September 13, 2017

Alexander Mitchell, Manager
Emerging Technology Section
Oil and Gas and GHG Mitigation Branch
Industrial Strategies Division
California Air Resources Board
1001 I Street
P.O. Box 2815
Sacramento, CA 95812

Re: Comments on California Air Resources Board's quantification methodology concept paper for carbon capture and storage from the State CO_2-EOR Deployment Work Group

Dear Mr. Mitchell:

We appreciate the opportunity to provide comments to the California Air Resources Board (ARB) regarding the recently released Quantification Methodology (QM) concept paper (including the permanence protocol). Further to previous communication with you, our comments are informed by officials from 14 states in the State CO2-EOR Deployment Work Group, and we hope that our input will further inform development of the State's approach to regulating carbon capture and storage (CCS). Additionally, we provide comments on regulations that would incorporate the QM, namely the Low Carbon Fuel Standard (LCFS) and Cap and Trade (C&T).

About the State CO_2-EOR Deployment Work Group

Wyoming Governor Matt Mead (R) and Montana Governor Steve Bullock (D) jointly convened the 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 to increase the use of CO_2 in enhanced oil recovery (CO_2-EOR), while safely and permanently storing that CO_2 underground and reducing net emissions in the process.

Fourteen states currently participate in the Work Group: Arkansas, Colorado, Illinois, Indiana, Kansas, Louisiana, 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 are joined by leading EOR, electric power, coal industry, regulatory and NGO experts. The Great Plains Institute coordinates and facilitates the Work Group.

The Work Group undertakes modeling and develops and supports the implementation of federal and state policy recommendations aimed at:

- Deploying carbon capture at power plants and industrial facilities;
- Building out pipeline infrastructure to transport CO_2; and
- Expanding the beneficial use and geologic storage of CO_2 through EOR.

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_2-EOR Industry, a white paper outlining recommendations for national CO_2 pipeline infrastructure in February 2017 - 21st Century Energy Infrastructure: Policy Recommendations for Development of American CO_2 Pipeline Networks, and another report in June entitled Electricity Market Design and Carbon Capture Technology: The Opportunities and the Challenges.

Introduction

Carbon capture and storage (CCS) has extraordinary potential for our nation and for California. Capturing carbon dioxide (CO_2) from power plants and industrial facilities for use in CO_2-EOR and other geologic storage significantly reduces net CO_2 emissions on a lifecyle basis, while enabling continued use of our domestic energy resources and providing a low-carbon path forward for energy intensive industries. Producing more oil in the U.S. through CO_2-EOR also further displaces more expensive heavier and carbon-intensive imported crudes from the domestic marketplace. Additionally, carbon capture can bring highly-skilled jobs and investment to key energy and industrial sectors in California and the U.S. economy as a whole.

States serve as laboratories of innovation in our federal system, and California has long sought to lead by example in U.S. energy and environmental policy. While the states represented in this Work Group bring a range of perspectives to energy and environmental policy, they share the view that the framework for CCS regulation that ARB establishes within the broader context of the state's existing LCFS and C&T policies could position California to lead in the realm of carbon capture. In addition, private sector leaders, notably those representing the ethanol and oil and gas industries in leading agricultural and energy-producing states—many of those jurisdictions participate in this Work Group—see the potential for California state policies to drive private investments that enable large-scale carbon management both within California and across the country.

At a time when California's state leaders are calling on the federal government to sustain continued progress in reducing our nation's carbon emissions, ARB has a strategic opportunity to design a regulatory system that not only helps California meet its own emissions goals cost-effectively, but can also drive industry investment in carbon capture and CO_2 pipeline infrastructure in states and regions that may have different policy priorities from California, but which share a common interest in deploying technology and infrastructure that beneficially reduces carbon emissions while achieving other energy and economic objectives.

Whether California plays this leadership role depends on ARB carefully addressing the business model challenges to commercial CCS deployment and drawing on and incorporating long-standing regulatory, technical and commercial operational experience from other jurisdictions and industry. In that context, CCS is fundamentally different from other issues such as vehicle emissions where California set higher standards than the federal government to drive innovation and investment. If California adopts a similar approach of setting requirements that exceed those of the federal government and leading states that regulate commercial CCS effectively today, California risks missing the opportunity to serve as a catalyst for commercial CCS deployment and associated carbon reductions within the state and beyond.

