RESPONSE TO PEER REVIEW

A *Greenhouse Gas Emissions Reduction Measurement and Monitoring Methodology for Carbon Capture and Storage Projects in Oil and Gas Reservoirs* has been developed by Blue Strategies and submitted to ACR for approval through the public consultation and scientific peer review process.

The methodology was posted for public comment from December 26, 2012 through January 31, 2013. In addition ACR held a stakeholder consultation webinar on January 18, 2013. The draft methodology, revised in response to public comments, was provided to a team of five expert peer reviewers. Peer review comments and responses are documented below organized by appropriate section of the methodology. Public comments and responses are documented elsewhere.

A. General Comments, if any

	1st Review	Response	2nd Review	Response
0.1	The methodology needs to better incorporate the basic concept of permanence. That is, emissions reduction	Methodology has been modified to make this		

	1st Review	Response	2nd Review	Response
	should be permanent as well as verifiable. In quantification of emissions from the storage component of a project, a distinction should be made between leakage which occurs only during the injection phase and leakage which could occur in the post-injection phase, and which, if not remediated, would compromise permanence. Examples would be leakage from faults or abandoned wellbores. Post injection leakage, which compromises permanence, and is not remediated, should be treated separately in the quantification section.	distinction		
0.2	The frequent use of quotation marks (e.g., "functional equivalence," "adjustment factor," "excess CO_2 emissions," "performance standard," "output," and "non-captured CO_2") in the document generally, and particularly on pages 18-24, is distracting. It is not clear why the terms require quotation marks when the terms are not direct quotations from another source and are not defined in the definitions section at the beginning of the document.	Quotation marks have been removed		
0.3	Consider writing out abbreviations of units of measurement the first time used in a section and/or the entire document (e.g., tCO_2e and MWh on page 10, MMscf on page 21). Also, use consistent format when abbreviating (e.g., enhanced oil recovery v. EOR).	Text modified as appropriate		
0.4	It would be helpful to include citations to supporting materials for many of the propositions in the text so that readers may identify and find those authorities for future research.	Additional citations included		
0.5	Many of the references seem to assume that the sequestered CO_2 will originate at a power plant.	We agree that CO2 can originate from other		

	1st Review	Response	2nd Review	Response
	However, CO_2 for EOR purposes is presently derived from other types of facilities, such as gas processing plants, refineries, etc. The methodology should avoid references or dependencies on source-specific metrics, such as megawatt hours, heat rates, or other numbers that may apply to one CO_2 emissions source (such as an EGU) but have no applicability to another. The methodology also should clarify that the source of the CO_2 is irrelevant and should be agnostic as to the type of source or number of sources. It is conceivable that EOR infrastructure is developed to take advantage of multiple CO_2 sources simultaneously, which could improve the overall efficiency and economics of such a project.	industrial sources besides power plants. The references to power plants is being made as an example only as we expect the majority of readers will be familiar with these concepts as they apply to power plants. Text has been added to clarify that CO2 can originate from other sources.		
0.6	The weakest section is 5.4, the MRV plan, which focuses on documenting the geologic storage. I am not sure why this document includes such details, as it does not include similar detail for the capture and pipeline parts of the accounting. I recommend that significant additional revision be done to make these requirements fit-to-purpose, and if possible, more harmonized with current protocols that may be used for near-term storage with EOR.	The section has been rewritten based on the overarching comments and many of the individual suggestions.		
0.7	The temporal implication of the word storage leads to a need to modify the annual reporting pattern for the capture and pipeline in the storage section. Accounting needs to consider future leakage risk and, if high, penalize storage credits. The monitoring program needs to formally assess the long-term leakage possibility and report the estimated quantified finding to the accounting section.	The reporting for the segments is harmonized as annual. While individual projects will assess injection and post-injection period risks of atmospheric leakage and devise their		

	1st Review	Response	2nd Review	Response
		monitoring strategy accordingly, storage credits should not be penalized until atmospheric leakage occurs. The accounting of credits, should atmospheric leakage occur is discussed in Sections 4.2.5 and 6.3.		
0.8	The methodology as proposed would not live up to the necessary standards. Crucial points have very little substance or the approach proposed is questionable. Substantial revisions are needed before this can pass the test – however I believe that this is doable.	More specific comments addressed in each section.		
0.9			Chapters 5 and 6 are improved and should be a positive contribution. The document still falls short of providing excellent guidelines, however given the current state of knowledge and expertise available to the writers, this is probably where this effort can get to.	

