June 24, 2022

California Air Resources Board
1001 I Street
Sacramento, CA 95814

Dear ARB Board Members and staff,

Thank you for the opportunity to comment on the May 2022 Draft Scoping Plan Update. As we have stated previously in our comments on the March 15th Initial Modeling Results Workshop[1] and the April 20th Initial Air Quality & Health Impacts and Economic Analyses Results Workshop,[2] we deeply appreciate the hard work that ARB staff and the Scoping Plan modeling teams are doing to prepare a strategy to achieve California's ambitious climate goals. We are energy modeling and policy experts from Stanford University focused on technical and policy innovation towards an equitable and sustainable energy transition. These comments reflect our personal views and not those of Stanford University, the Doerr School of Sustainability, the Woods Institute for the Environment or the Climate and Energy Policy Program.

Our comments in this letter focus on risks to the cost-effectiveness and implementability of the proposed scenario in the timeframe available to reach the state 2030 climate target and 2045 net zero goal. Uncertainty in the proposed scenario is relatively large because of its heavy reliance on emerging technologies that are not in wide deployment, in particular carbon capture & sequestration (CCS) and carbon dioxide removal (CDR). We recommend that ARB address the following issues in the final Scoping Plan Update and associated modeling updates:

1. The costs of the proposed scenario are sensitive to assumed CDR cost and availability that are highly uncertain.

---

[1] Michael Wara et al., Public Comment on 2022 Scoping Plan Update – Initial Modeling Results Workshop (April 4, 2022),
https://www.arb.ca.gov/lists/com-attach/65-sp22-modelresults-ws-BWQFcVMwUFxWI1Az.pdf

[2] Michael Wara et al., Public Comment on 2022 Scoping Plan Update – Initial Air Quality & Health Impacts and Economic Analyses Results Workshop (May 4, 2022),
https://www.arb.ca.gov/lists/com-attach/62-sp22-econ-health-ws-VDVSJgNgVIoBdAVm.pdf

2. The assumed costs of CCS should exclude time limited policy incentives that are net societal costs including the Low Carbon Fuel Standard (LCFS) and 45Q tax credits.
3. The assumed costs of CCS in the petroleum refining sector should be consistent with the assumed phasedown of needed refinery capacity in California in the proposed scenario.
4. The scale of proposed CDR and CCS implies potential risks associated with pipeline safety and induced seismicity that merit consideration.

1. The costs of the proposed scenario are sensitive to assumed CDR cost and availability that are highly uncertain.

In the proposed scenario, achieving both the 2030 target and the 2045 goal requires the implementation of unprecedented levels of direct air capture (DAC) as a mechanical CDR strategy. By 2045, total CDR required to achieve carbon neutrality is between 79 and 102 million metric tons per year under the proposed scenario, depending on whether the additional 23 million metric tons (MMt) CO_2 of CDR necessary to be consistent with the Natural and Working Lands (NWL) modeling presented in the Draft Scoping Plan Update is included.[3] At present, the largest mechanical CDR facilities in the world capture a few thousand tons or less at costs approaching $1000/ton. None of these facilities is currently storing CO_2 in deep saline aquifers in California.

The volume of one ton of CO_2 at supercritical temperature and pressure (the condition under which CO_2 is injected into geologic formations) is about 2 barrel equivalents. Mechanical CDR in 2045 in the proposed scenario would involve storage on the order of 160 million to 200 million barrels per year. This amount of CDR is significantly more than the volume of crude oil extracted and transported by the California oil industry today (~130 million barrels in 2021 according to the US Energy Information Administration).[4] The costs and potential challenges of creating an industry of this scale in California over a two decade period are highly uncertain. Yet the Scoping Plan Update does not investigate how uncertainty in technical capacity, economic cost,

[3] https://carbonplan.org/research/scoping-plan-comments
[4] https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=mcrfpca1&f=a

or speed of implementation might impact achievement of the 2045 target. We urge ARB to explicitly evaluate these uncertainties.

A. Technical Risks

The CDR technologies most commonly utilized today require the use of amine based scrubbers, copious amounts of water (often several tons of water per ton of CO_2 captured), and very large quantities of electric power (typically 2000kWh per ton of CO_2 captured). Storing the carbon in deep saline aquifers involves injection and pressurization of these formations at a regional scale that is unprecedented in California.

