



# Electricity Market Design and Carbon Capture Technology: The Opportunities and the Challenges

White paper prepared by the  
State CO<sub>2</sub>-EOR Deployment Work Group

June 2017

## Acknowledgements

While the final recommendations of this white paper represent the joint conclusions of state officials in the State CO<sub>2</sub>-EOR Deployment Work Group, participating state officials want to recognize the contributions of leading private sector stakeholders and CO<sub>2</sub>-enhanced oil recovery and energy transmission system experts who lent their expertise and guidance to the effort. The state representatives extend their thanks to all who contributed to this white paper, and to the Hewlett Foundation and the MacArthur Foundation for the funding that made this work possible.

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### About the State CO<sub>2</sub>-EOR Deployment Workgroup

Wyoming Governor Matt Mead (R) and Montana Governor Steve Bullock (D) jointly convened the State CO<sub>2</sub>-EOR Deployment Work Group in September 2015 as a key follow-on to the Western Governors Association resolution calling for federal incentives to accelerate the deployment of carbon capture from power plants and industrial facilities and increase the use of CO<sub>2</sub> in enhanced oil recovery, while safely and permanently storing the CO<sub>2</sub> underground in the process.

Twelve states currently participate in the Work Group: Arkansas, Colorado, Illinois, Indiana, Mississippi, Montana, Pennsylvania, Ohio, Oklahoma, Texas, Utah and Wyoming. State participation varies by state and includes governors' staff, cabinet secretaries, utility commissioners, and agency and commission staff. Some state representatives participate at the direction of the governor; others do not. State representatives were joined by leading enhanced oil recovery, electric power, coal industry, regulatory and NGO experts.

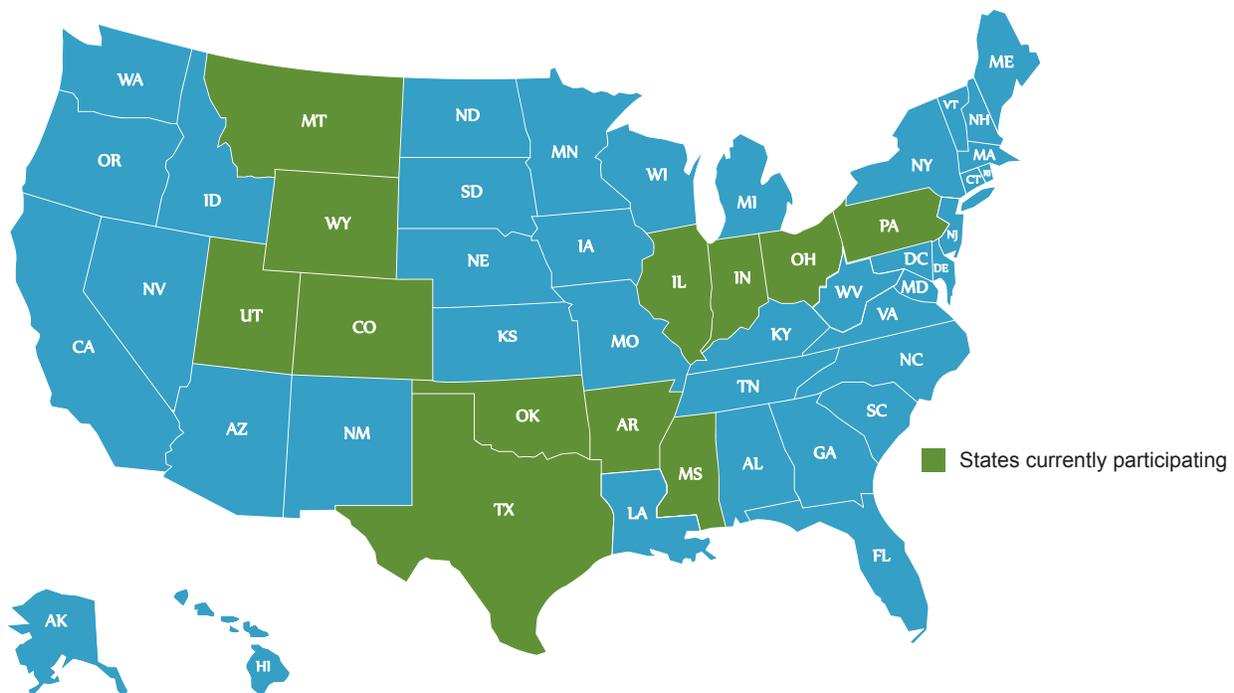
The Work Group identified three principal roles for its work, including modeling analysis and policy identification, developing recommendations for state and federal policy makers, and supporting the implementation of those policy recommendations.

The CO<sub>2</sub> EOR Work Group aims to foster:

- Expansion of CO<sub>2</sub> capture from power plants and industrial facilities;
- Buildout of pipeline infrastructure to transport that CO<sub>2</sub>; and
- Use of CO<sub>2</sub> in oil production, along with its safe and permanent storage.

The Work Group released a comprehensive set of federal and state policy recommendations in December 2016 – [Putting the Puzzle Together: State & Federal Policy Drivers for Growing America's Carbon Capture & CO<sub>2</sub>-EOR Industry](#) and a white paper outlining recommendations for national CO<sub>2</sub> pipeline infrastructure in February 2017 - [21st Century Energy Infrastructure: Policy Recommendations for Development of American CO<sub>2</sub> Pipeline Networks](#).

Figure 1: CO<sub>2</sub>-EOR State Deployment Work Group – Participating States



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## Executive Summary

### Overview

The United States is a global leader in both carbon capture and CO<sub>2</sub>-enhanced oil recovery (EOR), which together provide numerous economic, job and emissions benefits. CO<sub>2</sub>-EOR currently provides four percent of U.S. domestic oil production and the [federal and state incentives](#) recommended by this Work Group to capture carbon from manmade sources and [build out CO<sub>2</sub> pipeline infrastructure](#) could triple U.S. CO<sub>2</sub>-EOR production, greatly expanding the benefits. In this paper, the CO<sub>2</sub>-EOR State Deployment Work Group explores the electricity market challenges and opportunities facing carbon capture at power plants, the pertinent underlying market conditions, and potential policy responses to improve electricity markets to drive more investments in carbon capture in the electricity sector.

CO<sub>2</sub>-EOR enables the continued use of domestic fossil energy resources, extends the economic life of existing energy and industrial assets, and sustains the energy and industrial jobs base at a time when market forces and public policy increasingly drive lower carbon emissions. If the United States maintains and expands our technological edge in this area, there may be opportunities to export to other countries carbon capture and CO<sub>2</sub>-EOR technologies, products, and related manufacturing, engineering and other services.

While most carbon capture occurs in the industrial sector, it has expanded to the power sector, with two coal-fired power plants now capturing CO<sub>2</sub> at large commercial scale in North America. One of these power plants is in Saskatchewan and the other in Texas. Both sell their CO<sub>2</sub> to the EOR industry. Further deployment of carbon capture projects at power plants faces uncertainty, however, due to the difficulty of selling electricity into wholesale power markets on terms that will attract investors and qualify the projects for loans.

While carbon capture has now been commercially demonstrated successfully at coal-fired power plants, it remains expensive in the context of electric power generation and requires further

deployment and innovation to reduce costs. Carbon capture is both capital-intensive and innovative, making financing challenging, especially in competitive markets. Its CO<sub>2</sub> benefits are not valued in most power markets. Currently, coal plants with carbon capture have higher fixed and variable costs, yet must compete with low-cost natural gas, and both coal and natural gas plants with carbon capture must compete with nuclear, wind and solar power.

Implementing federal and state deployment incentives will help reduce carbon capture costs by enabling further units to be built, thus leading to the development of vendor supply chains and the optimization of unit configurations, components, construction methods, and financing.

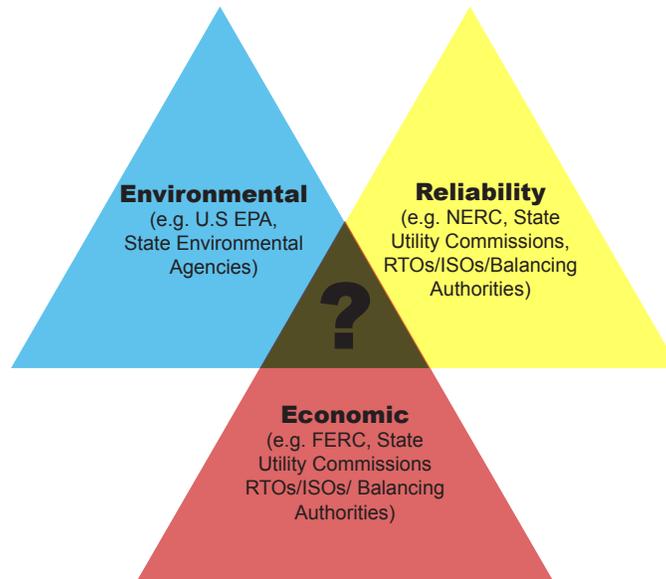
### Power sector policy and market issues pertinent to carbon capture

Important public policy objectives for managing our nation's power system include: (1) affordable and reasonable prices for consumers; (2) system reliability; and (3) environmental stewardship. These public policy objectives are addressed in a fragmented fashion through a complex web of governmental and market institutions and mechanisms. In the power sector, the lines between economic and environmental regulation, and between state and federal jurisdiction are somewhat blurred.

The complexity of the power system presents a two-fold problem for carbon capture and other low and zero-carbon technologies that are dispatchable, meaning that they can be called upon to operate when needed to maintain reliability:

- a. For the most part, its carbon reduction benefits are neither valued in the market, nor explicitly addressed by public policy; and
- b. No single actor or mechanism is responsible for accomplishing these three objectives of affordability, reliability and environmental stewardship and optimizing them on a

**Figure 2: Power Sector Regulation: Who Regulates the Overlap?**



combined least-cost basis over the long term. This greatly disadvantages prospective investments in dispatchable low-carbon generation like carbon capture and storage that have an attractive combination of attributes in a single technology package.

This paper focuses on electric power generation with CO<sub>2</sub> capture in alignment with the Work Group's mission, but readers should note that there are several other dispatchable low and zero-carbon power technologies facing similar market challenges:

- Geothermal;
- Combined heat and power (CHP);
- Solar thermal power plants with extra heat storage reservoirs; and
- New modular nuclear reactors and existing nuclear plants.

Therefore, the problems and potential solutions for carbon capture in the power sector have relevance and applicability for the other technologies listed above.

In both regulated and competitive power markets, the [federal and state financial incentives for carbon capture previously recommended by the Work Group](#) effectively lower the costs of power plants equipped with carbon capture and can therefore have a positive impact on their commercial viability. Without such incentives, generators will not be competitive and will fail to recover their cost of capital or even secure financing.

Carbon capture plants can be built and operated in either regulated or competitive markets. Regulated and competitive markets operate very differently in terms of how they (i) affect choices to build new power plants that will contribute to system reliability; (ii) determine dispatch, or choose to run or not run various plants on the system; (iii) affect decisions to retire plants; and (iv) are subject to control by federal regulators, system operators, and state regulators.

In a regulated monopoly market, the equipment cost for a new plant or retrofit with carbon capture, owned by a publicly-regulated, investor-owned utility (IOU) and authorized by the relevant

regulatory commission, is added to the rate base. This means that the utility's customers cover the costs through the rates they pay, which are approved by regulators, and the IOU is authorized to earn a specified rate of return on capital invested. In contrast, merchant plants in competitive markets cannot rely on such guarantees.

Power plants with carbon capture provide multiple broader benefits. Carbon capture produces pure CO<sub>2</sub>, which has commercial value for EOR, chemical production and other potential uses. A carbon capture-equipped power plant is also dispatchable and can be called on to operate when needed, thereby enhancing grid reliability. Carbon capture can take advantage of the extensive public and private investment already made in CO<sub>2</sub>-EOR and fossil fuel infrastructure, while further decarbonizing the power sector. Finally, plants with carbon capture have significant environmental benefit beyond carbon emissions reductions due to very low emissions of conventional air pollution because those pollutants must be removed beforehand to avoid compromising carbon capture systems.

The greater complexity of a power plant with carbon capture can make it relatively more difficult to increase or decrease its output, an increasingly desired attribute of dispatchable generation by grid operators as penetrations of variable generation such as wind and solar increase. At the same time, higher costs can make it financially difficult for a plant to run flexibly, and therefore at lower capacity factors (i.e., operating for fewer hours), and still recoup its investment in carbon capture equipment and added operational costs.

In most power markets, low-cost natural gas (without carbon capture) is the toughest competitor for other existing or potential electricity suppliers. Nationally, wind and solar power currently provide a small fraction of U.S. electric generation (one percent for solar and five percent for wind). However, their share is growing rapidly, and they are significant players in key markets at certain times. Federal and state financial incentives and other policy support for wind and solar power effectively lowers their fixed costs, and because

they have no fuel costs and very low or no variable costs, they can sell into wholesale markets at low and sometime even negative prices.

The lack of policy parity for carbon capture and other dispatchable low-and-zero-carbon generation options makes it difficult or impossible for them to compete with variable wind and solar generation on a market basis. This is exacerbated by the current market, where continuing low gas prices are pushing other generation sources such as existing conventional coal and nuclear out of the dispatch queue. Policy incentives for dispatchable low-carbon generation such as carbon capture could help level the playing field.

### **Policy options for carbon capture and other low-carbon resources**

As we have discussed, the fundamental policy problems for carbon capture are shared by other low and zero-carbon generation technologies that are dispatchable. Therefore, there are a number of policy options that could be implemented at the federal, ISO/RTO, or state levels that would benefit all low and zero-carbon dispatchable resources including carbon capture. In addition, there are some solutions that would specifically aid carbon capture alone, many of which were discussed in the Work Group's [initial recommendations](#) in December 2016.

Figure 3 below summarizes the types of options available.

### **Summary of the Work Group recommendations**

State and federal policymakers have only recently begun to consider policies to ensure the continued economic viability of dispatchable generation resources in evolving electricity markets. To date, existing zero-carbon nuclear generation has received the bulk of policymakers' attention. This report represents a first effort to suggest policies to help enable power plants with carbon capture to compete effectively in organized wholesale power markets. Work Group participants believe that more analysis of the impact of such policies and how best to implement them is needed, and

**Figure 3: Policy Options for Carbon Capture and Other Low-Carbon Resources**

	Federal	ISO/RTO	States
<b>All Dispatchable Low and Zero-Carbon Resources</b>	Provide financial value for CO <sub>2</sub> reductions in generation dispatch; Develop financeable capacity payment structures; Research, development, demonstration and deployment (RDD&D) programs and support;	Develop a low-carbon capacity standard; Provide financial value for CO <sub>2</sub> reductions in generation dispatch	Modify or supplement existing renewable portfolio standard (RPS) policies to expand eligible resources
<b>Carbon Capture Specifically</b>	45Q CO <sub>2</sub> storage tax credits; tax-exempt private activity bonds (PABs); Master Limited Partnerships (MLPs); CO <sub>2</sub> pipeline infrastructure financing; Carbon capture RDD&D programs and support		Modify or supplement RPS to at least cover carbon capture (adjusted for percentage of capture)

they hope that this initial report will prompt further evaluation of these and other potential policies to support widespread deployment and market participation of carbon capture in the power sector.

