Carbon capture, utilization and storage technologies make it possible to prevent up to 90% of a power plant's carbon dioxide emissions from entering the atmosphere. Utilities with carbon dioxide off-take potential can leverage these technologies to create a new revenue stream that enhances the economic performance of their existing generation assets, while helping to meet clean energy mandates.
Faced with renewable energy requirements and CO₂ reduction mandates, utilities with aging coal-fired power plants have had few choices other than to plan their plants’ retirements. Some — especially smaller operators — may now have another alternative.

Carbon capture technologies make it possible to remove CO₂ from plant emissions. Power plants retrofitted with these systems have the potential to meet regional clean energy mandates, continue supporting jobs in their communities and extend their operating lives by a decade or more.

When installing carbon capture systems, utilities must also consider how they will dispose of and benefit from the large amounts of captured CO₂. Currently there are two predominant options.

One is to sell the CO₂ to the oil industry for Enhanced Oil Recovery (EOR). Oil companies, which are typically willing to pay for CO₂, currently rely on natural CO₂ sources found underground. Captured CO₂ can be used to replace and supplement these resources. The potential supply of CO₂, however, greatly exceeds likely demand from EOR utilization. This option is also highly dependent on the proximity of the plant to CO₂ pipelines with sufficient capacity to transport the captured gas.

A second option is geological sequestration, which involves injecting the CO₂ into very large underground geological formations for storage. That essentially means disposing of CO₂ as a waste product, which requires costly infrastructure and permitting, along with overcoming likely public opposition. This option is also highly location-dependent, requiring a facility to be near the required geologic formation to remain cost feasible.

Can installation of a carbon capture system make good economic sense? That is the question a growing number of utilities and power producers are now asking, and a number of commercial-scale projects now in development are expected to provide the answer.

**DOE FUNDING INITIATIVE**

To jump-start the commercialization of carbon capture technologies, the U.S. Department of Energy (DOE) awarded $110 million in federal funding for research and development projects in September 2019. Approximately half of these funds are designated for front-end engineering design studies for commercial-scale carbon capture systems on nine coal and combined-cycle gas turbine (CCGT) technology power plants.

The funded work includes a project to remove post-combustion CO₂ from the flue gas from a power plant operated by Minnkota Power Cooperative of Grand Forks, North Dakota. The project is expected to contribute to yield insights that support the business case for similar projects, as well as information that may result in lower costs and improved capture efficiency. Because this plant is located next to the mine that provides its coal, this information can be especially helpful to communities where coal production and power plants are central to the local economy.

The other half of the recently awarded DOE funding has been earmarked for projects designed to accelerate the deployment of existing carbon capture technologies and the development and refinement of new ones, as well as the assessment and verification of commercial-scale carbon storage. By deploying a variety of large-scale carbon capture, utilization and storage pilot and demonstration projects, the DOE expects to build the knowledge base needed to test and further prove these technologies at the commercial scale.

**45Q TAX CREDITS**

The DOE funding is limited to front-end engineering costs. As these and other carbon capture projects move forward to implementation, investors have the opportunity to recoup additional costs through a performance-based federal tax credit program.

Section 45Q of the U.S. tax code was originally enacted by Congress a decade ago to incentivize the construction and deployment of carbon capture and sequestration
projects. Targeted primarily to coal-fired and combined-cycle gas turbine power plants, the Section 45Q tax credit program originally imposed a cap of 75 million metric tons on the amount of CO₂ that would qualify for the credits, which were valued at $10 per metric ton of CO₂ used for EOR and $20 per metric ton for CO₂ sequestered in geologic storage.

To help bridge the cost gaps on early projects and attract additional investment, Congress lowered the threshold for 45Q eligibility in 2018, while also increasing the value of the credits awarded. Today, utilities and their investors are eligible for a tax credits of up to $35 per metric ton for EOR and $50 per metric ton for geologic storage (sequestration). The cap of 75 million metric tons on tax credits has also been lifted. Changes to Section 45Q also expand eligibility to a broader array of industrial applications that emit CO₂ into the atmosphere. The credits are currently available on CO₂ captured and stored for 12 years after the project is placed in service.

The Treasury Department’s proposed 45Q rule lays out the requirements to qualify. To receive the tax credit for geologic storage, a utility must meet the Environmental Protection Agency’s (EPA) sequestration reporting rules (40 CFR Part 98, Subpart RR), which include a Monitoring, Reporting and Verification Plan that documents the amount of carbon injected and stored.

Those seeking credits for enhanced oil recovery (EOR) have the choice of satisfying either EPA regulations governing geological CO₂ sequestration or the CO₂ storage guidelines developed by the International Organization for Standardization (ISO) and the American National Standards Institute (ANSI) (CSA/ANSI ISO 27916:19).

The proposed rules also outline that the Internal Revenue Service (IRS) can recapture the credit if the carbon is intentionally leaked or withdrawn from storage. Once the carbon capture system begins commercial operation, the IRS can reclaim the credit up to five years after the date the tax credit is last claimed or the date when monitoring ends.

Together, these 45Q changes make implementation of carbon capture technology a more economically attractive proposition for utilities, while not limiting the industry with a tax credit cap. There is, however, a catch: To be eligible, construction of these projects must commence by Jan. 1, 2024.