The Draft Scoping Plan Update includes an estimate of the electric power requirements, noting that up to 40GW of off-grid solar would need to be constructed to achieve the CDR objective. This is 80% of the record peak demand of the CAISO system (50 GW).[5] Siting this amount of solar, in addition to the solar that will be needed to meet grid connected electric power needs in California, deserves further scrutiny given the increasing challenges of finding additional acceptable locations for utility scale solar installations in California.

ARB also does not consider the potential downwind community impacts from large quantities of ammonia based scrubbers that are exposed to large volumes of air (essential for the CO_2 capture process), nor the potential water requirements of such systems in California generally or in the locations where high quality storage exists - for example the San Joaquin Valley. Given the centrality of mechanical CDR to the preferred scenario, we urge ARB to fully explore the implications of creating a new air source of nitrogen at this scale. We also urge a thorough evaluation of how the water needs of these facilities may limit the scale at which they can feasibly exist in an already water stressed state like California.

Understanding of the regional impacts of deep aquifer injection has emerged in Oklahoma and Texas due to deep disposal of produced water from unconventional drilling.[6] This experience has illustrated the need to conduct significant geologic and hydrologic surveys prior to the advent of large scale storage and to combine these with geomechanical modeling in order to predict if and how induced seismicity may be caused by injection of significant quantities of

[5] https://www.caiso.com/documents/californiaisopeakloadhistory.pdf
[6] https://www.science.org/doi/full/10.1126/sciadv.1601542

liquid CO_2 in deep aquifers that may pressurize faults in basement rocks. In general, these types of surveys have been done for oil and gas reservoirs but not for the deep saline aquifers that are the preferred option for disposing of supercritical CO_2 from mechanical CDR and CCS. In Oklahoma, these studies have allowed continued use of deep well disposal, albeit at a reduced rate. Just as in Oklahoma, induced seismicity from deep saline aquifer storage of CO_2 may limit where storage can occur or limit injection rates at the regional level (for example in the San Joaquin Valley). As far as we have been able to determine, information needed to characterize this risk for California deep saline aquifers does not yet exist. Given the abundance of storage relative to ARB's targets for CDR and CCS in the Draft Scoping Plan Update, induced seismicity may turn out to be a non-issue. But it is premature to assume this without further evaluation.

B. Economic risks

The Draft Scoping Plan Update represents the costs of mechanical CDR as \$1000/ton CO_2 in 2030, falling to \$236/ton CO_2 in 2045. We believe that while these costs are certainly possible, they are also highly uncertain projections of a distant future. We note that if the cost of CDR falls only to \$500/ton rather than \$236/ton in 2045, our calculations indicate that the total costs of the proposed scenario in Pathways for 2045 increase from \$27 billion to \$48 billion in that year. A meaningful change in comparison to Alternative 1, which costs \$65 billion in 2045 under these assumptions, reducing the cost differential between these scenarios by \$15 billion or almost 50%. It is certainly possible that the technology costs projected by ARB may come to pass. It is also possible that CDR may turn out to be less expensive than ARB imagines.

We urge ARB to consider a range of possible project costs ranging from the optimistic to the pessimistic for a nascent technology that it envisions scaling by a factor of 20,000[7] in order to achieve its proposed scenario for carbon neutrality in California. Further, in order for this vision to come to pass, ARB will have to develop a revenue model for financing CDR that is unprecedented in scale. Even if costs are in line with agency predictions, developing a business and regulatory framework to generate \$12 billion (proposed scenario costs for CDR in 2035, 5 times current Greenhouse Gas Reduction Fund revenue) to \$19 billion (proposed scenario

[7] The largest operational CDR facility in existence captures and stores 4000 tons/y. The proposed scenario envisions 80,000,000 tons/y. https://en.wikipedia.org/wiki/Orca_(carbon_capture_plant)

costs for CDR in 2045, more than 8 times current Greenhouse Gas Reduction Fund revenue) will require new revenue sources supported by a robust policy framework.