B. Definitions

	1st Review - Consensus Draft v. 1	Response	2nd Review	Response
1.1	The physical boundary of the project should have a vertical and a lateral component. The vertical component should be set as the top of the confining zone, not the surface, under the assumption that permanence is not verified once it leaves the confining zone. There should also be a lateral boundary in the subsurface defined as a project boundary. Credit should not be given (should be rescinded) for CO2 leaving the lateral boundary unless the boundary is redefined so as to assure that there will be no atmospheric leakage as a result.	Text has been modified.	OK	
1.2	On page 6, Figure 2-1 lists "CO_2 Fugitive." The relationship between "CO_2 fugitive" emissions and "atmospheric leakage" is unclear. "Atmospheric leakage" is not currently defined to encompass fugitive emissions resulting from transport and compression. The sentence on page 22, "Fugitive emissions may arise from leakage of CO_2 from equipment such as flanges, valves and flow meters" further confuses the definition of leakage and fugitive emissions. Recommend using capitalized defined term "Leakage" to refer to project-level leakage (i.e. displaced emissions) and other terms like "leaking" "escaping" etc., to address sources of fugitive emissions. In addition, no definition is provided for "fugitive emissions." We recommend clearly differentiating between fugitive emissions and atmospheric leakage. Fugitive Emissions should include emissions created during the capture, transport and storage process, but not captured and sequestered. For example, emission	Definitions of fugitive emissions and vented emissions have been added. Fugitive emissions are emissions due to leaks from equipment such as flanges, valves and flow meters, headers, etc. Vented emissions are emissions through dedicated vent stacks during normal operation, process upsets, or shutdowns. Both types of emissions can occur in the capture, transport, injection, and storage segments of the project,	OK. Recommend potentially clarifying in definitions of "venting emissions" and "fugitive emissions" how those terms relate to the project boundary.	

	1st Review - Consensus Draft v. 1	Response	2nd Review	Response
	from compressors or amine systems. This may currently form part of the "CO_2 not captured" in Figure 2-1. We also recommend making a distinction between short-term fugitive atmospheric leakage in the injection phase and long-term atmospheric leakage (permanence). Focusing the methodology on sequestration, rather than on generation, will help to alleviate this issue. However, if ACR retains the current project boundary it should properly defined and reflect the concepts of fugitive emissions at each stage or component within the project boundary.	and equations to calculate these emissions are included. Atmospheric leakage refers specifically to leakage of injected CO_2 from the geologic storage reservoir to the atmosphere. A distinction between short-term and long-term atmospheric leakage has been added.		
1.3	Consider adding the defined term "Creditable Sequestered Amount" as follows – Creditable Sequestered Amount: the amount of carbon dioxide (in tonnes) permanently sequestered at the project's Reservoir excluding any carbon dioxide required to be sequestered to comply with any state or federal law or regulation applicable to the Primary Process, minus (i) fugitive emissions associated with the compression and transport to the Reservoir of the sequestered carbon dioxide and (ii) fugitive emissions associated with the capture of the sequestered carbon dioxide. The goal of this definition is to clarify the "additional" amount of sequestered CO2 for crediting purposes.	The approach suggested appears more streamlined. However, it does not account for adjustments required for functional equivalence. For example, the sequestered amount may include additional CO2 generated during the capture process which should not be credited. While this can be calculated separately, it would require knowledge of the primary process.	We reiterate our comment that it is possible to account for primary process emissions without including that process in the project boundary, and that this approach would streamline approval and expansion of projects. However, we are willing to accept the current approach and agree that CCS-related emissions should not	

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		Therefore removing the primary process from the project boundary may not necessarily simplify the calculations. As indicated in Sec. 2.1, emissions from only a part of the primary source that is affected by the GHG project must be included.	be credited.	
1.4	Defined terms, when used in the methodology, should be capitalized to avoid confusion (see above comment with respect to "Leakage").	Text has been modified.	OK	
1.5	Baseline is important in the accounting framework, and it has a significantly different usage than baseline in monitoring. Baseline references in the monitoring section could be removed to avoid confusion and because the concept of baseline is widely misused by many monitoring protocols. Terms such as characterization, pre-injection conditions, change-over-time, or time-lapse measurements can be substituted to reflect reservoir monitoring measurements. In addition, a methodology that draws a boundary to exclude the CO2 source, and that measures actual CO2 injected at the wellhead, presents fewer (or no) source-baseline calculation issues and instead accounts for compression/transport emissions as fugitive emissions netted from the total injected volume to arrive at a "creditable amount" of sequestered CO2. See above	References to baseline in the MRV section have been clarified as pre-injection. See response to 1.3 regarding the exclusion of the primary process.	OK.	

