Evaluation of Applicant's Responses to EPA's Comments on CTV II Computational Modeling
Class VI Pre-Construction Permit Application No. R9UIC-CA6-FY22-4.1-4.5

On February 28, 2024, CTV responded to EPA's November 27, 2023 primary request for additional information about computational modeling in the CTV II Class VI permit application. EPA's evaluation of the applicant's responses is summarized in the Evaluation Summary section and provided in detail in the "Reviewers' Evaluation of Company's Responses" column of the table below. Comments provided below in ***bold, italic*** text require additional information, clarification, and/or further work from the applicant. Comments provided below in <u>*italic, underline*</u> text give background information or recommendation for further work.

<u>Evaluation Summary</u>

Real evidence that the Stockton Arch Fault (SAF) is sealing / Boundary conditions

1. Upon reviewing the revised application, the applicant provided minimal evidence to support the primary request for additional information (#1, #4c, #8, #13a-c, #14a, #14c-d, #20a-e, #47, #68, #76) which focused on evidence pertaining to fault seal and stability along the Stockton Arch Fault. Results from fault seal analysis (i.e., Allan Diagram, Shale Gouge Ratio) are provided but methodology is not described in detail. ***Please describe the methodology used for the fault seal analysis in detail.*** Applicant's evidence would benefit greatly from well and/or seismic based facies analysis from the hanging wall of the fault in E-W cross section view. ***Please supplement the fault seal evidence with well and/or seismic based facies analysis from the hanging wall of the fault in E-W cross section view.*** Overall, fault seal/stability determination is a highly uncertain process. *It is recommended to focus on unique mitigations (e.g., additional monitoring well(s) on hanging wall of Stockton Arch Fault, operational limitations/phase in).*

Dynamic Simulations / Boundary Conditions / Model Properties / No-flow Boundary

2. Upon reviewing the revised application, the concerns with the dynamic modelling aspects have largely been satisfied. In particular, the sensitivity analysis (#5), and presentation of more detailed simulation results are much improved. However, the response to many of the reviewer's concerns were in a tabulated response document, and not included in the updated site characterization or AoR documents (e.g., #11, #14e, #14f, #18, #19, #21, #30, #34, #41, #71) and/or added discussion in the AoR document has created inconsistencies (#3, #4a, #7a, #29, #31, #41). ***Please include the response (#11, #14e, #14f, #18, #19, #21, #30, #34, #41, #71) in site characterization or AoR documents and added discussion (#3, #4a, #7a, #29, #31, #41) in the AoR document.*** In particular, the horizontal and vertical mesh upscaling process including QA of the new mesh, and the grid cell sizes resulting from each should be quantitatively discussed in the AoR document. ***Please quantitatively discuss the horizontal and vertical mesh upscaling process including QA of the new mesh, and the grid cell sizes resulting from each in the AoR document.***

3. The choice to model the overburden as impermeable (#5b, #45) seems unusual, as the applicant has detailed geological information about the caprock properties in the geological model in the site characterization document. However, this is likely to result in an over-estimation of injection pressure, this represents a conservativism in the AoR calculation. Modeling of the caprock/confining zone would require k-S-p data/parameters. ***Please perform model simulations using an expanded domain that includes an active caprock layer (#5b) if k-S-p data and parameters for the caprock are available.***

4. Population of modeled properties is supported by grid sensitivity analysis, but overall modeling inputs and methodology are lacking to support no-flow boundaries. No-flow boundaries were used liberally without supporting evidence; Confining zone no-flow, North Winters pinch out into shale no-flow, and SAF no-flow. ***Please provide modeling inputs and evidence that support no-flow boundaries.*** New simulation Figures B-17a-e show a potential no-flow in the Upper Winters formation; these new figures are not referenced in text and no justification is provided for the anomalous behavior in the Upper Winters. ***Please reference Figures B-17a-e in text and***

provide justifications for the anomalous behavior in the Upper Winters. Please justify your modeling decisions by providing well cross-sections and well data histograms which display raw log data, upscaled, and full model property outputs (#1, #2, #3, #5a, #5b, #13a, #13b #14a, #14e, #15, #18, #21, #26, #28, #33, #45, #70).

5. The choice of using only one set of relative permeabilities is unusual (#44), given the amount of data available for this field. However, this is unlikely to make a large difference in the AoR calculation.

Operational Parameters / Injection Interval/ Site Capacity

6. ***The applicant needs to make sure that the injection interval in the AoR calculation is consistent with the completion in the well planning documents and with what is technically possible in the field.*** The applicant has indicated in their response to #27a that they simulated injection across the full reservoir interval (e.g., 300 ft for the Sonol Securities 3 well). This is an unusually long injection interval, and in practice when buoyant fluids such as CO_2 are injected over long perforated intervals, the fluid only goes into the reservoir through the top part of the completion. This can have implications for the lateral spreading of the CO_2 plume. It is unclear if this would be an issue for this particular field, but an additional sensitivity run where the CO_2 is injected into only the top (or bottom) of the reservoir would allay this concern. ***Please perform a sensitivity analysis for where the CO_2 is injected into only the top (or bottom) of the injection reservoir.***

7. The static estimate of the site capacity is smaller than the AoR calculation for the site capacity (#52), and smaller than the injected CO_2 mass in many of the simulations in the AoR sensitivity analysis. This seems unusual. ***Please discuss why the static estimate is more conservative.***

End of Injection

9. ***The applicant needs to clarify early in the document that the engineering constraint for the end of injection is repressurization to 90% of the discovery pressure, not a pre-determined CO_2 mass.*** This unusual constraint goes a long way to explaining why the change in AoR for the variant cases is so small (#4a, #7b, #54).

Critical Pressure

10. Additional text should be included to clarify what is meant by 'critical pressure' (#7c). ***Please include additional text to clarify what "critical pressure" is.***

<table>
<tr><th>#</th><th>Section</th><th>Comment/Question for CTV</th><th>Report Section Updated</th><th>Response</th><th>Reviewers’ Evaluation of Company’s Responses</th></tr>
<tr><td>1</td><td>Summary of Significant Comments</td><td>Please provide strong evidence about the impermeability of the fault that would justify its consideration as a no-flow boundary. Alternatively, expansion of the eastern boundary of the modeled domain beyond the fault, and implementation of appropriate properties for the fault zone, could be used to show that the SAF is an appropriate no-flow boundary.</td><td>Attachment A Section 2.3</td><td>Additional analysis of fault sealing was added to Attachment A</td><td>A new section related to the discussion about the sealing properties of the fault was added (Section 2.3.2).
The primary evidence focuses on initial pressure conditions and drawdown conditions which are not being contested. <u>However, reliance on secondary pressure evidence from mudlogs - described as a second evidence - presents challenges, particularly in a mature field.</u> The final and most convincing evidence described by the applicant points to similarities in discovery pressure gradient between Union Island (0.519 psi/ft) and Lathrop gas (0.512 psi/ft) despite 10 years difference in discovery date.
<u>The modeling and understanding fault seal/stability are a highly uncertain process; It is recommended to focus on mitigation (e.g., additional monitoring wells, operational limitations/phase in).</u>
A methodology to show initial pressure gradient, GWC, Allan diagram, and Shale Gouge Ratio (SGR) determinations would bolster evidence that the fault is sealing:
Allan Diagram results (show mostly winters-Sacramento shale) are not consistent with text (states sand on sand).
3D seismic cross sections are not provided.
Figure A-20 should show Winters-Lathrop juxtaposition; facies model display (and stratigraphy consistent with Figure A-22).
Expansion across eastern boundary was not</td></tr>
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					included. How was fault seal calculated without modeled properties? • ***Gas-Water Contact: structural spill should be based on threshold pressure as well as structure (no methodology provided). It is unclear if the AoR surpasses original fill point.*** *It is recommended to add GW contact to base map in Figure A-23.* • ***SGR: The methodology is not described.*** *It is recommended to add inputs (VClay/Facies) to Figure A-24*. ***A justification and/or reference is needed for 15% SGR sealing cutoff (usually in the range of 18-25%). No figure is presented to show the results of SGR.*** • ***Hanging wall well penetrations are shown in Figure A-24. However, the reviewers would like to see facies log/3D cross section across facies model (more precise placement of Stockton Arch Fault).***
2		***Please discuss the cause/nature of the flow barrier and how the flow barrier was modeled.***	Attachment B Section 1.9	Text was added to Attachment B Section 1.9 to address this; including results of a new sensitivity analysis testing removal of the flow barrier.	The applicant has discussed how it was numerically implemented into the AoR model, and demonstrated that including it results in a lower storage volume than if it is ignored. This verifies that including the barrier is a conservative assumption, and addresses the comment from a reservoir engineering perspective. ***However, it doesn't inform the reviewers as to the nature of the geological feature that might be causing such a barrier.***
3		***Please provide a detailed discussion on the upscaling process and how the grid resolution was chosen.***	Attachment B Section 1.5	Text was added to Attachment B Section 1.5 to address this; note the predicted storage volume with slight increase, reservoir pressure and plume boundary	The applicant has included additional information about their upscaling methods, which appears to be done using industry-standard methods. *It would have been useful if the applicant gave numbers for the sector model study on how much the storage volume and pressure would be expected*

