OXY Occidental Oil and Gas Corporation
A subsidiary of Occidental Petroleum Corporation

Al Collins – Senior Director Regulatory Affairs
1701 Pennsylvania Ave NW, Suite 800
Washington, DC 20006
Phone: 202-857-3000

Via electronic submittal: http://www.arb.ca.gov/lispub/comm/bclist.php

July 5, 2018

Clerk of the Board
Air Resources Board
1001 I Street
Sacramento, CA 95814

Subject: Comments to the California Air Resources Board, Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard Version Dated June 20, 2018

Dear Mr. Mitchell:

Occidental Petroleum Corporation ("Occidental") appreciates this opportunity to provide comments on the most recent version of the California Air Resources Board's ("CARB") Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard ("Protocol") dated June 20, 2018.

Occidental is the largest injector of carbon dioxide ("CO_2") for enhanced oil recovery, or EOR, in the Permian Basin of West Texas and southeast New Mexico and is the industry leader globally in this technology. Occidental has more than 40 years of experience operating CO_2-EOR fields. Our CO_2-EOR operations are in mature seismically stable fields and are well located to assist California and fuel suppliers in meeting the requirements of AB32.

For Occidental, CO_2 is a commodity that has significant value and is carefully managed in a manner that reflects its importance to our enhanced oil recovery operations. We strive to avoid any preventable losses of the commodity because CO_2 represents a significant operating expense; the loss of a CO_2 molecule represents a corresponding increase to Occidental's operating expenses. Our objectives of protecting against the loss of CO_2 to the atmosphere are shared with CARB. Therefore, we encourage CARB to adopt regulations consistent with the techniques and tools used to successfully operate CO_2 floods for EOR. These tools and techniques are proven and by using them for other purposes (i.e., assurance of leak prevention and proper quantitation), costs can be minimized making the use of geologic sequestration more economic and widespread. Should the economics of purchasing CO_2 change in the future, these tools and techniques will still be the foundation of a regulatory system that is transparent and worthy of the public's trust.

Occidental manages its CO_2 with a sophisticated supervisory control and data acquisition (SCADA) system architecture that we rely on to monitor, measure and report on our CO_2 injection and recycling. Our SCADA system, which is described in more detail in the attached comments, provides information not only to our control centers in the Permian Basin but also to our senior management team in Houston and field personnel through a smart phone application. This system continuously monitors field and process conditions to ensure that the CO_2 we purchase and recycle is not lost from the reservoir or to the atmosphere. The deployment of this system is consistent with Occidental's perspective that CO_2 is a valuable commodity that must be properly managed to minimize loss. This business objective aligns perfectly with CARB's objective of avoiding and reducing CO_2 emissions and demonstrating that CO_2 is not lost to the atmosphere. We have additional processes and systems in place to maintain our pipelines, valves, compressors and reservoir penetrations. Again, Occidental's careful management of CO_2 to prevent losses and minimize expenses are aligned with those of CARB.

Occidental operates 34 CO_2 floods, over 2,500 miles of CO_2 pipeline and 14 CO_2 separation and recycling facilities. In 2017, Occidental injected more than half-a-trillion cubic feet of CO_2, or over 27 million metric tons. From this CO_2, about 40 to 50 percent is newly sourced from Occidental and other commercial suppliers, and the remainder is recycled from existing producing wells. Over time, virtually all injected CO_2 becomes sequestered in the oil and gas reservoir.

In 2015, the U.S. Environmental Protection Agency ("EPA") approved a Monitoring, Reporting and Verification ("MRV") plan for simultaneous CO_2 injection and sequestration for Occidental's Denver unit operations in Texas. This was the first-of-its-kind MRV Plan approved by the EPA and represents an important milestone in the development and commercialization of carbon capture, utilization and storage technology as an approach for long-term management of greenhouse gas emissions. In 2017, Occidental received approval for a second MRV plan for its Hobbs unit operations in New Mexico. These remain the only two MRV plans for CO_2-EOR that the EPA has approved for sequestration incidental to EOR. The continuing use of natural sources of CO_2 in EOR is essential to support investment in and expansion of infrastructure that can be used in the future to transport and inject CO_2 from man-made sources.

We hope our comments help you better understand how CO_2 floods are managed and the tools and architecture that are used to successfully manage these operations. We would like to discuss our comments in person with a team of our technical professionals. I will be reaching out to schedule a time mutually convenient for CARB and Occidental in the near future. In the interim, should you have any questions, I may be reached at (202) 857-3000.

Best regards,

Al Collins

Al Collins
Sr. Director – Regulatory Affairs

Encl.: Attachment A
Attachment B

Attachment A

Comments to the Carbon Capture and Sequestration Protocol
under the Low Carbon Fuel Standard

Our comments are organized with a brief description of the current proposed Protocol provision, or excerpt, that we are commenting on provided first. We then provide an explanation of how we understand the proposed Protocol provision and challenges we see in implementation. We close each comment, with few exceptions, with suggested revisions to the current proposed Protocol that we believe ensures that the Protocol will achieve CARB's goals and ensure permanent sequestration of CO_2 while increasing the likelihood that a CCS Project will be able to meet the Protocol's exacting standard.

1. Section C.2.3.1 requires a formation testing and well logging program. Generally, CO_2-EOR operations have already conducted formation testing and well logging. It appears that C.2.3.1(b) attempts to recognize that C.2.3.1(e) through C.2.3.1(i) shall apply to any new wells, not to current wells. Occidental supports such an interpretation as it may prove difficult to impossible to produce data for all wells in a CO_2-EOR operation occurring at a field that has been in operation for decades. We do believe that the formation testing and well logging program elements are critical to demonstrating permanence and operators should be required to provide a certification to CARB that its existing wells are performing properly. Accordingly, Occidental requests that this interpretation be recognized in the rule making package.

2. Section C.2.4.1(a)(2) requires the computer code utilized in the storage complex delineation to be "open source" and publically available to CARB and CCS Project Operators. To Occidental's knowledge, no such open source model exists.

   Occidental's EOR modelers have looked at this provision and have spoken with representatives from the Bureau of Economic Geology at the University of Texas UT BEG and other experts in the field. These resources advise that an "open source" code that can model the complexity of our reservoir does not exist.