**Federal Level Actions.** Major actions could include financial incentives, FERC initiatives, and RDD&D programs.

For the last twenty years, federal renewable energy incentives have been awarded based on energy production without specifically valuing capacity provided or carbon emissions reduced. Carbon capture has not benefited from such incentives and, as this paper has shown, its carbon emissions reduction and reliability benefits go unrecognized in wholesale power markets.

In the interest of policy parity, the most important near-term federal action would be enactment of the previously referenced suite of financial incentives for carbon capture as recommended by the Work Group in its December [report](#) released in December.

In addition, federal financing and other policies to foster the buildout of CO<sub>2</sub> pipeline infrastructure

would provide an important complement to federal carbon capture incentives, as recommended by the Work Group in its February [white paper](#) and [menu of financing options](#) released in March.

A second helpful federal policy change would be for FERC to affirmatively encourage the development of reliable low-carbon capacity, either by RTOs/ISOs that are FERC-jurisdictional, or by states whose utilities are part of RTOs/ISOs.<sup>1</sup>

Over the longer term, a federal incentive to reward the provision of low-carbon capacity on the grid could be designed and enacted by Congress that would be denominated in typical capacity contract terms of \$ per kW-month or \$ per MW-year and applicable to all low and zero-carbon resources (with the incentive adjusted for those resources with residual carbon emissions based on the percentage of reduction).

Finally, the federal government should sustain and expand its RDD&D portfolio through U.S. DOE to improve the performance and lower the cost of all major low and zero-carbon generation options. In particular, a robust RDD&D program to improve the performance and lower the cost of carbon capture is needed.

<sup>1</sup> Exelon, owner of nuclear plants, argued for such a permissive approach to be adopted by FERC in a recent filing. See <https://www.ferc.gov/CalendarFiles/20170426150548-Barron.%20Exelon.pdf>

**RTO/ISO Level Actions.** At the RTO/ISO level, beneficial changes to market rules could benefit all dispatchable low and zero-carbon resources.

Improving the functioning of capacity markets and/or out-of-market payments<sup>2</sup> could reward dispatchable low-carbon generation resources and make it easier to finance them.

**Beneficial changes could be implemented at the dispatch level and at the capacity contract level.** However, such reforms would not specifically benefit carbon capture unless they provide financial value for emissions reductions relative to other conventional fossil generation.

Applying a financial value for carbon reductions in generation dispatch would reward low-carbon generation options generally.

Combining a carbon value with measures to recognize and value reliability attributes of dispatchable low-carbon resources specifically would reward carbon capture and enhance its competitiveness by enabling them to dispatch and run more frequently.

**ISOs/RTOs could help address the need for long-term financing of such resources by supporting long-term (i.e., 20+ year) cost-of-service based contractual mechanisms to maintain long-term dispatchable capacity.**

This resembles the process agreed to among the California Independent System Operator (CAISO), the California Energy Commission (CEC) and the California Public Utilities Commission (CPUC).<sup>3</sup> Measures to influence generation dispatch alone may be insufficient to allow long-term financing of dispatchable low and zero-carbon resources, since such generation tends to have higher capital costs than conventional fossil generation.

**State Level Actions.** Generally, there are two ways carbon capture and other dispatchable low and zero-carbon resources could be better accommodated under state laws and regulations:

**Expand renewable portfolio standard (RPS) policies to include energy from low and zero-carbon nonrenewable generation.** A majority of states have opted to implement RPS policies and other binding requirements that specifically incentivize renewable resources; other states have not, including some represented in this Work Group. States with RPSs could benefit from broadening or supplementing such policies to include nonrenewable carbon capture, nuclear power and CHP as dispatchable low and zero-carbon resources. This would help achieve policy parity and a more level playing field for all zero- and low- carbon power generation technologies. Some states have instituted electricity resource goals or standards that set broader requirements and eligibility for “clean” or “alternative” energy, which include not only renewables, but also certain nonrenewable technologies. These can include nuclear power and carbon capture and are sometimes referred to as Clean Energy Standards (CESs). States that have implemented such broader portfolio standards include Colorado, Michigan, Ohio, Pennsylvania, and Utah.

**States could also develop separate low-carbon generation standards or credits.** Two states, New York and Illinois require purchases of certain amounts of nuclear power, with an additional financial credit applied to carbon reductions based on a quantitative estimate of their societal benefits, through zero-emission credit (ZEC) programs. As a supplement to RPS policies, some states may wish to replicate ZEC programs and expand them to include carbon capture and storage.

A variation of this approach is to create a separate low- or zero-carbon capacity portfolio standard or the equivalent. A direct approach could apply in cases where state regulators require utilities to maintain contractual access to long-term capacity resources adequate to maintain proper generation reserve margins. In these cases, a standard would simply mandate increasing amounts of capacity to be based upon low-carbon resources, including

2 Out-of-market payments are compensation generators receive outside of organized power markets, for example for renewable energy credits or long-term contracts. Arbon p

3 See <http://www.cpuc.ca.gov/LTPP/>

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retrofits of existing, already-contracted fossil units to add carbon capture, or retrofits of solar thermal resources to add thermal storage.

The changes to market rules at ISOs/RTOs and modifications or supplements to state portfolio standards described above could be implemented to benefit all dispatchable low and zero-carbon resources, or specifically targeted to power plants with carbon capture, depending on the resource options and preferences of different states and regions.

Designing and implementing comprehensive policies that apply to all low and zero-carbon generation resources and optimize system benefits effectively for affordability, reliability, and environmental stewardship is challenging. In the meantime, enacting the federal and state carbon capture incentives and federal CO<sub>2</sub> pipeline infrastructure financing already recommend by the Work Group would go a long way to providing some degree of policy parity and ensuring we advance the entire portfolio of low carbon options in the power sector.

In summary, the Work Group recommends the following:

- Redouble efforts to implement the carbon capture incentives and CO<sub>2</sub> pipeline infrastructure financing recommendations already prepared by the Work Group to begin leveling the playing field with other low and zero-carbon power generation options.
- Sustain and ultimately expand the federal energy RDD&D portfolio to improve the performance and lower the cost of all major low and zero-carbon power options. In particular, increase RDD&D funding to improve the performance and reduce the cost of carbon capture, including additional research to enable carbon capture-equipped power plants.
- Work toward more comprehensive policies that encompass all low and zero-carbon generation options, including market rules, incentives, portfolio standards and other measures, that optimize system benefits effectively for affordability, reliability, and emissions reductions.
- Improve energy and capacity markets to increase system flexibility, including rewarding low-carbon dispatchable resources and their carbon reduction benefits and making it easier to finance them.

## Introduction

Carbon capture technology in certain industry sectors and the use of CO<sub>2</sub> in enhanced oil recovery (CO<sub>2</sub>-EOR) have a long and successful history of commercial deployment outside the power sector going back nearly a half century (see Box 1 below). While roughly 80 percent of CO<sub>2</sub> presently used in EOR is naturally occurring and sourced from geologic domes, a long-established commercial market exists for captured CO<sub>2</sub> from industrial facilities used in EOR.

Today, large-scale carbon capture has expanded to the power sector, with two coal-fired power plants now capturing CO<sub>2</sub> at commercial scale in North America—one in Saskatchewan and the other in Texas—and selling their CO<sub>2</sub> to the EOR industry. The U.S. fleet of coal and natural gas power plants could contribute significantly to the future supply of CO<sub>2</sub> to this market and to ongoing reductions in U.S. carbon emissions through geologic storage. This CO<sub>2</sub>, in turn, could be transported by an expanded system of CO<sub>2</sub> pipelines from the point of capture to where it is injected for EOR and geologic storage. The current U.S. system of local and regional CO<sub>2</sub> pipeline networks exceeds 4,500 miles and continues to grow.

However, further deployment of carbon capture projects at power plants faces uncertainty due to the difficulty of selling electricity into wholesale power markets on terms that will attract investors and qualify those projects for loans. Policies, regulations, market structures, and procedures that determine how and when electric generators sell power into the marketplace represent an important realm of policy for carbon capture projects in the power sector, and one with which project developers, policy-makers and stakeholders have only begun to grapple.

The State CO<sub>2</sub>-EOR Deployment Work Group is turning to this topic as a follow-on to our December 2016 report recommending federal and state carbon capture deployment incentives. These incentives are essential to enabling investors to finance commercial carbon capture at power plants. However, we run the risk of financing such facilities, only to find them unable to operate viably in the marketplace, unless we also address the current patchwork of federal and state policies and RTO market rules that determine whether, how and when electric generators sell power into competitive wholesale markets.

While our specific charge in this paper is to describe the specific challenges facing power plants with carbon capture in competitive wholesale markets and to recommend ways to address them, there are other examples of low- or zero-carbon dispatchable power generation that are similarly deeply disadvantaged by the current framework of federal, state and RTO policies and market rules. These include nuclear, biomass, geothermal, solar thermal with associated storage, and combined heat & power.

In this paper, we explore the electricity market challenges and opportunities facing carbon capture, the pertinent underlying conditions, and potential policy responses.

## Box 1: Carbon Capture Works Across Multiple Industries: Commercial-Scale Technology Milestones in North America

Successful commercial-scale carbon capture deployment has a long history through the capture, compression and pipeline transport of CO<sub>2</sub> for use in enhanced oil recovery with geologic storage, especially in the U.S. Industrial processes where large-scale carbon capture are demonstrated and in commercial operation include natural gas processing, fertilizer production, coal gasification, ethanol production, refinery hydrogen production and, most recently, coal-fired power generation.

- **1972: Terrell gas processing plant in Texas**  
A natural gas processing facility (along with several others) began supplying CO<sub>2</sub> in West Texas through the first large-scale, long-distance CO<sub>2</sub> pipeline to an oilfield.
- **1982: Koch Nitrogen Company Enid Fertilizer plant in Oklahoma**  
This fertilizer production plant supplies CO<sub>2</sub> to oil fields in southern Oklahoma.
- **1986: Exxon Shute Creek Gas Processing Facility in Wyoming**  
This natural gas processing plant serves ExxonMobil, Chevron and Anadarko Petroleum CO<sub>2</sub> pipeline systems to oil fields in Wyoming and Colorado and is the largest commercial carbon capture facility in the world at 7 million tons of capacity annually.
- **2000: Dakota Gasification's Great Plains Synfuels Plant in North Dakota**  
This coal gasification plant produces synthetic natural gas, fertilizer and other byproducts. It has supplied over 30 million tons of CO<sub>2</sub> to Cenovus and Apache-operated EOR fields in southern Saskatchewan as of 2015.
- **2003: Core Energy/South Chester Gas Processing Plant in Michigan**  
CO<sub>2</sub> is captured by Core Energy from natural gas processing for EOR in northern Michigan with over 2 million MT captured to date.
- **2009: Chaparral/Conestoga Energy Partners' Arkalon Bioethanol plant in Kansas**  
The first ethanol plant to deploy carbon capture, it supplies 170,000 tons of CO<sub>2</sub> per year to Chaparral Energy, which uses it for EOR in Texas oil fields.
- **2010: Occidental Petroleum's Century Plant in Texas**  
The CO<sub>2</sub> stream from this natural gas processing facility is compressed and transported for use in the Permian Basin.
- **2012: Air Products Port Arthur Steam Methane Reformer Project in Texas**  
Two hydrogen production units at this refinery produce a million tons of CO<sub>2</sub> annually for use in Texas oilfields.
- **2012: Conestoga Energy Partners/PetroSantander Bonanza Bioethanol plant in Kansas**  
This ethanol plant captured and supplies roughly 100,000 tons of CO<sub>2</sub> per year to a Kansas EOR field.
- **2013: ConocoPhillips Lost Cabin plant in Wyoming**  
The CO<sub>2</sub> stream from this natural gas processing facility is compressed and transported to the Bell Creek oil field in Montana via Denbury Resources' Greencore pipeline.
- **2013: Chaparral/CVR Energy Coffeyville Gasification Plant in Kansas**  
The CO<sub>2</sub> stream (approximately 850,000 tons per year) from a nitrogen fertilizer production process based on gasification of petroleum coke is captured, compressed and transported to a Chaparral-operated oil field in northeastern Oklahoma.
- **2013: Antrim Gas Plant in Michigan**  
CO<sub>2</sub> from a gas processing plant owned by DTE Energy is captured at a rate of approximately 1,000 tons per day and injected into a nearby oil field operated by Core Energy in the Northern Reef Trend of the Michigan Basin.
- **2014: SaskPower Boundary Dam project in Saskatchewan, Canada**  
SaskPower commenced operation of the first commercial-scale retrofit of an existing coal-fired power plant with carbon capture technology, selling CO<sub>2</sub> locally for EOR in Saskatchewan.
- **2015: Shell Quest project in Alberta, Canada**  
Shell began operations on a bitumen upgrader complex that captures approximately one million tons of CO<sub>2</sub> annually from hydrogen production units and injects it into a deep saline formation.
- **2017: NRG Petra Nova project in Texas**  
NRG commenced 240 MW slipstream of flue gas from the existing WA Parish plant. The CO<sub>2</sub> is transported to an oil field nearby.
- **2017: ADM Illinois Industrial Carbon Capture & Storage Project**  
Archer Daniels Midland began capture from an ethanol production facility in April 2017, sequestering it in a nearby deep saline formation. The project can capture up to 1.1 million tons of CO<sub>2</sub> per year.

## Carbon capture is an important technology for energy security, environmental protection and economic competitiveness

Carbon capture technology and CO<sub>2</sub>-EOR already contribute to U.S. energy security, environmental protection and economic competitiveness, and they have enormous potential to do more. CO<sub>2</sub>-EOR provides four percent of U.S. domestic oil production and does so from existing fields that already bear the footprint of oil and gas development. With federal and state incentives recommended by this Work Group to capture carbon from manmade sources and build out CO<sub>2</sub> pipeline infrastructure, current U.S. CO<sub>2</sub>-EOR production could triple.

CO<sub>2</sub>-EOR enhances our nation's energy and economic security by lessening our dependence on foreign oil, often imported from unstable and hostile areas, and reducing our trade deficit by keeping dollars currently spent on oil imports at work in the U.S. economy. Production of coal, oil and natural gas plays a vital role in the economies of most states participating in this Work Group. These states and the nation benefit from all sectors involved in CO<sub>2</sub> - EOR.

Carbon capture technology is an essential component of a low-carbon power portfolio for the United States and the rest of the world. A body of literature demonstrates that continued carbon emissions reductions are much more likely to be achieved and be cost-effective, if we deploy our entire suite of low-carbon solutions. According to the International Energy Agency, we cannot achieve deep emissions reductions globally in the power sector cost-effectively without a comprehensive approach that includes carbon capture.<sup>4</sup> In addition, emissions from key industrial sectors cannot be managed without carbon capture. Domestically, power sector emissions account for 30 percent of U.S. carbon emissions, while industrial sector emissions account for 21 percent of U.S. carbon emissions.

The United States is a global leader in both carbon capture and CO<sub>2</sub>- EOR, which together provide a pathway for the continued use of America's abundant fossil energy resources, extending the economic life of existing energy and industrial assets, and sustaining an energy and industrial jobs base at a time when market forces and public policy increasingly demand lower carbon emissions. Moreover, if we maintain and expand on our technological edge, there may be opportunities to export to other countries carbon capture and CO<sub>2</sub>- EOR technologies, products, and related manufacturing, engineering and other services.

