improves the chance of project success

[17] Abdulla et al. "Explaining successful and failed investments in U.S. carbon capture and storage using empirical and expert assessments," Environmental Research Letters, 16, 2021 is licensed under CC BY 4.0

- **Credibility of project revenues:** more credible sources of revenue (for example, bilateral off-take[18] agreements for CO_2) strongly increase the odds of project success

A fourth variable, credibility of incentives, was found to be less statistically significant but was ranked as the most important element for determining the probability of success by experts. This suggests that a policy designed explicitly to address incentive credibility could have an important impact on project success.

2.1.3 Policy Interventions Supporting CCS

In addition to the econometric assessment of success factors, the Abdulla study reported on the results of an expert panel that graded 14 policy interventions in four categories based on their effectiveness in reducing CO_2 emissions and the likelihood that the policy would be enacted. The results are shown in Exhibit 2-3.[19]

Exhibit 2-3. Policy interventions in support of CCS

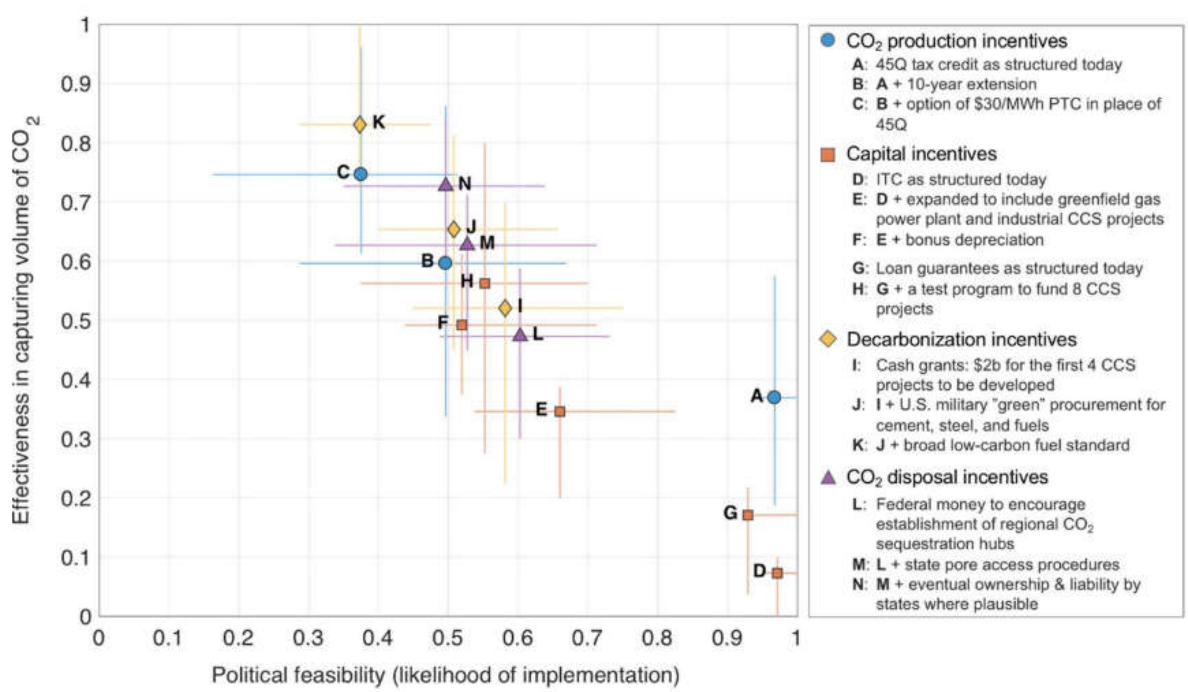


Figure 4. Expert judgments of the effectiveness and political feasibility of four clusters of policy instruments that could enhance the viability of CCS projects. Clusters comprise CO_2 production incentives, capital incentives, decarbonization incentives, and CO_2 disposal incentives. Scores for feasibility and effectiveness are normalized by the policy package each expert deemed most feasible and effective in enabling large-scale CCS deployment by 2030, which are both scored 1. These need not be the same package. ITC is the investment tax credit. Markers denote means and bars interquartile ranges.

Source: Abdulla et al., 2021

The interventions with the highest forecasted effectiveness were also perceived as the least politically feasible; interventions K, C, and N (a suite of decarbonization incentives including a

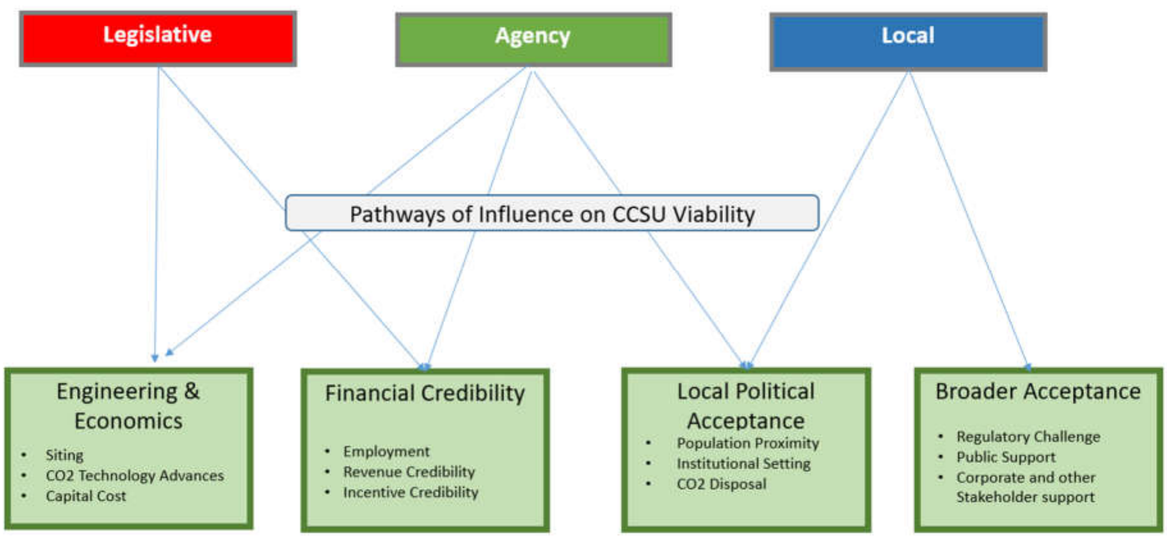
[18] An off-take agreement is a contract between a producer and a buyer to purchase goods that have not yet been produced.

[19] Abdulla et al., 2021

broad low-carbon fuel standard, CO_2 production incentives, and CO_2 disposal incentives including eventual state ownership) were rated as over 70 percent effective but were perceived to be only 50 percent likely to be adopted. Interventions A, G, and D (current 45Q tax incentives, loan guarantees, and current investment tax credits) were considered highly likely to be adopted but no more than 40 percent effective. Production tax incentives that are restricted to CCS (A through C) or that are tuned to reward investment in CCS or CO_2 capture facilities (D through H) are likely only to become effective (over 60 percent) when combined with disposal or decarbonization incentives (I through N) that are extremely generous to developers. In other words, experts believe that it is not direct support for the CCS industry that will lead to the largest volumes of CO_2 capture but policies that encourage systematic decarbonization, such as government procurement of decarbonized industrial products or a broad low-carbon fuel standard.

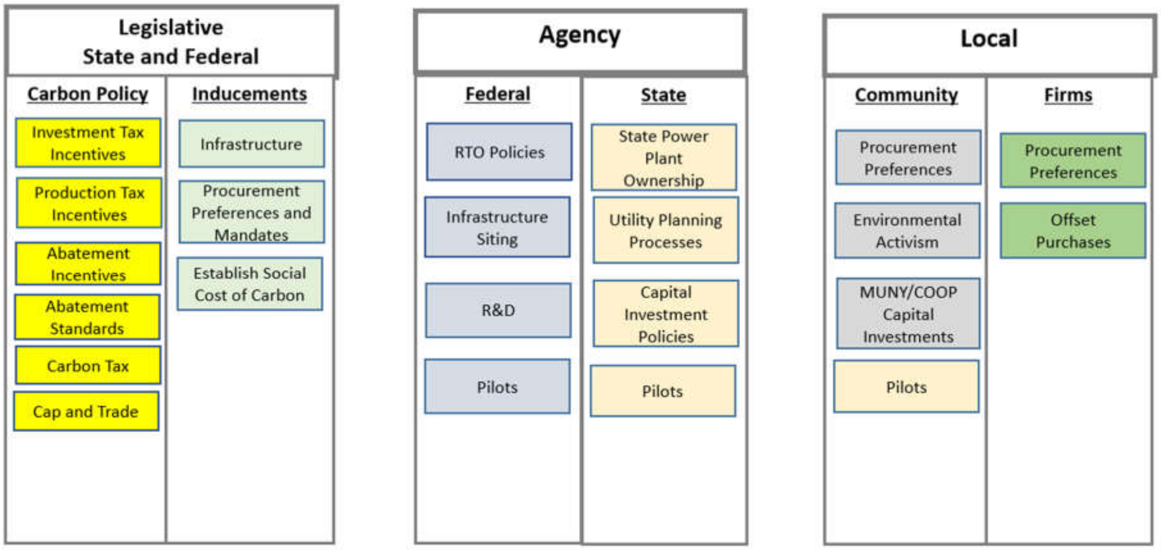
The governance of carbon reduction and carbon-related policies spans the political sphere, from international commitments to local building codes. Any effort to leverage the factors identified above (or any other strategy thought to promote CCS) must exist within this complex set of entities and their ability to influence the economics and operating environment for CCS. Exhibit 2-4 summarizes these influences.

Exhibit 2-4. Pathways of influence for CCS economics



Section 3 examines a variety of policies, strategies, and markets that may support CCS development. Exhibit 2-5 (below) groups these policies under major categories of influencers to demonstrate the challenge of creating a comprehensive, consistent, and holistic approach to promoting CCS.

Exhibit 2-5. CCS influencers



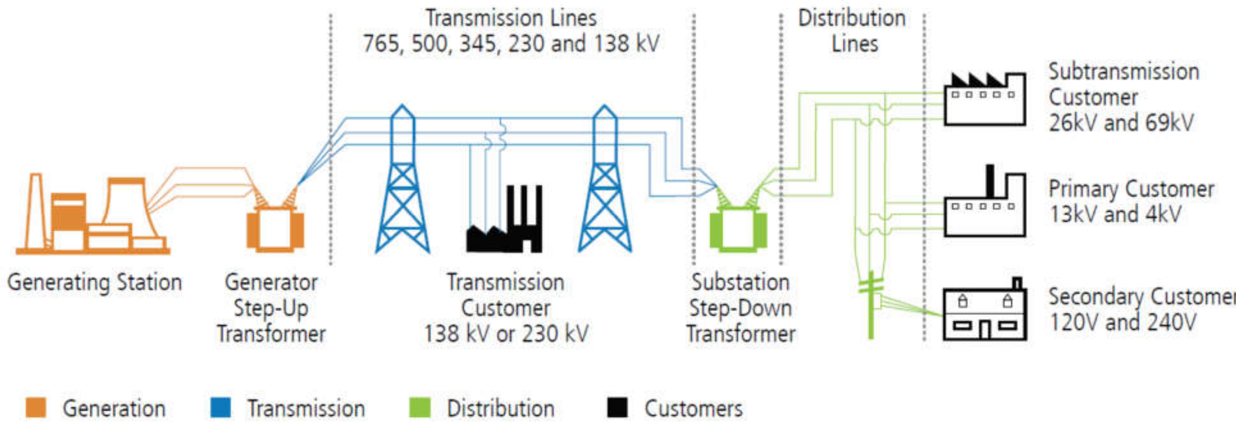
2.1.4 CCS Ownership Models

There are multiple ownership models for CCS, each with its own regulatory requirements across the national, regional, state, and local spectrum. These models will affect the way in which CCS plants are built and implemented.

A CCS plant is a sophisticated chemical plant added to a host facility (e.g., an electric generator or another type of industrial plant) that captures CO_2 and either stores it to remove it from the atmosphere or uses it for another purpose. Host industries include ethanol manufacturing and natural gas processing operations, as well as electric generators. These operations typically use (or sell) the captured CO_2 for enhanced oil recovery (EOR). This report focuses on the factors that affect the economics of CCS associated with electric generation that will encourage using CCS to reduce carbon. Much of the economics of this process depends on the ownership structure of the plant. There are a variety of forms of ownership, each requiring different decision processes and each governed by different entities that oversee those decisions. This section discusses these key ownership models.

To help understand these business models, it is important to recognize that the CCS plant can be viewed as a component of a generation facility in much the same way that a fluidized gas desulfurization facility or a cooling tower is. The economic structure of the CCS generator and plant will be determined by its commercial relations with the other segments of the electric grid. The segments of the electric grid most relevant to the economics of CCS are identified in Exhibit 2-6. Historically, this service has been provided by utilities at regulated rates. This regulation can be done at the municipal, state, or federal levels of governance, as well as through cooperative ownership.

Exhibit 2-6. Segments of the electric grid



Source: Department of Energy[20]

There are five primary ownership and business models for electric generation with CCS. These models differ by their ownership and by the relationship of the generation plant to other industry segments and to customers. These economic relationships, for example whether an asset is rate regulated or subject to market revenues, directly affect the nature of the revenues available to support the development of the projects.

The six ownership models are:

1. Investor-owned (utility)
2. Municipal/state (utility)
3. Rural cooperative (utility)
4. Self-generation (non-utility)
5. Merchant plant (non-utility)
6. State/federal (non-utility)

How a facility is regulated and interacts with the power grid is an important determinant of economic viability for CCS plants. Regulation affects the economics of a plant differently depending upon its ownership. The relationship between customers and generation facilities falls into two broad categories: 1) generation owned by vertically integrated utilities that span all segments of the industry (as shown in Exhibit 2-6), and 2) so-called "merchant" generation that is owned by entities that sell their power to distribution utilities for delivery to their end-user customers. The latter are referred to as load-serving entities (LSEs). Note that even vertically integrated utilities may purchase some power from merchant plants. The merchant-LSE relationship can take multiple forms. For example, power might be procured from merchant generators through the market, as bi-lateral transactions, or from federal power projects.

The electric business was built around vertically integrated utilities with retail monopoly franchises. Under this structure, a single entity provides service to customers by coordinating interactions across the three industry segments: generation, transmission, and distribution.

[20] United States Department of Energy. "Final Report on the August 14, 2003 Blackout in the United States and Canada" April 2004. http://www.energy.gov/sites/default/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf

Vertically integrated utilities can have a variety of ownership structures; the differences between them are relevant for the success of CCS.

Ownership type one, an investor-owned utility (IOU), is a public corporation funded by issuing debt and equity. The quality of the IOU's service (including resource adequacy and resilience) and the prices that it is allowed to charge its customers are regulated by state PUCs. As a consequence, the recovery of the costs required to build and operate a CCS plant would also be regulated by the state PUCs. In this structure, CCS plant investments must be justified to the regulator to be allowed recovery in rates. Currently, rates for recovering the capital cost of generation apply only to vertically integrated utilities. This may change if there is a clear societal need for credit worthy entities to develop CCS, expanding both the scope of restructured utilities and the development of rate mechanisms for competitive providers.

The second type of ownership arose during early days of electricity when municipalities had a fundamental choice--either to develop and operate their own electric system or to award a franchise to an IOU to develop and own the system. Many municipalities chose to develop their own systems. These were primarily vertically integrated systems usually referred to as municipals (munis). Going forward, munis could either develop their own CCS plants or enter into a contract to support the development of CCS. Typically, the approval and review of the behavior of the muni is overseen not by the state PUC but by a board that reports either to the city council, or, in some cases, directly to the local electorate.

The third type of ownership is the rural cooperative (co-op). Through the 1930s, electric infrastructure in rural areas was largely undeveloped, because of the high cost of developing distribution systems in areas with low customer density. Rural co-ops were developed as a result of the Rural Electrification Act of 1935 and are overseen by the U.S. Department of Agriculture's Rural Utilities Service.[21] There are two types of co-ops: 1) distribution and 2) generation and transmission. Co-ops have tax advantages that reduce the cost of building the power system and allow them to provide power at rates comparable to (or in some cases less than) those of surrounding IOUs. Today, there are 832 distribution co-ops and 63 generation and transmission co-ops.[22] Many operate coal plants that are candidates for CCS reconfiguration, a decision that may be made locally but will also be influenced by state and federal carbon policy.

Plants under ownership type four are generators located on a customer's premises that provide power to the customer's facility but may also inject power into the grid. These plants are not owned by utilities or governmental entities. At the beginning of the electric industry, these generators were called "isolated plants." They were usually large plants (several megawatts [MWs]) interconnected to the high-voltage segment of the local power grid. Many industrial facilities are powered by on-site generators.

[21] Initially, rural electrification was overseen by the Rural Electrification Administration created by executive order of President Roosevelt in 1935. The Rural Electrification Act of 1936 authorized the provision of federal loans for the installation of electric distribution systems to support rural electrification. The functions of the Rural Electrification Administration were absorbed by the Rural Utilities Service pursuant to the Department of Agriculture Reorganization Act of 1994.

[22] "Electric Co-op Facts and Figures," [webpage], National Rural Electric Cooperative Association. Accessed June 2021 https://www.electric.coop/electric-cooperative-fact-sheet

The fifth type of ownership is the merchant power plant. A merchant power plant is owned by a private corporation that sells power to the grid and uses the revenue to amortize the capital cost of its investment and generate a profit. Merchant power arose in large part due to limitations on the ability of industrial-owned facilities to participate in the growing power markets. Large industrial sites with waste heat wanted to use their facilities to provide power at a cost below that of power supplied from the grid but were prevented from doing so by restrictions on what they paid out for supplemental power and what they were paid for the power injected into the grid. These limitations began to erode with the implementation of the Public Utilities Policy Act of 1978 (PURPA), which required utilities to purchase generation from independent power producers and qualifying facilities[23] at their avoided costs. Avoided costs were defined as the cost that the utility would incur "but for" the purchase of power from the qualifying facility.

PURPA demonstrated that it was possible to operate a power system securely and safely with power provided by non-utility generators. However, there were significant implementation issues associated with PURPA. Given the complexity of developing the long-run cost scenarios required by PURPA, New York and California relied on open solicitations to procure power at a fixed price. In this pricing mechanism, if one power plant was economic, many were even more so. Unlike a typical market in which prices go down when supply increases, avoided cost pricing mechanisms did not respond to changes in supply, but were fixed on a multi-year cycle. The result was a significant financial burden on the utilities that led them to search for alternatives.

The alternative pursued was the restructuring of power systems by separating vertically integrated utilities into their three segments: generation, transmission, and distribution. In order to accomplish this, organized wholesale electric markets regulated by the Federal Energy Regulatory Commission (FERC) were developed. These markets combined two functions and were composed of independent system operators (ISOs) and regional transmission organizations (RTOs). The ISOs coordinate generation dispatch based upon price offers. RTOs oversee the operation of transmission. These organizations evolved into what are generally referred to as organized power markets.

During the transition to organized power markets in the 1990s, vertically integrated IOUs in some states were required to divest their generation assets, which then operated in FERC-regulated markets. Of the three segments of the once vertically integrated utility, only distribution remains squarely within the state's jurisdiction to determine the recovery of the physical cost of the distribution and delivery of power. In some cases, the regulated utility remains responsible for procuring power to fulfill either its obligation to serve or as a provider of last resort.[24] This change has resulted in the development of a class of investor-owned and state regulated distribution companies. The nature and regulation of those distribution utilities and of the vertically integrated utilities will determine whether the utility can enter into long-term agreements to procure CCS.

[23] A qualified facility is a generator that meets criteria specified by PURPA that allow it to receive special rate and regulatory treatment.

[24] The provider of last resort is the entity responsible for providing service to customers who have not chosen or do not have the credit quality to take service from LSE's. The obligation to serve, is an obligation to provide service to all customers.

The fifth category of generator, with its own unique form of federal regulation, Electric Wholesale Generators (EWGs), grew out of the restructuring effort described above.[25] EWGs have two different methods for generating revenues: selling power into organized wholesale markets or engaging in bi-lateral transactions (including long-term contracts) with LSEs. The critical difference between merchant generation, including EWGs, and generation owned by IOUs, munis, and co-ops is that the price they receive and use for capital cost recovery is a market price, not a tariff based upon costs.

Finally, a sixth type of ownership is state or federal. Some states, like New York, have developed their hydro-electric assets (e.g., Niagara Falls) for beneficial use in the state. The U.S. federal government owns a variety of types of generation. Typically, federally owned generation has been constructed for dual purposes. For example, the Hoover Dam was initially envisioned as a flood-control project. Other joint uses include providing power for military use (such as the Muscle Shoals Plant) and for economic development (such as the fertilizer plants built by the Tennessee Valley Authority).

There are a host of different types of cost recovery mechanisms, from direct federal aid to long-term contracts, based on plant ownership. This report focuses only on utility and merchant CCS ownership.

2.2 CCS Technology

2.2.1 Types of CCS

Understanding the economics and regulatory treatment of CCS requires a basic understanding of the physical and financial character of the technology. It is capital intensive and technically complex. There are dozens of technologies and processes that can be used for the major components of CCS, and potentially hundreds of ways of arranging these technologies into an integrated CCS facility. To illustrate the capital intensity and technological complexity of CCS, this report discusses the prototype facilities that are most commonly addressed in the literature about CCS in the power sector.

As the name suggests, CCS involves capturing CO_2 (emitted in the power generation process, for purposes of this report) and its subsequent use or storage in a manner that prevents its release to the atmosphere. For the analyses provided in this report, capture and use/storage are discussed separately.[26] In later sections, our analyses assume that the revenues from capturing power plant carbon emissions that would otherwise be released to the atmosphere (e.g., Regional Green House Gas Initiative [RGGI] credits) should provide the same payment on a \$/metric ton (Mt) basis regardless of how the CO_2 is captured and its ultimate “sink” (i.e., storage or beneficial use).

[25]PPUHCA imposed ownership restrictions on the electric utility industry which EPAC 92 withdrew?

[26] The captured CO_2 must also be transported from where it was captured (in this discussion, the power plant) to the location where it is ultimately stored or used. Later sections discuss the costs and other implications of transport.

2.2.1.1 Capture Technologies

Much of the literature on CCS classifies capture technologies into three broad categories: post-combustion, pre-combustion, and "oxy-fuel" combustion.[27] Each of these categories includes multiple variants related to the specific process by which CO_2 is separated from other compounds and isolated for further treatment and storage, either permanently or temporarily, prior to some beneficial use.

In post-combustion CCS, CO_2 is captured from the flue gases produced by combustion of fuels with air. Air is mostly nitrogen (N_2) and, therefore, the flue gas contains large amounts of N_2 and nitrous oxide (itself a potent GHG) in addition to CO_2 and water vapor. Because it is not feasible to capture and prevent the release of the entire volume of flue gas, the CO_2 must be separated from the combustion flue gas. This is most often accomplished by passing the flue gas through a material that can capture the CO_2. The material can be either a liquid solvent[28] or a solid sorbent[29] that is capable of trapping the CO_2. The remaining gases are released to the atmosphere. Liquid solvents are most often used for post-combustion capture, while physical sorbents are preferred for pre-combustion capture (as discussed below).[30] The CO_2-laden solvent is further treated with heat or pressure to release the CO_2 as a stream of nearly 100 percent CO_2 that is cooled and compressed for use or storage. The purged or "clean" solvent is then recycled and used to capture more CO_2 (see Exhibit 2-7). The energy required to separate the CO_2 from the solvent is the largest contributor to the energy penalty and added operating cost of CCS systems, although the equipment required for CO_2 capture also adds substantial capital cost.

The two CCS plants in the western hemisphere, the Petra Nova Carbon Capture Project in Texas and the Boundary Dam CCS Plant in Saskatchewan, Canada, use post-combustion sorbent capture technology. Emerging technologies for post-combustion capture include cryogenic separation, membrane separation, and pressure/vacuum swing adsorption. So far, these technologies have been used primarily in applications other than electricity generation (e.g., natural gas processing), and none have progressed beyond the demonstration phase of development.[31]

Exhibit 2-7 shows the process for CO_2 recovery from flue gas with chemical absorbents.

---

[27] See, for example IEA, 2020; Cuéllar-Franca and Azapagic, "Carbon capture, storage and utilization technologies," *Journal of CO2 Utilization*, (2015) 82-102; Koornneef, Henriks, et al, "Social costs and benefits of CCS research, development and deployment for the Dutch economy," *CATO 2 Protgram*, (2014); and Metz et al. "IPCC Special Report on Carbon Dioxide Capture and Storage," *Intergovernmental Panel on Climate Change*, 2005.

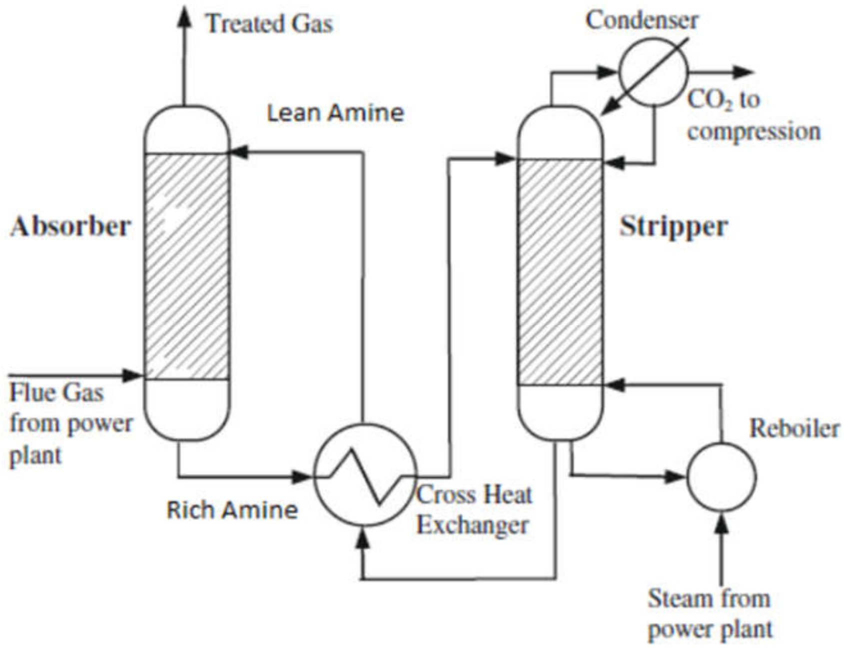
[28] Solvents are typically liquid substances capable of dissolving or dispersing one or more other substances. The most common solvent in use for CO_2 capture is aqueous monoethanolamine. Vega, Fernando, Mercedes Cano, Sara Camino, Luz M. Gallego-Fernandez, Esmeralda Portillo, and Benito Navarrete, "Solvents for Carbon Dioxide Capture," *Carbon Dioxide Chemistry, Capture and Oil Recovery*, 2018, https://www.intechopen.com/books/carbon-dioxide-chemistry-capture-and-oil-recovery.

[29] A sorbent is a material used to adsorb (by attracting molecules to its surface) or absorb (by dissolution or trapping in physical voids) liquids or gases. (https://archive.epa.gov/emergencies/content/learning/web/html/sorbents.html) Most sorbents for CCS are trademarked compounds such as Selexol™, Rectisol™, and Ifpexol™, among others. Vega et al, 2018.

[30] Vega et al, 2018.

[31] "Energy Technology Perspectives 2020". International Energy Agency, (2020): 98-100.

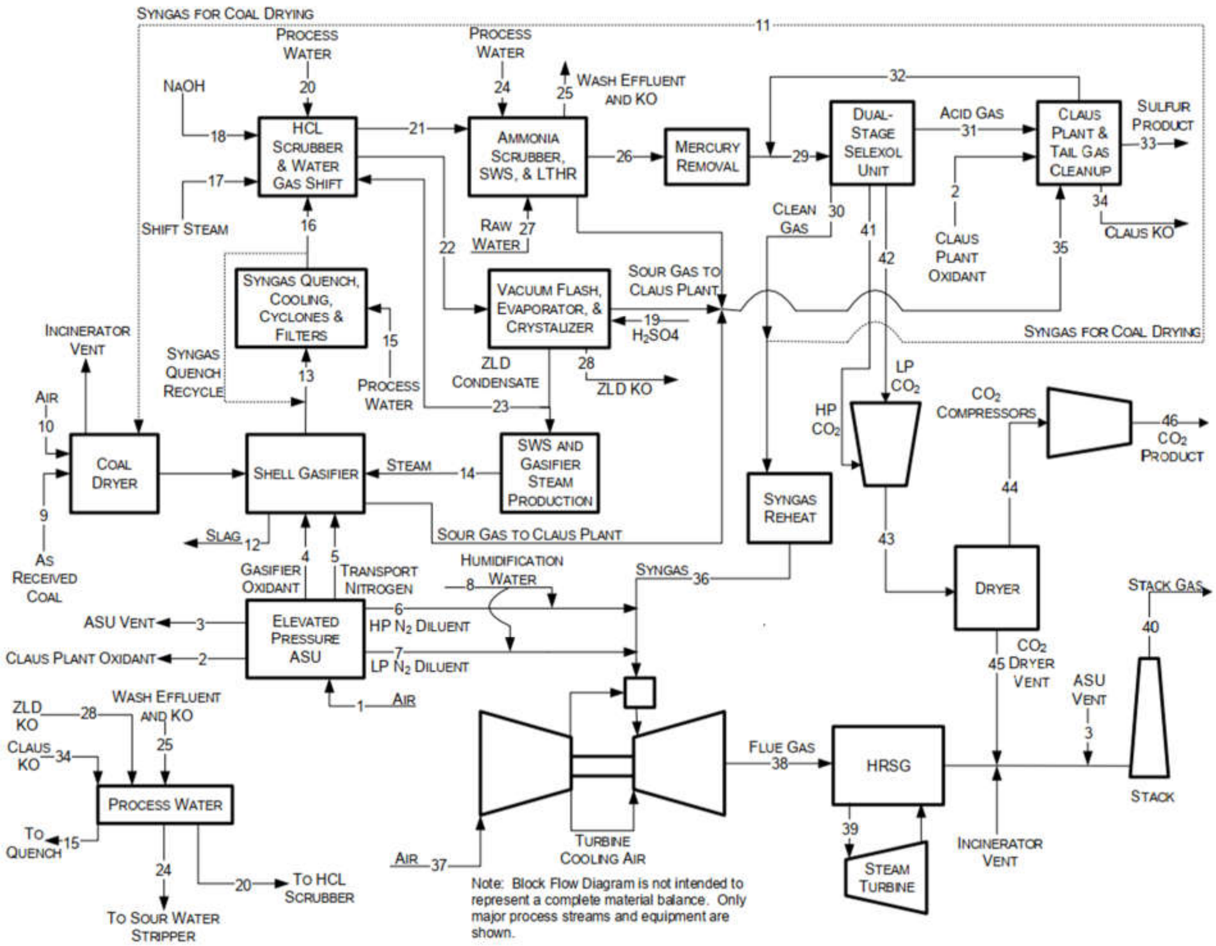
Exhibit 2-7. CO_2 recovery from flue gas with chemical absorbents



Source: Li, Zhang, et al., 2018

In pre-combustion CCS, the fuel is reacted with oxygen (O_2) to produce a "synthesis gas" or "fuel gas" composed of carbon monoxide (CO) and hydrogen (H_2). The CO is further processed with steam to produce CO_2 and more H_2. The CO_2 is separated with sorbent-based processes similar to the solvent absorption process used in post-combustion capture. The remaining H_2-rich fuel is then used to produce the desired heat or mechanical work in a boiler or combustion turbine. This pre-combustion process is the basis for coal-fired integrated gasification combined cycle (IGCC) plants such as the planned, but never operational, Kemper Project in Mississippi. The energy penalty and additional cost results from both the fuel processing step and the capture and sorbent regeneration system. The detailed process flow diagram of an IGCC plant shown in Exhibit 2-8 demonstrates the technical complexity of CCS. In addition to its immediate use for electric generation, it is also possible to divert some of the H_2-rich fuel produced in this process for storage and later use, either on site or elsewhere.

Exhibit 2-8. CCS technology process diagram



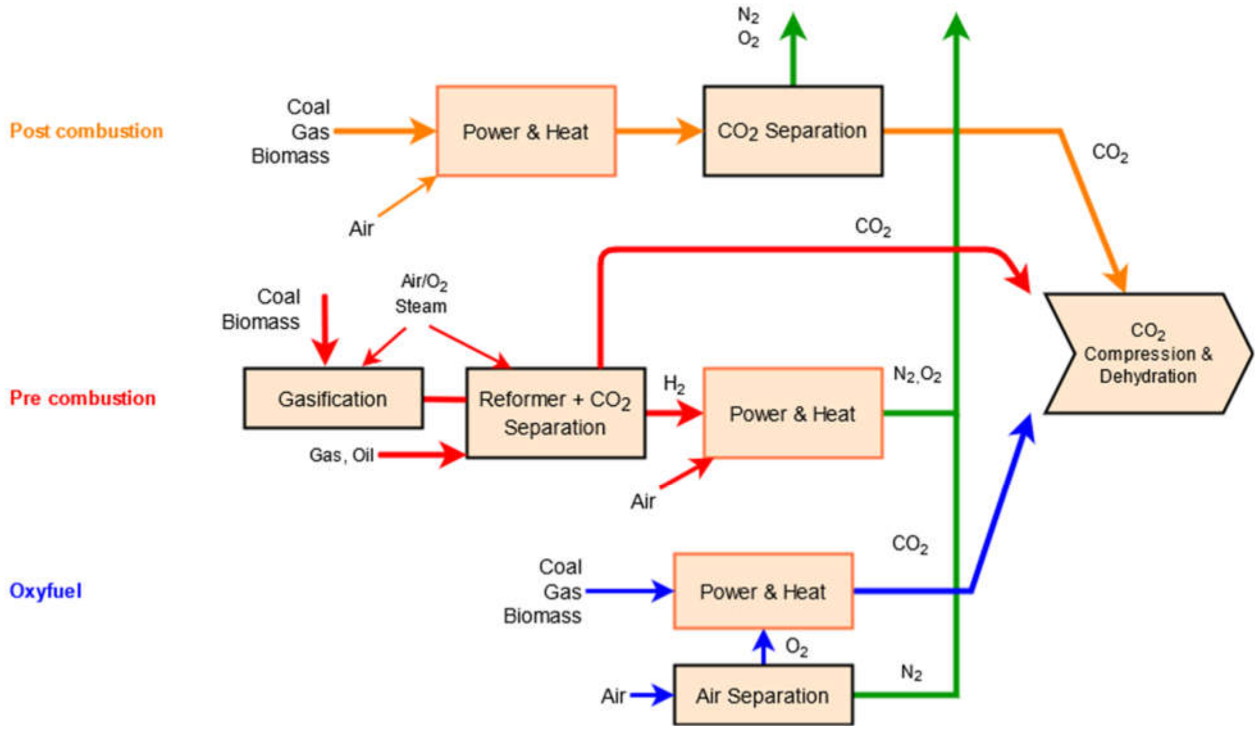
Source: James, Robert, Alexander Zoelle, Dale Keairns, Marc Turner, Mark Woods, and Norma Kuehn. 2019. "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity." NETL Report Pub-22638. Vol. 1.

Oxy-fuel combustion uses pure O_2 for combustion rather than air, producing a flue gas composed almost exclusively of water vapor and CO_2. The CO_2 is then captured directly with little further treatment. Here, the energy required for the production of O_2 for combustion is the largest source of the energy penalty. This technology has been tested at pilot scale in a few locations, including the NET Power Test Facility in Texas.

An emerging technology related to oxy-fuel combustion is chemical looping, where the O_2 for fuel combustion is supplied not by gaseous O_2 but by fine particles of metal oxides or other materials. A concentrated stream of CO_2 is produced, and the reduced form of the metal is re-oxidized for recycling into the process.

Exhibit 2-9 provides simplified process diagrams for each of the three major categories of CCS.

Exhibit 2-9. CCS technology simplified process diagrams[32]



Source: Metz, 2005, Figure 3.1

2.2.1.2 Transportation and storage technologies

Once CO_2 has been captured from a generating facility, it must be transported to a location where it will be used or stored.

For efficient transport, CO_2 must be compressed into a liquid state at a pressure of about 100 times atmospheric pressure, or 10 times the pressure of a typical liquid propane gas tank. The liquid can be transported through pipelines or via ship to another location for storage or use.[33] In the United States, compression and transportation of CO_2 for commercial use is routinely performed through roughly 50 individual pipelines with a combined length of over 4,500 miles. The vast majority of this network supports EOR operations and is concentrated in the Midwest. Most of the CO_2 transported by these pipelines is from geologic (e.g., natural gas production) rather than anthropogenic sources[34] (see Exhibit 2-10). Almost all of the large-scale CCS facilities currently in operation globally rely on pipelines to transport CO_2 from source to storage sites.[35]

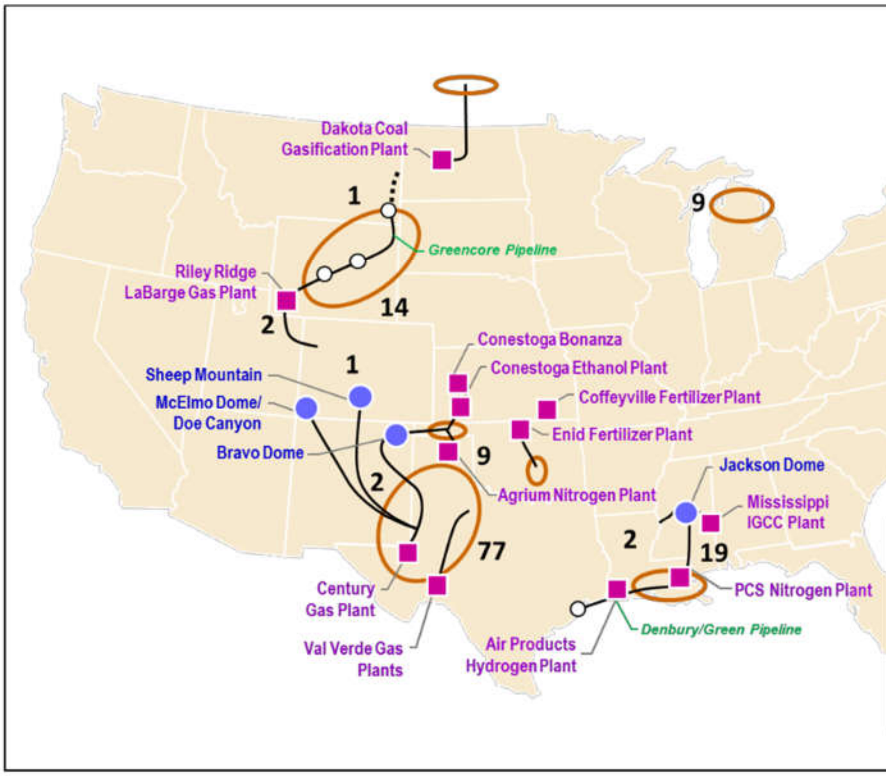
[32] NRRI construct based on data from B. Metz, O. Davidson, H. Coninck et. al., "Carbon dioxide capture and storage," Intergovernmental Panel on Climate Change. (2005): 108.

[33] The cost of transport by truck and rail ranges from two to ten times more per Mt than by pipeline transport due to economies of scale and is, therefore, rarely used. See, for example, Metz et al. "IPCC Special Report on Carbon Dioxide Capture and Storage," *Intergovernmental Panel on Climate Change*, 2005.

[34] Wallace et al., "A Review of the CO2 Pipeline Infrastructure in the U.S.," Department of Energy, (2015)

[35] Benson and Kenderdine, "An Action Plan for Carbon Capture and Storage in California: Opportunities, Challenges, and Solutions," Energy Futures Initiative and Stanford University, (2020)

Exhibit 2-10. Existing CO_2 pipelines in the United States



Oil Production (2014)	
CO_2-EOR Projects	136
Oil Production (MBbl/d)	300
CO_2 Supplies (2014)	
Number of Sources	17
• *Natural*	*5*
• *Industrial*	*12*
CO_2 Supply (Bcf/d)	3.5
• *Natural*	*2.8*
• *Industrial*	*0.7*

Source: Wallace, Matthew, Lessly Goudarzi, Kara Callahan, and Robert Wallace. 2015. "A Review of the CO2 Pipeline Infrastructure in the U.S." National Energy Technology Laboratory. DOE/NETL-2014/1681.

The current U.S. network of CO_2 pipelines carries approximately 68 million metric tons [MMT] of CO_2 per year. In comparison, decarbonization scenarios that include CO_2 capture may require transporting many hundreds or even thousands of MMT.[36] A recent study by the National Academies suggests the need for approximately 10,000 miles of "trunk lines" by 2035 to carry up to 250 MMT/year.[37]

Given the potential need for substantial new pipeline infrastructure to carry captured CO_2, studies have assessed the possibility of using existing natural gas pipelines for CO_2 transport. A study by Seevam et al. (2010) concluded that limitations on water content in existing natural gas pipelines are sufficient for transportation of CO_2 in the dense liquid phase but not in the gaseous phase.[38] An additional consideration for transporting CO_2 is the lack of clear regulatory authority over the current transport network. Federal regulation of pipelines carrying dense liquid CO_2 is largely limited to safety under the Pipeline and Hazardous Materials Safety Administration. Neither FERC nor the Surface Transportation Board has exercised price regulation jurisdiction over CO_2 pipelines. Different definitions among regulatory bodies have caused confusion about jurisdiction. FERC disclaims jurisdiction over CO_2, because it is not a

[36] See, for example, Larson, Eric, Chris Greig, Jesse Jenkins, Erin Mayfield, Andrew Pascale, Chuan Zhang, Joshua Drossman, et al. 2020. "Net-Zero America: Potential Pathways, Infrastructure, and Impacts Interim Report.".

[37] "Accelerating Decarbonization of the U.S. Energy System," National Academies of Science, Engineering, and Medicine, (2021)

[38] Seevam et al., "Capturing Carbon Dioxide: The Feasibility of Re-Using Existing Pipeline Infrastructure to Transport Anthropogenic CO2," Proceedings of the 8th International Pipeline Conference, IPC2010, (2010)

"natural gas" covered by the Natural Gas Act. The Surface Transportation Board finds CO_2 is not within its authority, because they do not regulate pipeline carriage of gas, and CO_2 is clearly a gas.[39]

Effective long-term storage of CO_2 requires that it be prevented from being re-released into the environment. Three main technologies are currently under investigation for storing CO_2 for a period long enough to be considered permanent (i.e., hundreds to thousands of years): geologic storage, ocean storage, and mineral carbonation. Each of these technologies is in different stages of development and use.

