ECONOMICS OF CO_2 RECOVERY IN GAS TREATMENT FACILITIES

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ABSTRACT

Carbon dioxide (CO_2) continues to gain notoriety as a greenhouse gas when emitted to the atmosphere. Multiple government incentives in the United States, at the state and federal level, put a value on CO_2 emissions and try to make it economical for private industry to capture their CO_2 emissions for further use or storage in underground reservoirs. These incentives traditionally target large CO_2 emitters such as coal-fired power plants, but recent changes to the laws provide an opportunity for smaller-scale CO_2 emitters such as gas treatment facilities, ethanol producers, and other industries to capture their CO_2 and potentially realize a profit.

This paper reviews the current U.S. regulatory environment for CO_2 emissions and examines the economic factors to consider when deciding whether it is economically justifiable to capture CO_2 emissions. The paper discusses the impact of the feed CO_2 purity, the required CO_2 product purity, and the required CO_2 delivery pressure on the economics of the capture facility. The paper will also present what opportunities exist for CO_2 captured from industrial producers.

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Introduction

Reducing carbon dioxide (CO_2) emissions from industrial producers has long been a goal of many developed nations in the world. In the United States, federal and state regulation of CO_2 emissions has been inconsistent and has changed as political parties have lost and gained power. The U.S. federal government has a tax credit program, known as Section 45Q, which grants a company federal tax credits if the company reduces CO_2 emissions by capturing and storing the CO_2 they would normally emit to atmosphere. Recently, the U.S. federal government amended this law to decrease the CO_2 emission threshold for which a facility can qualify for tax credits. The amended law opened up the federal tax credit to smaller CO_2 producers, such as gas treatment plants, ethanol producers, fertilizer plants, and similar sources that would normally emit CO_2 produced from their process to atmosphere. This paper reviews the current regulatory scheme and analyzes the economics for a small producer to capture CO_2 emitted from their process, inject the CO_2 into a local underground formation, and obtain federal tax credits.

Regulatory Environment and Credit Schemes for CO_2 at the Federal Level

The economics of capturing carbon emissions from gas treatment facilities can be materially improved if the carbon capture project can qualify for federal income tax credits under Section 45Q of the IRS Code. This portion of the paper introduces the Section 45Q tax credit for capturing CO_2 from industrial facilities such as gas plants, and optional methods for storing the captured carbon emissions including underground injection in various classifications of injection wells. This paper also addresses which company would claim the 45Q tax credit, the number of years the credit can be claimed, the deadline for beginning construction of carbon capture plants, and considers a likely corporate structure to allow the tax credits to be realized or monetized by a tax equity investor. The value of the tax credit is up to $50 per metric ton of captured CO_2 or more in some cases.

Introduction to the Section 45Q Tax Credit

An indirect price on carbon has been established in the form of a US federal income tax credit that incentivizes the capture and storage or utilization of CO_2 emissions. A 2018 Congressional change increased the number and types of industrial CO_2 emissions that qualify, including natural gas treating and processing, ethanol, cement, chemical, steel, and other industrial plants. Just as important, the value of the incentive for capturing and storing CO_2 emissions was significantly increased. This tax law is known as Section 45Q, named after 26 U.S. Code § 45Q.

While Section 45Q was originally adopted over 10 years ago, very few projects qualified under the old system because:

- The entire program sunset after tax credits were claimed for a nationwide aggregate of 75 million metric tons were captured and sequestered
- The minimum sized project to qualify for 45Q credits was at least 500,000 metric tons per year (equivalent to about 26,500 thousand cubic feet per day (mcf/d) of CO_2)
- The value of the credits (approximately US $10-$20 per metric ton) was considered by many to be too low to provide sufficient incentive to deploy carbon capture on a large scale.

Under the revised 45Q law adopted February 9, 2018, many hurdles imposed by the original law were addressed. For example,

- The nationwide aggregate limitation was eliminated for new projects.
- The minimum sized project to qualify for 45Q credits was reduced to 100,000 metric tons per year (equivalent to about 5,300 mcf/d of CO_2 stored underground) for industrial facilities, but not for power plants, which remained at the previous threshold.
- Approved storage methods are not limited to *underground* storage, but now include permanently fixing the gas in a commercial product. This is defined in 45Q as "utilization" of the CO_2, and the minimum sized "utilization" project to qualify for 45Q credits must capture 25,000 metric tons per year.
- Section 45Q was expanded to include capture of carbon monoxide (CO), not just CO_2. This means, for example, that 45Q credits are available when CO from a syngas plant is captured and the CO is either injected underground or "utilized" as described in the preceding sentence. Accordingly, any instance where "CO_2" is discussed in this section of this paper, "CO" can be used in its place.

Sources that Qualify for the 45Q Tax Credit

Many facilities, or sources of carbon emissions, qualify for the 45Q tax credit. According to IRS rules, the CO_2 must be captured from:

- a fuel combustion source,
- a manufacturing process, or
- a fugitive CO_2 emission source.

For example, the following facilities will qualify for 45Q credits, assuming the minimum amount of annual CO_2 emissions are captured from that facility and are stored or utilized:

- power plants
- ethanol plants
- cement plants
- fertilizer plants
- methanol plants
- steel plants
- chemicals plants
- industrial gas facilities
- refineries
- natural gas processing or treating plants
- gas-to-liquids plants
- liquefied natural gas plants
- direct air capture facilities

For power plants, at least 500,000 metric tons of CO_2 per year must be captured to qualify for the 45Q credit. Other than power plants, all other facilities only have to capture 100,000 metric tons per year of CO_2, assuming that carbon emission is injected underground. A request has been submitted to the IRS to define "power plant" narrowly, as a power plant that sells at least half of its power on the grid. If that request is granted, distributed power plants and microgrids that use at least half of their power on-site would be subject to the 100,000 metric ton of CO_2 per year requirement.

Storage Requirements and Options Under 45Q

Under 45Q, there are two methods by which CO_2 may be stored and qualify for a 45Q credit:

1. Underground injection, and
2. Utilization

Underground Injection

The 45Q tax credit becomes available if the captured CO_2 is injected underground and permanently sequestered or stored underground in what the law terms "secure geologic storage". Approved locations for secure geologic storage are as follows:

- oil and gas reservoirs
- deep saline formations
- unminable coal seams

As a result, enhanced oil recovery (EOR) and enhanced gas recovery (EGR) are approved methods that qualify as "secure geologic storage" of CO_2 under 45Q.

The IRS has previously interpreted the requirement that the CO_2 be injected into "secure geologic storage" to mean that injection operations must comply with Subpart RR of the Environmental Protection Agency (EPA) Greenhouse Gas Reporting Rule (GHGRP). Subpart RR of the GHGRP requires the operator of the injection facility (or EOR/EGR field) to report the amount of CO_2 captured from power plants and industrial facilities, and the amount injected underground for permanent storage or geologic sequestration.