C. Timeframe risks

We have tremendous confidence in California's leadership role in climate policy. And we believe that California will continue to break new ground in deploying the technologies of the future to achieve our ambitious climate goals. However we would urge ARB to consider a series of milestones for development of CDR policy in California. While Scoping Plan updates will occur every five years and will provide an opportunity to revisit a CDR dependent strategy for 2045, we would urge ARB, in adopting a preferred scenario that is highly dependent on widespread deployment of emerging technology and infrastructure, to develop a set of critical near- and mid-term milestones to evaluate deployment progress on technical, economic, and social acceptance dimensions.

2. **The assumed costs of CCS should not include time limited policy incentives including LCFS and 45Q tax credits.**

A. Explicit statement of CCS costs

While mechanical CDR costs are explicitly reported in the Draft Scoping Plan Update appendices, assumed CCS costs are more opaque. Appendix H provides references on which costs are reported to be based, but we urge ARB to disclose the specific cost assumptions utilized in Scoping Plan modeling, as done for mechanical CDR. This is particularly important for sectors like petroleum refining and cement production, where CCS is a key facet of the proposed scenario. In order to make these costs comparable to published cost estimates, ARB should report these costs in dollars per metric ton CO_2 captured by facility type (for example, fluidized catalytic cracker) rather than by fuel type and industry as is typical in pathways modeling output.

B. LCFS and 45q inclusion in CCS cost estimates

We also caution against the inclusion of LCFS and/or federal 45q tax incentives as cost-reducing measures for CCS in the proposed scenario. Given the lack of explicit information on CCS costs, it is not clear whether the Draft Scoping Plan Update includes such cost reductions, but they are included in cited studies, such as the 2020 study by the Energy Futures Initiative (EFI) and the Stanford Center for Carbon Storage which assumes that LCFS credits can be sold by the project at $100/ton for the first 15 years of project operation.[8] This type of cost estimate is entirely appropriate for a private cost but is inaccurate for a societal cost estimate in a rulemaking such as the Scoping Plan Update process.

LCFS incentives are a cost to California because revenues used to finance CCS come from California retail gasoline purchases. Therefore, they should not be counted towards reducing costs of CCS in the Scoping Plan process. Furthermore, the trajectory of LCFS requirements beyond 2030 is at this point unclear and subject to future rulemaking. Federal 45q tax incentives require commencement of construction no later than Jan 1, 2026 and thus will expire (unless extended) prior to the timeframe relevant to the proposed scenario. If new modeling is based on a 2028 startup for the first facilities using CCS as stated during the June 23, 2022 Board Meeting, it is not clear what fraction, if any, of facilities envisioned by the plan will be eligible for federal tax-based incentives triggered by commencement of construction.

We ask that ARB make clear in the final Scoping Plan Update what costs are assumed for CCS in each sector, whether LCFS and 45q incentives are incorporated into these costs and, given the long lead times for permitting of such facilities, to what degree ARB assumes that these incentives will be extended or in the case of the LCFS, modified, beyond their current program expirations and timelines. Ideally, ARB should make clear what it assumes regarding costs of CCS with and without these incentives in place given that their continued existence is subject to future legislative or regulatory action.

3. **The modeled costs of CCS in the petroleum refining sector should be consistent with the modeled phasedown of needed refinery capacity in California in the proposed scenario.**

In the proposed scenario, petroleum refining activity phases down in line with declining petroleum demand. As presented at the March 15 Initial Modeling Results Workshop, 33% of current petroleum refining output remains by 2035, and 13% remains by 2045. The costs of

---

[8] Energy Futures Initiative and Stanford Center for Carbon Management. “An Action Plan for Carbon Capture and Storage in California: Opportunities, Challenges, and Solutions.” October 2020.

CCS in the petroleum refining sector should be consistent with this assumed contraction and its implications for the lifetime of facilities installing CCS. It is impossible to determine if this is the case given the data provided in the Draft Scoping Plan Update. We ask for clarification on the assumed lifetime of CCS investments under the proposed scenario and the degree to which shortened lifetimes are factored into costs.