Geologic storage is the most well-developed method for storing CO_2 and the only one that has been used at commercial scale.[40] Injecting CO_2 into deep geological formations uses technologies that have been developed for and applied by the oil and gas industry for many years.[41] Selection of CCS sites can take years and millions of dollars that can be lost if the site is determined to be inadequate. It is possible to reduce the risk of selecting inadequate sites through an inexpensive and rapid assessment of CCS reservoir viability. This assessment can be performed before drilling by analyzing volatiles (e.g, CO_2, gas, oil) in rock samples from pre-existing wells even if they are decades old. Doing so allows the assessment of past fluid leakage and migration and informs the site selector about the probability of leakage in proposed CCS reservoirs before final site selection and drilling. For new wells, volatiles analysis of materials can be performed rapidly to help guide the go/no-go decision on continuing investment. The DOE has been successful in reducing the cost of developing solar facilities using a similar method through its Sunshot program. The early assessment process can reduce the time and cost of developing carbon sequestration sites.

While it is possible to reduce the cost of developing sequestration sites now, more research will be needed to expand the availability of sequestration locations. CO_2 has a lower density than water; as a consequence, the presence of an overlying, thick, and continuous layer of silt, clay, or mineral deposits is the single-most important feature of a geologic formation that is suitable for geological storage of CO_2.[42] Chemical changes, such as mineral carbonation, may also occur with geologic storage, but only over much longer time-scales that are enabled by robust physical isolation. Using CO_2 for EOR is also a form of geologic storage.

Injecting captured CO_2 into the ocean at great depth has the physical potential to store vast quantities of carbon, as much as hundreds of years of U.S. power sector emissions at current rates.[43] To date, this technology has not been tested at any appreciable scale. It currently exists only in the form of analysis, modeling, and preliminary research. Most proposals for ocean

---

[39] Cyrus Zarraby, "Regulating Carbon Capture and Sequestration: A Federal Regulatory Regime to Promote the Construction of a National Carbon Dioxide Pipeline Network," The George Washington Law Review, Vol. 80:950, (2012)

[40] Bui, Adjiman, et al., "Carbon capture and storage (CCS): the way forward," Energy & Environmental Science, Vol. 11, Issue 5, (2018)

[41] Metz et al. "IPCC Special Report on Carbon Dioxide Capture and Storage," *Intergovernmental Panel on Climate Change*, 2005.

[42] Benson and Orr, "Carbon Dioxide Capture and Storage," MSR Bulletin, Vol. 33, (2008) www.mrs.org/bulletin

[43] Increased ocean concentrations of CO_2 will increase atmospheric CO_2, but equilibrium will take hundreds or thousands of years. The estimated equilibrium at an atmospheric concentration of 350 parts per million, volume (less than current levels) would occur with an additional 2,300 billion Mt CO_2 absorbed by the ocean (Metz et al., 2005). Assuming annual emissions of 1.6 billion Mt CO_2 from U.S. electricity generation (based on data from the Energy Information Administration, https://www.eia.gov/tools/faqs/faq.php?id=74&t=11), over 1,000 years of emissions could be stored without raising atmospheric CO_2.

storage assume injection at greater than 3,000 meters depth, at which point CO_2 is denser than sea water and would, therefore, sink, rather than rise to the surface and re-enter the atmosphere. This solution would require creation of an extensive pipeline network to transport the captured CO_2 either to ports where it could be transferred to ships for the final disposal at depth or directly to an offshore disposal point. Beyond the technical challenges and financial investment needed, ocean storage faces issues regarding potential environmental consequences, public acceptance, the implications of existing laws, safeguards and practices that would need to be developed, and gaps in our current understanding of ocean CO_2.[44]

Another nascent decarbonization technology is "mineral carbonation," which involves reacting CO_2 with metal oxides such as magnesium and calcium oxides to form carbonates. Carbonation, also known as "mineral storage," can be considered both a storage and utilization option. The latter applies if the intended application of the carbonates goes beyond storing CO_2 to use as a material, for example, in the construction industry.[45] Mineral storage can occur either *in situ*, in which case it is similar to geologic storage, or *ex situ.* In either case, mineral storage of CO_2 is appealing because there is an abundance of naturally-occurring materials that could be used for this purpose, as well as the presumed near-permanence of storage of CO_2 in a stable, solid form.[46] Public acceptance of *ex situ* mineral storage is likely to be high, because it is easy to verify that carbon has indeed been permanently stored.[47] To date, only one large-scale *in situ* mineral storage project is in operation in Iceland.[48]

2.2.1.3 Carbon utilization technologies

There are many potential beneficial uses of CO_2 from a CCS facility, ranging from industrial refrigeration to food and beverage preparation. Currently, the most significant use by far is for EOR.[49] For the purpose of this report, the value of CO_2 to the end-user is of greatest interest, because the revenues generated by selling CO_2 are an economic lever that can promote investment in CCS plants. The many uses of CO_2 and the potential revenue associated with these uses is discussed in detail in Section 3.5.1.

2.2.2 Costs of CCS Generation

While there may be technological, organizational, or regulatory barriers to CCS, the cost of CCS is the primary limitation on its widespread adoption. Power generation using CCS is currently far more expensive than competing sources, both carbon-free renewables and traditional fossil-fuel generation. Section 4 examines a range of policy options that might improve the deployment prospects of CCS; many of these options aim to provide additional revenue to compensate for its higher cost. In order to assess the likely success of these policies, the cost of CCS generation and the resulting price premium that must be overcome must be understood.

[44] Metz et al., 2005.

[45] Cuellar-Franca and Azapagic, "Carbon Capture, storage and utilization technologies: A critical analysis and comparison of their life cycle environmental impacts," Journal of CO2 Utilization, Vol. 9, (2015)

[46] Metz et al., 2005.

[47] Bui, Adjiman, et al., 2018.

[48] IEA, 2020.

[49] Jennifer Wilcox, "The Essential Role of Negative Emissions in Getting to Carbon Neutral," Kleinman Center for Energy Policy, (2020)

2.2.2.1 Measuring the Cost of CCS

Just as power plants vary in scale and generating capacity, the cost of CCS varies from project to project. To facilitate comparison both across CCS plants and between CCS and other generation sources or other carbon-emission reduction methods, the cost of CCS is usually expressed in two normalized units: dollars per unit of energy generated and dollars per unit of CO_2 captured. In both cases, these metrics should include both operating costs and the amortized capital costs of the CCS project over its entire lifetime, as well as the total expected power generation and CO_2 emissions captured to correctly calculate the value of CCS.

2.2.2.2 Capital Costs vs. Operating Costs

As with any form of power generation, the final cost of the output from a CCS plant is determined by both the cost of the equipment needed to implement the processes (capital) and the cost of the energy, materials, and labor necessary to run the processes (operation). The capital cost of CCS is largely for the equipment to separate and capture the CO_2; the power generation facility itself remains more or less structurally unchanged.[50] This cost includes both the capital cost of the equipment for CO_2 separation and capture (e.g., absorption reactors) and the additional ancillary equipment required to prepare the CO_2 for transportation and storage, such as boilers for additional heat, air separation units (in the case of oxy-fuel combustion plants), gasifiers (in the case of pre-combustion capture), and dryers and compressors.

Converting the capital cost of a CCS plant into a useful metric like \$/megawatt-hour (MWh) or \$/Mt CO_2 requires a number of assumptions regarding plant operation and output. The total capital cost must be amortized over the plants' output (or capture) for these metrics to be meaningful. Yet for any given plant, the capital costs remain fixed while the output is variable

CCS and the Hydrogen Economy

In the pre-combustion approach to carbon capture, carbon is separated from the fuel (whether coal, natural gas, or biomass) before it is burned to create useful thermal energy. This results in a H_2-rich fuel that produces little to no CO_2 when combusted. Theoretically, this fuel stream could be diverted for storage for later use or transported for use in other processes. In fact, most H_2 produced in the United States today is produced in substantially the same manner by steam-reforming of natural gas. In most of these existing facilities, the CO_2 by-product is vented to the atmosphere. A CCS plant could potentially be configured with H_2 production and carbon-capture capacity that exceeds the boiler/turbine and generating capacity and could, therefore, be capable of generating "blue hydrogen" with a lower carbon-footprint than traditional sources. There may be economies in combining H_2 generation and power generation in one facility that can capture the carbon emissions from both processes. A CCS plant designed primarily for power generation could also produce excess H_2 during periods of low demand/low prices, thus maintaining a high utilization of the fuel-processing and carbon capture portions of the plant.

[50] In pre-combustion type systems, there are also changes needed to the burner or combustion turbine to burn H_2 rather than natural gas (which is primarily methane).

depending on the way in which the plant is operated.[51] Will the plant be operated for 6,000 hours per year, or 7,000? Will the overall capacity factor be 65 percent or 85 percent? Assumptions regarding plant life, annual operating hours, capacity factor, etc., are not always explicit in reported cost estimates for CCS.

The operating costs of CCS include the costs related to the separation and capture process (e.g., sorbents), as well as the energy required for the process. To avoid the capital expense of additional boilers and generators that would serve only the CCS process, this energy is often taken directly from the output of the power generation cycle. Some analyses of CCS have simply reduced the power output of the plant to account for the higher capital costs. This reduction has largely the same effect on the ultimate unit cost of generation as adding costs for additional fuel and purchased electricity, although it may mask the amount of capital required to build the plant and thus may affect its economic feasibility.

2.2.2.3 Transportation and Storage Costs

Regardless of the technology used, captured CO_2 must be transported to the location where it will be used or stored. For purposes of this discussion and subsequent analysis, transport by pipeline, the predominant method used today, is assumed.

The CO_2 content in the output streams from various capture technologies may range from 90 percent to over 99 percent, with accompanying differences in the types and quantities of impurities present. Despite this variability, research indicates that current specifications for CO_2 pipelines do not consider any impurities in the gas other than the water content.[52] For this reason, this report assumes that the cost of transport will not vary based on capture technology.

The cost of pipeline transport varies based on both the length and capacity of the pipeline. For example, the analysis of CCS technologies conducted by the Department of Energy (DOE) National Energy Technology Laboratory (NETL) assumed a constant transport cost of $2.07/Mt (2018 $) for a 100 kilometer pipeline, regardless of geographic region or capture technology.[53] More detailed modeling of pipeline networks for transporting CO_2 from both industrial sources and CCS plants to oil fields for EOR has found that a majority of pipelines in the network would cost less than $8/Mt (2014 $), with the exception of some longer, shared "trunk" pipelines that may cost $20/Mt or more.[54]

Storage costs may vary considerably across CCS systems, but this is a function of geology rather than technology. Due to the variances in the geologic formations in different regions, NETL estimates storage costs of roughly $8–20/Mt.[55] Other studies have presented costs as low as $7/Mt for the combined cost of transport and storage (T&S) in the United States.[56]

---

[51] This refers to variability in analytical assumptions, not variability in an actual CCS plant's output to meet grid and/or market conditions.

[52] Seevam et al., 2010

[53] James et al., "Cost and Performance Baseline for Fossil Energy Plants Volume 1," National Energy Technology Laboratory, (2019): Exhibit 2-21

[54] Wallace et al., "A Review of the CO2 Pipeline Infrastructure in the U.S.," Department of Energy, (2015)

[55] James et al. 2019

[56] Lawrence Irlam, "Global Costs of Carbon Capture and Storage," Global CCS Institute, (2017)

Even assuming relatively constant T&S costs on a per Mt basis, costs will vary on a per MWh basis, because different CCS plants have different emissions rates in terms of Mt CO_2/MWh. Natural gas-fired CCS plants capture less CO_2 per MWh of generation because the fuel is lower in carbon content. The cost of transportation and storage per unit of electricity produced is therefore lower for gas-fired than for coal-fired plants.

A recent workshop held by the Labor Energy partnership found that regional hubs would allow industry to share expertise, costs, products and infrastructure. Of critical importance is gaining economies in transportation. "(A)ggregating emitters to form hubs can align carbon dioxide source with companies and entities capable of transporting and storing carbon dioxide."[57]

2.2.2.4 *"All-in" Costs*

At least five studies published since 2000 provide cost estimates for CCS plants. It is assumed that a range of costs drawn from multiple sources provides the best yardstick by which to measure the potential economic and policy levers that can be applied to expand investment in CCS. Exhibit 2-11 is organized by major type of CCS system; the same data are also presented graphically in Exhibit 2-12.

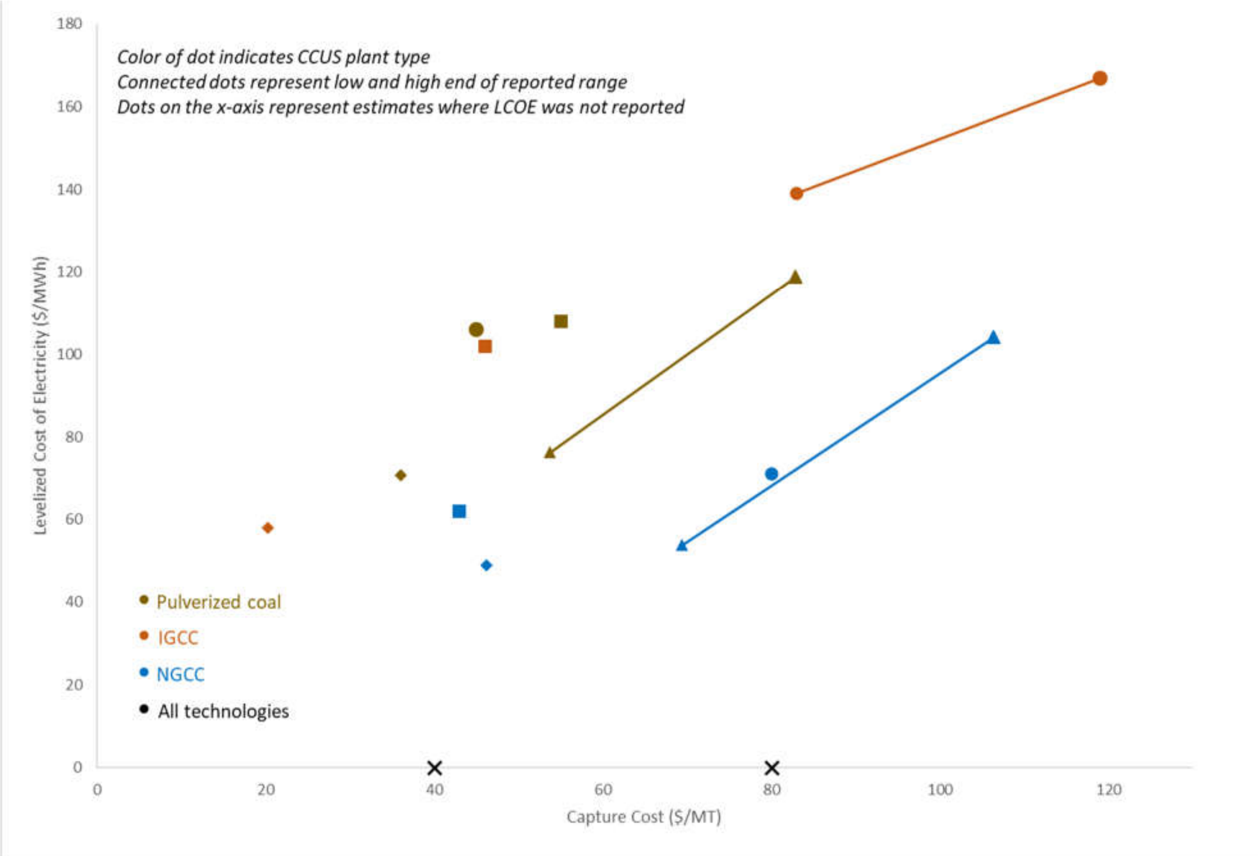
One factor not studied in this report that can affect the cost of CCS plants is whether plants are individually designed or are developed using a standardized design. A comparison of the history of nuclear and co-generation plant additions provides insights into the advantages of standardization. Nuclear power plants developed by U.S. electric utilities often had unique design. This led to both high engineering costs and unique plant components. The requirements developed after the Three Mile Island incident led to much re-engineering and the development of unique parts for each of these plants, which played a major role in driving costs. In contrast, combined cycle gas units were standardized, minimizing engineering costs, making spare parts more readily available, and reducing uncertainty about the cost of plant development. At this point, a significant amount of research and development is required for CCS plant design. Once best practices and plant designs are established, standardization offers the potential for reducing development costs.

[57] Labor Energy Partnership, "Ohio River Valley Hydrogen and CCS Hub Market Formation," September 2021, LEP_Ohio_River_Valley_Hydrogen_and_CCS_Hub_Market_Formation_Report.pdf (squarespace.com)

Exhibit 2-11. Itemized selected CCS cost estimates

Plant Type	Capture Type	Fuel	Capture Cost, \$/Mt (year)	COE, \$/MWh (year)	Source	Notes
Subcritical pulverized coal	Post-combustion	Coal	\$44.6 (2018)	\$106.3 (2018)	NETL (James et al. 2019), ES-4[62]	Excludes T&S; breakeven CO_2 sales price used for capture cost
Supercritical pulverized coal	Oxy-fuel	Coal	\$43-48 (2017)	\$108 (2017)	Irlam 2017, Table 1[61]	Cost is for "nth of a kind" plant; range based on backing out b/w \$7 and \$12/Mt for T&S
Supercritical pulverized coal	Post-combustion	Coal	\$53.76–82.88 (2019)	\$76.16-118.752 (2019)	Ferrari, et al. 2019[59]	Converted at 1.12 € per \$
Pulverized coal	Post-combustion	Coal	\$36.07 (2020)	\$70.57 (2020)	David & Herzog, 2000[58]	Excludes T&S (est \$10/MT); adjusted from 2012\$ to 2020\$
Integrated Gasification Combined Cycle (IGCC)	Pre-combustion	Coal	\$82.7–119.4 (2018)	\$139.4–166.5 (2018)	NETL (James et al. 2019), ES-4[62]	Excludes T&S; breakeven CO_2 sales price used for capture cost
IGCC	Pre-combustion	Coal	\$34-39 (2017)	\$102 (2017)	Irlam 2017[61]	Cost is for "nth of a kind" plant; range based on backing out b/w \$7 and \$12/Mt for T&S
IGCC	pre-combustion	Coal	\$20.29 (2020)	\$57.94 (2020)	David & Herzog, 2000[58]	Excludes T&S (est \$10/MT); adjusted from 2012\$ to 2020\$
Natural Gas Combined Cycle (NGCC)	Post-combustion	Natural gas	\$79.60 (2018)	\$70.90 (2018)	NETL (James et al. 2019), ES-4[62]	Excludes T&S; breakeven CO_2 sales price used for capture cost
NGCC	Post-combustion	Natural gas	\$31-36 (2017)	\$62 (2017)	Irlam 2017[61]	Cost is for "nth of a kind" plant; range based on backing out b/w \$7 and \$12/MT for T&S
NGCC	Post-combustion	Natural gas	\$69.44-106.40(2019)	\$53.76-104.16	Ferrari et al. 2019[59]	Converted at 1.12 € per \$
NGCC	Post-combustion	Natural gas	\$46.22 (2020)	\$48.81 (2020)	David & Herzog, 2000[58]	Excludes T&S (est \$10/Mt); adjusted from 2012\$ to 2020\$
All	N/A	N/A	\$40–80 (2019)	Not reported	IEA 2019[60]	Range based on a variety of techs and plant configurations; Assumed to exclude T&S

Exhibit 2-12. Selected CCS cost estimates



Note, corresponding studies are as follows: ◆ David and Herzog,[58] ▲ Ferrari, et al.,[59] **X** IEA,[60] ■ Irlam,[61] ● NETL (James, et al.)[62]

[58] J. David and H. Herzog, "The Cost of Carbon Capture," in In Proceedings of 5th International Conference on Greenhouse Gas Control Technologies (GHGT-5), 2001.

[59] N. Ferrari, L. Mancuso, K. Burnard and F. Consonni, "Effects of plant location on cost of CO2 capture," International Journal of Greenhouse Gas Control, vol. 90, 2019.

[60] "Levelised cost of CO_2 capture by sector and initial CO_2 concentration," *International Energy Agency*, 2019.

[61] L. Irlam, "Global Costs," 2017.

[62] R. James, A. Zoelle, D. Keairns, M. Turner, M. Woods and N. Kuehn, "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity," *National Energy Technology Lab*, 2019.

3 FACTORS AFFECTING THE ECONOMIC VIABILITY OF CCS

The economics of CCS plants depends upon the cost to remove and dispose of the carbon and the revenue the plant earns. Although these revenues are primarily from power sales, they can also include the sale of the recovered carbon. The way in which that revenue is treated is also dependent upon the ownership structure, which affects the cost of the capture technology and the way in which it is financed. There are five potential revenue sources:

- Electric market revenues
- Tax subsidies through Section 45Q
- Carbon pricing
- Greenhouse Gas-related revenue
- Utility rates that allow for CCS cost recovery

The nature of each of these revenue sources will change due to changes in policy imperatives and technology. Each of these sources is described in detail below in order to lay the groundwork for explaining the effects of evolving policies on the economics of CCS.

3.1 ELECTRIC MARKET REVENUES

This section examines the impact of competitive electricity markets on the economics of CCS plants. Opportunities related to rate-based cost recovery of CCS in vertically integrated markets are addressed in Section 3.5.

With the advent of organized wholesale markets for power coordinated by ISOs, electricity as a product began to be unbundled. The former vertically-integrated utilities did not need to quantify the value of each of the many attributes of generation required to operate an electric system. Those attributes were bundled and procured by the owners and operators of generation. Restructuring separated those attributes, unbundling the product known as electricity into three elements: energy, capacity, and ancillary services. The following sections address the relationship between the markets for these products and CCS.

3.1.1 Energy Markets

3.1.1.1 Economic Dispatch

The process by which an individual utility or the operator of an organized market coordinates generating units to continuously and reliably meet customers' real-time electricity demand[63] at least cost is called economic dispatch. The dispatch problem is a short-run (a day ahead or real-time) economic problem, because, in the short run, all capital is fixed. Cost minimization involves only the variable costs associated with generation and delivery. Historically, the objective of economic dispatch was to coordinate a fleet of generation to keep the lights on and building temperature comfortable at the lowest possible cost. As the range of resources available to supply service increased and the usage time profile of demand changed, the

[63] This requirement that instantaneous generation matches load stems from the basic physics requirement to maintain frequency within acceptable limits to prevent blackouts.

dispatch problem became more complex. As a result, utilities implemented time-based rates to reduce sharp upswings in demand that required expensive resources to serve. As renewable energy sources are added to the system, these support resources now include both the physical hardware that enables the reliable operation of the system (e.g., storage) and demand response (which relies on customer behavior).[64]

The current dispatch method is based on the "incremental method" developed in the 1930s. At that time, because the system included relatively few generators, all with the same fuel cost, a specific utility's problem was to allocate load responsibility within its state-granted service territory to different generating units and to manage their level of output. This involved what is referred to as optimal dispatch, finding the combination of generating units that would minimize the cost of production. This process was made easier, because at that time the incremental (marginal) thermal efficiency of each operating unit was equal since all generators used the same fuel type (coal) and thus did not differentiate the cost among units.[65] .

Over time, dispatch evolved to include different fuel types, including renewable energy sources, and prices were modified to reflect transmission constraints. In the incremental method, the marginal cost of supplying the next increment of load is the system marginal cost or "lambda,"[66] which is equivalent to a competitive market price. As Alfred Marshall found in 1890, "the more nearly perfect a market is, the stronger is the tendency for the same price to be paid at the same time."[67] This is similar to pricing in a competitive commodity market—each identical electron has the same price, just as each identical grain of wheat has the same price. In both cases, competition makes this price equal to the marginal cost of production.

In open, organized energy markets (e.g., PJM Interconnection [PJM], New York ISO [NYISO], and ISO-New England [ISO-NE]), as well as the other ISOs regulated by FERC), the system operator uses cost data in the form of supplier bids to provide energy to create a "merit order" that determines which type of generation is used to meet the load requirements of the system. This merit order is the market supply curve (also called the dispatch stack, bid stack, or generation stack) is shown Exhibit 3-1.[68] Bids are submitted to supply power for each hour of the next day and a merit order dispatch is developed, producing the day-ahead market price for each supplier. This process continues daily.

---

[64] On the customer side of the meter, there are customer ("prosumer") resources that facilitate grid operation, including distributed power generation, power storage, and modifying demand in response to system conditions.

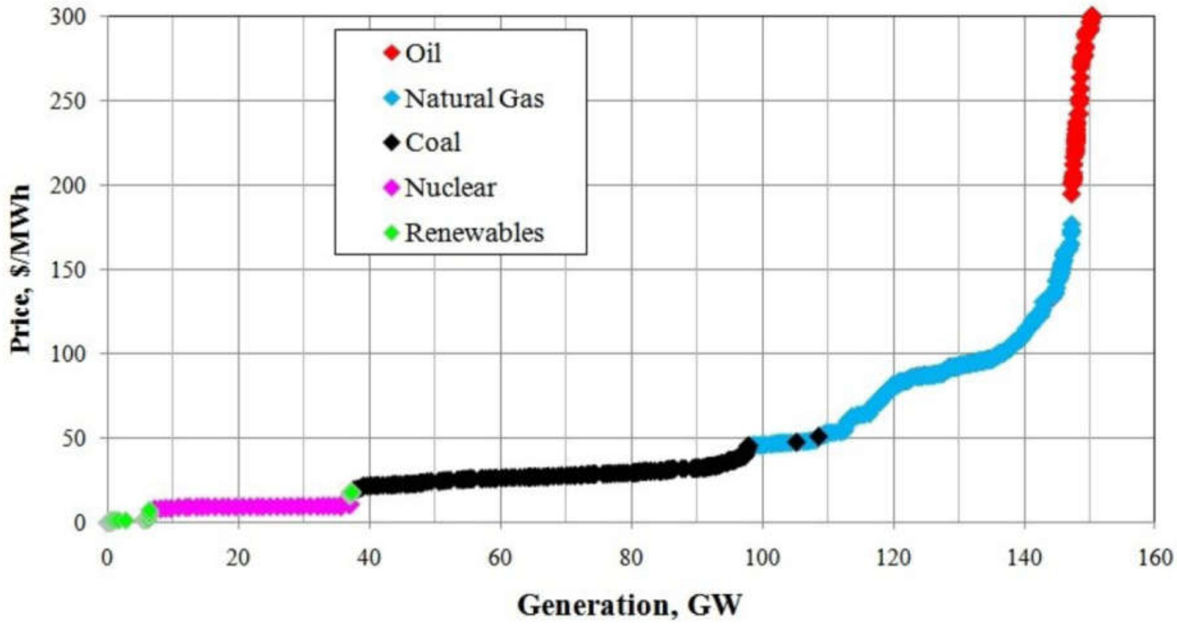
[65] Happ, H.H, *Piecewise Methods and Applications to Power Systems* (New York: Wiley, 198O).

[66] It is called lambda for the LaGrangian constraint. The formula for optimal dispatch is to minimize the cost of generation subject to the constraint that the needs of customers are met (the reliability constraint). Lambda, therefore, represents the system marginal cost of an increase in load.

[67] Marshall, A., *Principles of Economics*, (Porcupine Press, First edition 1890. Eighth edition 1982), pp. 271.

[68] Tayari, F., "Fundamentals of Electric Markets," 2020. Reproduced with permission of the author, https://www.e-education.psu.edu/ebf200/node/151.

Exhibit 3-1. PJM energy supply curve and bid stack



Used with permission from Tayari[69]

Currently, merchant generators are compensated at the cost of meeting a marginal increase in demand, the Locational Marginal Price (LMP), which reflects the marginal cost of serving an incremental increase in forecast load at a specific location, given the set of generators that are dispatched and any limitations of the transmission system.[70] Power system energy supply curves are often depicted as "hockey sticks." As capacity in the system becomes increasingly scarce, the marginal cost of supply increases dramatically, as shown in Exhibit 3-1. This is because the units dispatched later in the order are more costly to operate. The steepest part of the hockey stick is generally thought of as scarcity rents, based upon the customers' valuation of reliability, often referred to as the value of lost load (VoLL).

All power plants, including CCS plants, use revenues to cover the amortization of the capital cost of the plant and the variable cost of generation in order to accrue profits by earning what economists call inframarginal rents.[71] Exhibit 3-2 shows a price-duration curve for the ERCOT electricity market. The points on the curve describe the fraction of time (typically over one year) that the price of power equals or exceeds a given level. The lower the price, the higher the portion of the year that it exceeds that marginal value. The gray rectangle describes the economic results for a generator with a marginal cost of approximately $30/MWh. The revenues represented by the gray rectangle cover the operating costs of the generator. Above the rectangle, the market price is above the generator's marginal cost of operation and the generator earns inframarginal rents that cover investment costs. Scarcity rents are earned during periods of short capacity. Returning to the hockey-stick supply curve in Exhibit 3-1, these

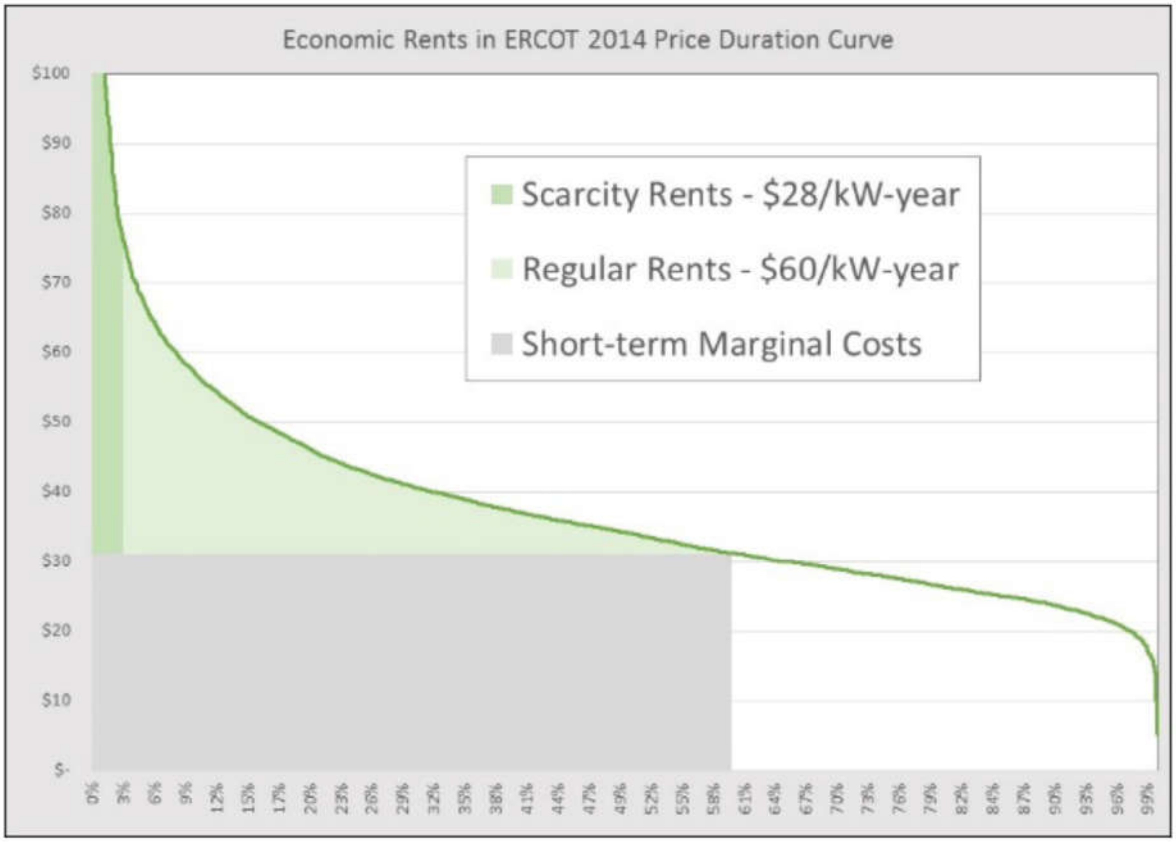
[69] Tayari, F., "Fundamentals of Electric Markets," 2020. https://www.e-education.psu.edu/ebf200/ node/151.

[70] "Energy Market Primer," Federal Energy Regulatory Commission, (2015): 60

[71] Inframarginal rents represent the difference between the market price and a market participants' marginal cost of production. If the marginal cost of production is less than the market price, the entity earns inframarginal rents or revenues that are available to help amortize the capital investment.

rents occur on the steep part of the supply curve. This pattern is representative of peak load pricing—the higher the demand for electricity, the higher the price of that electricity.

Exhibit 3-2. Price duration curve



Used with permission from Gimon[72]

Historically, rate-regulated utilities recovered the capital cost of generation through their revenue requirement, which they collected from ratepayers. The revenue requirement includes both the fixed and variable costs incurred to meet load and thus defines the revenue that must be collected to fully recover all costs. In energy-only electric markets, merchant generators rely on market prices and the ability to earn inframarginal rents to recover both their investment and operating costs in order to make a profit. As discussed below, there are markets that have centralized capacity provisions that also provide revenues to amortize investment costs.

Capacity shortages occur when there is insufficient generation to meet demand. If generators anticipate such situations, they can offer prices above their marginal costs, up to the market offer cap. The problem is that there is no theoretical limit to the level of scarcity pricing or the level of generator profitability except that defined by price caps. Because merchant generators do not share their financial books with regulators to determine how profitable they are, there must be a check on market power. For that reason, the RTOs and ISOs have adopted price caps in energy markets. The limitation imposed by price caps recognizes the ability of generators to

[72] Gimon, E., "On Market Designs for a Future with a High Penetration of Variable Renewable Generation," *Energy Innovation*, September 2017. Permission requested, https://www.energyinnovation.org/wp-content/uploads/2020/01/On-Market-Designs-for-a-Future-with-a-High-Penetration-of-Renew.pdf.

exercise market power during times of shortage. Price caps are limits on what the generators can be paid in the markets. They are an administrative proxy for the exercise of market power.

3.1.1.2 The "Missing Money" Problem

Economic theory predicts that generators in competitive energy-only markets will be unable to recover their capital investment without the unfettered ability to raise prices during periods of shortage.[73] The "missing money" problem is a shortfall of revenues required to cover the capital investment in generation. Advocates for generator owners argue that the missing money problem exists because of administrative price caps that are imposed on markets to thwart the unfettered exercise of market power during periods of scarcity.[74]

The extent of a generator's missing money problem depends on its accrual of inframarginal rents. For this reason, the ability to recover capital costs is dependent on the length of time the generator can remain on the price duration curve at levels above its marginal cost of operation. The closer to peak consumption, the higher the likelihood of moving up the steep portion of the supply curve with increasingly expensive generators to operate.

The peak load pricing literature explains the missing money problem through the finding that in an optimal capacity mix, with generators compensated at competitive market prices, there will be a revenue shortfall equal to the cost of a "peaker" plant.[75] A peaker is a generator that is used only during times of peak demand or system emergencies. The economic theory of peak load pricing demonstrates that there is no way to recover costs based on competitive energy market prices alone, because the installed capacity requirement necessitates idle generating capacity. Furthermore, price caps are designed to protect customers from market power abuse.

In an optimal system, with all costs recovered through energy prices and all generators in the economic dispatch stack compensated at the competitive market price set by the marginal cost of the last unit dispatched (the load following unit), there will still be a revenue shortfall equal to the cost of a peaker. This is explained by the fact that historically the only reason to build a peaker was that it was the least expensive way to achieve the last increment of generation needed to meet the reserve margin. A peaker would be used only during periods of peak demand or when there is a failure on the system, often less than 100 hours a year. Other kinds of generators earned inframarginal rents (again, the difference between the market price and the generator's marginal cost). Peakers do not earn inframarginal rents, because they are the most expensive units on the system to operate. This fits into the optimal system based on two

[73] This can also be the case in markets in markets that separately procure capacity.

[74] The term "missing money" was introduced in Shanker, R. "Comments on Standard Market Design: Resource Adequacy Requirement." Federal Energy Regulatory Commission, Docket RM01-12-000. (2003), p. 3, http://elibrary.ferc.gov/idmws/common/opennatasp?fileID=9619272.

[75] This problem was first solved by Marcel Boiteux in 1949. See: Boiteux, Marcel P. "La tarification des demandes en pointe: Application de la théorie de la vente au coût marginal", 1949, *Revue générale de l'électricité* This simple model has been further developed, using complex mathematics, into a more realistic stochastic model. The basic conclusions and results are not different in the more complex form. See: "Electricity Pricing and Plant Mix Under Supply and Demand Uncertainty," by Michael Crew and Paul Kleindorfer in *Regulating Reform and Public Utilities,* edited by Michael Crew, Lexington Books, Lexington Mass. 1982. See also Michael Crew and Paul Kleindorfer, "Peak Load Pricing with a Diverse Technology" *Bell Journal of Economics* 7, No. 1 (Spring 1976) pages 207-231., and Chao Hung Po, "Peak Load Pricing and Capacity Planning with Demand and Supply Uncertainty", *Bell Journal of Economics* Vol 14, (1983) pp. 179-190. And, Michael Crew and Paul Kleindorfer, *Public Utility Economics*, The MacMillan Press Ltd., 1979.

things: 1) the tradeoff between the capital cost of different types of capacity and the marginal costs of producing electricity, and 2) the need to maintain reserves to operate reliably.

When the peak load pricing literature was developed, there was a tradeoff between the different capital costs and the operating costs of different technologies. That tradeoff led to generators collecting inframarginal rents that supported capital cost recovery. The amount of capital cost recovery depended both on the level of inframarginal rents and the amount of time that the generator received those rents. Therefore, a baseload generator, such as a nuclear power plant, with high capital costs and low operating costs would typically accrue rents throughout the day. The tradeoff between capital costs and operating costs in creating an optimal generating mix leaves a revenue shortfall equal to the cost of a peaker. As a consequence of this shortfall, the peak load pricing theory suggests that a form of capacity payment is needed to recover capital costs and, therefore, to ensure that participants in the market will invest capital in building sufficient generation to maintain reliability. The mechanism for making up this shortfall is called the "Peaker Method" and was initially used for compensating generators as part of the valuation of avoided costs. As discussed further, the FERC has reflected this theory in its basic pricing formula for organized markets, that

$$\begin{Bmatrix} Wholesale\ Electricity \\ Price \end{Bmatrix} = \begin{Bmatrix} Energy \\ Price \end{Bmatrix} + \begin{Bmatrix} Capacity \\ Price \end{Bmatrix}$$

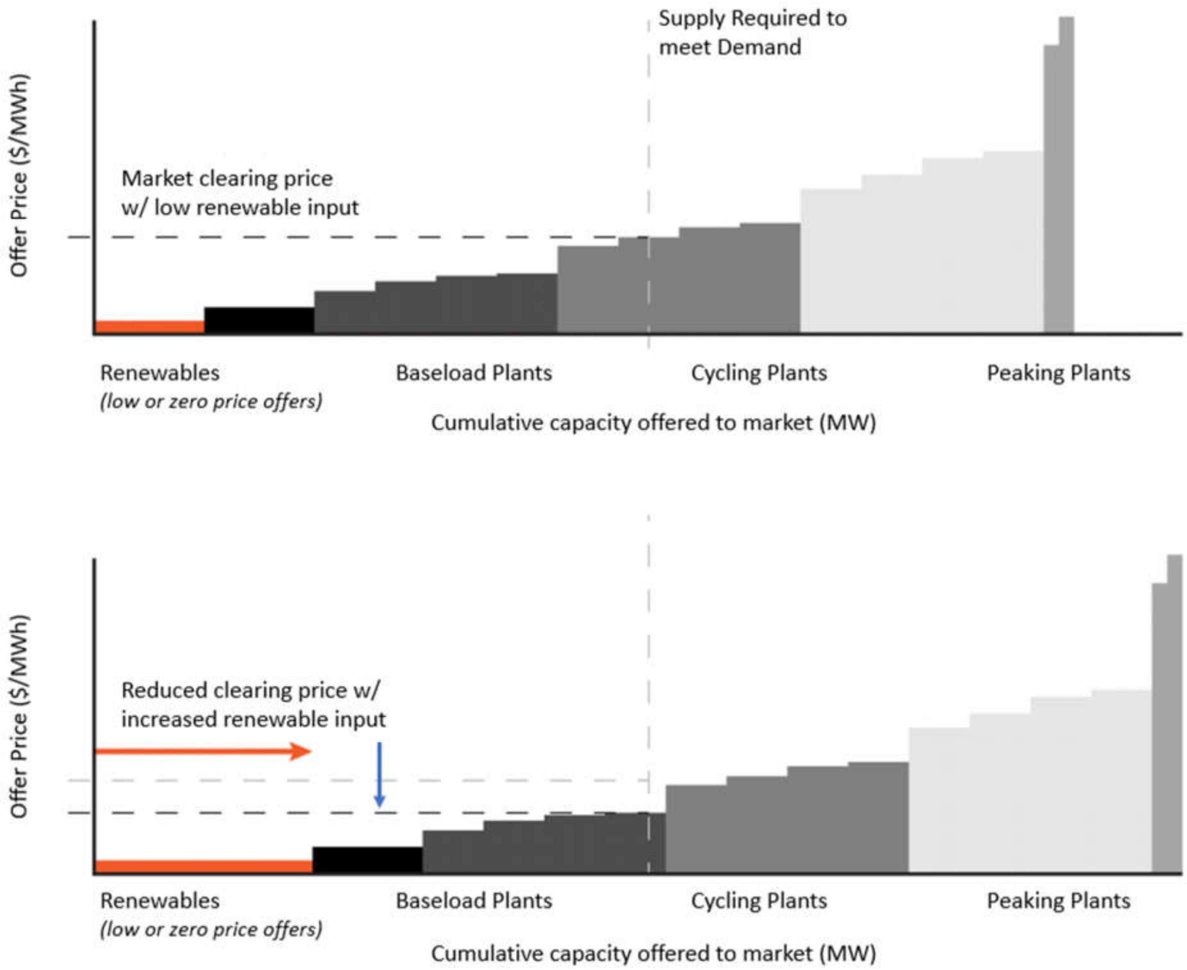
where the energy price is developed from the dispatch algorithm in organized energy markets and the capacity price is derived from capacity markets (when incorporated in market design).