Subpart RR also requires operators to obtain EPA approval of a "monitoring, reporting and verification" (MRV) plan for each storage project. The MRV Plan describes the reservoir into which the CO_2 is injected, any leakage pathways, and the methods for calculating and estimating the amounts of CO_2 delivered to the injection site so that the "net amount of CO_2 stored" can be determined.

The IRS currently requires an MRV Plan to be approved for a storage location prior to 45Q credits being authorized for underground injection of CO_2 into that storage location. An IRS internal legal counsel memo released in 2018 provided some clarity on this issue, even though the opinion was limited to that one specific case. In that case, the EOR operator chose not to follow Subpart RR rules and did not obtain EPA approval of an MRV Plan for the CO_2 storage location. The IRS internal legal counsel recommended that the IRS auditor disallow 45Q tax credits because the Subpart RR rules were ignored and no MRV Plan was approved by the EPA for that injection site.

In addition to recognizing compliance with Subpart RR and MRV Plans, it is anticipated that the IRS will adopt an additional method for demonstrating "secure geologic storage" that does not involve the GHGRP. Many formal comments have been submitted to the IRS suggesting the IRS also approve 45Q credits with respect to CO_2 injected underground pursuant to a recent standard adopted by the International Organization of Standardization (ISO). Known as ISO 27914 (available at www.iso.org/standard/65937.html), this standard, when adopted by a regulatory body, provides a method of quantifying the amount of CO_2 that is safely stored long-term in association with EOR operations. Because some EOR projects use both anthropogenic and non-anthropogenic sources of CO_2, the ISO standard also shows how allocation ratios can be used to determine the amount of anthropogenic CO_2 stored in the EOR project. Some in the EOR industry have suggested that this ISO standard (published in early 2019) provides an alternative to Subpart RR and MRV Plans for demonstrating "secure geologic storage" for Section 45Q purposes.

The IRS will likely adopt rules and regulations, or sub-regulatory guidance, to explain how an injection site operator may comply with the "secure geologic storage" requirement using both a method based on Subpart RR and based on the ISO standard. It is anticipated the IRS announcement on that issue will occur in early 2020.

Injection Well Permit Requirements

Virtually all injection wells in the US must be permitted under the US Environmental Protection Agency (EPA) program for Underground Injection Control (UIC) to mitigate risk to underground sources of drinking water. In some states, the EPA's primacy to implement those UIC regulations has been delegated to individual states but, for many other states, the EPA regional offices implement the UIC program.

Over the years, the EPA UIC program has adopted six (6) different well classifications. Two (2) of these classes involve the injection of CO_2:

- Class II – injection associated with the production of oil or natural gas
- Class VI – injection for carbon sequestration purposes

Differences between Class II and Class VI injection wells can include the following items:

- Geographic project area to be studied prior to grant of injection well permit (Class VI can be broader)
- Well construction requirements (Class VI has additional requirements)
- Mechanical integrity requirements of the well (Class VI has additional requirements)
- Remediation actions to be taken if leakage to groundwater is discovered
- Amount of time to obtain the permit (Class VI is much longer)

Providing flexibility, 45Q does not specify use of any particular classification of EPA UIC injection well permit.

Utilization and 45Q Credits

In addition to tax credit authorization for storing captured CO_2 underground, section 45Q credits are also authorized if the CO_2 is "utilized" or permanently fixed in a commercial product, such as growing algae or forming a chemical compound. In these instances, the minimum threshold to capture for 45Q tax credits is only 25,000 metric tons per year. For these "utilization" technologies, a life-cycle analysis (LCA) must be performed to determine the net amount of CO_2 that is captured or displaced from emission. For example, capturing CO_2 emissions from an ethanol plant but putting that CO_2 into carbonated beverages will not result in CO_2 emissions being permanently isolated from the atmosphere or displaced from being emitted to the atmosphere, and therefore 45Q credits are not available for that activity. However, capturing CO from a steel plant and converting that CO into a transportation fuel would result in a net reduction of carbon emissions, assuming the LCA demonstrates that result. Rules, regulations or guidance from the IRS will be necessary to determine the methodology for the LCA.

Credit Owner and Permissible Transfers

The 45Q tax credits are awarded to the owner of the carbon capture equipment. That capture equipment owner (CaptureCo) can be an individual taxpayer or any corporate entity (regardless of whether it is taxed as a partnership). If CaptureCo is a partnership (at least for tax purposes), then the 45Q tax credits claimed by CaptureCo would flow to the individual tax partners within CaptureCo, based on their capital account in the company.

CaptureCo can be the same company that also stores the carbon, but the statute provides flexibility and allows CaptureCo can contract with a third-party to physically inject the CO_2 underground (StorageCo). In another instance of flexibility, CaptureCo can claim the credit or CaptureCo can elect to transfer the credit to StorageCo.

Carryback and Carry Forward

45Q tax credits are general business tax credits, so they have the features of other regular business tax credits under Sections 38 and 39 of the IRS Code. As a result, 45Q tax credits are currently non-refundable, and they directly reduce a taxpayer's tax bill. The 45Q tax credits can be carried back one (1) year, and can be carried forward up to twenty (20) years. The carry forward, for example, allows for greater use of the tax credit in a situation where a tax credit generated in one year (i.e. a year of low tax liability) would not expire before being used to offset tax liabilities in a later year (i.e. a year of high tax liability).

Timing Requirement – 12-Year Rule

The 45Q tax credit is available for up to 12 years for new carbon capture projects. That 12-year time period begins on the date the carbon capture equipment is first placed into service.

Timing Requirement – Deadline to Begin Construction

There is a deadline for starting construction on new qualifying projects. In instances where the power plant or industrial facility is currently operating, the 45Q law currently requires that carbon capture equipment must at least begin construction before January 1, 2024 in order to qualify for 45Q credits.

In instances where a new power plant or industrial facility is being built, 45Q appears to be available if both (a) the power plant or industrial facility begins construction by January 1, 2024 and (b) the *design* of that plant/facility includes the future installation of carbon capture equipment (even if construction of that equipment is not begun by January 1, 2024). In coming years, there will likely be congressional proposals to extend the January 1, 2024 deadline.

The IRS will probably borrow some concepts from U.S. wind and solar tax credits regarding what actions are sufficient to "begin construction" of an industrial facility or carbon capture equipment. Interpretations of what activities are sufficient to "begin construction" will likely be issued by the IRS in a Notice or Guidance document in the coming months.