In that spirit, the Work Group understands that ARB's QM and permanence protocol are key steps in allowing carbon capture with EOR or other geologic storage to play significant roles in achieving California's CO_2 emission reduction targets. However, from a commercial deployment standpoint, Work Group members believe that addressing the comments below will enable wider adoption and scaling up of carbon management practices that would help California meet its state goals, as well as constructively inspire and support public and private leadership on emissions reductions in other jurisdictions and regions.

Work Group Comments

The Work Group respectfully requests that ARB consider the following comments.

I. **Business model challenges:**

a. Eliminate on-site requirement in the LCFS: LCFS regulation currently requires that "Carbon capture must take place onsite at the crude oil production facilities." The CCS-EOR business model has the potential to avoid tens of millions of tons of CO_2 emissions generated in non-oil industries (or at oilfields, but from non-crude activities). Capturing this potential means that site boundaries will need to be crossed. The LCFS regulation should be amended to also allow LCFS credits to be generated by capture of CO_2 outside the oilfield for generating low carbon intensity crude at the oil field. Moreover, we were unable to locate technical or environmental justification for this requirement.

b. Redefine system boundaries for quantification of credits & allowances: Currently, as per the C&T regulation for the 'covered emitter' such as a cement plant, power plant, steel mill, etc., the captured tons of CO_2 would only create a benefit to the capturer in the context of the C&T market for allowances. The project system boundary would end with injection. However, CO_2 emissions associated with innovative crude production would affect carbon intensity of the crude thereby produced, which would create a "charge" in the context of LCFS credit market for the oilfield operator. Consider that right now the value of emission allowances is much lower in the C&T market than the value of credits in the LCFS market. Even though the volume of emissions to be accounted for by the oilfield operator is lower than the reductions accounted for by the capturer, the value of the "charge" in the LCFS market is greater than the benefit in the allowance market. This creates a disincentive for the oilfield operator and CO_2 capturer to transact, thereby preventing CO_2 reduction opportunities through the CCS-EOR business model. This commercial impediment to achieving emissions reductions can and should be addressed by redefining the system boundary. For a detailed explanation and a numerical example of this scenario, please see appendix A.

c. Accounting for out-of-state innovative crude oil or fuel sold in California: We request that ARB lay out guidelines on how innovative crude produced in another U.S. state would be accounted for when it is delivered into California. The guidelines should also establish how to account for refined low carbon intensity (CI) fuel delivered into California for in-state consumption. We propose that the following principles be considered while developing these guidelines:

- Innovative crude that is produced out of state and transported or sold into California should be eligible for low CI credits, whether it is delivered directly to California or through product exchanges. In the case of direct delivery, innovative crude accounting should allow producers to generate low CI credits by delivering low CI crude into California directly. In such cases, the producer should be able to withdraw the same quantity of low CI crude from a ship or pipeline, for example, that it delivers into the same ship or pipeline. Product exchanges, which are commonly used in most commodity industries to simplify logistics, should follow a similar approach. For example, a low CI crude producer could deliver crude oil to a counterparty which has a need for the oil in close proximity to its point of production. The low CI producer would then arrange for the counterparty to deliver an equal quantity of crude oil on behalf of the low CI producer to a location in California. Although the delivered barrels are not the same barrels that were produced by innovative crude methods, the low CI crude attributes should be attached to the barrels delivered into California and thus awarded to the low CI producer. Since product exchanges reduce the distance products travel to a destination, they can also reduce the emissions associated with transportation. ARB should provide guidelines for CI accounting in cases such as business models described above.

- Low CI crude refined out of state and sold for consumption in California should be treated as low CI fuel, gasoline or diesel. The guidance for calculating the CI in such a scenario should be laid out in the QM.

- Innovative crude production outside California should be allowed to source CO_2 from any anthropogenic source as long as the innovative crude producer is covered as an eligible entity and meets the requirements of the permanence protocol. The entity should not be limited to sourcing CO_2 only from an on-site source. This requirement limits deployment opportunities for CCS, and therefore the emissions reduction that the innovative crude credits will trigger, because it is extremely rare for a source of CO_2 and appropriate sink to be co-located.

d. Eliminate cap on innovative crude credits under the LCFS: Anthropogenic CO_2-EOR has significant potential to provide substantial GHG emissions reductions at relatively low cost. A cap on LCFS credits undermines the incentive for CCS and its potential to help California meet its GHG goals and to do so cost-effectively. The number of credits awarded to Innovative Crude Oil production should not be subject to a cap.

e. Expeditious Adoption of QM into Cap and Trade: We request that ARB integrate QM into the C&T regulation as soon as possible, to enable non-fuel related CCS projects such as those in the power sector to be deployed, which will form a significant share of total CCS projects in California provided the right policy signals.