3.1.1.3 The Challenges Posed by Renewable Energy Sources

Renewable power creates an issue for economic dispatch and exacerbates the problem of peak load pricing in energy markets. Renewables interfere with the bids offered by generation used to establish the merit order of dispatch. They do so because the marginal cost of production from renewable generation is zero (or nearly so) because their energy resource (wind, solar) has no cost. If one were to assume a power system with 100 percent zero marginal cost renewables, the relative prices of different resources would all be equal, and the ability to dispatch on operating costs would no longer exist given the current dynamics of dispatch. In such a market, when there is no more capacity available to serve load, the market value of power will be based upon the customers' value of continuing service, i.e., the VoLL. Pricing will follow a bi-modal pattern. During periods of low demand, the energy price will approach zero. During periods of shortage, the price will be set at a price cap, presumably at a measure called the scarcity price that is administratively determined to be equal to the VoLL.

In reality, the bid stack includes a mix of resources. Exhibit 3-3 illustrates the impact of renewables on the bid-stack. In this illustration, the first panel has a relatively low proportion of renewables. In the second panel, increased renewables shift the conventional portion of the supply curve to the right, resulting in a lower market clearing price.

Exhibit 3-3. Impact of renewables on the energy bid stack



Source: Kerstine Appunn, 2015 [76]

With a substantial portion of renewables in the supply mix, some generators may not be able to earn the inframarginal rents they need to pay for the capital costs of the generation. Therefore, capital cost recovery from energy markets will occur primarily during times of scarcity. For this reason, developers and financiers of CCS plants will need to create energy price scenarios reflecting these potential changes as part of their due diligence.

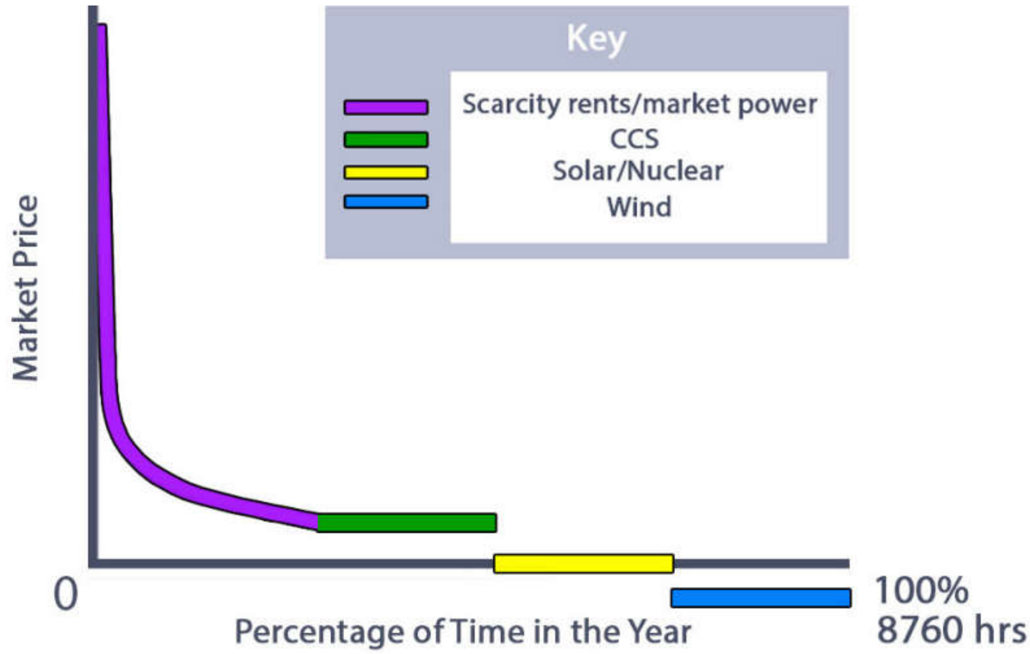
How will the developers of CCS plants develop energy price scenarios that reflect renewables in the mix? One might speculate on what a price duration curve would look like for a zero-carbon electric system comprising renewable generation and CCS, as shown in Exhibit 3-4. This illustrative price duration curve is based on the amount of time a particular type of unit is on the margin.[77] There are obviously many uncertainties in developing such a graph; for example, the extent to which new generation with biofuels or coal and CCS are developed, the future role

[76] NRRI construct based on data from Kerstine Appunn, "Illustrating electricity price fluctuations due to the merit order effect," Clean Energy Wire (2015). https://www.cleanenergywire.org This is licensed under CC BY 4.0. *Author relabeled axes and revised notations.*

[77] The generating unit following load in the dispatch system.

of nuclear power, the impact of storage, the inclusion of demand response, and other new technologies.

Exhibit 3-4. Potential load-duration curve for a zero-carbon electric grid



The lowest prices on the price duration curve could be negative (below zero) because wind generation receives a production tax credit. The production tax credit is paid based upon energy production. It is profitable for a wind generator to produce power up to the value of its production tax credit. Therefore, wind generation, which has zero marginal costs because of this subsidy, will be able to offer to pay to provide power to the market at prices below zero. Without the production tax credit, the generator's offer to supply would presumably be zero, the same amount as would be bid by solar and nuclear power generators. There is also a technical issue with respect to determining nuclear power's marginal cost. Although there is a cost for nuclear fuel, it is often viewed as a fixed-cost, because refueling is based on a pre-determined schedule and not the level of fuel consumed for production.[78] If it is assumed that new generation additions are gas-fired CCS power plants, however, they will likely all have a very similar price, and the portion of the price duration curve will be relatively flat.[79]

The shape of the scarcity pricing portion of the curve is also hard to predict. Will it be broader than depicted? What resources will be in the steep part of the supply curve hockey stick? How will demand response and storage participate in the market and what will be their effect on the price duration curve? This ultimately leads to the question of the way in which the cost of generating infrastructure will be recovered. This price curve is very different from that supporting FERC's pricing formula. The notion of the optimal capacity mix is gone. The rules for power plants over an extended period of zero-price power will need to be reconsidered. The shape of the price duration curve will determine the ability of the generator to recover its costs

[78] Kee, E., "Nuclear Power & Short-Run Marginal Cost," *Nuclear Economics Consulting Group*, October 1, 2014, https://nuclear-economics.com/nuclear-power-short-run-marginal-cost/.

[79] Over time, CCS will evolve to include other fuel sources such as biomass.

and earn a profit. Cost recovery for generation and the extent of the missing money problem will be more uncertain and complicated than it is today, with the likely result being the growing importance of capacity payments as a potential source of revenues for CCS plants.

Given the limitations of peak load pricing and the missing money problem, the path to ensure revenue adequacy for the generation required to maintain reliability would be to increase capacity payments or rely more heavily on scarcity pricing. Paul Joskow predicts that "if we expect to rely on the standard RTO/ISO decentralized wholesale market model, scarcity pricing and/or capacity pricing will have to be a much more important source of revenues for CCS."[80]

The next section examines the nature of capacity markets and considers whether they can generate sufficient revenue for CCS plants in an era of increasing penetration of zero marginal cost renewables, demand-side resources, and new models for customer participation in energy markets.

3.1.2 The Peaker Method as the Basis for Capacity Markets

The peaker method provides the basis for the capacity markets regulated by the FERC. As described below, the markets in place when the peaker method was developed had a very different technology mix and function than current markets. Four major trends compel the rethinking of electric markets: 1) the changing role of the customer, 2) the emergence of zero marginal cost renewable generation, 3) the growing concern about maintaining resilience, and 4) concern for decarbonization. Despite these trends, current markets remain focused on minimizing the cost of electricity and meeting installed reserve margin requirements. The installed reserve margin requirements are increasingly a vestige of planning methods that do not reflect current market realities. Going forward, the design of markets must be re-evaluated to successfully decarbonize and recognize the full value of CCS.

Restructuring has fundamentally changed the way that electric markets were regulated and priced. FERC's focus and practice of regulation changed from a cost of service to a market focus, altering the way it fulfilled its statutory obligation to ensure that rates are just and reasonable. FERC's core assumption in its restructuring efforts has been that competitive markets—what it sometimes refers to as "the forces of competition"—can be relied upon to ensure that prices for natural gas and electricity satisfy the statutory requirement to be just and reasonable.[81]

Energy markets involve the real-time coordination of generation resources to meet customers' instantaneous demand. These markets are fairly straightforward extensions of methods developed by vertically integrated utilities. Practically, they differ only in that dispatch order and final price are determined by competitive bids and the grid's capacity to deliver power to consumers. As now designed, these energy markets are insufficient to ensure rates that allow recovery of the cost of building and maintaining generation. Historically, utilities recovered the capital cost of generation through their revenue requirement, which they collected from ratepayers. Now, merchant generators rely on market prices for recovering their investment and

[80] Paul Joskow, "Challenges for wholesale electricity markets with intermittent renewable generation at scale: the US experience," *Oxford Review of Economic Policy*, Volume 35, Number 2, 2019, p. 305.

[81] Boyd, W. "Just Price, Public Utility, and the Long History of Economic Regulation in America." *Yale Journal on Regulation*, Vol. 35, 2018. p. 727.

making a profit. The question in the transformation to market-based rates for electricity is how to structure the payment to generators for their energy and capacity.

The transformation to a competitive market meant that the services that had been performed as a matter of course by regulated utilities to keep the lights on were no longer the key consideration. It is not surprising, therefore, that, as Joskow observed, "(i)n my view, the initial 'centralized' wholesale market designs in the [United States] paid too little attention to their investment incentive properties."[82] These incentive properties would include the ability to earn adequate revenues to both amortize generation investments and make a profit. In the case of CCS, the objective function is expanded to include decarbonization. At the same time, it is important to pay attention to the decarbonization investment incentives regarding carbon pricing in the wholesale markets. An important part of that carbon investment is assuring that the services that CCS provides to the system are adequately compensated.

Capacity markets are potentially a significant source of revenues for CCS. As a consequence of the missing money revenue shortfall, the peak load pricing theory suggests that a form of capacity payments is needed to recover costs. Economists have equated the established reserve margins[83] with economically optimal levels of capacity. An increase in consumption incurs the marginal cost of the increased generation plus a reduction in the expected reliability of the system (this reduction can be quite small). This incremental reduction in reliability is called "the marginal expected curtailment cost."[84] Therefore, at the required reserve margin, economists and utility planners often equate the marginal expected curtailment cost to the cost of a peaker.[85] This is because the only reason to build a peaker was for reliability, since they were typically the most expensive generators to run.

The Peaker Method is based on the peak load pricing literature.[86] Price provides the basis for investment cost recovery. Although the theory underlying the Peaker Method was developed in the late 1940s, when cost recovery was solely through utility rates, its practical implications were revealed as generation recovered costs through the market prices. The peak load pricing literature foreshadows the missing money problem through the insight that in a system with an optimal capacity mix with generators compensated at competitive market prices will have a revenue shortfall equal to the cost of a peaker.[87]

The peaker does not earn inframarginal rents, because it is the most expensive generator to operate. Every other kind of generator earns inframarginal rents, calculated as the difference

82 Paul Joskow, "Challenges for wholesale electricity markets with intermittent renewable generation at scale: the US experience," *Oxford Review of Economic Policy*, Volume 35, Number 2, 2019, pp. 291–331, p. 302.

83 The required amount of generation above the forecast peak load.

84 More formally – this is the VOLL times the probability of being disrupted.

85 Typically, this is evaluated over the course of a year, so that the cost of the peaker would be presented as an annual revenue requirement.

86 This problem was first solved by Marcel Boiteux in 1949. See: Boiteux, Marcel P. "La tarification des demandes en pointe: Application de la théorie de la vente au coût marginal", 1949, *Revue générale de l'électricité* This simple model has been further developed, using complex mathematics, into a more realistic stochastic model. The basic conclusions and results are not different in the more complex form. See: "Electricity Pricing and Plant Mix Under Supply and Demand Uncertainty," by Michael Crew and Paul Kleindorfer in *Regulating Reform and Public Utilities,* edited by Michael Crew, Lexington Books, Lexington Mass. 1982. See also Michael Crew and Paul Kleindorfer, "Peak Load Pricing with a Diverse Technology" *Bell Journal of Economics* 7, No. 1 (Spring 1976) pages 207-231., and Chao Hung Po, "Peak Load Pricing and Capacity Planning with Demand and Supply Uncertainty", *Bell Journal of Economics* Vol 14, (1983) pp. 179-190. And, Michael Crew and Paul Kleindorfer, *Public Utility Economics*, The MacMillan Press Ltd., 1979

87 Pechman, C. *Regulating Power: The Economics of Electricity in the Information Age*, Kluwer Academic Publishers 1993.

between the market price and the generator's marginal cost. This all fits into an optimal system based on two factors: 1) the tradeoff in the capital cost of different types of capacity and the marginal costs of producing electricity and 2) the need to maintain reserves to operate reliably. When the literature supporting the Peaker Method was developed, there was a tradeoff between the different capital costs and operating costs of different technologies. As discussed further below, this tradeoff, based upon technologies that are largely in the process of being retired, no longer exists in a manner that creates an optimal capacity mix. That tradeoff led to generators collecting inframarginal rents that supported capital cost

While the Peaker Method foreshadows the missing money problem it also defines the marginal cost of electricity:

$$\begin{Bmatrix} Marginal\ Cost\ of \\ Electricity \end{Bmatrix} = \begin{Bmatrix} Marginal\ Energy \\ Costs \end{Bmatrix} + \begin{Bmatrix} Marginal\ Expected \\ Curtailment\ Costs \end{Bmatrix}$$

which leads to the FERC's pricing formula already introduced:

$$\begin{Bmatrix} Wholesale\ Electricity \\ Price \end{Bmatrix} = \begin{Bmatrix} Energy \\ Price \end{Bmatrix} + \begin{Bmatrix} Capacity \\ Price \end{Bmatrix}$$

3.1.3 Capacity as a Product

Capacity is a somewhat elusive product. It is not like electricity that performs work. Capacity is the ability to produce electricity when called upon.[88] Capacity used to be thought of only as steel in the ground, but that concept has evolved to include the ability of customers to reduce their demand (demand response) to help maintain system reliability. Unlike energy, capacity is a stock not a flow. The issue is how to measure it. Until capacity is called upon to perform, there is no way to ensure that it is available, as required under the various capacity payment schemes.

A variety of performance incentive methods have been tried to help ensure generator performance and the availability of capacity when needed. One example, the New York capacity market, known as ICAP, reduces the level of capacity that a generator is allowed to offer to the market in future auctions by historic unforced outage rates. This approach has a lagged impact by derating the amount of capacity that the generator can offer in a future period and therefore does not reflect whether or not the outage occurred during critical system requirements. Other approaches, such as the ISO-NE options-based approach, penalize non-performance by leveling penalties based upon market prices at the time of the generator's failure to perform. What is most important from the standpoint of CCS is whether capacity markets adequately value the ability of a unit to operate as a baseload unit. As we demonstrate in the following paragraphs—it clearly is not.

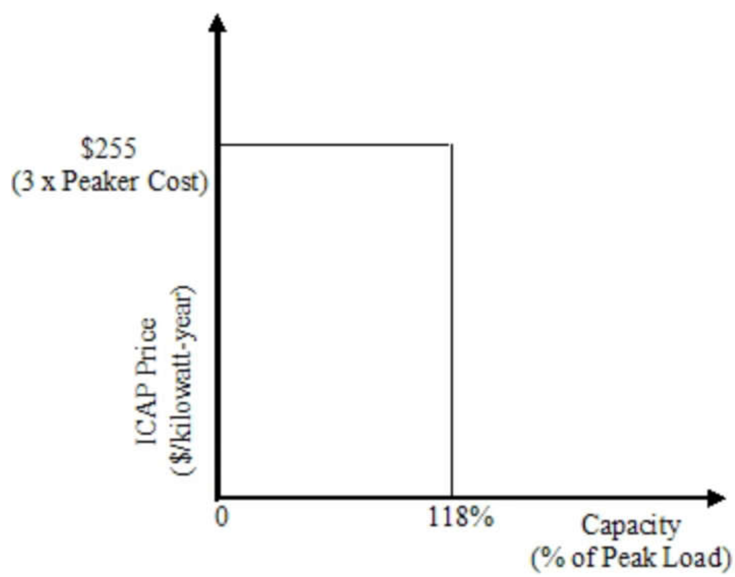
The early transition to competitive markets handled the issue of revenue adequacy through traditional cost-of-service rates, but it did so only for the power plants required to maintain adequate short-run reliability. These rates, called Reliability Must Run contracts (RMR), were used to ameliorate the revenue shortfall for power plants in critical locations. In California,

[88] Or, in the case of demand response, reduce the level of load that the ISO needs to meet.

"(s)ince the ISO startup in 1998, the ISO has relied on RMR contracts to secure essential services from resources to reliably operate the grid."[89]

The earliest capacity markets were established by adopting procedures developed to ensure resource adequacy (i.e., the required installed reserve margin) in power pools. The three northeastern ISOs (NYISO, ISO-NE, and PJM) all evolved from power pools that had established installed reserve requirements. Members of the pool were assigned capacity requirements that they then acquired, and their regulator approved. Restructuring raised the question of which entities would be responsible for ensuring that installed reserve margins were met. As discussed earlier, under the competitive regime called "retail access,"[90] new entities, competitive LSEs,[91] provided competitively priced energy to retail customers. Because it was not feasible to have the incumbent utility incur the cost of reserves for power sold by its competitors, this responsibility was shifted to the LSEs, which included 1) utilities in non-retail competition states and 2) utilities in retail competition states that had the obligation to provide service to customers that did not purchase energy service from a competitive supplier. This made capacity a product in the competitive markets. The Deficiency Payment concept depicted in Exhibit 3-5[92] emerged from the rules of the New York Power Pool as an early method for addressing the need for ensuring capacity reserves.

Exhibit 3-5. Price curve based on deficiency payments



Source: ECRC v. FERC [93]

As illustrated by exhibit 3-5, the problem with the deficiency charge is that it created a bimodal pricing structure. If a utility did not meet its reserve margin requirements of 18% (118% of peak

[89] "Review of Reliability Must Run and Capacity procurement Mechanism," *California* ISO, March 13, 2018. http://www.caiso.com/Documents/DraftFinalProposal-ReviewofReliabilityMustRunandCapacityProcurementMechanism.pdf.

[90] Retail access refers to the ability of non-utility entities to provide service to retail customers over the incumbent utility's wires.

[91] LSE refers to any entity that serves retail customer, including incumbent utilities providing last resort service.

[92] See, Electricity Consumers Resource Council v. F.E.R.C., 407 F.3d 1232, 1234 (D.C. Cir. 2005). ("ECRC v. FERC").

[93] Ibid.

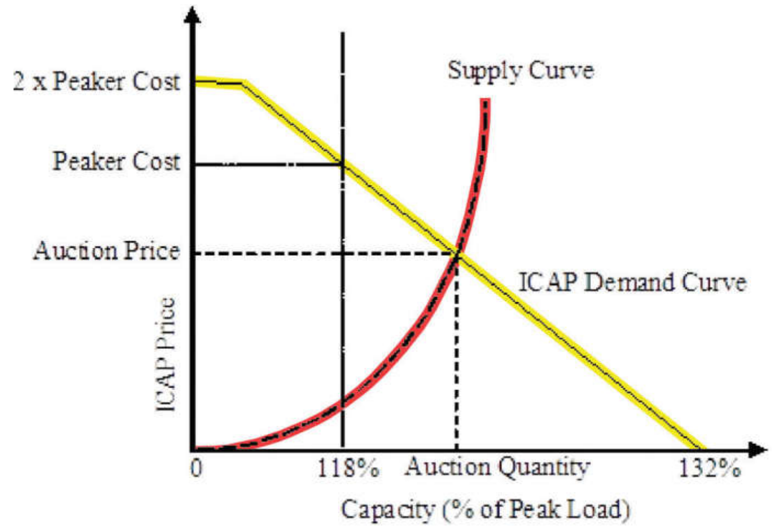
load) it was charged a deficiency charge. This charge became the ICAP price. Therefore, when there was a shortage of capacity, the market capacity price was equal to the deficiency (three times the cost of a peaker). When there was excess generation capacity available to the market, the market price approached zero. The result is a bimodal pricing system, with prices at the deficiency charge during periods of shortage and approaching zero when there is adequate capacity.

In response to complaints by the state's merchant generators about volatile revenues resulting from a capacity market based on deficiency payments, NYISO proposed a generation capacity market based on what was labeled the capacity "demand curve" proposal. The notion behind the demand curve is that it seeks to reflect customer valuation of reliability as not an "all or nothing level," but on a continuum where the marginal price is equal to the marginal reliability contribution of an increment of capacity (i.e., the expected curtailment cost). Using the demand curve, instead of a fixed reserve margin criteria that reflects inelastic demand for reliability, smooths out price volatility while providing revenues to generators.

Exhibit 3-6 demonstrates market making in the New York ICAP market. This price-making mechanism is known as the demand curve. Exhibit 3-6 demonstrates both the reliance on the Peaker Method and the role of administrative pricing and market intervention in price making. The parts of the demand curve highlighted in yellow are a purely administrative price making mechanism. The supply curve is highlighted in red to indicate that it is subject to administrative price intervention, by which FERC mandates buyer-side mitigation, which requires some sellers to offer to sell power in the organized markets at or above an offer floor. (Unfortunately, this has the effect of increasing prices to consumers.) Therefore, it can be seen that the fundamental dynamics in this so-called market are administratively determined.

The key theoretical feature sets the demand curve's pivotal point, that the value of capacity at the desired reserve margin (118 percent of peak load) is equal to the Cost of New Entry (CONE). Given technological change, combustion turbines are efficient enough to earn inframarginal rents. Consequently, there has been an evolution in the paradigm away from calling the measure of pure capacity a peaker to calling it the CONE. The estimate of CONE accounts for energy revenues from inframarginal rents when calculating the capacity cost of a hypothetical new entrant. As in New York, what is clear is that the capacity markets do not recognize the value of a plant to meet decarbonization targets. The other two pivotal points that define the demand curve are 1) the maximum allowable price (two times the cost of CONE) or 2) the point at which the incremental value of capacity (i.e., its price) is zero are not supported by empirical analysis, for example, a study of customer behavior.

Exhibit 3-6. The New York demand curve



Source: ECRC v. FERC [94]

It is worth questioning whether the demand curve structure in the New York ICAP market leads to an efficient outcome that supports its use as part of its role in customer protection, although, as FERC acknowledged in accepting the demand curve (ICAP) proposal, setting specific parameters required "some measure of judgment."[95] In fact, the demand curve is a demand curve in name only, since it does not reflect any estimate of customer demand for reliability or show how the curve would look if it were based on a ratio of the loss of load probability of the system as found to its target level. The loss of load probability is a reliability metric used for determining resource adequacy. It is simply an administrative schedule with arbitrary parameters. And the question of the value of CCS and its ability to meet carbon targets is not on the table.

The NY-ISO is not the only system that adopted a mandatory capacity market. The capacity market is used in other ISOs where generation has been divested and customers can choose their energy providers. Both ISO-NE and PJM have adopted capacity markets. The three ISO markets are very different but, at their core, all three share the idea that at the target reserve margin, the value of capacity is equal to the cost of the peaker—or its modern incarnation—CONE.

3.1.4 Reliability and Ancillary Services

FERC issued two orders in 1996 (Order nos. 888 and 889) that effectively unbundled the costs of generation and transmission. It also required utilities to file Open Access Transmission Tariffs. It did so based upon the powers entrusted to it by the Federal Power Act through the prohibition against "undue preference and advantage."[96] These tariffs enabled the unbundling of

[94] NRRI construct based on Electricity Consumers Resource Council v. F.E.R.C., 407 F.3d 1232, 1234 (D.C. Cir. 2005).

[95] *New York ISO*, 103 FERC ¶ 61,201, 61754 (2003).

[96] 16 U.S.C. §§ 824d - 824e (2000). Section 205(b) states that "[n]o public utility shall, with respect to any transmission or sale subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue preference or disadvantage.

generation from vertically integrated utilities by providing information about the price and value that utilities placed on the various aspects of providing service. In this process, the role of the tariff changed from providing explicit price schedules, to providing mechanisms for establishing price.

Today, the Open Access Same-time Information System (OASIS) provides transparent information on transmission availability and cost to all market participants giving the transmission market the information needed to become competitive. Importantly, Order nos. 888 and 889 also established the basis for creating the ISOs that coordinate the power markets and operate the reliable delivery of power, similar to the way that air traffic controllers direct airplanes.

3.1.5 The Evolution of Market Structure

There are a growing number of proposals on the way to transform the structure of wholesale markets to accommodate renewables and decarbonization. At least three different approaches have been articulated:

- Bifurcated resource adequacy/energy market construct
- Decentralized market approach
- Long-term markets working with short-term energy markets

Dr. Susan Tierney introduced the concept of a bifurcated market design through her "Resource-Adequacy Construct," model, which provides assurance of the availability of appropriate and valuable resources installed on the electric system, and the "Energy-Production Construct," which coordinates electric production. The latter design relies on a "Central Buyer" to procure local and other resources that are needed by electricity consumers for reliable electricity supply. The Central Buyer, a role that can be fulfilled by either an existing or new entity, would rely on targeted solicitations to determine the portfolio of local resources needed to assure a reliable, as well as clean, power supply to all customers. Resource-adequacy products (and the activities of LSEs, as well as the Central Buyer with respect to resource adequacy) would be regulated by the state PUC. In the Tierney proposal, the ISO/RTO would operate the bulk-power system, with its security-constrained dispatch and wholesale rates for the provision of energy and ancillary services regulated by FERC. Informed by the IRP process (which focuses on clean-energy and climate needs and on LSEs' plans to achieve them in a least-cost way), the state PUC would identify the types of resources that are needed to maintain resource adequacy and the loading order (or preference order) for those different types of resources. In this proposal, the ISO/RTO would use a transparent process to identify the amounts of resources needed for each type of resource adequacy product in each year of the upcoming multi-year (e.g., 3-year or 5-year) period.[97] In this case, the capacity supply would meet the market requirements.

Rob Gramlich and Michael Hogan articulate the polar opposite approach: a decentralized market. This market model is largely based on the current Electric Reliability Council of Texas (ERCOT) market. In this approach, there would be a centralized spot market and de-centralized

[97] Susan Tierney, "Resource Adequacy and Wholesale Market Structure for a Future Low-Carbon Power System," *Analysis* Group, July 10, 2018, https://www.analysisgroup.com/insights/publishing/resource-adequacy-and-wholesale-market-structure-for-a-future-low-carbon-power-system-in-california/.

forward procurement between wholesale buyers and sellers. The authors argue that such a market mechanism "puts [LSEs] in the role they should be in—determining and implementing their resource and risk management objectives." They recognize that a "principal challenge" is the credit worthiness of buyers, a problem that they suggest could be resolved by putting PUCs in an expansive role of determining the credit worthiness of buyers.[98]

The third approach integrates long-term markets and short-term markets. This market model provides long-term purchase power agreements (PPAs) for desired projects. These contracts rely on customers as a counterparty, as opposed to a more regulated structure. PPAs act as a backstop to the short-term markets, assuring revenue adequacy. In one proposal, Corneli suggests a "configuration market" based upon system expansion models to determine how to efficiently incorporate high levels of solar, wind storage, and transmission into the grid. All existing and proposed resource providers (including transmission) would submit bids into the configuration market based upon the revenues required to continue operating or, for proposed resources, commit to project development and operation. A configuration computer model would use the various bids to identify a least-cost configuration for the system in both the short and long run. The configuration model would include not only the standard constraints on delivering safe and adequate service at minimum cost but would also include clean energy objectives.[99] Another version of this approach, suggested by Pierpoint, builds on renewable portfolio standards and renewable procurement objectives for capital-intensive low-marginal-cost resources. In yet another version of this approach, Gimon envisions that a long-term market might evolve from forward capacity markets.[100] An important issue that will need to be resolved is the nature of the counterparty contracts, including identifying the liable counter-parties.

The range and complexity of transforming the current electricity market regimes is large, and these changes could help to encourage the development of CCS plants. Incorporating CO_2 emissions as a constraint may favor CCS for existing plants as a transition to a portfolio that can better meet the complex requirements. Each model has different implications for state utility regulators and FERC.

3.2 Maintaining Adequate Levels of Essential Reliability Services

The establishment of and implementation of renewable portfolio standards (RPS) in 30 states and the District of Columbia is impacting resource decisions for over 58% of U.S. retail electricity sales.[101] States project significant generator retirements in order to meet their individual RPS requirements. According to Sector & Sovereign Research:

---

98 Gramlich, R., and Hogan, M., "Wholesale Electricity Market Design for Rapid Decarbonization: A Decentralized Markets Approach," in Aggarwal, S. et al., *Wholesale Electricity Market Design for Rapid Decarbonization*, June, 2019, pp. 24. https://energyinnovation.org/wp-content/uploads/2019/07/Wholesale-Electricity-Market-Design-For-Rapid-Decarbonization.pdf

99 Corneli, S., 'Efficient markets for High Levels of Variable Renewable Energy," *Oxford Energy Forum*, June 2018: Issue 114, pp. 15-19. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2018/06/OEF-114.pdf.

100 Corneli, S., Gimon, E and Pierpont, B., "Wholesale Electricity Market Design for Rapid Decarbonization: Long-term Markets, Working with Short-term Energy Markets," in Aggarwal, S. et al., *Wholesale Electricity Market Design for Rapid Decarbonization*, June, 2019, https://energyinnovation.org/wp-content/uploads/2019/07/Wholesale-Electricity-Market-Design-For-Rapid-Decarbonization.pdf

101 "U.S. Renewables Portfolio Standards 2021 Status Update: Early Release," *Lawrence Berkeley National Laboratory*. P. 9. https://eta-publications.lbl.gov/sites/default/files/rps_status_update-2021_early_release.pdf/.

> *The cumulative impact of these capacity retirements, we calculate, will be to decommission ~300 GW or almost a third of U.S. dispatchable generation capacity by 2030, ~600 GW or 63% of dispatchable capacity by 2035, and ~680 GW or 72% of dispatchable capacity by 2040. Allowing for ongoing additions of dispatchable capacity at the average pre-pandemic pace of 11 GW per year, the scale of these retirements will cause U.S. dispatchable capacity to fall short of the historical peak in power demand by 150 GW by 2032, 250 GW by 2034 and by 300 GW by 2036.*[102]

Most of the retirements projected through 2030 are due to the average age and economic viability of fossil-fired steam turbine and simple cycle gas turbine power plants. The added carbon constraints of state RPS goals also impact regulatory decisions due to their high CO_2 emission rates. Specifically, coal-fired steam turbine plants average 1 metric ton of CO_2 per MWh. Simple cycle gas turbines and gas-fired steam turbines average 0.6 Mt CO_2 /MWh and 0.5 Mt CO_2/MWh, respectively.

The transition to a carbon-free electric system will require ensuring that new technologies and resources are able to provide the level of reliability necessary to ensure successful and continuous operation of the system. The North American Electric Reliability Corporation (NERC), the FERC-designated electric reliability organization in the United States, has codified the reliability attributes provided by different types of resources. Essential reliability services (ERS) include frequency and voltage support, as well as ramping and balancing capability. The operating capabilities of conventional generators, including gas- and coal-fired plants, are well-documented compared to those of relatively new wind, solar, and battery technologies. Systems with growing amounts of intermittent resources will require more controllable, fast-ramping generation, so that system operators can balance supply and demand. However, there are limited options for carbon-free resources that can also provide certain types and levels of ERS. Descriptions of the essential reliability services follow.

An emerging issue is the availability of enough baseload and dispatchable resources with the technical capability to provide the system with adequate levels of reliability services to maintain adequate system stability and to address the operational challenges associated with variable wind and solar. Carbon capture technologies can play an important role in this transition by extending the use of two important fuel types: natural gas and coal.[103] While coal plants are designed to run as baseload generation, natural gas plants that are highly dispatchable are increasingly being utilized as the predominant baseload resource for power generation in many regions.[104] While combusting natural gas produces roughly half of the CO_2 emissions of coal (on a MWh basis), emissions from natural gas power plants will ultimately need to be controlled in order to meet carbon reduction policy goals.[105] CCS technology will be an important mechanism for maintaining adequate levels of dispatchable and baseload capacity with limited emissions. Policies that address the current costs and investment risks associated with this technology will be needed to make these CCS projects economically viable.

---

102 Selmon, E. and Wynne, H., "The Looming Crisis in Generation Capacity," Sector & Sovereign Research, June 7, 2021. P. 1. https://www.ssrllc.com/publication/the-looming-crisis-in-generation-capacity/.

103 These plants currently provide approximately 20 and 40 percent of total generation, respectively.

104 "Single Point of Disruption to Natural Gas Infrastructure," *North American Electric Reliability Corporation,* November 2017. P. 7. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SPOD_11142017_Final.pdf.

105 "Natural Gas At-a-glance," *Center for Climate and Energy Solutions* https://www.c2es.org/content/natural-gas/.

As older fossil-fueled resources are retired to comply with decarbonization policies, it will be important to ensure there are enough new resources on the system to provide adequate essential reliability services. This transition will introduce complex challenges, especially when additional transmission is needed to deliver that power to load. Installing CCS technology on existing coal or natural gas plants with significant remaining operational life may be a more reliable and affordable approach for meeting carbon-reduction policies until other non- or low-carbon-emitting technologies (e.g., batteries) are developed and deployed in the coming decades. As older fossil-fuel plants are retired, economic incentives will be needed to either retrofit existing plants with CCS technology or identify replacement capacity capable of providing the system with adequate levels of ERS.

The North American Electric Reliability Corporation (NERC), the FERC-designated electric reliability organization (ERO) in the United States, has codified the reliability attributes provided by different types of resources. Essential reliability services include frequency and voltage support, as well as ramping and balancing capability. The operating capabilities of conventional generators, including gas- and coal-fired plants, are well-documented compared to those of relatively new wind, solar, and battery technologies. Systems with growing amounts of intermittent resources will require more controllable, fast-ramping generation, so that system operators can balance supply and demand. However, there are limited options for carbon-free resources that can also provide certain types and levels of ERS. Descriptions of the essential reliability services follow.

Frequency Support: According to NERC, frequency support is provided through the combined interactions of synchronous inertia and frequency response to maintain specified levels for reliable system operation.[106] Conventional thermal generation units (e.g., coal, nuclear, reservoir hydro) provide frequency support services as a co-product of power output due to large spinning mass. This translates to a resource's ability to "ride-through" a disturbance and remain online during unexpected drops or spikes in voltage and/or reactive power on the system. Typically, conventional thermal plants offer generator governor control settings that can provide automated reactive support for voltage control.[107] Power system operators use these services to plan and operate the grid reliably under a variety of system conditions. A large outage (e.g., the loss of a large generator or transmission line) can cause frequency to drop across the entire interconnection. In order to withstand such an event, the system must have enough responsive resources that are capable of increasing output rapidly, slowing the decline in frequency, and ultimately contributing to the event recovery.[108] Traditional resources that typically operate with installed governor control settings can provide automated reactive support and voltage control. Certain types of inverter-based resources can also provide voltage control.

The three different types of frequency response, primary, secondary, and tertiary, are shown in Exhibit 3-8 below. Each of these types of response is used in different system circumstances in different time frames.

---

[106] "ERS Sufficiency Guidelines White Paper," *North American Electric Reliability Corporation*, December 2016. P. iv. https://www.nerc.com/com/Other/essntlrlbltysrvcstskfrcDL/ERSWG_Sufficiency_Guideline_Report.pdf.

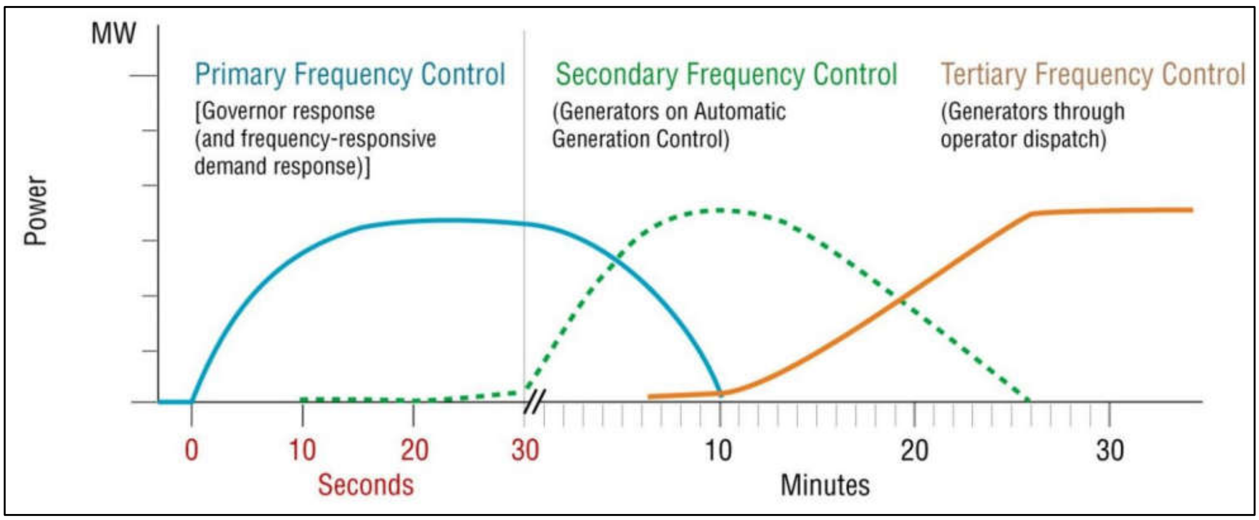
[107] A generator's governor is used to control the speed of the turbine, thus controlling the output of the unit.

[108] "ERSTF Measures Framework," *North American Electric Reliability Corporation*, November 2015. P. v. www.nerc.com/com/Other/essntlrlbltysrvcstskfrcDL/ ERSTF%20Framework%20Report%20-%20Final.pdf.

Primary or "fast" frequency response is provided by certain generators immediately following the first stage of an event. This capability is automatically initiated by generator governors to arrest locally detected changes in frequency within seconds (based on a local set-point) and helps to arrest frequency drops following the sudden loss of generation on the system. After a frequency decline is arrested, primary frequency response helps stabilize frequency back to 60 Hz. Generators that provide this service are essential for maintaining grid reliability as the first line of defense in keeping the system at NERC-specified operating levels.[109]

Secondary frequency response is also provided by certain generators through a specific set-point to the automatic generation control (AGC). AGC is determined by software and computing that sends signals every four seconds to a subset of resources to either increase or decrease generator output to maintain local (and system) supply and demand. Additional direction may be provided by the system operator on 15-minute basis.[110] When there is a destabilizing event on the system, restoring frequency to appropriate levels is accomplished through a combination of primary frequency response, AGC, and dispatchability. Finally, tertiary frequency control can be requested by the system operator to replace both primary and secondary frequency response to restore system stability.

Exhibit 3-7. Primary, Secondary, and Tertiary Frequency Control[111]



Source: Lawrence Berkeley National Laboratory, 2018

Voltage Support and Reactive Power: Voltage regulation and reactive resource management are critical parts of reliable system planning and operation. Voltage must be maintained within narrow limits to protect the system and move power where it is needed. As demonstrated in Exhibit 3-8, voltage control and the maintenance of reactive power require the coordination of

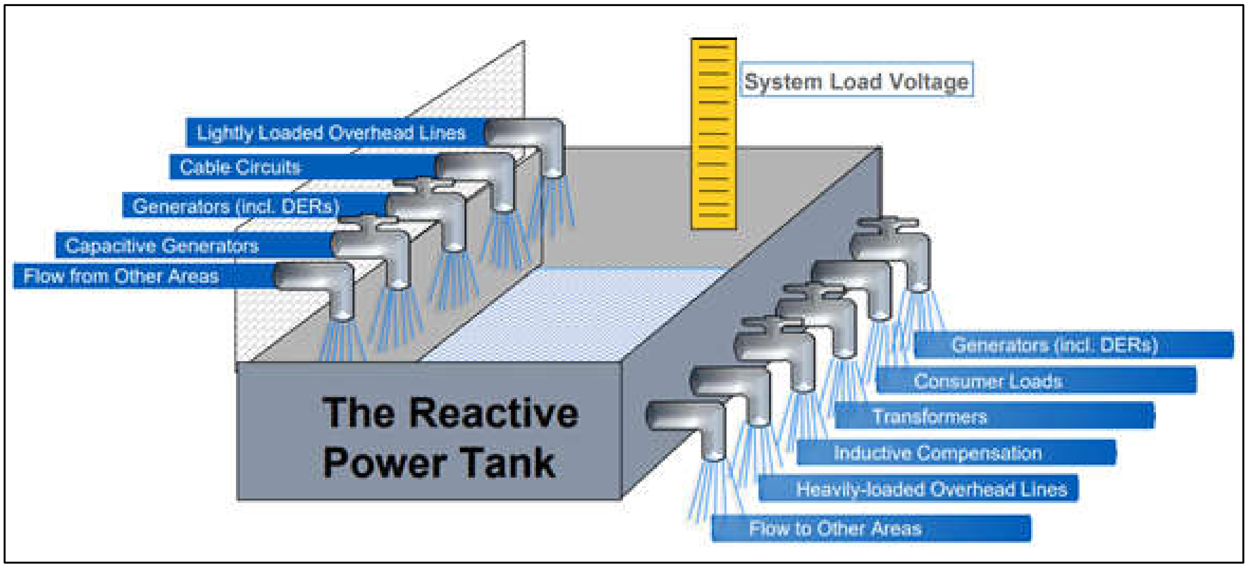
[109] see: NERC Reliability Standard BAL-003-1.[109] Manual 12 Update Primary Frequency Response Performance Measurement. January 8, 2019. Slide 8. https://www.pjm.com/-/media/committees-groups/subcommittees/sos/20190201/20190201-item-12-m12-update-primary-frequency-response.ashx

[110] Pietro Tumino, "Frequency Control in a Power System," *EEPower*, October 15, 2020. https://eepower.com/technical-articles/frequency-control-in-a-power-system/#.

[111] "Frequency Response Study for FERC," *Lawrence Berkeley National Laboratory*, (July 2018): Slide 7. https://www.energy.gov/sites/prod/files/2018/07/f53/2.1.1%20Frequency%20Response%20Panel%20-%20Eto%2C%20LBNL_1.pdf.

many system resources and are monitored by system planners and operators to ensure system reliability.