Value of the Incentive

The value of the 45Q tax credit falls into two categories, based on where the carbon is stored. The first category is for CO_2 that is "utilized" to make a product or is injected underground for enhanced oil/gas recovery. The 45Q credit value for this first category is US $20.22 per metric ton in 2020, and gradually increases by about US $2.50 per year, up to US $35 per metric ton in 2026.

The second category of 45Q credit value is for underground injection of CO_2 into a formation *other than* EOR/EGR. The 45Q credit value for this second category is higher. It is US $31.77 per metric ton in 2020, and gradually increases by about US $3.00 per year up to US $50 per metric ton in 2026. After 2026, both categories of credit values are adjusted based on an inflation factor.

Table 1. 45Q Tax Credit Amounts per Year.

45Q Tax Credit Amounts				
	$ PER METRIC TON		$ PER MCF	
YEAR	EOR	Non-EOR	EOR	Non-EOR
2017	12.83	22.66	0.82	1.45
2018	15.29	25.70	0.98	1.64
2019	17.76	28.74	1.13	1.83
2020	20.22	31.77	1.29	2.03
2021	22.68	34.81	1.45	2.22
2022	25.15	37.85	1.60	2.41
2023	27.61	40.89	1.76	2.61
2024	30.07	43.92	1.92	2.80
2025	32.54	46.96	2.08	3.00
2026	35.00	50.00	2.23	3.19
2027 +	prior year's tax credit amount, adjusted for inflation			

Table 1 assumes a conversion rate of 19.05 mcf of CO_2 = 1 metric ton of CO_2.

These changes in value of tax credits over time can also be depicted by the chart shown below in Figure 1. The increasing value of 45Q tax credits depicted in Figure 1 below assume a 1.5% inflation rate for values beyond 2026.

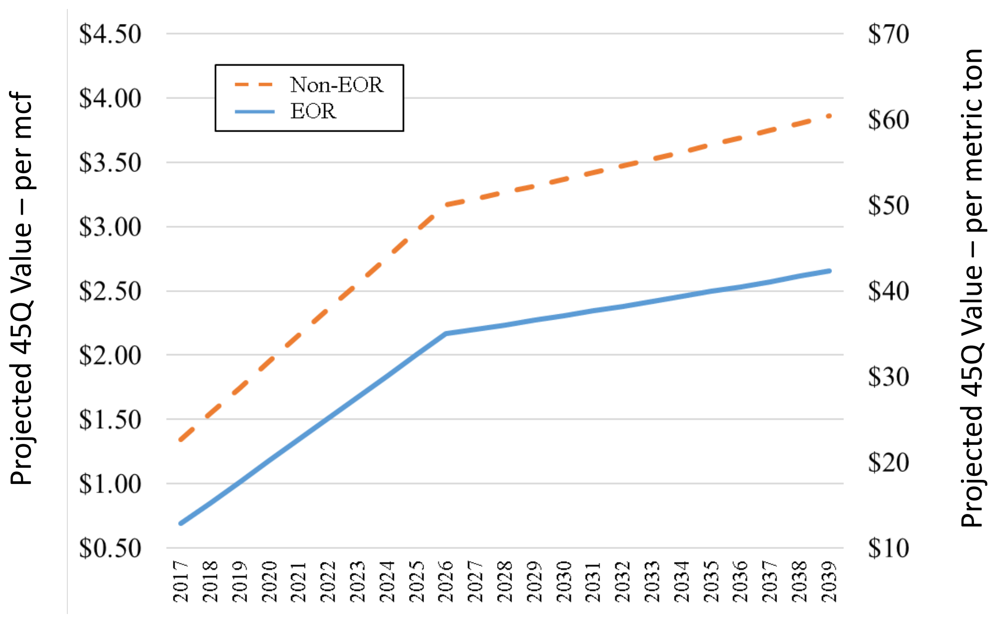

Figure 1. 45Q Tax Credit Amounts per Year.

As an example, a 45Q tax credit project that captures the minimum of 100,000 metric tons per year from an industrial facility, and begins capture and injection operations in 2021 into an EOR formation, will generate:

- approximately US \$2-4 million of tax credits per year if the CO_2 is injected into an EOR formation
- approximately US \$3.5-5.5 million of tax credits per year if the CO_2 is injected into a saline aquifer formation.

The US 45Q tax credit values increase over time and are lower for geologic storage of CO_2 associated with EOR/EGR operations compared to saline aquifer storage. The increasing value of 45Q tax credits for this example are depicted in Figure 2 below (values beyond 2026 assume a 1.5% inflation rate).

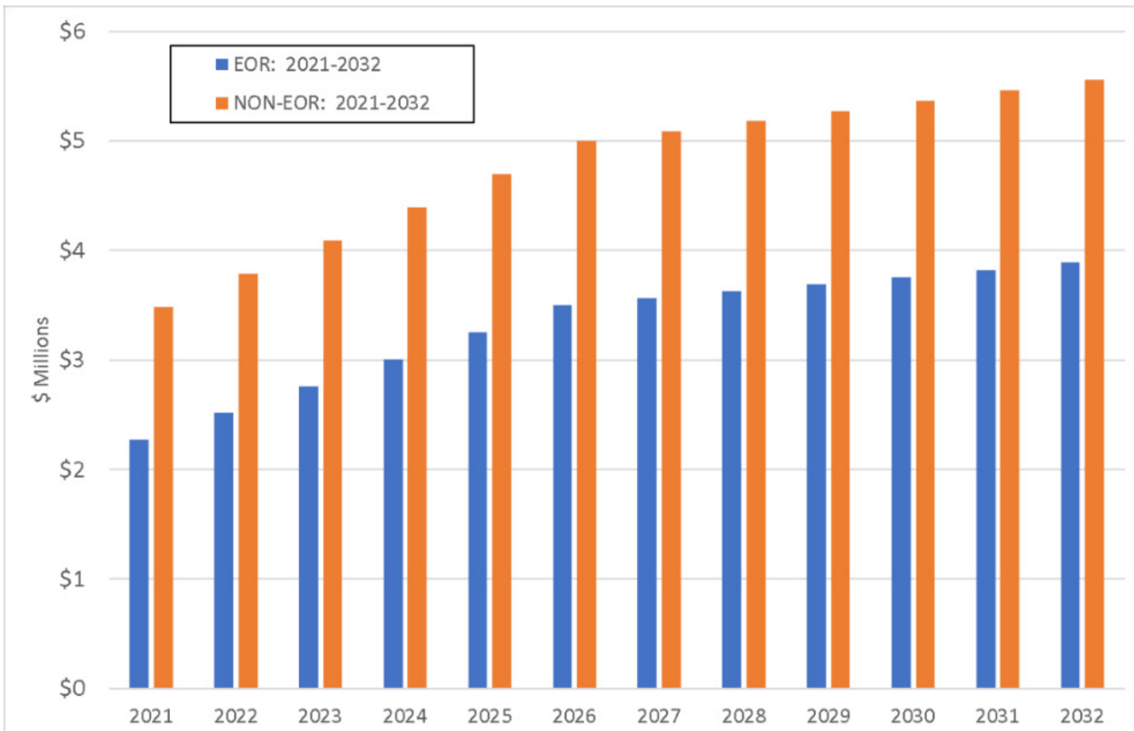

Figure 2. 45Q Tax Credit Value Over Time for 100,000 Metric Tons per Year of Sequestered CO_2.