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4 International Energy Agency. Energy Technology Perspectives 2012: Pathways to a Clean Energy System. (Paris, France: International Energy Agency, 2012), 11, accessed June 27, 2016  
[https://www.iea.org/publications/freepublications/publication/ETP2012\\_free.pdf](https://www.iea.org/publications/freepublications/publication/ETP2012_free.pdf)

## Deployment is needed to bring down carbon capture costs

Carbon capture has been well-established at large scale for decades in industrial sectors such as natural gas processing<sup>5</sup>, fertilizer production<sup>6</sup>, and coal gasification<sup>7</sup>. However, transferring the chemical processes involved in carbon capture to the power industry is relatively new since there has traditionally been no policy requirement to separate CO<sub>2</sub> to produce saleable electricity.

Therefore, while carbon capture has now been commercially demonstrated successfully at coal-fired power plants, it remains expensive in the context of electric power generation and requires further deployment and innovation to reduce costs. Implementing federal and state deployment incentives will help foster such cost reductions by enabling further units to be built, thus leading to the development of vendor supply chains and the optimization of unit configurations, components, construction methods, and financing.

In the United States, we have numerous options for generating electricity, including coal, natural gas, nuclear power, and renewables. Affordable power and economic competitiveness are important societal objectives. Because adding carbon capture to existing fossil-fueled power plants can provide a direct means of managing CO<sub>2</sub> without abandoning existing dispatchable generation that forms the reliable backbone of the power system, it represents an attractive option to policy makers, industry and stakeholders. To accomplish that goal, it is imperative that the U.S. power industry gain significant experience in carbon capture, experience that will inevitably drive down costs.

The State CO<sub>2</sub>-EOR Deployment Work Group's first report, [Putting the Puzzle Together: State & Federal Policy Drivers for Growing America's Carbon Capture & CO<sub>2</sub>-EOR Industry](#), provides detailed analyses and federal and state recommendations for accelerating commercial deployment of carbon capture and CO<sub>2</sub>-EOR with geologic storage.

Recommendations for federal financial incentives include:

- Improving and expanding the existing Section 45Q tax credit for storage of captured CO<sub>2</sub>;
- Deploying a revenue-neutral mechanism to stabilize the price paid for CO<sub>2</sub>—and carbon capture project revenue—by removing volatility and investment risk associated with CO<sub>2</sub> prices linked to oil prices; and
- Offering tax-exempt private activity bonds and master limited partnership tax status to provide project financing on better terms.

The Work Group's second report, [21st Century Energy Infrastructure: Policy Recommendations for Development of American CO<sub>2</sub> Pipeline Networks](#), recommends that:

- President Trump and Congress incorporate the development of long-distance, large-volume CO<sub>2</sub> pipelines as a priority component of a broader national infrastructure agenda;
- The federal government play a targeted role, supplementing private capital, in financing

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5 To meet pipeline standards, natural gas may not have CO<sub>2</sub> in excess of 2-3 percent, but raw gas at the wellhead can be as much as 50 percent CO<sub>2</sub> in some fields. Thus, many natural gas processing plants have extensive CO<sub>2</sub> capture systems. For instance, Exxon Mobil's Shute Creek facility captures roughly 6 million tons per year.

6 Outside of China, the bulk of nitrogen fertilizer plants (i.e., ammonia and urea) use natural gas as a feedstock and combine natural gas and steam to create CO<sub>2</sub> and hydrogen gas. All of the hydrogen is needed to make ammonia, but some CO<sub>2</sub> is needed at later stages, if ammonia is converted to urea. Thus, virtually every gas feedstock fertilizer plant that has the capability to make urea must have built-in, flexible CO<sub>2</sub> capture capabilities.

7 China is the world leader in urea fertilizer manufacturing with a ~50 percent market share at ~100 million MT/year of urea product, implying an excess of 150 million MT/year of carbon capture. Virtually all that urea is made via coal gasification systems that feature 100 percent carbon capture, though the portion of CO<sub>2</sub> not needed for urea is simply vented to the atmosphere.

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increased capacity for priority trunk pipelines to transport CO<sub>2</sub> from industrial facilities and power plants not currently served by pipeline infrastructure to oilfields for EOR; and

- Congress and the President, in consultation with states, tribal governments and key stakeholders, identify and foster the development of five such priority CO<sub>2</sub> trunk pipelines, including support for planning, streamlined permitting, and financing.

We also note that a combination of tax incentives and research, development, demonstration, and deployment (RDD&D) will be critical to developing transformational carbon capture technologies and to driving down their cost.

## Carbon capture is cost-effective in reducing emissions and maintaining reliability

How should the cost-effectiveness of carbon capture be measured? We can begin by identifying the least expensive options on a cost-per-ton of CO<sub>2</sub> emissions reduced or avoided basis, recognizing that taxpayers and customers ultimately pay for the reductions. Doing so requires evaluating the cost of building and integrating a particular emission reduction option into the broader energy system over time at progressively higher levels of deployment.

Too often, cost analyses treat new projects and resources in isolation and/or consider their integration only at early stages and lower levels of deployment. However, as greater emissions reductions are demanded from the energy system, carbon capture becomes increasingly cost-effective relative to other options.

Supplying reliable power to the modern grid depends upon a diversity of generation types (including carbon capture), with each having different production, cost, and reliability characteristics. Each type of generation has positive and negative consequences for the whole

system and must be managed to optimize cost and performance tradeoffs between reliability and emissions reductions.

A challenge in achieving very high penetration of variable wind and solar electricity on the grid is ultimately not one primarily of supply, but rather of managing higher levels of intermittent generation. This challenge increases as the amount of variable generation grows. As shown by a major study examining California’s goal of renewables reaching 50 percent of consumed electricity, if that target is met principally with variable wind and solar photovoltaic generation—in contrast to a broader mix of low and zero-carbon generation resources that also includes solar thermal with storage, geothermal, CHP, carbon capture and nuclear—the system can become saturated with variable resources, leading to curtailment, or the need to reduce intermittent generation from those sources (e.g. feathering the blades on wind turbines or running solar energy to ground to reduce output to the grid) in order to leave room on the system for dispatchable generation to maintain system reliability<sup>8</sup>. As described below,

**Figure 4: Different Resource Types Feature Different Packages of Benefits And Drawbacks**

	Produces CO <sub>2</sub> emissions	Provide dispatchable power	Variable (either less available or provide excess power during some seasons or times of day)
Wind			✓
Solar Photovoltaic			✓
Conventional Fossil Fuel Power Plants	✓	✓	
Fossil Fuel Power Plants with Carbon Capture	*	✓	

\* Note that a combustion coal or natural gas-combined cycle power plants with carbon capture would could manage over 90 percent of their CO<sub>2</sub> emissions, but they could not reach zero like wind, solar or nuclear power.

8 For study of abatement costs (\$403-\$1,020/MT) under various 50 percent renewables scenarios see Investigating a Higher Renewables Portfolio Standard in California, Energy+Environmental Economics (E3), January 2014, Figure 38, p. 144.

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this can lead to increasing costs to manage the grid and to reduce carbon emissions on a cost per ton basis.

Numerous studies from diverse sources such as industry consultants, the National Renewable Energy Laboratories (NREL)<sup>9</sup> and the Natural Resources Defense Council<sup>10</sup> point out that the upper limits on intermittent resources do not occur when variable solar or wind generation exceed total current electricity demand. Rather, the upper limits on useable intermittent energy are based on total demand minus the amount of dispatchable generation that must remain on line to maintain system reliability.<sup>11</sup>

Further, the amount of traditional dispatchable generation that must be kept running to preserve grid stability is surprisingly large. Grid operators must avoid both insufficient generation (voltage drops, motors slow, and lights dim) and excess generation (voltage spikes, motors burn out, and light bulbs blow), and they typically need to keep some larger generators operating for the system to respond rapidly to relatively small changes in output.

For instance, assume the system operator believes that fluctuations in net electric load during a particular hour are expected to be no bigger than 1,000 MW. To use fossil thermal generation to effect either a 1,000 MW drop (also known as a “decrement” or “downward regulation”) or a 1,000 MW increase (“increment” or “upward regulation”), the system may need to have 4,000 MW of NGCCs running at 75 percent of their rated maximum output. Here is why:

- The 4,000 MW of NGCCs can be scheduled to run at 75 percent capacity (3,000 MW), assuming all goes according to plan.
- If 1,000MW extra is needed, the plants quickly power up to 100 percent and generate 4,000 MW.
- If generation need to drop quickly, the NGCCs throttle back to 50 percent or 2,000 MW.

The implications of this concept—that it takes a lot of running dispatchable generation to accommodate intermittent resources—can be shown in a simple 24-hour chart derived from CAISO data from a single day in fall 2016 (See Figure 5 below).<sup>12</sup> As shown on the graph (which depicts total MWhs of generation used during one-hour periods):

- During the hour beginning at 2 pm (hour 14 on x-axis), with variable solar generation soaring, there was a total of approximately 14,000 MWh of rooftop solar, utility scale solar, and wind available (yellow, beige, and green strips on figure).
- As solar output rose during the day, CAISO did its best to turn down other resources such as hydro production (down ~750 MWh vs. early morning) and imported electricity (down ~1800 MWh vs. early morning)
- However, system operators needed to maintain 8,516 MWh of dispatchable (in this case, natural gas) generation on line (the gray strip in the middle).

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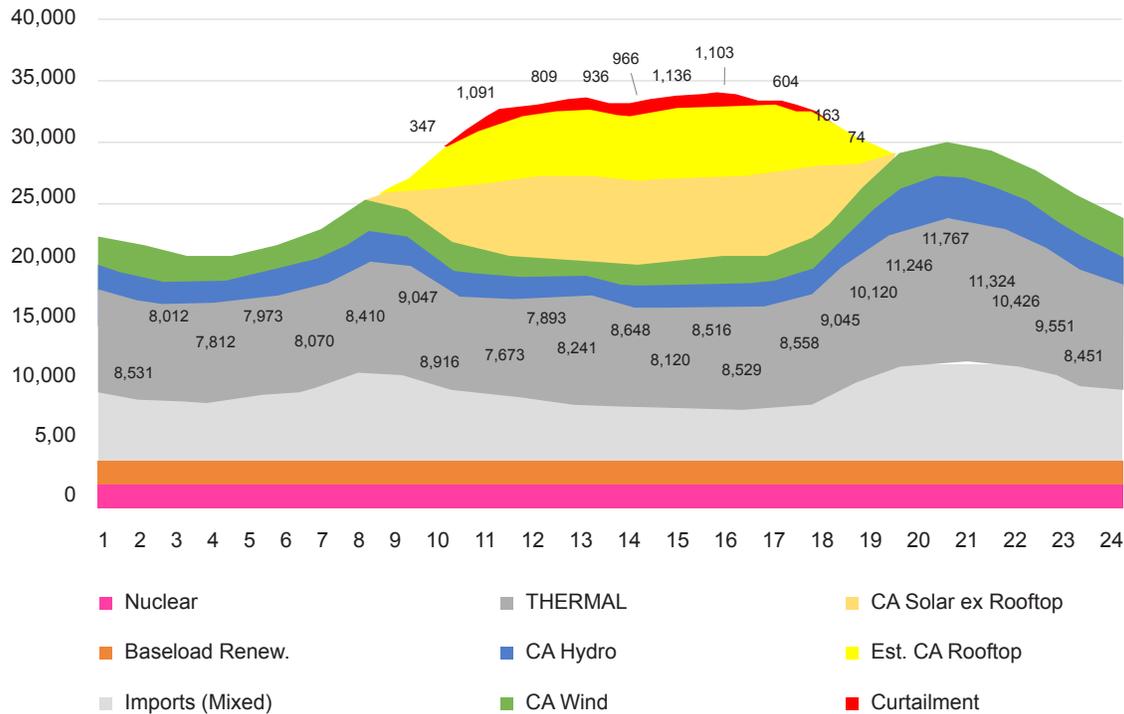
9 Denholm et al., National Renewable Energy Laboratories (2015). Overgeneration from Solar Energy in California: A Field Guide to the Duck Curve.

10 Nelson, J., & Wisland, L. (2015, August). Achieving 50 Percent Renewable Electricity in California. See p. 8/65. “Still, natural gas power plants will play important roles in meeting a 50 percent RPS in 2024. . .”

11 Different analysts come to different conclusions about the maximum ratio of intermittent resources to flexible resources that can be technically achieved without sacrificing reliability. Hence, environmental groups may conclude that with more careful operations, the bare minimum thermal generation could be smaller (but not zero) and a bit more intermittent (i.e., wind and solar) could be absorbed.

12 The data on the chart is a combination of daily renewable and thermal output information from CAISO reports, separate CAISO weekly reports on curtailment, and extrapolation of information from the California Energy Commission and utility filings regarding rooftop solar.

Figure 5: Curtailment at Minimum Thermal Generation, Excess Solar, 10-04-2016



- But in the end, CAISO apparently was forced to curtail (i.e., turn off and waste) 1,136 MWh of solar and wind (the red strip at the top of the figure).<sup>13</sup>
- To maintain system reliability, operators needed to keep dispatchable generation at a floor level of ~25 percent of total generation, resulting in the purchase of natural gas fuel, extra carbon emissions, and failure to utilize variable wind and solar generation for which consumers have already paid.

Effective measures have and are being taken to reduce the minimum of dispatchable generation required for system reliability, and some regions

have greater capacity to manage variable generation resources due to more robust transmission capacity and greater diversity of generation resources than does California, from which examples are drawn for this report.<sup>14</sup> However, once variable generation starts to reach the limits of a given system's ability to absorb intermittent energy, two things happen:

1. The effective cost of electricity rises. Typical power contracts for variable wind and solar PV-generated electricity require buyers to pay for power that was available from the generator, but not used by the purchaser. For example, if a solar PV installation is contracted to produce 2,000 MWh in a year at a cost of

<sup>13</sup> CAISO. Wind Solar Real-time Dispatch Curtailment Report Oct 04 2016, page 4/5.

<sup>14</sup> These steps include increases in storage, buildout of transmission systems, and investments in demand response. All have economic and physical limitations that in practice should be evaluated as alternatives to investment in all types of generation. The scope of that analysis is beyond this paper.

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\$50/MWh, but the plant is curtailed down to 1,000 MWh, the effective power cost doubles to \$100/MWh.<sup>15</sup>

2. Capturing the carbon otherwise emitted by the minimum dispatchable fossil generation required on the system becomes a more compelling objective.

Building on the operational characteristics of the grid system described above, Figure 6 below illustrates what system-level analysis and the inclusion of carbon capture deployment means from the standpoint of comparative costs of emissions reductions. It shows where carbon capture retrofits of existing coal and natural gas power plants fall along the spectrum of avoided CO<sub>2</sub> emissions costs—approximately in the middle—underscoring the financial and economic benefits of an all-of-the-above approach to reducing carbon emissions.

The chart bears explanation. While there are only single bars for cost of carbon abatement at gas and coal power plants equipped with carbon capture, there are multiple bars for wind and solar. There are several reasons for this:

- First, recall the chart depicts the cost of avoided tons of CO<sub>2</sub> emissions, not the cost of energy or ¢ per kWh.
- Second, cost per ton of CO<sub>2</sub> avoided depends on which existing generation resource is being displaced on the grid. For example, if 1 MWh of solar PV allows the grid operator to turn down 1 MWh from a coal plant, ~1 ton of CO<sub>2</sub> emissions is avoided (hence a low abatement cost). If the grid operator turns down lower-emitting NGCC gas turbines instead, ~0.4 ton of CO<sub>2</sub> emissions are avoided (hence a much higher abatement cost in terms of dollars per ton of emissions avoided).