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	comments.			
1.6	Add definition “Monitoring” or MVA or MMV, or MRV or “testing and monitoring” and then use consistently throughout document. Verification is used in the accounting framework part with meaning by itself for example in 1.3, where it refers to a third-party verifier. What does verification mean as part of MRV? I think it means model verification, but here it usage is undefined. Reporting in MRV is also unspecified, so is the activity best called MRV? Some of the newer protocols (e.g. RRC rules) use ”testing, monitoring, and sampling”. The document title says “measurement and monitoring”, a phrase that never shows up again!	A definition for MRV has been added. Reporting and verification requirements have been added to 5.4	OK	
1.7	A name is needed for the area where CO2 is placed as part of a managed flood, maybe “CO2 flood volume and area”. The edges of the CO2 flood volume may be natural, like faults or structural closure, but commonly they are managed, by pattern design, either by water injection well “curtains” or by drawing fluid to pressure sinks at producers. Another name is needed for the area which will be occupied by CO2 at the end of the project, maybe “long term CO2 storage volume”. The long term CO2 storage volume might be the same as the CO2 flood volume but might not be same if the CO2 flood volume does not include the whole geologic structural closure. A third term is needed for a rock volume determined by risk assessment, where CO2 is not predicted to migrate, but it is possible that it may migrate because of error during characterization or operation. Furthermore, if CO2 did migrate into this volume, it may result in	The term storage volume has been used to describe the “box” expected to contain the CO2 through the project-term. Long-term and short-term atmospheric leakage has been differentiated	OK	

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	Atmospheric Leakage (short or long term). Identification (and possibly mitigation) of migration of CO2 toward or into this volume is the goal of monitoring. This could be an area where production is not part of the CO2 flood, or where well integrity has not been assured, or toward a potentially transmissive fault. I call these no-go areas, perhaps a more formal term such as high risk volumes can be defined.			
1.8			Definition of "permanence" uses the word "permanent". This is tautological and should be fixed to describe a minimum timeframe and likelihood.	

C. Background and applicability

	1st Review - Consensus Draft v. 1	Response	2nd Review	Response
2.1	Figure 1-1 (page 2) is identical to figure 1 in the Center for Energy and Climate Solutions' (C2ES) report, *A Greenhouse Gas Accounting Framework for Carbon Capture and Storage Projects*. If the figure was pulled from the C2ES report, then the figure should cite the report.	Figure has been adapted from the referenced document. Citation added	OK. There are rendering issues with the graphic - please check for straight lines, etc.	
2.2	Section 1.2, p. 2 figure 1-1. Storage is not only during the EOR operation, but to continue after closure.	Figure has been modified to reflect this.	OK	

	1st Review - Consensus Draft v. 1	Response	2nd Review	Response
2.3	p. 3 If projects are required to transition from Class II to class VI… We recognize that this is a hot issue, but this sentence lacks meaning and should be clarified.	Clarification has been added	OK. Please clarify if this is the initial crediting period and how extensions are handled in this case.	
2.4	p.2 The text states that "In considering the geological storage of CO2, the methodology applies to enhanced oil and gas recovery projects utilizing Class II wells" yet earlier on it says that it applies to projects in North America. Injection in Canada will not feature Class II wells, which are regulated by US states or USEPA.	Text has been modified.	OK	
2.5	p.8 No Justification is offered as to why " EOR displaces an equivalent quantity of current production". In fact, credible economic analyses use "displacement factors" that account for the effect that local production has to local and global markets (supply, prices, and demand). We agree that the methodology should not consider emissions related to use of produced oil or other hydrocarbons, due to displacement. However, if this argument and accounting pathway are used, we suggest additional explanation with supporting citations.	Text has been modified	OK. Consider elaborating and/or adding displacement argument back to text if it can be supported with relevant citations to peer-reviewed studies. We agree with the concept and want to assure it is well defended.	
2.6	Sec. 1.3 Triggers/criteria (regulatory or other) for revision of the methodology need to be defined.	Triggers will be set by the ACR Standard.	OK	