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				were similar with minor difference for sensitivity analyses with a finer grid.	*to change, the way they did for their investigation of grid orientation using the 9-point stencil.* ***The text is inconsistent on the vertical scaling. The first paragraph on page B-10 indicated that the model is 9 ft vertical resolution while the text refers to 5 to 14 ft at the top of B-11.*** ***On close inspection, Figure B-4 seems to show the reservoir properties on the same mesh in both subfigures. Similarly, Figure B-6 is a comparison of the fine-scale (5ft) vertical mesh with the well log, not the upscaled 5-14 ft vertical mesh, as indicated in the text (top B-11).*** ***Evidence that all well data is honored appropriately would include upscaling results compared to raw data for all wells (Figure B-6 shows Sonol Securities 8, Figure B-9 shows only full model properties with no comparison to raw or upscaled log data).***
4a		***Please conduct more thorough uncertainty analysis that includes:*** ***Larger range of absolute permeability (e.g., this should be changed by an order of magnitude in each direction);***	Attachment B Section 2.3	Two uncertainty analyses were conducted using upper and lower permeability datapoints to shift the permeability transform to 10th percentile and 90th percentile (as opposed to an arbitrary order of magnitude increase and decrease). Permeability multipliers of 3 and 0.3 were used with the base case model. Results showed a difference is storage of -15% to	***Given the uncertainty associated with permeability measurements and the fact that the permeability value was taken from off the site, and with lack of discussion as to why that measurement is definitely representative of the proposed injection site, one order of magnitude in the model uncertainty for the permeability may be reasonable. The statement "An order of magnitude shift is not supported by the project- specific permeability data and transform." Is not valid.*** ***The applicant needs to clarify at the start of the***

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				+4%, respectively. The plume boundary for both cases resulted in a reasonable change, including 6% reduction of plume size for CASE A and minor plume shape shift to the Northeast direction. An order of magnitude shift is not supported by the project- specific permeability data and transform.	***Uncertainty study that their engineering design criteria appears to be to inject CO_2 until the reservoir is re-pressurized to 90% the discover pressure, not to inject a pre-determined mass of CO_2. The pressure-based criteria means that in the sensitivity cases there is little change in the AoR for most cases, but as much as 20% change in the injected CO_2 mass.***
4b		***Please conduct more thorough uncertainty analysis that includes:*** ***Relative permeability-capillary pressure- saturation function parameters (ideally also including hysteresis);***	Attachment B Section 2.3	The computational flow model presented in Attachment B includes hysteresis with a maximum residual gas saturation of 0.25. This is an adjustable parameter in the computational flow model that determines the imbibition Krg curve as a function of the given drainage curve. Two uncertainty analyses were conducted using relative permeability end points and shape. The endpoint analysis resulted in a larger impact to the injection zone storage with a 6% increase of Swr from 0.34 to 0.25 and a 6% reduction of Swr from 0.35 to 0.43. Plume boundary reduced 3% for CASE H and increased 4% for CASE I. The relative permeability shape analysis resulted in a storage	The new relative permeability ranges and hysteresis are much more satisfactory and support a robust sensitivity analysis. The applicant included sensitivity analysis on relative permeability parameters for Winters sands. The applicant showed 3 relative permeability curves. The differences between them are the residual gas saturation, liquid (water) saturation and the Corey exponents. The applicant performed sensitivity analysis on the relative permeability parameters of the Winters sand. The analysis corresponds to cases E through K. The result showed decrease gas relative permeability leads to a smaller in AoR and vice-versa. The applicant only provides one pressure-saturation function. ***The applicant should also discuss how the hysteresis is modeled (both relative permeability and capillary pressure) if it is used in the flow simulation.***

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				volume change of around 1%. Plume boundary increased 9% for CASE J and reduced 6% for CASE K. The plume boundary for both cases resulted in reasonable change to the carbon dioxide plume, and results were still within submitted AoR.	

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4c		***Please conduct more thorough uncertainty analysis that includes:*** ***Boundary and/or fault properties (i.e., certainty that the boundary fault is sealing needs to be better demonstrated);***	Attachment B Section 1.9, Section 2.3	The dynamic model uses a closed boundary for the reference case and is considered conservative. The eastern boundary is the Stockton Arch Fault (add text to reference questions). The northern boundary is closed because of the facies changes to 0 net sand (see response to #14e). Initial reservoir pressure at discovery was 5,040 psi and the current reservoir pressure is 1,200 psi with limited water production (West and South aquifer flux is limited). A sensitivity analysis was completed using an appropriate pore volume multiplier to the West side and South side of the model. This analysis showed an increase in storage volume of 15% and plume size increased of 15% as well, which is still within submitted AoR.	The description of the uncertainty analysis and what was done with respect to the no-flow boundaries is adequate. ***However, the rationale for the use of no-flow boundaries is still lacking (see other comments).*** The additional explanation of the modelling of the closed northern boundary clarifies this choice, and this satisfies with the rationale for having this boundary as closed. The sensitivity analysis on the west and south boundaries seems adequate. ***It must be noted that the initial question references boundary fault and the applicant's response focuses on northern boundary, water production, and sensitivity analysis via pore volume multiplier. "Add text to reference questions" appears to be an incomplete response.***
4d		***Please conduct more thorough uncertainty analysis that includes:*** ***Impact of gas distribution and trapped gas in the initial conditions; and***	Attachment B Section 2.3	An uncertainty analysis was completed for phase trapping. In the first analysis the critical gas saturation increased from 0.05 to 0.15. Results showed that storage volume and reservoir pressure were similar to the base case, however, there was a slight decrease in the footprint of the CO_2 plume. In the second analysis, the residual gas saturation was reduced from 0.25 to 0.05. Results showed that storage volume and reservoir pressure were similar to the base case, however there was a slight increase in the footprint of the CO_2 plume.	The additional sensitivity analysis on hysteretic parameters and residual saturation addresses this point satisfactorily. The issue of trapped gas saturation between the original gas-water contact and the present gas-water contacts is addressed by Cases L and M.