Exhibit 3-8. Reactive power and voltage support



Used with permission from MacDowell[112]

Dispatchability (Ramping and Balancing): Maintaining ramping and balancing capabilities are particularly important within Balancing Authorities[113] with high levels of variable resources that are not dispatchable or controllable by the system operator.[114] Dispatchability is defined as a resource's ability to increase or decrease output on demand. Most thermal resources that are synchronized to the grid can be dispatched across a wide range of operating levels relatively quickly. Other resources, such as reservoir hydro, nuclear, and some coal plants, have minimum generation levels and thus cannot be dispatched below certain output levels (this is known as the PMin). All resources also have maximum output levels (PMax).

Output from renewable resources is dependent on the availability of their respective energy sources (the wind or the sun). Systems with high amounts of non-dispatchable resources require ramping capabilities from dispatchable, responsive resources such as gas-fired generators or energy storage (i.e., flywheels, pumped storage, or batteries). Without sufficient ramping capabilities, operating conditions may lead to ramping shortfalls – particularly when system loads are high and the wind suddenly stops blowing, or cloud cover reduces solar

[112] Graphic: J. MacDowell, GE Energy Consulting, 2018. Presented to National Association of Regulatory Utility Commissioners Bulk Power System Learning Modules on June 10, 2021. https://pubs.naruc.org/pub/A21DDD6F-1866-DAAC-99FB-A5BE8022DD5A.

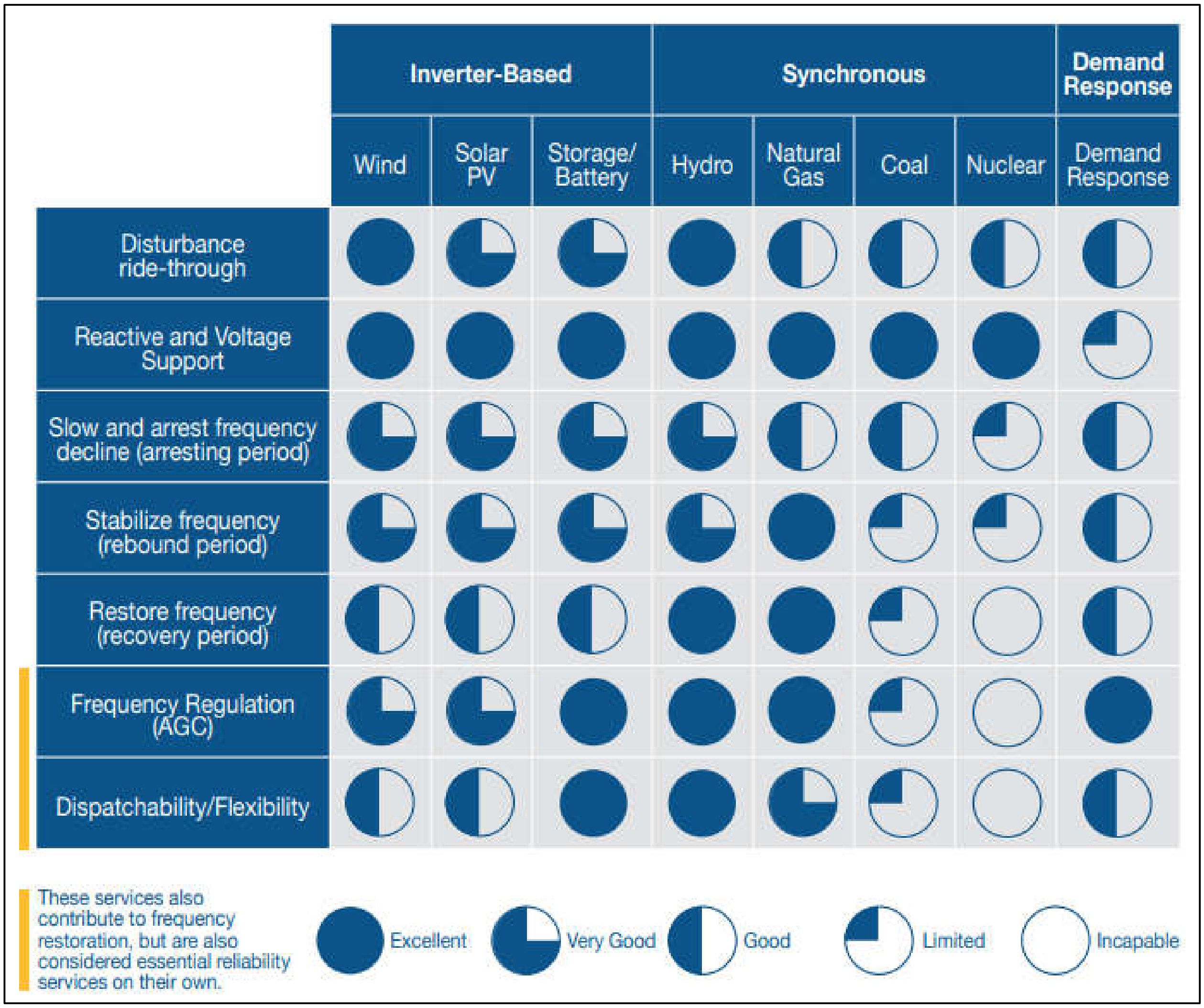
[113] Balancing Authority is defined by NERC as: "The responsible entity that integrates resource plans ahead of time, maintains load interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time." "Reliability Functional Model – Function Definitions and Functional Entities. Version 5.1," North American Electric Reliability Corporation, (August 2018): 34. https://www.nerc.com/pa/Stand/Functional%20Model%20Advisory%20Group%20DL/Functional_Model_V5.1_clean_10082019.pdf

[114] "ERS Sufficiency Guidelines White Paper," *North American Electricity Reliability Corporation*, (December 2016): v. https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSWG_Sufficiency_Guideline_Report.pdf

output. While forecasting has become more reliable, especially in the short-term, there is still a risk for certain systems that are heavily dependent on variable resources.

Exhibit 3-9 summarizes the different reliability characteristics provided by each resource type. The actual reliability service provided by each generation type depends on the physical characteristics of each resource.[115]

Exhibit 3-9. Synchronous and inverter-based ability to provide reliability services



Used with permission from Milligan et al.[116]

[115] For example, Type 1 and Type 2 wind turbines do not provide inertia. Most installed turbines throughout the country are Type 3 and Type 4, which provide limited amounts of inertia, voltage support, and ramping capability, assuming the use of "headroom." Voltage support depends on the type of nuclear unit. For combined cycle units, there are often limitations on steam units.

[116] Milligan, M. "Sources of Grid Reliability Services," *Milligan Grid Solutions*, http://milligangridsolutions.com/Sources%20of%20Essential%20Reliability%20Grid%20Services%20Fact%20Sheet.pdf

3.2.1 Reliability Standards and Market Design Enhancements to Maintain Adequate Levels of ERS

The evolving nature of the electric grid in the United States will require changes to wholesale electricity market design that assign value to resources capable of providing essential reliability services. Although resource mix, market design, and reliability policies differ across the country, all organized markets will need to prioritize long-term system reliability, while also providing efficient price signals to balance supply and demand. Markets must also provide the appropriate incentives for operational reliability and flexibility in an economically efficient manner. Developing the appropriate incentives will require a comprehensive approach to ensure that resource adequacy is reflected in market prices to ensure enough responsive or dispatchable resources are available for the system to maintain needed levels of grid services at all times. Maintaining enough responsive or dispatchable resources is particularly important for systems with growing reliance on variable renewable resources, such as wind or solar, that will require more ramping capability during certain periods of the day. For this reason, it will be important to design markets and capacity requirements that promote the adequacy and availability of resources that can respond to rapidly changing system conditions (temporal, locational, and service-related).

Resources that provide various levels of ERS to maintain the system stability and balance between load and generation—especially during rapid ramping periods and extreme weather events—will require reliability planning and market enhancements throughout the country. FERC has established some interconnection requirements for small and large generators to promote system reliability. For example, Order 828 modified the Small Generation Interconnection Agreement to require newly interconnecting generators (under 20 MW) to sustain power delivery to the grid during abnormal frequency and voltage events.[117] NERC has also established Reliability Standards that require the system to plan for and maintain the levels of frequency, outlined in Exhibit 3-10.

In addition to these standards, NERC formally identified additional "essential" reliability services in 2016 and established corresponding measures to track ERS levels throughout the country. While this effort is ongoing, establishing requirements and standards, or assigning value to resources that provide ERS is more complicated.[118] As NERC and the industry continues collaborative efforts to collect data and track different ERS measures, there may be a determination that new NERC Reliability Standards are needed, or that existing ones require enhancement.

Exhibit 3-11 summarizes current or proposed planning and market design enhancements related to reliability services provided by resources in each ISO/RTO.

[117] "Interconnection Standards for Small Generators," [webpage], *Database of State Incentives for Renewables & Efficiency*, last updated July 27, 2016, https://programs.dsireusa.org/system/program/detail/2774

[118] PJM has introduced some tariff modifications that offer compensation for reactive service.

Exhibit 3-10. NERC Reliability Standards related to system reliability services

Reliability Service	Reliability Standards[119]		
	Standard	Title	Purpose
Dispatchability /Flexibility	PRC-024-2	Generator Frequency and Voltage Protective Relay Settings	Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions
Reactive & Voltage Support	VAR-001-5	Voltage and Reactive Control	Requirements related to voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real-time to protect equipment and the reliable operation of the Interconnection
	PRC-019-2	Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection	Verify coordination of generating unit facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings
Inertia/ Disturbance Ride-Through	MOD-025-2	Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability	Ensures accurate information is reported for generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models
	MOD-033	Steady-State and Dynamic System Model Validation	Establishes consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system
Frequency Response	MOD-027-1	Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions	Verify that the turbine/governor and load control or active power/frequency control models and the model parameters used in dynamic simulations, accurately represent generator unit real power response to system frequency variations
	BAL-003-2	Frequency Response and Frequency Bias Setting	Requires sufficient Frequency Response from the Balancing Authority to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting

[119] "Mandatory Standards Subject to Enforcement," [webpage], *North American Electric Reliability Corporation*, https://www.nerc.net/standardsreports/standardssummary.aspx.

Exhibit 3-11. Planning and market design enhancements for changing reliability needs

Market	Enhancements
ERCOT	Designate synchronous generator as reliability-must-run under certain operational conditions (involves dispatching synchronous generation out-of-merit and potentially curtailing variable resources)[120]
CAISO	• Incorporate forced outage rates in reliability requirements and net qualifying capacity calculation • Develop a new flexible resource adequacy framework • Update rules for resource adequacy import provisions • Improve resource deliverability through updated must-offer obligations[121] • Develop methodology to calculate unforced capacity value for use in resource adequacy requirements and assessments to reflect the impacts of high forced outage rates[122]
ISO-NE	• Align longer-term market-based approaches for multi-day energy needs and fuel security with appropriate price signals through • Retain resources for the Fuel Security Key Project for near-term winter seasons • Incorporate resource compensation into the Forward Capacity Market Fuel Security Reliability Review methodologies • Implement Competitive Auctions with Sponsored Resources to efficiently reflect the costs of state policies in its forward capacity market
MISO	• Identify availability and flexibility needs related to resource adequacy program[123] • Identify need to improve reliability requirements to reflect reliability needs across all hours of the year, and to better accredit resource contributions towards resource adequacy
NYISO	• Conduct a comprehensive mitigation review to evaluate buyer-side mitigation (BSM) rules to accommodate state climate policies • Review revisions to resource capacity ratings for renewables and storage to reflect their reliability contribution • Modify other capacity market-related activities, including LMP of capacity, seasonal procurement requirements, and a capacity demand curve. NYISO also conducted a fuel security analysis to evaluate the risks associated with fuel and energy availability during the winter season
PJM	• Value frequency response and balancing capability in capacity markets by paying for different levels of AGC[124] • Introduce tariff modifications to offer compensation for reactive service[125] • Modify the capacity market with a Minimum Offer Price Rule to accommodate state-subsidized electric generation resources
SPP	• Identify security resilience, regional resource needs, and grid resilience initiatives as priorities in its strategic plan initiatives[126] • Adopt ELCC methodology to determine accreditation of wind and solar resources[127]

120 "Bulk Power System Learning Modules," *National Association of Regulatory Utility Commissioners*, presented June 10, 2021. Slide 27. https://pubs.naruc.org/pub/A21DDD6F-1866-DAAC-99FB-A5BE8022DD5A.

121 "Resource Adequacy Enhancements Draft Final Proposal," *California ISO*, (December 17, 2020): 104-110, http://www.caiso.com/InitiativeDocuments/DraftFinalProposal-SixthRevisedStrawProposal-ResourceAdequacyEnhancements.pdf

122 122 "Resource Adequacy Enhancements Second Revised Straw Proposal," *California* ISO, (October 3, 2019): 15-28 http://www.caiso.com/InitiativeDocuments/SecondRevisedStrawProposal-ResourceAdequacyEnhancements.pdf (I know 2018 was cited, but best to use the 2019 revised straw proposal.

123 "2019 State of the Market Report," *Potomac Economics for MISO, (June 2020):66-67,* https://www.potomaceconomics.com/wp-content/uploads/2020/06/2019-MISO-SOM_Report_Final_6-16-20r1.pdf

124 See "PJM Manual 18," *PJM*, (2021) https://www.pjm.com/~/media/documents/manuals/m18.ashx

125 "Open Access Transmission Tariff," *PJM*, (2010): Attachment K, appendix section 3.2.3B. https://agreements.pjm.com/oatt/3897

126 "2017 Strategic Plan Revised Initiative," *Southwest Power Pool*, (2017): 4, https://spp.org/documents/55101/2017%20strategic%20plan%20-%20revised%20initiatives.pdf

127 Warren, et. al., "State of the Market," Southwest Power Pool, (May 11, 2019): 222, https://www.spp.org/documents/62150/2019%20annual%20state%20of%20the%20market%20report.pdf

Resources with different operational characteristics are difficult to value in existing wholesale electricity market structures. This is because the existing and planned resource mix varies by market area, making it difficult to determine the levels of ERS needed to maintain reliability. In particular, the more diverse the resource and ownership mix, the greater the challenges for scheduling and operations. Different levels of ERS are measured across a Balancing Authority,[128] or system, or entire interconnection. The responsibility for meeting the existing standards falls primarily on the Transmission Operator or Generator Operator. These standards need to be updated to account for the changing resource mix and the corresponding NERC ERS guidelines to maintain long-term system reliability, particularly given the rapidly changing resources mix that will be needed to meet the ambitious RPS goals of individual states.

In addition to the existing standards described above, NERC's technical committees have approved ERS guidelines that recommend tracking ramping capability, frequency levels, and inertia.[129] These levels are measured for each Balancing Area or interconnection. NERC's ERS efforts might lead to the establishment of NERC Reliability Standards that could require minimum levels of ERS, making CCS-equipped thermal plants important in providing reliability services with limited carbon emissions. NERC's Reliability Standards development process can take many years and there is notable industry resistance to creating new requirements that might favor certain resources over other, which may impact the economic viability of existing capacity investments.

Designing markets that properly value ERS is complicated. There are varying approaches for valuing reliability contributions (e.g., net qualifying capacity values in California[130]). Because the output for all resources fluctuates and thus provides varying levels of ERS throughout the hour, day, or season, a more practical approach might involve examining the ERS provided by each resource type on a capacity basis. For example, a generator with a higher ramp rate could receive an annual or seasonal capacity payment for providing this important service. A resource with a slower ramp-rate would receive a smaller capacity payment. This approach could help incent the availability of enough baseload and flexible resources to maintain system reliability as systems reach new levels of variable resources.[131] The continued development and deployment of CCS technology could extend the operation of existing thermal generation. These generating units can continue to provide important reliability services to support the ongoing deployment and integration of variable resources like wind and solar. Ultimately, appropriate compensation for these services could provide incentives for the development of CCS plants, particularly if FERC considers examining how to effectively capture the value of these services in the ancillary services and capacity markets.

---

[128] A Balancing Authority is an entity that coordinates generation to meet load within a specific area.

[129] "Essential Reliability Services Working Group (ERSWG) and Distributed Energy Resources Task Force (DERTF)," [webpage] *North American Electric Reliability Corporation*, https://www.nerc.com/comm/Other/Pages/Essential-Reliability-Services-Task-Force-(ERSTF).aspx

[130] NCQ values are used by CAISO to determine "the amount of capacity that can be counted from each resource toward meeting Resource Adequacy … requirements in the CPUC's RA program." See: "2021 Net Qualifying Capacity and Effective Flexible Capacity Values for Resource Adequacy Resources," *California ISO*, (August 14, 2020) http://www.caiso.com/Documents/2021NetQualifyingCapacity-EffectiveFlexibleCapacityValues-ResourceAdequacyResources.html

[131] Another approach is to conduct capacity planning by incorporating a wider range of operational properties and recognizing physical constraints, along with imposing directly on the solution carbon and other emission limits. This will lead to a more robust and effective portfolio as plant operating values are monetized.

3.3 Applying Section 45Q of the Tax Code to CCS

Section 45Q of the U.S. tax code provides a per ton credit for the capture and geologic storage of CO_2 that would otherwise be emitted by a power plant or industrial application. This credit was enacted by the Energy Improvement and Extension Act of 2008.[132] The intent of this credit is to encourage carbon-emitting industries to reduce their emissions and support the deployment of CO_2-free energy through various capture and storage technologies.[133]

The Internal Revenue Service (IRS) maintains authority over the certification of commercial utilization of emissions storage by qualifying facilities, with applicable credits on a per-ton basis for storage of CO_2.[134] Section 45Q is an important factor for companies making investment decisions on CCS technology, because it provides a stable and predictable revenue stream for carbon that is captured and stored.

The initial 45Q program, established in 2008, provided a credit of $20/Mt for CO_2 stored in geological formations, and $10/Mt for CO_2 used for EOR or enhanced natural gas recovery (EGR).[135] The initial program required individual facilities to capture at least 500,000 Mt/year, with the credits ending after 75 MMT of CO_2 were captured and stored. The Bipartisan Budget Act of 2018 amended the law to expand the eligibility parameters to include qualified carbon oxides (COx),[136] reduce the annual CO_2 capture minimum, provide greater flexibility for entities to claim credits, and modify the CO_2 credit amounts, as shown in Exhibit 3-12.

Exhibit 3-12. 2018 Bipartisan Budget Act: Eligibility and credits for power plants

	MINIMUM SIZE OF ELIGIBLE CARBON CAPTURE PLANT BY SIZE	RELEVANT LEVEL OF TAX CREDIT GIVEN IN OPERABLE YEAR (USD/tCO_2) 2018	2019	2020	2021	2022	2023	2024	2025	2026	LATER
DEDICATED GEOLOGICAL STORAGE	500 $KtCO_2$/YR3	$28	31	34	36	39	42	45	47	50	
STORAGE VIA ENHANCED OIL RECOVERY	500 $KtCO_2$/YR	$17	19	22	24	26	28	31	33	35	
OTHER UTILIZATION PROCESSES*	25 $KtCO_2$/YR	$17	19	22	24	26	28	31	33	35	

*each CO_2 source cannot be greater than 500$KtCO_2$ /yr. Any credit will only apply to the portion of the converted CO2 that can be shown to reduce overall emissions.

[132] H.R.6049, *Energy Improvement and Extension Act of 2008*, 110th Cong., Introduced in House May 14, 2008, https://www.congress.gov/bill/110th-congress/house-bill/6049.

[133] The 45Q credit is eligible for CO_2, CO, and carbon suboxide. EOR is performed by injecting carbon into existing wells, a process that improves extraction efficiency and increases the volume of oil recovered.

[134] "Drilling Down—Examining the Section 45Q Tax Credit," *KPMG*, March 5, 2020, https://home.kpmg/us/en/home/insights/2020/03/examining-section-45q-tax-credit.html l

[135] Department of the Treasury, Internal Revenue Service, *Credit for Carbon Oxide Sequestration*, https://www.irs.gov/pub/irs-drop/td-9944.pdf

[136] Includes CO_2, or any other carbon oxide that qualifies under provisions of the enacted law.

Beck, 2020[137]

The 45Q credit is available for a 12-year period after the equipment is placed in-service. The tax credits are issued on a per-Mt basis, rather than based on the capital cost of the facility (in contrast to the Investment Tax Credit provided for solar).[138] The owner of the capture equipment must physically or contractually ensure the storage or utilization of the CO_2 with the option to transfer the credit to a second eligible party for storage or beneficial use. The taxpayer claiming the 45Q credit must report the name and location of each qualified facility at which the qualified CO_2 was captured.[139] An important consideration for investors evaluating modifying existing power plants with CCS technology, or building a new electricity generating facility, is that if the unit's annual emissions exceed 500,000 Mt of CO_2, the CCS technology must capture at least 500,000 Mt of qualified CO_2 per year.[140] The 45Q credit will increase to $35/Mt and $50/Mt by 2026 for dedicated geological storage and EOR, respectively. A 2019 analysis by the Great Plains Institute revealed that the estimated cost of capture for coal and gas fired power plants is $56/Mt, and $57/Mt, respectively.[141]

3.3.1 Impact of 45Q Credits

The impacts of the 45Q tax credit are especially notable in the power sector. A 2019 study released by the Clean Air Task Force projected that the tax credit alone could incent the deployment of CCS at levels that could remove approximately 49 million tons of CO_2 per year by 2030.[142] The International Energy Agency (IEA) projects that CCS could account for 7 percent of global emissions reductions by 2040.[143] The modeling by IEA demonstrates that 45Q-supported CO_2 reductions in the power sector are additive to those achieved through renewable sources of electricity generation. For this reason, the tax credits provided for CCS on coal- and gas-fired power plants will serve as a crucial component in reducing U.S. carbon emissions.

---

137 Beck, L. "The US Section 45Q Tax Credit for Carbon Oxide Sequestration: An Update," *The Global CCS Institute*, (April 2020): 2. Chart modified by NRRI staff.

138 "Developing CCUS Projects in Louisiana and the Gulf Coast," *Global CCS Institute*, (2020): Slide 17, https://www.globalccsinstitute.com/wp-content/uploads/2020/11/PPT-LA_Day-1-and-Day-2.pdf

139 The IRS requires that each party to a binding written contract for CCS report the contract, the names, and the tax ID numbers of the parties involved, the amount of qualified CO_2 claimed by each party, EPA GHGRP e-GGRT ID number, location of the storage site, etc. The "Credit Claimant," and electing taxpayer who transfers credit to Credit Claimant, must both report significant details of their actions to allow IRS to trace the transfers. Any taxpayer who claims the 45Q credit must report a recapture event that occurs during a project's recapture period, along with the recapture amount, the quantity of leaked qualified CO_2, the credit rates involved and a statement providing details regarding the leak. Finally, 45Q credits will not be allowed to a taxpayer that fails to timely provide all required information, documentation and certifications.

140 26 USC § 45Q(d)(2)

141 "Developing CCUS Projects in Louisiana and the Gulf Coast," *Global CCS Institute*, (2020): Slide 17, https://www.globalccsinstitute.com/wp-content/uploads/2020/11/PPT-LA_Day-1-and-Day-2.pdf. Additional analysis from 2016 available here: "FY 2017 Congressional Budget Request," *U.S. Department of Energy*, (2016): 554, accessed August 24, 2016, https://netl.doe.gov/projects/files/CostAndPerformance BaselineForFossilEnergyPlantsVol1BitumCoalAndNGtoElectBBRRev4-1_092419.pdf

142 Nagabhushan, D. & Thompson, J. "Carbon Capture and Storage in the United States Power Sector: The Impact of 45Q Tax Credits," *Clean Air Task Force*. (February 2019):17. https://www.catf.us/wp-content/uploads/2019/02/CATF_CCS_United_States_Power_Sector.pdf

143 "Carbon capture, utilization and storage," [webpage] *International Energy Association*, https://www.iea.org/fuels-and-technologies/carbon-capture-utilisation-and-storage

3.3.2 Remaining Financing Gaps

The 45Q tax credit provides several routes for potential investors to leverage the benefits that will make a power plant retrofit or new-build economically viable. The general investment model used to leverage the 45Q tax credit has important ramifications for the success of the project. This model, described in the Clean Air Task Force report,[144] uses an approach similar to the tax structures used for wind and solar investments over a decade ago by creating tax equity partnerships. These partnerships allow large investors with significant tax liability to partner with qualifying entities to use the 45Q tax credits to offset tax obligations from other operations.[145] The 45Q tax credit offsets may ultimately attract investments from larger corporations interested in reducing their overall tax burden, encouraging CCS.

The business model identified in the Clean Air Task Force report involves creating a separate, private entity that provides the capital investment in CCS equipment and then leases the facility to a power plant operator. This model allows the investor to leverage the actual 45Q credits for the geologic storage of CO_2 (e.g., EOR) and pay the plant operator an upfront amount equal to the net present value of all projected returns from the EOR credits using a predetermined discount rate (e.g., 15 percent). The initial amount is then subtracted from the capital costs of the CCS technology.

Additional 45Q tax credit considerations are described below:[146]

- **Capital costs** for the installation of a CCS system (upfront investment from a tax equity investor reduces costs, and the project's debt, thus lowering the overall capital charge rates
- **Annual run time** of a CCS unit over the entire modeling period
- **Capacity factor** of a CCS unit[147]
- Estimated emissions and **captured and stored CO_2**
- **Capital charge rates** must be calculated outside the model, dependent on run-rate assumptions of a CCS unit
- Total **tax credit value**, determined by multiplying CO_2 volume by the annual EOR tax credit for each year the unit can receive credit

The 45Q tax credit has served as an important driver for the few current CCS projects currently in place or being developed. Going forward, investors, owners, and operators can also use other grants and loans, as well as state and local clean energy programs and investment tax credit

[144] Nagabhushan, D. & Thompson, J. "Carbon Capture and Storage in the United States Power Sector: The Impact of 45Q Tax Credits," *Clean Air Task Force*. (February 2019):17 https://www.catf.us/wp-content/uploads/2019/02/CATF_CCS_United_States_Power_Sector.pdf

[145] Randall Connally, "Denbury: Carbon Capture Business A Major Differentiator," Seeking Alpha, (2020) https://seekingalpha.com/article/4384224-denbury-carbon-capture-business-major-differentiator

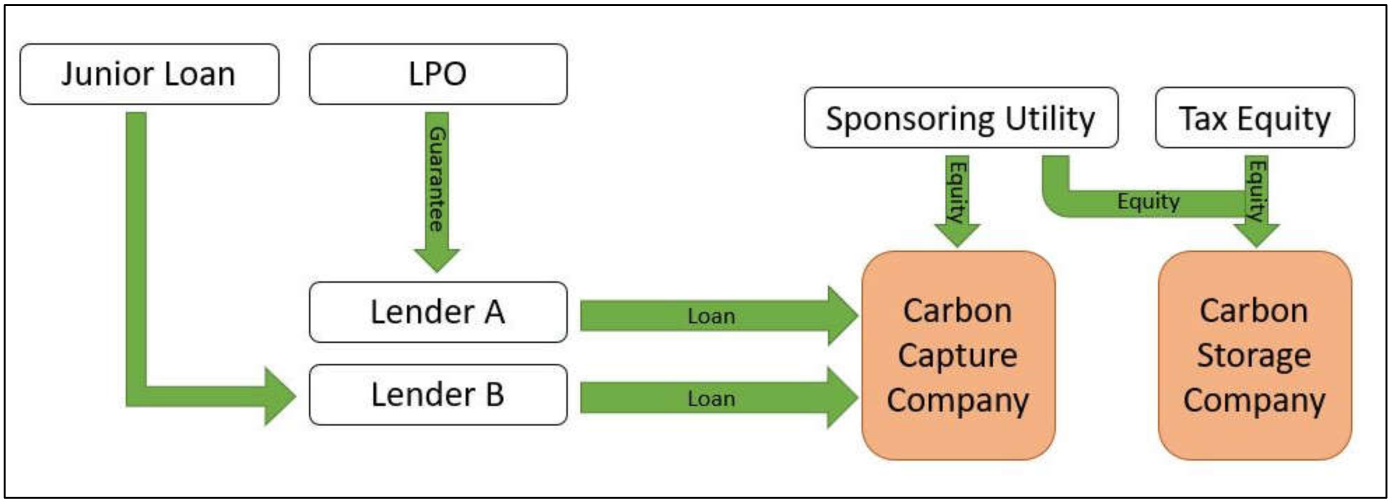
[146] The in-service date of the CCS unit affects the cumulative amounts of tax credits, because the price of carbon captured increases over time. Assuming the investor capitalizes the tax credits (at a discount rate of 15 percent), the amount of the 12-year tax credit would be deducted to arrive at the capital cost at the time of investment.

[147] CCS units are generally more viable with higher capacity factors (90–95 percent after accounting for forced outages). However, the Clean Air Task Force applied a more conservative capacity factor of 85 percent. https://www.catf.us/wp-content/uploads/2019/02/CATF_CCS_United_States_Power_Sector.pdf

incentives, to make CCS projects viable.[148] A description of the state policies are included in Appendix A.

The financing structure for a given project can be extremely complex and the various elements are subject to change. Exhibit 3-13 provides a construct for what a project's financing structure could look like.

***Exhibit 3-13. Example of preliminary financing structure*[149]**



Note: Graphic is based on the potential financing structure of a CCS project currently under development (and confidential).

In this example, the project depends on a combination of investments, a tax equity partnership (supporting the storage portion of the project), and support from a federal loan guarantee program.

Tax equity partnerships have been used to support the development of and transition to renewables and usually include at least two investors. There is a sponsor (usually the utility) and at least one investor from an entity with sizable tax responsibility that is interested in using tax credits to lower their own tax burden (see Exhibit 3-14).

The tax equity investor will establish a separate LLC (in adherence with IRS guidelines) that allocates tax reductions and cash distributions to the investors over the life of the partnership. An example of the application of a tax equity partnership is that used by NextEra Energy Resources to fund its fleet of wind generators. Its reliance on tax equity partnership grew from 0 percent in 2005 to over 80 percent in 2017.[150] Armando Pimentel, Nextera's chief financial officer, emphasized the usefulness of a tax equity partnership structure that "…represents an

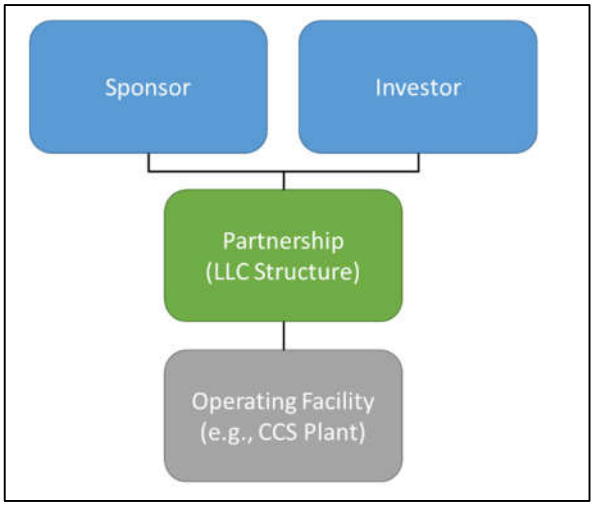
148 Several state governments have established tax policies since 2005.

149 This figure was developed by NRRI staff using information provided by Minkotta Power, a Touchstone Energy Cooperative.

150 NextEra Energy. Represents new money tax equity investments only; excludes secondary market transactions. Source: Chadbourne & Parke LLP; Renewable Energy World; Platts; Norton Rose Fulbright; Mayer Brown. https://www.investor.nexteraenergy.com/~/media/Files/N/NEE-IR/investor-materials/supplemental-resources/supplemental-presentations/tax-equity-partnerships-differential-membership-interests-vf.pdf (See Slide 5).

evolution of a structure we first used in September 2010 where the tax equity investor makes an initial up front payment and additional investments over time…"[151]

Exhibit 3-14. Tax equity partnership structure[152]



A 2020 Columbia University report examined the financial gaps and potential policies for CCS projects. One of the report's findings is that the capital-intensive nature of CCS projects creates significant barriers to investment—even when retrofitting existing power plants with this new technology. CCS project costs amount to as high as 46 percent of the total cost of a standard natural gas combined cycle (NGCC) power plant. Ultimately, lower energy prices may not cover the capital and operating costs, creating significant risks for potential project investors.[153]

While the 45Q tax credits create a certain value stream for many projects, the program does not appear to be sufficient to support project financing alone. The financial gaps presented in Exhibit 3-15 demonstrate the need for additional incentives or policies to make a CCS project viable.[154]

---

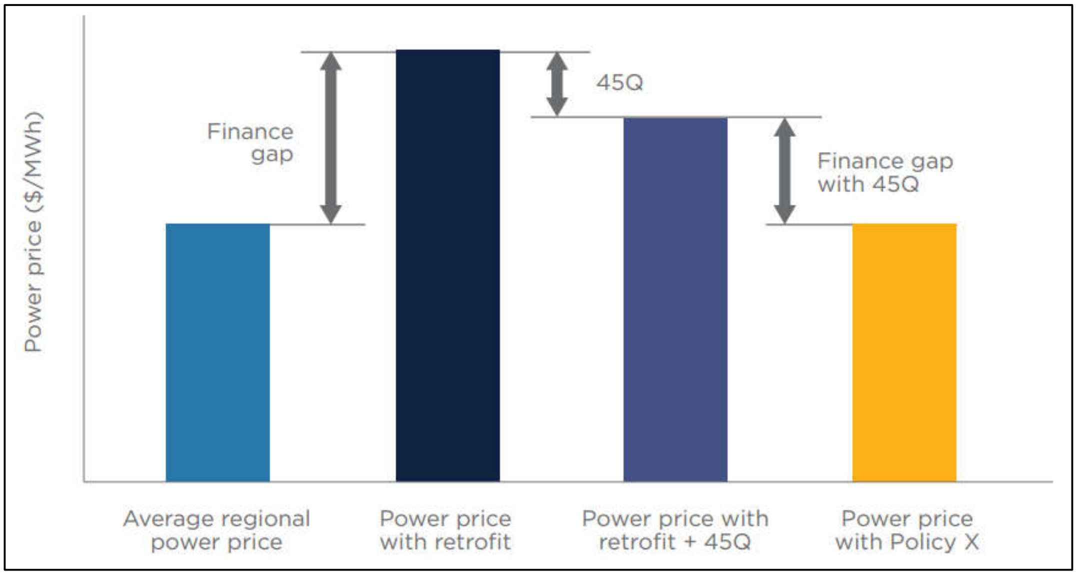
151 NextEra Energy Resources, LLC. Press Release: "NextEra Energy Resources subsidiary raises $118 million in capital for wind projects through differential membership transaction." https://newsroom.nexteraenergy.com/news-releases?item=123428.

152 This figure was developed by NRRI staff using information provided by Minkotta Power, a Touchstone Energy Cooperative.

153 S.J. Friedmann, Emeka R. Ochu, and Jeffrey D. Brown, "Capturing Investment: Policy Design to Finance CCS Projects in the U.S. Power Sector," Columbia Center on Global Energy Policy, (2020): 11. https://www.energypolicy.columbia.edu

154 Ibid.

Exhibit 3-15. Financing gap for a CCS project on U.S. power plants



Source: Friedmann, et. al., 2020 [155]

3.3.3 Recent 45Q Developments

The most recent revision to Section 45Q was signed into law on December 27, 2020, as part of the Consolidated Appropriations Act (H.R. 133). H.R 133 extended the initial construction start date for CCS projects provided by the Bipartisan Budget Act of 2018 (enacted February 9, 2018) from to December 31, 2025. The 2020 legislation extended this deadline again, allowing CCS projects that begin construction has begun as late as December 31, 2025,[156] to generate tax credits. The original bill required construction to begin by the end of 2023 to qualify for the 45Q tax credit.

Most importantly, the 2020 legislation removed the cap on qualifying captured and/or stored CO_2, creating more certainty for investing private capital in the deployment of CCS technologies across a range of industries, including electric power generation.

Proponents of the 2020 legislation argued that CCS projects would not be economic without Section 45Q, given the significant equipment and infrastructure investments required to construct such plants. After this provision was signed into law, the IRS issued Notice 2020-12,[157] providing the additional guidance.[158] The IRS released a final rule[159] implementing 45Q in December 2020, increasing the credit to $50/Mt for qualified CCS technology placed in service

[155] Ibid., p. 12

[156] U.S. Congress, House, *Text of the House Amendment to the Senate Amendment to H.R. 133*, 116th Congress, introduced December 21, 2020, https://rules.house.gov/sites/democrats.rules.house.gov/files/BILLS-116HR133SA-RCP-116-68.pdf

[157] Department of the Treasury, Internal Revenue Service, *Beginning of Construction for the Credit for Carbon Oxide Sequestration under Section 45Q*, https://www.irs.gov/pub/irs-drop/n-20-12.pdf

[158] Department of the Treasury, Internal Revenue Service, *Beginning of Construction for the Credit for Carbon Oxide Sequestration under Section 45Q*. https://www.irs.gov/pub/irs-drop/n-20-12.pdf

[159] Department of the Treasury, Internal Revenue Service, *Credit for Carbon Oxide Sequestration*, https://www.irs.gov/pub/irs-drop/td-9944.pdf.

on or after February 9, 2018.[160] IRS Notice 2020-12 also removed the upper limit on benefits from capturing CO_2 (previously restricted to a total of 75 MMT).

The tax code was further modified in Notice 2020-12, which became effective on January 13, 2021, and established the following:

- Requirements for adequate security measures for the geological storage of qualified carbon oxide
- standards for measuring utilization of qualified carbon oxide[161]
- Exceptions to the general rule for determining to whom the credit should be attributed
- Procedures for a taxpayer to elect to allow a third-party to claim the credit
- A more detailed definition of carbon capture equipment
- Standards for measuring utilization of qualified carbon oxide
- The ability to aggregate smaller CCS facilities into a single project to claim the credit based on factors such as common ownership and location
- guidance on "recapture," including the introduction of a 3-year recapture period[162]

Exhibit 3-16 provides an overview of how the 45Q tax credit has evolved since it was established in 2008.

[160] Beck, L. "The US Section 45Q Tax Credit for Carbon Oxide Sequestration: An Update," *The Global CCS Institute*, (April 2020): 2. https://www.globalccsinstitute.com/wp-content/uploads/2020/04/45Q_Brief_in_template_LLB.pdf

[161] The final regulations reconcile this by requiring the use of a life cycle analysis to measure CO_2e, but limiting the section 45Q credit to the amount of qualified carbon oxide measured at the source of capture. Internal Revenue Service.26 CFR Part 1 [TD9944] RIN 1545-BP42. P.66. https://www.irs.gov/pub/irs-drop/td-9944.pdf

[162] Under section 45Q(f)(4), recapture applies to any qualified carbon oxide that ceases to be captured, disposed of, or used as a tertiary injectant in a manner consistent with the requirements of this section, not to qualified carbon oxide that is utilized according to section 45Q(f)(5)(A). Further, recapture does not apply to utilization of qualified carbon oxide because a life cycle analysis accounts for all emissions of GHGs throughout the life cycle of the utilized product. Therefore, the final regulations provide that a recapture event occurs when qualified carbon oxide for which a section 45Q credit has been previously claimed ceases to be disposed of in secure geological storage or used as a tertiary injectant during the recapture period. The final regulations do not provide for recapture when qualified carbon oxide is utilized. P. 87 (https://www.irs.gov/pub/irs-drop/td-9944.pdf).

Exhibit 3-16. Changes to the 45Q tax credit[163]

Legislation / IRS Rule Changes	2008 Energy Improvement and Extension Act of 2008	2018 Bipartisan Budget Act of 2018	2020 The Consolidated Appropriations Act (December 2020)
Credit Per Mt of Captured and Stored CO_2	2008: \$20 2017: \$22.48	2017: \$22.66 2026: \$50	Note current requirement
Credit Per Mt of Captured CO_2 Used as a Tertiary Injectant (EOR, EGR)	2008: \$10 2017: \$11.24	2017: \$12.83 2026: \$35	Varies
Cap on Qualifying Captured and/or Stored CO_2	75,000,000 MT[164]	Removes cap	No cap
Minimum Annual CO_2 Capture Rate for Power Plants	N/A	500,000 MT[165]	Note current requirement
Deadline to Begin Construction	N/A	2023	Extended until 2025

3.3.4 Proposed CCS Policy Changes and Federal Legislation Under Consideration

3.3.4.1 Direct Pay

One of the challenges to the economic viability of CCS projects relates to the limited and complex options for leveraging the full benefits of 45Q and other state tax credits and incentives. The tax equity partnership described earlier is essentially the only way these projects can take advantage of tax subsidies. For that reason, several enhancements to the 45Q tax rule have been proposed.

A direct pay option could potentially provide a more cost-effective and efficient way of subsidizing CCS projects by eliminating the value of the tax credit lost to the transactions cost of the tax equity partnerships.[166] In addition, alternative options have been proposed for project developers and investors without the tax position that would allow them to fully utilize the credits from the existing 45Q program. For example, cooperative and municipal utilities are exempt from federal tax liability and, therefore, cannot directly access the 45Q benefits, limiting their incentive to build CCS plants.

Finally, the parameters of the 45Q tax credit limit the full benefits of the program to entities with large annual tax burdens, adding complexity to project financing arrangements and excluding some prospective investors. Direct pay would eliminate the need to seek tax equity

[163] Table developed using information from: Nagabhushan, D. & Thompson, J. "Carbon Capture and Storage in the United States Power Sector: The Impact of 45Q Tax Credits," *Clean Air Task Force* (2019) www.catf.us/2019/02/catf-releases-modeling-study-45q-carbon-capture/.

[164] "…a taxpayer may not claim credits under section 45Q(a)(1) and (a)(2) in taxable years after the year in which the 75,000,000 metric ton limit is reached with respect to carbon capture equipment placed in service before February 9, 2018." https://www.federalregister.gov/documents/2020/06/02/2020-11907/credit-for-carbon-oxide-sequestration

[165] "…in the case of a facility which emits not more than 500,000 metric tons of carbon oxide into the atmosphere during the taxable year, not less than 25,000 metric tons of qualified carbon oxide during the taxable year which is utilized in a manner described in subsection (f)(5)…" https://www.congress.gov/bill/115th-congress/house-bill/1892/text

[166] "Carbon Capture Coalition Statement for the Record," *Carbon Capture Coalition*, (April 27, 2021) https://carboncapturecoalition.org/wp-content/uploads/2021/04/Carbon-Capture-Coalition_SFR-SFC-Hearing-on-Climate-Challenges.pdf

investors, who would usually charge higher rates of return to support such CCS projects, potentially reducing the overall cost of capital. Debt financing for CCS projects would also become more accessible, which would make these projects more attractive to investors.