II. Quantification Methodology

a. Transfer of CO_2 to other fields: Transfer of CO_2 from field to field, both interstate and intrastate, should be allowed under the QM protocol as long as both fields are compliant with the permanence protocol. Any CO_2 stored in one oil field, and then transferred to another, should be eligible under LCFS and C&T regulations to meet greenhouse gas (GHG) reduction goals instead of being considered as emitted. Industry has demonstrated that the volume of CO_2 produced from one oil field providing carbon storage, that is transported and then stored in another field can be easily calculated. Existing accounting provisions to prevent double-counting are straightforward. Projects that use CO_2 that is extracted from an existing CO_2 reservoir, compressed, transported via pipelines (often long distances) and then injected into an oil field operate under robust accounting methodologies, which acknowledge that CO_2 used for in EOR remains within a closed loop. From an accounting standpoint, the transfer of CO_2 produced in one eligible oil field to another is no different. CO_2 that is transferred from one EOR field and injected into another is not emitted to the atmosphere and should not be considered emitted because once it is produced or captured, it remains out of the atmosphere in a closed loop between eligible oil fields.

III. Permanence protocol:

a. Site-specific approach: All permanence protocol requirements relating to site characterization, monitoring period, monitoring methods and reporting during and post injection should be based on site-specific risk analysis. Understanding and evaluating local geology and its associated risks is highly site-specific in nature. Using a risk-based approach will lead to development of targeted assurance monitoring and leak mitigation plans based on several factors including geological conditions, pressure behavior, available pore space, existing faults and fractures and presence and accuracy of existing well records. Recently, in a meeting with stakeholders, ARB conveyed that a 50-year post closure monitoring period is being considered. We believe that assurance monitoring should take a long-term approach from the start of a project and require a non-prescriptive post-injection monitoring period. Monitoring methods should also be determined based on an understanding of the storage complex and on methods proven to be able to detect CO_2 in the subsurface. ARB should not utilize a checkbox approach to meet permanence protocol requirements as that approach cannot assure long term CO_2 storage integrity. A prescriptive approach could prove limiting as it might not take into account techniques and materials that would be available in the future.

b. Standards additional to Class VI: We would like to understand from ARB the substantive differences identified between the U.S. EPA Class VI rule and GHG reporting established by U.S. EPA under subpart RR of the Federal Greenhouse Gas Reporting Program (GHGRP) on the one hand and the requirements under development by ARB on the other. U.S. EPA has already established regulations that address the issues identified in the California ARB scope. We would like to know the reasons why ARB plans to develop additional requirements beyond these existing ones.

c. Standards additional to Class II**:** We would like to understand better the additional California-specific monitoring, reporting and verification (MRV) requirements that ARB envisions for CO_2-EOR projects and the reasons behind them. These projects would be reporting CO_2 storage volumes under an EPA-approved MRV plan for Class II wells under Subpart RR of the federal GHGRP. The currently approved MRV plans address well integrity, for example, in addition to providing mitigation actions and observing state regulations that mitigate leakage of CO_2 to the surface from existing wells.

d. Post closure treatment of oil fields: Preventing any form of use of oil fields after CO_2 injection has ended in order to prevent any atmospheric leakage of CO_2 misses taking into account the possibility of future technology development, market changes and potential opportunities to utilize the storage complex without risking leakage of CO_2. The key priority in allowing post closure activity that may impact the storage complex should be to minimize the risk that stored CO_2 will be released to the atmosphere. ARB should provide guidelines to manage this risk rather than completely prevent post closure activity.

e. Third party independent review for permanence protocol: Third-party verification may be used to verify the permanence of CO2 storage, including site assessment, well-integrity, storage models used, failure scenarios evaluated, and adequacy of the monitoring strategy to detect leakage as part of the permitting process. Third-party verification may also be used to verify the permanence protocol during operations or the post-closure period. For EOR, however, the need for third-party verification could risk being redundant and unnecessary given existing federal and state regulatory oversight for underground CO2 injection under the Underground Injection Control (UIC) Program, CO2 storage and post injection monitoring under Subpart RR of the Greenhouse Gas Reporting Program and well integrity under state regulatory bodies such as the Texas Railroad Commission.