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				Even though the plume size increased, the plume boundary was still contained inside of the final AoR since the base case plume plus includes a 500 foot buffer zone.	
4e		***Please conduct more thorough uncertainty analysis that includes:*** ***A tornado chart showing relative importance of model variables to dynamic outcomes.***	Attachment B Figures	Tornado charts are provided as new Figures B-28a and B-28b. The computational model is controlled by pressure therefore the tornado chart is mainly focused on storage volume and plume size.	***Tornado chart figures are provided but not referenced or discussed in text to support appropriateness of analysis.***
5a		***Please provide more details about how the geological model was populated with heterogeneous parameters.***	Attachment B Section 1.5	The geological model was populated with properties using petrophysical modeling algorithms available in Schlumberger Petrel software platform. Petrel is widely recognized as an Industry standard software for subsurface modeling. The properties were distributed in the model by upscaling the well log data to the grid cells that the wells intersect. The upscaled data were then distributed between wells using sequential gaussian simulation (SGS). SGS is a stochastic estimation algorithm based on the Geostatistical Software Library (GSLIB) developed at the Stanford University (Deutsch & Journel, 1997). SGS uses well data, data distribution, variograms and trends to estimate property values between wells. References Deutsch, C. V., & Journel, A. G. (1997). GSLIB: Geostatistical Software Library and User's Guide. Oxford University Press, New York.	This method of populating the model with geostatistical properties is standard industry practice. *To support evidence that the model properties appropriately capture heterogeneity (shale pinch-outs, porosity and permeability distributions, etc.), Sections 1.5, 1.6 would benefit from figures that show petrophysical input data (log/core availability), outputs, and upscaling results per well (cross-section and histogram).*

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5b		***...Is the interface between the reservoir rock and confining zone treated as a no-flow boundary?***	Attachment B Section 1.5	The injection-zone/confining-zone interface is treated as a no-flow boundary. This is based on shale properties and fluid flow requirements. Based on Attachment A 2.4.2.2 and 2.4.2.3, upper confining zone permeability is 0.59 mD, and lower confining zone permeability is 0.04 mD. In dynamic modelling the confining zone grid cells are treated as inactive, and do not have any impact on the predicted performance.	***The Applicant did not provide raw vs upscaled log data along with petrophysical outputs, so the reviewers are unable to evaluate seal properties to determine if the no-flow choice is appropriate. Treating the confining zone grid cells as inactive is a curious choice as the applicant has geological information and has built a geological model that contains this information in the confining zone.*** ***If confining zone is low permeability, why not let it act as seal instead of forcing a no flow? The reviewers understand the computational requirements as no discretization of the caprock and overlying layers would be needed but letting the data speak for itself would be a more rigorous approach.*** Regarding the impact of this choice on the AoR extent, using a no-flow boundary for the caprock/reservoir interface should lead to a conservative estimate of AoR extent. Having the overburden as inactive cells is likely to result in an over-estimate of injection pressure. Should there be some caprock leakage, the pressure would be dissipated by leakage, resulting in a smaller AoR. ***Modeling of the caprock/confining zone would require k-S-p data/parameters. If k-S-p data and parameters for the caprock are available, model simulations should be performed using an expanded domain that includes an active caprock layer.***

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6		***The application needs more discussion of the potential (or lack thereof) for reservoir compaction due to the very low initial pressure of the gas field.***	Attachment A Section 2.5.4; Attachment B Section 2.3	Compressibility was calculated for the Winters formation using Newman's equation for consolidated sandstones (SPE 3835, 1973). Using the average porosity of the Winters formation of 18.9%, this yields a pore volume compressibility of 2.95 x 10^{-6}/psi. From field discovery conditions to the present day, reservoir pressure has dropped from 5,040 psi to 1,200 psi, resulting in an effective stress increase on the rock of 3,840 psi. This results in a decrease in porosity from 18.9% to 18.69%, or a change of only 1% in porosity from the initial conditions. One sensitivity case was run with a decrease in porosity of 10%, which is much greater than the expected decrease caused by the compaction of the rock due to decreased reservoir pressure. An additional sensitivity case was run with the calculated results of a 1% reduction in porosity, and a compressibility of 2.95 x 10^{-6} /psi. Results showed only a minor difference compared to base case results, including storage volume, reservoir pressure and plume boundary.	The applicant provided an adequate response to the comments and will also do core analyses of the well when it is drilled to validate this calculation. The compaction of the reservoir affects the reservoir compressibility and perhaps storage volume. It may also affect the intrinsic permeability. *Although these effects may not be dominant, it would have been useful to add a brief discussion about this effect.*

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7a		The material submitted has insufficient information regarding: ***What is the rationale for using 0.1 CO2 global mole fraction to delineate the AoR?***	Attachment A Section 2.3	The plume boundary is defined by a 0.01 CO_2 global mole fraction cutoff post-injection 100 years, which has 99.99% mass over the total injected mass within the plume boundary. This method is a conservative strategy and provides confidence that the corrective action well review and potential impact to USDWs is conservative and has been appropriately evaluated. Simpler definitions of the "separate phase" CO_2 are not applicable to the CTV II dry gas field where CO2 is present within multicomponent mixtures; therefore a global mole fraction cutoff was used with a check to make sure at least 99% of the mass is contained within the defined plume.	***The rationale for the 0.01 number is still not clear—it seems like the rationale is based on 99% being a sufficiently large number, but it's not explicitly described this way.*** ***Figure B-27a shows plan view areas of the plume with the boundary defined as 0.01 global CO_2 global mole fraction cutoff, while Figure B-27b shows the same plots defined as 0.05 gas saturation. There is no text that the reviewer could find explaining the rationale for having two plume boundary metrics.*** ***The figures are similar, but not the same. In particular, the plume in Figure B-27a exceeds the AoR in the southwest boundary for several of the uncertainty scenarios, but in Figure B-27b only one uncertainty scenario (Case A) exceeds the AoR boundary and it does so on the northeast side of the plume. The text seems to be written around the results shown in Figure B-27b, which was confusing since there is no discussion of the other figure.***
7b		*The material submitted has insufficient information regarding:* ***Pressure at the wells and in the reservoir at times before plume stabilization.***	Attachment B Section 2.1	Additional discussion of pressure results were added to Section 2.1. The 5-points methods were used to calculate the average reservoir pressure near the injectors, which is pore volume weighted average pressure of block containing each well's bottomhole reference layer and four of its immediate neighboring blocks. Refer to Figures B-19a/b/c and B-20a for the average	These additional figures, and the table of maximum injection pressures have addressed the reviewers' concerns about near-well pressures. Also, it was not clear previously that the simulations were run with a maximum injection pressure that was based on 90% of the fracture pressure but this has been addressed as well.

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				reservoir pressure plots in the AoR for Injectate 1, Injectate 2 and 100% CO_2 scenarios.	

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7c		The determination of the critical pressure provided in Appendix 10. There is a clear pressure boundary between the north and south of the field, but no explanation has been given (see comment on section Nature and Impact of the Flow Barrier: comment 2).	None	The pressure boundary is a result of the flow barrier discussed in response #2.	***As stated in comment #2, the nature of the geological feature that might be causing such a barrier is still not discussed.*** ***Additionally, the applicant doesn't really define "critical pressure", despite it being the title of the section in the text, unless it is meant to be the same as "threshold pressure front". Please clarify this in the text.***
7d		The material submitted has insufficient information regarding: ***More simulation results***	Attachment B Section 2.1	Several new figures have been added to Attachment B showing model results in time-series, plan view and cross-section view.	*The applicant provided new figures Figure B-17a-e. These new figures would benefit from location label (A-A' as shown in Figure B-16?).* ***It appears that a flow barrier has been added to the upper section of injection zone limiting CO_2 saturation/mole fraction. New figures are not referenced in text and justification for flow barrier in upper portion of Winters is still not provided.***
8		***Geomechanical modeling is needed because of the presence of the fault. Leakage risk assessment for fault and penetrating wells is also needed.***	Attachment A Section 2.5.3	Fault reactivation modeling has been added to Attachment A Section 2.5.3, as requested.	Fault reactivation modeling is completed. Fault leakage evidence provided in response #1. ***Applicant did not provide additional details regarding leakage risk assessment for penetrating wells. Per Appendix 7, > 29 wells that penetrate confining zone, only 4 are identified for corrective action, but other wells will need to be P&A'ed per Class VI regulation (Applicant proposes CalGEMs regulations using Class G cement as opposed to Class H, CO2 resistant cement). Please explain how the proposed cement would meet the Class VI P&A requirements. 5 wells are identified in Appendix 7 with "none" indicating they penetrate confining but will not be re- abandoned with CO_2 resistant cement – what is leakage risk?***