The costs of CCS are often calculated based on an assumed facility lifetime of 20 years or more. The EFI-Stanford financial analysis, for example, assumes a 20 year lifetime in its financial and technoeconomic calculations. Shorter facility lifetimes, which are probable under the proposed scenario, would substantially increase annualized CCS costs. While the issue of facility lifetime is likely not relevant in the cement industry (we will still need cement in 20 years), it is very important for understanding costs in California's petroleum refining industry under the proposed scenario.

The Pathways modeling underlying the proposed scenario assumes that, as the transportation fleet electrifies over the next two decades, the demand for refined petroleum products from California refineries will also decline dramatically. Under this scenario, California will still need some refinery capacity - for aviation fuels and the many other products these facilities produce. However, thanks in part to the supportive policy environment created by ARB, refineries' core products - gasoline and diesel fuels - will find far fewer buyers as the transportation fleet goes electric over the next two decades,.

This presents a fundamental challenge to the economics of CCS projects that might be implemented at these refineries. CCS projects like the Quest and Sturgeon facilities in Alberta, discussed in more detail in our earlier comments[9], cost billions of dollars. These costs are supported by large public subsidies and planned operational lifetimes of at least two decades. In the United States, CCS facilities in the US have generally relied on very large public subsidies from DOE,[10] in Alberta, similar subsidies have facilitated the construction and operation of Quest, Alberta Carbon Trunk Line,[11] and the Sturgeon Refinery.[12] Financing for all of these facilities was predicated on long-term operation that allowed for amortization of the high

[9] https://www.arb.ca.gov/lists/com-attach/65-sp22-modelresults-ws-BWQFcVMwUFxWI1Az.pdf
[10] https://www.gao.gov/products/gao-22-105111
[11] https://www.alberta.ca/carbon-capture-utilization-and-storage-funded-projects-and-reports.aspx
[12] https://open.alberta.ca/dataset/cbd7147b-d304-4e3e-af28-78970c71232c/resource/4da34006-a913-46e7-b7cc-eb8d66e2e999/download/energy-annual-report-2020-2021.pdf

capital costs over long facility lifetimes. This is typical for long-lived infrastructure like these plants but is inconsistent with planned phasedown of refinery capacity in California.

We recommend that ARB adopt a “tranched” approach to estimating the costs and needs for CCS at refineries in California that explicitly recognizes that CCS for refinery capacity (hydrogen, fluid catalytic cracking, and combined heat and power) that is expected to operate through 2045 is likely to be lower cost per ton of CO_2 captured than refinery capacity that will retire “early” as California gasoline and diesel demand falls over the next two decades. Put another way, ARB should explicitly incorporate stranded asset costs in its simulation of CCS deployment at refineries because if transportation plays out as projected, refinery CCS investments will be stranded.

A modeling approach with three tranches of CCS could be implemented in Pathways as follows: Two thirds of refinery capacity begins operation with CCS in 2028 (this was stated at the June 23, 2022 Board Meeting as the likely start date given permitting and construction lead times) and retires by 2035 (7 years later) as modeled transportation fuels demand falls. This capacity would likely be somewhere between 50 and 100% more expensive than projected by EFI-Stanford using a 20-year lifetime, depending on the operating costs at facilities. ARB could assume a second CCS tranche, 20% of existing refinery capacity, might have an operating lifetime of 15 years - representing capacity that comes online in 2030 and retires by 2045 when petroleum refining activity falls to just 13% of current levels. Finally, ARB could assume that 13% of refinery capacity that is equipped with CCS could operate for a more standard lifetime for a CCS investment - perhaps of 20 to 25 years.

The alternative, not discussed in the proposed scenario but also possible, would be that refinery capacity within California pivots from supply of domestic refined gasoline and diesel products to export, thus operating for its intended 20 to 25 year lifetime. The challenge here is that the Pathways modeling indicates a maximum capture rate of 63% of total refinery emissions. While this is possible given studies of feasible capture from refinery operations,[13] it will leave substantial unabated fossil emissions, not to mention community impacts, as California strives to achieve ever more stringent emissions targets. We note in passing that most refinery sites in

13 https://ieaghg.org/publications/technical-reports/reports-list/10-technical-reviews/819-2017-tr8-understanding-the-cost-of-retrofitting-co2-capture-in-an-integrated-oil-refinery

both Southern and Northern California are located in highly urbanized areas with very strong interconnection to rail that make them ideal, if properly remediated, for redevelopment as low-VMT high-transit housing. We note that if export is intended as the outcome for petroleum refinery output that California no longer needs to meet domestic demand, then uncaptured emissions from refineries (37% of total emissions) should be included in emissions from the sector even as domestic demand falls.

