EBR Development LLC

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Dear Mr. Mitchell:

The undersigned organizations appreciate the opportunity to offer comments on the Carbon Capture and Storage (CCS) concept paper presented by California's Air Resources Board (ARB) staff on May 8th, 2017.

We represent a diverse group comprised of industrial sources of greenhouse gases (GHGs), potential CCS project developers, technology providers, academics, and non-governmental organizations (NGOs).

We are united in our views that deployment of CCS is critical to reaching California's GHG reduction goals, and that the outcome of ARB's current effort to adopt a Quantification Methodology (QM) and regulatory requirements for CO_2 storage will, in great part, determine the extent to which CCS can play that role.

In comments submitted on February 3rd, 2017, members of this group stated that we believed ARB must focus on appropriate revisions to its climate programs to increase the likelihood of CCS deployment. In further comments submitted on April 10th on the draft Scoping Plan, we stated that technologies are rapidly advancing, but that the pace at which CCS is deployed will be determined largely by legal, regulatory, and policy issues such as those that ARB is now considering. Finally, we noted that CCS could deliver considerable reductions in GHG emissions in the 2030-2050 period, but only if supportive policies were to be adopted now.

The stated "Design Principles for CCS Program" ("Concept Paper") are sound, and we believe that the process will allow stakeholders and regulators the opportunity to resolve issues that arise (including those described below). The Concept Paper and May 8th public workshop discussion demonstrated ARB's commitment to thoroughness in working through the many topics and concerns that this process demands. Due to the complexity and technical nature of this effort, as well as the number of stakeholders jointly submitting comments, we recommend that ARB hold future workshops sooner after the publication of future versions, and provide longer comment periods following public workshops to allow stakeholders to fully absorb the material, enabling more opportunity for participation.

We support ARB's two overarching goals in this effort: first, to ensure that CCS is environmentally protective and effective, and second, to encourage deployment of CCS in California and in other jurisdictions that affect the state's carbon footprint. As stated by several commenters at the workshop, a test of this regulatory process must be whether it leads to planning, development, and deployment of new CCS projects in the near and mid term. If new projects are not operating by 2025, it is less likely that they will contribute to the state's 2030 goal for GHG reductions, leaving yet more ground to be covered for the 2050 goal.

ARB has also stated that it hopes its QM and storage requirements can serve as a model for other states. To date, seven other states and two Canadian provinces have overseen the deployment of CCS projects under their own regulatory regimes, and we encourage ARB to consider what California may learn from other jurisdictions' experience.

With that, we offer the following specific comments on issues outlined below. In addition, the Concept Paper raises several questions on which we are not yet prepared to comment, for example the definition of "depleted fields". We offer thoughts on such issues as well, and urge that the next draft offer clarification.

QM Design Principles

We thank ARB for incorporating several important design principles and provisions into the Concept Paper. These include:

- A recognition that CCS projects are site-specific in nature, including, for example geology, facility location and technology or project constraints;
- Requirements for site characterization, selection and operation, monitoring, reporting, verification and decommissioning that aim to ensure safety and storage permanence;

- Following a risk-based approach for project selection and operation;
- Allowing for performance-based options that do not limit the choice of technologies or materials;
- Assuming that injected CO_2 is sequestered unless otherwise shown or detected;
- Allowing for both deep saline formation and oil fields undergoing enhanced recovery using CO_2 to qualify;
- Planning to allow the inclusion of out-of-state projects that qualify under California's climate programs; and
- Recognizing that capture and storage facilities do not need to be collocated.

Expeditious adoption and integration under both the Low Carbon Fuel Standard and Cap & Trade

We understand that ARB has plans to incorporate the QM into the Low Carbon Fuel Standard (LCFS) in the coming months, but that its inclusion in Cap & Trade (C&T) is left as a future option. <u>It is important that ARB also send the appropriate signals that the QM for the C&T regulation will also proceed on a similarly expeditious, but separate, track</u>. CCS projects that are not fuel related will continue to be an important segment of CCS deployment and any indication that the regulatory framework for these projects will lag significantly will have a chilling effect on investment.

In the Concept Paper and in its May 8th workshop materials, ARB contemplates the use of direct measures for CCS. ARB should carefully consider how the use of a direct measure scheme that mandates the use of CCS at every facility within a sector would be in balance with the emphasis in the regulation on utilizing a site-specific approach – both from an environmental protection and effectiveness standpoint. As ARB acknowledges, not all geologies and not all facilities are suited for CCS projects.