- Third, if the system cannot use all of a variable generator's output, or sell the excess power to other consumers within or outside the regional market, its effective cost goes up (both per MWh and per ton of CO<sub>2</sub> avoided). Once the system begins hitting limits on its ability to absorb variable generation, those intermittent resources begin to be curtailed. Thus, for example, Denholm (NREL 2015) estimates for California that, by the time total renewable electricity reaches 50 percent, the last few units of solar added will be curtailed as much as 50 percent of the time.

- Fourth, while battery storage or other forms of storage can avoid curtailment, they remain an expensive way to avoid CO<sub>2</sub> emissions. In the example above, if a utility installs one of the last incremental solar PV arrays with forecasted 50 percent curtailment, it might be required by regulators to provide battery storage to save energy that would otherwise be lost to curtailment. However, the economics of such storage is challenging:

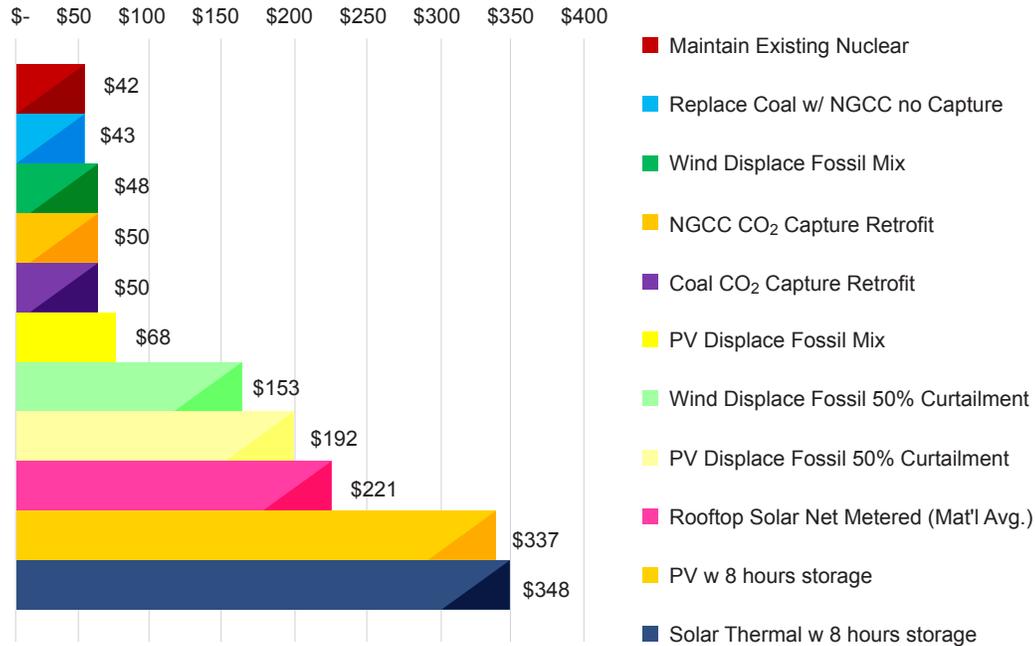
- With a typical utility-scale solar PV installation costing ~\$1,500 per kW of capacity, and assuming 50 percent curtailment, half of that sum, or ~\$750/kW is lost.
- Acquiring a lithium ion battery sufficient to store half of a day's output (e.g. 4.5 kWh/KW of installed solar capacity) and re-deliver the power at night would cost \$2,000 to \$5,000/kW of installed solar PV capacity. The lifespan of the battery would also be only half as long as the solar panel.
- So, at current battery prices, the storage solution costs on the order of three to seven times more than the curtailment problem it seeks to solve.<sup>16</sup>

The phenomenon of rising costs of reducing carbon emissions by deploying variable generation

<sup>15</sup> This is because a solar plant has effectively 100 percent fixed costs and zero variable costs. Its annual cost of producing energy is simply \$X of fixed cost divided by Y MWh of production. If production halves, the effective energy costs doubles.

<sup>16</sup> Solar thermal power generation with storage provides a renewable alternative to solar PV that provides greater system benefits. However, with just as with carbon capture, the current federal, state and RTO policy and regulatory framework disadvantages solar thermal relative to solar PV by failing to recognize the former's system benefits, leaving it less able to compete effectively in the marketplace.

Figure 6': Cost per Ton of CO<sub>2</sub> Reduction for Various Generation & Storage Technologies



\* Costs of generation and storage estimated through comparisons of numerous sources including Lazard's "Levelized Cost of Energy-Version 10.0", Lazard's "Levelized Cost of Storage Analysis-Version 2.0", USEIA's "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2017", NETL's "Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3" of July 6, 2015, SAIC's "Review of Power Plant Cost and Performance Assumptions for NEMS" February 2013, Black & Veatch's February 2012 study for NREL "Cost and Performance Data for Power Generation Technologies" Appendix C re Solar Thermal. All figures represent costs with no investment tax credits, production tax credits or other subsidies. Fossil fuel prices were based on USEIA AEO "2017 Total Energy Supply Disposition and Price Summary" using year 2020 nominal dollar forecast for WTI of \$68.47/bbl, Henry Hub Natural Gas of \$4.21/mmBtu, and Delivered Coal of \$2.52/mmBtu. "Fossil mix" assumes that any non-fossil plant is displacing a marginal fossil generation mix of 80% natural gas power plants and 20% coal plants, following methodology used by NREL in 2016 "Impacts of Federal Tax Credit Extensions on Renewable Deployment and Power Sector Emissions" Technical Report NREL/TP-6A20-65571, p. 21. Avoided carbon calculations used U.S. 20015 fleet average heat rates from USEIA of 10,495 Btu/kWh for coal and 7,878 for gas. Fuel carbon content based on USEIA figures of 205.8 lbs CO<sub>2</sub>/mmBtu for bituminous coal and 117 lbs CO<sub>2</sub>/mmBtu for gas. The above factors resulted in a blended displaced CO<sub>2</sub> emissions rate of 0.58 s-tons/MWh. The "50% curtailment scenario" is indicative of marginal curtailment (i.e., of most recent intermittent renewable plant added) as a system reaches high (i.e., 40-50%) levels of renewable penetration--see Denholm et al, NREL "Overgeneration from Solar Energy in California: A Field Guide to the Duck Chart" Technical Report NREL/TP-6A20-65023, Figure 17. Net capacity factors, attempting to be nationally representative were 23% for PV, 40% for wind, 50% for solar thermal with storage, 75% for new NGCC or NGCC with CCS, and 90% for Pulverized Coal with CCS (since capture assumed to be sized to minimum plant turndown capacity). Retail rate for purposes of rooftop solar price was national average of 12.9 cents/kWh sourced from USEIA, though current time of day pricing in some states is far higher (i.e., 30 cents/kWh or more).

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at higher levels of grid penetration is illustrated by the chart in Figure 6. The left side of the figure shows that intermittent wind and solar PV cost less at low penetration levels, when they displace generation from existing coal-fired power plants. On the higher-cost right side of the chart, solar PV at higher penetration rises significantly in cost when it begins displacing highly efficient existing NGCC plants, especially in cases of solar over-generation and curtailment, or of the need to deploy battery storage.

A key take-away is that a solar PV array or a power plant carbon capture system may not physically change and its operating costs may remain the same, but the relative costs to taxpayers and consumers of the CO<sub>2</sub> reductions they achieve when deployed on an integrated power system change markedly at higher levels of grid penetration and greater overall emissions reductions targets, underscoring the cost-effectiveness of a greater role for power plant carbon capture in a portfolio of low and zero-carbon generation.

While differences in the cost of reductions per ton of CO<sub>2</sub><sup>17</sup> between these examples are large, they were generated using standard cost estimates and comparing the cost of a proposed low-carbon option to a business-as-usual option under various operating rates.<sup>18</sup> The avoided cost figures are not unusual—a major study performed for California’s four largest utilities by an internationally respected energy consulting firm projected that, as the state moves from 40 to 50 percent renewable generation, and in the absence of power plant carbon capture and/or new nuclear generation

(which were not considered), the incremental avoided cost of CO<sub>2</sub> would range from \$403-\$1,020 per MT, depending on the particular strategy chosen.<sup>19</sup> In the study, the principal driver of these high costs is over-generation of solar, especially during spring and fall, which is often exacerbated when peak wind occurs simultaneously with peak solar generation.<sup>20</sup>

The CO<sub>2</sub> reduction strategies in Figure 2 can be thought of as a supply curve, creating an economically efficient approach to investments in carbon reductions. While innovation taking place across this technology spectrum is changing the nature of this supply curve, it is also clear that investing in an all-of-the-above-low and zero-carbon energy strategy has increasing returns as higher penetration levels are reached, by taking advantage of the middle portion of the supply curve. In addition, high penetrations of variable generation create a new need for dispatchable generation to ensure reliability and system flexibility, which at present is usually met with CO<sub>2</sub>-emitting generation resources. Instead, incremental investments in carbon capture and other low and zero-carbon dispatchable resources can reduce carbon emissions cost-effectively and reliably, while reducing curtailment of variable zero-carbon resources and over-investment in capacity while reducing CO<sub>2</sub> emissions.

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17 Cost of abatement per ton of CO<sub>2</sub> generally calculated as (full cost of new lower-emitting plant per MWh – variable operating cost savings per MWh from turning down higher-emitting plant) divided by (carbon emissions per MWh of higher-emitting plant – carbon emissions of per MWh of lower-emitting plant).

18 Lazard’s Levelized Cost of Energy Analysis-Version 9.0, Lazard Freres, November 2015 for renewables and combined cycle natural gas. Lazard’s Levelized Cost of Storage Analysis-Version 1.0, Lazard Freres, November 2015 for battery costs. Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 23, National Energy Technology Laboratory, DOE/NETL-2015/1723, July 6, 2015 various cases for carbon capture, supplemented by industry estimates and interviews. Note that “50 percent battery” means that for 1MW of solar PV plant, capable of typically producing ~9MWh a day, you have a battery capable of storing 4.5MWh during daylight hours when the PV plant would have been curtailed, then discharging the stored energy at night.

19 E3 study, page 144.

20 Overgeneration from Solar Energy in California: A Field Guide to the Duck Chart, Paul Denholm et al, National Renewable Energy Laboratory, Technical Report NREL/TP=6A20-65023, November 2015, pp. 3-4, chart on p. 22. Market Performance Report August 2016, California ISO, October 7, 2016, Figures 17 & 18, p. 18 of 43. <http://www.aiso.com/Documents/MarketPerformanceReportforAug2016.pdf>

## Achieving public policy objectives for the power system

Important public policy objectives for managing our nation's power system include (1) affordable and reasonable prices for consumers; (2) system reliability; and (3) environmental stewardship. Some jurisdictions also promote particular energy resources and technologies within their jurisdiction for various economic and environmental reasons. These objectives sometimes complement and sometimes compete with one another. Also, there is a complex web of institutional roles and responsibilities at federal, RTO and state levels for achieving these objectives, as shown in Table A-5 below.

America's systems—plural, because we have a host of different systems—for regulating the electric sector have evolved over more than a century. There are two major forms of regulation: economic regulation, to ensure affordable and reasonable power prices and electric reliability, and, environmental regulation, to protect public health and welfare. Economic regulation is accomplished by the Federal Energy Regulatory Commission, or FERC, which regulates wholesale power sales and interstate transmission; and state public utility commissions or PUCs which regulate retail power sales and the electric distribution system.<sup>21</sup> Environmental regulation is accomplished by the U.S. Environmental Protection Agency and state environmental agencies, with the respective federal and state roles varying by environmental statute and environmental problem.

The lines blur between economic and environmental regulation, and between state and federal jurisdiction. In particular, selection of generation resources, generally considered the purview of economic regulation, has environmental implications. For example, the implementation of renewable portfolio standards, whose purpose is in part environmental, is overseen by economic, not environmental regulators.

Amidst this policy, regulatory and jurisdictional patchwork, two major problems for carbon capture emerge:

1. For the most part, its carbon reduction benefits are neither valued in the market, nor explicitly addressed by public policy; and
2. The public policy objectives articulated above are addressed in a piecemeal fashion through a complex web of governmental and market institutions and mechanisms. No single actor or mechanism accomplishes these three objectives on a combined least-cost basis over the long term. This greatly disadvantages prospective investments like carbon capture and storage that have an attractive combination of attributes in a single technology package.

This paper focuses on electric power generation with CO<sub>2</sub> capture in alignment with the Work Group's mission, but there are several other dispatchable power technologies facing similar market challenges:

- Geothermal;
- CHP;
- Solar thermal power plants with heat storage reservoirs; and
- New modular nuclear reactors and existing nuclear plants.

Therefore, the problems and potential solutions for carbon capture in the power sector have relevance and applicability for the other low and zero-carbon generation technologies listed above.

Figure 7 shows the public policy arenas and institutions responsible for overseeing them. It falls to the electric system operator to keep U.S. electricity supply and demand in balance every minute of every day while meeting the public policy objectives. This is highly complex, and is achieved primarily through the following mechanisms:

- Dispatch (running) of generation resources on a real-time basis to meet each hour's power demand at minimum generation cost—

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<sup>21</sup> PUCs regulate investor-owned utilities, or IOUs. In most states, public power companies and cooperatives self-regulate.

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**Figure 7: Broad Overview of Jurisdictional Roles in the Electricity Industry**

Federal Jurisdiction (FERC, DOI, DOE, EPA, NRC, others)	State Jurisdiction (PUC, policymakers, enviro/energy agencies)	Local Jurisdiction (Local governing bodies)	Tribal Jurisdiction (Tribal utility authorities)
Generation siting (DOI, EPA)	Generation siting (PUC, policymakers, enviro agencies)	Generation siting	Generation siting
Limited interstate transmission siting (DOE, FERC, DOI)	Interstate transmission siting (PUC, policymakers, enviro agencies)	Interstate transmission siting	Interstate transmission siting
Environmental impacts (DOE, EPA, USDA, DOI, others)	Environmental impacts (enviro agencies)	Environmental impacts	Environmental impacts
M&A for regulated utilities (FERC, DOJ, SEC, FTC)	M&A for regulated utilities (PUC, policymakers)	Zoning approval	Govern operational market, planning activities of tribal utilities and have a say in the majority of activities that occur on tribal lands
Resource adequacy in RTO/ISO markets	Resource adequacy & generation mix (PUC, legislatures)	Local elected or appointed boards govern public power and cooperatives. These boards typically oversee the majority of public power/ coop activities	
Managing system operation and planning challenges arising from an increase in devices that can participate at both the wholesale and retail level	Managing system operation and planning challenges arising from an increase in devices that can participate at both the wholesale and retail level		
Interstate transmission commerce (FERC)	Retail sales to end users (PUC)		
Interstate wholesale commerce (FERC)	Utility planning (PUC, policymakers)		
Hydro licensing and safety (FERC)	State energy goals/policies (policymakers)		
Nuclear plant oversight (NRC)	Power plant safety standards (OSHA)		
Bulk system reliability (FERC/NERC)			
Power plant safety standards (OSHA)			

Indicates Federal–State–Local–Tribal Jurisdictional Ambiguity

Indicates Federal–State Jurisdictional Ambiguity

Jurisdictional responsibility of the electricity industry is divided between Federal, state, local, and tribal jurisdictions. Several issues, such as generation siting, transmission siting, and environmental planning, span all of the four jurisdictions. Federal and state jurisdictions overlap in planning, resource adequacy, and mergers and acquisitions for regulated utilities. Other areas, such as interstate transmission commerce and retail sale to end users, are regulated by the Federal Government (FERC) or the states (public utility commissions), respectively.