The example project would generate, over a 12-year period from 2021-2032, cumulative tax credits that total approximately \$40 million for injection into EOR formations, and about \$57 million for injection into non-EOR formations. The cumulative tax credits during that time period are depicted in Figure 3.

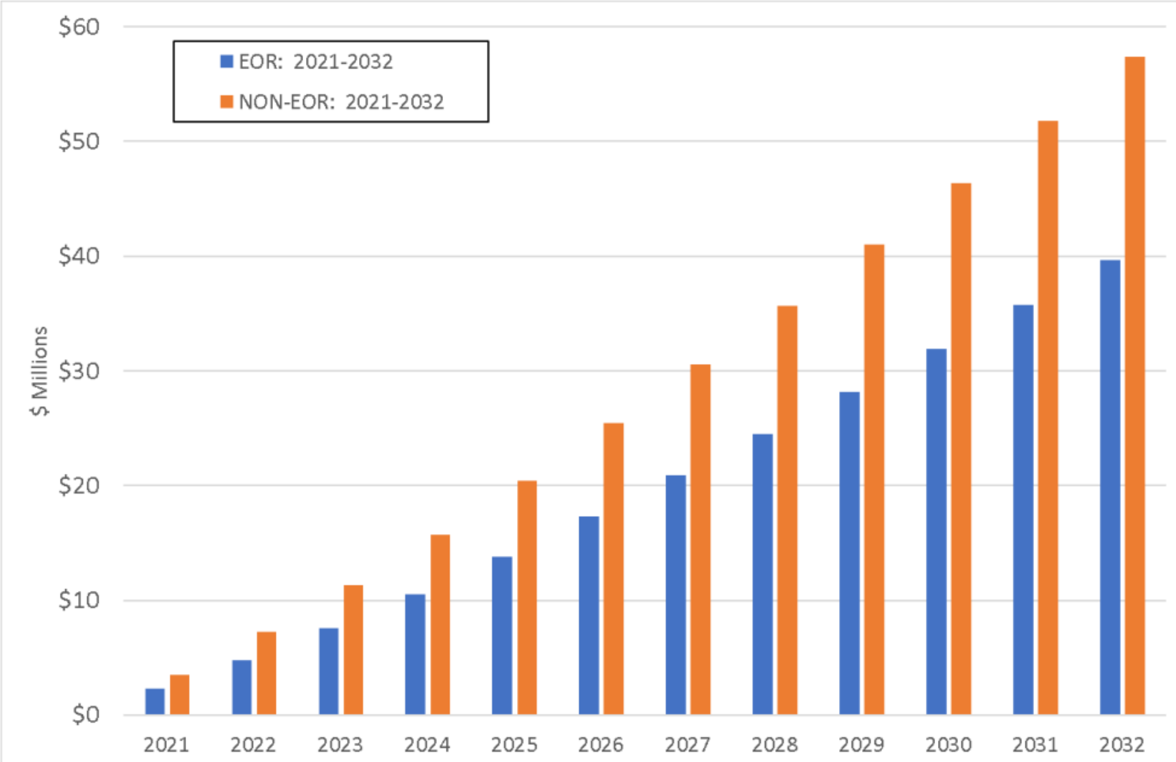

Figure 3. Cumulative Tax Credits Under 45Q for 100,000 Metric Tons per Year of Sequestered CO_2.

Many additional requirements are imposed by Section 45Q and IRS interpretations. For example, annual reports must be filed with the IRS to show the net amount of CO_2 stored by the project. 45Q only applies to carbon captured and sequestered in the US or its territories so, for example, CO_2 captured or stored in Canada does not qualify. Also, special rules apply for "applicable facilities" which are older carbon capture projects that did not claim credits under the old law. Advice of a tax attorney or 45Q consultant is recommended for all projects seeking to qualify for Section 45Q tax credits.

It is anticipated that the IRS will soon be adopting additional and revised guidance on various aspects of the Section 45Q tax credits. The concepts of "utilization" and direct air capture facilities were added to 45Q in the recent amendments, so future IRS guidance could address those topics as well. Further clarification regarding various details surrounding the Section 45Q tax credit is anticipated in the first half of 2020.

Section 45Q tax credits present an extensive motivation to capture and sequester carbon. Whether the CO_2 is "utilized" and stored in a product, or is sequestered underground in a geologic formation, the expanded incentive is sure to stimulate activity in the US carbon capture industry.

Regulatory Environment and Credit Schemes for CO_2 at a State Level

At the state level, some states are considering regulatory and other policies that would incentivize carbon capture from gas treatment and other facilities. California, for example, enacted Assembly Bill 32 (AB 32), the California Global Warming Solutions Act, and issued executive orders in 2005-2007 to implement long-term carbon emission reduction goals and, in 2011 began implementing the Low Carbon Fuel Standard (LCFS). The LCFS requires an annual reduction in the "carbon intensity" of the state's transportation fuels so that the carbon intensity (CI) of California's fuels by 2030 is 20% less than in 2011. The CI benchmark for each fuel declines annually and low carbon fuels that score below the benchmark generate LCFS credits, while fuels above the benchmark generate deficits. In the past year, the total annual credits and deficits exceeded 12 million metric tons, and the value of the LCFS credit was between $150-200 per metric ton.

Capturing CO_2 emissions from a facility, such as an ethanol plant, that produces a transportation fuel used in the California market creates an opportunity to claim the LCFS credit associated with that fuel. The LCFS credit can also be applicable to certain low carbon sources of methane when that gas is sold into the interstate pipeline system with connections to a compressed natural gas (CNG) station located in California.

In 2018, California adopted a Carbon Capture and Sequestration Protocol as part of the LCFS program, which became effective in early 2019 (available at https://ww2.arb.ca.gov/sites/default/files/2019-03/CCS_Protocol_Under_LCFS_8-13-18.pdf). The CCS Protocol is rigorous, and various market participants are determining how to comply with the CCS Protocol requirements.