LCFS and C&T credit requirements

The workshop slides propose that storage facilities would be a co-applicant with the separation facility. We suggest that the storage facilities should have their own certification. California would thus certify certain facilities as acceptable for California storage. The approach described in the slides would reduce the permitting complexity of a tri-party permit. It would also make it more difficult for a storage facility to serve as a hub and receive CO_2 from multiple sources by potentially obliging it to apply multiple times. Alternatively, we suggest that the application be filed by the party earning the credits. In any case, storage facilities should be designated.

The workshop slides also propose to attribute the emissions reduction to the capture facility, if it is a covered entity under C&T, based on the notion that the capture facility is removing CO_2 from its emission stream. Alternatively, some projects could qualify for LCFS credits or file for a reduced carbon intensity pathway. Either of these may work for a simple case where there are not two potential options for credit generation.

However, if there are potential LCFS credit options between CO_2 sources, this division could be managed contractually. For example, if an ethanol production facility sends CO_2 to an enhanced oil recovery (EOR) site, the ethanol could claim a lower carbon intensity. However, it is our understanding that the EOR facility could also potentially claim Innovative Crude credits, and there may be cases where the EOR facility is better equipped to provide all the application information to ARB. <u>In all cases, we believe that the applications should be reviewed and tested for environmental integrity and to ensure that there is</u>

no double counting. We support the maximum degree of flexibility in apportioning the CO_2 reductions between qualified entities to facilitate CCS without pre-judging the best place to give credits.[1]

Transfer of CO_2 to other fields

During EOR operations, CO_2 is produced along with hydrocarbons, water and other non-hydrocarbon gases from oil production wells. Once the liquids (oil and water) are separated in tank batteries, the gas mixture can either be further processed or re-injected directly into the reservoir for continued EOR operation. The decision to process the gas stream or re-inject directly depends on economic factors, the presence of a gas processing plant and sour injection permitting requirements.

The produced gas mixture or the processed CO_2 stream is generally reinjected into the same reservoir. However, sometimes it is transferred to another unit within the same field when gas processing or compression capacity is limited. Today, albeit rarely, it could be transferred to another field. The notion of field "blowdown", whereby CO_2 from an EOR flood that has come to an end is produced and sent to another field, is more theoretical at this time due to its limited application to date.

We recommend that the transfer of CO_2 from one unit to another, or from one field to another, be permitted. Because such transfers would require transporting via pipeline, volumes of CO_2 transferred could be easily measured and deducted in a method of accounting that calculates the CO_2 that is sequestered in the original unit or field. If the units or fields to which the CO_2 has been transferred are certified under the QM and permanence protocol, it would be included in the method of accounting for sequestered volumes for that field, provided there is no double counting.

"Post-closure" treatment of oil fields

With regard to CO_2 storage in depleted oil and gas reservoirs and CO_2-EOR fields, ARB suggested approach is to "ensure these fields will not be put back into production" following cessation of injection. While this is a seemingly simple approach to guard against release of stored CO_2, we recommend against a prohibition of future activity within a storage complex. Technology, market value changes, and/or additional usage opportunities associated with the storage complex may arise to justify or fail to prevent future activity. We believe there are other mechanisms that will preserve the option for such future activity without allowing the release of stored CO_2, and encourage ARB to consider alternatives**.**

For CCS operations in California that store qualified CO_2 through EOR or through saline storage, ARB should designate in-state storage complexes as covered entities (i.e. potential emission sources) under its climate programs such that any operator conducting activity within the storage complex or causing the potential release of CO_2 from the storage complex is responsible for ensuring such CO_2 is not emitted, is re-stored permanently, or accounted for as a new emission.

For CCS operations, outside of California certified by ARB, it may be legally difficult to enforce a ban on post-closure activity within or around a storage complex by a private party. It may also be difficult for the state to enforce an activity ban upon the governments in those other jurisdictions in cases where the state has assumed liability for the injected CO_2. However, in addition to certification of these facilities, ARB could require CO_2 storage operators in out-of-state locations to:

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[1] Some, but not all, of the undersigned believe that once CCS is a viable compliance pathway under the LCFS, ARB should account for this as part of its compliance modeling for setting future LCFS targets.