Acronyms: Department of Agriculture (USDA); Department of Energy (DOE); Department of the Interior (DOI); Department of Justice (DOJ); Environmental Protection Agency (EPA); Federal Trade Commission (FTC); independent system operator (ISO); North American Electric Reliability Corporation (NERC); Nuclear Regulatory Commission (NRC); Occupational Safety and Health Administration (OSHA); public utility commission (PUC); regional transmission organization (RTO); Securities and Exchange Commission (SEC).

Source: QUADRENNIAL ENERGY REVIEW TRANSFORMING THE NATION'S ELECTRICITY SYSTEM: THE SECOND INSTALLMENT OF THE QER, January 17th, 2017, Electricity Appendix <https://energy.gov/sites/prod/files/2017/02/f34/Appendix--Electricity%20System%20Overview.pdf>

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i.e., keeping cost of energy down for consumers by running the lowest cost (in terms of marginal cost <sup>22</sup>) generation first and the most expensive last.

- Acquisition of sufficient, cost-effective generation and/or storage, so that even when generation is interrupted or when demand spikes, the lights stay on—i.e., maintaining resource adequacy.
- Acquisition of ancillary services – i.e., providing voltage support, reactive power and other electrical engineering needs through operational requirements and/or ancillary service markets.
- Generating specified amounts of energy from defined resources – i.e., implementing a technology mandate. Note that RPSs are typically not defined in terms of minimizing CO<sub>2</sub>, but rather as requirements to generate a minimum amount of electricity from certain resources for which being low or zero-carbon is just one of several attributes.
- In the case of certain states (including California and the northeastern states that form the Regional Greenhouse Gas Initiative), creating a separate set of regulations that explicitly limit CO<sub>2</sub> emissions by requiring power companies to surrender tradeable carbon allowances for their emissions.

It should be noted that there are significant interactions between RPS and explicit CO<sub>2</sub> emissions limits or CO<sub>2</sub> pricing policies. RPS policies have broader objectives than CO<sub>2</sub> emission reductions, and hence do not necessarily include all low-carbon generation types.<sup>23</sup> In addition, different states will designate different generation sources as renewable. On the other hand, policies explicitly limiting CO<sub>2</sub> emissions are ostensibly more technology neutral and could encompass any and all means of limiting carbon emissions, including nuclear power, carbon capture and CHP. However, in practice, many jurisdictions use the RPS as their main policy lever, leaving policy measures that place a value on emissions reductions in the marketplace to play a lesser role. This favors technologies that are defined as renewable over other low and zero-carbon technologies.

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22 Marginal cost is the cost of adding the next available megawatt of power to the dispatch system.

23 For instance, in 1983 Iowa was the first state to establish an RPS, known as an “Alternative Energy Law.” The purpose of the law was not to avoid CO<sub>2</sub> emissions, but rather to avoid consumption of finite energy sources. “It is the policy of this state to encourage the development of alternate energy production facilities and small hydro facilities to conserve our finite and expensive energy resources and to provide for their most efficient use.” Iowa Statutes 476.41. In fact, it is quite difficult to find mention of CO<sub>2</sub> in any state RPS statute.

## Costs matter in both regulated vertically integrated monopoly and competitive markets

Both regulated monopoly and organized competitive markets impose cost discipline on generators and retail providers of electricity, but in different ways. In regulated monopoly markets, PUCs require vertically integrated utilities that both generate and provide electric power to customers to justify their costs in a transparent public ratemaking process, and only allow utilities to recover justifiable costs through customer electric rates. In organized competitive markets, competition occurs among merchant generators to sell power into wholesale markets organized by RTOs or ISOs. If a power plant's costs are too high, it cannot consistently bid successfully into such competitive markets and will not remain financially viable.

In either type of market, the carbon capture-related financial incentives and policy tools previously recommended by the Work Group (see above) effectively lower the carbon capture plants' costs; these policies can therefore have a positive impact on their commercial viability. Without such incentives, generators will not be competitive and fail to recover their cost of capital or even secure financing.

In a regulated market, such incentives and policies would make a utility more likely to propose, and a PUC to allow, a plant with carbon capture to be built or carbon capture equipment to be installed on an existing plant. In a competitive market, the incentives would make a merchant plant owner more likely to invest in and deploy carbon capture. In both types of markets, carbon capture incentives would make it more likely that these plants would be called upon to dispatch by enabling the plant operator to submit lower, more competitive bids to the grid operator overseeing the wholesale market.

See Box 2 below for a basic explanation of the major types of power markets and how they work.

## Box 2: Explanation Of How Regulated Monopoly And Competitive Markets Work

Regulated and competitive markets operate very differently in terms of how they (i) affect choices to build new power plants that will contribute to system reliability; (ii) determine dispatch, or choose to run or not run various plants on the system; (iii) affect decisions to retire plants; and (iv) are subject to control by federal regulators, system operators, and state regulators. Carbon capture plants can be built and operated in either regulated or competitive markets.

Decisions about building power plants, and the extent to which such plants operate (dispatch), are complex. Historically, such decisions were made for the most part by regulated monopolies—vertically-integrated, IOUs overseen by state PUCs—or by public power companies or power cooperatives.

With respect to dispatch, several states have shifted in recent years toward organized competitive markets, in which existing plants owned by merchant generators are dispatched based on the decisions of a regional (usually multi-state) RTO or ISO. More than 60 percent of electricity in the United States now moves through competitive wholesale power markets. The remainder of the transactions largely occur in state-regulated monopolies and in public power systems owned by governments or by their consumers.

Decisions to build. In a regulated monopoly market, the equipment cost for a new plant or retrofit with carbon capture, owned by a publicly-regulated IOU and pre-authorized by the relevant regulatory commission, is added to the rate base. This means that the utility's customers cover the costs through the rates they pay, which are approved by regulators, and the IOU is authorized to earn a specified rate of return on capital invested. By contrast, merchant plants in competitive markets cannot rely on such guarantees.

But how is the decision made to build such a plant? With respect to building new facilities, there is a range of approaches in which power generators seek to ensure profitability, and regulators and system operators seek to ensure resource adequacy, or the ability to meet demand and energy requirements of end-use customers, considering scheduled and unscheduled outages. Planning for adequate investment in generation and transmission capacity to ensure resource adequacy is a critical component of ensuring a reliable electricity system.

Traditionally, vertically integrated regions and some utilities in organized competitive markets conduct an integrated resource planning process to plan for necessary capacity investments. Some organized competitive markets have implemented capacity markets as a mechanism for ensuring future resource adequacy. In

the organized competitive markets, the system operator conducts an auction process, and retail service providers procure resources to meet the electricity demands of their customers. These markets can be mandatory (PJM Interconnection and ISO New England); voluntary, where utilities can choose to operate under an integrated resource planning process (Midcontinent ISO-MISO); or voluntary, but backstopped by a mandatory process (New York ISO-NYISO). Other regions (CAISO and the Southwest Power Pool-SPP) have capacity obligations where market operators require utilities to procure necessary generation reserves, either through ownership or through contracts with third-party providers. Another market-based approach, used in the Electric Reliability Council of Texas (ERCOT), relies on energy prices alone and does not have formal requirements or markets for capacity. In this approach, market scarcity pricing, or relatively high energy prices during high-demand periods reflecting the lack of ample additional resources, is expected to provide necessary financial incentives for investment in generation capacity.

Differences in requirements imposed on a load or customer-serving utility to have assured power supply, and the time period over which that assurance must be demonstrated, have a huge impact on the financing of capital intensive, high-reliability resources:

- At one end of the spectrum, ERCOT does not require demonstrated capacity and is fully competitive. Capacity is only added if a prospective new market entrant thinks that it can take advantage of high energy prices at certain times of the year (i.e., power prices in the \$50-\$500/MWh range in the summer). In such competitive markets, spot power prices typically hover at or near the variable cost of generation, with big price spikes occurring during relatively few hours per year, making it difficult for any entrant to obtain low-cost long-term financing for a conventional power plant, much less a unit with carbon capture that could roughly double the funding needed.
- By contrast, in a vertically-integrated system that examines long-term resource adequacy and authorizes utilities to enter long-term bilateral contracts with new generators, financing is relatively simple to obtain once the regulatory decision is made. In such a case, a question may be whether the regulator will take carbon emission reduction attributes into account and thereby give extra consideration to a more expensive plant with carbon capture.

## Box 2: Explanation Of How Regulated Monopoly And Competitive Markets Work (cont.)

Dispatch decisions. In both regulated and competitive markets, plants are dispatched based on their marginal costs. In regulated markets, the utility both owns the plants and makes dispatch decisions. In competitive markets, RTOs make their dispatch decisions based on plant owners bidding to sell power; these bids are based on the plants' marginal costs to generate power. In other words, whether a power plant is in the money, allowed to dispatch and sell power depends on whether it bids at or below the market clearing price, meaning the level at which the competitive auction provides enough generation capacity to meet demand projected by the RTO.

Retirement decisions. In competitive markets, individual merchant generating plants cannot survive if they are not profitable. It is easier to keep individual plants running in regulated than competitive markets because profitability is determined on a company-wide rather than individual plant basis; regulated, vertically-integrated utilities have more flexibility to take longer-term operational and system diversity into account. The utility does not need all of its individual plants to be profitable, as long as the company as a whole is meeting expectations for an overall return

on investment. The situation in competitive markets is different, in that each merchant plant must be profitable in order to continue to operate. Generators that find themselves out of the market can lower bids below their marginal costs in the short term, dispatching and selling power at a loss, but they cannot do so indefinitely.

Respective roles of states, FERC, and RTO/ISOs. RTOs and ISOs ensure smooth operation of competitive wholesale markets under FERC oversight. States cannot interfere with the operation of these markets. However, states can set policies, such as portfolio requirements, that favor renewable or low-carbon resources, and therefore may affect net generation costs. It is not the organized markets themselves that value, or fail to value, environmental costs and benefits. Such costs and benefits will only be reflected in power prices to the extent that state or federal policy requires it. Recently, FERC, states and the courts have been paying careful attention to state actions that influence the wholesale power markets to ensure that states and FERC do not infringe on each other's jurisdiction.

## Carbon capture has advantages, but faces cost, financing and market challenges

Carbon capture provides multiple benefits. It produces pure CO<sub>2</sub>, which has commercial value for EOR, chemical production and potentially other uses. A power plant equipped with carbon capture is dispatchable, meaning that it can be called upon to operate when needed. Carbon capture can take advantage of the extensive public and private investment that have already been made in CO<sub>2</sub>-EOR and fossil fuel infrastructure, while further decarbonizing the power sector. Finally, plants equipped with carbon capture have significant environmental benefits beyond carbon emission reductions due to very low emissions of conventional air pollutants, which must be removed to avoid compromising carbon capture systems.

However, carbon capture in the power sector faces cost, financing and market challenges. It is both capital-intensive and innovative, making financing challenging, especially in competitive markets. Its CO<sub>2</sub> benefits are not valued in most power markets. Currently, coal plants with carbon capture have higher fixed costs, yet must compete with low-cost natural gas, and both coal and natural gas plants with carbon capture must compete with nuclear, hydro, wind solar, and other sources of power.

The greater complexity of a power plant with carbon capture can make it relatively more difficult to increase or decrease its output, an increasingly desired attribute of dispatchable generation by grid operators as penetrations of variable generation such as wind and solar increase. At the same time, higher costs can make it financially difficult for a plant to run flexibly and, therefore, at lower capacity factors (i.e. operating for fewer hours), and still recoup its investment in carbon capture equipment and added operational costs.

In most power markets, low-cost natural gas (without carbon capture) is the toughest competitor for other existing or potential electricity suppliers. Nationally, wind and solar power currently provide a small fraction of U.S. electric generation (one percent for solar and

five percent for wind). However, their share is growing rapidly, and they are significant players in key markets at certain times. Federal and state financial incentives and other policy support for wind and solar power effectively lowers their fixed costs, and because they have no fuel costs, and very low or no variable costs, they can sell into wholesale markets at low and sometime even negative prices.

The key policies favoring renewable generation are the federal production tax credit for wind (PTC), the federal investment tax credit (ITC) for solar, and renewable energy credits (RECs) that states award under their RPSs. The PTC is 2.3 cents per kWh for wind, closed-loop biomass, geothermal energy resources, and solar systems that have not claimed the ITC, and 1.2 cents per kWh for open-loop biomass, landfill gas, municipal solid waste, qualified hydroelectric, and marine and hydrokinetic energy resources. The residential, commercial and utility ITC are equal to 30 percent of the basis that is invested in eligible property. The PTC is scheduled to phase out by the end of 2019; the ITC for residential solar phases out by 2021; the ITC for commercial and utility solar declines to 10 percent but remains in place beyond 2021.

The lack of policy parity for other low-and-zero-carbon generation options such as carbon capture makes it difficult or impossible for them to compete on a market basis. Similar policy incentives for other low-carbon solutions could help level the playing field vis-à-vis wind and solar power. The zero-emission credits (ZECs) recently established for nuclear power in Illinois and New York are examples of efforts to advance such a policy approach.

More fundamentally, wind and solar characteristics also present an emerging challenge to how the grid and competitive markets function. Wind and solar power are variable, meaning that their generation varies to the degree to which the sun

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shines or the wind blows. Integrating variable wind and solar power into the grid requires the rest of the system (competing suppliers, demand response programs, and/or electricity storage) to be more flexible in response.

When these variable resources are operating, because they have no fuel cost, they have very low marginal operating cost. Their net marginal costs are even lower, and sometimes even zero or negative, when accounting for PTC and REC payments, which leads to generators bidding into the market and dispatching at zero or negative marginal prices. This can make it very difficult for even low-cost competing suppliers to earn money through power markets.

As elaborated in the box below, in competitive power markets, having multiple objectives implemented by different policy and institutional mechanisms and by different federal, state and RTO/ISO authorities deeply disadvantages technologies such as carbon capture that offer attractive packages of attributes—relatively low hourly cost, dispatchability and comparatively cost-effective environmental benefits. However, while all the attributes of a carbon capture plant may prove cost-effective when considered together, that may not be the case when those attributes are evaluated on a piecemeal basis. This is a complex insight that bears further explanation.

For example, adding CO<sub>2</sub> capture may well help a plant to be more competitive in the hourly power market due to the sale of commodity CO<sub>2</sub>. However, there is unlikely to be any appetite to amend an existing generation capacity contract to pay for carbon capture equipment that provides no extra generating capacity over a conventional dispatchable plant (and the broader energy production and economic benefits of using captured CO<sub>2</sub> for EOR fall outside the power sector). And the environmental attributes of CO<sub>2</sub> capture do not help meet a RPS because the power plant's fuel source is not renewable. To make matters worse, CO<sub>2</sub> allowances are currently much less valuable than RECs.

Perversely, a power plant carbon capture project is thus unlikely to proceed, even though:

- Its carbon emissions are vastly lower than existing natural gas plants dispatched into the hourly markets, but it would have roughly the same marginal generation costs;
- It would provide dispatchable low-carbon energy in contrast to intermittent resources; and
- As explained earlier, in many circumstances it would nearly eliminate CO<sub>2</sub> emissions at a cost below that of some intermittent resources that are currently required to meet a RPS.