   In preparing these comments, Occidental did conduct a literature review and is aware of several efforts to develop a reliable, verifiable and accurate open source model for sequestration. These include software available through the Matlab Reservoir Simulation Toolbox (or "MRST") and the Carbon Capture Simulation Initiative ("CCSI") led by the Office of Fossil Energy's ("FE") National Energy Technology Laboratory ("NETL"). These and similar efforts hold great promise that an open source code powerful enough to model operations and reservoirs used in enhanced oil recovery will be developed. However, the process of development could take many years if not decades and currently, each has limitations. For example:

- MRST recognizes that it "is not primarily a simulator, but is mainly intended as a toolbox for rapid prototyping and demonstration of new simulation methods and modeling concepts;"
- The CCSI code, recently released on April 2, 2018, is in its early formative stage available to researchers in "industry, government, and academia to freely use, modify, and customize in support of the development of carbon capture technologies;" and,
- Critically, for purposes of CO_2-EOR operations, no open source code can incorporate, manipulate and predict performance that is dependent on the miscibility of CO_2 in oil.

To model its operations, Occidental purchases a license to access peer reviewed commercially available proprietary models including, CMG Gem, Haliburton/Landmark VIP (Nexus), and Roxar's MORE. Each of these main-line simulators are well established, fully Peer reviewed, and competes for market shares based on the simulators accuracy and speed to solve fluid flow equations of state through complex geological models. The models Occidental uses have 20+ million lines of code and can take several days to weeks to run each scenarios. E.g., we are currently analyzing performance of 280 wells against predicted model performance for a CO_2flood, and the VIP/Nexus model requires 40 hours each run to complete. A typical history matched model requires hundreds of runs.

While it is possible that an open source code may work for sequestration projects with a small number of injectors, for CO_2-EOR projects with hundreds of injectors and thousands of producers, open source codes are simply not able to process all the available data and provide meaningful results. In Occidental's case, we purchase multiple licenses for the three software models mentioned. These models are more robust, accurate and provide results superior to those publically available models.

We suggest that CARB focus on what the models must be able to provide. Briefly, reliable, verifiable and accurate models that will provide the level of detail necessary for EOR to qualify for Low Carbon Fuel Standard ("LCFS") must have the following essential simulator capabilities:

a. Equation of State (EOS) driven Hydrocarbon Fluid Properties, including
    i. Miscibility Functions keyed on IFT (and Parachors)
    ii. CO_2 Solubility in Water
b. Sophisticated Three-Phase Relative Permeability, including
    i. Relative Permeability Hysteresis (for Trapped Gas)
    ii. Relative Permeability Endpoint Scaling
    iii. Choice of Three-Phase Relative Permeability Calculation Methods
c. Sophisticated Well-Bore Modeling, including
    i. Multi Segment Wellbores with capability to handle multilateral completions
    ii. Analytical Wellbore Friction Calculations for Horizontal Wells
d. Corner Point Gridding (for transmissibility calculations), including

        i. Efficient Local Grid Refinement, or Grid Coarsening
  e. Fully Implicit Model Solution Formulation (Implicit Pressures and Saturations) for handling Water Alternating with Gas (WAG) with hysteresis
  f. Multi-level Well Reporting and Control, including
        i. Reservoir Voidage Control with History Data - Specifying Well Histories as observed 3-phase rates, model calculates reservoir volume equivalent
        ii. Reporting Production and Injection as User Defined Gatherings Centers, or Groups (including groups of groups, overlapping groups, or total field)
        iii. For Prediction, Injection Rates (by Group) calculated from reservoir production (Voidage)
  g. Visualization of Results, including:
        i. 3D Visualization Tool for all Simulation Properties (Static and Dynamic) as a Function of Time, including relative position of wellbores
        ii. Efficient Well and Gathering Center Performance Plotting

We suggest that this language be revised to permit the use of a proprietary commercially available model as follows:

Section C.2.4.1(a)(2). The computer code(s) utilized in the storage complex delineation model and plume extent modeling must be (1) validated for use in peer reviewed literature; and, either (2) open source and publically available to CARB and CCS Project Operators; or (3) a validated commercially available software.

3. Sections C.3.3(b) and C.4.3.1.3(c) require that a CCS Project Operator ensure that injection pressure does not exceed 80% of the fracture/parting pressure of the sequestration zone.

   Companies that sequester CO_2 incidental to enhanced oil recovery (EOR) must balance the need to inject CO_2 at a pressure above minimum miscibility pressure (MMP) to optimize oil production, and to maintain injection below the fracture/parting pressure of the reservoir. Injection pressure that exceeds fracture/parting pressure or less than required to maintain MMP will result in oil accelerated production decline. The operator of a mature EOR project manages this balance by maintaining an injection to withdrawal ratio of or near one. Once an optimum reservoir pressure for injection and production is achieved, an EOR reservoir pressure does not increase overtime. In many instances, the required injection pressure of 80% below frac pressure may result in reservoir pressure drop to below MMP and/or an inability to continue injection due to injection pressure being less than existing reservoir pressure.

   To ensure that it injects below fracture/parting pressure and above field pressure, Occidental uses a SCADA (Supervisory Control and Data Acquisition) system that collects data from sensors at each well and other locations and sends this data to a central computer system that manages and controls the data and processes in real time. Although there is some minor variations possible, through its 40+ years of CO_2-EOR experience, Occidental recommends using an optimum injection pressure that is at least 50 psi below fracture/parting pressure. Occidental has determined that this is sufficiently below the fracture/parting pressure to protect the reservoir while optimizing production. Further, this is a more precise limit that will prove easier to implement, measure, monitor and report. Occidental has included a detailed description of its SCADA system in Attachment B.

Consequently, the Protocol's proposed language limiting injection pressure to 80% of the fracture/parting pressure is not necessary given the degree of control an operator of an enhanced oil recovery operation should exercise and will preclude any CO_2-EOR from qualifying under the CARB protocol for generation of LCFS credits.

Occidental acknowledges that until a new sequestration project develops a full understanding of its reservoir, an 80% limitation may be appropriate to safeguard a reservoir's cap rock. However, such a limitation is not necessary where a CO2-EOR operation has 40 years or more of operational data demonstrating performance. To retain such a provision will preclude a CO_2-EOR project from qualifying under this protocol.

Occidental suggests that the protocol's language in sections 3.3(b) and 4.3.1.3(c) be revised as follows:

C.3.3(b) The CCS Project Operator must ensure that injection pressure is continuously monitored and:

(1) For a CO_2-EOR Project, is maintained such that there is a minimum differential of 50 psi between the operating pressure in the reservoir and the fracture/parting pressure.