Other states are considering similar LCFS-type policies, including Oregon, Washington, Colorado, New York, and a collection of Midwestern states such as Minnesota, Iowa, and South Dakota.

CO_2 Feed and Product Purity Concerns for Facility Design

Different end-users of CO_2 will have different product purity requirements, which can impact the design of the CO_2 recovery facility. Three different end-users, and their product purity concerns, are touched upon in this paper. The end-users considered here are as follows:

- Food and beverage grade CO_2 users. The food and beverage grade CO_2 market is one traditional user of CO_2, and recovering CO_2 for this use would prohibit the facility from realizing tax breaks or CO_2 credits for selling CO_2 to a food and beverage grade user. However, this CO_2 has the highest dollar value as a final product and may be attractive if the CO_2 producer is located close to an end-user of this type. Food and beverage grade CO_2 is sold as a liquid, and the markets for it are highly regional and dependent upon trucking costs associated with moving the liquid CO_2 from the producer to the end-user. A complete specification for food and beverage grade CO_2 can be found in *Commodity Specification for Carbon Dioxide, CGA G-6.2* published by the Compressed Gas Association, Inc., but in general the CO_2 will need to be at least 99.9% pure with low amounts of hydrocarbon allowed and less than 1 ppmv total sulfur allowed.

- Enhanced Oil Recovery CO_2 users. Enhanced Oil Recovery (EOR) CO_2 users inject high pressure CO_2 into oil reservoirs to realize higher oil recovery rates in mature oil reservoir assets. The injected CO_2 is miscible with the oil remaining in the reservoir, so EOR wells produce a mixture of CO_2, oil, water, and natural gas. Produced CO_2 (and usually the natural gas) from these wells is flashed out of the liquid product and compressed in recycle compression facilities for injection back into the oil reservoir. Any CO_2 lost from this system, or CO_2 that remains in the oil reservoir, must be replenished by make-up CO_2. The make-up CO_2 traditionally is supplied by natural CO_2 sources such as those found in the Four Corners area or in the Jackson Dome area of Mississippi. However, anthropogenic CO_2 vented from processes may be captured and used as make-up CO_2 as well, provided it meets typical specifications for EOR grade CO_2 shown in Table 2. A typical contaminant of concern for EOR CO_2 users is oxygen, but high concentrations of H_2S may also be a problem for some EOR users.
- CO_2 Sequestration users. Sequestration users do not have an end-use for the CO_2 and are only capturing it for research purposes, or for realizing tax credits or CO_2 credits in federal and/or state markets. This CO_2 can be of fairly low quality, at least in theory, but there is not an established specification for CO_2 for sequestration. Instead, companies rely upon Department of Energy (DOE) recommended limits, which are usually similar to the EOR specifications. Table 2 shows the DOE recommendations for sequestration CO_2 [1], [2].

Table 2. Typical End-User CO_2 Specifications.

Component	**Unit**	**EOR End-User**	**Sequestration End-User**
CO_2	vol %	95	95
H_2O	ppmv	500	500
N_2	vol %	1	4
O_2	ppmv	10	10
CH_4	vol %	1	4
C_2H_6	vol %	1	4
C_3H_8+	vol %	1	4
H_2	vol %	1	4
CO	ppmv	35	35
H_2S	ppmv	100	100
SO_x/NO_x	ppmv	100	100

* At least one large CO_2-EOR company has amended their CO_2 specification to limit NO_x, SO_x, Particulates and Amines to <1pmm each by weight, to limit hydrogen to <1 mole %, and modified their CO specification to 4,250 ppm by weight.

The source of the CO_2 can also have an impact on the design of the CO_2 recovery facility. Different impurities are common in different CO_2 sources. For a typical gas treatment facility, the source CO_2 is usually coming from an acid gas removal unit, such as an alkanol amine process, and will have different impurities than CO_2 from an ethanol plant or a syngas plant. Table 3 shows typical impurities that might be expected from different CO_2 sources, in addition to the expected concentration of CO_2. Typical impurities for each CO_2 source are marked by an X. A more complete table of expected impurities and additional CO_2 sources may be found in

CGA G-6.2-2011 *Commodity Specification for Carbon Dioxide, 6th Ed.* by the Compressed Gas Association, Inc.

Table 3. Typical Feed Composition from CO_2 Sources.

Component	Acid Gas Removal Unit	Ethanol Plant	Syngas Plant	Flue Gas
CO_2	Variable	99% Mol	Variable	Variable (4-14% Mol)
N_2		X		X
O_2		X		X
Hydrocarbons	X	X	X	X
H_2			X	
CO		X	X	X
H_2S	X	X		
SO_x/NO_x		X		X

Table 2 and Table 3 in combination will help set the design of the CO_2 capture facility. The flue gas composition is shown in Table 3 to demonstrate how difficult it is to achieve on specification CO_2 from a flue gas source. Significant quantities of low purity CO_2 gas must be handled, and large quantities of impurities must be addressed by the CO_2 capture facility. Contrasting this with sources such as acid gas removal units, ethanol plants, and syngas plants helps to highlight why, with the current regulatory environment for CO_2, relatively few CO_2 capture facilities will be built to capture CO_2 from combustion sources.

For gas treatment facilities, the CO_2 source should be as pure as possible. The presence of H_2S exceeding the 100 ppmv limit for EOR and sequestration CO_2 is likely if the feed gas to the gas treatment plant has an appreciable amount of H_2S present, and the acid gases are not removed selectively in the acid gas removal section of the plant. Removing large quantities (more than a few ppmv) of H_2S from a CO_2 stream is technically feasible, but increases costs.

CO_2 Recovery Facility Design Options

The CO_2 capture facility design is based upon the composition of the feed gas and the required product specifications. Traditionally, CO_2 capture facilities were primarily for the food and beverage grade industry, which require a high purity liquid CO_2 product. A typical liquefaction facility for the food and beverage grade industry is composed of the unit operations shown in Figure 4, and for EOR or injection grade facilities this process may be applicable as well depending upon the impurities (especially oxygen) in the feed gas.