D. Project boundaries

	1st Review	Response	2nd Review	Response
3.1	Project boundary should be defined explicitly as one within which the CO2 will be permanently stored and will not result in atmospheric leakage. The definition should include both vertical and lateral limits. The definition should be used consistently throughout the document, and eliminate other vague/undefined terms such as “reservoir boundary” or “storage unit”.	This concept has been included in the methodology		
3.2	The methodology could be simplified and improved by focusing on sequestration, rather than establishing a project boundary that encompasses the Primary Source. This approach would eliminate the need for imprecise baseline measurements or calculations, which could be replaced with more precise monitoring equipment at the sequestration site. If current project boundaries are retained, consider refining the definition of “physical boundary.” “Physical boundary” is first defined as “demarcat[ing] the GHG emission sources included in the project and baseline emissions calculation.” On page 4, it is clarified that “physical boundary” includes “the full CCS value chain, including emissions from CO_2 capture, transport and storage in oil and gas reservoirs, as well as CO_2 recovery and re-injection operations at enhanced oil recovery sites.” Assuming the baseline emission calculation accounts for all of the emissions sources in the project/CCS value chain, then it is redundant to say that the physical boundary includes all of the emissions sources in the project and the baseline emissions calculation. Recommend shortening the definition of “physical boundary” to “emissions sources included in	See response to 1.3 on exclusion of the primary process from the project boundary. The definition of physical boundary has been shortened as suggested.		

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	the project."			
3.3	The concept of "primary process" (defined as "the specific power generation or industrial process (e.g., natural gas processing, hydrogen production, steelmaking) creating the capture CO_2") is introduced without explaining how a "primary process" fits within the definition of "physical boundary" (page 4). The relationship between "primary process" and "physical boundary" should be briefly explained for clarity. The methodology should reflect four distinct aspects to CCS projects: • Primary Process (CO_2 generation) • Carbon Capture System and Compression • Transport and Supplemental Compression • Injection and Storage As explained above, we recommend eliminating the Primary Process from the project boundary. In addition, consider the possibility of transportation occurring via mechanisms other than pipeline, such as truck, rail, etc.	The text has been reorganized. The definition has been excluded from the text in this section. (since it is defined under "Definitions") See response to 1.3 for the need to include the primary process Transportation by barge, rail, or truck is already included.		
3.4	Figure 2-1 (page 5) is identical to figure 2 in the Center for Energy and Climate Solutions' (C2ES) report, *A Greenhouse Gas Accounting Framework for Carbon Capture and Storage Projects*. If the figure was pulled from the C2ES report, then the figure should cite the report.	Citation added		
3.5	The term "physical boundary" may be misleading because it does not focus on the geographic and/or	The focus of the physical boundary is the sources		

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	geologic dimensions of a CCS project. Assessing the geographic boundaries of a CCS could be important in determining whether there is overlap in CCS projects, for example in transport. The geographic boundaries of CCS project might also have important jurisdictional implications. Similarly, subsurface geologic boundaries (the Reservoir) may face differing and unique regulatory, liability, or contractual issues. Importantly, a CCS "project" may have multiple CO_2 sources. That is, multiple "Primary Processes" may hook into a single transportation, injection, and storage system. This is especially true in an EOR context, where diverse entities may have different objectives with respect to the overall CCS system. Eliminating the Primary Process from the geographic boundary would help to alleviate this potential problem in defining the physical boundary of the project.	of GHG emissions, which are relevant for accounting. As such, these sources are a surrogate to the physical dimensions, since we focus on individual sources of emissions from equipment within the confines of capture, transport, etc. Therefore if CO2 is captured from multiple primary processes that are part of the project, then each of those processes are analyzed to determine the baseline. If another primary process hooks into the same transportation system and that process is not part of the project, then its captured emissions are not included in the baseline.		
3.5	A graphic illustration of a "physical boundary" for a CCS project would be helpful.	The physical boundary (sources) is shown in Figure 2-1		