In every jurisdiction in the United States with organized competitive markets, the results turn out to be similar, even though the details vary significantly. That is, the lack of system-wide optimization of cost, reliability, and emissions reductions tends to preclude consideration of dispatchable low- and zero-carbon technologies like carbon capture.

### Box 3: Key Market Challenges

With its economic, reliability and environmental benefits unrecognized and unrewarded by the prevailing federal, state and RTO/ISO electricity policy and regulatory framework, a fossil fuel power plant with carbon capture resembles a superb multi-sport, all-around athlete who participates in the Olympic decathlon. He or she may excel enough to make the semi-finals in ten different events, but never win a gold medal in any single one.

This box illustrates how carbon capture is disadvantaged under current policy and regulation by summarizing the four different policy arenas in which a fossil power plant with carbon capture must compete. Appendix A provides specific examples of how resource decisions are made in each arena in the context of one ISO, in this case California. Future research should similarly evaluate other ISOs and non-ISO markets, some of which have more robust regional transmission systems, greater diversity of generation resources and load centers and, therefore, greater capacity to integrate and manage higher levels of variable generation than does California.

#### Summary of Policy Arenas

The policy arenas for low-carbon generation resources in different U.S. jurisdictions are often quite similar, even though the details differ: capacity, dispatch, RPS policies, and carbon emissions limits. Decisions about capacity and dispatch are present in all power markets, whereas no RPS or renewable goals exist in 12 states, and carbon pricing is present in only ten states:

1. **Capacity:** This is the core question. How does a dispatchable low-carbon resource such as a carbon capture-equipped power plant obtain a long-term contract sufficient to enable it to attract lenders and equity investors? If capacity is procured for resource adequacy without regard to environmental considerations, the low-carbon resource will often be the high bidder, rather than the low bidder.
2. **Dispatch:** Typically, a dispatchable, low-carbon emission resource will be acquired under a contract that is a version of a tolling agreement, in which the utility needing additional capacity agrees to pay annual amounts that cover financing charges (like loan payments) and fixed overhead (like maintenance

staff, insurance, and taxes).<sup>1</sup> Further, if and when the plant's power is needed and the plant is started up, the purchasing utility is required to pay for the variable operating costs and fuel charges. Thus, with an adequate tolling contract in place, the owner of a dispatchable, low-carbon unit would be largely indifferent to how often it dispatches.<sup>2 3</sup>

3. **RPS:** Since RPS standards generally prescribe a percentage of energy<sup>4</sup> to be purchased from certain eligible resources (i.e., total MWh procured during a year)—typically limited to statutorily-defined renewables under state law—the environmental benefit of most dispatchable zero and low-carbon resources will typically fail to be rewarded because:
  - a. RPS are generally indifferent to capacity or reliability, which constitutes an important selling point of a power plant with capture.
  - b. Carbon capture and other readily-scalable non-renewable low and zero-carbon alternatives—nuclear, and CHP, for example—are ineligible in most states (Ohio, Pennsylvania and Michigan are examples of exceptions).
4. **Valuing CO<sub>2</sub> Reductions:** Carbon capture could benefit from policies that value carbon reductions. However, state and regional policies implemented thus far have not been sufficiently stringent to yield allowance prices high enough to provide a substantial incentive for new project deployment involving higher-cost and more capital-intensive technologies such as carbon capture.

In summary, our misaligned patchwork system of policy incentives and regulatory oversight at federal, RTO/ISO and state levels frustrates the integration of economic, reliability and environmental benefits in the procurement of electric generation resources. If such optimization were valued by our policy and regulatory framework, power plants with carbon capture would be better positioned to compete in organized competitive wholesale electricity markets due to their all-around high performance in all three areas.

*Please see Appendix A of this report for a more detailed analysis of this topic.*

- 1 This description would not necessarily hold true in the case of a traditional, PUC-regulated, vertically-integrated utility. In such a case, it is possible that a PUC approves of construction and ownership of a new generator by the utility itself, with the asset value included in the rate base and the plant simply utilized by the utility as needed to meet loads; i.e., there is no separate tolling agreement.
- 2 By the same token, with major capital and fixed costs already contractually covered, the actual cash cost of generation may effectively be zero. For instance, once the fueling for a nuclear plant has been completed at the beginning of a plant's fuel cycle, its actual variable hourly cost is effectively zero.
- 3 A low carbon plant that captures and sells CO<sub>2</sub> for utilization in a non-electric industry (such as CO<sub>2</sub>-EOR) would not at all be indifferent to its operating rate. Such a plant would likely be relying on CO<sub>2</sub> sales revenues and possibly storage tax credits (such as §45Q) for financial feasibility.
- 4 Only Texas and Iowa specify their RPS in terms of capacity.

## Policy Options

As we have discussed, the fundamental policy problems for carbon capture are shared by other dispatchable, low-carbon generation technologies. Therefore, there are a number policy options that could be implemented at the federal, ISO/RTO, or state levels that would benefit all such resources including carbon capture. In addition, there are some solutions that would specifically aid carbon capture alone, many of which were discussed in the Working Group's December 2016 [Putting the Puzzle Together report](#).

Figure 8 below summarizes the types of options available.

**Federal.** Major actions could include incentives, FERC initiatives, and RDD&D programs.

For the last twenty years, federal renewable electricity incentives have been awarded based on energy production without specifically valuing capacity provided or carbon emissions reduced. Thus, the federal PTC can be claimed for wind generation, even if the electricity is produced at a time and amount that cannot be fully utilized on the grid. In addition, wind power is sometimes produced when grid prices are negative to garner the ~\$23 per MWhr PTC. The current federal

incentives for wind and solar are phasing out, with the wind PTC ending after 2019 and the solar ITC dropping to 10 percent after 2021.

Carbon capture has not benefited from such incentives and, as this paper has shown, its carbon emissions reduction and reliability benefits go unrecognized in wholesale power markets.

- In the interest of policy parity, the most important near-term federal action would be enactment of the previously referenced suite of financial incentives for carbon capture as recommended by the Work Group in its report released in December.
- In addition, federal financing and other policies to foster the buildout of CO<sub>2</sub> pipeline infrastructure would provide an important complement to federal carbon capture incentives, as recommended by the Work Group in its February white paper and menu of financing options released in March.
- Another helpful area of federal policy change would be for FERC to affirmatively encourage the development of reliable low-carbon

**Figure 8: Policy Options for Carbon Capture and Other Low-Carbon Resources**

	Federal	ISO/RTO	States
<b>All Dispatchable Low-Carbon Resources</b>	Provide financial value for CO <sub>2</sub> reductions in generation dispatch; Develop financeable capacity payment structures; Research, development, demonstration and deployment (RDD&D) programs and support	Develop a low-carbon capacity standard; Provide financial value for CO <sub>2</sub> reductions in generation dispatch	Modify or supplement existing renewable portfolio standard (RPS) policies to expand eligible resources
<b>Carbon Capture Specifically</b>	45Q CO <sub>2</sub> storage tax credits; tax-exempt private activity bonds (PABs); Master Limited Partnerships (MLPs); CO <sub>2</sub> pipeline infrastructure financing; Carbon capture RDD&D programs and support		Modify or supplement RPS to at least cover carbon capture (adjusted for percentage of capture)

capacity either by RTOs/ISOs that are FERC-jurisdictional, or by states whose utilities are part of RTOs/ISOs.<sup>24</sup>

- Over the longer term, a federal incentive to reward the provision of low-carbon capacity on the grid could be designed and enacted by Congress that would be denominated in typical capacity contract terms of \$ per kW-month or \$ per MW-year, and applicable to all low and zero-carbon resources (with the incentive adjusted for those resources with residual carbon emissions based on the percentage of reduction).
- Finally, the federal government should sustain and ultimately expand its RDD&D portfolio through U.S. DOE to improve the performance and lower the cost of all major low- and zero-carbon generation options. In particular, a robust RDD&D program to improve the performance and lower the cost of carbon capture is needed.

**RTO/ISO Level Actions.** At the RTO/ISO level, beneficial changes to market rules could benefit all dispatchable low and zero-carbon resources.

Improving the functioning of capacity markets and/or out-of-market payments<sup>25</sup> could reward dispatchable resources and make it easier to finance them.

Beneficial changes could be implemented at the dispatch level and at the capacity contract level. However, such reforms would not specifically benefit carbon capture unless they provide financial value for emissions reductions relative to other conventional fossil generation.

Applying a financial value for carbon reductions in generation dispatch would reward low-carbon generation options generally.

Combining a carbon value with measures to recognize and value reliability attributes of

dispatchable low-carbon resources specifically would reward carbon capture and enhance its competitiveness by enabling them to dispatch and run more frequently.

**ISOs/RTOs could help address the need for long-term financing of dispatchable low-carbon resources by supporting long-term (i.e., 20+ year) cost-of-service based contractual mechanisms to maintain long-term firm and dispatchable capacity.** This resembles the process in California agreed to among CAISO, CEC and the CPUC.<sup>26</sup> Measures to influence dispatch alone may be insufficient to allow long-term financing of such resources, since such generation tends to have higher capital costs than conventional fossil generation without carbon capture.

**State Level Actions.** Generally, there are two ways carbon capture and other dispatchable low and zero-carbon resources could be better accommodated under state laws and regulations:

**Expand RPS policies to include energy from low and zero-carbon nonrenewable generation.** Most states have opted to implement utility portfolio standards and other binding requirements that specifically incentivize renewable resources; other states have not, including some represented in this Work Group. States with RPSs could benefit from broadening or supplementing such policies to include nonrenewable carbon capture, nuclear power and CHP as dispatchable low and zero-carbon resources. This would help achieve policy parity and a more level playing field for all zero- and low- carbon power generation technologies. Some states have instituted electricity resource goals or standards that set broader requirements and eligibility for “clean” or “alternative” energy, which include not only renewables, but also certain nonrenewable technologies. These can include nuclear power and carbon capture and are sometimes referred to as Clean Energy Standards (CESs). States that have implemented

24 Exelon, owner of nuclear plants, argued for such a permissive approach to be adopted by FERC in a recent filing. See [https://www.ferc.gov/CalendarFiles/20170426150548-Barron\\_%20Exelon.pdf](https://www.ferc.gov/CalendarFiles/20170426150548-Barron_%20Exelon.pdf)

25 Out-of-market payments are compensation generators receive outside of organized power markets, for example for renewable energy credits or long-term contracts.

26 See <http://www.cpuc.ca.gov/LTPP/>

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such broader portfolio standards include Colorado, Michigan, Ohio, Pennsylvania, and Utah.

**States could also develop separate low-carbon generation standards or credits.** Two states, New York and Illinois require purchases of certain amounts of nuclear power, with an additional financial credit applied to carbon reductions based on a quantitative estimate of their societal benefits, through zero-emission credit or ZEC programs. As a supplement to a RPS, some states may wish to replicate ZEC programs and expand them to include carbon capture and storage.

A variation of this approach is to create a separate low- or zero-carbon capacity portfolio standard or the equivalent.

A direct approach could apply in cases where state regulators require utilities to maintain contractual access to long-term capacity resources adequate to maintain proper generation reserve margins. In these cases, a standard would simply mandate increasing amounts of capacity to be based upon low- carbon resources, including retrofits of existing, already-contracted fossil units to add carbon capture, or retrofits of solar thermal resources to add thermal storage.

The changes to market rules at ISOs/RTOs and modifications or supplements to state portfolio standards described above could be implemented to benefit all dispatchable low and zero-carbon resources, or specifically targeted to power plants with carbon capture, depending on the particular resource options and preferences of different states and regions.

Designing and implementing comprehensive policies that apply to all low and zero-carbon generation resources and optimize system benefits effectively for cost, reliability, and emissions reductions is challenging. In the meantime, enacting the federal and state carbon capture incentives and federal CO<sub>2</sub> pipeline infrastructure financing already recommend by the Work Group would go a long way to providing some degree of policy parity and ensuring we advance the entire portfolio of low carbon options in the power sector.

## Recommendations

We recommend the following:

- Redouble efforts to implement the carbon capture incentives and CO<sub>2</sub> pipeline infrastructure financing recommendations already prepared by the Work Group to begin leveling the playing field with other low and zero-carbon power generation options.
- Sustain and ultimately expand the federal energy RDD&D portfolio to improve the performance and lower the cost of all major low carbon resources. In particular, increase RDD&D funding to improve the performance and reduce the cost of carbon capture.
- Work toward more comprehensive policies that encompass all low and zero-carbon generation options, including market rules, incentives, portfolio standards and other measures, that optimize system benefits effectively for affordability, reliability, and emissions reductions.
- Improve energy and capacity markets to increase system flexibility, including rewarding low and zero-carbon dispatchable generation resources and their carbon reduction benefits and making it easier to finance them.

## Conclusions

Carbon capture can play an important role in achieving all three major public policy objectives for our nation's power system: (1) affordable and reasonable prices for consumers; (2) system reliability; and (3) environmental stewardship. Yet, in our complex web of regulatory and market policies, structures and institutions, no single actor or mechanism considers and optimizes these three objectives on a combined least-cost basis over the long term. This greatly disadvantages prospective investments in carbon capture and other dispatchable low and zero-carbon generation resources that have an attractive combination of attributes in a single technology package.

Federal, state and RTO/ISO policy and market reforms could help overcome this disadvantage by recognizing multiple beneficial attributes. Implementing the recommendations in this report would encourage investment in all low and zero-carbon dispatchable resources, including carbon capture.