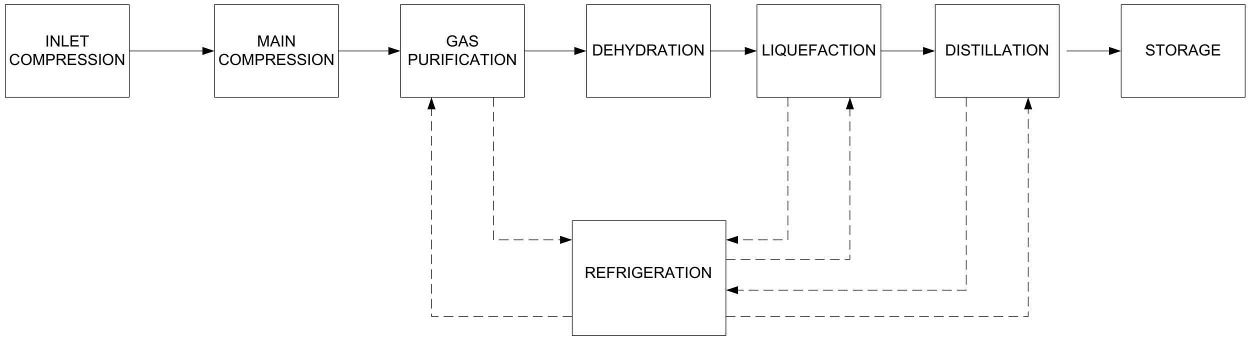

Figure 4. Typical Block Flow Diagram for CO_2 Liquefaction Process.

The facility shown in Figure 4 produces a liquid CO_2 product at approximately 300 psig and 0 °F, which can be loaded into trucks or rail cars and shipped to third parties for their use. A brief description of each unit operation follows:

- Inlet Compression. Most anthropogenic CO_2 is available at nearly atmospheric pressure. AGR unit regenerators, ethanol fermenters, and other typical CO_2 sources run at single digit pressures, so inlet compression equipment is used to compress the feed gas up to a high enough pressure for the feed gas to be economically transported via piping to the main capture facility. Inlet compression also reduces the size and quantity of main compression equipment. The inlet compression equipment is often one or more multistage centrifugal blowers (in parallel); capable of compressing ambient pressure feed gas up to approximately 15 psig.
- Main Compression. The feed gas from the inlet compression equipment is compressed up to approximately 300 psig in the main compression equipment. The main compression equipment is often an oil-flooded screw compressor, which can achieve a high compression ratio across the compressor without having to cool the feed gas between stages. Compound screw compressors, essentially two screws on a common driveshaft, can accomplish the entire compression requirement in a single machine without any interstage cooling. The oil-flooded screw technology injects oil directly into the process gas stream, and the oil helps seal the space between the screws to limit gas leakage while also absorbing some of the heat generated in the compression process.
- Gas Purification. This unit operation will vary based upon the impurities present in the feed gas and the purity requirements of the product CO_2. For EOR and sequestration applications, this unit operation consists only of cooling the feed gas and condensing as much water out of the gas stream without approaching the CO_2-H_2O (s) hydrate formation temperature. For food and beverage or other uses, it may also include removal of hydrocarbon and sulfur compounds.
- Dehydration. For the liquefaction process, essentially all water must be removed from the gas stream to avoid ice formation in the downstream liquefaction and distillation units. Dehydration to this level is usually accomplished in molecular sieve dryers, which are regenerated by a heated slipstream of dry gas.
- Liquefaction. The feed gas is cooled and condensed to liquid by exchanging heat with evaporating refrigerant. This is typically done in shell and tube kettle-type heat exchangers.
- Distillation. Liquid from the condensers is pumped to the top of a distillation column, where non-condensable gases are stripped out of the liquid. The gases vent out of the top

of the column, and eventually to atmosphere. Liquid flows out of the bottom of the column, and a portion of it is reboiled by exchanging heat with the incoming feed gas and potentially warm refrigerant. The remainder of the liquid is purified product CO_2.

- Storage. High pressure (300 psig) storage tanks store the liquid CO_2 until it can be loaded onto trucks for shipment.
- Refrigeration. The refrigeration cycle is similar to that commonly found in gas treatment plants, and there are several different refrigerants in use industrially. The most common refrigerant for this process is anhydrous ammonia, but propane and HFC refrigerants are also used at times depending upon operator preference.

For EOR grade CO_2 facilities, the liquefaction process in Figure 4 is modified slightly to remove the storage tanks and install high pressure pumps to supply the CO_2 to a pipeline or injection well, as shown in Figure 5.

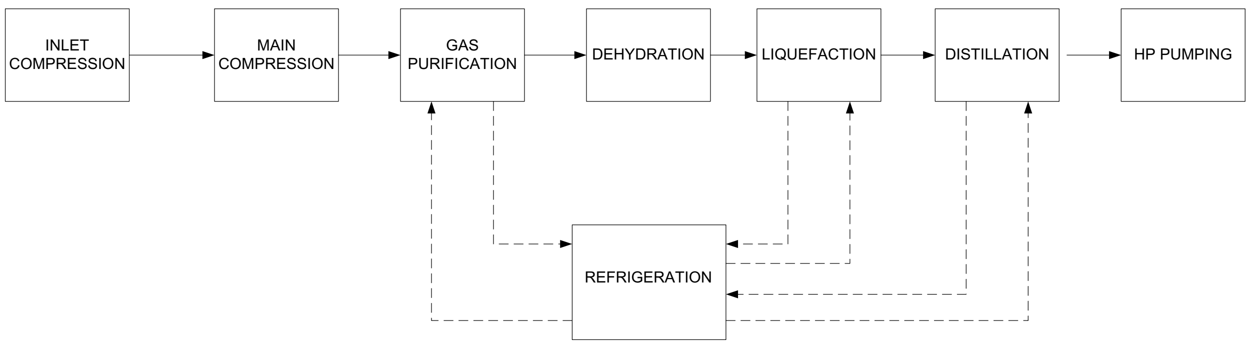

Figure 5. Typical Block Flow Diagram for EOR Grade Liquefaction Facility.

This facility design assumes the feed gas contains less than 15% by volume non-condensable gases. If non-condensable gas fractions are higher than 15% by volume, the amount of CO_2 lost from the top of the distillation column is considerable and the facility may become uneconomic. In a typical CO_2 recovery process, these gases might include nitrogen, oxygen, hydrogen, and/or methane (hereafter called light components). The fraction of light components in the feed gas will directly impact the recovery of CO_2 in the distillation area of the facility; with higher concentrations of light components, the top of the distillation column must operate at a lower temperature for a given pressure in order to recover the same amount of CO_2. There is a practical limit for the minimum top temperature of the distillation column, and an economic limit, as lower temperature at the top of the distillation column will increase the operating cost of the refrigeration cycle.

For recovering CO_2 for EOR purposes or for sequestration purposes, the process shown in Figure 4 and Figure 5 may be applicable for any CO_2 source gas that contains oxygen, or other light gas components above the specification in Table 2. Oxygen is a typical contaminant in CO_2 from ethanol facilities, anywhere in a range of 50 ppmv up to 1,000 ppmv depending upon the fermentation process (batch or continuous), and how careful the ethanol producer is in managing the fermenter pressures and operations. The tight specification on oxygen for EOR and sequestration applications means that when oxygen is present, it will likely be above the specification limit and oxygen removal from the gas will be required. Other CO_2 sources such as syngas facilities or acid gas removal units are less likely to contain oxygen, but air ingress in the feed equipment should be carefully avoided, since oxygen is a costly contaminant to remove from the CO_2. Liquefaction of the CO_2 is the only commercially proven process for removing oxygen from CO_2 in the applications discussed in this paper. Other processes such as catalytic oxidation have been used in other industries, but have not been commercially proven for these CO_2 purification applications.