(2) For all other CCS Projects, does not exceed 80 percent of the fracture/parting pressure of the sequestration zone so as to ensure that injection does not initiate or propagate existing fractures in the sequestration zone.

(3) In no case may injection pressure initiate fractures in the confining system, cause movement of the injection or formation fluids out of the storage complex, or unacceptably increase risk of significant induced seismicity.

It appears that Section 4.3.1.3(c) is redundant and not necessary. However, should CARB prefer to retain this provision because it merits repeating in the section on Continuous Monitoring of Injection Pressure, we suggest ensuring that both protocol provisions are identical:

C.4.3.1.3(c) The CCS Project Operator must ensure that injection pressure is continuously monitored and:

(1) For a CO2-EOR Project, is no greater than 50 psi below fracture/parting pressure.

(2) For all other CCS Projects, does not exceed 80 percent of the fracture/parting pressure of the sequestration zone so as to ensure that injection does not initiate or propagate existing fractures in the sequestration zone.

(3) In no case may injection pressure initiate fractures in the confining system, cause movement of the injection or formation fluids out of the storage complex, or unacceptably increase risk of significant induced seismicity.

4. Sections C.3.3(f)(1) provides that if a shutdown is triggered or a loss of mechanical integrity is discovered, the CCS Project Operator must (1) immediately cease injection, otherwise all credits generated are subject to invalidation; …(3) notify the Executive Officer in writing within 24 hours….

   CO_2-EOR projects have much in common with other industrial processes. Like industrial processes, computer control systems may alarm from time to time for minor issues and operator intervention is required to check and reset the system. Occidental utilizes a SCADA control system to monitor its CO_2-EOR operations. The system is designed to continuously monitor conditions within the EOR operation. Events beyond Occidental's control and that do not reflect a downhole upset condition may occur that could trigger a shutdown. E.g., inclement weather that may cause a temporary interruption of power, voltage spikes, an unexpected failure of a monitoring probe or wiring despite proper and timely checks and maintenance. In many of these cases, the SCADA will trigger an alarm and may shutdown injection until the situation can be checked and repairs, if needed, initiated. None of these events risk a loss of CO_2 from the reservoir and we don't believe that it is CARB's intent to have the protocol require 24-hour written notice for all events. Rather, we understand that CARB seeks to have notice of significant events. We suggest that minor events of the nature describe above should be reported quarterly or annually. Accordingly, Occidental agrees that major event, e.g., a system failure accompanied by a loss of sequestered CO_2 from the reservoir should trigger notice to the Executive Officer.

   To recognize these scenarios, we suggest the following revisions:

   C.3.3(f)(1). If an un-remedied shutdown is triggered or a loss of mechanical integrity is discovered with an accompanying loss of CO_2 from the sequestration zone that results in an invalidation of LCFS credits, the CCS Project Operator must (1) immediately cease injection, otherwise all credits generated are subject to invalidation[1]; …(3) notify the Executive Officer in writing within 24 hours….

   Similarly, C.3.4(a) states that the CCS Project Operator must cease injection into the affected injection well and must not resume injection…without Executive Officer subsequent approval if (1) MI testing has not been performed as required; (2) the well fails MI; (3) an automatic alarm is triggered….

[1] Although the suggested revision retains the term "invalidation", Occidental submitted comments related to this on April 23, 2018. The comments on page 15 of the attached link should be considered simultaneously with the suggested revisions. https://www.arb.ca.gov/lists/com-attach/123-lcfs18-BmpWMwZhU3NVDFc0.pdf

Again, an automatic alarm could be triggered by a relatively benign process condition or other conditions like inclement weather. We do not understand CARB's intent as requiring Executive Officer approval to restart injection after a CO_2-EOR operator responds to and corrects a false alarm or other relatively benign and corrected operating condition. We suggest the following revisions:

C.3.4(a). The CCS Project Operator must cease injection into the affected injection well and must not resume injection…without EO subsequent approval if (1) MI testing has not been performed as required; (2) an un-remedied automatic alarm is triggered with an accompanying loss of sequestered CO_2 that results in an invalidation of LCFS credits, ….

5. C.4.3.1.5(a) requires CCS Project Operators to perform a pressure fall-off test for <u>each</u> well once every five (5) years

CO_2-EOR operations conduct fall-off tests to monitor reservoir pressure so that the reservoir pressure is never higher than reservoir fracture pressure, thereby avoiding fracture propagation and the corresponding risk of a CO_2 release outside of targeted injection interval. Occidental accomplishes this by monitoring reservoir pressure during fall off tests in our injectors and build up tests in our producers. We have found that our reservoir pressures do not change significantly from one area to the other. In addition, because we maintain an injection to withdrawal ratio ("IWR") near 1.0, our reservoir pressure does not increase noticeably through time.

Due to Permian reservoirs having low permeability, each fall-off test takes two weeks to a month to complete. Our enhanced oil recovery operation have hundreds and sometime thousands of injection wells. Continuously or regularly conducting fall-off tests would be an inefficient method of maintaining reservoir conditions. As a result, in addition to the fall-off tests, Occidental relies on its SCADA system to maintain and continuously monitor field pressure to ensure that its injection wells are operating as intended; injecting below fracture pressure. This system enables us to maintain reservoir pressure by setting injection pressure setpoints for each injector at 50 psi below fracture pressure as established from step rate tests or nearby producers fracture data. This approach automates our processes, provides continuous information on injection well performance, enables Occidental to respond to any issues rapidly, creates a verifiable performance record and is more efficient.

Occidental suggests revising section C.4.3.1.5(a) to permit a range of options for operators:

CCS Project Operators must monitor for changes in the well bore environment that may indicate fluid leakage through the wellbore. Monitoring may include fall-off test of each well at least once every five years pursuant to subsection C.4.1 or other methods approved by the Executive Officer.

6. C.4.3.2.3 requires the CCS Project Operator to deploy and maintain a permanent, downhole seismic monitoring system to determine the presence or absence of any induced micro-seismicity events.

   Occidental, the oil and gas industry and states with oil and gas producing regions recognize the importance of understanding, monitoring and reporting seismicity events that may be induced through human activities.