11	Model Suitability	***Please provide equations for how heat transport and residual phase trapping are considered in model simulations in Attachment B.***	Attachment B Section 1.2	Attachment B Section 1.2 was added with GEM governing equations.	The energy conservation equation is added as Eq. 11. The equation considered the fluid convection, conduction, and heat loss to the formation. ***Residual phase trapping is not clearly explained. Applicant should explain what Sgc and Sgcr are in their relative permeability model.*** *It would have been handy if the applicants had put the relative permeability and capillary pressure equations in the document, but they are available in the literature*.
13		***What is the proof for fault sealing? It is stated that the field boundary fault is a proven seal, but this has not been demonstrated in the Narrative. For more information see the Appendix of this document for comprehensive explanation of the implication.***	Attachment A Section 2.3	Attachment A was updated with additional analysis and discussion of fault sealing covering the items requested.	A new section related to the discussion about the sealing properties of the fault was added (Section 2.3.2). The applicant tried to convey the fault is sealing using: 1. decreased reservoir pressure, 2. pressure interference from other wells 3. normal drilling mud weight at Sonos Security 11 well west of the SAF. *See comment #1*.
13a		***Additional questions about the SAF sealing properties:*** ***Is it a simple juxtaposition seal against shale? If there's a sand-sand juxtaposition across the fault: is the original gas-water contact deeper than the structural spill point?***	Attachment A Section 2.3	Attachment A was updated with additional analysis and discussion of fault sealing covering the items requested.	***Text in Section 2.3 points to sand-on-sand contact as evidence for SAF seal. Figure A-22 shows limited sand-sand juxtaposition, and most of Winters juxtaposed against Sacramento Shale contradictory to Section 2.3 text. The applicant did not provide methodology to describe facies population for hanging wall juxtaposition. Figure A-23 shows two GWCs; one north and one south showing the GWC is below the structural spill point; however, no methodology provided for original GWC analysis.***

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13b		***Additional questions about the SAF sealing properties:*** ***Has the area to the east of the SAF been penetrated by wells? Some maps show no wells in that area, others only one.*** ***Is there a valid structural test of the Lathrop Sand in the hanging wall? The fact that off-structure penetrations of the Winters Sand in the hanging wall were water-bearing does not mean that the fault is sealing.***	Attachment A Section 2.3	Attachment A was updated with additional analysis and discussion of fault sealing covering the items requested.	***Several wells penetrating east of the SAF are shown in Figure A-24. It is unclear if the applicant reviewed all wells east of the SAF. Hanging wall structure is omitted from Figure A-23 GWC cross sections; including hanging wall in GWC cross section would facilitate a better understanding of spill point pathways.***
13c		***Additional questions about the SAF sealing properties:*** ***Please provide information from the previously drilled wells about the presence or absence of hydrocarbons in the hanging wall.***	Attachment A Section 2.3	Attachment A was updated with additional analysis and discussion of fault sealing covering the items requested.	Applicant provides Figure A-24 which includes wells drilled in the hanging wall of the SAF. In Section 2.3.2 where Figure A-24 is referenced, applicant states wells drilled on hanging wall into the Lathrop are water-bearing, using Moran-1 as an example. ***However, "Austral" Moran-1 (07720086) well record states trace gas. Please clarify.***
14a		***Please provide a cross-section with the original fluid contacts, spill point and fault juxtaposition to demonstrate the sealing nature of the fault and the trapping mechanisms. (See Appendix of this document.)***	Attachment A Section 2.3	Attachment A was updated with additional analysis and discussion of fault sealing covering the items requested.	***Facies Juxtaposition provided in Figure A-22, but it is unclear what data was used to populate hanging wall facies. Please clarify.***
14b		***Show original gas-water contact (OGWC) to explain how the trap works, especially because the top reservoir map does not close.***	Attachment A Section 2.3	Attachment A was updated with additional analysis and discussion of fault sealing covering the items requested.	See review response provided in #1.
14c		***Explain why some figures show an antithetic fault to the SAF, but others do not. An antithetic fault will change the juxtaposition against the hanging wall, which is important for the explanation of the fault seal.***	Attachment A Section 2.3	Attachment A was updated with additional analysis and discussion of fault sealing covering the items requested. The Antithetic fault was modeled and referenced while generating the Allan	***Results of Allan diagram are provided in Figure 22-A, but applicant did not describe methodologies for hanging wall facies population. SGR results are included but methodology not described (see comment #1). No methodology provided on the***

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				Diagram and calculating the shale gouge ratio.	***incorporation of the antithetic fault in these calculations.***
14d		***Provide an Allan diagram of the SAF indicating fluid contact and spill point level.***	Attachment A Section 2.3	Attachment A was updated with additional analysis and discussion of fault sealing covering the items requested.	***Allan diagram is provided but no fluid contacts or spill point are included in Figure 22-A.***
14e		***Winters facies change: Why has the shale-out line not been used as a 0-thickness line in the isochore gridding?***	None	The winters zone itself is not set to 0 isochore thickness because the winters interval exists east of the 0 net-sand line, albeit as a shaly interval. Areas outside the 0-foot net sand line were defined as shale in the simulation grid.	The response is adequate, but more information should be added into the text. *To support evidence of Winters shale-out the application would benefit from figures that show petrophysical input data (log/core availability), outputs, and upscaling results per well (cross-section and histogram).* .
14f		***Explain why the AoR does not follow the gas field outline.***	None	The plume extends below the field original gas/water contact (OGWC). Most of the plume does not go below the deep contact on the southern part of the field (-9990 feet). Some of the CO_2 dissolves in the water leg and goes into solution below this contact as seen in the cross-sections. Due to the effects of differential pressure and reservoir heterogeneity some CO_2 is pushed below the OGWC, where it is trapped due to capillary trapping, end point trapping and hysteresis. CO_2 also goes into solution in the water leg.	The applicant's responses are plausible explanations for why the shape of the AoR differs from the OGWC outline. ***However, these responses should be substantiated by including plan view and cross-section plots of dissolved and trapped CO_2.***
14g		***Does the CO_2 plume extend below the OGWCs?***	None	See response to #14f	See comment #14f.

#	Section	Comment/Question for CTV	Report Section Updated	Response	Reviewers' Evaluation of Company's Responses
15		***What causes the N-S divide or flow barrier within the field: A fault or a facies change? Is there a sealing fault there that is not known or described? Identify the flow barrier mentioned in the text in Figure 3.3 of Attachment B and explain the causes of the boundary. ...Can the flow barrier be seen in seismic profiles?***	Attachment B Section 1.9; Attachment A Section 2.2.2	A facies change as can be seen in the stratigraphic cross-section presented by Hill (1979) in new Attachment A Figure A-16. Response #2 describes how this barrier was modeled. Seismic data shows a change in seismic amplitude observed in this transition area where a single reflector becomes a doublet suggesting a second lobe coming in from the northeast. However, this amplitude transition is not consistently mappable, likely due to seismic resolution issues. Reference: Hill 1979 - California Well Sample Repository Special Publication No. 2, Figures 2 & 8	Applicant references literature and seismic observations to explain change in Winters facies N-S. Literature contains cross sections to explain facies changes; *modern cross sections with facies logs showing Winters facies change N-S would strengthen the argument for a flow barrier.*
16		***Lithology older than the Delta Shale needs to be described.***	Attachment A Section 2.2.2	Attachment A was updated with discussion of formations underlying the Delta Shale, as requested.	The comment has been addressed. Lithology deeper than Delta Shale (Top Lathrop and Sacramento Shale) is mentioned in Section 2.2.1, limited description of Lathrop provided in Section 2.2.2 under Delta Shale though.
17		***The statement of different gas-water contacts (GWCs) at discovery in Attachment B documents needs to be made in the Narrative as well.***	Attachment A Section 2.2.2.	Attachment A was updated as requested.	The comment has been addressed. Applicant includes statement regarding differences in N-S discovery GWC in Section 2.2.2. under Winters Reservoir (Injection Zone).