f. CO_2 purity: Purity requirements can be technology-limiting because some industrial processes and/or capture technologies yield CO_2 with differing composition. While there are practical limitations on CO_2 composition for use in EOR, operators have specifications in place to ensure that these limits are met. Additionally, the nature of transporting CO2 in a supercritical phase requires pipeline operators to set specifications that must be met in order to comply with pipeline construction materials and to allow for the safe delivery of CO2. Thus any CO_2 purity requirements risk being redundant, forcing CO_2 producers to comply with multiple specifications. We recommend that ARB balance the risks and practical considerations, such as commercial feasibility, in developing any specifications for CO_2 purity.

g. Well materials: Prescribing the use of specific well-materials will risk excluding future development in materials that can be used by eligible entities. We recommend that ARB not restrict the use of materials and base the requirements under this category on results of various studies so far.

We appreciate the opportunity to provide comments. Work Group members would welcome the opportunity to engage with ARB staff on any points in these comments. Please do not hesitate to reach out to either one of us, if you have questions or wish to discuss the comments in more detail.

Sincerely,

Adam Schafer
Senior Advisor
Office of Montana Governor Steve Bullock

Matt Fry
Senior Policy Advisor
Office of Wyoming Governor Matt Mead

APPENDIX A: Problems with Crediting and Charging Carbon in Two Different Markets

The comments that follow in this subsection are intended to raise the possibility that under current conceptions of how captured CO2 is apparently required to be credited to either the Cap-and-Trade system or the LCFS system based on how regulatory "system boundaries" are drawn, it is possible that adverse and counter-intuitive economic results will arise. These adverse, counter-intuitive results could make CCS *appear* to be a poor idea to companies in the economic/industrial value chain, even though the real world economic and environmental calculations show the opposite—i.e., that CCS, in conjunction with CO2-EOR, is a CO2 reduction mechanism that is both comparatively cost-effective and essential to meeting the State's goals. The problem, as outlined below, would occur if system boundaries are drawn in such a way that the *emissions reduction benefits* of capture are valued in one market (e.g., the Cap-and-Trade market) while the *emissions costs* of operating CO2-EOR are charged in a different market (e.g., the LCFS regime).

When CO2 is captured at a site remote from oilfields or refineries, the sole nexus between the capture facility and the crude oil lifecycle is the sale of CO2 by the capture facility to a CO2-EOR producer. The CO2 is simply a purchased input to the EOR process. That said, the CO2 is an indispensable input. Without CO2 from some source, the CO2-EOR production cannot occur. But the CO2-EOR operator could have purchased the CO2 from any number of man-made or natural sources. The general goal of government programs, whether state or federal, has been to create incentives (i) for the former polluter to install equipment to capture the CO2, and (ii) for the oilfield to use anthropogenic CO2 in preference to other CO2 sources.

Under various Federal precedents, it is recognized that there is a complete, unified, industrial value chain connecting the capture facility and the CO2-EOR producer. As two examples:

1. Under the proposed Clean Power Plan, a fossil fuel power plant that captured CO2 could treat the CO2 as "not emitted" as long as the CO2 was transported to a CO2-EOR operation that would then account for the purchased CO2 under the Sub-part RR federal GHG reporting rules. So the power plant could generate CO2 allowances that could be sold in whatever trading system might emerge, but only if the oilfield were in compliance.
2. On the other hand, tax credits would have been available under the Section 45Q storage tax credit regime, amounting to $10 per MT stored via CO2-EOR (proposed to rise to $35 per MT under pending legislation). Those §45Q tax credits could be claimed by the capture facility, but the capture facility could also assign the right to claim the credits to the oil field. The tax law was not particular about where in the value chain the credits were claimed.

The State and the ARB, if we understand recent presentations and documents correctly, is taking a very different approach. As we understand the current conception of the future implementation of regulations for CCS in both the Cap-and-Trade regime and the innovative crude/LCFS regime, especially as described in the workshop held on April 4, 2017 (relating to the OPGEE model) and on May 8, 2017(relating to QM), staff's conception would more or less bifurcate the industrial value chain.