Capital costs for the liquefaction and distillation process are well-established, and for EOR or injection grade CO_2 production, the total installed costs for a CO_2 liquefaction facility capable of producing 100,000 metric ton per year may be approximated as shown in Table 4. The main operating cost for a liquefaction facility is the cost of electricity, with a typical electricity demand for the liquefaction process shown in Table 4. Capital costs and electricity demand in Table 4 are based upon the authors' experience and *Evaluation of Carbon Dioxide Capture Options from Ethanol Plants* [2].

Table 4. Expected Capital and Operating Costs for 100,000 Tonne/Year CO_2 Liquefaction Facility.

Total Installed Cost for 100,000 Tonne/Year Facility	$10.6 Million
Electricity Demand	162 kWh/Metric Ton

When oxygen or other light gas contaminants are not present in the CO_2, or are below the specification limits for the CO_2 product, the purification process for EOR grade or injection grade CO_2 is much simpler, as shown in Figure 6.

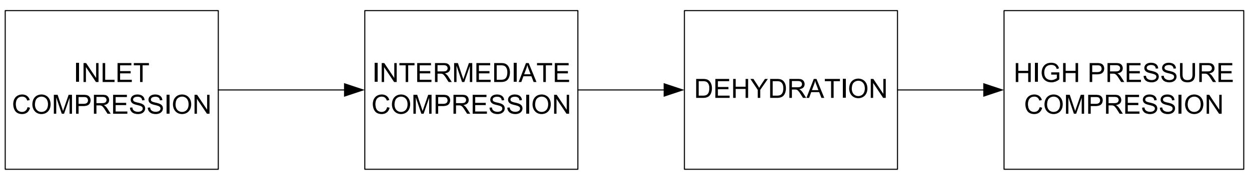

Figure 6. Typical Block Flow Diagram for Straight Compression Facility.

The process in Figure 6 produces a CO_2 product at the required injection or pipeline pressure, and the CO_2 is dehydrated to meet pipeline specifications. The dehydration process is the only unit operation that is not a part of the compression train, and it is much simpler than in the previous example. A brief description of each unit operation is as follows:

- Inlet Compression. Most anthropogenic CO_2 is available at nearly atmospheric pressure. AGR unit regenerators, ethanol fermenters, and other typical CO_2 sources run at single digit pressures, so inlet compression equipment is used to compress the feed gas up to a high enough pressure for the feed gas to be economically transported via piping to the main capture facility. Inlet compression also reduces the size and quantity of main compression equipment. The inlet compression equipment is often one or more multistage centrifugal blowers (in parallel); capable of compressing ambient pressure feed gas up to approximately 15 psig.
- Intermediate Compression. Feed gas from the inlet compression equipment flows to the intermediate compression equipment, which may be a variety of different compression technologies including oil-flooded screw, reciprocating, or centrifugal compression. The intermediate compression operation increases the feed gas pressure to a suitable pressure for dehydration.

- Dehydration. The feed gas does not need to be as deeply dehydrated as it does in the liquefaction process; the gas only needs enough water removed to meet the pipeline specification so expensive and less energy-intensive dehydration processes such as triethylene glycol (TEG) dehydration or DexPro™ may be used to dehydrate the gas.
- High Pressure Compression. Dehydrated gas flows to another compression unit, typically a reciprocating or centrifugal compressor, to compress the CO_2 above the critical pressure of 1,070 psia. The compressor may deliver CO_2 at pipeline pressure, or there may be an additional *pumping* step beyond the compressor. Once above the critical pressure, CO_2 is a dense fluid and may be efficiently pumped to a higher pressure. Depending on the required pipeline or injection pressure, a dense phase pump may be employed downstream of the main compression.

The authors are aware of several different companies operating straight compression facilities for EOR or injection grade CO_2 production in several different states including Texas, Louisiana, Kansas, Illinois, and Wyoming. Table 5 shows the expected total installed cost for a straight compression facility capable of injecting 100,000 metric tons per year of CO_2. Similar to the liquefaction facility, electricity is the largest operating cost for the facility, and is shown in Table 5. Capital costs and electrical demand shown in Table 5 are based upon the authors' experience.

Table 5. Expected Capital and Operating Costs for 100,000 Metric Tons/Year CO_2 Compression Facility.

Total Installed Cost for 100,000 Metric Ton/Year Facility	$9.0 Million
Electricity Demand	112kWh/Metric Ton

Example Economics for 100,000 Metric Ton per Year Injection Facility

This section examines the economics of installing a CO_2 capture facility at a gas treatment facility with the following CO_2 capture conditions:

- The gas treatment facility produces a low-pressure, high-purity CO_2 stream from an acid gas removal unit such that the CO_2 can be captured and processed in the straight compression system detailed above in Figure 6. The gas treatment facility produces 100,000 metric tons per year of CO_2 from the acid gas removal unit.
- The gas treatment facility is remotely located, and not easily reached for beverage grade CO_2 applications or EOR applications. The CO_2 will be injected in a local formation on the plant site for sequestration, so pipeline costs will be negligible.
- Power costs for the facility are $0.05 per kWh and the required injection pressure at the surface of the injection well is 2,000 psig.
- Capital outlay for the facility occurs in 2020, with operation commencing in 2021.
- Operating costs escalate by 2% per year.

Permitting costs for this facility are not included in this analysis. There have been very few Class VI injection permits applied for, approved, and operated under in the United States for CO_2

geologic sequestration. The approval portion of the permitting process may take years to get approved. Costs for the application process can be significant, and should be fully understood before a company makes an investment decision. The Class VI permitting process for the facility may also depend upon the location of the injection well; the state of North Dakota has been granted primacy by EPA to regulate Class VI injection wells and other states are expected to file for and be granted primacy by the EPA to regulate Class VI injection wells. EPA granting primacy for state regulatory bodies can also be a lengthy process.

The total capital required for the construction of the surface facilities, injection well, and monitoring well is shown in Table 6. Other costs such as permitting costs, baseline monitoring costs, and pipeline costs are not included here.

Table 6. Total Capital Cost Breakdown for 100,000 Metric Ton per Year Compression Injection Facility.