#	Section	Comment/Question for CTV	Report Section Updated	Response	Reviewers' Evaluation of Company's Responses
18		***Were other locations for the northern boundary considered? (See also sensitivity analysis section of this document.)***	None	The northern boundary of the model is based at the 0-foot net sand line as mapped in a regional study by California Geological Survey (Downey, 2010). Since this boundary is based on the mapped extent of the Winters sands, other locations for the northern boundary were not considered. The lack of aquifer support in the field's production history also suggests a close boundary to the North. References: Downey, Cameron, and John Clinkenbeard. 2010. Preliminary Geologic Assessment of the Carbon Sequestration Potential of the Upper Cretaceous Mokelumne River, Starkey, and Winters Formations – Southern Sacramento Basin, California. California Energy Commission, PIER Energy-Related Environmental Research. CEC-500-2009-068.	Response is adequate. ***However, this information should be added into the application text.*** *Evidence for northern shale-out (Winters pinch-out) would benefit from site specific N-S cross section of well facies data to complement regional mapping from Downey 2010.*
19	Model Suitability (cont.)	***Please describe the gridding around the injection wells and the upscaling process.***	None	The dynamic model uses a 200 foot by 200 foot grid including in the vicinity of injection wells. A local grid refinement sensitivity case was conducted, which includes 10 areas around each injector, refining the current grid 200 foot by 200 foot to 40 foot by 40 foot and maintaining the vertical resolution. Results show 1% difference for storage volume, plume boundary with minor	The response is adequate. However, there is no report section update for this response. ***The applicant should discuss this and the results of different grid resolutions and storage volume, plume sizes in the report.***

#	Section	Comment/Question for CTV	Report Section Update d	Response	Reviewers' Evaluation of Company's Responses
				difference and maximum injection pressure for local grid refinement model approximately 10% lower. This demonstrates the submitted case is conservative.	
20a-e		***Please provide seismic lines and well correlation panels to explain the following features:*** ***- Regional geological setting;*** ***- Original fluid fill, (both North and South parts of the field) including structural spill point;*** ***- Fault juxtaposition across the SAF;*** ***- Reservoir shale out; and*** ***- N-S divide of the field.***	None	The seismic data is licensed therefore seismic lines cannot be shown in this report. The structural model incorporates the seismic interpretation.	***Sharing of confidential business information (CBI) is now supported by the GSDT; therefore the applicant should provide justification in the form of a written statement from the seismic data provider. CBI is exempt from FOIA and sharing CBI with regulators is typically not in violation of licensing agreements. Applicant did not provide seismic lines or well correlation panels to explain facies changes related to fault juxtaposition, reservoir shale-out, or N-S divide of the field.***

#	Section	Comment/Question for CTV	Report Section Updated	Response	Reviewers' Evaluation of Company's Responses
21		***Figure 3.2 of Attachment B is an important figure showing a reservoir facies change. Please include this figure in the Narrative as well. Can the shale-out be seen on seismic? Are there wells that penetrate the Winters formation in both the hanging wall and footwall? If so, please show the hanging wall penetrations.***	Attachment A and B figures	The shale-out has been added to multiple figures in Attachment A and Attachment B. The shale-out can be seen on the seismic data but cannot be relied upon for a defined edge. The Winters sand lobe creates an additional reflector within the data. However due to seismic interference patterns this mostly creates a doublet that softens the seismic response at the top of the Winters. As you move to the north and northeast of the AoR the Top Winters amplitude response increases indicating the shaling out of the sand lobe. The shape of this amplitude loss is consistent with the model shown in Figure B-2	Shale-out added to Narrative Figure A-14 and A-33. ***No seismic evidence provided to describe shale-out; if seismic cannot be relied upon for defined edge, how was edge defined? Would have expected applicant response to tie back to Downey 2010 reference in question #18. Applicant does not address if well data is available to define shale- out on hanging wall.***
22		***Figure 3.4 of Attachment B: Please provide a strike section that shows the flow boundary separating the North and South of the field.***	Attachment B Figure B-10b.	Please refer to response #2 and #15. A strike section figure has been added, as requested.	***Applicant added Figure B-10b cross section which does not show flow boundary. Permeability and porosity properties appear continuous N-S along dip. The shale out is shown on Figure B-10b. The porosity and permeability on this strike section don't look particularly low between Sonol_securites_3 and Inj-1, as compared with the permeability at Inj-1.***
23		***Figure 3.6 of Attachment B: Please display the reservoir shale-out line in the figure.***	Attachment B Figure B-7	Figure 3.6 has been updated in Att B and is now labeled Figure B-7	Comment was addressed. Shale out line was added to Figure B-7.
24		***Figure 3.16 of Attachment B: Will any new wells be drilled for monitoring (e.g., in the north)?***	None	The only new drill monitoring well currently planned for CTV II is M-1. The monitoring program is discussed in Attachment C.	Comment was addressed.
25		***In Attachment A, section 2.2.1, why is the Lathrop formation not listed? (see Appendix of this document).***	Attachment A Section 2.2.2	See response to #16	Lithology deeper than Delta Shale (Top Lathrop and Sacramento Shale) is mentioned in Section 2.2.1; ***there is still limited description of Lathrop in Section 2.2.2 under Delta Shale.***

#	Section	Comment/Question for CTV	Report Section Updated	Response	Reviewers' Evaluation of Company's Responses
26		***In Figure 2.2-5 of Attachment A, the fault boundary is clear but what determines the boundary downdip? Why has the shale-out line not been used as a 0-thickness line in the isochore gridding?***	None	Please refer to response #14e for shale-out line discussion.	***To support evidence of Winters shale-out the application should include figures that show petrophysical input data (log/core availability), outputs, and upscaling results per well (cross-section and histogram).***
27a		***Please clarify how well completion was implemented into the simulations.***	Attachment B Section 1.11	In Dynamic modeling, the entire injection zone is opened (i.e., it is assumed the injection wells are perforated throughout the thickness of the injection zone).	***The applicant stated that injection wells are perforated in the injection zone, but the question becomes how does the simulation account for such perforations? This may hint to increase permeability or skin factor, please discuss about this.*** ***Is this consistent with the well completion plans? Looking at Appendix 5 from the original proposal, some of the completions (e.g., Sonol Securities 3) would be perforated for 300 ft, which seems like an unusually long perforated interval.***
27b		***Please confirm if the wells are constant-rate injectors subject to a maximum injection pressure.***	Attachment B Section 1.11	All injection wells are constant-rate controlled subject to a maximum allowable injection pressure that is based on the fracture gradient plus a 90% safety factor.	***In section 1.11, the applicant stated all injection wells are constant rate and subject to the maximum injection pressure. Detail with the injection rate and pressure are provided in Tables B6 and B7. However, injection rate still ranges between 530 – 794 t/day, and perhaps a 0 rate when maximum pressure is reached. Please check the tables or explain it more clearly.***
28	Model Design	***Please explore and provide information on the impact of the northern boundary location, as mentioned in Comment 18 above.***	None	Please refer to response #18	*Evidence for northern shale-out (Winters pinch-out) would benefit from site specific N-S cross section of well facies data to complement regional mapping from Downey 2010.*