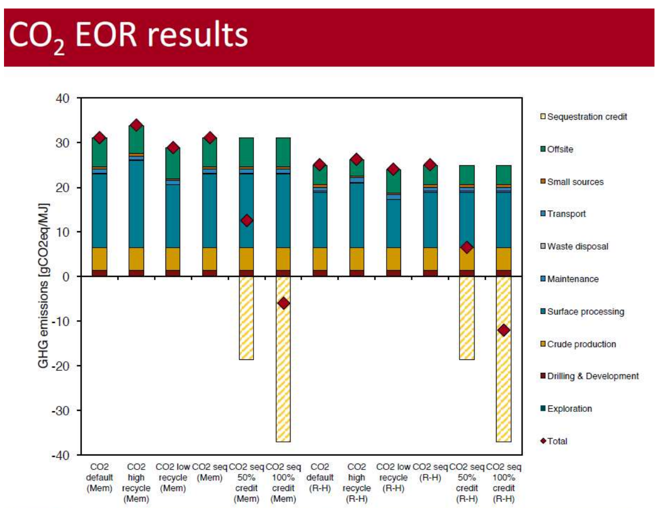
- Staff's conception is that if CO2 is captured by an AB32 Cap-and-Trade "covered emitter" that is not on an oilfield or refinery premises, such as a cement plant, power plant, steel mill, etc., the captured tons of CO2 could only be usable, only create a benefit to the capturer, in the context of the AB32 Cap-and-Trade market for allowances. The capturer (e.g., a natural gas combined cycle power plant) would need to purchase fewer allowances during a given year because its total CO2 emissions would be reduced by the captured tonnage. Staff states, "The project system boundary [for the capturer] would end with injection operations." [1] *In short, for the capture facility, the credit/benefit side would be monetized solely through the current trading value of AB32 Cap-and-Trade allowances; and apparently the crediting under Cap-and-Trade would not consider oilfield operations.*
- However, assuming that the CO2 is sold to an oil field, and the oilfield then uses that CO2 in CO2-EOR operations, the CO2 emissions relating to the oilfield operations would impact the Carbon Intensity of crude produced thereby. Staff stated in its Concept Paper of April 2017, "In the case of CO2 enhanced oil recovery

[1] CCS Concept Paper April 2017, page 3/9

(CO2-EOR) *emissions* [emphasis added] associated with oil production would be considered part of the system boundary and be included in the accounting, for example by allocating in some proportion between oil production and CO2 capture."[2] As shown in the presentation by Professor Adam Brandt of Stanford on the OPGEE model[3], the CO2 emissions costs of conducting CO2-EOR operations—without considering any benefit for storage—would amount to ~30 grams of CO2 released per MegaJoule of oil produced. *So, as we understand the proposal, the carbon costs would solely be charged at the current trading value of tons of CO2 in the LCFS market.*

What is the consequence of having carbon benefits credited in the Cap-and-Trade market, but the carbon costs charged in the LCFS market? That depends on the amounts of CO2 on each side and the prices on each side. Here are the explanations of key parameters:

- Amounts of CO2 stored and emitted per bbl of oil produced in CO2-EOR:
  - Typical oilfield operations with which we are familiar, such as Texas' Permian Basin use on a net basis, roughly 8-9 thousand cubic feet (MCF) of CO2 to produce a barrel of oil. A frequently cited journal article by Azzolina (2015) cites median net usage of 8.7 MCF per barrel.[4] Converting to MT[5],that would be <u>0.45 MT permanently stored per bbl produced</u>, over the full life of the field.
  - Emissions of CO2 by conducting CO2-EOR operations vary by field and by analyst. Utilizing the OPGEE presentation by Professor Brandt (see clipped slide excerpt below) it appears that, ignoring any storage benefit, the gross emissions associated with CO2-EOR operations are in the range of 25-35 grams CO2 per MegaJoule of oil. For simplicity, using 30g/MJ, that would be approximately 0.183 MT/bbl.[6]



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[2] CCS Concept Paper April 2017, page 3/9.
[3] "*OPGEE v2.0a Oil Production Greenhouse Gas Estimator*" PowerPoint presentation dated 4/04/2017 and presented at ARB workshop.
[4] Azzolina et al, "*CO2 storage associated with CO2 enhance oil recovery: A statistical analysis of historical operations*", International Journal of Greenhouse Gas Control 37(2015) 384-397.
[5] 19.3 MCF per MT per standard conversion tables. The EOR industry typically uses MCF to measure CO2 purchase and injection, as opposed to the pollution control industry which usually works in MT.
[6] One barrel of oil equivalent (BOE) typically contains 6.11 x 10^9 or 6.11 GigaJoules, using standard industry conversion tables found online.