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3.6	It is not clear how a determination is made that a CCS project will be able to generate offsets over the next 10 years. The ability to generate offsets is linked to the generation of emissions, and, therefore, should have some nexus to projections of emissions and identify any assumptions in projections. Specifically, the methodology assumes that electricity market demand and heat rate efficiency will remain constant over 10 years for EGU by using present emissions rates for the baseline determination. Regulations providing credit for GHG reductions from CCS may require some demonstration that the facilities will continue to emit at the same rate over the 10 year period (e.g., electricity dispatch modeling for EGU from Energy Information Administration's national Energy Modeling System (NEMS) used for the Annual Energy Outlook) to meet the quantifiable criteria for pollution controls. *See*, EPA, Improving Air Quality with Economic Incentive Programs, 34 (2001); 51 Fed. Reg. 43,814, 43,814 (Dec. 4, 1986). Accounting for the CO2 emissions associated with the CO2 capture process is, however, necessary in order to have a measure of parasitic energy use.	The use of a fixed-term crediting period (10 years in this case), which is renewable at the end of the term is typical of all GHG projects registered in the US and abroad. This period provides an adequate term during which market participants (project proponents, offset buyers, registries, etc.) have a level of assurance that offsets will be generated from the project as long as they are successfully verified in accordance with the project's approved project plan. Regulations may change during the crediting term but the potential emission reductions from the project remain unaffected as long as the project is verified in accordance with its approved GHG Project Plan, At the end of the ten-year period, a new		

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		Project Plan will be developed in accordance with the regulations in effect at that time. We agree that CO2 emissions associated with the capture process is necessary and are included in the methodology.		
3.7	In the temporal boundary section, the methodology defines the "project term" as "the minimum length of time for which a project proponent commits to project continuance, monitoring and verification" (page 6). The methodology dictates ongoing 5-year project terms until permanence is assured. But the methodology does not define permanence nor explain how permanence is assured. Recommend defining permanence and explaining how permanence is "assured" in this section or an appendix, considering that other organizations may have preexisting definitions of permanence.	Text on permanence has been discussed in Section 5.4. A definition has been added.		
3.8	In the GHG assessment boundary section (page 8), the methodology states that "emissions of hydrocarbons produced by EOR products (i.e., produced oil or gas), which occurs outside of the project boundary at the point of use, are excluded. This approach is consistent with other GHG emission reduction methodologies, where emissions related to the use of the products are not included." We agree with this principle, but recommend including a more comprehensive and	Text from response to public comments has been added.		

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	defensible statement in the methodology on this issue. Such statements currently appear in the responses to public comments.			
3.9	In the GHG assessment boundary section, the justification for not including CH_4 and N_2O emissions from primary processes in the baseline is "exclusion is conservative." (page 8). In the response to the Clean Air Task Force comments on an explanation for the omission, Blue Strategies clarified that CH_4 and N_2O from primary processes were not included in the baseline because the emissions are negligible. Thus, the burden of monitoring CH_4 and N_2O is not warranted. Include a footnote providing this full justification for the exclusion and/or changing "exclusion is conservative" to "excluded because negligible."	"Emission is negligible" has been added to the Table		
3.10	What is relationship between (a) the project term, (b) the crediting period, and (3) monitoring periods (for assessing permanence)? The methodology should clarify each of these distinct periods. Regardless of the project term (whether 10, 20, or 30 years) ERTs should be issued annually, based on the creditable amount of CO_2 sequestered that year, and with an appropriate vintage.	The project term and crediting period definitions are included under "Definitions" in the methodology. In the case of CCS projects, the project term and monitoring periods are similar and span the same time-period. Crediting Period refers to the time span for which the project's GHG Project Plan is valid. For CCS projects it is ten years. At the end of the ten year period, the		

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		crediting period can be renewed by the project proponent by updating the Project Plan to meet the requirements of the methodology that are in effect at that time. For e.g., if Project term is 35 years, then the 1st crediting period spans yr 1-10. If successfully renewed the second crediting period is yr 11-20, and so on until the end if injection. Agree that the credits should have an appropriate vintage based on the year of sequestration. However, the schedule for verification will be at the discretion of the project proponent provided it conforms to ACR guidelines. ACR will issue credits after successful verification.		
3.11	Section 2.1 p. 5, figure 2-1. Suggest add electricity purchase for transport and storage, which is an important element described in method but not shown	Figure updated to add electricity usage in capture, transport, and		