#	Section	Comment/Question for CTV	Report Section Updated	Response	
29		***In the Appendices (CTV II AoR _CA AoR Delineation.pdf), the plume front is defined by a CO_2 mole fraction of 0.05. While the appendix seems outdated and corresponds to a former version of the model including two injectors, how and why was such a decision/change made?***	None	CTV II Class VI EPA technical questions on computational modeling is based on Attachment B, Version 3.2. We did not find any maps, plots or text showing 2 injectors for the project, but does show 5 proposed injectors (sentence unclear). Back to November 2023, CRC uploaded the Attachment B, Version 3.2 with CBI removal to GSDT. Also, CTV II plume boundary is defined by 0.01 CO_2 global mole fraction cutoff, not 0.05.	***There is still some confusion around this point, as Figure B-27 a and b use different criteria for the plume boundary, which result in different numbers of the sensitivity studies having a plume that goes past the proposed AoR boundary. Please clarify.***
30		***Was a grid sensitivity test performed? What metrics did the applicant use to decide this grid was "adequate resolution for plume development"?***	Attachment B Section 1.5	Discussion of grid refinement sensitivity was added to Attachment B Section 1.5, as requested. Grid sensitivity analysis was performed. Simulation grid design can be used to optimize the simulation grid and maximize the geological details that are represented, and allows for selecting the maximum grid block size that maintains important features of the finer gird. A sector model was built to analyze the horizontal and vertical grid sensitivity. Two sets of models were investigated: (1) with a vertical grid size ranging from 3 to 9 feet while maintain the horizontal grid size 100 feet; and (2) with a horizontal grid size ranging from 100 to 200 feet while maintaining the vertical grid size of 3 feet. Results showed that for increased vertical grid block size from 3 to 9 feet storage volume reduced approximately 1%, plume boundaries were similar with minor difference, and maximum injection pressure increased slightly. For the 100 feet to 200 feet horizontal grid size models, storage volume reduced 3.6%, plume boundary differences were minor and maximum injection pressure increased slightly. This analysis	***Response is adequate but needs to be included in B-Section 1.5, where the discussion of the horizontal mesh refinement study is still only qualitative. Is the fine vertical resolution 3 ft or 5 ft? The text here says 3 ft, but the AoR document says 5 ft.*** The applicant used constant horizontal cell geometries and therefore plume geometries would be less sensitive to grid cell geometries. Additionally, grid sensitivity analysis usually investigates more than 2 model geometries. ***Figure B-4 provides no tangible value to support grid sensitivity analysis results.*** *The vertical heterogeneity is captured; but it would have been useful to see results of 3 ft vs 9 ft vertical upscaling and a justification backed up by vertical variogram analysis.* *The applicant could have included some verbiage about pinch outs and impact on cell size.*

				Demonstrated that the 200 foot by 200 foot by 9 foot grid size is conservative and appropriate for plume and pressure modeling.	
31		***Please explain distribution of cell heights.***	Attachment B Section 1.5	Cell thickness range from 5 to 14 feet, with an average height of 9 ft.	***The AoR document is still confusing on this point. The vertical mesh is referred to as 9 ft at the top of page B-10 and 5-14 ft with an average thickness of 9 ft at the top of page B-11. Please clarify.***
32		***Please provide a table in the document with all this information for all the formations included in the dynamic simulation model.***	Attachment B Table B-3	Table B-3 was added, as requested.	***Table only appears to have information for Winters Formation. Please include information for the other formations.***
33		***Please explain why no preferential pathways for fluid movement were incorporated into the dynamic fluid flow model.***	Attachment B Section 1.5	Discussion of preferential flow pathways was added, as requested.	Applicant states current dynamic fluid flow model captures heterogeneity caused by preferential flow pathways using well data and variograms to guide modeling without providing evidence or methodology; *the application would benefit from a discussion regarding facies and channelized modeling options. More importantly, the justification to include or exclude channel (object) modeling would be strengthened by inclusion of figures that show petrophysical input data (log/core availability), outputs, and upscaling results per well (cross-section and histogram).*

#	Section	Comment/Question for CTV	Report Section Updated	Response	
34		***Please provide plots or tables of the time-history of well pressures from discovery to present day.***	None	It is a dry gas reservoir, and therefore most wells were drilled at an early stage. Most recent reservoir pressure of 1,200 psi is based on the Pool B-2 pressure and temperature gradient survey in 2022. Minor gas production occurred after this measurement and the field has completely shut down since June 2023. Additional pressure data will be collected during pre-operational testing, at which time modeling will be revised and the AoR delineation reevaluated.	The applicant states these data are not available therefore, did not revise the application for these comments. ***This response should be captured in the site characterization document.***
35		***Model results should include an estimation of the extent of the separate-phase carbon dioxide plume migration and changes in fluid pressures within the injection zone over time.***	Attachment B Section 2.	Additional figures of pressure and CO_2 global mole fraction have been added as requested.	***The global mole fraction and separate-phase carbon dioxide are different quantities.*** Figure B-23 shows top view snapshot of carbon dioxide saturations, and there is a high gas saturation (~0.5) near the SAF.
36	Model Design (Cont.)	Cross-section plots through the line of injection wells would be useful to have in addition to a cross section or two parallel to the one shown in Attachment B (Figure 3.14A), but through locations where the plan-view plume plots show larger CO_2 mole fractions reaching the fault.	Attachment B Section 2.	Additional figures of pressure and CO_2 global mole fraction have been added as requested.	Comment was resolved. Additional cross-sectional plots are added, and the applicant resolved this comment.
37		***Please show the pressure throughout injection in plan-view and/or side view. This information needs to be included in more detail.***	Attachment B Section 2, Figure B-21	New Figure B-21 has been added to show pressure through time in plan-view.	Comment was resolved. The top view of the pressure distribution at different time post-injection is included in Figure B-21.
38		***Please clarify what time step values were used in the simulation.***	Attachment B Section 1.13.	Time step values were added to Attachment B, as requested.	Comment was resolved. The applicant states the timestep are between 0.000001 to 31 days, but additional details are not provided.
39		***Please review the choices of boundary conditions for the delineation of the AoR and evaluation of plume stability.***	Attachment B Section 1.9, Section 2.3	See responses regarding boundary conditions at #1 and #4c, above.	See response to comments #1, #4, and #5.

40	Input Parameters vs Site-Specific Conditions	***Why is there an omission of dissolved gas in the liquid phase between the current gas/water contact and the original gas/water contact?***	None	Union Island Gas reservoir is a dry gas reservoir, with Methane and Nitrogen constituting >99% of the in- situ gas based on gas analysis. These two components have far less solubility in water compared to CO_2. Nitrogen solubility in water is around 2% of CO_2 solubility in water, and methane solubility in water is around 4% of CO_2 solubility in water.	Comment was addressed, although *it would be useful to provide numbers to support the response (Henry's coefficients of nitrogen, methane, and CO2 in water at the reservoir pressure).*
41		***Please compare the relatively simplistic assumed initial condition with the simulated current state of the reservoir based on the known gas production since discovery in 1972.***	None	The model was initialized based on the most recent pressure data in the reservoir gas cap from well Pool B-2 of 1200psi, which matches well with material balance based on the field production since 1972. Additional pressure data will be gathered during the pre-operational testing phase to confirm that the pressure in the gas cap is as expected and AoR modeling will be updated if necessary. During initialization, model will calculate each point reservoir pressure based on the depth and fluid density. Near the injector it will use gas density, and far from the wells it will use the water density. That is why the pressure far from wells is higher.	***Response is adequate, but it should be included in the AoR document.*** The applicant takes the water-gas contact, and calculated the initial pressure based on hydrostatic and capillary equilibrium.
42		***Please provide maps of permeability and porosity at different angles than Figure 3.9 of Attachment B.***	Attachment B Figure B-10b.	New Figure B-10b has been added to show a north-south cross section of permeability and porosity	Response is adequate. Applicant provides a strike cross section in Figure B-10.)
43		*Despite the fact that the applicant plans to collect additional core data from the actual field as per the pre-operational testing plan, it is recommended that the applicant try to gather additional site-specific data during the pre- construction phase of the project.*	None	The Pre-Operational Testing Plan covers data that will be collected prior to injection.	Response is adequate.