   Occidental belongs to and is a funder of the University of Texas CISR consortium (Center for Integrated Seismicity Research or CISR) which manages the TexNet monitoring system. Occidental is a member of CISR Science Advisory Committee. The goal of this committee is to "...provide a robust mechanism for dialog, guidance, and exchange of technical advice..." for TexNet.

   TexNet has two primary goals: (1) to monitor, locate, and catalog seismic activity with magnitudes of M 2.0 and larger, and (2) to improve the state's ability to rapidly investigate ongoing earthquake sequences in Texas. The system operates 17 permanent systems with an additional 22 planned and maintains numerous portable unites to monitor, locate, and catalog seismic activity of magnitude 2.0 and higher. A catalog of events are available here: http://www.beg.utexas.edu/texnet-cisr/texnet/earthquake-catalog. Occidental also accesses the USGS Advanced National Seismic System.

   Faults can be found in all reservoirs, and Occidental's are no different. In the course of field development, 3D seismic shoots were conducted that identified faults present in Occidental's reservoirs. We found relatively few that penetrate the reservoir interval. None of these faults are believed to breach the regional seal, a finding supported through more than 40 years of injection history. Time-lapse, or 4D, seismic monitoring of CO_2 is not possible in Occidental's Permian Basin reservoirs due to the lack of baseline (pre-CO_2 flood) data and reservoir properties are not conducive to seismic fluid substitution calculations. Namely, the reservoir he rock is dense dolostones, which feature fast velocity and low seismic resolution. Porosity is low to moderate at 4% to 15% and burial depth is great at 5,000 ft to 7,000 ft. Rather than rely on seismic data with poor resolution due to the reservoir's properties, Occidental relies on direct measurement of CO_2 concentration and pressure at its wells. These direct measurements enable us to monitor injected CO_2 with greater accuracy than direct seismic data.

   Furthermore, Occidental's enhanced oil recovery operations vary from several hundred to several thousand wells, both injectors and producers . E.g., at our Denver Unit, we operate more than 1700 wells including 600 injectors. These wells feature close spacing on the order of 600 ft to 2,000 ft. Downhole seismic monitoring of each closely spaced well would be redundant and unnecessary and is simply not feasible. The current seismic monitoring available through CISR provides resolution greater than the 2.7 resolution proposed by CARB combined with our SCADA system renders downhole seismic monitoring redundant and unnecessary.

We recommend that CARB revise the proposed protocol language to recognize that existing surface-based seismicity measuring systems allow for monitoring of events of lower magnitude than 2.7.

We suggest the following revisions to C.4.3.2.3:

(a) The CCS Project Operator must either:

1. deploy and maintain a permanent, downhole seismic monitoring system in order to determine the presence or absence of any induced micro-seismic activity within the vicinity of all wells and near any discontinuities, faults, or fractures in the subsurface, or

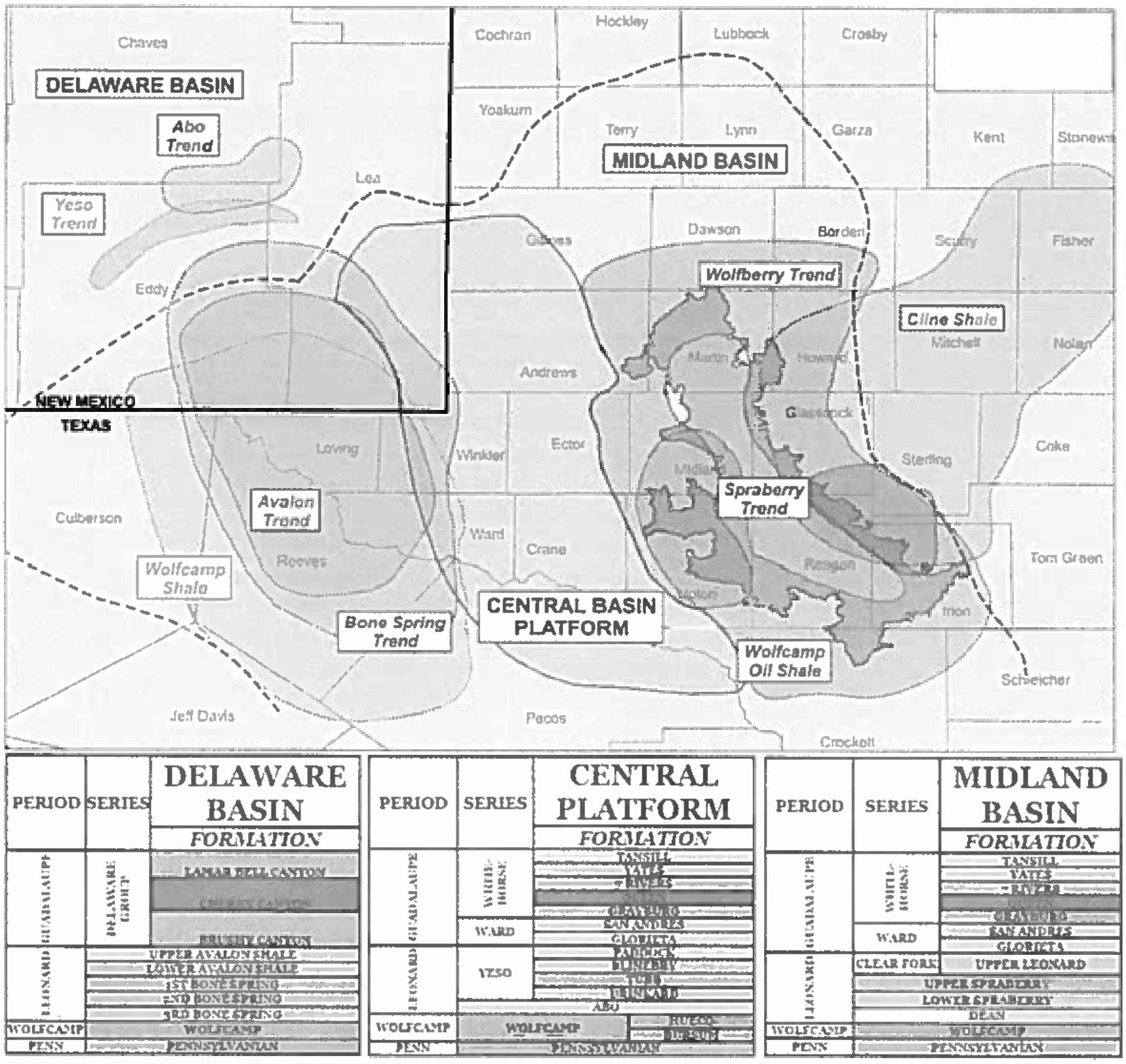
2. Participate in a state or regional seismic study zone designed to (1) monitor, locate, and catalog seismic activity with magnitudes of M 2.0 and larger, (2) improve the CCS Project Operator's ability to rapidly investigate and respond to ongoing earthquake sequences, and is publically available. The design of an array should consider the seismic risk. Location of small events can be helpful in risk reduction, but sufficient planning is needed to collect and analyze the data.