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	in figure.	storage segments.		
	Section 2.2 p. 6 Temporal boundary discussion is a place to deal with the issue of expectation of long term storage. As written, the merit of the project with respect to long term isolation from atmosphere is not properly defined. Some plan should be made for the case in which project failure occurs, but leakage will take 10’s or 100’s of years or more to reach the atmosphere. The five year post injection period with two year extensions is inadequate to accomplish this, principally because it (similar to the EPA’s 50 years) does not require any activity which would discriminate between a successful project with high assurance of permanence and a project with significant future leakage. “Monitored for leakage” and “conformance to model predictions” are too weak, have no teeth that would separate excellent storage from any poor quality projects. A case for considering: a project developer starts injection into several patterns which access different parts of the field. After injection of a significant volume, an unsuspected connectivity is discovered from part of the flood area into “no-go” parts of a field, perhaps across a fault into an area that is in production by another operation. The operator stops injection in the problematic part of the flood area, and produces it strongly to decrease pressure, so that cross-fault leakage will be delayed to after the operational period. However post-closure, the pressure will recover and some CO_2 is likely eventually migrate into the “no-go” unmanaged area, and some part of may be produced up unmanaged wells. We should not to give project credit for the amount of CO_2 that is in poor quality storage and may	Long-term monitoring and storage discussion is included in Section 5.4. The distinction among projects as having a higher or lower level of assurance is subjective. We believe that all projects show through their individual site-specific monitoring strategy that leakage does not occur outside the storage volume and that it is verifiable. The case examples described by the commenter are examples of failure scenarios that should be evaluated. See response to comment 3.13 with regard to the 5-yr period		

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	be reemitted. The term reversal is provided first time on p. 54; it should have a use, here it is. Another example of failure of storage over the long term is where CO2 migrates out of the reservoir and is dissolved in water, where the water travels over a long flow path, and eventually (10's to 100's of years) discharges to the surface, releasing the CO2 to atmosphere. This is how many natural CO2 springs are created.			
3.12	A performance-based section should be added to require, periodically during injection, affirmation of effective storage, saying that selected elements of the performance of the flood have been evaluated by monitoring, testing, and modeling, and that confidence in the expectation of long term storage remains high or has increased. If some storage is found to provide poor long term assurance, the accounting system should require an estimate of the possible long term emissions, and discount them using reversal.	Periodic reporting of the data will occur during each reporting period. The verifier will verify the performance of the monitoring strategy during each period. Reversals are applied when leakage to the atmosphere occurs and is not remediated.		
3.13	The five year period of unspecified monitoring should be removed, in favor of a during-injection affirmation described in last paragraph. In a case where final affirmation of the long term migration requires some evaluation of relaxation and gravity stabilization post-injection, this should be called for in the monitoring and testing section, and the duration tuned to metric that produces adequate confidence of long term storage (something more stringent than generic "model match"). For example, the case of ROZ, where the oil has been swept out by past processes, might need such an	The five year period of post-injection monitoring is included as a minimum requirement to assure permanence after injection has ceased. We believe pressure equilibration will occur well within this period and should there be any		

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	evaluation, to determine that the same process will not sweep the CO2 at unacceptably high rates (I don't think it will, but does need an evaluation). In many cases, patterns of the field will be taken out of production well before the end of the EOR flood. It is common to end the life of a pattern by "blowing it down" which means decreasing the CO2 and water injection while continuing oil and CO2 production to economic limits, so that the pattern is left at low pressure. Alternatively, the operator may do a "tapered flood" where less and less CO2 is injected, and the pressure maintained by water injection. Another situation that should be considered is that the end of project is a matter of stopping CO2 injection, and doing instead some other type of tertiary recovery to strip out the last oil. Not sure what this would be, but the possibility that something new will replace CO2 flooding should be considered. In this case, the quality of storage under changed conditions should be evaluated, and if needed a reversal applied.	anomalies, it would show up and be detected. While an affirmation occurs at various times during the injection period, there will still be a need for project proponents to undertake some monitoring for assurance. We believe the accumulation of five years of monitoring data post-injection together with all the injection period monitoring data and intermediate verifications are adequate to provide that assurance. The two-year increments are included as an added buffer if needed.		
3.14	The physical boundary of the project should not just cover the CO2 plume, but also potential pathways that could lead to its leakage. Is this stated elsewhere in the document?	This point has been clarified.		