- Pricing of CO_2:
  - The most recent AB32 allowance auction in March 2017 produced a sales price of ~$13.57[7] per allowance, with one allowance equal to 1 MT of CO_2. That is the legal floor level.
  - The March 2017 LCFS Credit Transfer Activity Report showed an average credit price of $93.[8]

The table below shows the results if: (i) the only party permitted to claim a benefit for storage is the Cap-and-Trade covered emitter such as the power plant, using Allowance Prices to measure benefit; and (ii) the party that is required to include CO_2 emissions costs of running the CO_2-EOR operation is the oilfield operator, using LCFS credit prices to assess cost. [Note: The commenters are not sure that this is exactly staff's intent. The commenters are concerned that the situation portrayed below is one possible outcome—a very concerning outcome--based upon the presentations, documents, and comments made by staff in the process so far.]

	MT/bbl oil emitted /(stored)	Market for Credits /Allowances	Price/MT	Revenue/ (Cost) per bbl
Carbon Sold to Oilfield by Capture Facility	(0.45)	AB32 Cap-and Trade	$ 13.57	$ 6.11
Oilfield Emissions of CO2 in Conducting CO2-EOR	0.18	LCFS	$ 93.00	($17.02)
Net	(0.27)			($10.91)

In the left hand column we can see that the oilfield must buy approximately 0.45 MT of CO_2 in order to produce a barrel of oil. During the conducting of CO_2-EOR operations, the OPGEE program indicates a rough 0.18 MT /bbl emission of CO_2. So on a net basis, approximately 0.27 MT/bbl are stored (ignoring any emissions associated with burning the fuel—a factor already encompassed in California's overall regulatory regime). So, as an environmental matter, this is a very good outcome as compared to, say, the "California Baseline Crude Average applicable to crudes supplied during 2015 and subsequent years" of 11.98 g/MJ or ~0.07 MT/bbl emitted.[9]

However, in the far right hand column, we can see that the gross "value/benefit" of Cap-and-Trade allowances relating to the 0.45 MT/bbl of CO_2 was only $6.11, since it was valued at $13.57/MT. The "cost" to the oil producer in terms of Carbon Intensity of the smaller 0.18 MT/bbl emitted, since it was valued at $93/MT was a much larger ($17.02). The far higher price/MT charged on the smaller emitted tonnage outweighs the benefit on the tons stored. Thus the aggregate regulatory value produced by the capture and undertaking of CO_2-EOR is negative--$10.91 net cost per MT. This is a disincentive to CCS caused by pricing benefits and costs in two disjointed markets.

To restate, in terms of relative magnitudes: the tonnage of CO_2 stored is roughly 2.5x bigger than the amount of CO_2 emitted by CO_2-EOR operations.[10] But the LCFS "charge" in terms of valuation of Carbon Intensity is about 6.9x bigger than the valuation of a MT of CO_2 in the Cap-and-Trade market. [11] The relatively arbitrary, policy-dictated pricing differential between tonnes of CO_2 in the LCFS market vs. the Cap-and-Trade market is big enough to negate the real world, physical factors—namely that far more tons are sequestered in CO_2-EOR than are emitted in conducting the CO_2-EOR operations.

[7] Auction settlement price USD 13.57 Auction #10 March 1, 2017. https://www.arb.ca.gov/cc/capandtrade/auction/feb-2017/summary_results_report.pdf Prior auction USD 12.73.
[8] See Monthly Report posted 4/11/2107. Accessed online 6/6/2017 at https://www.arb.ca.gov/fuels/lcfs/credit/20170411_marcreditreport.pdf
[9] See LCFS final order § 95489, Table 8, Carbon Intensity Lookup Table for Crude Oil Production and Transport.
[10] 0.45 tons stored / 0.18 tons emitted = 2.5 : 1 ratio.
[11] $93/MT LCFS credit price / $13.57/MT Cap-and-Trade price = 6.9 : 1 ratio.