## Glossary

<b>Ancillary services (electric power)</b>	Ancillary services are specialty services and functions provided by the electric grid that facilitate and support the flow of electricity so that supply will continually meet demand. The term ancillary services refers to a variety of operations beyond generation and transmission that are required to maintain grid stability and security. Traditionally, ancillary services have been provided by generators; however, the integration of intermittent generation and the development of smart grid technologies have prompted a shift in the equipment that can be used to provide ancillary services.
<b>Anthropogenic CO<sub>2</sub></b>	Carbon dioxide that is produced or released through human activity, as distinct from naturally occurring CO <sub>2</sub> obtained from geologic sources.
<b>Bbl</b>	The abbreviation for barrel, a unit of volume for crude oil and petroleum products. A barrel contains 42 gallons of crude oil.
<b>CAISO</b>	The abbreviation for California Independent System Operator, a regional transmission organization.
<b>CCS</b>	Carbon capture and storage, or CCS, describes the process of capturing and preventing the release of man-made or anthropogenic CO <sub>2</sub> into the atmosphere and then ensuring its permanent storage in an oil and gas field, deep saline formation or other geologic formation.
<b>CCUS</b>	Carbon capture, utilization and storage, or CCUS, reflects the commercial use of CO <sub>2</sub> prior to permanent geologic storage through its injection into oil fields to recover additional crude through CO <sub>2</sub> -EOR.
<b>CES</b>	The abbreviation for clean energy standard.
<b>CHP</b>	The abbreviation for combined heat and power.
<b>CO<sub>2</sub>-EOR</b>	Carbon dioxide enhanced oil recovery, or CO <sub>2</sub> -EOR describes the process of injecting CO <sub>2</sub> into an oil field, usually in a tertiary phase of production (beyond what can be recovered by normal flowing and pumping operations), to increase the amount of crude oil that can be extracted. The commercial purpose of CO <sub>2</sub> -EOR is to increase oil production, but permanent geologic storage of the injected CO <sub>2</sub> in the formation is an incidental result of the process.
<b>Competitive (electricity) market</b>	<p>A competitive market is a system enabling purchases, through bids to buy; sales, through offers to sell; and short-term trades, generally in the form of financial or obligation swaps. Bids and offers use supply and demand principles to set the price. Long-term trades are contracts similar to power purchase agreements and private bi-lateral transactions between counterparties.</p> <p>Wholesale transactions (bids and offers) in electricity are typically cleared and settled by the market operator or a special-purpose independent entity charged exclusively with that function. Market operators do not clear trades but often require knowledge of the trade to maintain generation and load balance. The commodities within an electric market generally consist of two types: power and energy. Power is the metered net electrical transfer rate at any given moment and is measured in megawatts (MW). Energy is electricity that flows through a metered point for a given period and is measured in megawatt-hours (MWh).</p>

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<b>Curtailement</b>	A temporary, mandatory power output or load reduction taken when there is a risk of oversupply or a risk that the utility cannot meet its power requirements and retain a prudent reserve margin.
<b>Dispatchable generation</b>	Dispatchable generation refers to sources of electricity that can be dispatched at the request of grid operators or of the plant owner; that is, generating plants that can be turned on or off, or can adjust their power output according to an order. Often baseload power plants such as nuclear or coal cannot be turned on or off in less than several hours or days. The time periods in which dispatchable generation plant may be turned on or off may vary. The most common dispatchable power plant is natural gas.
<b>DOE</b>	The U.S. Department of Energy (DOE) is a federal Cabinet-level department concerned with policies and technology investments regarding energy and safety in handling nuclear material. Its responsibilities include the nation's nuclear weapons program, nuclear reactor production for the U.S. Navy, energy conservation, energy-related research and development, radioactive waste disposal, and domestic energy production.
<b>EIA</b>	The U.S. Energy Information Administration (EIA) is a principal agency of the U.S. Federal Statistical System responsible for collecting, analyzing, and disseminating energy information. EIA programs cover data on coal, petroleum, natural gas, electric, renewable and nuclear energy and energy efficiency. EIA is part of the U.S. Department of Energy, but its data, analyses, and forecasts are independent of approval by DOE.
<b>ERCOT</b>	The abbreviation for Electric Reliability Council of Texas, a regional transmission organization.
<b>FERC</b>	The Federal Energy Regulatory Commission (FERC) is the U.S. federal agency that regulates the transmission and wholesale sale of electricity and natural gas in interstate commerce, and regulates the transportation of oil by pipeline in interstate commerce. The FERC also reviews proposals to build interstate natural gas pipelines, natural gas storage projects, and liquefied natural gas (LNG) terminals. Finally, the FERC licenses non-federal hydropower projects.
<b>Gasification</b>	Gasification is a long-established process of applying heat and pressure to an organic or fossil fuel-based carbonaceous feedstock, transforming it into carbon monoxide and hydrogen, with a pure stream of carbon dioxide ultimately resulting as a chemical byproduct that can readily be compressed and transported.
<b>GW</b>	The abbreviation for a gigawatt, or the equivalent of 1,000 megawatts or 1,000,000 kilowatts.
<b>IEA</b>	The International Energy Agency (IEA) is a Paris-based autonomous intergovernmental organization established in the framework of the Organization for Economic Co-operation and Development in 1974 in the wake of the 1973 oil crisis. The IEA was initially dedicated to responding to physical disruptions in the supply of oil, as well as serving as an information source on statistics about the international oil market and other energy sectors. It is now responsible for a broader portfolio of activities.

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<b>IGCC</b>	Integrated gasification combined cycle (IGCC) is a technology that uses a high-pressure gasifier to turn coal and other carbon-based fuels into hydrogen and ultimately a synthesis gas (syngas), removes impurities from the syngas, and then combusts the syngas in combined cycle power generation. With additional process equipment, a water-gas shift reaction can convert carbon monoxide to carbon dioxide. The resulting CO <sub>2</sub> from the shift reaction can be separated, compressed, and used for EOR or in other geologic storage.
<b>Industrial CO<sub>2</sub></b>	For the purposes of this report, industrial is meant to distinguish anthropogenic carbon dioxide generated from a wide range of industrial processes and activities from CO <sub>2</sub> produced through electric power generation.
<b>Investor-owned utility</b>	or IOU is a business organization, providing a product or service regarded as a utility (often termed a public utility regardless of ownership), and managed as a state-regulated monopoly private enterprise rather than a function of government or a utility cooperative.
<b>ISO</b>	An independent system operator (ISO) is an organization formed at the direction or recommendation of the Federal Energy Regulatory Commission (FERC). In the areas where an ISO is established, it coordinates, controls and monitors the operation of the electrical power system, usually within a single state, but sometimes encompassing multiple states. RTOs typically perform the same functions as ISOs, but cover a larger geographic area.
<b>ITC</b>	An investment tax credit (ITC) helps defray upfront capital costs by providing a federal tax credit for investments in the development of a qualified project.
<b>kWh</b>	The kilowatt-hour (kWh) is a derived unit of energy equal to 3.6 megajoules. If the energy is being transmitted or used at a constant rate (power) over a period of time, the total energy in kilowatt-hours is the power in kilowatts multiplied by the time in hours.
<b>Manmade CO<sub>2</sub></b>	See anthropogenic CO <sub>2</sub> definition.
<b>Merchant plants</b>	Merchant plants are independent commercial power plants competing to sell power.
<b>MLP</b>	In the U.S., a master limited partnership (MLP) is a limited business partnership that is publicly traded on an exchange qualifying under Section 7704 of the Internal Revenue Code. It combines the tax benefits of a limited partnership with the liquidity and ability to raise capital of publicly-traded securities.
<b>MT</b>	The abbreviation for metric ton.
<b>MWh</b>	The abbreviation for a megawatt hour, or the equivalent of 1,000 kilowatt hours.
<b>Natural CO<sub>2</sub></b>	Naturally occurring carbon dioxide is CO <sub>2</sub> that is released or obtained from geologic sources, as distinct from CO <sub>2</sub> that is produced or released through human activity.
<b>NGCC</b>	Natural gas combined cycle is an advanced and efficient power generation technology which utilizes the heat produced from combustion of natural gas in a gas turbine to generate additional electricity with a steam turbine.

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<b>NYISO</b>	The abbreviation for New York Independent System Operator, a regional transmission organization.
<b>PAB</b>	Private activity bonds (PABs) are a type of revenue bond that allows tax-exempt debt to be issued in order to fund the construction of a qualified project.
<b>PTC</b>	The Production Tax Credit (PTC) is a federal incentive that provides financial support for the development of renewable energy facilities.
<b>PUC/PSC</b>	A public utilities commission (PUC) or public service commission (PSC) is a governing body that regulates the rates and services of a public utility at the state level.
<b>RDD&amp;D</b>	The abbreviation for research, development, demonstration & deployment.
<b>Regulated market</b>	A regulated market is a market where the government controls supply and demand, for example by determining who is allowed to enter the market and/or what prices may be charged. It is common for some markets to be regulated under the claim that they are natural monopolies – such as telecommunications, water, gas or electricity supply.
<b>RPS</b>	The abbreviation for renewable portfolio standard.
<b>RTOs</b>	A regional transmission organization (RTO) in the U.S. is an organization that is responsible for managing the electric grid and the dispatch of generation over large interstate areas and for overseeing the operation of wholesale electricity markets. RTOs are regulated by the FERC.
<b>Section 45Q Credit for Carbon Dioxide Sequestration</b>	<a href="#">26 USC §45Q</a> provides a federal tax credit of \$10 per metric ton of carbon dioxide stored through enhanced oil recovery or \$20 per ton stored through other geologic storage. Section 45Q was enacted by § 115 of the Energy Improvement and Extension Act of 2008.
<b>SPP</b>	The abbreviation for Southwest Power Pool, a regional transmission organization serving the central United States.
<b>Wholesale market</b>	A term referring to the purchase and sale of energy products – primarily electricity, but also steam and natural gas – in the wholesale market by energy producers and energy retailers. Other participants in the wholesale energy market include financial intermediaries, energy traders and large consumers. Wholesale energy markets developed following the restructuring of utilities and electricity markets around the world in the 1990s. There are independent system operators that coordinate, control and monitor the operation of the energy market.
<b>ZECs</b>	The abbreviation for zero-emissions credits.

## Appendix

### Details on How Power Plants are Evaluated in Each of Four Policy Arenas

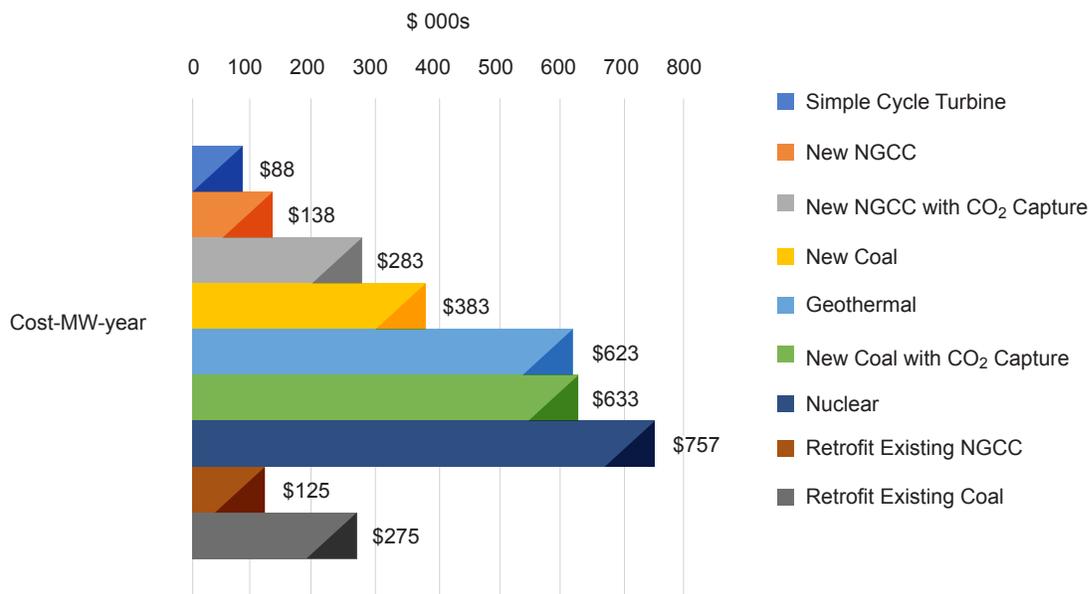
As summarized in Box 2 of the main text, the overarching issue for a dispatchable low-carbon power project is that no comprehensive approach exists to minimizing the cost of achieving high performance in all four arenas.

1. **Capacity: System Operator Imposes Requirement on a Single Utility, Overseen by Regulator.** As discussed in Box 2, the main arena in which a power plant with carbon capture would expect to compete is in providing dispatchable capacity to a load-serving utility on a cost-minimizing basis. The requirements to maintain sufficient capacity (resource adequacy) are usually imposed by either the ISO or a state upon an individual utility. For instance, a utility with a 1,000 MW maximum load that often, but not always, has 300-400 MW of renewable resources available, may be ordered to keep ~1,000 MW of gas power plants available in case all the renewable generation goes off line at the same time.

Figure 9 below shows how the decision to buy new generating units looks to the regulator, based on the cost to keep the unit on hand, per MW per year (figures in thousands of dollars). The costs include fixed operating and maintenance plus an annual capital charge of 12 percent of original plant cost. (Note that the chart is simplified to focus on capacity cost, thus excluding fuel cost, if and when the plant is actually turned on and used. Those costs are dealt with under “dispatch” below.)

- a. For relatively infrequently used peaking units, the utility and its regulator will gravitate towards the lowest-cost equipment (e.g., simple cycle gas turbines at \$88/MW-yr). For higher usage, the regulator will probably direct the utility to use the slightly more expensive, but more fuel-efficient NGCC. Other options will not be selected.
- a. Furthermore, the regulator is unlikely to consider retrofitting an existing fossil plant with carbon capture (see far right bars on graph). If more capacity is the

Figure 9: Decision to Acquire Capacity



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Coal Plant Selected to Run Based on 50¢/MWh Lower Operating Cost		
	Coal Plant	Gas Plant
Fuel Cost \$ per Unit	\$2.00	\$3.00
Units of Fuel per MWh	X 10	X 7
Fuel Cost \$ per MWh	\$20.00	\$21.00
Other Variable Costs \$ per MWh	\$ 3.00	\$2.50
Total Cost Bid per MWh	\$23.00—selected	\$23.50—not used
Pounds CO <sub>2</sub> emitted per MWh	2,050	826

only objective considered, such a retrofit provides zero benefit because the existing power plant is already built, and the extra electric power needed to run the capture equipment may reduce power output.

2. **Dispatch: System Operator Runs Pooled Generation.** The generators that will run the most have the lowest marginal cost in a given hour. If a decision has been made to build a plant, either pursuant to the need for reliable capacity (as described above) or pursuant to the need to meet a RPS (described below), then the system operator just runs plants according to a merit order of dispatch, meaning plants are told to run beginning with the cheapest generator first (in terms of variable cost of generation per MWh) and going to more expensive plants as needed<sup>27</sup>. The implication for a carbon capture plant is mixed. Effectively, if CO<sub>2</sub> captured can be sold at reasonable prices for EOR, that revenue will roughly cover the added operational costs, leaving it with similar net costs to the original unit. The principal challenge for the capture plant arises from the uncertainty, as underscored below, regarding how much it will run in a competitive market, calling into

question future revenue from both the sale of power and CO<sub>2</sub>.

- a. In general, subject to system reliability needs, an ISO will first call on plants that have the lowest marginal cost of operation. Hence hydro, nuclear, wind, solar and other lower-variable-cost units will run first.
- b. Next the ISO will dispatch generators with the cheapest variable operating and fuel costs per MWh<sup>28</sup>. The chart below shows a specific example of competition between a coal plant and a gas plant in the hourly dispatch market.<sup>29</sup> No party at the ISO is authorized to choose the more expensive bid from the gas plant, even if, for only an extra 50¢ per MWh, 0.6 tons of CO<sub>2</sub> emissions could be avoided at a cost of only 82¢ per ton.
- c. On the other hand, within each fuel type (e.g., natural gas-fired plants), the ISO will generally seek to run more energy-efficient units before less efficient units—an environmental benefit achieved by coincidence, not by policy design per se. That is, the ISO will run an efficient

27 In this summary, we are ignoring the fact that units may bid prices to run that are significantly more than variable costs, as in a system like ERCOT. We are summarizing a system more like CAISO's in which units with dedicated capacity specify prices at which their units will run, including at various operating rates less than 100 percent.

28 The ISO will not consider carbon impacts; although if carbon limits are in place, the cost of meeting them will be reflecting in the plant costs.

29 This is a simplified example to illustrate the point. There are also start-up and shut-down considerations involved that make the analysis more complex, but the complexity obscures the fundamental point of the motivation of the ISO in its operations. The example is based on the real world, with a pulverized coal plant of a Heat Rate of 10,000 Btu per KWh and coal price of \$2/million BTU; and a natural gas combined cycle (NGCC) power plant with a Heat Rate of 7,000 Btu per KWh and gas price of \$3/million BTU.

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NGCC plant before it runs a simple cycle gas combustion turbine (CT). The NGCC uses approximately two-thirds the fuel of the CT, so running the NGCC rather than the CT results in a one-third reduction in emissions.