- Provide assurance that transfer of liability for stored CO_2 is included in the terms of any purchase and sale agreement of the storage complex; or
- Demonstrate the existence of storage permanence regulations that are functionally equivalent to California's; or
- Demonstrate the existence of provisions for the transfer of storage liability to the other state post-closure, provided there is a bilateral agreement between that state and California that provides for permanent storage of that CO_2.[2]

"Checkbox" option for complying with the permanence protocol

We reserve final judgement until details are made available regarding the "checkbox" option for complying with the permanence protocol. At this point, we remain cautious regarding this approach. Our reservations, listed below, span a range of perspectives, from a lack of certainty in environmental outcome and potential for sub-par projects to qualify, to concerns about the workability and value of this approach from a project developer and industry perspective.

- Demonstrating command of the local geology and associated risks is a highly site-specific matter. Geology can vary materially over short distances. We remain skeptical that the in-depth considerations of available geologic and other site data, and the related hazards and probabilities, can be boiled down to a check list.
- If some items on a check list are to rely on public well records, we question the quality and completeness of those in some cases. There are several known contexts where well records are missing, incomplete, inaccurate, or hard to obtain.
- As part of a checkbox approach, risk attributed to well vintage could define "no-go" zones. We support a thorough consideration of the integrity of existing and plugged and abandoned wells as a part of a site-specific risk analysis. However, the oldest wells tend to be the shallowest and thus may not present a significant containment risk.
- Techniques and materials for monitoring, well construction and more, will likely evolve as time passes. A check list, unless updated, may not capture the latest developments and stay abreast of new technology and best practice.
- In being prescriptive while at the same time endeavoring to be protective, a check list may simply become too restrictive to be usable in practice. Limiting the acceptable techniques and materials to a few options may not allow sites or projects to qualify in practice under this approach, leaving it unused.
- While we appreciate ARB's efforts to offer an expeditious and workable regulatory option, we are concerned that the development of the check list might be done at the expense of efforts to make the more thorough, risk- and performance-based compliance approach workable as well.

We advise ARB to carefully weigh the merits and risks of the "checkbox" approach, and to remain prepared to remove it in the final protocol if the version that appears in the proposed protocol is shown to be inadequate**.**

[2] Such agreements may not always be possible or desirable by other states, so ARB should examine these possibilities. Also, ARB should examine its ability to invalidate LCFS CCS credits previously generated in cases of fraud or error.

Third party independent review for permanence protocol

Third-party verification should be applied to review site assessment, well-integrity, and should look at the storage models used, the failure scenarios evaluated, and the adequacy of the monitoring strategy to detect leakage as part of the permitting process. The process should also be applied to reviews of these elements during operations or in the post-closure period.[3] For example, as part of the Shell Quest CO_2 Injection Project (Alberta) permitting process, Shell contracted Det Norske Veritas (DNV) to assemble a multi-disciplinary team of experts to review technical aspects of the project. DNV issued the world's first "certificate of fitness for safe storage" to the Quest Project in 2011.

Permanence Protocol

Secondary containment system (including under-burden)
The proposed checkbox site ranking approach includes buffer zones beneath and above the injection reservoir to reduce leakage and induced seismicity risk (respectively). Whereas such features may be desirable, characterization and dynamic simulation would reveal a more accurate view of the risks, whether these features are present or not. Further, a requirement for secondary zones may discourage consideration of otherwise suitable sites which could substantially reduce options of CCS-schemes in California. While the presence of such buffer zones may be preferable generally speaking, we urge ARB to take a holistic view of site characterization and not de facto require buffer zones at all sequestration sites regardless of site-specific risk, provided leakage and seismicity risks are properly analyzed and mitigated. We note that USEPA Class VI rules do not require secondary buffer zones to be present at all sites but that they may be required at the Director's discretion:

> 40 CFR §146.83(b): "The Director may require owners or operators of Class VI wells to identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation."

We also note that Class VI rules contain a separate requirement for operators to assess induced seismicity risk and submit such information with the permit application:

> 40 CFR §146.82(a)(3)(v): "Information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment"

Monitoring Reporting and Verification
Monitoring Reporting and Verification (MRV) is a crucial component of any carbon dioxide sequestration project. A properly designed and implemented monitoring plan serves several purposes:

- It verifies that injected CO_2 is indeed staying within its intended confinement zone;
- It provides a warning when the risk of leakage increases or when confinement is breached;
- It serves as a means of refining model inputs and improving operators' predictive capabilities regarding the injection and their knowledge of the structure and geochemistry of the subsurface; and

[3] Some EOR operators of the undersigned organizations perceive the recommendation for third-party verification at EOR fields as redundant and unnecessary given existing regulatory oversight from state and federal agencies for oil and gas operations and certain greenhouse gas reporting requirements.