3. Analysis of the microseismicity must consider if the risk of triggering an earthquake of Richter magnitude 2.7, or greater, is significantly increased by injection. If an increase in risk is detected and determined, mitigation of the risk is required; and

4. The array should be calibrated with check-shots, preferably at depth

7. C.9.(c) requires the CCS Project Operator to show proof of a binding agreement among relevant parties that drilling or extraction that penetrates the storage complex is prohibited.

We understand the intent behind this provision is to ensure there is not movement of stored CO_2 out of the intended sequestration zone and above the storage complex or to the atmosphere. In oil and gas development, split estates, where the mineral estates and surface estate are owned by different parties are common. Different mineral estates underlying a single surface estate often exist at several different depths. For example, the Permian Basin consists of several basins, each with multiple formations lying at different depths, as illustrated in the figure below:



CO_2-EOR projects already take place in different formations that lie at different depths that are owned by different parties. Drilling through multiple formations is a technical challenge with engineered solutions. Drilling through multiple formations that may be owned by different parties requires drillers to set casing strings to prevent communication and mixing between different zones. These same techniques are used to protect underground sources of drinking water ("USDW") as well as safeguard freshwater aquifers from cross contamination and prevent the mixing of varying concentrations of brackish water present at different subsurface depths. These techniques have been successfully employed for over 100 years and are regulated by the Clean Water Act, the Safe Drinking Water Act and state law. These same engineered solutions prevent the release of CO_2 from a CO_2-EOR project during the drilling and construction of wells.

Given the engineered solutions that are already available and in use, it is not necessary for relevant parties to meet an agreement that prevents drilling through one formation to access another formation – an activity that already occurs. While it is not possible to predict with certainty whether future technology will permit development of deeper formations that may underlie a CO_2-EOR project, past experience indicates that this is highly likely to occur.

Further, should economic quantities of oil and gas be found in a formation below a formation used to sequester CO_2, there is no current legal pathway for an owner of one mineral estate to prohibit drilling by a company with a property interest in a different mineral estate. In California, Texas and New Mexico, an owner of a mineral estate has the exclusive right to drill for oil and gas and to retain all substances brought to the surface. *Callahan v. M*artin (1935) 3 Cal.2d 110. That is, the mineral estate is the "dominant" estate. As the owner of the dominant estate, the owner of the mineral estate has the right to use the surface estate "as is [reasonably] necessary and convenient" to extract minerals and (if necessary) may preclude other surface uses. *Id.* These rights are specific only to the mineral estate. *Id.* The surface owner retains all rights not held by the mineral owner and may not unreasonably interfere with the operation of the mineral estate. *Cassinos v. Union Oil Co. of Cal.* (1993) 14 Cal.App.4th 1770.

Owners of surface estates and mineral estates are aware of the legal landscape, the likelihood that their property may be developed in the further and are reticent to take their property permanently out of production at any cost. .

To account for these issues, and to still provide CARB the assurances it seeks, we suggest revising the language as follows:

C.9(c). Upon injection completion, the CCS Project Operator must show proof that there are sufficient safeguards in place to prevent leakage from the sequestration zone. These safeguards may include:

(1) A binding agreement among relevant parties that drilling or extraction that penetrate the confining layer above the sequestration zone are prohibited within the AOR;

(2) Enforceable regulatory or other legal mechanisms that require wells that penetrate the confining layer above the sequestration zone to prevent unauthorized mixing or loss of fluids from the sequestration zone and confining layer.

8. Section C.1.2.(b) provides that the Permanence Certification is non-transferrable. Should this CARB effort create a successful and robust market, it is expected that the Permanence Certificate will have significant value. Value generated not only through the LCFS credits but value created by a party's skill in qualifying for the generation of LCFS credits. This value may be monetized through the sale of a CCS project. Where a corporate entity is sold, there will be no question that the new owner of the company holds the Permanence Certificate. The same should hold true if the asset is sold. In such cases, the Permanence Certificate for the

asset should be able to be transferred to the new owner, along with any accompanying obligations, where the parties to the transaction provide notice to CARB and the new owner can demonstrate compliance with the protocol.

We suggest revising the language as follows:

The Permanence Certification is may be transferable where the transferee demonstrates that compliance with LCFS and this protocol.

9. Section 2.4.2 (c). Requires a single modeling exercise for all wells within a single CCS project.

   Occidental provided detailed and extensive comments to the computer modeling provision above. In addition, the complexity of a given reservoir and operation may necessitate multiple modeling exercises. The critical questions are whether the model provides reliable, verifiable and accurate results. If multiple modeling exercises provide better results, there should be no prohibition on conducting such an exercise.

   We suggest deleting 2.4.2(c) in its entirety or revising the language as follows:

   (c) A single AOR modeling exercise may be conducted for all wells within a single CCS project.

10. C.3.1(c)(1). All well materials must be compatible with the fluids with which the materials may be expected to come into contact with and must meet or exceed standards developed for such materials by API, ASTM or comparable standards acceptable to the Executive Officer.

    All well materials must be selected and formulated to minimize corrosion caused by fluids that the materials may be expected to contact. Tubular well components must meet or exceed standards developed for such materials by API, ASTM or comparable standards acceptable to the Executive Officer – e.g. corrosion inhibitors may be added to wells in a CO_2-EOR project to retard corrosion as well as using CO_2 resistant coatings on injection well tubulars. Annular sealant materials between wellbore and tubular components must be corrosion resistant to CO_2 and formation fluids within the sequestration zone. We believe the aforementioned measures satisfy the intent of this provision but suggest the following revision to the language for clarification:

    C.3.1(c)(1). All well materials must be constructed to minimize corrosion caused by the fluids with which the materials may be expected to come into contact with and must meet or exceed standards developed for such materials by API, ASTM or comparable standards acceptable to the Executive Officer. E.g., corrosion inhibitors may be added to wells in a CO_2-EOR project to retard corrosion.