E. Baseline determination (and additionality assessment)

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	1st Review	Response	2nd Review	Response
4.1	4.2.4 Page 41 “CO2 injection and production wells”: there may be other types of wells within the boundaries, so ‘all wells’ should be considered for potential leakage.	The potential for leakage from other wells will be evaluated during site characterization of the storage reservoir.		
4.2	Equation 4.17: PE_S-PElec,y “used to operate equipment at the producing formation”; is inconsistent with eq. 4.21 which references “I think you should add ‘ at the storage site”	Recommended phrase added		
4.3	Equation 4.18: PE: “associated hydrocarbon production facilities” seems too broad, for large fields may include non-EOR production	Rephrased as “EOR-associated hydrocarbon production facilities”		
4.4	Equation 4.19: V_blowdown i: this term is not valid for well release – using zero will make the result zero – need a separate equation for well release?	Equation text modified		
4.5	Definition of “Electricity” includes storage and production, while PE just says ‘equipment’ – there seems uncertainty if this calculation includes production equipment.	Details of the types of equipment are included in the introductory text to Equation 4.21. It includes production equipment.		
4.6	Page 52: “assessing for potential leakage pathways is… monitoring program” – I think this may refer to a characterization program. I think assessing/finding faults, etc. is characterization while monitoring is separate.	Assessing potential leakage pathways is an important step in developing the monitoring strategy. The project’s MRV includes the characterization in addition to the monitoring.		

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4.7	Page 53: The 10% added to leakage for conservatism is arbitrary, and inflating a potentially inaccurate number by 10% does not necessarily add conservatism. Better to ask for an assessment of uncertainty and allow for some negotiation.	Text modified to include an uncertainty calculation.		
4.8	The methodology defines a baseline as "a hypothetical situation that represents the condition most likely to occur in the absence of the GHG emission reduction project. It serves as a reference case against which to quantitatively compare GHG emissions associated with the project and derive net emission reductions" (page 9). The definition of baseline needs some temporal component. In this case, the baseline is based on (average?) historic emissions for some undefined period of time. By not projecting future energy demand and emissions in the baseline determination, the methodology assumes a constant heat rate, market conditions, and regulatory conditions for the 10 year credit period. For consistency in the baseline determination, the methodology should provide greater detail on how the primary process's emissions are estimated in the baseline determination.	Per Eq. 4.1, the baseline is the actual CO2 emissions from the primary process during the crediting year (subscript y in the equation) with the adjustments shown in that equation. It is not based on historic emissions.		
4.9	Consider revising sentence for clarity: "Depending on the circumstances, it [a performance standard] could correspond with a similar or different technology than the CCS project's actual CO_2 capture site, but which fulfills the same purpose and function" (page 10). We assume that this sentence is in reference to technology-based performance standards (that can be expressed in the form of emission rates) such as EPA's proposed 1,000 lbs CO_2/MWh GHG NSPS for EGUs, which is based on natural gas combined-cycle technology. It would be	Sentence modified. Example added.		

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	helpful to provide various examples rather than referring to technologies "similar or different" to CCS "which fulfill the same purpose and function." Further, while CCS is obviously a carbon control technology, it may not be intuitive that NGCC is a carbon control technology, especially when there are economic drivers for building NGCC. As discussed above, it is possible to perform netting calculations such that CO_2 sequestered for regulatory purposes is excluded from the issued ERTs. The suggested definition of Creditable Sequestered Amount is intended to address this issue.			
4.10	The methodology states that the standards-based option for baseline determination "is expressed in the form of an intensity metric or "performance standard" (tCO_2e/unit of output)" (page 10). The methodology does not define performance standard or provide reasoning for why it must be expressed as an emissions rate. This could lead to confusion with the Clean Air Act section 111 definition of "standard of performance" applicable to GHG NSPS for EGU. Clean Air Act, Section 111(a)(1), 42 U.S.C. § 7411(a)(1). Note, the Section 111 does not require that a performance standard be expressed as an emissions rate. Also, it is not clear how the discussion of rate-based performance standard on page 10 relates to the performance standard/threshold on page 13.	The methodology recognizes that EPA's performance standards can be based on the "best system of emission reduction", and therefore, the standard can be based on a technology. Subsequent text in the methodology indicates that it can be technology-based. However, for the methodology, the emission rate associated with that technology is relevant for the calculation of the baseline. The discussion		