3.3.4.2 Multiyear Extension of the 45Q Construction Window

CCS projects are especially complex in nature, so it can take several years to secure project financing. Several stages of project design (capture, transportation, and storage) must be planned, executed, and aligned before construction can begin. For example, the infrastructure needed to transport and store CO_2 must be secured following a construction timeline that aligns with the design and deployment of the CCS facility. This makes the project financing more challenging and riskier for potential investors, who are depending on discrete components working in concert before construction can begin. The current 45Q policy requires all projects to begin construction by 2025 to maintain eligibility. A multi-year extension of this eligibility window could improve long-term certainty for private investment.

3.3.4.3 Increasing 45Q Credit Values

Carbon-intensive sectors, including electric power generation, will require significant investment and greater commercial risk for early deployment of these technologies. Higher 45Q tax credit values for CCS projects would help to increase project deployment. The Carbon Capture Coalition recently suggested that CCS power plants would require a price of $85/Mt for CO_2 captured and stored in saline geologic formations and $60/Mt for captured CO_2 stored in oil and gas fields to be economically viable.[167]

3.3.4.4 Elimination of Annual Capture Thresholds

The capture thresholds that limit the total credits that can be received by a single CCS project can stifle innovation and limit the overall ability to leverage the program. Existing thresholds can also limit CCS projects only to large-scale projects, due to the corresponding economies of scale. Thresholds also decrease the overall number of potential projects and deter innovation.

3.3.4.5 Modifications to Section 48A

Section 48A of the IRS code was established in 2005 and allows credits for qualifying advanced coal projects for a taxable year to equal: "(1) 20 percent of the qualified investment for that taxable year in the case of any qualifying advanced coal project using an integrated gasification combined cycle, and (2) 15 percent of the qualified investment for that taxable year in the case of any other qualifying advanced coal project."[168] The advanced coal project credits are specified in section 48A, and qualifying gasification project credits are identified in section 48B.

[167] "Carbon Capture Coalition Statement for the Record," *United States Senate Finance Committee Hearing on Climate Challenges: The Tax Code's Role in Creating American Jobs, Achieving Energy Independence, and Providing Consumers with Affordable, Clean Energy*, (April 27, 2021) https://carboncapturecoalition.org/wp-content/uploads/2021/04/Carbon-Capture-Coalition_SFR-SFC-Hearing-on-Climate-Challenges.pdf

[168] U.S. Internal Revenue Service. "Audit Technique Guide for Sections 48A and 48B - Advanced Coal and Gasification Project Credits." (https://www.irs.gov/businesses/audit-technique-guide-for-sections-48a-and-48b-advanced-coal-and-gasification-project-credits#1).

In 2006, $1.3 billion in qualifying 48A project credits were allocated, with $800 million going to integrated gasification combined cycle projects, and the remaining $500 million to other advanced coal projects.,

Additional CO_2 capture projects were made eligible through the Energy Improvement Extension Act of 2008, which included various provisions that were incorporated into future Phase II allocation rounds.[169]

Legislation to change the Section 48A tax credit has been proposed as another way to encourage the building of CCS plants by applying existing incentives to CCS technology retrofits for thermal power plants. Reforming Section 48A to modify plant heat rate requirements for compatibility with operating carbon capture equipment could also encourage project development. Combined with the direct pay proposal, this could allow approximately $2 billion in currently available funding to be applied to retrofits.[170]

3.3.4.6 Production Tax Credit

As described above, the existing 45Q tax credit, combined with the 48A tax credit, can increase revenue by reducing the project's tax liability based on the amount of CO_2 captured and stored. A renewable electricity production tax credit (PTC) would provide an additional revenue incentive through a volume-based tax relief. Specifically, the PTC would allow the government to subsidize electricity from renewable energy sources (e.g., wind, geothermal, and bioenergy) on a dollar per kilowatt-hour (kWh) basis to encourage CCS development and investment.

3.3.4.7 Federal Legislation Under Consideration

Several legislative proposals were introduced in 2021 that would increase the economic viability of CCS and create federal programs to support the development and deployment of CO_2 storage and infrastructure. The *Carbon Capture, Utilization, and Storage Tax Credit Amendments of 2021 (S. 986)*, and the *Accelerating Carbon Capture and Extending Secure Storage (ACCESS) through 45Q Act (H.R.1062)* would establish direct pay options for eligible projects and extend the construction window through 2030.[171] Modifications to the *Carbon Oxide Sequestration Credit (CATCH) Act* would increase the value of the 45Q tax credit up to $85/Mt for saline storage and increase the value of EOR storage and other utilization from $35/Mt to $60/MT.[172] The CATCH Act would also reduce credit eligibility thresholds based on the CO_2 quantities that were established in Section (d)(2) of the 45Q program. The proposed revision would allow all project types, including CCS projects, to be eligible for 45Q credits, regardless of the amount of captured CO_2.[173]

An overview of the federal legislation under consideration is provided in Exhibit 3-17.

[169] 26 U.S. Code § 48A *Qualifying advanced coal project credit* https://www.law.cornell.edu/uscode/text/26/48A.

[170] Ibid.

[171] "Fact Sheet for ACCESS Act (H.R. 1062)," *Carbon Capture Coalition* (March 2021) https://carboncapturecoalition.org/wp-content/uploads/2021/04/ACCESS-45Q_Fact-Sheet.pdf

[172] "Rep. Ryan Leads Bipartisan Coalition of House Members in Introducing CATCH Act to Boost Carbon Capture Tax Credits for Industrial Facilities & Power Plants," [press release] *U.S. Representative Tim Ryan*, May 25, 2021. https://timryan.house.gov/media/press-releases/rep-ryan-leads-bipartisan-coalition-house-members-introducing-catch-act-boost

[173] "Section-By-Section for the CATCH ACT," *Carbon Capture Coalition*. (2021) https://carboncapturecoalition.org/wp-content/uploads/2021/05/CATCH-Act-Section-by-Section.pdf

Exhibit 3-17. Selected federal legislation under consideration

Legislation	Impact			
	Introduces Direct Pay	Increases Credit Value	Multi-Year Extension of Construction Window	Eliminates of Capture Threshold
Carbon Capture, Utilization, and Storage Tax Credit Amendments Act of 2021 (S. 986)	X		X	
ACCESS Act (H.R. 1062)	X		X	
CATCH Act		X		X

Federal legislation that would create mechanisms to facilitate the development and deployment of CO_2 transportation and storage infrastructure throughout the country was proposed in March 2021. The Storing CO_2 and Lowering Emissions (SCALE) Act (S. 799/H.R. 1992) would establish CO_2 financing methods to attract private financing for CO_2 storage options. Specifically, the bill would create a CO_2 infrastructure finance and innovation program at DOE to provide developers with flexible, low-interest grants and loans. The bill would also establish a secure geological storage infrastructure development program to provide cost sharing for the development of saline geological storage projects, with an emphasis on creating large-scale commercial projects that could serve as regional storage hubs for multiple CCS facilities. Finally, the SCALE Act would provide increased funding for the development of dedicated CO_2 storage wells (Class-6 wells) and provide grants for state and local governments to support more local storage programs.

The American Jobs Plan, H.R. 3684, includes many of the proposals described above, including direct pay, a 10-year extension for 45Q construction window, and increased 45Q credit values for CCS projects. It also implements the SCALE Act to further support CO_2 T&S infrastructure. The American Jobs Plan would provide funding for ten pioneer industrial carbon capture retrofits.

3.4 Carbon Pricing

EPA has issued an endangerment finding[174] for CO_2 and other GHG pursuant to the Clean Air Act: "The Administrator finds that the current and projected concentrations of the six key well-mixed [GHGs] … in the atmosphere threaten the public health and welfare of current and future generations."[175]

Despite this finding, the price for power generation that results in CO_2 emissions reflects neither the cost of the harm caused by these emissions nor the cost of mitigating the impact of those emissions. This allowance of endangerment without mitigation is a form of market failure resulting from the transaction price failing to properly reflect an externality. Alfred Marshall[176] developed the concept of externalities in 1890 and Arthur Pigou[177] proposed taxing externalities

[174] Clean Air Act, § 202(a)(1), 42 U.S.C.A. § 7521(a)(1).

[175] "Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Section 202(a) of the Clean Air Act," [webpage], *Environmental Protection Agency,* (2020) https://www.epa.gov/ghgemissions/endangerment-and-cause-or-contribute-findings-greenhouse-gases-under-section-202a-clean

[176] Marshall, Alfred, *Principles of Economics,* Macmillan, London, 1890.

[177] Pigou, Arthur C., The Economics of Welfare, *London: Macmillan, London, 1920.*

to create efficient market outcomes in 1920. Because CO_2 emissions endanger public health and welfare, prices that do not reflect or collateral actions that in some way mitigate those externalities cannot be economically efficient.

Selecting the proper pricing mechanism for carbon emissions will enable federal and state governments to speed decarbonization by creating price signals to generators. Because prices in competitive power markets are set based upon the marginal cost of production, a tax on carbon emissions would increase the marginal cost of production by carbon-emitting electric generators and, therefore, increase the market price for power. Placing a cap on emissions would force facilities to invest in abatement technology to comply. The former is known as carbon pricing and the latter as cap and trade. This section reviews the potential carbon pricing mechanisms that could be implemented on a federal or state basis and their implications for the economics of CCS.

Carbon pricing is viewed by many commenters as the best economic mechanism for achieving reductions in CO_2 emissions.[178] Pricing carbon directly through a tax or indirectly by capping emissions would encourage companies to reduce emissions more efficiently and effectively than other command-and-control policy instruments like emissions standards or payments to facilities for emissions reductions. The extent of the emissions reductions depends on the level of the tax or cap, and the cost of compliance.[179] In addition to carbon pricing, several other methods to reduce emissions have been developed, each with varying degrees of effectiveness and efficiency.

Emissions standards specify maximum levels of allowable emissions. As part of a decarbonization plan, regulators might establish standards that would ratchet down the level of allowable emissions over time. Standards could create more certainty in the trajectory of emission reductions than price mechanisms that require a behavioral response. Historically, standards often result in higher costs, however, because they are inflexible, requiring the same level of emission reductions across facilities regardless of differences in their cost of reducing emissions, which appear to be substantial.

Direct payments to facilities to reduce CO_2 emissions, such as using Section 45Q, might also be helpful, although such an inducement would be subject to ambiguity in cost and effectiveness, because it requires establishing a baseline emissions level (the basis for imposing reductions) to determine the emissions that would have been emitted at each facility but for the payment. Since only the actual emissions can be measured, setting baseline levels could result in over- or underpayments; the former adds costs, while the latter discourages participation or compliance.

Offsets provide another type of mechanism for reducing the cost of meeting specified emissions targets. Offsets are an investment made by a facility to reduce carbon emissions at one location that has already met its reduction requirements to fulfill a carbon emission reduction obligation at another facility. Offsets can complement other carbon pricing mechanisms.

---

178 Stavins provides an accessible and well-organized comparison of carbon pricing policy mechanisms that informed and guided the development of this narrative: Stavins, R., "The Future of US Carbon-Pricing Policy," *National Bureau of Economic Research* (2020) (978-0-226-71117-1/2020/2020-0003).

179 Cap and trade programs are also referred to as emissions trading protocols, especially outside the United States.

3.4.1 Carbon Taxes

A carbon tax is a financial assessment on a dollar-per-ton basis applied to measured emissions of facilities. The amount of the tax is set by legislation or the responsible state or federal regulatory agency. The amount of the CO_2 emissions reduction resulting from the tax depends on the cost of the abatement technology used and the demand for the products produced at the facility (in the case of CCS, in the electric sector). Affected facilities must determine the marginal value they realize from operations that result in CO_2 emissions. They may then make abatement technology investments up to the point where the marginal cost of abatement (after consideration of subsidies such as 45Q) is equal to the tax. More spending on technology will reduce net earnings, while less spending will leave earnings on the table. Some producers may find that the facility is no longer economically viable, because the tax raises the cost to produce above what buyers are willing to pay. In some cases, industry will relocate to an area that does not impose carbon restrictions, and in doing so move the source of carbon emissions. This is called leakage. Implementing a carbon policy at the national level would prevent the leakage of emissions from facilities relocating from a regulated area to one with no carbon regulation (for example, from California to a neighboring state) to avoid the abatement cost.

Carbon taxes (like the cap-and-trade programs discussed below) are generally considered to be effective when they are enacted at least regionally, although they perform even better when implemented on a national or even international scale to avoid leakage and take advantage of diversity of economic and technological conditions. Targeting a carbon pricing policy at the beginning of the supply chain for energy producers and products may be the most effective approach, because it would regulate a smaller number of entities that supply primary energy downstream to more numerous producers of goods and services, rather than apply the policy to millions of end-users. For that reason, measuring and assessing a tax on carbon at a few oil refineries or generating plants would be less costly and far easier to administer than assessing the tax on millions of automobiles and electric consumers. Such a model would be prone to fewer measurement errors and thus less likely to induce fraud.[180]

Most carbon pricing policies are enacted by a single country as an emissions island (for example, Australia) or by several countries that share a common air shed (European Union [EU]). The United States does not have a national carbon pricing policy, but has two regional initiatives, RGGI (on the east coast) and California; these are discussed below.

3.4.2 Cap-and-Trade Allowances

A cap-and-trade (C&T) program establishes emissions limits (allowances) on regulated facilities that can be traded with other facilities. Under this mechanism, each facility must acquire allowances at least equal to its CO_2 emissions. The regulator sets the desired maximum quantity of emissions across all regulated firms. The price of the allowances is determined by allowance supply and demand, often through an auction where firms compete to buy allowances for emissions. Cap-and-trade allowances are typically allocated to existing entities based upon their historic emissions levels. Some C&T programs give back some of the allowances to the affected

180 The carbon tax or cap-and-trade allowance could be established based on the engine technology of the automobile and the fuel the vehicles burn, but still requires establishing how much gas is consumed per mile of use and the miles traveled. Both would be challenging until all vehicles are equipped to record and transmit that data to the owner so it can react accordingly) and the regulator (to enforce the provisions).

facilities, often with a gradual reduction in the give-back, in order to mitigate the impact of compliance and to provide time for facilities to adopt abatement measures.

Affected facilities may invest in abatement technology up to the point where the marginal cost of abatement equals the value of selling allowances. Like a carbon tax, a C&T allowance could provide a price signal to affected facilities to minimize the cost of achieving a specified level of CO_2 reduction. Firms with low abatement costs could reduce emissions more that those with higher costs, thereby minimizing the overall cost of achieving carbon reduction goals.

C&T allowances are fungible; they are rights that can be bought and sold. A facility that has more allowances than it needs (presumably because it invested in abatement equipment beyond what is needed to meet the cap) can sell the surplus to a facility that has a higher abatement cost. Trading is denominated in tons of carbon for a specified year and usually conducted through organized and regulated marketplaces. The price of the allowances on the trading exchanges depends on supply and demand. Prices are further defined through limiting or extending the trading window and may be increased or reduced further over time. The C&T price set by these exchanges matches the marginal value of allowances to those plants that can use them with facilities willing to trade the allowances, resulting in a single price for the market.[181] Each facility participating in the market will take measures to reduce its CO_2 emissions to the point where its marginal cost of abatement is equal to the current price of an allocation. At some point, the price for acquiring additional allowances may be higher than the marginal value of additional production, leading to reductions in output. Collectively the C&T process produces the socially efficient (i.e., least cost) outcome given the CO_2 reduction goal.[182]

3.4.3 Carbon Taxes Versus Tradable Allowances

3.4.3.1 Certainty of Emissions Reductions

A cap on emissions sets the total CO_2 allowances available for a particular industry or group of covered facilities, usually at a level below what they would otherwise emit. Assuming that the cap is enforced and that the trading of allowances is validated, C&T will ensure that the plants meet their specified level of emissions reductions. With a carbon tax, the regulator must estimate the cost of compliance for facilities that emit CO_2 (or the social cost of carbon emitted) and attempt to set the tax at a level that ensures that the CO_2 reduction meets the desired goal. This is challenging due to the heterogeneous nature of production across the regulated facilities, including those in the same industry but with different abatement costs.[183] The tax may overshoot or undershoot the target due to abatement costs being lower or higher than anticipated. Given the potential for errors in the level of the carbon tax required, it is important to design a carbon tax regime that allows the tax to be adjusted based on market conditions so as to ensure that the desired trajectory of emissions can be achieved over time. For this reason,

181 Trading is conducted for the current year and future years employing standard commodity trading practices, including regulation to ensure authenticity of trades and prevent mischief.

182 The presumption is that facility managers are profit maximizers and have available the information required to make these marginal decisions and the inclination to act marginally. When a carbon pricing policy is enacted, some firms may need technical support to be able to identify abatement measures and do the marginal calculations. Even then adjustments may not be seamless because of uncertainty about available technology in the future and the quantity and availability of allowances in the future.

183 Setting the tax is also complicated by technical innovation that may reduce the cost of abatement and changes in economic conditions that determine facilities' capital availability.

a C&T approach may be the preferred method for ensuring that emissions reduction do not exceed a specified target.

Carbon taxes have very different equity considerations than cap and trade. In cap and trade, the allowances are allocated based upon historic usage, providing a wealth transfer to emitters. In contrast, a carbon tax, treats each emitter the same – you emit – you pay.

3.4.3.2 Price Certainty and Economic Cost

Carbon taxes provide greater cost certainty than C&T programs, particularly in the short term. The tax rate is known with certainty, making the cost of compliance certain, at least initially. Estimates of abatement costs in the near-term should allow for an accurate assessment of total costs (i.e., tax payments plus abatement costs incurred to reduce tax exposure). Typically, the tax adjustment process would be transparent.

In contrast, allowance prices under a C&T program can be highly uncertain and volatile, because they are established in a competitive market, complicating the decision-making process for investment in CCS facilities. Price stability may be achieved by adjusting allowances, banking allowances for future use, or releasing banked credits to provide temporary relief, while still maintaining the long-term goal of CO_2 emission reduction.

3.4.3.3 Cost-Shifts

Carbon taxes are based on the premise that the way to deal with the unintended and undesirable consequences of production (i.e., carbon emissions) is to internalize the costs of avoiding and mitigating these consequences. The revenues generated by the tax can be used to address other environmental concerns through funding complementary programs (e.g., investment in energy efficiency), made available to regulated firms to invest in abatement technology, or used to offset taxes in other areas of the economy. This may create cost-shifts from some groups of consumers to others or between producers and consumers, depending on how the revenue is used. There will also be shifts in the cost of production (and, therefore, consumption); some goods will be more or less expensive relative to others, depending on the carbon intensity of their production.

Allowances under a C&T program may be auctioned rather than simply allocated to emitters based on historic emissions levels. Affected firms can purchase allowances to meet their emissions limit. This can result in dramatic cost-shifts among market participants with undesirable consequences; some industries or facilities will be better able to reduce emissions at a cost below the allowance prices, thereby gaining a competitive advantage. These price shifts can be mitigated by giving allowances directly to existing emitters to reduce their need to acquire allowances on the open market, although as discussed above, doing so undermines the intent of the cap, because emissions can rise to the sum of the cap plus the distributed allowances.

A recent review of carbon pricing programs concludes that carbon pricing policy, either C&T or a carbon tax, has not been effective at achieving the aggressive carbon reduction goals set by the United States and others. The analysis found that of the 58 carbon policy programs in existence at the time of the study, very few have been subjected to a rigorous ex-post analysis of the impact of price on emissions. The study found that the performance of only 18 of these programs was peer reviewed to ensure the accuracy of the results. Moreover, most found little or no incremental emissions reductions, with estimates ranging from 0 to 3 percent. This includes the extensive European C&T system. Other studies reported higher impacts, only up to 3 to 5 percent a year. These studies re-enforce the idea that there must be a feedback mechanism that allows the level of the carbon tax to be adjusted until the final emissions meet the desired level. Achieving CO_2 reduction goals solely through carbon policies like C&T and a carbon tax thus may not be sufficient to achieve the desired goals, at least in the short term.[184]

3.4.3.4 Other Differences

Finally, C&T and carbon taxes differ in the potential for market manipulation (although this is more of an issue with C&T), as well as their administrative complexity (C&T is more burdensome, because allowances need to be tracked). These problems can be largely eliminated by careful program design. C&T and carbon taxes are alternative ways to implement a carbon policy to reduce CO_2 emissions, but both can be highly effective in efficiently enacting emission controls, although they may be less effective when it comes to other goals, such as equity. Both programs are potentially economically efficient mechanisms for reducing emissions because producers can optimize their response. They can balance their marginal revenue against the marginal cost of emissions reductions (or payments in lieu of reductions). The result should be the least-cost solution to achieving any specific level of CO_2 reductions.[185]

Distributing Cap-and-Trade Program Allowances

One nuance in the implementation of a C&T is the method for distributing CO_2 emissions allowances. One option is to allocate them to emitting facilities at no charge, potentially in proportion to the historic level of CO_2 emissions. For example, if the goal were to reduce emissions by 20%, each facility would receive an allowance equal to 80% of its historic base CO_2 emissions. Each recipient would, therefore, have to reduce emissions by 20% that year or acquire allowances from a facility willing to sell them to cover emissions above the allowance. Free allocation of first-year allowances may be justified in some cases in order to limit adjustment costs and soften impacts to consumers. As allowances are lowered over time, facilities would have to either make further abatement investments, purchase allowances from others, or reduce their level of economic activity to meet the emission reduction obligation. Using allowances in this way could encourage the development of plants using CCS.

Alternatively, all allowances may be auctioned at the outset of the compliance period. Auctioning allocations is founded on the premise that no facility has the right to emit CO_2, because a stable climate is a right of all citizens. Facilities must, therefore, buy the right to emit CO_2 just as they buy other inputs to their production or service business. These purchases establish the initial price of allowances and the price offered by allowance exchanges as companies seek to optimize their financial interests. Many commenters regard auctions as the best method for distributing allowances, because they require facilities to buy rights to release CO_2 emissions. The initial auction clearing price is the same for everyone, which means that marginal decisions across firms with diverse production and service technologies result in a least-cost adjustment to the policy

[184] Green, J., "Does Carbon Pricing Reduce Emissions? A Review of Ex-post Analysis," *Environmental review* (2021) (16 043004)

[185] Importantly, they will likely not result in the most socially efficient outcome, because knowing that requires knowing the marginal costs of failing to control emissions, a value of great uncertainty and wide range of estimates.

C&T and carbon taxes represent different approaches to reducing pollution and use different inducement mechanisms. Ultimately, because C&T and carbon taxes are so similar, the choice between them may be political rather than economic. According to Stavins,

> the tax approach is clearly favored by three elements; complexity and administrative requirements; interactions with complementary policies; and effect on carbon price volatility. Cap-and-trade is favored by its ease of linkages with policies in other jurisdictions; and possibly by its anticipated performance in the presence of uncertainty.[186]

Exhibit 3-18 illustrates the similarities and differences between carbon taxes and cap and trade programs to reduce carbon emissions.

Exhibit 3-18. Similarities and differences between carbon taxes and carbon C&T

Similarities and Differences between Carbon Taxes and Carbon Cap-and-Trade

Perfectly Equivalent	Nearly Equivalent	Similar	Some Distinctions	Differences	Significant Differences
Incentives for emission reductions					
Aggregate abatement costs					
Effects on competitiveness					
	Possibilities for raising revenue				
		Costs to regulated firms			
		Distributional impacts			
			Transaction costs		
				Performance in presence of uncertainty	
				Ease of linkage with other jurisdictions	
					Effects on carbon price volatility
					Interactions with complementary policies
					Potential for market manipulation
					Complexity and administrative requirements

Source: Stavins, 2020

3.4.4 Experience with Carbon Pricing Initiatives

To better appreciate the impact of carbon pricing on CCS, it is helpful to review the outcomes of carbon pricing initiatives throughout the world.[187]

Over 50 carbon policy initiatives have been implemented in the last 30 years, almost evenly split between carbon taxes (26) and C&T (24)[188] (see Exhibit 3-19). These initiatives include policies that apply to a single region or multiple regions of a country (for example, China has seven regional programs; the United States has two), individual countries (Australia), and a single region composed of multiple countries (EU plus Norway, Iceland, and Liechtenstein).

Exhibit 3-20 summarizes these data by decade. As Exhibit 3-20 shows, these programs were initially weighted toward carbon taxes (1990) but have recently been trending toward C&T.

[186] Stavins, "The Future of US Carbon-Pricing Policy," *National Bureau of Economic Research*, (2020): 47

[187] Only regional C&T programs have been implemented in the U.S.

[188] At the time the census was conducted (2018), initiatives were scheduled for implementation in Canada (2) and Chile.

Exhibit 3-19. Implemented and scheduled carbon-pricing initiatives, 1990–2020

Implemented and Scheduled Carbon-Pricing Initiatives, 1990–2020

Initiative	Type	Status	Type of Jurisdiction	Jurisdiction	Year	GHG Emissions ($MtCO_2e$)
Alberta Carbon Competitiveness Incentive Regulation	Trading	Implemented	Subnational	Alberta	2007	120
Alberta Carbon Tax (repealed, May 2019)	Tax	Implemented	Subnational	Alberta	2017	109
Argentina Carbon Tax	Tax	Scheduled	National	Argentina	2019	79
Australia Emissions Reduction Fund Safeguard Mechanism	Trading	Implemented	National	Australia	2016	381
BC Greenhouse Gas Industrial Reporting and Control Act	Trading	Implemented	Subnational	BC	2016	0
BC Carbon Tax	Tax	Implemented	Subnational	BC	2008	42
Beijing ETS	Trading	Implemented	Subnational	Beijing	2013	85
California AB-32/AB-398 Cap-and-Trade System	Trading	Implemented	Subnational	California	2012	378
Canada Federal Output-Based Pricing System	Trading	Scheduled	National	Canada	2019	?
Canada Federal Carbon Tax	Tax	Scheduled	National	Canada	2019	?
Chile Carbon Tax	Tax	Implemented	National	Chile	2017	47
China National ETS	Trading	Scheduled	National	China	2020	3,232
Chongqing ETS	Trading	Implemented	Subnational	Chongqing	2014	97
Colombia Carbon Tax	Tax	Implemented	National	Colombia	2017	42
Denmark Carbon Tax	Tax	Implemented	National	Denmark	1992	22
European Union ETS	Trading	Implemented	Regional	European Union plus Nor., Ice., and Lich.	2005	2,132
Estonia Carbon Tax	Tax	Implemented	National	Estonia	2000	1
Finland Carbon Tax	Tax	Implemented	National	Finland	1990	25
France Carbon Tax	Tax	Implemented	National	France	2014	176
Fujian ETS	Trading	Implemented	Subnational	Fujian	2016	200
Guangdong ETS	Trading	Implemented	Subnational	Guangdong	2013	366
Hubei ETS	Trading	Implemented	Subnational	Hubei	2014	162
Ireland Carbon Tax	Tax	Implemented	National	Ireland	2010	31
Japan Carbon Tax	Tax	Implemented	National	Japan	2012	999
Kazakhstan ETS	Trading	Implemented	National	Kazakhstan	2013	183
Korea ETS	Trading	Implemented	National	Korea	2015	453
Latvia Carbon Tax	Tax	Implemented	National	Latvia	2004	2
Liechtenstein Carbon Tax	Tax	Implemented	National	Liechtenstein	2008	0
Massachusetts Cap-and-Trade System	Trading	Implemented	Subnational	RGGI States	2018	10
Mexico Carbon Tax	Tax	Implemented	National	Mexico	2014	307
New Zealand ETS	Trading	Implemented	National	New Zealand	2008	40
Norway Carbon Tax	Tax	Implemented	National	Norway	1991	40
Poland Carbon Tax	Tax	Implemented	National	Poland	1990	16
Portugal Carbon Tax	Tax	Implemented	National	Portugal	2015	21
Quebec Cap-and-Trade System	Trading	Implemented	Subnational	Quebec	2013	67
Regional Greenhouse Gas Initiative	Trading	Implemented	Subnational	RGGI States	2009	94
Saitama ETS	Trading	Implemented	Subnational	Saitama	2011	7
Shanghai ETS	Trading	Implemented	Subnational	Shanghai	2013	170
Shenzhen ETS	Trading	Implemented	Subnational	Shenzhen	2013	61
Singapore Carbon Tax	Tax	Scheduled	National	Singapore	2019	42
Slovenia Carbon Tax	Tax	Implemented	National	Slovenia	1996	5
South Africa Carbon Tax	Tax	Scheduled	National	South Africa	2019	360
Spain Carbon Tax	Tax	Implemented	National	Spain	2014	9
Sweden Carbon Tax	Tax	Implemented	National	Sweden	1991	26
Switzerland ETS	Trading	Implemented	National	Switzerland	2008	6
Switzerland Carbon Tax	Tax	Implemented	National	Switzerland	2008	18
Tianjin ETS	Trading	Implemented	Subnational	Tianjin	2013	118
Tokyo Cap-and-Trade System	Trading	Implemented	Subnational	Tokyo	2010	14
UK Carbon Price Floor	Tax	Implemented	National	United Kingdom	2013	136
Ukraine Carbon Tax	Tax	Implemented	National	Ukraine	2011	287
Washington State Clean Air Rule	Trading	Implemented	Subnational	Washington	2017	58

Source: World Bank Group (2018).
Note: GHG = greenhouse gas; $MtCO_2e$ = metric tons of carbon dioxide equivalent; BC = British Columbia; ETS = emissions trading system.

Source: Stavins, 2020

Exhibit 3-20. Count of carbon pricing strategies by decade

Decade	Carbon Tax	C&T
1990–2000	6	0
2001–2010	5	5
2011–2020	15	19

Exhibit 3-21 summarizes selected C&T from the United States and the European Union (EU).

Exhibit 3-21. Most important C&T systems

Most Important Cap-and-Trade Systems

System	Geographic Scope	Coverage and Sectors	Time Period	Allowance Allocation Method	Cost-Containment Mechanisms	Environmental and Economic Performance
Leaded Gasoline Phasedown	USA	Gasoline from refineries	1982–1987	Free	Banking	Phasedown completed successfully, faster than anticipated, with cost savings of 20% or $250 million/year
Sulfur Dioxide Allowance Trading	USA	SO_2 from electric power	1995–2010	Free	Banking	Cut SO_2 emissions by half, with cost savings of $1 billion/year; but market closed due to judicial actions
Regional Clean Air Incentives Market	South Coast Air Quality Management District, CA	NO_x and SO_2 from electric power and industrial sources	1993–present	Free	. . .	Emissions lower than with parallel regulations; unquantified cost savings; electricity crisis caused allowance price spike and temporary suspension of market
NO_X Trading in the Eastern United States	12–21 US states	NO_x from electric power and industrial sources	1999–2008	Free	. . .	Significant price volatility in first year; NO_x emissions declined from 1.9 (1990) to .5 million tons (2006); cost savings 40%–47%
Regional Greenhouse Gas Initiative	Nine northeastern US states	CO_2 from electric power	2009–present	Nearly 100% auction	Banking, cost containment reserve, auction reservation price	Cap nonbinding then barely binding due to low natural gas prices; has generated more than $1 billion for participating states
AB-32 and AB-398 California Cap-and-Trade	California, USA	CO_2 from electric power, industrial, and fuels	2013–2020 2021–2030	Transitions from free to auction	Banking, allowance price containment reserve, auction reservation price	Covers 85% of emissions, reduced 40% below 1990 by 2030; reduces competitiveness effects without output-based updating allocation; linked with Quebec cap-and-trade system
European Union Emissions Trading System	27 European Union member states plus Iceland, Lichtenstein, and Norway	CO_2 from electric power, large industrial, and aviation	2005–	Transitions from free to increased use of auctions	Banking after 2008, previous use of offsets from CDM	Covers half of emissions, has cut abatement costs by about 50% compared with no trading; overallocation by member states in pilot phase; suppressed allowance prices due to "complementary policies," CDM glut, slow economic recovery

Source: Stavins, 2020

No national carbon pricing program (C&T or carbon tax) has been implemented in the United States. A national tax was implemented in the 1980s to achieve the phase out of leaded gasoline; another was implemented in the mid-1990s to reduce sulfur dioxide emissions, but no national program specifically targeting carbon emissions has been implemented at this time.

Several Northeast states jointly enacted a tax for NOx emissions from power plants between 1999 and 2008. This program was supplanted in 2009 by the RGGI, focused on carbon emissions from power generating plants. Most RGGI allowances were auctioned. The RGGI auction policy is ongoing.[189]

In addition to these programs, California implemented a CO_2 carbon tax program applicable to electric power generation (and later extended to industrial and fuel production facilities) under Acts AB-32 in 2014 and AB-398 in 2021. Allowances were initially allocated freely to affected facilities with a provision that reduced those allowances over time. As the program progressed and allowance were reduced, the program transitioned to allowance auctions. The California

[189] Regional Greenhouse Gas Initiative, About Auctions [Web page, retrieved August 2021], https://www.rggi.org/auctions/about-auctions

CO_2 initiative is authorized until 2030. Both the California and RGGI programs employ allowances, allowance banking, and other mechanisms to limit price volatility.

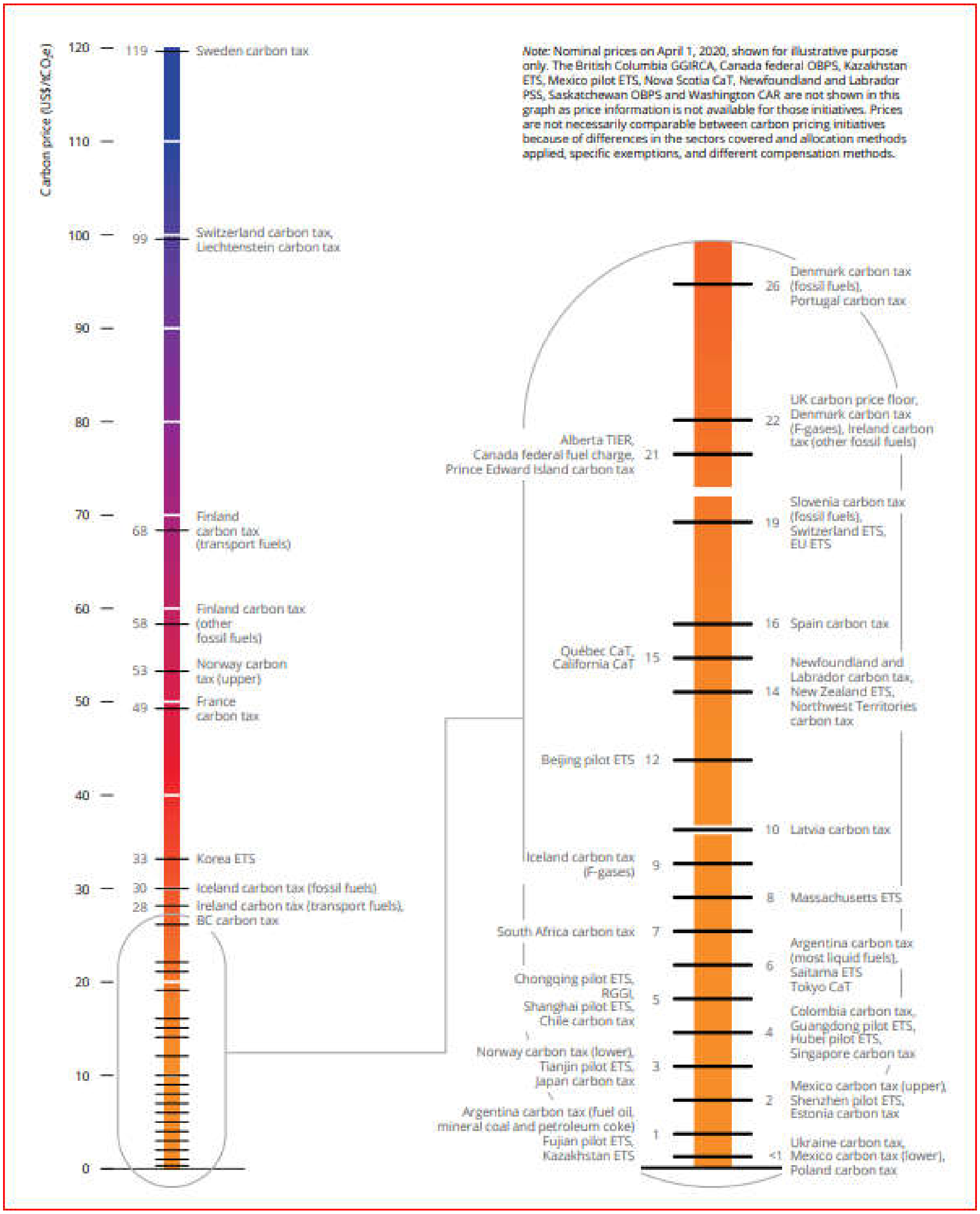
Exhibit 3-22 reviews world carbon pricing initiatives in 2020, the type of emissions covered, and the price of carbon by country or region. The EU program is the largest (over 2,300 Mt of CO_2 covered), followed by Korea, California, and Australia, each with emissions set at 20 percent or less than the EU. Together, these four regions account for two-thirds of all program emission coverage. C&T programs account for almost 60 percent of the emissions reductions realized in 2020. Prices ranged $0–120/Mt in 2020. The highest reported price was $120 in Sweden, with several prices below $10/Mt.

Exhibit 3-23 shows the overall distribution and tremendous variation of carbon prices in areas that have implemented pricing initiatives. Over 85 percent were below $40 per ton, with 63 percent under $20.

Experience with CO_2 pricing in the United is similar to the global pricing experience. RGGI C&T allowance prices in the fourth quarter of 2020 were trading at $8.18/Mt CO_2 on the secondary market exchanges (and via auctions), up substantially from the previous quarter and the same quarter of 2019.[190] The number of bids for allowances in 4Q20 was 2.4 times the amount that cleared the auction. The minimum bid was $12.86. If bid prices reflect the marginal cost of abatement, electric market economics will result in the dispatch of lower levels of output from emitting plants or reduced electricity demand (because prices are passed on to customers), or a combination of both.

[190] "Report on the Secondary Market for RGGI CO2 Allowances: Fourth Quarter 2020," *Prepared for RGGI by Potomac Economics*, (February 2021) https://www.rggi.org/sites/default/files/Uploads/Market-Monitor/Quarterly-Reports/MM_Secondary_Market_Report_2020_Q4.pdf

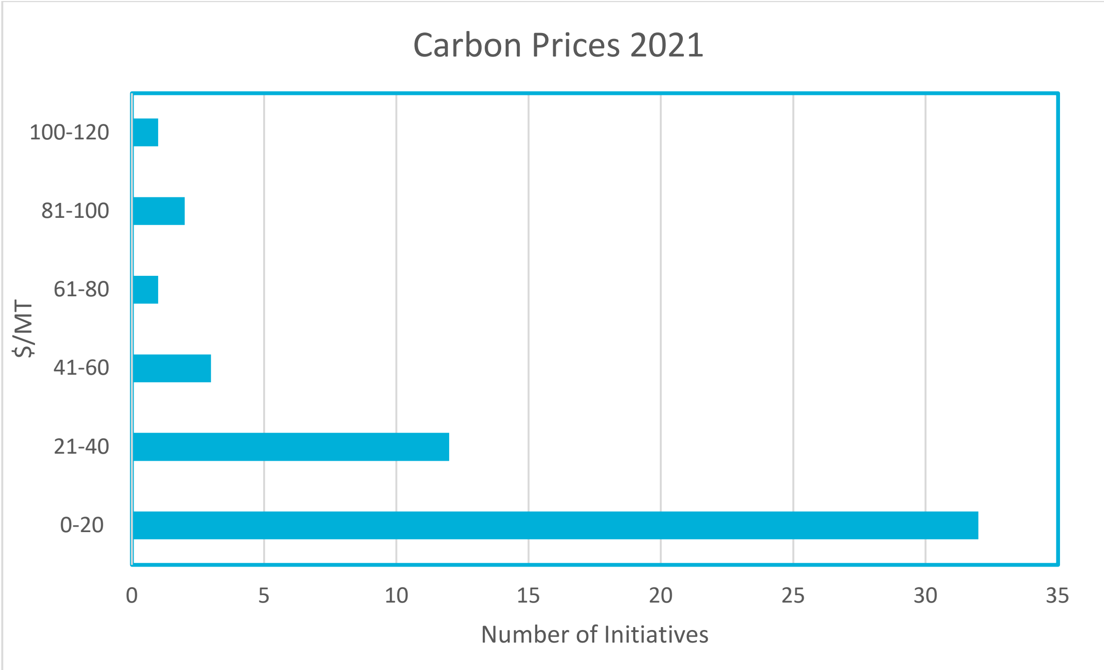
Exhibit 3-22. Prices in implemented carbon pricing initiatives



Used with permission from World Bank Group[191]

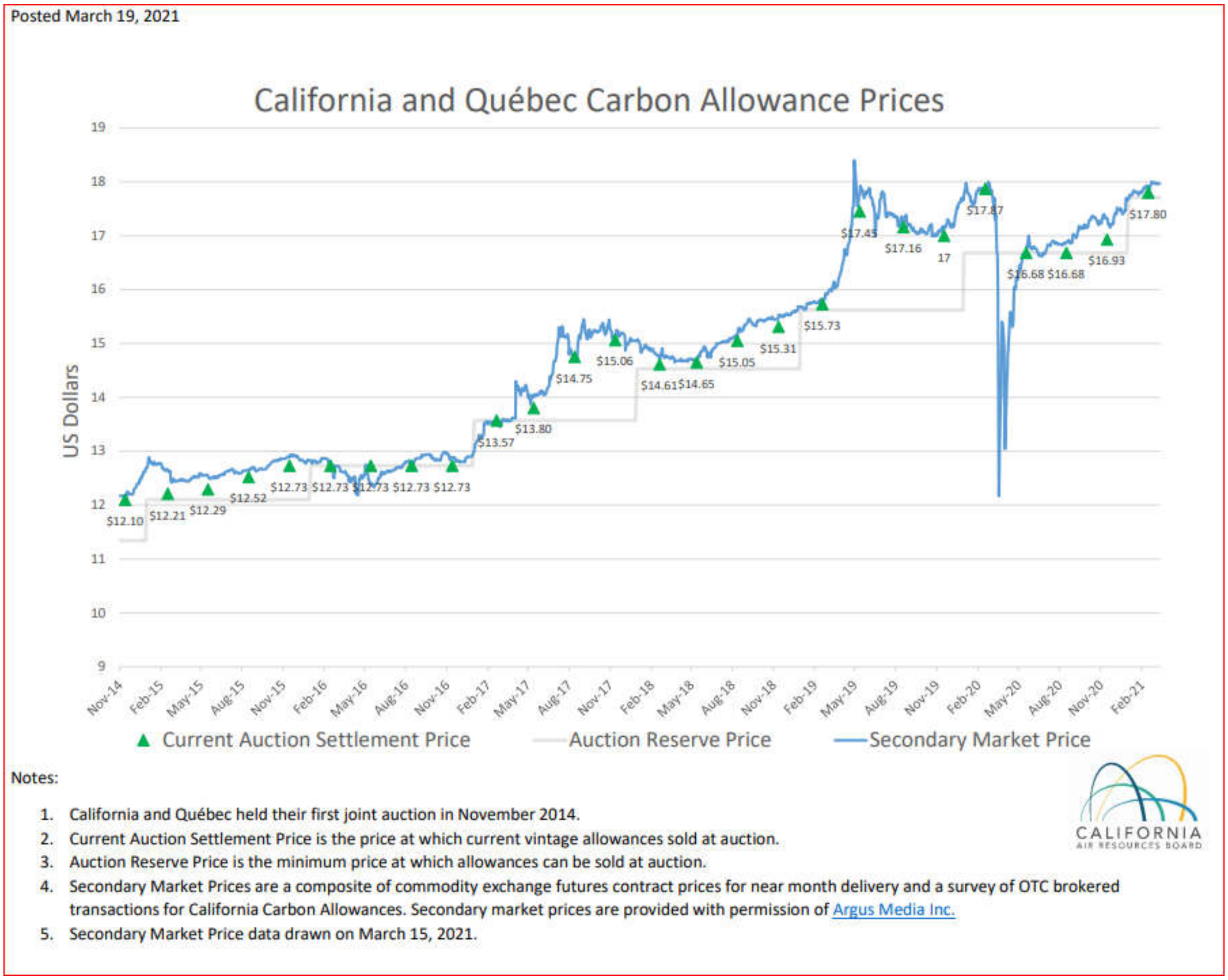
[191] "State and Trends of Carbon Pricing 2020," *World Bank Group,* (May 2020). https://openknowledge.worldbank.org/handle/10986/33809. This is licensed under Creative Commons Attribution (CC BY 3.0 IGO).