Similarly, C.3.1(c)(5) states that cement and cement additives must be compatible with the CO_2 stream and formation fluids within the sequestration zone. We suggest the following revision:

C.3.1(c)(5). Cement and cement additives must be corrosion resistant to the CO_2 stream and formation fluids within the sequestration zone.

C.3.2(a)(1). During drilling and construction of wells, the CCS Project Operator must…determine or verify permeability and porosity….

In CO_2-EOR we do not test during drilling because of the presence of drilling fluids in the well. We wait until the well has stabilized after drilling. Otherwise, drilling mud and other residues would compromise the results. We suggest revising the language as follows to clarify that in CO_2-EOR projects, testing occurs after drilling and is part of the construction of a well:

C.3.2(a)(1). When drilling and constructing wells, the CCS Project Operator must…determine or verify permeability and porosity….

C.3.2(c)(1). The CCS Project Operator must submit…a descriptive report that includes interpretation of the results of…(1) Deviation checks during drilling on all holes constructed by drilling a pilot hole that is enlarged by reaming or other method.

We have had Occidental's drilling and completion specialists examine this provision and it is not clear what is required or what CARB intends. Occidental personnel advise that at no point would we drill a pilot hole that is enlarged by reaming or other method. We request that CARB review this provision and provide clarification as to its intent and application.

11. C.3.1(c)(2) requires that surface casing must extend through the base of the lowermost freshwater aquifer and be cemented to the surface through the use of a single or multiple strings of casing and cement.

    Occidental extends the surface casing of its injection wells to the surface. Depending on their age, active production wells may not be cemented to the surface. The nature and use of a production well is very different from an injector. A production well is essentially a pathway out of the reservoir. Oil, produced water and gas, that may include entrained CO_2, is extracted through production wells. Each of these products are captured at the surface and separated. Oil and natural gas is captured for sale. Virtually all of the CO_2 (except for a very small percentage of CO_2 lost as fugitive emissions) and a percentage of the produced water is captured and recycled for reuse. Consequently, the surface casing of production wells do not necessarily need to extend to the surface. It would be extremely expensive with no corresponding enhancement in performance for a CO_2-EOR operator to rework or plug and abandon structurally sound, properly functioning, and sound production wells.

    Occidental suggests that compliance with sections C.2.4.3(b), (c) and (d), which require an assessment of wells that penetrate the storage complex and require corrective action, provides the storage complex with the requisite level of protection from leaks. In addition, the protocol's calculation methodology already ensure that a project operator will not generate LCFS credits for CO_2 lost due to fugitive emissions, entrained CO_2 or other leakage.

We suggest the following revision:

C.3.1(c)(2) Surface casing of all injection wells must extend through the base of the lowermost freshwater aquifer and be cemented to the surface through the use of a single or multiple strings of casing and cement. Production wells must be assessed pursuant to C.2.4.3 and, if necessary, take any required corrective action.

12. C.5.2(b)(3)(A) requires all injection (and production, if applicable) wells associated with the CCS project to be plugged and abandoned pursuant to C.5.1(d), with the exception of any wells that the CCS Project Operator plans to transition into observation or monitoring wells.

    We understand CARB's intent here as ensuring that upon closure, a CCS Project Operator will ensure safe and permanent storage of CO_2. A properly designed and operated CO_2-EOR project will provide this safe and permanent storage.

    To optimize production, CO_2-EOR operations will adjust operations throughout the life of a field. At this time, operations will include an extended period of CO_2 injection that may be followed by water injection, or a water chase. Currently, Occidental is planning to conduct enhanced oil recovery by injecting CO_2 into its reservoirs for several more decades, in some cases into 2100. At that time, Occidental will convert portions of its fields to a water chase operation and still produce oil, which will have some CO_2 entrained. As required by the protocol, Occidental will be required to calculate the CO_2 entrained in the oil and account for it in its LCFS credit. When oil production from the reservoir is complete, Occidental will enter into the Post-injection site care period pursuant to C.5.2. We request that the protocol recognize this operating scenario and suggest the following revision:

    C.5.2(b)(3)(A) Within 24 months after injection is complete, all inactive injection wells associated with the CCS project must be plugged and abandoned pursuant to subsection C.5.1(d), with the exception of any wells that the CCS Project Operator plans to transition into observation or monitoring wells or to operate for continued oil and gas production.

13. C.4.1(a)(2). Testing and monitoring associated with CCS projects must include…(2) installation and use…of continuous recording devices to monitor…(3) the annulus fluid volume added….

    In CO_2-EOR operations, we monitor the annulus pressure. We do not maintain fluid in the annulus. We suggest the following revision to recognize this well requirement:

C.4.1(a)(2). Testing and monitoring associated with CCS projects must include...(2) installation and use...of continuous recording devices to monitor...(3) annulus fluid volume, if present....

14. C.4.1.(a)(3) requires corrosion monitoring of well materials upon completion and a minimum of once every five years thereafter...to ensure that well components meet the minimum standards for material strength and performance set by API, ASTM International, or equivalent....

    All wells that Occidental has installed at its CO_2-EOR operations were installed in accordance with consensus standards developed by national and international standard setting organizations, including API and ASTM International standards. As explained earlier, Occidental's CO_2-EOR operations feature hundreds to thousands of wells, both injectors and producers. Where a CCS project operator has hundreds to thousands of wells, monitoring of a statistically significant number of wells, rather than all wells, is appropriate. We suggest the following revision to recognize this well requirement:

    C.4.1(a)(3) Corrosion monitoring of well materials, upon well completion and a minimum of once per every five years thereafter, for loss of mass, thickness, cracking, pitting, and other signs of corrosion, to ensure that well components meet the minimum standards for material strength and performance set by API, ASTM International, or equivalent, by:
    (A) Analyzing corrosion coupons from the construction materials a statistically significant number of well placed in contact with the CO_2 stream; or
    (B) Routing the CO_2 stream through a loop constructed with the material used in the well and inspecting materials in the loop;
    (C) Performing casing inspection logs; or
    (D) Using an alternative method approved by the Executive Officer.

15. Section C.4.1(a)(7) requires a demonstration of external mechanical integrity at least once per year until the injection wells is plugged.