- It provides a quantitative basis upon which to make operational decisions that can affect the integrity of storage.

Monitoring is essentially the eyes and ears of the operator, enabling detection and characterization of leakage and promoting an understanding of a subsurface environment that is otherwise inaccessible.

The appropriate monitoring strategy and techniques will depend on site-specific characteristics. There are references to various aspects of surveillance in the permanence protocol. Some of these infer the need for baselines, continuous pressure data acquisition from all wells and possible mandating of technology and its placement. Surveillance design is optimally developed on a risked basis. Certain monitoring techniques may be effective in some settings but not others, for example:

- Surface-based soil and atmospheric monitoring;
- Groundwater sampling, because it relies on fortuitous shallow well placement;
- Continuous pressure monitoring in available wells, which become a maintenance challenge and information may be redundant;
- Seismic, which can be very useful in both pre-injection characterization and operational monitoring, but has limits in complex geological settings and where the CO_2 plume is thin.

<u>Given that monitoring instrumentation and techniques approaches and technologies are rapidly evolving in terms of cost-effectiveness,[4] it would be unwise to establish "lock in"</u>.

CO_2 Purity

The permanence protocol suggests that CO_2 impurities could result in increased acidity which could degrade well materials. Combustion impurities such as sulfur and nitrogen oxides form acids in solution although the concentration is limited and additional acidity may not be appreciable relative to that produced by CO_2 dissolved in water. A simple geochemical model is diagnostic. Co-injecting incidental amounts may be beneficial as a criteria pollution control strategy too. <u>We recommend that ARB balance risks and practical consideration in its CO_2 purity specifications</u>.

Well Materials

The potential for inferior bonding with casing and country rock and complications with emplacement are also considerations. Studies have shown that proper primary cementing that creates a robust seal is the best approach for reducing leakage over the life of the well.[5] <u>We urge ARB to weigh pros and cons of prescribing the use of specific well materials and consider all available data</u>.

Leakage Mitigation Plan

In an EOR setting, existing wells are a potential leakage pathway that must be examined. Operating wells that have been constructed to modern standards generally pose lower risk than older or legacy wells. Wells that could become leakage pathways should be identified, evaluated and, if necessary, remediated to sufficiently establish permanence. Operators should develop a site-specific plan and consider various methods for identifying wells including historical records review, site reconnaissance, aerial and satellite imagery review, and geophysical and air emissions surveys. The techniques selected should be based on the history of field ownership, accuracy of well records, and other efforts to locate

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[4] For example, "above-zone" pressure monitoring, electro-magnetic configurations, combined gravity and remote techniques.

[5] Dusseault, M.B., Jackson, R.E., and MacDonald, D., "Towards a Road Map for Mitigating the Rates and Occurrences of Long-Term Wellbore Leakage," Geofirma Engineering Ltd., 2014.

existing wells. In fields with a single or few owners and with complete well records, very little action may be necessary. Conversely, in fields with complicated ownership history and/or where well records are incomplete, a more robust program may be needed. We also recommend that ARB review *ASTM D6285-99(2012)e1, Standard Guide for Locating Abandoned Wells*, for additional guidance.

Once existing wells are identified the condition of each should be assessed and corrective action must be performed as necessary to ensure that such wells will not act as leakage pathways. Steps to evaluate existing wells may include a well record review, field inspection and testing, and remediation. The need to progress through the series of steps should be based on the results of the preceding step. For example, field inspection and testing may be unnecessary for wells with complete and accurate well histories; on the other hand, if records indicate that wells were constructed or plugged using outdated methods, or if well records are incomplete or nonexistent, field inspection and testing of these wells may be necessary.

Post-injection monitoring

This is a complicated issue that calls for balancing developers' ability to pursue long-term projects, site-specific risks, public acceptability and environmental protection. On one hand, corporations are not used to dealing with very long or open-ended time frames for projects. The 50 and 100 year default periods currently proposed are arbitrary without consideration to project-specific parameters, and originate in precedents from other sectors (forestry, an inapplicable analog) or regulations (Class VI). In fact, the industry members among the undersigned view the 50 or 100 year default as the most significant obstacle to project development in the Concept Paper.