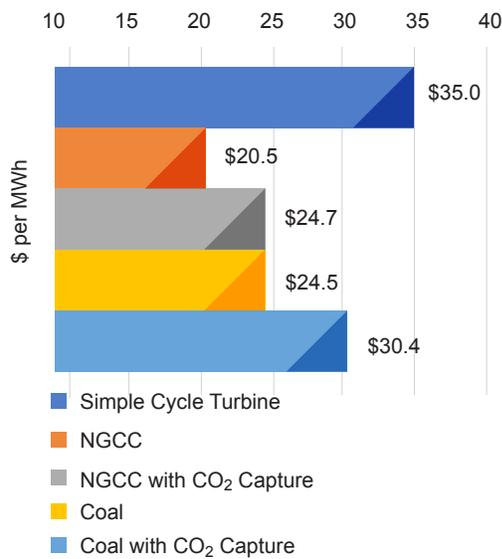
Figures 10 and 11 below include many more possible options, showing how the merit order of dispatch among the fossil fuel plants can change depending on the relative prices of gas, coal, and oil<sup>30</sup>, and illustrating the uncertainty about operating rates for plants that have invested in carbon capture equipment.

- In the first bar chart, with prices of \$2.50/MMBtu gas, \$2/MMBtu coal<sup>31</sup>, and low oil prices (\$30/bbl), conventional NGCC would run most

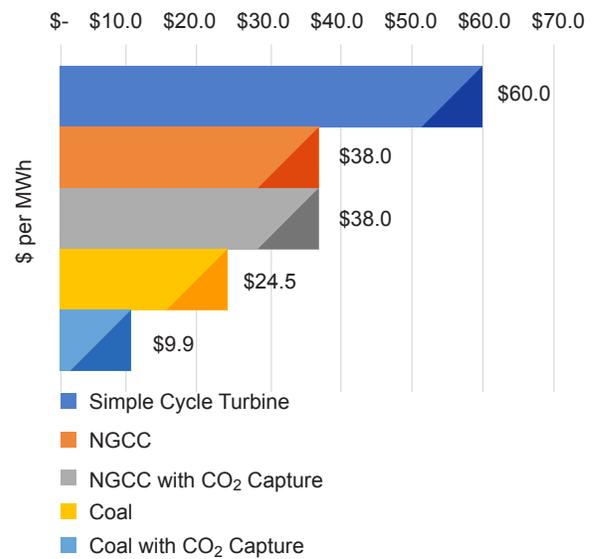
(orange bar), then coal without capture (yellow bar), followed by NGCC with capture (grey bar), coal with capture (dark blue bar), and a simple cycle turbine.

- With higher gas and oil prices (\$5 gas, \$2 coal, and \$75 oil) the situation changes dramatically: first, coal's fuel cost makes coal plants relatively attractive; and second, coal with carbon capture receives very substantial CO<sub>2</sub> sales revenues.<sup>32</sup> Thus coal with capture becomes the first plant to run, followed by conventional coal & NGCC with capture, NGCC without capture, and simple cycle turbine again being last.
- The point is not that any forecast is right or wrong, but that once a plant is built, it is impossible to know whether or how often the

**Figure 10: Dispatch/Generation Cost  
\$2.50gas/\$2 coal/\$30 oil**



**Figure 11: Dispatch/Generation Cost  
\$5 gas/\$2 coal/\$75 oil**



30 Coal prices have remained relatively steady for several years, averaging in the \$2.00 per MMBtu range, primarily varying because of distance required for rail hauls. Gas has varied dramatically from \$12 to \$2 in the last decade, with U.S. EIA forecasting a rise to the \$5/MMBtu range within the decade. Oil prices are similarly volatile and are relevant because oil companies engaging in CO<sub>2</sub>-EOR typically seek to link CO<sub>2</sub> purchase contracts directly to the price of the oil they help to produce.

31 These coal and gas prices are similar to typical U.S. prices over the past couple of years; although recently gas prices have been a bit higher and coal prices a bit lower.

32 Prices of CO<sub>2</sub> used for enhanced oil recovery tend to rise with oil prices.

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	Solar Installation that Displaces NGCC during the Day	Wind Farm that Displaces CT during Evening and Night
Renewable Power Purchase Agreement Bid to Utility	\$50/MWh	\$55/MWh
Less Credit for Savings from Displaced Fossil Plant	(\$24/MWh)	(\$40/MWh)
Net System Cost of Displacing Fossil	\$26/MWh	\$15/MWh
Tons CO <sub>2</sub> Avoided	0.41	0.59
\$ Cost per Avoided Ton	\$63	\$25

plant will run on any given day, if it is dispatched simply on its net variable cost of operation. If a plant needs to enter into contracts that depend on a particular annual operating rate, such as a contract to sell CO<sub>2</sub> to an oil company, this can create significant financial uncertainty.

3. **Renewables: State Law Imposes a Technology Requirement on Each Utility, Overseen by State Regulator.** Typically, RPSs are legislated, created by voter initiative, or mandated under general authority by the governor or PUC in a single state. Thus, a multistate, ISO-governed grid, can have a host of differing state policies. A power plant with carbon capture does not qualify under most state RPS policies.
  - a. Under an RPS mandate, an individual utility must simply try to acquire the cheapest qualifying renewable electricity it can, with the regulator carefully monitoring costs and types of contracts executed. However, broader considerations such as general impacts on system reliability, how likely additional variable renewable generation is to be curtailed, or the cost of avoided CO<sub>2</sub> are not explicitly considered.
  - b. Since an individual utility only considers the price of the MWh of renewable electricity purchased—not the ultimate economic or environmental value of the renewable energy on the grid, it will not optimize energy cost and carbon reductions. The utility wants inexpensive

renewable power to meet its RPS mandate and avoid fines—not the optimal generation option to minimize electric rates and carbon emissions.

The following simplified example illustrates the concern. The utility and its regulator are likely to choose a solar installation at \$50/MWh as lower cost than a wind farm at \$55/MWh. However, in practice, the wind farm in question is likely to displace a considerably more expensive gas plant and would have offered a better net deal to consumers. The net cost (renewable cost less gas plant cost saved) is higher for the solar option (\$26 vs. \$15 per MWh) than for this wind option. The solar option also has a smaller impact on carbon reductions (0.41 tons vs. 0.59 tons) and a higher cost per avoided ton of CO<sub>2</sub> (\$63 vs. \$25/ton) than this wind option.

4. **Valuing Carbon Reductions: State Environmental Agency Sets Emission Limits on Generators.** In cases where states have opted to regulate carbon emissions, if generators cannot meet the generally declining emissions limits set by regulators, generators may need to buy carbon emission allowances. However, the more aggressive the RPS requirements (#3), the lower the likely prices for carbon in an allowance market. There are many ways to reduce carbon emissions in addition to installing solar PV or wind turbines, and many of those solutions may be considerably cheaper on

a cost per ton basis.<sup>33</sup> However, if the state or regional need for emissions reductions is largely achieved by separately mandated compliance with RPS standards, then the market for additional action outside of RPS compliance will be small. This means that the price of traded carbon allowances will be very low, thus providing little incentive or commercial basis for pursuing dispatchable low-carbon power generation options, whether solar thermal with storage or carbon capture. Non-RPS options may reduce emissions more cheaply, but the cost comparison is irrelevant to a utility or its regulator.

This subsection uses actual policies in California as a real-world example of existing policies and how they would affect a possible natural gas power plant retrofit to add carbon capture. Since the situation in each ISO is quite different, California is not necessarily representative of the entire United States. It just happens to be a well-documented example.

Consider a hypothetical proposal to add carbon capture to a NGCC plant near Bakersfield, California. This is an area of the state with ample geologic potential to store CO<sub>2</sub> safely at large scale, while producing oil through EOR, thus cost-effectively providing an additional revenue stream and achieving substantial net lifecycle carbon emissions reductions in the process. How is such a holistic proposal with multiple system benefits likely to fare in multiple regulatory processes? The table below summarizes the issues, with details below.

### Specific Example of Fossil Plants with Carbon Capture in California: Left by the Wayside

The preceding section gave hypothetical examples of how the four different policy arenas may overlap, conflict, or lead to sub-optimal results.

	Issue	Result
<b>Capacity</b>	Adding CO <sub>2</sub> retrofit does not increase capacity, and decreases it somewhat because of carbon capture's parasitic loads.	Retrofit would be non-germane to resource adequacy proceeding at the CPUC.
<b>Dispatch</b>	Higher operating costs; No proven offsetting CO <sub>2</sub> sales revenues (no current market for CO <sub>2</sub> for EOR in CA); No allowances earned (CA has no approved protocol for CO <sub>2</sub> -EOR related storage).	Plant after retrofit is less likely to be utilized than before retrofit. Unlikely to run under CAISO procedures.
<b>RPS</b>	Fossil plant with CCS not eligible under RPS (not even on a pro-rata for 90 percent capture).	CPUC would not approve CCS procurement to meet RPS.
<b>Cap and Trade Policy</b>	No current protocol for treating geologically stored CO <sub>2</sub> as "not emitted." Even if protocol were created, cap-and-trade prices have been at legislated floor level, equating to ~\$5/MWh incentive.	No compliance benefit under existing regulations. Even with a protocol in place, cap-and-trade allowance prices are too low to create economic motivation to add capture equipment.

33 For a good, short explanation see "Time to Unleash the Carbon Market?" posted on Haas (Berkeley Business School) website. Accessed 5/6/2017. <https://energyathaas.wordpress.com/2016/06/20/time-to-unleash-the-carbon-market/>

- 1. Reliability/Capacity—unlikely.** Typically, California utilities go through a periodic review of their capacity resource adequacy overseen by the CPUC. The CPUC will typically direct or authorize a utility to enter into long-term bilateral contracts with natural gas power plants if the CPUC, with an eye on the rules of CAISO, feels that the utility has insufficient reserve margins.<sup>34</sup> In order to add the carbon capture equipment, the plant owner would need to reopen its power purchase agreement (PPA) with a regulated California IOU (i.e., for the existing plant without capture). It would then need to get the CPUC to approve the addition of ~\$125,000 per MW-year of extra fixed payments to pay for the new equipment that will reduce CO<sub>2</sub> emissions by 90 percent. On a typical ~630 MW NGCC plant, that would be an extra \$79 million per year. But the CPUC has no mandate, per se, to reduce CO<sub>2</sub> emissions from dispatchable fossil fuel plants. So, the CPUC is unlikely to approve the extra \$79 million a year toward an objective that it is not explicitly required to achieve through a capacity procurement docket.
- 2. Hourly Dispatch—possible.** Before adding carbon capture to the power plant, the owner needs to consider how it will fare in the hourly spot market once built. Adding carbon capture will effectively increase variable generation costs per MWh by ~\$5, which may be offset by possible sales revenues (also roughly ~\$5) earned by selling captured CO<sub>2</sub> to EOR producers or by possible benefits of earning CO<sub>2</sub> allowances (more on this below).<sup>35</sup> Even though the plant owner believes it may be relatively competitive in the hourly market (if CO<sub>2</sub> sales outweigh higher generation costs), the plant owner certainly has no confidence that the unit will ever run in preference to NGCC plants without carbon capture, unless it can underbid the higher-emitting plants. A key barrier in that regard is uncertainty about oil prices—impacting revenues from CO<sub>2</sub> sales and, therefore, the plant's net variable cost of generation—which undermines the carbon capture plant's ability to execute critical contracts to sell CO<sub>2</sub>.
- 3. Renewable Portfolio Standards—does not qualify.** Despite its ability to accomplish cost-competitive carbon emissions reductions, a power plant with carbon capture does not qualify as a renewable energy facility under California law. If such a plant ran at a relatively high operating rate—displacing much higher-emitting natural gas plants—it would be reducing emissions at roughly \$40/ton. This seems attractive, since the most optimistic cost of CO<sub>2</sub> emissions reductions from California is about \$50-60 per ton for utility-scale solar, about \$60 per ton for wind, and over \$1,000 per ton for rooftop solar. However, California's RPS is not a carbon reduction program. If the load-serving utility gets near zero-carbon energy from the NGCC after the plant owner adds capture equipment—together with all the attendant reliability and other system benefits—that will not help the utility to meet its legal compliance obligation to reach 33 percent renewables by 2020 or 50 percent by 2030.
- 4. CO<sub>2</sub> Reduction—insufficient incentive.** California's cap-and-trade system requires fossil generators to buy CO<sub>2</sub> allowances at periodic state-conducted auctions for every ton of CO<sub>2</sub> emitted by their operations. In theory, after installing a carbon capture

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34 A reserve margin means the extra amount of generation capacity that a utility can command to run, either by means of ownership or contract, above and beyond the utility's peak load at a particular time. So, if a utility has a 1,000 MW peak load (say mid-summer on a hot day), the regulator may require a 10 percent safety factor (i.e. the reserve margin) or 100MW. If the total generation capacity the utility controls is only 950 MW it cannot show resource adequacy and needs to contract for another 150MW. For specifics, see <https://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx>

35 For this particular example, depending on ultimate regulations to be written in California, such a plant with carbon capture equipment might be able to avoid the need to purchase CO<sub>2</sub> allowances for ~0.4 short tons of CO<sub>2</sub> per MWh, with allowance prices of ~\$11/short-ton, thus saving an extra \$4.40 and possibly tipping the balance toward winning hourly auctions.

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system, the NGCC plant owner's need for such allowances should drop by 90 percent. If, hypothetically, CO<sub>2</sub> allowance prices in the cap-and-trade market were comparable to the implicit ~\$100/ton cost of CO<sub>2</sub> abatement via utility-scale solar PV contracts in the RPS market, the financial situation for the NGCC plant with capture would be highly favorable. There would either be a big boost in plant revenues (if excess allowances were sold) or the plant's competitiveness (because its NGCC competitors without capture would have to buy allowances that the capture plant does not). However, with allowances selling in the \$13/ton range (the legal floor of the California CO<sub>2</sub> allowance trading program administered by the California Air Resources Board), this allowance value provides very little incentive. There is no low-carbon and zero-carbon combined resource procurement system that forces all low-emitting resources to compete head-to-head based on the actual cost of carbon reductions. Hence, a ton of captured CO<sub>2</sub> would sell cheaply at prices determined in the allowance market, and a ton of avoided CO<sub>2</sub> is not explicitly priced<sup>36</sup> in the RPS market.

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36 In some cases, renewable resources are acquired by mandate without any particular regard to or public disclosure of the actual cost per ton of CO<sub>2</sub> avoided. The actual commercial terms of utility scale solar PPAs are treated as confidential, therefore making it impossible to calculate the historical avoided cost of CO<sub>2</sub> in such contracts. In contracts examined for PV facilities coming on line in the 2015 timeframe, were in the range of \$250 per MWh energy cost (taking account of time-of-day premiums built into such contracts) and ~\$600 per avoided ton of CO<sub>2</sub>. Taking a different form of mandate that is not explicitly part of the RPS framework, California IOUs were required to sign "Net Energy Metering Contracts" up to certain maximum installed capacity levels. For example, the particular rate under which San Diego Gas & Electric Company is currently required to purchase solar energy from customers with qualifying rooftop solar installations via "net energy metering" (Schedule DR-SES effective 3/1/2017) is currently approximately 51 cents per kWh, or \$510 per MWh, which equates to approximately \$1,275 per avoided ton of CO<sub>2</sub> given avoided CO<sub>2</sub> emissions of displaced natural gas generation at 0.4 tons CO<sub>2</sub> per MWh ( $\$510/\text{MWh} \div 0.4 \text{ tons/MWh} = \$1,275/\text{ton}$ ).