CARBON CAPTURE AND STORAGE TECHNOLOGIES

Utilities and others contemplating post-combustion carbon capture projects currently have two basic technologies to choose from.

Amine-based conventional absorber process — Originally developed in the 1930s, amine technology has been used for decades in a variety of applications. Only in the past decade, as climate change discussions have taken center stage, has it been repurposed as a post-combustion carbon capture technology. Since then, amine processes have become the primary method used by power plants, having been proven capable of removing as much as 90% of CO₂ from emissions.

Amines are chemical solvents that undergo a reversible reaction with CO₂ and other acid gases. When exhaust gas containing CO₂ comes in contact with a liquid amine solution, the CO₂ chemically binds to the amine molecules and is removed from the gas stream. This amine solution can then be pumped into a separate column where heat is used to reverse the process, stripping the high-quality CO₂ from the amine. The CO₂ can then be compressed for use for EOR or injected into a suitable geological formation for storage.

Most of the DOE-funded carbon capture projects to date employ amine-based processes. The differences between individual processes are primarily in their “secret sauce” — the proprietary chemicals used to increase the efficiency of the amine solution. Researchers continue to seek solutions that reduce the amount of auxiliary power amine-based systems need to capture and recover carbon, as well as the volume of steam and heat these processes consume during regeneration. Efforts are also underway to minimize their relatively high capital, operating and installation costs.
Membrane technology — A smaller number of projects rely on membrane technology to capture carbon from exhaust gases. With it, exhaust gases are passed through a novel packaged membrane system, which captures the carbon. Compared to amine-based systems, membrane technology is simple, compact and relatively low in cost. It is also less efficient, recovering about half of the CO₂ that passes through it. Research efforts are making headway in increasing efficiency, with some solutions on a path toward 80% CO₂ capture efficiency. CO₂ recovery rates will need to improve to these higher rates to make these solutions cost competitive in the long term.

THE INTEGRATION PROCESS
Operators of power plants will need to determine not only the best carbon capture solutions for their operation, but also the best way to integrate them into their existing systems. Both amine-based and membrane technologies have the potential to impact power generation operations and efficiency. An experienced integrator that understands power plant operations and can model carbon capture process integration is essential to minimizing potential power production losses and identifying opportunities for efficiency and process optimization.

OPPORTUNITIES AND CHALLENGES AHEAD
Before carbon capture, storage and utilization systems can be fully commercialized, additional challenges must be addressed.

Reduced capacity factors — The economic feasibility of a carbon capture facility depends on a coal-fired plant’s ability to produce enough flue gas to capture the CO₂ and generate an adequate revenue stream. This poses special challenges to coal plants in regions with high renewable penetration and which face reduced run time as a result. Since the early 2000s, the capacity factor of many coal plants has dropped significantly, reducing the economic benefit of the capital investment by over half in many cases.

The number of coal-fired power plants with adequate run time, therefore, is limited. Even in states like Texas, where these plants have relatively high capacity factors, the future addition of combined-cycle plants and the ever-increasing amount of renewable energy being placed in to service could put coal-fired plant dispatch at risk.

Sequestration vs. EOR concerns — Given the increase in 45Q tax credits, power plants appear initially to have the most revenue to gain by sequestering recovered CO₂ in geological formations. But that may not be the case, long term. The DOE has identified this as an issue to be explored and has earmarked additional funding opportunities for R&D to explore this question.

Power plants that sell captured CO₂ to an EOR off-taker have the potential to supplement their operations with 45Q revenue. Plants located near oil fields are likely in a better position to market their captured carbon for EOR use than those that must transport it hundreds of miles or more for sale.

Competitive markets — Independent System Operators (ISOs) recognize the potential impact that CO₂ reduction strategies can have on the competitive markets the ISOs design and operate. Those markets optimally operate with minimal out-of-market influences, such as subsidies or carbon taxes. ISOs, however, must also create markets that properly reflect the economic impact of state and federal regulations, even without the benefit of any oversight of those regulations.

At the time of publication, ISO efforts focused on exploring mechanisms that recognize the economic consequences (both positive and negative) of items such as a carbon tax. They are also incorporating these relatively new operating costs and benefits (compared to traditional fuel and variable operating costs) into their price forming mechanisms to facilitate competitive procurement of energy and capacity, while compensating generators in ways that incentivize their availability and efficiency.

Regulatory support — In states with regulatory support for carbon capture, utilization and sequestration, the clock is ticking. If the necessary permitting at nearby oil fields is not already in place — and decisions on CO₂ sequestration versus sale are not made — quick action will be needed to
meet the Jan. 1, 2024, construction start date needed for tax credit eligibility.

Looking ahead, state regulators would be well-advised to consider incorporating carbon capture strategies in their state's asset mix and comprehensive renewable energy plans. One thing is for certain: The 45Q tax credit will not last forever. It is a temporary revenue incentive designed to facilitate investment in carbon capture technologies.

Despite its challenges, carbon capture has substantial utility, regulatory and academic support and will likely continue to be incentivized through federal legislation, DOE support and state mandates. For utilities and power producers with carbon dioxide off-take potential, it offers an economically viable way to balance aggressive environmental mandates with reliable power generation.

**BIOGRAPHY**

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