In any case, we urge ARB to consider in its scoping plan update revisions the economic and business challenges associated with building long-lived, capital-intensive infrastructure that is not intended to bemused for its useful life. And we request that ARB make explicit what it thinks the costs of CCS would be given the timelines over which it is expected to operate in each Pathways scenario. These issues cannot be separated and are clearly important to many constituents. Greater transparency and hence confidence in the modeling and its underlying assumptions can only strengthen confidence in the proposed scenario.

4. **The scale of proposed CDR and CCS implies both a very large pipeline infrastructure and a need to carefully evaluate the potential for induced seismicity.**

As mentioned previously, the combined magnitude of CDR and CCS raise important questions around scaling that need careful evaluation. Both pipeline safety and induced seismicity issues would benefit from further analysis in the final Scoping Plan Update.

A. Pipeline safety

As ARB is no doubt aware, a supercritical CO_2 pipeline accident occurred in 2020 in Mississippi. Subsequently, the Pipeline Safety Trust commissioned an expert report that was highly critical of the current state of CO_2 pipeline regulation in the United States, particularly given the large number of CO_2 pipeline proposals currently under development or in review.[14] Further, in response to this accident, PHMSA has recently opened a new rulemaking on CO_2 pipeline safety.[15] We urge ARB to estimate, at least in a preliminary sense, what degree of CO_2 pipeline infrastructure might be required to serve the envisioned CCS and CDR infrastructure deployed

[14] https://pstrust.org/wp-content/uploads/2022/03/3-23-22-Final-Accufacts-CO2-Pipeline-Report2.pdf
[15] https://www.phmsa.dot.gov/news/phmsa-announces-new-safety-measures-protect-americans-carbon-dioxide-pipeline-failures

in California under the proposed scenario, and the degree to which it would have to be sited in heavily populated areas (because that is where sites requiring capture are located)..

The combined scale of CDR and CCS in the proposed scenario also raises important questions regarding the actual usable amount of CO_2 storage in deep saline aquifers in California. The EFI-Stanford report has estimated that up to 70 gigatons of storage are available.[16] But this estimate does not fully account for induced seismic risks associated with pressurization of aquifers as injection occurs. Evidence from Oklahoma indicates that deep water disposal at similar scales in aquifers close to bedrock - or even in some cases separated from bedrock by seemingly impermeable layers - can create induced seismicity as pressures build.[17] There is good reason to think that CO_2 injection at scale may cause similar impacts if not carefully managed.[18]

This is not a new phenomenon. What is new is the level of disposal in deep aquifers that occurred in Oklahoma's Arbuckle Formation and what is proposed in terms of long term injection of liquid supercritical CO_2 in California deep saline aquifers. We believe that this issue can be managed with careful assessment of storage formations and of injection rates and locations.

We urge ARB to consider these risk as it proposes a ramp to 80MMt CO_2 or more of CDR over the next two decades. If the proposed scenario, or a modified version of it is ultimately adopted, the ARB should develop programs to safely construct and operate supercritical CO_2 pipelines as well as responsibly develop a detailed and nuanced understanding of induced seismic risk for deep saline aquifers in California.

Respectfully submitted,

Michael Wara, JD, PhD
Director, Climate and Energy Policy Program

---

16 https://sccs.stanford.edu/sites/g/files/sbiybj17761/files/media/file/EFI-Stanford-CA-CCS-FULL-rev2-12.11.20_0.pdf
17 https://www.science.org/doi/full/10.1126/sciadv.1601542
18 https://www.pnas.org/doi/10.1073/pnas.1202473109

Woods Institute for the Environment
Stanford University
mwara@stanford.edu

Michael Mastrandrea, PhD
Research Director, Climate and Energy Policy Program
Woods Institute for the Environment
Stanford University
mikemas@stanford.edu

Alison Ong
Emmett Interdisciplinary Program in Environmental Resources
Stanford University
alisonjo@stanford.edu