    Occidental relies on its sophisticated process controls to monitor mechanical integrity. Even with continuous process control monitoring, periodic external mechanical integrity tests are a critical component to verify injection well performance. Occidental has determined that with its SCADA system, mechanical integrity tests no less often than once every five years provides a superior level of confidence in injection well integrity. In addition, where an operator has hundreds of injection wells, a MI test interval of five years means that dozens if not a hundred or more wells are undergoing testing in any given year. This yields an enormous amount of mechanical integrity data for the operator and, assuming compliance with other protocol provisions, CARB. E.g., at Occidental's Denver Unit, a MI test interval of at least once every five years means that 120 injectors will be checked every year. If there are mechanical integrity issues, they will be found. We suggest the following revision to recognize this operational reality:

C.4.1(a)(7). A demonstration of external mechanical integrity pursuant to subsection C.4.2 on a schedule agreed to with the Executive Officer, but in no event less frequent than once every five years, taking into consideration the number of active injectors at a CCS Project and, if required by the Executive Officer, a casing inspection log pursuant to requirements at subsection C.4.2(c) at a frequency established in the Testing and Monitoring Plan;

16. C.4.1(a)(8) requires a pressure fall-off test at least once every five years, pursuant to subsection C.4.3.1.5, unless more frequent testing is required by the Executive Officer based on site-specific information.

    Occidental does perform fall-off tests. However, similar to mechanical integrity testing pursuant to C.4.1(a)(7), the need for periodic fall-off tests has been largely obviated at enhanced oil recovery operations by sophisticated control systems. As explained in greater detail above, Occidental's SCADA system provides continuous monitoring of field conditions. Consequently, fall-off tests are now conducted much less frequently because field and well conditions are continuously monitored and reported. We suggest the following revision to recognize this operational reality:

    C.4.1(a)(8). A pressure fall-off test on a schedule agreed to with the Executive Officer pursuant to subsection C.4.3.1.5.

17. C.4.2(b)(6) requires demonstration of mechanical integrity prior to plugging a well.

    This appears to be a redundant requirement already satisfied elsewhere. In the event a MI test finds that a well's mechanical integrity is compromised, one solution is plugging and abandoning the well. In the case of this provision of the protocol, a P&A of the well is already planned. An MI test is a needless requirement. We suggest deleting this requirement.

18. Section § 95490(h)(3) introduces a new approach to credit retirement 50-years post-injection.

    Occidental understands that some project operators may be uncomfortable with a 100-year post-injection liability. Other operators, Occidental included, with mature CO_2-EOR fields, have analyzed the likelihood of a release from a CCS Project and have determined that the chance of a release is vanishingly small. In consideration of those operators that favor a shorter limit to their long-tail liability, Occidental proposes that CARB retain the option that a CCS Project Operator may opt into a 50-years post-injection liability approach in exchange for a 5% increase in their contribution to the buffer account. However, Occidental proposes that CARB retain the initial approach as an option for those CCS Project Operator's that are comfortable with a long-tail liability of 50-years post-injection.

    Occidental suggests the following revision to provide for this option:

§ 95490. [Reserved.] Provisions for Fuels Produced Using Carbon Capture and Sequestration.

(h) CO2 Leakage and Credit Invalidation.

(1) Credits for verified GHG emission reductions can be invalidated if the sequestered CO2 associated with them is released or otherwise leaked to the atmosphere.

(2) The number of invalidated credits is equal to the quantity of CO2 released or leaked from the sequestration zone, which must be determined in accordance with the CCS Protocol.

(3) A project operator must select one of the following options:

(A) Prior to 50-years post-injection:

(i) The Executive Officer may retire credits from the buffer account, up to and including the project's total contribution, to count toward the number of invalidated credits.

(ii) The project operator must retire credits for any balance after retiring credits pursuant to 95490(h)(3)(A).

(iii) The Executive Officer may retire credits from the buffer account equivalent to remaining outstanding balance after retiring credits pursuant to 95490(h)(4)(3)(A) and (B).

(B) After 50 years post-injection:

(i) The project operator is no longer responsible to make up any credits found to be invalid due to leakage.

(ii) The Executive Officer may retire credits from the buffer account to cover any credits found to be invalid due to leakage.

(C) Prior to 100-years post-injection:

(i) The Executive Officer may retire credits from the buffer account, up to and including the project's total contribution, to count toward the number of invalidated credits.

(ii) The project operator must retire credits for any balance after retiring credits pursuant to 95490(h)(3)(A).

(iii) The Executive Officer may retire credits from the buffer account equivalent to remaining outstanding balance after retiring credits pursuant to 95490(h)(4)(3)(A) and (B).

(B) After 100-years post-injection:

(i) The project operator is no longer responsible to make up any credits found to be invalid due to leakage.

(ii) The Executive Officer may retire credits from the buffer account to cover any credits found to be invalid due to leakage.

This would also necessitate a corresponding change to Appendix G in the protocol, i.e., revising the calculation in equation G.1 to account for those operators that choose to retain the long-tail liability.

Attachment B

SCADA Summary:

The OXY SCADA (Supervisory Control And Data Acquisition) system monitors and controls geographically widespread processes. This includes all equipment and functions for acquisition, processing, transition, and display of the necessary process information. This allows the automation system to securely control the process and make process changes to mitigate risk. It also makes data, alarm and control functions accessible to operators remotely.

SCADA Overview:

The OXY SCADA system may be described by looking at the individual components. The components of the system are the wells, satellites, batteries, and gas processing facilities which are linked together through The Open Automation System (TOAS) Servers. The defining element of OXY SCADA, as displayed in figure one, is its ability to integrate all of these components to create a harmonious system. This system then allows for the numerous devices in the field to communicate with one-another, through "Supervisory Control", which improves the safety, efficiency, and functionality of the system. Supervisory control is defined as the act of viewing process data and alarms, and affecting the process by changing set-points, loop tuning, or starting and stopping equipment. This action can be manual with operator intervention or automatic. The SCADA system can automatically cause an action in one controller based on conditions in another controller and can automatically move data between controllers. OXY SCADA is constantly being reviewed, updated, and improved in order to enhance and expand upon these features.