Exhibit 3-23. Distribution of implemented carbon pricing



Like the RGGI prices, California settlement and auction reserve carbon allowance prices, developed jointly with Quebec since 2014, have risen from the opening price in 2014 of $12/Mt CO_2 to almost $18/Mt (Exhibit 3-24). Auction allowance prices generally exceeded the floor price, sometimes by as much as 20 percent.

Exhibit 3-24. California and Quebec carbon allowance prices



Source: California Air Resource Board

3.5 Greenhouse Gas-Related Revenue

The preceding sections discuss economic policies that improve the economics of generating power with CCS compared to carbon-emitting technologies by reducing the capital and operating costs for CCS or by increasing the operating costs (e.g., through a carbon tax) for higher-emissions energy sources. The economics of CCS are dependent not only on the cost of building and operating the facility, but also the revenues that plant can earn by capturing CO_2. The revenues generated by CCS plants include selling CO_2 emissions removed from the plant's operations to create other products for beneficial uses and/or income from the sale of GHG offsets. This section describes several possible revenue sources for CCS plants.

3.5.1 Beneficial Uses of CO_2

Once carbon is captured, there are two options for keeping it out of the atmosphere: storage or conversion of the CO_2 for use in other products or processes, known as "beneficial uses." Using captured CO_2 as a chemical input for industrial processes not only provides a method for keeping carbon out of the atmosphere, but is also a potential source of revenue to the CO_2

producer. The beneficial use of captured CO_2 at the source or nearby has the potential to alter the economics of CO_2 management by avoiding or reducing storage and transportation costs.

Several long-standing industrial processes use CO_2 as an input; for example, urea production for N_2-rich fertilizer, beverage carbonation, and food production. Unfortunately, the supply of CO_2 outstrips demand.[192] Developing new uses for carbon could expand the market for carbon and thus help reduce the cost of removing it from flue gasses. To that end, several beneficial uses are in the early stages of pre-commercial development and continuing advances in material sciences, chemical engineering, and building construction systems could identify more. Exhibit 3-25 lists beneficial uses of CO_2 currently in development.

The World Bank reports 2019 volumes and average prices of CO_2, including biogas, landfill methane, and livestock methane totaled 7.2 million tons of carbon dioxide equivalent (CO_2e),[193] at an average price of $2.80/Mt. Since those categories can include projects both with and without beneficial use, more detailed categorization is needed to differentiate among them.[194] In addition, there is a need for greater transparency in markets for CO_2 to help producers understand where, to whom, and in what volumes captured carbon can be sold. Currently available market data sources are proprietary, leaving major gaps in the publicly available data about uses and prices.[195] Government agencies could play an important role in helping to make market data more accessible.

If carbon is captured and made available for beneficial uses, an important determinant of cost-effectiveness will be the technologies employed for temporarily storing and delivering the gases to end users. Transport by pipeline is the most cost-effective approach, but costs will be distance sensitive. For that reason, CO_2 hubs and clusters could prove valuable, combining geographic proximity for producers, sinks for the CO_2, and beneficial use production facilities. Hubs or clusters could also help develop larger, local markets, which could support large carbon-

[192] Naims, Henriette, "Economic Aspirations Connected to Innovations in Carbon Capture and Utilization Value Chains," Journal of Industrial Ecology 24 (5), (2020) 1126–39, doi:10.1111/jiec.13003. Naims reports that recent estimates show slightly more than 200 megatons of CO2 used, worldwide, in chemical synthesis. Naims also reports an estimate that approximately 600 megatons of CO2 could be used in producing chemicals and fuels by 2030. (Naims p. 1127). See also: "Evidence Brief: Carbon Dioxide Removal and Its Governance," Carnegie Climate Governance Initiative, (March 2021) https://www.c2g2.net/wp-content/uploads/CDR-Evidence-Brief.pdf. The Carnegie Brief (March 2021, p. 3) cites IPCC estimates of the need for capturing and removing from the atmosphere over 1,600 times that much CO2 equivalent by 2100 (1,000 gigatons) under models for emissions pathways intended to limit the global temperature increase to not more than 1.5-degrees Celsius.

[193] The Environmental Protection Agency defines carbon dioxide equivalent or CO_2e as the number of metric tons of CO2 emissions with the same global warming potential as one metric ton of another greenhouse gas. "Footprint Calculator definitions: CO2e," [webpage] *Environmental Protection Agency*, accessed August 11, 2021 https://www3.epa.gov/carbon-footprint-calculator/tool/definitions/co2e.html

[194] "State and Trends of Carbon Pricing 2021" *World Bank*, (2021):*43* https://openknowledge.worldbank.org/handle/10986/35620

[195] See, for example: "Global Carbon Dioxide Market - By Type (Liquid Carbon Dioxide, Solid Carbon Dioxide, Gaseous Carbon Dioxide), By Application (Beverages, Food, Metal Products, Oil And Gas, Medical, Chemical, Firefighting), By Grade Type (Medical Grade, Food Grade, Industrial Grade, Other Grade), And By Region, Opportunities And Strategies – Global Forecast To 2030, *Business Research Company* (2021) https://www.thebusinessresearchcompany.com/report/carbon-dioxide-market; "CO2 Enhanced Oil Recovery Market Size, Industry Analysis Report, Regional Outlook, Application Development, Competitive Market Share & Forecast, 2021 – 2027," *Global Markets Insights*, no date, https://www.gminsights.com/industry-analysis/co2-enhanced-oil-recovery-market; "Food-Grade Industrial Gases Market - Growth, Trends, Covid-19 Impact, and Forecasts (2021 - 2026)," *Mordor Intelligence*, (2020) https://www.mordorintelligence.com/industry-reports/food-grade-industrial-gasses-market; and, "Market size of carbon dioxide in the United States in 2018 and 2025, by source," *Statista* (2019) https://www.statista.com/statistics/1060137/us-carbon-dioxide-market-value-by-source/.

capture, collection, storage, and delivery facilities, thus helping to reduce the cost per ton of captured carbon.[196]

Exhibit 3-25. Beneficial uses for captured CO_2[197]

Broad Classification	Examples
Agriculture and Forestry Based[1]	• Algae production (for food, fuel, plastics, chemical feedstocks) • Enhancing growth in commercial greenhouses
Alternative Energy Carriers[2]	• Synthetic fuel production
Construction Products, Industrial and Commercial Products	• Materials that embody stored carbon, such as cement, wallboard, metals (e.g., steel), and mineralized materials as fillers or fire retardants (e.g., in paper, paints, textiles, polymers, electronics) • Use in beverages, for sterilization, or in food preservation • As a fumigant for grain silos • As a solvent for food processing, dry cleaning, and supercritical fluid extraction • Used in processes for recovering rare earth elements or other valuable metals, from bottom ash, mining wastes, desalination plants, and in wastewater processing
Power Production[1]	• Used in Brayton cycle turbines • As a cushion for natural gas storage

Notes: [1] Climate and Clean Air Coalition and U.N. Environment Programme, 2021, Global Methane Assessment: Benefits and Costs of Mitigating Methane Emissions, https://www.unep.org/resources/report/global-methane-assessment-benefits-and-costs-mitigating-methane-emissions; and, Feblowitz, Jill, The Colors of Hydrogen – Brown, Grey, Blue and Green – Think About It [Electronic article], Utility Analytics Institute, October 27, 2020, https://utilityanalytics.com/2020/10/the-colors-of-hydrogen-brown-grey-blue-and-green-think-about-it/; and, U.S. EPA AgStar: AgSTAR: Biogas Recovery in the Agriculture Sector [Web page], https://www.epa.gov/agstar.
[2] EPRI and GTI, 2021, Low-Carbon Resources Initiative Research Vision, https://lcri-vision.epri.com/; Global CCS Institute, Bioenergy and Carbon Capture and Storage: delivering negative emissions with bioenergy, biofuels and waste-to-energy [Webinar recording], March 2020, available at https://www.globalccsinstitute.com/resources/multimedia-library/webinar-bioenergy-and-carbon-capture-and-storage-delivering-negative-emissions-with-bioenergy-biofuels-and-waste-to-energy/; and, National Academies of Sciences, Engineering, and Medicine, 2019, Negative Emissions Technologies and Reliable Sequestration: A Research Agenda, Washington, DC: The National Academies Press, doi 10.17226/25259.
[All web pages retrieved June 2021.]

3.5.2 Greenhouse Gas Emissions Offsets

States, regions, and countries have developed policies that require GHG emitters to reduce or eliminate emissions. In some cases, emitters are given the option of offsetting some or all of their emissions by purchasing credits for reductions that are made by other entities in other

196 "Understanding Industrial CCS Hubs and Clusters," *Global CCS Institute*, (2016) https://www.globalccsinstitute.com/wp-content/uploads/2019/08/Understanding-Industrial-CCS-hubs-and-clusters.pdf

197 Data sources: Naims, Henriette, 2020, "Economic Aspirations Connected to Innovations in Carbon Capture and Utilization Value Chains," *Journal of Industrial Ecology* 24 (5), 1126–39, doi:10.1111/jiec.13003; Taskforce on Voluntary Carbon Markets, *Final Report*, January 2021, p. 58, https://www.iif.com/Portals/1/Files/TSVCM_Report.pdf; U.S. DOE, Office of Fossil Energy, Carbon Storage R&D [Web page], https://www.energy.gov/fe/science-innovation/carbon-capture-and-storage-research/carbon-storage-rd.

locations. A GHG offset is a mechanism by which any source with a requirement for GHG emissions reporting can "register the reductions achieved by another entity," in effect becoming the party responsible for the reductions.[198] Offsets offer a potentially low-cost pathway for emitters to achieve GHG targets or objectives. Emitters such as coal or gas-fired power plants can use offsets to compensate for or neutralize their own emissions.[199] Emitters seeking to offset their emissions may contract with another party at another location that agrees to achieve specific quantities of emissions avoidance or reduction, purchase offset credits from others, or purchase these credits in a marketplace created for this purpose.

Because a CCS plant generates power and captures the CO_2/GHG that would otherwise be emitted, it could generate saleable offset credits, thus producing revenue to offset the cost of CCS-generated power. Doing so, however, would require the development of an accounting system to track incremental emission reductions beyond what is required by a carbon standard.

CO_2 and GHG offsets are currently traded in at least two dozen markets, each established to address a particular geographic region, industry sector, or other defined universe of actors and participants.[200] Provisions for creating, accounting for, and trading carbon offsets were included

State-Level Climate Action and Policies

A total of 18 states and two U.S. territories have adopted formal goals for achieving 75% or greater GHG emissions reductions by no later than 2050.[1] Many of those states are in the preliminary stages of establishing explicit GHG emissions reduction interim targets and identifying specific pathways for achieving them.[2] Some of these contemplate the use of offsets. The District of Columbia climate action plan anticipates achieving part of its goal by using either local storage or carbon offsets that support energy efficiency, renewable energy, or forestry projects outside the District.

Many other states have renewable or clean energy portfolio standards aimed at reducing GHG emissions from the power sector, even in the absence of an economy-wide GHG goal. The effect of these policies on CCS opportunities is discussed in Section 3.5.3.

In addition, at least a dozen states are already formally engaged in GHG markets and emissions trading, including the 11 states that participate in the RGGI discussed in Section 3.5.4.

[1] "NRRI Clean Energy Policy Tracker," [Web page], National Regulatory Research Institute, accessed August 2021, https://www.naruc.org/nrri/nrri-activities/clean-energy-tracker/.
[2] Climate Xchange, State Climate Policy Network [Web page, retrieved August 2021], https://climate-xchange.org/network/.

---

[198] 10 CFR 300, 20807 *Federal Register,* Vol. 71, No. 77, April 21, 2006. See also: "Mitigating Greenhouse Gas Emissions: Selected Policy Options," *U.S. Congressional Research Service*, March 15, 2021. https://www.everycrsreport.com/files/2021-03-15_IF11791_ac258e149b892b739bdb50267b7353b784b41a7f.pdf.

[199] 51165 Permit Requirements, §(a)(3)(ii) and §(a)11. 40 C.F.R. § 51.165 (December 24, 2020). Offsets are also incorporated into these EPA rules governing state implementation plans for stationary sources of air pollution. Credits are allowed for offsets that are "surplus, permanent, quantifiable, and federally enforceable."

[200] Op. cit. World Bank 2021 (note 2) and Stavins 2020 (note 176). The World Bank reports as of May 2021 there are 64 carbon pricing initiatives already operating worldwide, and three more scheduled for implementation. These include both emissions trading systems and carbon taxes, covering an estimated 21.5% of global GHG emissions. The number of initiatives has more than tripled since 2011 and the percent of global emissions covered has grown by over four times. In addition, World Bank reports over 1,500 corporations have adopted voluntary net-zero targets, and about half of them report they will rely in part on offsetting to achieve their targets. For 2020, World Bank reports a total of U.S. $53 billion was generated by these GHG market initiatives.

in the Clean Development Mechanism (CDM) established in the 1997 Kyoto Protocol.[201] It allowed emission-reduction projects in developing countries to earn certified emission reduction credits, each equivalent to one Mt of CO_2. These certified emission reductions could be traded, sold, and used by industrialized countries to a meet part of their emission reduction targets under the Protocol. As another example, the California Air Resources Board provides a market for trading both emissions credits under their C&T program and offsets. Under the C&T program, covered entities may use compliance offset credits to satisfy a small percentage of their overall compliance obligation.

Voluntary markets for GHG offsets are important, because large numbers of organizations are already taking voluntary actions to reduce their GHG emissions, irrespective of any formal federal and/or state GHG commitments. Voluntary markets in the EU and North America reported over 200 Mt CO_2e offsets issued in 2020, with nearly one-third more offsets issued and one-third more offsets retired in 2020 compared to 2019.[202]

The Task Force on Voluntary Climate Markets anticipates that the global market for carbon offsets could increase to as much as 1.5 to 2 GtCO_2 per year in 2030.[203] The Task Force reports that "30% of Fortune 500 companies have made climate commitments" for action by 2030 and explains that "more than 700 of the world's largest companies . . . account for around 20% of global emissions."[204]

Offset prices vary widely across markets. At the global scale, prices range from lows of about $1 to highs over $100/Mt CO_2e. Reports for 2020 show prices in the California market of about $12.50–17.50/Mt CO_2e, and in the EU market of about $17.50–40/Mt CO_2e.[205] For a coal-fired, post-combustion CCS plant, a $1/Mt offset price would result in $0.70 in potential revenue per MWh sold. This drops to just $0.30/MWh for an NGCC plant.[206] At $10/Mt, these offsets increase to $7 and $3/MWh, respectively.

Offset use has been challenged based on concerns about the ability to create effective, measurable offset systems. There is widespread interest in ensuring that offsets are "real, additional, verifiable, and permanent reductions or removals."[207] This leads to the need to carefully monitor, audit, and verify offset projects, which in turn adds complexity and cost to deriving offset revenue from CCS generators, potentially limiting the effectiveness of such a program. Multiple efforts are underway to both standardize procedures for and reduce the costs associated with certifying projects and accounting for offsets.[208] Certification procedures ensure that emissions reductions projects will qualify for offsets only if they are:

---

201 "Clean Development Mechanism," [Webpage] *United Nations Framework Convention on Climate Change*, retrieved March 2021]

202 "Issuances & Retirements Meta-Registry" *Ecosystem Marketplace* [Web page] retrieved June 2021, https://www.ecosystemmarketplace.com/carbon-markets/em-data-dashboard/

203 Task Force on Voluntary Carbon Markets, January 2021, Phase 1 Final Report, pp. 50, 52, https://www.iif.com/tsvcm

204 Ibid.

205 Op cit World Bank 2021 (note 2), p. 27.

206 Based on data from James et al 2019, Exhibit 6-1.

207 Op cit World Bank 2021 (note 2), p. 47.

208 "Final Report," *Taskforce on Voluntary Carbon Markets*, (January 2021) https://www.iif.com/Portals/1/Files/TSVCM_Report.pdf.

- Measured, monitored, and verified independently and objectively, using standardized, best-available practices to prevent over-estimating and double-counting.
- Provide incremental GHG emissions reductions beyond business-as-usual requirements.
- Are based on modeling that accurately accounts for the indirect emissions (called leakage) associated with each project.
- Represent long-lasting, or even permanent, emissions reductions.[209]

An important concern about offsets is the potential for double counting and whether offsets are additive. For example, if the output of a CCS plant is used to fulfill a state energy portfolio standard as described in Section 3.4.4, can the associated emissions reductions also be sold as a GHG offset? Vermont was criticized in 2014 for selling renewable energy certificates (RECs) generated in-state to out-of-state power suppliers to meet their requirements, while also counting them toward Vermont's own standard.[210] This practice has since stopped.

The appropriate role of offsets in meeting climate action goals is also subject to much debate. Many parties are suggesting that offsets should: (1) apply in only incremental, limited, supplementary, and interim roles, complementing direct decarbonization strategies; and, (2) be used in mitigating only the most difficult-to-address emissions.[211] In addition, policies frequently restrict the use of offsets to only a small portion of total requirements.[212] Section 4 addresses these concerns as part of the discussion and recommendations of policy mechanisms to support CCS implementation.

As discussed in more depth below, carbon offsets also raise an important issue for public utility regulators. If the price of offsets is less than the cost premium for CCS, is it reasonable to approve a CCS plant with the goal of meeting state GHG reduction targets? That is, would the public be better served by continuing with carbon-emitting sources and offset purchases?

3.5.3 Energy Portfolio Standards and Certificates

At least 30 states have implemented RPS, CEPS, or other requirements for low- or zero-emissions resources to be used in energy production.[213] State rules vary about which energy suppliers are obligated to achieve the standards and about what technologies qualify. Portfolio

---

[209] See for example: "Ensuring Offset Quality," *Center for Climate and Energy Solutions*, (2008) https://www.c2es.org/document/ensuring-offset-quality/; "Carbon Accounting Project," *Columbia University Center on Global Energy Policy*, [Web page, retrieved April 2021], https://www.energypolicy.columbia.edu/research/columbia-carbon-accounting-project; and, "Columbia University's Center on Global Energy Policy launches new carbon accounting project" [Press Release, April 14,2021], https://www.energypolicy.columbia.edu/columbia-university-s-center-global-energy-policy-launches-new-carbon-accounting-project

[210] Trabish, Herman K., "NextEra drops Vermont RECs, adding weight to fraud claims" [Electronic article], *Utility Dive*, May 21, 2014, https://www.utilitydive.com/news/nextera-drops-vermont-recs-adding-weight-to-fraud-claims/265767/.

[211] Op cit World Bank 2021 (note 2), pp. 46-47.

[212] See: "Compliance Offset Program – About," *California Air Resources Board*, [Web page, retrieved May 2021], https://ww2.arb.ca.gov/our-work/programs/compliance-offset-program/about; and, "RGGI Compliance: CO2 Budget Source Frequently Asked Questions," *Regional Greenhouse Gas Initiative*, (2020) https://www.rggi.org/sites/default/files/Uploads/Compliance-Materials/RGGI_Fourth_Control_Period_Compliance_FAQ.pdf California limits offsets to up to 8% of compliance obligations through 2020. That maximum changes to 4% from 2021 to 2025, and then it will be 6% from 2026 to 2030. RGGI limits offsets to not more than 3.3% of allowances and 4 of the 11 RGGI states do not allow offsets at all.

[213] "Clean Energy Policy Tracker," [Web page, accessed March 2021], *National Regulatory Research Institute*, https://www.naruc.org/nrri/nrri-activities/clean-energy-tracker/. The NRRI Clean Energy Policy Tracker provides the current status of formally adopted state GHG targets, RPS, CEPS, and energy efficiency portfolio standards.

standards generally support specific technologies by assigning quotas for the percentages of energy to be delivered from qualifying resources and obligating suppliers to achieve them. The standards effectively encourage some technologies but not others.[214]

Regardless of the definitions that apply, supply portfolio requirements are enforced through the use of verifiable trading certificates, often called RECs.[215] Entities comply with portfolio standards by demonstrating that they have sufficient RECs, either by reducing emissions from facilities they own or by purchasing RECs from other generators. Some of these programs include price caps, while others require alternative compliance payments from producers that do not otherwise control their required volume of credits.

The potential value of RECs or other clean energy credits is highly location specific, because each state establishes its own demand for RECs. In Texas, with its modest RPS target (10,000 MW by 2025, which has already been achieved), RECs were trading at roughly $1.60/MWh early in 2021. In contrast, during the same period, RECs were trading at $11/MWh in New Jersey and Maryland and at roughly $40/MWh in New Hampshire and Massachusetts.[216]

If a CCS plant were to qualify as an eligible resource under a state portfolio standard, it could generate fungible credits. However, none of the state standards currently include CCS as a qualifying resource.[217] Including CCS as an eligible technology in portfolio standards is one possible means of supporting the technology by providing an additional source of revenues.

In addition, state certificate accounting and trading systems could be amended to include tracking of GHG attributes. Because each state has different rules, the trading platforms are can already track the multiple attributes eligible for credit in each jurisdiction's compliance program and can support cross-border trading. It could prove practical to support climate action by including supplies from CCS plants by adding GHG emissions attributes to REC tracking and trading systems.[218]

---

214 See: National Conference of State Legislatures, *State Renewable Portfolio Standards and Goals* [Web page, retrieved August 2021], https://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx; and, North Carolina Clean Energy Technology Center, Database of State Incentives for Renewables and Efficiency (DSIRE), *Renewable Portfolio Standards and Clean Energy Standards* [Detailed Summary Map, Updated September 2020], accessed from https://www.dsireusa.org/resources/detailed-summary-maps/.

215 "Guide to Purchasing Green Power, September 2018 Update," *U.S. EPA Green Power Partnership*, https://www.epa.gov/greenpower/guide-purchasing-green-power ; and, "Green Power Partnership, Renewable Energy Tracking Systems," [Web page] *Environmental Protection Agency,* retrieved May 2021, https://www.epa.gov/greenpower/renewable-energy-tracking-systems. EPA explains a REC is generally defined as "a tradeable market instrument that represents the generation of one … MWh of electricity from a [qualifying] renewable energy source."

216 Shafto, Jodi, "U.S. renewable energy credit prices lean upward in week to Jan. 14," *S&P Global Market Intelligence*, (January 14, 2021) https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/us-renewable-energy-credit-prices-lean-upward-in-week-to-jan-14-62124505. Data reported is from January 2021 and does not include solar-specific RECs.

217 "Database of State Incentives for Renewables & Efficiency," *NC Clean Energy Technology Center*, (accessed 1 June 2021) https://www.dsireusa.org

218 Brown, C. Baird, and Robert B. McKinstry, Jr., "From RPS to Carbon: An Evolutionary Proposal," *Environmental Law Reporter 50* (9), September 2020, ELR 10765, available from https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3639372. Taskforce on Voluntary Carbon Markets, Final Report, January 2021, pp. 9-11, https://www.iif.com/Portals/1/Files/TSVCM_Report.pdf.

3.5.4 Existing State Carbon Market Programs: RGGI and California

Formal state GHG requirements provide the underlying basis for C&T programs. Because a CCS plant would need to purchase far fewer allowances (assuming a 90 percent capture rate) compared to a carbon-emitting plant with equal electricity production, the CCS plant would have an economic advantage. State participation in programs like RGGI and California's Western Climate Initiative could improve the economics of CCS by adding a compliance-cost to non-CCS alternatives, making them more expensive to operate, increasing market prices, and generating additional CCS plant revenues.

RGGI is the first mandatory market-based program in the United States dedicated to reducing GHG emissions. It is a cooperative effort among eleven mid-Atlantic and Northeastern states to cap and reduce CO_2 emissions from the power sector.[219] The first RGGI compliance period began in January 2009.[220] All generators larger than 25 MW are required to purchase allowances equal to their CO_2 emissions. Allowances are made available through periodic regional auctions or resold in secondary markets.[221] The initiative is designed so that the quantity of allowances available decreases over successive years.

Prices for RGGI allowances over the past 5 years have ranged from $2.78 to $8.36/Mt. For an NGCC plant with an emissions rate of 0.34 Mt/MWh (net) and 90 percent CO_2 capture, this translates into an approximately $2.26/MWh advantage over emitting generators subject to the fee.

Participating RGGI states invest the revenues from allowance auctions in energy efficiency, renewable energy, and other consumer benefit program in order to spur innovation in the clean energy economy and create green jobs. If a state determined that it was a priority for public investment, proceeds could be directed to developing CCS plants in their territory, thus providing another potential source of revenue.

California launched its C&T program in 2013, implementing a plan authorized by the legislature in 2006.[222] The California program began applying to about 80 percent of the state's total GHG emissions, including electricity generators and large industrial facilities in 2013, with distributors of transportation fuels, natural gas, and other fuels added in 2015.[223]

3.6 UTILITY REGULATION AND CCS

Each of the three forms of electric utilities (investor owned, munis, and co-ops have different types of oversight. Investor-owned utilities, which provide approximately 70% of the nation's

[219] Pennsylvania could become a 12th state to join RGGI. Pennsylvania Department of Environmental Protection has initiated a rulemaking process, in response to Governor Tom Wolf's Executive Directive 2019-07 (amended June 2020). The draft rules propose joining RGGI, with the initial allowance requirements beginning January 1, 2022. https://www.dep.pa.gov/Citizens/climate/Pages/RGGI.aspx

[220] "Regional Greenhouse Gas Initiative Auction Process Goes Live Today," Regional Greenhouse Gas Initiative, (July 24, 2008) https://www.rggi.org/sites/default/files/Uploads/Press-Releases/2008_07_24_Auction_Open.pdf

[221] "Elements of RGGI," [webpage], *The Regional Greenhouse Gas initiative*, accessed May 2021. https://www.rggi.org/program-overview-and-design/elements

[222] AB-32: California Global Warming Solutions Act of 2006 [Web page] *California State Legislature*, retrieved June 2021, https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200520060AB32.

[223] "Overview of ARB Emissions Trading Program," *California Environmental Protection Agency, Air Resources Board*, (February 9, 2015) https://ww2.arb.ca.gov/sites/default/files/classic//cc/capandtrade/guidance/cap_trade_overview.pdf

load requirements, are regulated by state public utility commissions. A key aspect of that regulation is the determination of rates that enable cost recovery of capital investments such as CCS. This section describes how the ratemaking process for IOU's can impact the economics of CCS for that form of utility.

3.6.1 The Determination of Rates

The ratemaking process is prospective—determining an estimate of the expected costs of providing service (the revenue requirement[224]) and establishing rates for some future period to collect that revenue requirement from customers.

Unlike a competitive firm that realizes profits as a residual of economic activity, a regulated firm incorporates a measure of profits (return on equity) into its cost structure.[225] The utility incurs the cost of providing service and covering its financial obligations such as bond payments, and in the case of IOUs, providing a return on equity to its stockholders. Earnings are the remainder of actual revenues earned minus the utility's expenses (including contributions to fixed costs).

The revenue requirement is based upon a forecast of the cost of providing service for a specific estimate of customer demand. The price charged ratepayers is determined by allocating the revenue requirement over the expected demand of the residential, commercial, and industrial customer classes. Each kWh that the utility sells typically has some level of contribution to fixed costs.

The fundamental rule of ratemaking defines the components of the revenue requirement as:

$$\begin{Bmatrix} \text{Revenue} \\ \text{Requirement} \end{Bmatrix} = \begin{Bmatrix} \text{Return to} \\ \text{Capital} \end{Bmatrix} + \{\text{Expenses}\} + \{\text{Taxes}\}$$

where:

$$\begin{Bmatrix} \text{Return to} \\ \text{Capital} \end{Bmatrix} = \begin{Bmatrix} \text{Return on} \\ \text{Capital} \end{Bmatrix} + \begin{Bmatrix} \text{Return of} \\ \text{Capital} \end{Bmatrix}$$

3.6.1.1 Return to Capital

The return to capital is the aggregate revenue requirement of investments in utility capital. Utility capital is accounted for as the rate base. Bonbright defines the rate base as the total amount of invested capital or of property values on which the company is entitled to a reasonable rate of compensation.[226] The rate base is the prudently incurred cost of the utility plant required to provide service.

The return to capital has two components: the return on capital and the return of capital. The return on capital represents the financial cost of the outstanding balance of utility investment. It is the allowed return on capital multiplied by the undepreciated portion of the rate base. The right of a utility to earn a return on invested capital avoids the taking of a utility's property.

---

224 The revenue requirement is a forecast of the revenues that a utility will be allowed to recover through rates from ratepayers for the providing service.

225 Irwin. MR. "The Integrated Firm Under Regulatory Constraint: the A-J Effect Inverted," In H.M. Trebing (ed.), New Dimensions in Public Utility Pricing. East Lansing: Michigan State University Public Utilities Studies, 1976.

226 Bonbright, J.C. *Principles of Public Utility Ra/es.* New York: Columbia University Press 1961.

Brandeis has written that "the compensation which the Constitution guarantees an opportunity to earn is the reasonable cost of conducting the business. Cost includes not only operating expenses but also capital charges. Capital charges cover the allowance, for the use of the capital...the allowance for the risk incurred; and enough more to attract capital."[227] The cost of capital, therefore, "should measure the rate of return which the Constitution guarantees opportunity to earn."[228]

The rate of return is often thought of as the utility's profits. This is not entirely accurate. Utility profits are the difference between the costs incurred by the utility and the revenues that it raises from providing service. Therefore, although the rate of return incorporates a measure of expected profits into the calculation of the revenue requirement, these profits are not guaranteed.

State PUCs determine the utility's allowed rate of return. Rate-of-return estimates are a weighted average of the utility's cost of debt, cost of preferred stock, and return on common equity capital. The estimation of the return on common equity is accomplished using analytical models such as the capital asset pricing model and discounted cash flow. Sometimes, regulatory commissions provide incentive rates of return to encourage utilities to pursue different investments. The FERC provides an incentive rate of return to encourage the construction of transmission.

If investors received only the financial return on their investment but no recovery of the cost of the investment, then they would have no remaining asset at the end of the asset's life and would not have recovered the cost of the asset. The return would cover the financial cost of the asset and not the capital cost of the asset. Investors are allowed to recover the original cost of the investment by incorporating depreciation expenses into the determination of the revenue requirement. An asset will be fully depreciated over its accounting life, returning the original cost of the asset back to the investor. The Supreme Court recognized depreciation as a legitimate utility expense in Knoxville v. Knoxville Water Company in 1909 (212 U.S. 1 (1909)). The Court stated that:

> a water plant, with all its additions, begins to depreciate from the moment of its use. Before coming to the question of profit at all, the company is entitled to earn a sufficient sum annually to provide not only for current repairs, but for making good the depreciation and replacing the parts of the property when they come to the end of their life.

In practical terms, this means that a regulated utility that builds a CCS plant will be entitled to recover the cost of building it (the capital cost) from its ratepayers, as well as the financial cost of acquiring the asset.

3.6.1.2 Expenses

Expenses are non-capital items associated with the provision of service. For example, the sorbent described in Section 2.2.1 is an operating cost—an expense—whereas the cost of the vessel where flue gasses are decarbonized using the sorbent is a capital cost. Ownership matters

[227] Cited in Bums, R.R, Poling, RD., Whiniham, MJ., *The Prudent Investment Test in the 1980s*. Report no. NRRI·84-16. Columbus, Ohio: National Regulatory Research I, 1985. on pg. 24.

228 Ibid.

in determining which items are considered as an expense or a capital cost. Transportation costs can be either expenses or capital costs. For a CCS plant, the cost of paying pipeline fees for transportation of carbon is an expense. If a utility built, owned, and operated the CCS plant, pipes to transport the CO_2 to the storage site and the actual storage itself would be capital costs.

3.6.1.3 Taxes

The final component of the fundamental rule of ratemaking is taxes. This, along with providing a return on common and preferred equity, is one of the major financial differences between IOUs, munis, and co-ops. IOUs are obligated to pay taxes under the Federal Tax Code. PUCs incorporate both tax liabilities and tax benefits into the calculation of the revenue requirement. Any tax benefit (such as 45Q) is captured and used to reduce the revenue requirement, thereby reducing rates. Unlike IOUs, munis and co-ops cannot take advantage of the subsidies directly. Each of the components of the revenue requirement and, therefore, the cost to ratepayers is affected by regulation and government policy.

3.6.2 Regulatory Mechanisms That Impact the Economics of CCS

3.6.2.1 CWIP and AFUDC

The treatment of capital costs during construction can have a significant effect on large capital projects such as CCS. The determination of the rate treatment of construction costs will impact both the impact of adding the CCS plant into the rate base, and the cost of financing the CCS plant.

When utilities build large capital projects, they must pay a return on the funds that they borrow, in much the same way that a homeowner will pay interest on a construction loan prior to the project being completed. Utilities have been allowed to recognize a return on the funds used to support construction programs since the early 1900s. Construction Work in Progress (CWIP) is the sum of the costs of constructing an asset plus the cost of financing construction. There are two basic methods for computing this cost—either including CWIP in rate base as the plant is being constructed or to adding all costs to the rate base when the plant is completed and goes into service. Adding CWIP to the rate base as the plant is being built means that current customers are pre-paying for the cost of the project.

The interest on the funds used during construction is called Allowance of Funds Used During Construction (AFUDC). An alternative is capitalizing the AFUDC by adding to the asset value of the project.[229]

An intermediate treatment of cost is cash return on CWIP or collecting AFUDC as it is incurred, which has the effect of reducing the rate base. In this method, ratepayers pay financing costs as they are incurred during construction to improve the utility's cash flow. Cash flow coverage ratios are a factor in credit rating agencies' determination of credit quality. The higher a firm's credit quality, the lower its cost of capital. In addition, because this portion of CWIP is collected prior to the plant going into service, it reduces the rate base addition, thereby mitigating

[229] Westmoreland, G. "Electric Utilities' Accounting for Construction Work in Progress: The Effects of Alternative Methods on the Financial Statements, Utility Rates and Market to Book Ratio," Ph.D. Dissertation, University of Florida, 1979.

potential rate shock.[230] Therefore, thoughtful regulatory treatment of CWIP and AFUDC may simultaneously improve the ability of a CCS plant to obtain financing and reduce political opposition by providing customers some protection against rate increases.

3.6.2.2 Securitization

One way to reduce the cost of capital for a CCS plant is through utility securitization, a financial instrument designed to lower a utility's borrowing costs and pass the savings on to customers.[231] Utility securitization is enabled via state legislation allowing IOUs to petition state PUCs for a financing order that authorizes the utility to create a special purpose entity that issues bonds for an express purpose, in this case, a system acquisition or infrastructure repairs.

Securitization creates a property right for debt holders enabling a non-bypassable charge on customer bills to cover this funding requirement. The property right is then assigned to a limited purpose entity that pledges it as collateral for securitized utility bonds sold to investors. The revenue requirement associated with the bond amortization is periodically reviewed for revenue sufficiency and adjusted as needed. Because of the nature of the special purpose entity, the non-bypassable nature of the charge, and the automatic adjustment of the revenue stream, these bonds have historically received "AAA" ratings, which makes them attractive to investors and provides utilities with a lower interest rate than they would achieve through normal borrowing instruments.[232] After the debt is securitized, the utility no longer has a financial responsibility for the cost of the asset, and any related rate base or other regulatory assets are removed from the utility's books.[233] As a consequence, securitization reduces a utility's debt burden, while increasing its coverage ratios and enhancing its credit worthiness.

Securitization has been used since the 1990s to address stranded generation assets (such as the early retirement of nuclear projects) and hurricane damage. Twenty-three states and the District of Columbia have passed enabling legislation for securitization.[234]

After securitization, customers are no longer charged for the utility's cost of capital held by the newly securitized bond, but instead pay a special charge on their bill to repay bondholders. This benefits customers because the utility's base rates decrease significantly more than the securitized charges increase. An independent board established during the securitization process has the authority to adjust the special charge regularly to ensure payment of principal, interest, and associated costs without further regulatory review.[235]

Customers benefit from securitization in two ways. The first is that the cost of capital associated with the acquisition is lower. The second is that the utility does not receive a return on equity for what would have been the addition to the rate base. Eliminating the return on equity benefits customers, because the cost of equity is typically higher than the cost of debt. In

---

230 Rate shock is a significant increase in rates from a capital addition. The term was initially used to describe the rate impact of adding nuclear power plants to rates.

231 Joseph Fichera, "Managing Electricity Rates Amidst Increasing Capital Expenditures: Is Securitization the Right Tool? An Update," *National Regulatory Research Institute,* January 2019: 1.

232 Art Graham, "Ask the Chairman: What is "securitization," and how does it impact their bills?," *Florida Public Service Commission*, 2017, http://www.psc.state.fl.us/Files/PDF/Consumers/AskTheChairman/2015_07.pdf.

233 Fichera, "Managing Electricity Rates," p. 3.

234 Fichera, "Managing Electricity Rates," p. 1.

235 Ibid, p. 3.

addition, customers avoid the corporate income tax liability associated with paying a return on equity. Revenues associated with the cost of equity are typically grossed up to reflect corporate tax liability.

3.6.3 The Prudence Standard

The prudence standard is used to determine whether costs incurred by utilities are recoverable from customers. In practical terms, the prudence standard evaluates whether a decision that supports cost recovery is reasonable, given the information that is known and knowable at the time the decision was made

The determination of prudence has played an important role in shaping today's utility industry. Between 1981 and 1991, PUCs disallowed $19 billion of "imprudently" incurred capital investment related to power plant construction (primarily nuclear) from ratepayer cost recovery.[236] In present value terms, that is more than $100 billion. Mississippi Power and Light entered into an agreement with the Mississippi PUC in 2018 that disallowed $6.4 billion related to failed gasification technology at the Kemper County Power Plant lignite coal gasification facilities.[237]

CCS plants will need to pass the prudence test for recovery of their costs. This test can have many layers. The utility seeking rate base treatment would need to be able to explain why a generator with CCS is needed.

Historically, the prudence standard was implemented after the investment was made and the utility was ready to put the investment into the rate base. The prudence disallowances associated with the construction of nuclear power plants occurred largely after the plants were completed. Some PUCs now grant a pre-declaration of prudence.

A pre-declaration of prudence can reduce the regulatory risk of a disallowance for utilities investing in CCS. The case of the Little Gypsy repowering project demonstrates how it can do so.

The Louisiana Public Service Commission provided Entergy Louisiana (ELL) with a pre-declaration of prudence for the repowering of the Little Gypsy power plant in Baton Rouge, finding that the project was in the public interest and accepting that the decision to proceed was prudent. The proposed repowering was designed to provide ELL,

> "Approximately 538 MW of new baseload solid-fueled generating capacity through the installation of two modern circulating fluidized-bed boilers capable of burning a mixture of petroleum coke and coal at ELL's existing Little Gypsy power plant site, replacing the current Little Gypsy Unit 3 . . . [The] cost was an estimated $1.547 billion, which amounts to roughly $2,875 per kW."[238]

The primary justification for repowering Little Gypsy was to replace a technologically obsolete natural gas generator. The choice of solid fuel was based upon the expectation of continuing

[236] Michael A. Laros, "Prudence Revisited," *Electric Light and Power* 85, no. 4, (2007): 32, http://www.elp.com/articles/print/volume-85/issue-4/ sections/finance/prudence-revisited.html.

[237] "Public Service Commission Closes Book on Kemper," *Mississippi Public Service Commission*, (February 6, 2018) https://www.psc.ms.gov/sites/default/files/2018-08/PSCJointKemperSettlement.pdf

[238] LOUISIANA PUBLIC SERVICE COMMISSION ORDER NO. U-30192 "Docket No. U-30192 In re: Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction And for Certain Cost Protection and Cost Recovery." November 8, 2007 Pg. 7

high gas prices, a reasonable expectation prior to the spread of hydraulic fracturing. As the project proceeded, construction costs increased from $1 billion to $1.6 billion, while natural gas prices fell and the expected cost savings associated with building the plant were no longer available.[239] Given this change, the Louisiana Public Service Commission approved the cost recovery using securitization and creating a non-bypassable asset for recovery of the cost of rate base.

Munis and co-ops operate similarly in terms of declarations of prudence. Both answer to their respective governance structures. In the case of co-ops, governance is by the customers who are the owners of the co-op. Some form of municipal presence (either elected or representing the city council) will determine whether a muni's plans are reasonable.