Capital Cost Item	**Expected Capital Cost ($ Million)**
Straight Compression Surface Facility	9.0
Injection Well	3.2
Monitoring Well	3.2
Total Initial Capital Investment	15.4

Once the facility is operational, variable operating costs for the facility will be dominated by electrical costs to run the equipment and monitoring activities around the injection well. Labor costs for the facility should be minor; the facility is not complex and should be online most of the time. Annual maintenance, taxes, and insurance for the facility are assumed to be 5% of the surface facility cost. The injection facility will also be required to maintain the MRV plan that will have ongoing costs associated with the injection process. The costs associated with MRV compliance are variable from year to year, but may be approximated for this analysis as $0.25 Million per year. Table 7 shows the estimated annual operating costs for the injection facility [3].

Table 7. Total Operating Cost Breakdown for 100,000 Metric Ton per Year Compression Injection Facility.

Operating Cost Item	**Expected Operating Cost ($ Million)**
Electricity	0.6
Taxes, Maintenance, Insurance	0.5
MRV Compliance	0.3
Total Annual Operating Expenses	1.4

*Escalation of 2% annual not shown

Table 8 shows the net present value of the project assuming a 10-year life for the project and 15% internal rate of return.

Table 8. Net Present Value for 100,000 Metric Ton per Year Compression Injection Facility.

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capex	-15.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Opex	0.0	-1.3	-1.3	-1.3	-1.3	-1.4	-1.4	-1.4	-1.4	-1.5	-1.5
Tax Credit	0.0	3.5	3.8	4.1	4.4	4.7	5.0	5.1	5.2	5.2	5.3
Cash Flow per Year	-15.3	2.2	2.5	2.8	3.1	3.3	3.6	3.7	3.7	3.8	3.8
NPV over Time	-15.3	-13.1	-10.6	-7.8	-4.7	-1.4	2.2	5.9	9.6	13.3	17.1

* All Costs in $ Millions

Table 8 shows that the capital investment for the CO_2 capture facility will be economically justified approximately 5.5 years after the investment. This represents a "best case" for the economics of the capture facility since it uses the least capital and operating expense technology and does not have a large pipeline transportation cost associated with it. Additional revenue for the project may be available from state tax or carbon credit schemes, and this would improve the economics shown in Table 8.

For CO_2 recovery plants that need to liquefy the CO_2 to meet specifications, the economics are slightly worse than the straight compression case. A similarly sized facility, but one that requires the CO_2 to be liquefied will have the capital costs shown in Table 9.

Table 9. Total Capital Cost Breakdown for 100,000 Metric Ton per Year Liquefaction Injection Facility.

Capital Cost Item	**Expected Capital Cost ($ Million)**
Liquefaction Surface Facility	10.6
Injection Well	3.2
Monitoring Well	3.2
Total Initial Capital Investment	17.0

The same considerations for operating costs for the straight compression facility can be assumed for the liquefaction facility, albeit with a higher power requirement as shown in Table 10 [3].

Table 10. Total Operating Cost Breakdown for 100,000 Metric Ton per Year Liquefaction Injection Facility.

Operating Cost Item	**Expected Operating Cost ($ Million)**
Electricity	0.8
Taxes, Maintenance, Insurance	0.5
MRV Compliance	0.3
Total Annual Operating Expenses	1.6

*Escalation of 2% annual not shown

Table 11 shows the net present value of the project assuming a 10-year life for the project and 15% internal rate of return.

Table 11. Net Present Value for
100,000 Metric Ton per Year Liquefaction Injection Facility.

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capex	-16.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Opex	0.0	-1.5	-1.5	-1.6	-1.6	-1.6	-1.7	-1.7	-1.7	-1.8	-1.8
Tax Credit	0.0	3.5	3.8	4.1	4.4	4.7	5.0	5.1	5.2	5.2	5.3
Cash Flow per Year	-16.9	2.0	2.2	2.5	2.8	3.1	3.3	3.4	3.4	3.5	3.5
NPV over Time	-16.9	-15.0	-12.7	-10.2	-7.4	-4.3	-1.0	2.4	5.8	9.2	12.7

* All Costs in $ Millions

The liquefaction facility will be economically justified 6 years after the initial investment, which is slightly longer than the straight compression facility shown in Table 8. Again, other factors such as substantial pipeline costs for the facility will impact the economics, and some additional revenue from state tax or carbon credit schemes may be possible.

Conclusions

The original intent of the Section 45Q tax credit adopted in 2008 focused on incentivizing large CO_2 emitters such as coal power plants to capture their CO_2 emissions to atmosphere. However, the prohibitively high cost for capturing and compressing CO_2 from power plant flue gas made these capture facilities difficult to justify economically, without more incentives than the 2008 45Q tax credits. Recent changes to the 45Q law opened the tax credit up to smaller CO_2 emitters, such as gas treatment facilities, and increased and expanded the tax credits to 12 years for all sources. However, it remains to be seen if even the revised 2018 45Q tax credits will be sufficient to spur CO_2 capture from power plant flue gas. A gas treatment facility emitting 100,000 metric tons of CO_2 per year or more now qualifies for the 45Q tax credit, and can realize these tax credits by installing a CO_2 capture facility. The threshold for power plants remains at 500,000 metric tons per year. For the project to be economic, the following items must be addressed:

1. Injection well permitting can be a significant hurdle to any CO_2 capture project. If the injection well will be permitted as a Class VI injection well, the time required to permit the well can be very long, even several years in duration.
2. Additional guidance from the IRS will be necessary to reduce risks and ambiguities in the 45Q tax credit law for companies hoping to realize tax credits.
3. Project economics are better when the CO_2 emitted by the facility is relatively high concentration, at least 85% by volume CO_2. At concentrations lower than this, the CO_2 must be enriched in a separate process, which makes the capital and operating costs of the facility much more expensive.
4. The impurities present in the CO_2 are economically preferred to be light impurities that can be stripped out of liquid CO_2. Heavy impurities in the CO_2, such as H_2S, that will tend to stay in the liquid CO_2 may make the recovery process more expensive.
5. The injection site should be geographically located as close to the emitting facility as possible, to minimize transportation costs via pipeline to the injection location. For EOR

applications, close access to the CO_2 pipeline or the EOR injection well system will be necessary.

Provided the conditions above can be met including taking into account the Section 45Q tax credit, a CO_2 recovery and injection facility could be economically justified after five to six years of operation, depending upon the type of surface facility required to process the CO_2. Low CO_2 concentration streams, such as power plant flue gas, cogeneration facility flue gas, or other furnace flue gases will be difficult to capture economically under the existing federal tax credit structure. State tax credit and carbon credit market schemes are still in development at this time and, while there are limited opportunities for gas producers to enter these state level markets, they are important additional economic incentives for consideration.

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