The first phase of the SCADA system is at the well. Both producers and injectors have various setpoints configured to reduce risk, which include pressure and flowrate setpoints at injectors along with pressure and artificial lift setpoints (such as rod load) at producers. Each well has its own shutdowns based off these predetermined setpoints. In the event that a setpoint is reached, the Remote Terminal Unit (RTU) will shutdown the well (producer or injector) virtually instantaneously. There is no need for manual intervention through typical user interfaces such as LOWIS, Iconics, etc. which would delay the shutdown process. This direct line of process control allows the wells to be shutdown in the most efficient manner. Typical shutdowns on producers would include, but are not limited to, high flowline/tubing pressure, high rod load, high motor temp, and high/low amps. Typical shutdowns on injectors would include, but are not limited to, high/low injection rate, high/low injection pressure, and high casing pressure. In addition to the above mentioned shutdowns, Occidental also has a proprietary software that is used to calculate the bottom hole pressure (BHP) of injection wells. This software is patented and only Occidental has access to it. This gives Occidental superior control over the BHP on the injection wells and significantly helps reduce the chance of exceeding fracture pressure on a well-by-well basis. If a shutdown does occur at a production or injection well, the site is reviewed, and when deemed safe, brought back online.

The SCADA system also has the ability to distribute alarms or alerts prior to a shutdown occurring. For example, if the casing pressure is rising on an injection well, an alert is sent to the parties responsible for that well so it can be reviewed prior to a shutdown occurring. This applies to all aspects of the SCADA system (wells, satellites, batteries, and gas processing facilities). However, not all upsets occur at the well level, and at times large groups of wells need to be shutdown based on an upstream issue at a satellite, battery, or gas processing facility.

Satellites are the second phase of the SCADA system. Satellites are defined as a central location to perform two-phase separation for groups of production wells located geographically close to one another. Liquid is sent to the battery and the gas is sent to the gas processing facility. Again, each satellite is equipped with its own predetermined setpoints for variables such as vessel level/pressure, inlet pressure, or outlet pressure. In the event that a setpoint is reached, the Programmable Logic Controller (PLC) will shutdown the satellite virtually instantaneously, which will then trigger the production wells associated with that satellite to shutdown. Again, there is no need for manual intervention though typical user interfaces such as LOWIS, Iconics, etc. which would delay the shutdown process. Typical shutdowns on satellites would include but are not limited to high vessel level, high/low vessel pressure, high liquid gathering pressure, and high gas gathering pressure. If a shutdown at the satellite level occurs, the cause of the shutdown is determined and remedied, and when deemed safe, the satellite and all corresponding wells are brought back online in a safe manner.

The liquid separated out at the satellites is then sent to a central battery where oil/water separation occurs. The oil is transferred to the sales tanks and the water is transferred to the injection station where it is pressurized and reinjected downhole into the injection/production interval. Batteries have various shutdowns that are implemented in order to reduce risk, which include inlet/outlet pressures and tank levels. Each battery has its own shutdowns based on predetermined setpoints. In the event that a shutdown setpoint is reached, the PLC will then shutdown the battery. This shutdown will trigger a train of events that will shutdown all the satellites that are routed to the battery and the wells associated with those satellites. Again, there is no need for manual intervention, which would delay the shutdown process. If a shutdown at the battery does occur, the cause of the shutdown is reviewed and remedied, and when determined safe to do so, the battery is opened back up followed by the opening of satellites and wells in a safe manner.

The gas that is separated out at the satellites is sent to a gas processing facility where it can be processed in various ways, but inevitably the CO_2 rich stream is reinjected downhole in the injection/production interval. Gas compression facilities have various shutdowns that are implemented to reduce risk such as high suction pressure and high discharge pressure which could shutdown the entire facility or an individual compressor. If the suction or discharge pressure of the facility reach a shutdown level, the Distributing Control System (DCS) will shutdown the facility. This shutdown will trigger a train of events that will shutdown the batteries, satellites that are routed to the batteries, and the wells associated with these satellites. If a shutdown at the facility does occur, the cause of the shutdown is reviewed and remedied, and when determined safe to do so, the facility is opened, followed by the battery/batteries, satellites, and wells in a safe manner.

Attachment B

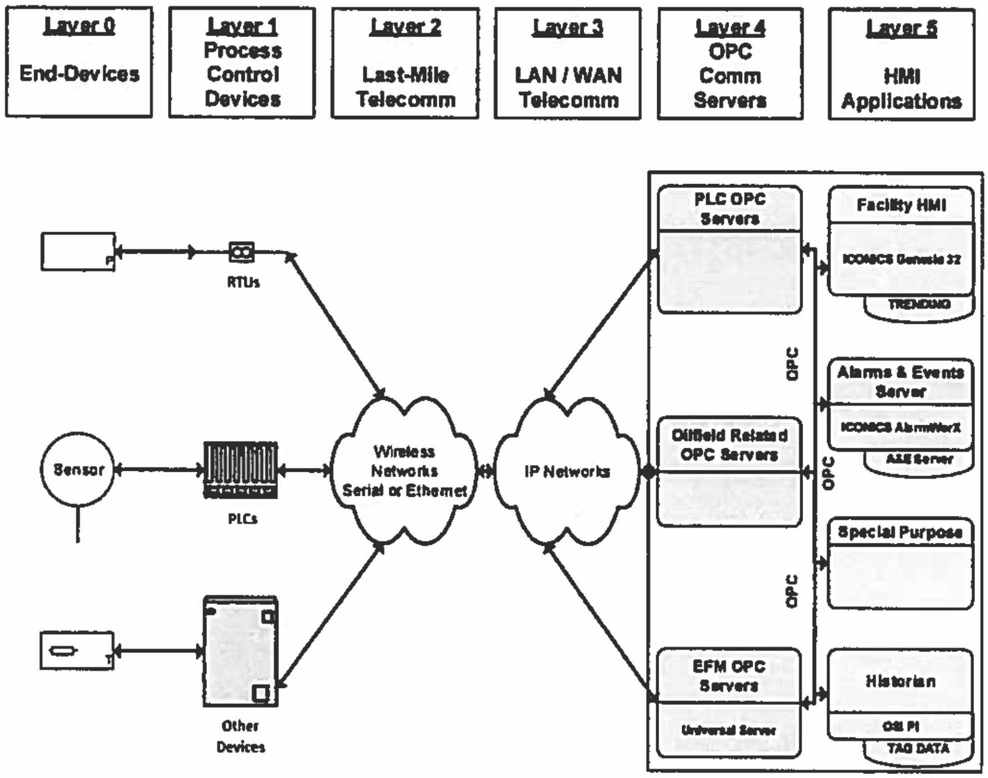


Figure 1: Outline of how the various components of the SCADA system tie together and can communicate back and forth