The first step in establishing the prudence of a CCS investment is to explain why it is needed. There are no clear regulatory guidelines for defining need in the decarbonizing generation sector. Historically, need was based upon having sufficient installed generation (steel in the ground) to meet its customers peak load requirement plus a reserve margin to support reliability.[240]

There are three reasons that a plant with CCS might be needed:

- To provide an element of the least cost capacity addition necessary for achieving carbon goals,
- To deliver significant carbon reductions quickly,
- To provide electric reliability services.

Once the utility proves need, it must be able to address the next question—why use this technology? In answering that question, it will be important to weigh factors such as the certainty and level of cost, and the expected efficiency of the plant. The anticipated operations and maintenance cost of the plant (i.e., house power, reagents, fuel supply, etc.) will also play a large role.

The final step in the prudence investigation is to determine whether the costs the utility is requesting to be added to the rate base and recovered from ratepayers are reasonable. There are two different regulatory approaches to determine that costs were incurred in a reasonable and prudent manner. The first is to audit the construction of the plant and determine whether the costs that were incurred were the result of prudent judgement. The second is to establish target capital costs for completing an operational plant that would be put into rate base. As an incentive, if the capital costs are below the target, the utility would keep a portion of the savings. If the cost of the plant is above the target, the utility would pay part of the overage.

3.7 The Role of Planning

Developing a CCS plant is a time consuming and costly endeavor. A key issue for developers, regulators, and stakeholders is determining whether the plant is needed. One indicia of need is whether the plant is economic, i.e., whether the revenues earned are sufficient to support cost

[239] "Entergy cancelling Little Gypsy conversion project," *St. Charles Herald Guide*, (November 11, 2009) https://www.heraldguide.com/news/entergy-cancelling-little-gypsy-conversion-project/

[240] Article 8 New York Generation siting statute

recovery of the capital and operating costs of the plant with a level of profit (for private entities) sufficient to attract capital investment. Another indicia is whether the need for the plant has been demonstrated through a planning process, e.g., whether the plant will be required to maintain resource adequacy. From a regulatory standpoint, the identification of CCS as an element in a comprehensive energy plan will support a prudence finding that the CCS plant is needed and therefore rate recovery is appropriate. It will also support the development of regulatory mechanisms to support the plant. Yet this can only occur if the planning construct includes decarbonization as necessary criterion or at least a desirable outcome.

Planning can occur at the national, state, regional, market, and utility levels. In some cases, planning is indicative, providing guidance about the future. In other cases, as in the California resource adequacy process, planning directly provides the basis for resource acquisition that meets decarbonization goals.

3.7.1 Federal

The purpose of this section is to describe how the emphasis of federal energy planning has changed over time, and why a national plan for decarbonization is now warranted. The federal government has been involved in the operation and planning of the electric system for over a century. Its initial focus is what we now call resource adequacy, having sufficient capacity to meet customer requirements. This focus has changed over time, and now must do so again, with an increased focus on decarbonization. Planning at the national level can include broad policy mandates or more specific actions, such as targeted tax incentives or support for the strategic petroleum reserve.

World War I (WWI) provided the early impetus for federal intervention into the operation of power systems and resource planning. The United States was unprepared for entry into WWI. Equipping an army of 2 million men in a short period of time placed a huge burden on American production capacity. During the war, the priority for turbo generators was their use for ships and ammunition plants, rather for meeting the country's growing power needs. Faced with the prospect of severe electric-capacity shortages, Bernard Baruch, Chairman of the War Industries Board, ordered a survey of electric generation facilities in the United States. The survey revealed "the possibility of using existing power facilities more effectively by interconnecting power stations and utilities that had complementary load and diversity factors."[241] While utilities responded, interconnecting with each other, increasing capacity utilization, and reducing reserve requirements, the increase in available capacity was insufficient. By October 1, 1918, the War Industries Board began to ration power.

After the war, the first national study of generation resource adequacy, *The Power Situation During the War* (1921), was written by Colonel Charles Keller and published by the Authority of the Secretary of the Army. One of the stunning observations in that report was that "Only the sudden end of the war prevented [the revelation of] a serious shortage of power supply with which to meet the increased demands for the equipment of an army of 5,000,000 men."[242]

[241] Thomas Hughes, Networks of Power: Electrification in Western Society, 1880–1930, (Baltimore: Johns Hopkins Press, 1983), 291.

[242] Twentieth Century Fund, Electric Power and Government Policy: A Survey of the Relations Between the Government and the Electric Power Industry, (New York:, 1948), pp 732-733.

Both the federal government and the states understood the perils of inadequate power planning during WWI. With war clouds gathering again in the mid-1930's, the National Association of Railroad and Utilities Commissioners (NARUC's predecessor) reported that "It is highly necessary that in times of peace the nation should prepare to meet the demands of war."[243] As war broke out in Europe in 1939, President Roosevelt empowered the National Power Policy Committee, under the Chairmanship of the Secretary of Interior, to "devote itself to the development of national policy in the interest of national defense as well as peace time needs." By July of 1941, the Federal Power Commission (FPC) had submitted a plan to the President to ensure the development adequate power between 1943 and 1946 [244]

After World War II, the United States experienced sustained growth in electric demand of 7 percent year over year, with demand doubling every ten years. In January 1962, the FPC staff began preparing the National Power Survey, with assistance from Industry Advisory Committees. The intent of the survey was to "provide a guide for the future planning of the electric power industry."[245] Recognizing that the National Power Survey would have a short shelf life due to changing technology, the FPC planned to update it every five years.

The first National Power Survey (released in 1964) was an attempt to exercise leadership over the technical contours of the future of the power system. "Through long range planning, the Commission has tried to anticipate technology, to understand its implications for policy, and to influence entrepreneurial choices governing its development and use."[246] Joseph C. Swidler, chairman of the FPC noted that "the basic finding of the survey was that each of the nation's 3,600 power systems, large and small, could achieve savings in the cost of generation and transmission of electricity by moving away from isolated or segmented operations and existing (power) pools of limited scope, to participation in fully coordinated power networks covering broad areas of the country."[247]

The 1970 National Power Survey renewed the focus on transmission and pooling. The survey was created by workgroups that provided regional analysis. Building on the 1964 survey's acknowledgement of the importance of transmission and the role of operation of interconnected systems pools, the 1970 survey asked the questions: (1) how do systems obtain and coordinate power supplies; (2) how do existing federal laws, policy, and regulatory supervision relate to power pools and transmission services; and (3) should the availability of transmission and power pool services be a private contractual matter or an obligation required by national objectives?[248]

The 1970's were a tumultuous energy decade, with significant oil supply disruptions (embargoes), national coal strikes, natural gas shortages, and the Three Mile Island nuclear

243 National Association of Railroad and Utility Commissioners, "Report on the Committee on Generation and Distribution of Power," Proceedings, 1938. P 656.

244 Twentieth Century Fund, Electric Power and Government Policy: A Survey of the Relations Between the Government and the Electric Power Industry, (New York:, 1948), pp 732-733.

245 Federal Power Commission, The 1970 National Power Survey," Vol II, pg. II-1-1. 1970.

246 Hughes, William, "Regulation and Technological Destiny: The National Power survey," The American Economic Review, Col 56, no. ½, 1966. Pg. 330

247 New York Times, "Utilities Study National Power Survey and Relax; F.P.C. Assessment Is Termed Milder Than Expected,"20, December 1964, section F, pg,1.

248 Fairman, J.F. and Scott, J.C., *Transmission, Power Pools, and Competition in the Electric Utility Industry*, 28 Hastings L.J. 1159 (1977).

incident. President Carter announced his energy plan in a speech on April 18, 1977. The plan submitted to Congress was based on ten principles that he outlined in his speech:

1) We can have an effective and comprehensive energy policy only if the government takes responsibility for it and if the people understand the seriousness of the challenge and are willing to make sacrifices.
2) Healthy economic growth must continue. Only by saving energy can we maintain our standard of living and keep our people at work.
3) We must protect the environment.
4) We must reduce our vulnerability to actions like the oil embargoes
5) We must be fair. Our solutions must ask equal sacrifices from every region.
6) We must reduce demand through conservation.
7) Prices should generally reflect the true replacement costs of energy. We are only cheating ourselves if we make energy artificially cheap and use more than we can really afford.
8) Government policies must be predictable and certain.
9) Both consumers and producers need policies they can count on so they can plan ahead.
10) We must conserve the fuels that are scarcest and make the most of those that are more plentiful.[249]

The Carter energy plan had explicit goals, such as constructing 2.5 million solar houses by 1985. It included more than 100 interdependent proposals aimed at reducing petroleum consumption, converting from oil and natural gas to coal as an energy source, and increasing domestic energy supplies. President Carter's energy policy led to the passage of sweeping energy legislation, including the Public Utility Regulatory Policies Act (PURPA) (which spawned the development of non-utility generation) and the Department of Energy Organization Act (Public Law 95-91, August 4, 1977) (which consolidated the many energy functions spread across a wide variety of agencies into the Department of Energy). It also created the U.S. Energy Information Administration which produces the Annual Energy Outlook that provides "modeled projections of what may happen given certain assumptions and methodologies."[250]

In July 1981, the Reagan Administration issued its energy plan, "Securing America's Energy Future: The National Energy Plan." The Reagan plan took a very different tack than President Carter's Plan. Carter's plan placed the government in the central role of managing energy issues comprehensively. The Reagan approach focused on private sector decision-making, in which "the role of the Federal Government in energy is distinctly subordinate to decision-making in the private sector."[251] This approach sought to increase energy production by reducing regulation and facilitating access to public lands for oil exploration. The Reagan Administration also proposed disbanding the DOE, eliminating certain functions, and reallocating others to various agencies. As a report by the Heritage Foundation at the time noted, "These

[249] Jimmy Carter, "Address to the Nation on Energy," April 18, 1977 (excerpts), https://energyhistory.yale.edu/library-item/jimmy-carter-address-nation-energy-april-18-1977-excerpts

[250] https://www.eia.gov/outlooks/aeo/narrative/introduction.php

[251] Parker, L.B et al., The Unfolding of the Reagan energy Program: The First Year," Congressional Research Service, Report no. 81-266 ENR, December 17, 1981. Pg, 7.

expectations remain unfulfilled. After its initial fast start, Reagan's energy offensive seemed to bog down."[252]

President George H. W. Bush was somewhat more successful than President Reagan in shifting federal focused energy policy to a market-based approach. Shortly after taking office, he directed Secretary of Energy Admiral James Watkins to prepare "a comprehensive and balanced National Energy Strategy (NES) in recognition of the vital importance of energy to our economy and to our daily lives and the need for changes to Government policies and programs to take full advantage of the tremendous resources our Nation possesses." The goal of the plan was "a blueprint for our energy future while ensuring that our environmental and economic goals would also be met."[253]

The Bush plan provided the basis for the Energy Policy Act of 1992 (EPACT), which he characterized as "plac(ing) America upon a clear path toward a more prosperous, energy efficient, environmentally sensitive, and economically secure future."[254] One of the lasting legacies of EPACT was providing the legislative basis for moving wholesale electric transactions from regulated to market-based prices.

The Clinton administration created a number of policy initiatives related to electricity. These included increased use of tax incentives for energy efficiency, a clean car initiative to increase automobile mileage, continued transformation of the wholesale electric markets, and, most importantly, in October 1993, the Climate Change Action Plan (CCAP). The CCAP "was prepared to achieve the objectives of the 1992 Framework Convention on Climate Change which set as an initial goal that industrialized countries reduce their emissions of greenhouse gases by 2000, to the same level as that of 1990."[255]

President George W. Bush's energy plan was designed to "encourage energy efficiency and conservation, promote alternative and renewable energy sources, reduce our dependence on foreign sources of energy, increase domestic production, modernize the electricity grid, and encourage the expansion of nuclear energy. "[256] It did so by applying policy levers, including new federal appliance efficiency standards, tax credits for energy savings, extending the wind production tax credit, providing tax incentive for solar energy, encouraging geothermal production, granting FERC the power to establish an Electric Reliability Organization (NERC), transforming limitations on power plant ownership by repealing the Public Utility Holding Company Act, and providing tax credits for clean coal facilities.[257]

The Obama administration focused its energy policy primarily on decarbonization. Early in the administration, it pursued the Clean Energy and Security Act (ACES/the Waxman-Markey Bill). After the senate failed to ratify Waxman-Markey, the administration undertook administrative

---

[252] R., Milton, "Reagan's Fading Energy Agenda," The Heritage Foundation, August 17, 1882, pg. 2. https://www.heritage.org/environment/report/reagans-fading-energy-agenda

[253] Bush, GHW, "Statement on Signing the Energy Policy Act of 1992," October 24, 1992. https://www.govinfo.gov/content/pkg/PPP-1992-book2/pdf/PPP-1992-book2-doc-pg1962.pdf

[254] Bush, GHW, "Statement on Signing the Energy Policy Act of 1992," October 24, 1992. https://www.govinfo.gov/content/pkg/PPP-1992-book2/pdf/PPP-1992-book2-doc-pg1962.pdf

[255] Miller, A.S., "Energy Policy from Nixon to Clinton: from Grand Provider to Market Facilitator," Environmental Law, Vol. 25, No.. 3,, 1995 Pg. 722

[256] The White House, President Bush Signs into Law a National Energy Plan," August 8, 2005

"The Energy Policy Act of 2005 Public Law 109-58, August 8, 2005.

actions that could enhance the deployment of renewables. Principal among these actions was the FERC's passage of Order 1000, which was designed to enhance the delivery of renewables to load centers.[258] The Obama administration advanced smart grid development through expenditures from the American Reinvestment and Recovery Act (ARRA). President Obama also created an Interagency Task Force on Carbon Capture and Storage to deliver recommendations to support "the widespread, cost-effective deployment of CCS within 10 years." [259]

In his second term, President Obama initiated two additional significant energy initiatives. The first was the Clean Power Plan promulgated by the EPA to regulate greenhouse gas emissions. The second was the development of the Quadrennial Energy Review, which took a comprehensive look at the way in which energy policy was developed by various agencies and how the efforts could be coordinated to be more effective. The capstone of Obama's energy policy was the successful negotiation of the Paris Climate Accord.

President Trump's energy policy was largely based on rescinding the progress made by previous administrations. These actions included withdrawing from the Paris Climate Accords, rescinding "Executive and Agency actions centered on the previous administration's climate change agenda," disbanding the Interagency Working Group (IWG) on the Social Cost of Greenhouse Gases, and encouraging domestic energy production, including continuing the use of coal.[260]

The Biden administration has begun reversing President Trump's rejection of the energy policy developed by the presidents that preceded him. It is firmly committed to finding new approaches to decarbonization. Doing so will be enhanced by a comprehensive strategy that establishes targets for decarbonization and identifies paths for achieving those targets. The analytical infrastructure for doing so exists within the DOE, EIA, EPA, and the National Labs. Such a planning effort will be a significant undertaking and will require coordinated planning across all stakeholders, including regional, state, and utility partners.

3.7.2 States and Utilities

Utilities have a long history of planning that involves close coordination with the states in which they operate. Traditional planning processes focused on resource adequacy, defined as meeting the installed reserve margin requirements. The required installed reserve margin is designed to enable an electric system to provide generation at the system peak.[261] The reserve margin is required to cover the loss of generator unit capacity due to either forced or planned outages or capacity reductions (e.g., equipment failures), load forecast errors, including those resulting from abnormal weather, and delays in the completion of new generation capacity.[262] Utilities and power systems determine reserve margins by establishing the desired level of reliability and then designing an electrical system to meet that reliability target. Reliability is measured by a reliability index. The dominant index used by the electric utility industry for determining the required installed reserve margin is the Loss of Load Probability (LOLP).[263] The determination of

258 Jody Freeman, Climate and Energy Policy in the Obama Administration, 30 Pace Envtl. L. Rev. 375 (2012).

259 Council on Environmental Quality, "Interagency Carbon Capture and Storage Tas Force," press release. August 12, 2010.

260 The White House, "President Trump's Energy Independence Policy," March 28, 2017.

261 The reserve margin = (installed capacity-peak load)/peak load

262 French, RX. "System Reserve Margins and Their Effect on Reliability." *Proceedings of the American Power Conference,* 1976, 38, 1137-1146.

263 The original formulation of this metric was called the loss of load expectation (LOLE).

the reserve margin is based on an analysis to determine the amount of generation above expected peak load needed to meet the index criteria.[264] Traditionally, once the reserve margin was determined, utilities would determine which type of power plant was expected to minimize the cost of providing power to customers. In the 1970s, this process focused on a debate over whether coal or nuclear was the lowest cost generation addition. Once the location of the proposed generation addition had been determined, the utility would evaluate the need to build additional transmission to deliver the power from generator to load.

The 1964 National Power Survey provided a description of electric planning that forms the basis for the peaker method discussed earlier.

> The basic objective in planning a power system is to develop a generation-transmission expansion pattern which will reliably meet expected load growth in an economic manner. Generally, the expansion of predominantly thermal systems has been accomplished by the installation of efficient steam turbine-generator units for base load service, thus displacing less efficient thermal units into a peaking or reserve role. . . the decreasing efficiency improvement between successive thermal units now being installed has brought about a situation in which good planning must take into account the economics of generating capacity especially suited for peaking and reserve operation. Typically, such equipment is characterized by lower first cost, lower manning cost either because of its adaptability to automation or incremental character of its operation, and usually by higher cost.[265]

The traditional planning process focused solely on providing service through supply-side (i.e., generation) additions. Traditional generation planning did not consider non-generation alternatives. This process changed due to federal environmental review requirements and the judicial interpretation of those requirements. In Calvert Cliffs Coordinating Committee v. Atomic Energy Commission (449 F.2d 1109 (D.C. Cir. 1971)), the Supreme Court found that the Atomic Energy Commission's (AEC) granting of a license to construct a nuclear power plant constituted a major action under the National Environmental Policies Act and therefore required the development of an Environmental Impact Statement (EIS). The EIS needed to address two important requirements. The first was that the benefits of building the power plant must exceed its costs. The second was that the AEC consider not only the environmental impact of building and operating a proposed nuclear power plant but must also consider alternatives to the plant.

The outline of an environmental impact statement for a nuclear facility includes a description of the need for the proposed facility. In essence, this requirement involves weighing the value of the environmental impacts against the benefits associated with the production of electricity. Because the major benefit of a power plant is the electricity produced, if there is no demonstrable need for the electricity, the significant environmental, construction, and operational costs of a nuclear power plant would weigh heavily against its chances of receiving a license.[266]

---

264 The most common criteria is called one day in ten years, in which generation will exceed load once every ten years.

265 Subcommittee of the Generation Stations Special Technical Committee, "Methods of Carrying Peak Loads and Methods of Reducing Peak Loads." In National Power Survey, Part II – Advisory Reports, 1964. Pg 3.

266 Goldsmith. R., ''Power Production and Regulatory Reform: Easing the Transition to an Economic Energy Future, Buffalo Law Review. 1983. 32(10):221-280.

The standard for valuing electricity production was established in the Vermont Yankee case in which the Supreme Court found that "If the electricity to be produced by a proposed project is genuinely needed...then the societal benefits achieved by having that electricity available are immeasurable."[267] As a consequence, the NRC assumed that if a nuclear power plant was needed to meet installed reserve margins, then it automatically passed a cost-benefit test. By the mid-1970s, many states required a demonstration of need before a power plant could be constructed.

Some state determinations of need were made by public utility commissions. In other states, the determination of need was made through legislation or by the agencies that administered the state's siting laws. States had relied on the federal government's decisions during much of the early history of siting nuclear powerplants. State legislatures responded to the growing opposition to nuclear power and the high level of proposed capacity additions requested by passing siting legislation that gave state agencies explicit responsibility for evaluating the need for additional power plants. Under this regime, need was determined by assessing whether there was adequate capacity on the system to meet forecasted demand, particularly peak load demand. To meet the requirements of forecast load in a reliable manner, it was necessary construct sufficient capacity to meet peak load plus installed reserve margin requirements.

The U.S. Court of Appeals decision in Natural Resource Defense Council. Inc. v. Morton resulted in the requirement that in its consideration of alternatives to a proposed action an agency include that which might be beyond the agency's responsibility to implement. Both the Morton and the Calvert Cliffs decisions prompted opponents of nuclear power to champion the conservation alternative before the AEC.

During the 1970s, that process involved determining the type of power plant to build and identifying the transmission needed to transport that power from the plant to load. With the introduction of energy efficiency as a resource in the 1970s, utility planning began to change its focus. The transition from traditional planning involved a change from a "focus on utility-owned central station power plants" to a review of a "diversity of resources, including utility-owned plants, [p]urchases from other organizations, [c]onservation and load-management [programs], [t]ransmission and distribution improvements, [and] [p]ricing."[268]

Resource planning requirements may differ significantly from state to state. In some cases, utilities will establish multiple resource plans that may arrive at different outcomes, despite being governed by the same regulations.[269] State IRPs are often established through the legislature or through state administrative code, requiring utilities to engage in resource planning. State utility commissions often institute regulations guiding resource planning through administrative rules or separate docketed proceedings.

Energy markets and planning processes are increasing in complexity. Industry structure and the resources available to satisfy customer demand have changed dramatically. Customers have many more service options than in the past, including self-supply. In addition, the very nature of

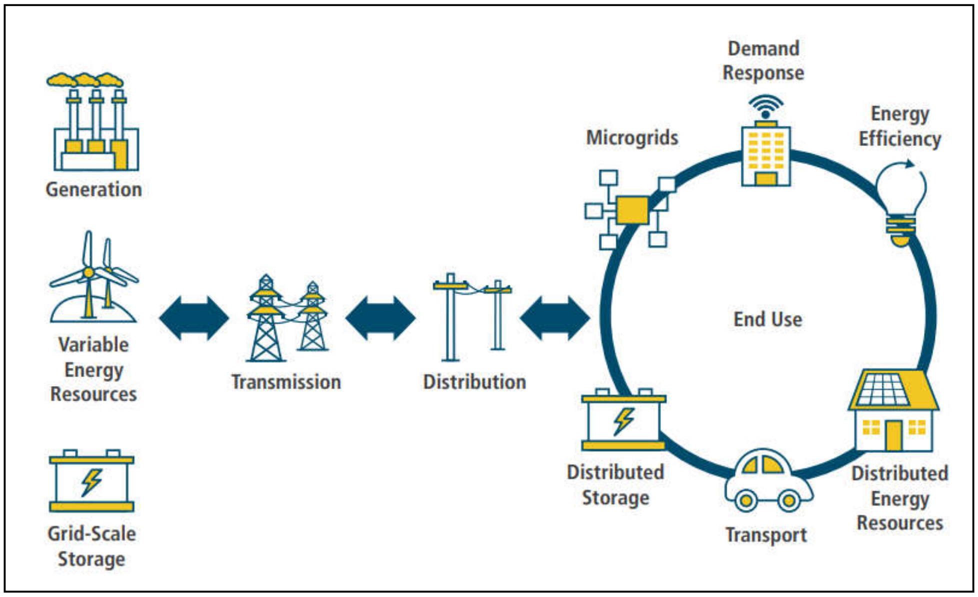
[267] *Vermont Yankee Nuclear Power Corp. v. Natural Resources Defense Council*, 35 U.S. 519 (1978)

[268] Hirst, E., Goldman, C. and Hopkins M.E., "Integrated resource planning: Electric and gas utilities in the U.S.A.,' Utilities Policy, January 1991.pg. 173

[269] Wilson, R., Biewald, B. Regulatory Assistance Project. Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans. p.4. (https://www.raponline.org/wp-content/uploads/2016/05/rapsynapse-wilsonbiewald-bestpracticesinirp-2013-jun-21.pdf).

the distribution system itself is changing, with customers injecting power back into the grid, creating a two-way flow, as shown in Exhibit 3-26.

Exhibit 3-26 Emerging 21st-Century electricity two-way flow supply chain



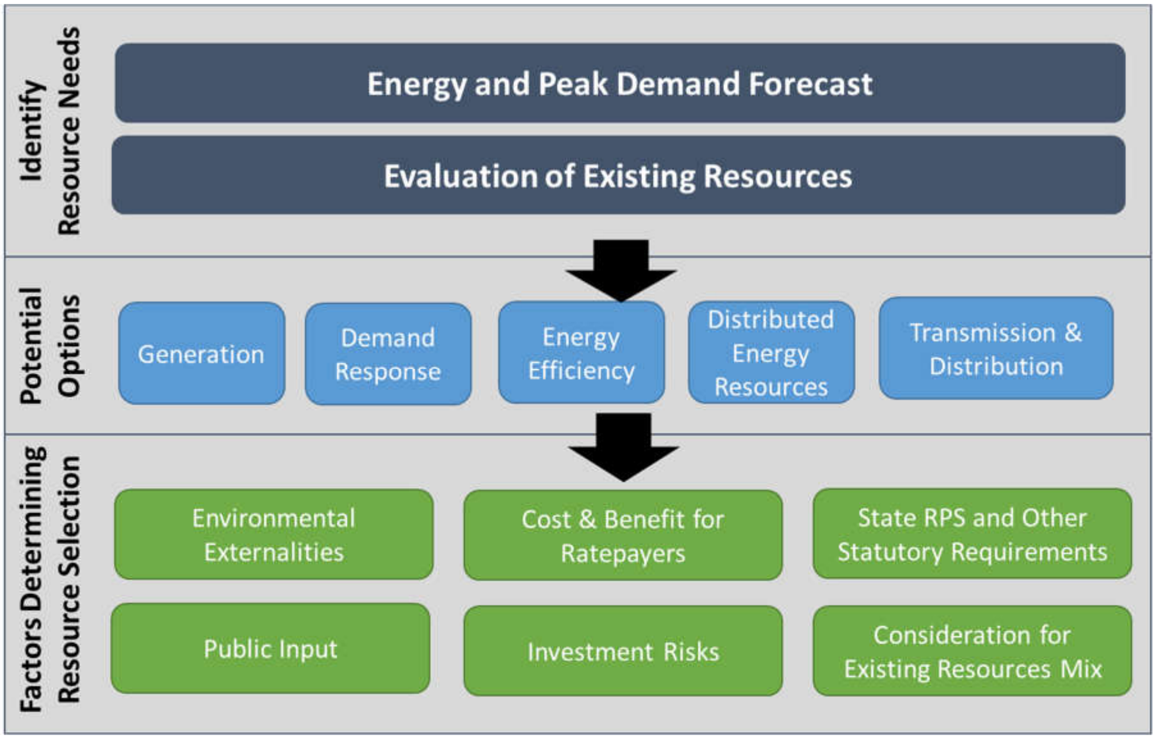
Source: Quadrennial Energy Review Task Force[270]

The state IRP analytical process focuses largely on minimizing costs for the end-use customer by determining a resource mix that meets resource adequacy requirements while minimizing costs. A critical part of the development of a robust resource portfolio is the inclusion of demand-side management and energy efficiency programs. Other alternatives to new generation include customer-owned generation, combined heat and power generation, new transmission and distribution lines, and/or bolstering transfer capability so that additional power can be imported from neighboring areas. Additional inputs of the process are included in Exhibit 3-27.

Of particular importance in the development of IRPs is the nature of the costs to be minimized. Costs can be defined in a variety of ways, from the out-of-pocket cost of serving customer demand, to costs that reflect environmental and social justice concerns. In the past, the economic value of environmental externalities was reflected by the use of "adders" to the rate base to change the nature of resource optimization. California does this to some extent through their C&T program, in which "resource-specific compliance obligations are determined by. . . [California ISO] CAISO's optimization based on energy bids and greenhouse gas bid adders."[271] An alternative approach would involve the introduction of carbon constraints, so that the total carbon emissions for each resource type becomes a constraint in the analytical planning process.

[270] Quadrennial Energy Review – Transforming the Nation's Electricity System: The Second Installment of the QER. January 2017. Figure S-3. https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf
[271] CAISO's Department of Market Monitoring "2019 Annual Report on Market Issues and Performance." P. 66. http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf.

Exhibit 3-27 Typical State IRP Process



Recently, IRPs have put an increased emphasis on resilience, including considerations for fuel supply and diversity, localized load growth, electricity spot prices, acknowledgement of the variability of hydro resources, market structure, and environmental regulations (including limiting CO_2 emissions). This creates opportunity for CCS plants, since they are dispatchable thermal resources that provide important reliability services while also addressing emission concerns.

3.7.3 Organized Markets

3.7.3.1 Basic Planning Approaches in Organized Markets

Approximately two-thirds of the electricity demand in the United States is served by entities that participate in organized markets. Resource and transmission planning activities are conducted by various planning entities within an ISO.[272] These activities typically focus on system reliability and transmission investment, while promoting efficient investments. Planning decisions in multi-state market areas are especially complicated because states can have varying policy goals. Any attempt to define a standard process for all market areas would be accurate for some and inaccurate for others, given the complexity of their different processes.

There are different approaches that can be taken once the ISO identifies the need to maintain resource adequacy. The typical ISO planning process "rolls-up" the plans of the individual members or market participants that own and operate generation or provide other resources such as demand response. The ISO plans are predicated on the assumption that the many

[272] NERC defines the different planning entities in the NERC Functional Model: (https://www.nerc.com/pa/Stand/Functional%20Model%20Advisory%20Group%20DL/Functional_Model_V5.1_clean_10082019.pdf).

entities that are providing their own plans are in compliance with planning-related NERC Reliability Standards.

Although planning processes and the entities involved differ for each ISO, they typically include the following three components.

Load and Resource Study: The planning process begins with a long-term load forecast for the area. This generally includes energy needs and peak projections for at least 10 years and including the impacts of energy efficiency, behind-the-meter or distributed generation, and other factors that may impact load. Some areas conduct extreme load scenarios and/or load projections to examine local resource adequacy in parts of the region with high load growth. After load projections are complete, a comprehensive resource study is developed to examine the availability of existing generation, as well as projected new builds, uprates that increase output, derates that decrease output, outages, retirements, and other factors that may impact the supply of energy.

ISOs vary in their response to capacity shortages. In some cases, for example ISO-New England, the expectation of resource shortages impacts the parameters used in their capacity market, as described below:

> In order to achieve a certain level of resource adequacy/system reliability, ISO-NE sets a yearly system capacity requirement. This requirement is done through the Installed Capacity Requirement (ICR) calculation. The ICR calculation accounts for uncertainties, contingencies, and resource performance under a wide range of existing and future system conditions. . . In short, the ICR is a measure of the installed resources projected to be necessary to meet both ISO-NE's and the Northeast Power Coordination Council's reliability standards for satisfying the region's peak demand forecast while maintaining required operating reserves. . . The ICR is calculated as part of the FCM and used as an input into the FCA for each capacity commitment period (CCP).[273]

In contrast, the CAISO can directly acquire capacity to meet short-run resource adequacy requirements when shortfalls are projected. These include backstop capacity procurements, including Reliability Must-Run (RMR) contracts and the Capacity Procurement Mechanism (CPM).[274]

Transmission Planning Deliverability Assessment: Under FERC Order 1000, different regions of the country participate in regional transmission planning processes. The regions differ; some include areas where there is no organized market, while others are covered by these markets. Each of the ISOs prepares a transmission plan that covers its footprint. The plan evaluates the adequacy of transmission to support the delivery of generation to load. To do so, the designated planning entity must develop a 5-year transmission deliverability study that meets the NERC planning-related reliability standards.[275] This study examines the existing and future capability

---

[273] NARUC Resource Adequacy Primer for State Regulators. P. 30. 2021. (https://t.co/tG7RrRVLtj?amp=1).

[274] Hildebrandt, et. al., "2020 Annual Report on Market Issues & Performance," *California ISO*, (August 2021) http://www.caiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdf.

[275] A complete list of NERC Reliability Standards are available here: "United States Mandatory Standards Subject to Enforcement," [Webpage] *North American Electric Reliability Corporation*, https://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States.

of the area's transmission network, with consideration for upgrade costs or other investments. Merchant transmission projects are usually examined separately.

An important aspect of transmission planning is accommodating the injection of power from small- and large-scale generators through interconnection agreements. There are two types of interconnection agreements: small and large generation interconnection agreements (SGIA and LGIA). An analytical challenge faced in all transmission planning studies is how to incorporate prospective generator interconnections.

Updates and Adjustments to Address Changing System Conditions: After taking interconnections into consideration, transmission planners often conduct additional studies to capture ongoing changes to the system (e.g., local load growth, unscheduled, long-term outages). As the process moves from a planning to an operation time horizon, specific generating and transmission characteristics are updated.

3.7.3.2 Impact of RPS on Planning in Organized Markets

Historically, state and regional planning processes did not directly account for the policies created to constrain carbon emissions. During the past two decades, however, state renewable portfolio standards (RPS) have become an important driver for reducing carbon emissions in the electricity sector. In the absence of a federal plan to reduce carbon emissions, more states are implementing their own RPS goals. RPS policies exist in 30 states and the District of Columbia.[276] More recently, Arizona, Maryland, New Mexico, Nevada, Virginia, Washington, and the District of Columbia have created new RPS targets or increased existing ones.[277] Ten states and the District of Columbia have set 100 percent clean or renewable resource requirements to take effect between 2030 and 2050.[278] Exhibit 3-28 shows RPS developments across the United States since 2018.

Although the requirements and implementation details for these state RPS programs vary significantly (for example, resource eligibility parameters), in almost all of these cases, state RPS programs impact resource planning decisions at the state and regional level.

California has modified its IRP process to ensure that the state's RPS requirements are the primary driver of resource procurement decisions. This is achieved through coordination between the CPUC, the CEC, and the CAISO. The CPUC and CEC together implement and administer RPS compliance rules.

---

[276] Galen L Barbose, "U.S. Renewable Portfolio Standards 2021 Status Update: Early Release," *Lawrence Berkeley National Laboratory*, (February 2021) https://emp.lbl.gov/publications/us-renewables-portfolio-standards-3

[277] Ibid.

[278] "State Renewable Portfolio Standards and Goals," [Webpage] *National Conference of State Legislatures*, (August 13, 2021) https://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx

***Exhibit 3-28: State Amendments to RPS/CES Legislation Since 2018**[279]*

State	New RPS/CES Target	By Years
California	100%	2045
Colorado	100%	2050
Connecticut	44%	2030
Delaware	40%	2035
Maine	100%	2050
Maryland	50%	2030
Massachusetts	35%	2030
Minnesota	26.5%	2025
Nevada	100%	2050
New Jersey	50%	2030
New Mexico	100%	2045
New York	70%	2030
Oregon	100%	2040
Virginia	100%	2045/2050
Washington	100%	2045
Washington D.C.	100%	2032

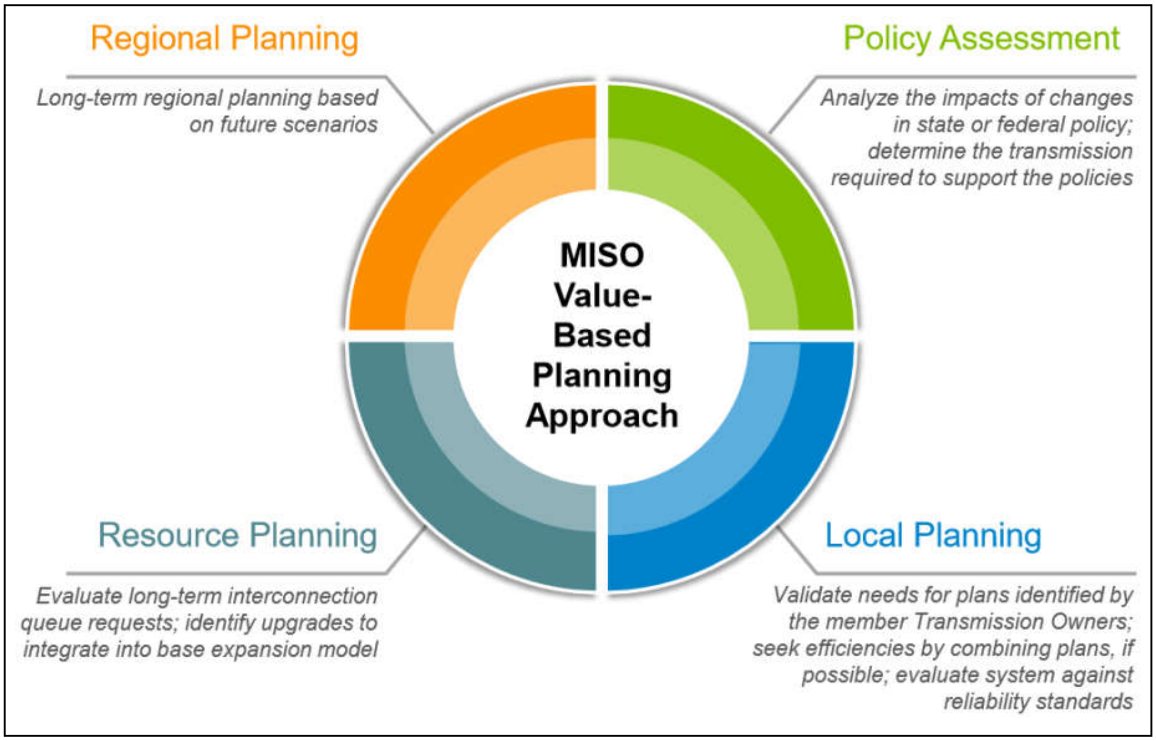
Source: NCSL

Multi-state market areas like PJM, MISO, and SPP require additional coordination to evaluate and incorporate how state RPS programs impact regional resource planning decisions. For example, the states within ISO-New England have various emission-reduction policies. These different policies may conflict with the established objectives of the wholesale market, which were designed to procure the most efficient, cost-effective resources system without regard to fuel source or resource characteristics. Over time, many of the states within the ISO-New England region have made policy decisions favoring renewable and low-carbon emitting resources. As the system continues to evolve, balancing resources (resources that can reliably provide supply as needed when supply constraints or interruptions occur) are vital to system reliability. It will also be important for multi-state markets to examine potential mechanisms that incorporate decarbonization into the planning process.

The Organization of MISO states was established create a forum where state public utility regulators can share information, debate, and exchange ideas on policy issues, including RPS impacts. Through this forum, MISO has developed the value-based planning approach, outlined in Exhibit 3-29, that incorporates state and federal policies (including RPS requirements) into the planning process.

279 Ibid.

***Exhibit 3-29: MISO Value-Based Planning Approach*[280]**



Source: MISO

As state RPS goals continue to have a growing impact on resource planning decisions at the state and regional level, it will be important to understand the aggregated impacts of state policies across the country. Meeting the carbon-reduction requirements for all states (and a potential national requirement) will necessitate the retirement of significant amounts of existing fossil-fuel fired thermal generation. As discussed in Section 3.2, achieving existing state RPS targets, while also maintaining adequate levels of essential reliability services will be a challenge for system planners and operators. This is something system planners will need to consider more critically. In doing so, the value of CCS technology in supporting thermal generation will be recognized and the need for those facilities will be supported.

280 "2021 MISO Transmission Expansion Plan," [webpage] *MISO*, (2021):11 (https://www.misoenergy.org/planning/planning/mtep21/)

4 Regulatory Policy and Market Design Recommendations

4.1.1 Conclusions

CCS has an important role to play in decarbonizing the American economy. That role will be determined by a combination of factors, most importantly, the overall governance of carbon policy—including decarbonization goals, carbon pricing, markets for power, tax treatment, revenues from beneficial use, and the regulatory treatment of utility investments in CCS. This paper describes how policy, technology, markets, and regulation will intertwine to affect the economics of CCS, in particular CCS plants associated with electric generation.

There are a number of core takeaways from this analysis. The first is that the value that CCS brings to decarbonization is not sufficiently recognized by either public policymakers or markets. As a consequence, the economics of building a CCS plant are a heavy lift. It is unlikely that under current conditions we will see merchant plants develop CCS facilities associated with electric generators. There are a number of reasons for this. The first is that, as a rule, carbon emissions are not priced in the United States, and when they are, the price is well below the estimate of the social cost of carbon. The second is that electricity markets are not appropriately valuing CCS capacity and the essential reliability services that it provides. Further, the structure of electric planning is still largely focused on resource adequacy, with the primary decision point whether or not resources are required to satisfy customer demand.

A second takeaway from the study is that the role of CCS in decarbonizing the American economy needs to be clearly articulated. A national decarbonization plan will help define that role and therefore the need for CCS. It will demonstrate whether or not CCS is a critical resource for achieving decarbonization goals. If it is, then state and federal policymakers must develop methods that will enable the financing of CCS and other decarbonization methods. Current mechanisms that rely upon tax credits are not as effective as systems that directly subsidize CCS, because the entities interested in developing CCS cannot always use tax credits (e.g., if they are tax exempt) and must rely on tax equity partners. In addition, to take advantage of this federal subsidy, developers must enter into tax equity partnerships, a task that comes with a cost that ultimately limits interest in the program.

Public utility regulation will play a significant role in determining whether CCS plants will be built. IOU's serve 70 percent of the country's electric load. Regulatory commissions will determine cost recovery for CCS investments based upon whether the utility's decision to build a CCS plant is prudent. Demonstrating that the decision to build CCS was reasonable will be facilitated by national, state, and regional plans that require that plants meet decarbonization targets. Doing so will require that the utility show that decarbonization alternatives such as offsets are not a sufficient substitute for the plant—either because the quality of the carbon reductions is not as secure or because substitutes cannot provide the essential reliability services required to operate a renewable rich power grid. Once the regulator has found a project prudent, there are a number of mechanisms at its disposal for helping to reduce the ratepayer impact of the investment.

4.1.2 Recommendations

1. **Develop a national decarbonization plan that articulates the role of and need for CCS.**

The decarbonization of the American economy is perhaps the most significant economic challenge the nation has ever faced. Its size is certainly on the order of a major war. Every activity that uses energy will need to be re-evaluated to rout out the carbon emissions. Electrification activities implemented to reduce carbon emissions will also drive demand for electricity at a time when it needs to decarbonize. A national decarbonization plan would help provide coherence among the many moving parts that require coordination, chart a least cost path to decarbonization, identify the market mechanisms and subsidies required to support its implementation, alert planners to supply chain vulnerabilities, and identify the uncertainties associated with achieving carbon reduction targets. A national decarbonization plan would clearly articulate the role of CCS in decarbonization and provide critical information on its need.

2. **Encourage state regulatory actions that reduce the in-service cost and regulatory risk associated with the development of CCS plants, including pre-declarations of prudence, providing cash returns for Construction Work in Progress (CWIP), and securitization.**

PUCs have tools at their disposal that can help to foster the development of CCS. PUCs will determine whether the decision to build CCS is prudent and therefore whether the utility will receive cost recovery. One way to reduce the regulatory risk associated with the development of CCS is to evaluate the decision to develop the CCS facility before significant expenditures are made on its construction. Once a PUC determines that the plant is prudent, it can take actions to reduce the impact on ratepayers. These include allowing the utility to recover the financing costs of construction work in progress before the plant is put into the rate base, thereby reducing the rate base cost and rate impact. An additional approach is to securitize the capital cost of the CCS by creating a special purpose entity that has a higher credit rating and therefore a lower cost of capital than standard utility financing.