On the other hand, we may not be able to anticipate all eventualities today. For example, we have neither the data that definitively proves nor disproves that the long-term longevity and durability of plugged and abandoned wells is sufficient for permanent storage. An analysis of a SACROC Field (West Texas) well indicates that cement exhibits "self-healing" phenomena whereby dissolved cement is replaced by other mineral phases.[6] However, if new information comes to light that challenges current understanding of plugged and abandoned wells, an extension of monitoring periods may be justified. Note that, given the planning and operational timeframes for CCS projects, such a decision in California may not have to be made for several decades yet, by which time new data would be available. In any case, regulators, developers and stakeholders alike benefit from certainty in post-injection treatment.

Below are some precedents that we are aware of today:

- The operator of the Gorgon Carbon Dioxide Injection Project can apply for site closure at some point after injection operations have ceased. The time line for this is not specified but is based on the objective of the operator demonstrating the site is performing as expected and any residual risks are acceptably low and managed. At least 15 years following site closure, the site operator may apply for indemnity against certain third party claims for loss or damage that might arise as a consequence of the injection operations in the longer term.
- Quest will be performing 10 years of post-injection monitoring. This was determined at the outset of injection based on reservoir modeling and site specific risk assessment.

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[6] Carey WJ, Wigand M, Chipera SJ, WoldeGabriel G, Pawar R, Lichtner PC, Wehner SC, Raines MA and GD Guthrie (2007) Analysis and performance of oil well cement with 30 years of CO_2 exposure from the SACROC Unit, West Texas, USA. Int. J Greenhouse Gas Control 1(1): 75-85.

- Peterhead/Goldeneye had a performance-based period which could be six years or longer, based on surveys demonstrating containment of the stored CO_2 and no irregularities.
- The FutureGen project in Illinois accepted the 50 year default period in its USEPA Class VI permit.
- USEPA approved a modification of the default 50 year period to 10 years for the ADM Industrial Project in Illinois. This was done based on computational modeling to delineate the Area of Review; predictions of plume migration, pressure decline, and carbon dioxide trapping; site-specific geology; well construction; and the distance between the injection zone and the nearest Underground Sources of Drinking Water.
- The Oxy operated Denver Unit in the Permian Basin is establishing the long-term containment of CO_2 in the San Andres formation for a Specified Period of 10 years. At the conclusion of the Specified Period, Oxy will submit a request for discontinuation of reporting when Oxy can provide a demonstration that current monitoring and models show that the cumulative mass of CO_2 reported as sequestered during the Specified Period is not expected to migrate in the future in a manner likely to result in surface leakage. It is expected that it will be possible to make this demonstration within 2-3 years after injection for the Specified Period ceases and will be based upon predictive modeling supported by monitoring data.

<u>To resolve these concerns, we recommend the following approach</u>:

- Instead of a single default post-injection monitoring period that applies to all projects, we propose a tiered structure into which projects fit based on site attributes. Two or more tiers could exist, pointing to a shorter or longer default period.
    - A shorter default period to apply in cases where risk factors are reduced:
        - A proven seal exists that has held fluids for geologic time (e.g. an oil field that has not leaked)
        - Structural closure limits movement and location of injected CO_2 and any spill points are not reached
        - Wells are fewer in number, more recent, well-recorded, and plugged/abandoned using reliable methods by reputable operators.
    - A longer default period to apply in cases where risk factors compound:
        - Wells are more numerous, older, not well-documented and plugged/abandoned using unknown or questionable methods by less-than-reliable operators.
        - Movement of the CO_2 plume is likely to continue for some time after injection.
        - Presence of known faults or fractures that may not be sealing.
        - Concerns that natural seismicity may impact well or reservoir integrity.
- A preliminary post-injection monitoring period to be determined at the time a project/operator applies to ARB using an approach based on modeling and risk analysis as a starting point. This would modify the default period upward or downward by a modest amount.
- The preliminary post-injection monitoring period to be revised upward or downward as data and understanding of reservoir increase. The operator would propose a revision, and ARB would approve or edit if appropriate. This could happen during set review periods, similarly to Class VI:
    - Every 5 years during the injection phase.
    - After injection stops, at the start of post-injection monitoring activities.

- Later in the post-injection monitoring phase.

We thank ARB for its continued, diligent work on this topic, and stand ready to answer any questions.

Sincerely,

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[7] The views of the researcher do not necessarily represent the views of Stanford University.