#	Section	Comment/Question for CTV	Report Section Updated	Response	
44		***Please provide a detailed discussion of these parameters and clarify whether a single set of parameters are used for the full model, or if they are based on facies or absolute permeability.***	Attachment B Section 1.7	Additional information was added to Section 1.7 as requested.	Response is adequate, though usually different relative permeability endpoints and residuals for 'sand' vs 'shale' grid cells. However, it is not likely to make a significant difference in the AoR. *In a reservoir engineering perspective, changes in the pressure-saturation curve can lead to different initial saturation state. This may have further implications to gas flow and CO_2 composition. The applicant did not discuss such implications in the revised report.*
45		***Please provide more information about the confining zone properties. It appears that the confining zone is assumed to be homogeneous, which seems unnecessarily simplistic, given the level of characterization data available for this field.***	None	See response to #5b; the confining zone is not incorporated in dynamic modeling.	See comments under #5b.
46		***Please clarify whether the model included a geothermal gradient.***	Attachment B Section 1.10.	Section 1.10 was revised to clarify no geothermal gradient was assumed in the base case simulation, and report results of a sensitivity run with a geothermal gradient.	Response is adequate but lacks clarity. For example, ***it is not clear how the isothermal and non-isothermal cases differ from each other. What is the value of the geothermal gradient for the sensitivity analysis?***

47		***While pressure is expected to remain lower than discovery conditions, analysis of potential for fault reactivation is needed, from a risk assessment perspective.***	Attachment A Section 2.5.3	See response to #8, above.	Response is adequate, fault reactivation modeling is completed.
48		0.7 psi/foot fracture gradient is assumed for the injection zone at present. ***Please provide a rationale for this assumption.***	None	Attachment A Section 2.5.2 includes explanation on what data was used to justify the fracture gradient.	Response is adequate. The fracture gradient is based on the formation integrity test, which measured ~0.75 psi/ft.
49		Fig 2 in Appendix 10 Critical Pressure Calculation shows simulated pressures across the whole plan-view extent of the model domain, and a sharp discontinuity in the pressure field, but no explanation for it (is it a mistake and were the wrong simulation files (i.e., two injectors) represented?). The model is also bounded to the South-East by the SAF, which is treated as a no-flow boundary. ***How do we know this fault boundary is impermeable?***	Appendix 10, Attachment A Section 2.3	Appendix 10 has been updated based on several comments; see responses to #7c, #13, #14a-d; #50.	The critical pressure calculation in the appendix is verified. ***However, the pressure discontinuity in Appendix 10 Figure 2 is not discussed. The applicant should clearly explain this discontinuity.***
50		***Please show the injection well locations in Figure 2 of Appendix 10.***	Updated Appendix 10 Figure 2	Appendix 10 Figure 2 has been updated to show injection well locations as requested.	Response is adequate. The locations of the injection wells are added to the figure.
51		***Please provide equations for how mass transport is considered in model simulations in Attachment B.***	Attachment A Section 1.2	Section 1.2 was added with GEM governing equations, as requested.	Response is adequate. The corresponding updated section is in attachment B (instead of attachment A). Equation 2 is the transport equation.
52		***In the Narrative, it is stated that the "CTV forecasts the potential CO_2 stored in the Winters Formation at 0.97 million tonnes annually for 23 years.", but operating details provided in Table 3.5 of Attachment B seem to show that the injection duration is 24 years. Is this just a mistake or does this have consequences on the numbers provided?***	Attachment A Section 1	Attachment A Section 1 was updated to state 23.5 years of injection.	***A discussion is needed to understand why the site capacity estimated by static methods 22 MMT of CO_2 is smaller than the dynamic capacity of 22.7 MMT (page A30-31). Usually, one would expect to see the opposite. Additionally, it is not clear where the revision is in attachment A. Some figures in attachment B stated 23.5 years as the end of the injection.***

53	Description of Computational Modeling Results	***Model results should include an estimation of the extent of the separate-phase carbon dioxide plume migration and changes in fluid pressures within the injection zone over time because the boundaries of the AoR are based on simulated predictions of the maximum extent of the separate-phase CO2 (i.e., supercritical, liquid, or gaseous) plume and pressure front over the lifetime of the project. Please include a scale to these figures.***	Attachment B Section 2.	Additional figures of pressure and CO_2 global mole fraction have been added as requested.	***Figures of CO_2 global mole fraction have been added in attachment B Figure B17a-e, but it is not equivalent to separate-phase CO_2. There still doesn't look like there is a scale (Figures B-15A/B).*** ***Please provide a figure that shows the overlay of the modeled maximum extent of the separate-phase carbon dioxide plume migration and changes in fluid pressures within the injection zone. See Figure 3-6 on page 47 of the EPA UIC Class VI Well AoR Evaluation and Corrective Action Guidance as an example.***
54		***Regarding the reservoir pressure, section 3.2.2 of Attachment B indicates that "For both injectate scenarios, CO2 was injected into the depleted Injection zone until the reservoir pressure reached 90% of the discovery pressure of 5,040 PSI.", which leads to 0.9*5,040 = 4,536 psi. However, Table 3.6 of Attachment B refers to maximum injection pressure that could not exceed 90% of the fracture pressure (e.g., 0.9*0.7*6,714 = 6,043 psi for SONOL SECURITIES 1-A injector). Shouldn't these values be consistent?***	None	No, these values will not necessarily be consistent. The reservoir discovery pressure of 5,040 psi is the average reservoir pressure whereas the fracture pressure is based on the pressure at each individual well location. During dynamic modeling all the injectors are constant-rate controlled subject to a maximum allowable injection pressure based on the fracture gradient with a 90% safety factor. In addition, all cases have injection cease when the average reservoir pressure reaches 4,500 psi (approximately 90% of discovery reservoir pressure). This is to ensure that the reservoir pressure is lower than discovery pressure in all portions of the reservoir. Please see Figure B-22.	***Figures 19 a-c shows the reservoir pressure vs. time near the injection wells. The maximum pressure is well dependent, with the highest reservoir pressure at roughly 4800 psi. This implies the discovery pressure should be less than 5333 psi. The original calculation is just an example, but the applicant should clearly state the maximum injection pressure for each well.*** ***Additionally, the applicant should clarify that the project design is based on injecting CO_2 until average pressure is 4500 psi and not based on injecting a pre-determined mass of CO_2 much earlier in the AoR document. This was not clear until the section on the sensitivity analysis.***

55		*However, units/parameters are not consistent with the equation provided in the guidance (SI vs imperial units, depth vs elevation), and it would be recommended to use such a visual and/or clearly list the parameters and associated units considered to make the review process easier and conceptually represent the system.* ***Please see the example in Box 3-2 beginning on p.43 of the EPA AoR and Corrective Action Guidance.***	Appendix 10	Appendix 10 has been updated to show calculation and units used.	Response is adequate. The applicant updated the calculation with units for each parameter.