One way to encourage PUCs to adopt regulatory mechanisms that enable reducing the cost of facilities that are deemed to be needed would be to prepare a regulatory guide for utilities and PUCs that would provide the rationale for those mechanisms and explain the basis for their adoption.

3. **Encourage states and the federal government to adopt direct pay provisions to support CCS.**

Currently federal subsidies for CCS are provided through tax credits. To fully take advantage of those credits, CCS developers must enter into agreements with Tax Equity Partners. As a consequence, the developer incurs transactions costs to establish that partnership and also a penalty in the form of profits to the Tax Equity Partner for having facilitated the deal. Direct subsidies would provide a more effective option for dollars coming out of the federal treasury.

4. **Provide funding and technical assistance to enhance the analytical capabilities of state PUCs, utilities, and stakeholders to better plan decarbonization pathways.**

Currently, utility planning and PUC reviews of those plans are primarily focused on maintaining resource adequacy. In the IRP process, the typical approach for reflecting carbon externalities is with administrative adders. Meeting decarbonization targets requires a different analytical structure, where the analytics are based on imposing constraints, as opposed to altering relative prices. New methods are needed to enable utilities, PUCs, and stakeholders to evaluate and develop decarbonization plans. The Department of Energy and the national laboratories are in a unique position to develop those methods and provide technical assistance to support their adoption.

5. **Include CCS as an eligible technology in state renewable portfolio standards.**

Renewable and clean energy portfolio standards are tools used by states to support decarbonization. There is a great deal of variation in the types of supply technologies that are included in state portfolio standards. In some cases, the standards require that the assets be renewable energy sources, like wind and solar; in others, the focus is broader and can include other clean energy technologies. Another policy being adopted by states is direct climate action mandates, which generally include the goal of achieving major reductions in or meeting net-zero GHG emissions by 2050 or sooner. The narrowing of options for what qualifies as a resource to decrease carbon emissions reduces the efficiency of achieving decarbonization. Enabling CCS as a qualifying resource would increase the efficiency and reduce the cost of meeting decarbonization goals.

6. **Examine the impact of wholesale market design on the recovery of capital costs for CCS.**

One of the principal sources of revenues for amortizing the investment in CCS is the sale of electricity. The price of electricity is determined by market rules, which, in the case of the organized markets, is regulated by the FERC. These rules were developed at a time when there was not an imperative to reduce carbon emissions, renewables did not play a significant role in the overall generation mix, and large numbers of customers were not supplying power at the grid edge. These factors have a significant impact on the nature of the power markets and raise important issues about whether a market structure based upon technologies that are increasingly obsolete (that is, fossil-fueled thermal power plants without CCS) is sufficient to support cost recovery for CCS. A public dialogue on market structure is warranted. The DOE has the power to convene a dialogue with the FERC, state regulators, utilities, generators, and stakeholders on challenges to current market design and how alternatives can meet those challenges.

7. **Examine the value of CCS in ensuring sufficient capacity for providing essential reliability services.**

Each type of generator brings different attributes for maintaining power system reliability. As the proportion of intermittent renewable energy on the system increases, displacing thermal units, certain services provided by those retired units will decrease. Essential reliability services reflect the generation attributes required for the reliable operation of the grid. Properly valuing the output of generators with CCS requires identifying the essential services required to operate the grid reliably and determine the contributions that CCS plants can offer.

8. **Develop mechanisms to measure and verify the value of carbon offsets.**

Carbon offsets can affect the economics of CCS in two ways. First, the offsets may be viewed as a substitute for CCS. Therefore, from a regulatory standpoint, there is a question of whether it would be prudent to develop a generator with CCS if it would be less expensive to use a conventional generator and buy offsets. Offsets are also an important positive tool for CCS because they may provide operators with an additional revenue stream.

Offsets can vary in quality. For example, the value of an offset from maintaining a stand of trees is different from that of capturing and securely storing carbon with CCS. The value of the carbon offset for the stand of trees is diminished by harvesting the forest. The value of sequestration can be measured by the amount of carbon pumped into the ground, where geologic studies have demonstrated that that storage is secure. For a fungible market in offsets to be established, it is necessary to have clear measures that will allow investors to determine their value. This can be done by defining various classes of offset options and developing measurement and verification methods to ensure that offsets meet necessary quality standards.

9. **Create trackers on state regulatory and legislative actions affecting decarbonization, including the treatment of carbon offsets, policies affecting CCS, renewable portfolio standards, and methods for integrated resource planning.**

Understanding and determining an overall policy for decarbonization and the role of CCS is information intensive. Different states do things in different ways. Understanding lessons learned (how, why, and the outcome) from activities in different states will facilitate the development of legislation and policy. Policy trackers will help reduce the transaction cost of developing policy and legislation and will hopefully result in the adoption of policies that support efficient paths to decarbonization that include the role of CCS.

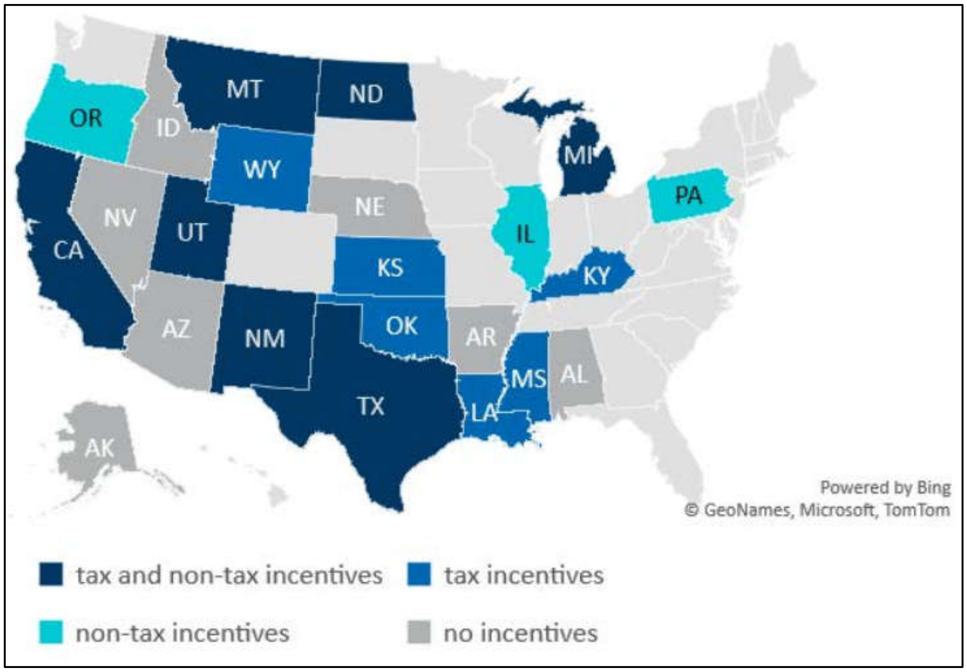
10. Analyze carbon pricing proposals and their impact on CCS

Carbon pricing proposals will affect CCS in different ways. Knowing the potential impact of various proposals will help to tailor pricing mechanisms to support rather than discourage the development of CCS. Therefore, it is important, to provide feedback on carbon pricing proposals as part of the relevant legislative and administrative processes.

APPENDIX A: STATE TAX PROGRAMS TO SUPPORT CCS

The 45Q tax credit has served as a key driver for many carbon capture and storage (CCS) projects; however, the economic viability of these projects could benefit from additional state tax incentives. Similar to the federal 45Q, these state programs can include specific tax credits for eligible carbon dioxide (CO_2) enhanced oil recovery (EOR), enhanced (natural) gas recovery (EGR), and geologic storage. These credits are designed to promote business and investments in the state by reducing corporate income taxes, providing exemptions from property and sales taxes on capital stock (such as machinery and equipment), and reducing severance taxes on oil produced through CO_2 EOR. The United States Energy Association (USEA) has identified 12 states with tax incentives that could affect CCS investment decisions.[281] Exhibit A-1 maps the various incentives for each state. A summary of these tax incentives follows.

Exhibit A-1. States with CCS incentives



Source: FTI Consulting and Orrick Research[282]

KANSAS

Accelerated Depreciation: This tax program addresses accelerated depreciation on machinery or equipment that is installed to capture, store, or utilize CO_2. The taxpayer may deduct an amount equal to 55 percent of the amortizable cost of such equipment in year 1, and 5 percent for years 2–10 from its state adjusted gross income. Accelerated depreciation shifts the time over which tax benefits can be taken. Accelerated depreciation increases deprecation in the

[281] Connors, P., Ditzel, K., Emmett, J., Li, F. "Review of Federal, State, and Regional Tax Strategies and Opportunities for CO_2 -EOR-Storage and the CCS Value Chain." *United States Energy Association*, (September 2020) https://usea.org/article/usea-doe-offer-assessment-tax-incentives-carbon-capture-and-storage

[282] Connors, P., Ditzel, K., Emmett, J., Li, F. "Review of Federal, State, and Regional Tax Strategies and Opportunities for CO_2-EOR-Storage and the CCS Value Chain," *FTI Consulting and Orrick Research for United States Energy Association*, (September 2020) https://usea.org/article/usea-doe-offer-assessment-tax-incentives-carbon-capture-and-storage

early years of a project and increases the present values of tax benefits by ensuring that they are not deflated over the period during which they are granted.[283]

Property Tax Exemption: Provides a five-year exemption from state property taxes for CCS or CCS property and any electric generation unit that captures and stores all CO_2 and other emissions.[284]

KENTUCKY

The Kentucky tax incentives are structured to offset the amount of tax owed by entities with qualifying levels of capital investment that "construct, retrofit, or upgrade facilities" with CCS. The minimum capital investment is $100,000,000 for gasification facilities using oil shale, tar sands, or coal as the primary feedstock.[285] The total claimable tax incentive for each eligible project is limited to 50 percent of the capital investment.[286] The developer must enter into a tax incentive agreement with the Kentucky Economic Development Finance Authority. Terms and conditions of the tax incentive agreement are negotiated based on various project attributes and can potentially include the other state tax incentives described below.[287]

Sales and Use Tax Exemption: Up to the entire amount of the sales taxes for investments to construct, retrofit, or upgrade an eligible CCS project, up to a cap equal to 50 percent of the actual capital investment in the eligible project, may be exempted.[288]

Severance Tax Credit: Facilities that construct, retrofit, and upgrade existing plants to become CCS-ready may receive up to an 80 percent offset of and severance taxes paid for coal used by an alternative fuel, energy-efficient fuel, or gasification; or from natural gas (or liquids) used by an alternative fuel.

Credit on Corporate Income Taxes: These programs can offset up to 100 percent of the state income tax and limited liability entity tax imposed on the income, gross profits, or gross receipts generated by an eligible CCS project.[289]

Credit on Personal Income Taxes: Project developers can assess up to 4 percent of the gross wages paid to employees, subject to state income tax, if the job was created by an eligible project.[290]

LOUISIANA

Sales and Use Tax Exemption: This provision exempts anthropogenic CO_2 from the state's sales and use tax. The CO_2 must be used in a tertiary recovery project that is approved by the state's Assistant Secretary of the Office of Conservation of the Department of Natural Resources.[291]

---

283 52 Kan. Stat. Ann. §79-32,256

284 Kan. Stat. Ann. §79-233(a)

285 KY. Rev. Stat. Ann. § 154.27-020(4)(a).

286 KY. Rev. Stat. Ann. § 154-27-020(6).

287 KY. Rev. Stat. Ann. § 154.27-040.

288 KY. Rev. Stat. Ann. § 154.27-020(5)(b); KY. Rev. Stat. Ann. § 139.517.

289 KY. Rev. Stat. Ann. § 154.27-020(5)(d).

290 KY. Rev. Stat. Ann. § 154.27-020(5)(e).

291 La. Rev. Stat. Ann. § 47:301(10)(gg) & (18)(p).

Severance Tax Reduction: Any severance tax imposed on crude oil production from a qualified tertiary recovery project that uses anthropogenic CO_2 may receive a 50 percent tax reduction.[292]

MICHIGAN

Severance Tax Reduction: The state reduces severance tax rates for natural gas and oil produced from CO_2 (secondary or enhanced) recovery projects.

MISSISSIPPI

Ad Valorem Tax Exemption: This ten-year exemption applies to ad valorem taxes (other than taxes imposed for school district purposes) for equipment (e.g., pipelines, dehydrators, compressors) used to transport CO_2 for use for in-state EOR projects.[293]

Severance Tax Reduction: A reduced rate is offered for oil produced and transported via pipeline using an EOR method in which CO_2 is utilized.[294]

Gross Income Tax Reduction: A reduced tax rate is offered to public utilities for fuel (e.g., electricity, steam, coal, and natural gas) sold to a producer of oil and gas for use directly in EOR using CO_2, and/or in connection with the permanent storage of CO_2 in a geological formation.[295]

MONTANA

Reduced Property Tax: Montana imposes an equipment tax on property owned by businesses. There are 17 business property classes, each subject to different rates. Class 15 property includes “carbon [storage] equipment,” which is reduced from 3 percent to 1.5 percent of its “reduced market value.”[296]

NEW MEXICO

Alternative Energy Product Manufacturers Tax Credit: Provides tax incentives for investments in alternative energy products, including components for integrated gasification combined cycle coal facilities and equipment related to the storage of carbon from these plants.[297] An eligible project developer can receive up to 5 percent of the qualified expenditures, following approval by the state’s Taxation and Revenue Department. The credit can offset the developer’s modified combined reporting taxes.[298]

Other State Taxes: New Mexico imposes a 5.125 percent gross receipts tax to engage in business within the state.[299]

---

[292] La. Rev. Stat. Ann § 47:633.4(B)(2).

[293] Miss. Code Ann. § 27-31-102.

[294] Miss. Code Ann. § 27-25-503.

[295] Miss. Code Ann. § 27-65-19(b)(ii).

[296] See Mont. Code Ann. §15-6-122 through §15-6-162.

[297] NMSA 1978 § 7-9J-2(A).

[298] NMSA 1978 § 7-9J-2(I). Additional time limits and requirements are outlined in the New Mexico tax code (see NMSA 1978 § 7-9J-5(B)).

[299] NMSA 1978 § 7-9-4.

North Dakota

Sales and Use Tax Exemption: North Dakota provides an exemption from the sales and use taxes (5 percent) imposed for all gross receipts from sales of CO_2 used for EOR or EGR. The exemption also applies to gross receipts from sales of tangible personal property used to construct or expand a system used to compress, gather, collect, store, transport, or inject CO_2 for secure geologic storage or use in EOR or EGR within the state.[300] The state's tax commissioner must provide the owner with a certificate that confirms the property was incorporated into a new system or in the expansion of an existing system.[301] Depending on when the property was purchased, the owner can also apply for a refund.

Property Tax Exemption: North Dakota exempts property taxes for constructed pipelines and other equipment used to transport or store CO_2 for use in EOR, EGR, or geologic storage. The exemption does not apply to the actual land and is valid during the construction period and the first ten full taxable years following initial operation.[302]

Ad Valorem Taxes: All coal conversion facilities with associated CO_2 capture systems, as well as any equipment directly used for secure geologic storage of CO_2 or EOR or EGR classified as personal property are exempt from all ad valorem taxes. The land on which the facility, capture system, or equipment is located is not included.[303]

Oklahoma

Gross Production Tax Exemption: A 7 percent tax is imposed on the gross value of oil and gas production. This tax can be reduced for the "incremental production" that results from secondary recovery projects, from the date the project begins until the "project payback" is received or ten years (whichever occurs first).[304]

Texas

Texas provides one of the most substantial tax programs designed specifically to advance CCS projects for generating units. This program contributed to the successful retrofit of the Petra Nova project. The Texas Commission on Environmental Quality defines a "clean energy project" as a coal-fueled, natural gas-fueled, or petroleum coke-fueled electric generating facility, as well as facilities that gasify fuel prior to combustion.[305] These projects must 1) have capacity over 200 MW; 2) satisfy the emissions profile, capturing at least 70 percent of the CO_2 with long-term CO_2 storage capability; and 3) produce CO_2 that is able to be utilized for an EOR project.[306]

Texas Franchise Tax Credit: This credit is provided for qualifying clean energy projects based on the amount of capital investment and reduces the top franchise tax rate (0.75 percent) of the entity's taxable margin. The project must be a newly constructed facility with the credit issued

[300] N.D. Cent. Code § 57-39.2-04(49); N.D. Cent. Code § 57-40.2-04(24).

[301] N.D. Cent. Code § 57-39.2-04.14(1).

[302] N.D. Cent. Code §57-06-17.1.

[303] N.D. Cent. Code § 57-60-06.

[304] Okla. Stat. 68 § 1001(D)(2) & (3)

[305] Texas Health and Safety Code § 382.003(1-a).

[306] Texas Tax Code § 171.602; Texas Natural Resources Code §120.004(b).

upon completion. The total tax credit must be the lesser of 10 percent of the capital costs or $100 million. The taxable entity is limited to the three eligible projects.[307]

Severance Tax Reductions: The state provides a 50 percent reduction of the severance tax rate for oil (4.6 percent) used in EOR projects.[308] An additional 50 percent reduction (up to 1.15 percent) is offered if the EOR project is able to use CO_2 captured from an in-state, anthropogenic source that would have otherwise been emitted. The CO_2 must be measured at the source and ultimately stored in one or more in-state geological formations.[309] The appropriate state agency must certify the storage process.[310]

Sales and Use Tax Exemption: This exemption is offered on the sales and use tax rates for property (6.25 percent) for qualifying clean energy projects.[311] Specifically, personal property used in connection with a qualifying CCS project is exempt from sales and use tax if the components are installed to capture CO_2 from an anthropogenic emission source, transport or inject the CO_2 in-state, and prepare CO_2 for transportation or injection. The project must also meet the requirements for the additional 50 percent severance tax reduction described above.

Gross Receipts Tax Exemption: The gross receipts tax imposed on utilities is no more than 1.997 percent and varies based on customers served.[312] The state exempts this tax on utility sales of electricity generated by advanced clean energy projects.[313]

WYOMING

Sales Tax Exemption: The sale of CO_2 used in tertiary production receives an exemption from the state's 4 percent sales and use tax.[314] The actual tertiary production process must meet certification requirements established and reviewed by the Wyoming Oil and Gas Conservation Commission or the federal government.[315]

Severance Tax Credit: Wyoming imposes a severance tax on crude oil, lease condensate, or natural gas at a combined rate of 6 percent of the value of the gross product extracted. CO_2 is qualified in Wyoming as a natural gas subject to the state's 6 percent severance tax. The severance tax paid on the crude oil produced from the injection of CO_2 is credited against the severance tax imposed on the oil produced.[316]

---

[307] Texas Tax Code § 171.602(c) and (d).
[308] Texas Tax Code § 202.052(b).
[309] Texas Tax Code § 202.0545(a).
[310] Texas Tax Code § 202.0545(d)(1) & (2).
[311] Texas Tax Code § 151.334.
[312] Texas Tax Code § 182.022(b)(3).
[313] Texas Tax Code § 182.022(c).
[314] Wyo. Stat. § 39-15-104(b); Wyo. Stat. § 39-16-104(b); Wyo. Stat. § 39-15-105(a)(viii)(F); Wyo. Stat. § 39-16-105(a)(viii)(A).
[315] Wyo. Stat. § 39-15-101(a)(xi); Wyo. Stat. § 39-16- 101(a)(xi).
[316] Wyo. Stat. § 39-14-205(d).

APPENDIX B: NON-TAX STATE INCENTIVES FOR CCS

California: The state's Low Carbon Fuel Standard with carbon capture and storage (CCS) protocol provides eligible suppliers of low-carbon fuels with credits that can be sold to suppliers of higher-carbon fuels. The state's cap-and-trade program offers operators of low-carbon power resources, including power plants with CCS technology, the ability to avoid most carbon allowance costs, which can provide a competitive advantage in the California electricity market. Currently no such projects have been brought online.[317]

Michigan: The state's integrated renewable portfolio standard allows up to 1 percent of the requirement to be met through the use of advanced cleaner energy systems, including CCS on coal-fired electric generating facilities. The CCS technology must capture at least 85 percent of CO_2 emissions.[318]

Montana: New electric generation capacity fueled by coal constructed after January 1, 2007, must capture and store at least 50 percent of CO_2 emissions.

North Dakota: I CO_2 pipelines are exempt from eminent domain.[319]

Oregon: Oregon regulations allow the use of CCS when calculating a low-carbon fuel pathway. As a result, credits may be generated for a qualifying CCS project that is part of an approved fuel pathway. The Oregon Clean Fuels program includes a CCS protocol and provides suppliers of low-carbon fuels with credits that can be sold to suppliers of higher-carbon fuels.[320] Currently no such projects have been brought online.

[317] https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard.

[318] https://www.michigan.gov/mpsc/0,9535,7-395-93308_93325_93423_93502-500271--,00.html.

[319] N.D. Cent. Code § 57-60-06.

[320] https://www.oregon.gov/deq/ghgp/cfp/Pages/default.aspx.

APPENDIX C: OVERVIEW OF ENVIRONMENTAL REGULATORY MARKET MECHANISMS AND OFFSETS

C.1. INTRODUCTION

Environmental offsets have been used in the United States (U.S.) since the early 1970s, when emissions allowance-trading mechanisms were first included in the Environmental Protection Agency (EPA) air emissions trading program. Under that program, six common air pollutants, designated under the U.S. Clean Air Act as "criteria pollutants,"[321] could be emitted in areas that were identified as not attaining current air-quality standards, as long as the pollution producers could demonstrate that they had acquired equivalent emissions reductions from other sources within the same zone. The essence of an emissions offset is that the atmosphere is no worse off as a result of emissions from one source when those emissions are "counteracted by a verifiable reduction or removal of equivalent emissions elsewhere."[322] The theory supporting the ability to trade environmental allowances is that an open, efficient market mechanism for emissions reductions will help to reveal the least expensive means for reducing total emissions to achieve the levels required under a predetermined emissions cap.[323] As EPA explains on its web page, market-oriented approaches are preferable to prescriptive regulatory approaches, because they offer emitters greater flexibility in determining how to reduce emissions.[324]

Early experience with market-oriented policies demonstrates that offsets can be less expensive compared to direct retrofits of polluting sources in reducing emissions. Carbon Market Watch explains: "[T]he argument behind carbon trading is that the best way to take climate action is to reduce emissions where it is easiest (i.e., least costly) to do so."[325] Success in offset markets, particularly for emissions associated with acid rain (sulfur oxides and nitrogen oxides), encouraged air quality policy makers and regulators to continue offering market-based mechanisms for achieving compliance with multiple environmental mandates.[326] The implication for power plants with CCS is that offsets can be produced by capturing and storing or capturing and utilizing greenhouse gas (GHG), and those offsets are likely to be associated with market-determined values in emissions trading systems.

Cap-and-trade is a system for controlling carbon emissions by establishing an upper limit on the amount of emissions a given business may produce. Businesses that cannot meet these limits may purchase (i.e., trade) for further emissions reductions from organizations that have not

---

321 "Criteria Air Pollutants," [Web page] *Environmental Protection Agency*, retrieved June 2020, https://www.epa.gov/criteria-air-pollutants

322 hlberg, Malin, and Nicolas Kreibich. "Corresponding Adjustments not an Unsurmountable Obstacle," *Carbon Mechanisms Review* **9**, 1 (Spring 2021), p. 12. ISSN 2198-0705.

323 Hahn, Robert W., and Kenneth R. Richards. 2012. "Environmental Offset Programs: Survey and Synthesis." *SSRN Electronic Journal*, January. Elsevier BV. doi:10.2139/ssrn.1721544.

324 "Environmental Economics, Economics of Climate Change," [Web page] *Environmental Protection Agency*, retrieved April 2021, https://www.epa.gov/environmental-economics/economics-climate-change

325 "Carbon Markets 101 The Ultimate Guide to Global Offsetting Mechanisms (Second edition, July 2020), *Carbon Market Watch,* (2020) https://carbonmarketwatch.org/publications/carbon-markets-101-the-ultimate -guide-to-global-offsetting-mechanisms/

326 Schmalensee, Richard, and Robert N. Stavins, "Policy Evolution under the Clean Air Act." *Journal of Economic Perspectives*, 33 (4): 27-50 (2019) doi: 10.1257/jep.33.4.27

used their full allowance.[327] Voluntary carbon trading started in 1989, prior to the first United Nations Conference of Parties, with many of these early markets focused on reforestation and forest preservation efforts. The first centralized cap-and-trade system, the voluntary but legally binding Chicago Climate Exchange, was launched in 2003.

The United Nations Framework Convention on Climate Change (UNFCCC) initiated the Activities Implemented Jointly, a voluntary pilot market for GHG emissions in 1995 to better understand the potential for carbon trading.[328] This project focused on voluntary reductions of GHG emissions, but did not include carbon trading per se. The initial goal was to learn about potential approaches to GHG reductions and to see whether such projects might prove successful. A 2006 UNFCCC report identified over 150 joint projects in Africa, Asia, the Pacific, Latin America, the Caribbean, and in emerging-economy countries in Europe. The projects included 62 centered on energy efficiency, 54 on renewable energy, and others involving fuel switching, afforestation, fugitive gas capture, forest reforestation and preservation, and agriculture.[329]

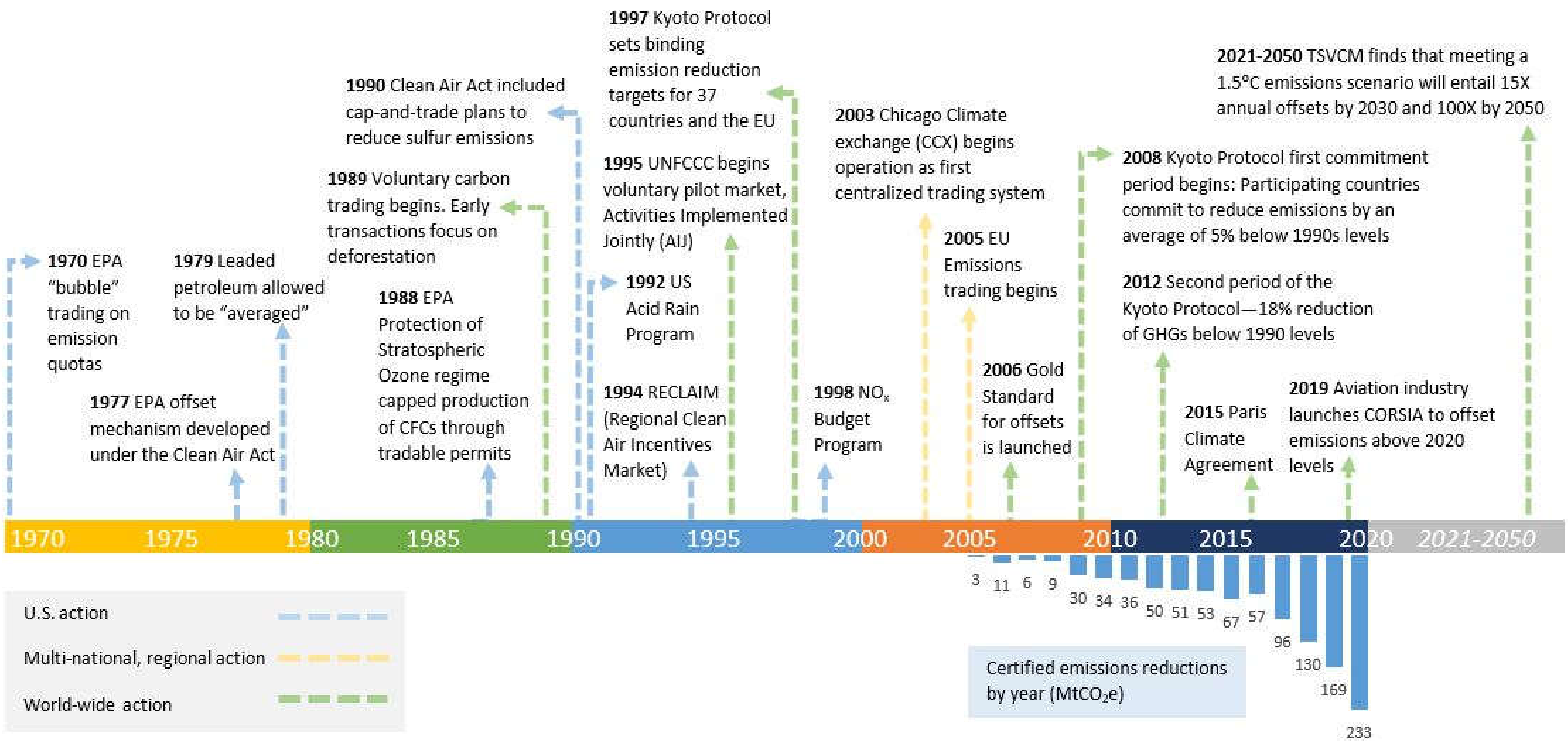
Exhibit C-1 provides a timeline of market-oriented approaches to environmental regulation. The timeline includes brief summary reports of actions from 1970 to the present, with some forecast of activity through 2050.

[327] "Final Report," *Taskforce on Voluntary Carbon Markets*, (January 2021): p. 38-39. https://www.iif.com/Portals/1/Files/TSVCM_Report.pdf. Chicago Climate Exchange ceased operations in 2010.

[328] "Joint Implementation," [Web page] *United Nations Framework Convention on Climate Change*, retrieved May 2021, https://unfccc.int/process/the-kyoto-protocol/mechanisms/joint-implementation

[329] "*Activities implemented jointly under the pilot phase -- Seventh synthesis report*," *United Nations Framework Convention on Climate Change, Subsidiary Body for Scientific and Technological Advice*, FCCC/SBSTA/2006/8, 13 (September 2006). https://unfccc.int/sites/default/files/resource/docs/2006/sbsta/eng/08.pdf

Exhibit C-1. Summary timeline of offsets history



Sources: Authors' construct based on data from: "The History of Cap and Trade," [Web page], *AltFuelsNow.com*, http://www.altfuelsnow.com/carbon/cap-and-trade.shtml; *"History of Emissions Trading,"* [Web page], Carbon Market Solutions https://www.carbonmarketsolutions.com/emissions-trading/history-of-emissions-trading/; Calel, Raphael, "Climate change and carbon markets: A panoramic history," *Centre for Climate Change Economics and Policy*, Working Paper No. 62, July 2011, http://eprints.lse.ac.uk/37397/1/Climate_change_and_carbon_markets_a_panoramic_history(author).pdf; Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA). Emissions trading system data compiled by "EM Carbon Market Dashboard -- Issuances and Retirements Meta-Registry,*"* [Online database], *Ecosystem Marketplace*, https://www.ecosystemmarketplace.com/carbon-markets/em-data-dashboard/; "Three Decades of Carbon Markets Success," [Web page], *Environmental Defense Fund*, https://www.edf.org/sites/default/files/documents/EDF_Carbon_Market_Timeline.pdf; Taskforce on Scaling Voluntary Carbon Markets (TSVCM), *Final Report*, January 2021, pp. 38-40, 50-57, https://www.iif.com/Portals/1/Files/TSVCM_Report.pdf; and, "Evolution of Voluntary Carbon Market (VCM)," [Web page], *Voluntary Carbon Market*, https://voluntarycarbonmarket.org/. [All sources retrieved May 2021].

Exhibit C-1 provides annual data from 2005 through 2020 reported publicly by the world's emissions trading systems.[330] As the data shows, annual trading volumes more than doubled from 2016 to 2018 and nearly doubled again from 2018 to 2020.

In the period prior to and soon after the start of the timeline, several authors helped to provide a theoretical foundation for market-based approaches. For example, Ronald Coase considered the issue of the social cost of carbon in a 1960 article, arguing that ideally market participants should be allowed to negotiate the best possible solutions. Thomas Crocker in the United States and John Dales in Canada both supported the idea of auctioning off pollution rights to the highest bidder, arguing that this type of arrangement could result in an economically optimal level of pollution, similar to an intentionally designed pollution tax. In 1972, David Montgomery demonstrated mathematically that the total cost of achieving an environmental standard could be minimized by developing marketable permits that were tradable among firms focused on reducing their total production costs.[331]

As shown in Exhibit C-1, EPA began implementing market-oriented approaches in the 1970s and 80s. The Kyoto Protocol and the Paris Climate agreement have played significant roles in developing a coordinated approach to offset markets beginning in 1997 and 2015 respectively. Section C.2 briefly summarizes activities regarding offsets and beneficial uses under the Kyoto protocol; Section C.3 does the same for the Paris Agreement.

C.2. Offsets and Beneficial Uses in the Kyoto Protocol: The Clean Development Mechanism

Provisions for creating, accounting for, and trading carbon offsets were included in the Clean Development Mechanism (CDM) established by the 1997 Kyoto Protocol.[332] At that time, researchers and planners believed that technologies to reduce GHG emissions, including low- and zero-emissions energy production systems like solar or wind energy, would cost more than traditional fossil fuel technologies with higher emissions levels. The framers of the Kyoto Protocol thus included provisions for an emissions trading market where participating countries could meet at least part of their early commitments for emissions reductions by exchanging emissions reductions. The initial idea was that low-cost offsets could be created in less developed countries by financing conservation practices for agriculture and forestry management, and those offsets could then be purchased by more developed countries. Thus, developed countries would help finance valuable projects in less developed countries, "providing greater benefits to the atmosphere and to sustainable development."[333] Voluntary

---

330 "State and Trends of Carbon Pricing 2020," *World Bank*, (2020): pg. 7. https://doi.org/10.1596/978-1-4648-1586-7. The World Bank reports that as of 2020, there were 31 Emission Trading Systems and 30 carbon taxes scheduled to begin operation or currently operating.

331 Davies, M. H. "The Origins and Practice of Emissions Trading." *Journal of Policy History* 129 (9): 201–6. (2002) https://doi.org/10.1192/bjp.129.3.201

332 "Clean Development Mechanism," [Webpage] *United Nations Framework Convention on Climate Change*, retrieved March 2021, https://unfccc.int/process-and-meetings/the-kyoto-protocol/mechanisms-under-the-kyoto-protocol/the-clean-development-mechanism.

333 Bumpus, Adam G., and Diana M. Liverman, "Accumulation by Decarbonization and the Governance of Carbon Offsets." *Economic Geography (*2008) 84 (2). Clark University: 127–55. https://doi:10.1111/j.1944-8287.2008.tb00401.x.

carbon offsets markets, with their own governing structures, developed in parallel with the regulated CDM.[334]

In their review of the CDM and offset markets, Gillenwater and Seres (2011) observe that the CDM has already resulted in tangible successes. They cite :

- The existing "library" of over 140 different approaches for developing and delivering offsets, including the methods for reviewing and approving projects
- Standardized tools for determining additionality and emissions baselines, plus models and tools for estimating emissions associated with grid-connected electricity projects
- Standardized manuals, rules, and templates for emissions auditing, and procedures for project oversight by auditors
- A global registry for tracking projects and offset credits that is linked with national GHG emission trading registries[335]

In addition, they note that many national governments have already supported international agencies for reviewing and approving projects, and associations of project developers, auditors, and others have been formed "to share knowledge and promote best practices."[336] These researchers conclude, "[T]he CDM should be judged not on its past, but rather on its current operation and a realistic assessment of its potential, taking into account ongoing efforts at improvement and reform."[337,338]

C.3. Offsets and Beneficial Uses Under the Paris Agreement: The Sustainable Development Mechanism

The Kyoto CDM expired in 2020. It will be superseded by the Sustainable Development Mechanism (SDM) in the Paris Agreement. Under the Paris Agreement, the Conference of Parties (COP) will develop standards for SDM projects, including rules and procedures for designing and implementing climate change mitigation actions and verifying the associated emissions reductions.[339] Action to finalize the SDM rules was scheduled for November 2021.[340]

334 Ibid.

335 Gillenwater, M., and S. Seres, 2011, "The Clean Development Mechanism: a review of the first international offset programme," *Greenhouse Gas Measurement and Management* ***1***(3–4), 179–203, https://doi.org/10.1080/20430779.2011.647014.

336 Ibid.

337 Ibid.

338 Narassimhan, Easwaran, Kelly S. Gallagher, Stefan Koester & Julio Rivera Alejo. "Carbon pricing in practice: a review of existing emissions trading systems," *Climate Policy, 18*:8, 967-991, (2018) DOI: 10.1080/14693062.2018.1467827. These researchers report extensive information exchanges among ETSs, to address knowledge gaps and understand best practices.

339 "Paris Agreement Annex, Articles 6.2--6.7", *United Nations Framework Convention on Climate Change*, (2015): 24 https://unfccc.int/resource/docs/2015/cop21/eng/l09r01.pdf

340 Marchant, Christopher, "Alok Sharma: COP 26 'will see agreement' on Article 6 debate" [Electronic article], *Environmental Finance*, September 22, 2020, https://www.environmental-finance.com/content/news/alok-sharma-cop-26-will-see-agreement-on-article-6-debate.html. See also "Glasgow Climate Change Conference," *[Webpage] United Nations Framework Convention on Climate Change*, https://unfccc.int/process-and-meetings/conferences/glasgow-climate-change-conference

The Paris Agreement (Article III, ¶38) recommends that the parties "adopt rules, modalities and procedures" for implementing Article 6-4, which provide for "[r]eal, measurable, and long-term benefits… [r]eductions in emissions that are additional… [and] [v]erification and certification." Articles 6-2 and 6-4 of the Paris Agreement direct that the rules and procedures for offsets should "avoid double counting. . . [and] promote the mitigation of greenhouse gas emissions while fostering sustainable development." The agreement seeks to "ensure environmental integrity and transparency, including in governance, and shall apply robust accounting."[341]

Efforts are underway to coordinate GHG offset projects with the United Nations Sustainable Development Goals (SDGs).[342] The UNFCCC is collaborating with multiple parties, including the United Nations Sustainable Development Solutions Network, to develop guidance and tools to allow stakeholders "to assess and report transparently and independently [on] the impact of their climate initiatives and their contributions towards the SDGs." The objective of this process is to encourage projects that will reduce GHG emissions while at the same time making substantial progress toward achieving the 17 sustainable development goals. Participating parties are working to define procedures for identifying and quantifying SDG co-benefits, "making the process more efficient and minimizing the cost of monitoring, reporting and verification … for both project developers and auditors."[343] According to Carbon Market Watch,

> [T]he design of a robust and effective Sustainable Development Mechanism… means a shift away from offsetting towards results based finance and an integration of the SDGs, human rights, transparency and public consultation as core principles into the activities of the mechanism.[344]

Exhibit C-2 summarizes important distinctions between offset projects considered under the Kyoto CDM, compared to the Paris Agreement SDM.[345]

---

341 "Adoption of the Paris Agreement," *United Nations Framework Convention on Climate* Change, (December 11, 2015) https://unfccc.int/resource/docs/2015/cop21/eng/l09r01.pdf

342"Sustainable Development," [Web page] *United Nations Department of Economic and Social Affairs*, accessed March 2021, https://sdgs.un.org/. See also: "*Global Warming of 1.5°C,* Chapter 5: Sustainable Development, Poverty and Inequality in a 1.5°C Warmer World," *IPCC*, (2018) https://www.ipcc.ch/sr15/.

343 Gold Standard SDG Impact Tool Piloting Consultation [Web page] *Gold Standard*, accessed March 2021, https://www.goldstandard.org/our-work/innovations-consultations/gold-standard-sdg-impact-tool-piloting-consultation. See also: "United Nations Sustainable Development Solutions Network," [webpage] *United Nations,* https://www.unsdsn.org/about-us. There is a total of 17 United Nations SDGs. SDG13 is directly related to climate action, including an explicit focus on "integrating climate change measures into national policies, strategies, and planning." Beneficial use projects could conceivably provide support for and produce many co-benefits for sustainable development. Preliminary modeling has already identified potential pathways for beneficial use projects to assist with achieving 11 of the 17 UN SDGs (Nos. 1, 2, 3, 4, 5, 6, 7, 8, 12, 13, and 15). See *Gold Standard SDG Impact Tool* at https://www.goldstandard.org/sites/default/files/documents/sdg_tool_road_testing_v0.5_1.xlsx.

344 "Building Blocks for a Robust Sustainable Development Mechanism," *Carbon Market Watch*, (2017) https://carbonmarketwatch.org/wp-content/uploads/2017/05/BUILDING-BLOCKS-FOR-A-ROBUST-SUSTAINABLE-DEVELOPMENT-MECHANISM_WEB-SINGLE_FINAL.pdf

345 Ibid.

Exhibit C-2. Comparison of emissions offset policy frameworks under Kyoto Protocol and Paris Agreement

Kyoto Protocol CDM	Paris Agreement SDM
Offsets shift, but do not reduce, emissions	Offsets must contribute to overall emissions reductions or mitigation
Developing countries do not have reduction targets, nor future climate action commitments	All countries' mitigation targets and their progress over time are considered
Created incentives to continue business-as-usual, in some cases increasing emissions in order to be paid to reduce them	Incentives should support countries' climate action ambitions and encourage implementing climate friendly policies
Credits were authorized for many non-additional projects	Credits must reflect and reinforce changing low-emissions technologies and policies
Offsets made questionable contributions toward sustainable development, sometimes locking-in fossil fuel utilization	Offsets must contribute to 1) real, measurable, and long-duration mitigation; and 2) sustainable development that contributes to shifting away from fossil-fuel lock-in

Preliminary indications for COP26 suggest that few countries will oppose including cooperative and market-based approaches to GHG reductions. A recent study of the Nationally Determined Contributions (NDCs) reports published by 51 countries indicates that one-third are intending to include these approaches, another one-third are "considering" them, and only four of the 51 countries state that they are "excluding" these approaches.[346]

[346] Brandemann, V., N. Kreibich and W. Obergassel "Implementing Paris Cooperatively. Market mechanisms in the latest NDC submissions," *Wuppertal Institute for Climate, Environment and Energy*. (2021) www.carbon-mechanisms.de/PP_01_2021.

www.netl.doe.gov

Albany, OR • Anchorage, AK • Morgantown, WV • Pittsburgh, PA • Sugar Land, TX

(800) 553-7681

NATIONAL
ENERGY
TECHNOLOGY
LABORATORY