#	Section	Comment/Question for CTV	Report Section Updated	Response	
56		*The modeling results only reflect the extent of CO2 plume. Very limited pressure front results prior to stabilization are presented. The pressure is only presented in tabular form for the wells (max, average) and after plume stabilization for the full-field model.*	Attachment B figures	See responses to #7b and #37.	The applicant provided additional results on pressure vs time in Figures 17, 21, 22. Overall, the pressure does not show large changes after 33 years. *However, without snapshots between 22 to 33 years post-injection, it is difficult to visualize when the pressure stabilizes. Please consider use of a small timestep when approaching 22 years post-injection.*
57		*No plots or tables are shown that directly indicate that the simulation results are consistent with the planned injection amounts.*	Attachment B figures	Table B-6 displays the planned injection rates for each well; in addition Figure 20b was added to show simulated injection volume.	***Table B-6 shows a wide range of injection rates, whereas Figure 20b shows a fixed rate. Please check if they are consistent. The applicant should include the cumulative injection per well, and check if it is consistent with result shown in Figure 20b.***
58		*The pressure front modeling results that are presented are very limited. The AoR was not defined by the pressure front, but rather by the CO2 mole fraction of 0.05. Some of the plots that show the simulated CO2 mole fractions have legends that are not labeled, so it's not always clear from the presented results what is being displayed.*	Attachment B figures	The AoR was defined by a CO_2 mole fraction of 0.01 not 0.05, see response to #7a.	Response is adequate.

59	Model Calibration and Sensitivity Analyses	*Porosity, permeability, and injectate type were varied. The results were not sensitive to these varied parameters according to the application. The sensitivity analysis conducted is limited and the result isn't described quantitatively as in Table 3.7 of Attachment B. It is difficult to know which parameter is the most impactful.*	Attachment B Section 2.3	See response to #4e.	Response is adequate.
60		***An uncertainty of ±10% was applied to porosity and permeability. Two injectate compositions were tested. A greater range of uncertainty is needed. A larger range of absolute permeabilities should be considered. This should be changed by an order of magnitude in each direction, not 10%.***	Attachment B Section 2.3	Please refer to response to #4a.	See response to #4a.
#	**Section**	**Comment/Question for CTV**	**Report Section Updated**	**Response**	
61		***Please determine the model sensitivity to relative permeability and capillary pressure-saturation relations/function parameters. Both are based on limited core data from single wells in the field. This is particularly important as the relative permeability model used is quite simple and does not appear to include hysteresis.***	Attachment B Section 2.3	Additional sensitivity analyses were conducted as requested.	Response is adequate. Table B-8 shows the sensitivity analysis. Different relative permeability parameters are included in this study. ***The variation in capillary pressure curves is limited to trapped gas saturation (0 to 0.03). Also, there are several typos in the table.***
62		***Simulations with trapped gas below the present gas/water contact should be conducted, as the lower CO_2 trapping in the presence of residual gas may increase the size of the plume.***	Attachment B Section 2.3	Additional sensitivity analyses were conducted as requested.	Response is adequate. Applicant used different trapped gas saturation in the capillary pressure curve and different residual gas saturation in the relative permeability function to study how residual CO_2 trapping affects the plume size.

63	Model Calibration and Sensitivity Analyses (cont.)	***The applicant mentions in the section 3.2.2 of Attachment B that the model was validated by comparing the area of the reservoir that has been depleted by gas production and initial gas contacts with the modelling results. Please show results from this comparison.***	Attachment B Figure B-23	Figure B-23 as added as requested.	Figure B-23 shows the modeled area, gas saturation, and cumulative gas production data. ***A scale is needed for cumulative gas and any other indication of comparison. What is the source of the original w/g contact data? The AoR covers most of the wells and it crosses GWC in the north part. The applicant should discuss the figure, and what is the difference between $scCO_2$ plume boundary and the boundary of CO_2 plume.***

64		A qualitative discussion of the impact of vertical refinement was presented, but no discussion of the impact of horizontal mesh refinement was presented**. *This should be explained in more detail, as discussed in Comment 30.***	Attachment B Section 1.5	See Response to #30, above.	See comments under #30.
65	**General Comments**	The application needs more discussion of the potential (or lack thereof) for reservoir compaction due to the very low initial pressure of the gas field. Compaction would lower the amount of pore space available for CO2 storage and could also negatively impact injectivity.	See response to Question 6	See response to #6	Response is adequate.
66		In general, more results (even intermediate results) shown would be helpful in interpreting how sensitive the results presented in the application are to model choices.	See response to Question 30 and 61	See responses to #30 and #61	Response is adequate.
67		Mismatch between Narrative and critical pressure calculation. The latter shows a clear discontinuity in pressures between the north and south parts of the field, but no explanation has been given.	See response to Question 7c	See response to #7c	See comments under 2. ***There is still little explanation of the cause of the flow barrier.***

68		Geomechanical modeling is needed especially for the fault, leakage risk assessment for fault and penetrating wells.	See response to Question 8	See response to #8	Fault reactivation/geomechanical modeling is completed; fault leakage risk assessment would benefit from description of methodology (both Allan Diagram and SGR), ***no risk assessment was conducted for penetrating wells***.
69		Pressure build-up is not negligible (Appendix 10), and the pressure front plume is not considered enough for risk assessment. The leakage of not only CO_2, but also formation brine is also a risk.	None	As stated in Section 2.4, injection is in a depleted reservoir being repressured to below the discovery conditions. The final pressure of the Winters formation Union Island gas reservoir will be at or below the initial reservoir pressure to ensure that CO_2 occupies the same pore space that was initially saturated with hydrocarbons and the pressure front is at equilibrium with initial conditions.	***Please provide plan view and cross-sections of figures showing snapshots of the pressure outlines and CO_2/gas or CO_2/brine interfaces over time.***

70		Additional analysis of the closed northern boundary assumption is needed.	See response to Questions 18 and 28	See responses to #18 and #28	See response to comment #18. *Evidence for northern shale-out (Winters pinch-out) would benefit from site specific N-S cross section of well facies data to complement regional mapping from Downey 2010.*
71		Quantitative discussion of upscaling to 200x200 m simulation grid is recommended	See responses to Questions 3 and 19	See responses to #3 and #19	See comments under 3 and 19. ***The information on upscaling provided in this document should be in the application.***
72		Plots and discussion of pressure at the wells as a function of time and pressure distribution throughout the reservoir at various snapshots in time (e.g., use the same times as the plume snapshots: 1, 5 10, 15, 23, 30 and 50 years) are needed.	See responses to questions 35, 37, 53, 56 and 58	See responses to #35, #37, #53, #56 and #58	Response is adequate.
73		Additional uncertainty simulations with a larger range of absolute permeability are needed.	See response to Question 4	See response to #4	Response is adequate.

#	Section	Comment/Question for CTV	Report Section Updated	Response	Response is adequate.
74		Simulations including trapped gas below the present water/gas contact are needed	See response to Questions 4 and 62	See responses to #4 and #62	***Response is adequate but needs to be included in the AoR text.***
75		A grid sensitivity study would be helpful.	See response to Question 30	See response to #30	Response is adequate.
76		Applicant should either provide more evidence about the impermeability of the SAF or expand the domain to the East beyond the SAF to show the potential extent of the plume in later years.	See response to Questions 1, 13, 14, 20 and 49.	See responses to #1, #13, #14, #20 and #49.	***Applicant provided limited or incomplete evidence for SAF sealing capacity and did not expand the model domain east beyond the SAF.***
77	Corrective Action Assessment	N/A	Attachment B Section 3.5	Note that the Bomberger 1 well was previously incorrectly shown on Figure B-30. After correcting the location of the well, it falls outside of the project AoR and it is no longer considered a Corrective Action Well. Reference to this well has been removed.	Response is adequate.