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		on pg 13 is aimed at determining whether CCS technology is commonplace for each source category.		
4.11	The methodology states that “[t]he baseline for new facilities will often correspond with the common practice in the region and the most economic option available to the project proponent” (page 11). It is not clear that there are common regional practices for establishing baselines for carbon emissions and emission reductions from CCS. What are the regional practices referenced?	Today there are only a few projects with CCS so common regional practices are unavailable for establishing baselines. In the future, as more projects are built, a regional practice could serve as a baseline.		
4.12	The methodology switches between the terms “surplus” and “additionality,” and defines neither (page 12). The methodology should provide definitions for these terms and use them consistently.	General terms and concepts like “regulatory surplus” and “additionality” are defined in the ACR Standard are not repeated in individual methodologies.		
4.13	The methodology uses the terms “new sources,” “new build facility” and “new or modified facility” interchangeably in reference to entities subject to New Source Performance Standards (pages 11-12). When discussing Clean Air Act or other regulatory provisions, the methodology should cite and use the appropriate Clean Air Act definition for clarity. 42 U.S.C. § 7411. Similarly, the methodology should cite the Clean Air Act	The use of the NSPS is only as an example and intent is not to use the NSPS definition to make a determination of “new” or “existing” sources. To avoid confusion, the reference		

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	definition of "existing sources" when using the term. *Id*. In referencing the NSPS regulation, clarify that the regulation applies only to EGU, not facilities in other source categories. *See*, EPA, Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Generating Units, 77 Fed. Reg. 22,392, 22,421 (Apr. 2012).	to the NSPS has been removed and replaced with a more generic "regulation"		
4.14	The methodology states that "[p]rojects must remain in compliance with regulations that are in place at the time of project registration and remain in compliance with those regulations through the injection period" (page 13). Which regulations – state and federal? Wouldn't projects also be subject to new regulations, unless grandfathered? The methodology should clarify this compliance with laws provision.	Federal and State laws compliance has been added. A footnote added for clarification		
4.15	The methodology states "[p]rojects are required to achieve a level of performance that, with respect to emission reductions or removals, or technologies or practices, is significantly better than average compared with recently undertaken practices or activities in a relevant geographic area" (page 13). Wouldn't the standard technology and practices for a <u>sector</u> or source category be more relevant than the standard practices of a <u>geographic area</u>? And why is this requirement included at all? What if two identical CCS projects are proposed within a given area, both depending on similar sources? Would only the first project be approved under the methodology? How is this defensible, and how does it further the overall goal of sequestration and additionality?	The sentence is a generic introductory sentence of ACR's guidance to performance standard applicable across various project types. We agree that sector or source category is more relevant than geographic area with respect to CCS projects and the reference to "relevant geographic area" has been deleted. In the methodology, the additionality discussion		

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		is focused on capture sources. That said, even if we had two projects in a given area with similar technologies, both would qualify. As more CCS projects are built it becomes common practice and may then cease to be additional.		
4.16	The response to comments states that "new industrial sources" are subject to BACT/RACT and that performance standards are promulgated for "industrial sectors." NSR applies to all sources meeting a statutory threshold, not just industrial sources. *See,* Tailoring Rule, 75 Fed. Reg. 31,514. Under section 111, performance standards are promulgated for source categories, but just industrial sources. *See*, Clean Air Act, Section 111, 42 U.S.C. § 7411. Recommend clarifying this reference.	The sentence has been modified		
4.17	Include citation for CO_2 usage rates referenced in Table 3-2, if available (pages 15-16).	Reference was included		
4.18	Section 3.2, p. 14, "there are no power or hydrogen plants with CCS." is out of date. AEP Mountaineer plant in West Virginia captured CO2 with chilled ammonia and injected it into saline aquifer. Southern' s Plant Barry, is capturing CO2 with a MHI post-combustion process and sending for injection to saline aquifer at Citronelle. Air Products hydrogen plant is capturing under DOE-funded industrial sources program and sending to Hastings field for EOR. Several more a poised to start – Sask Power-Boundary Dam, Southern's Kemper County. Suggest cite	AEP Mountaineer and Southern's Plant Barry projects are pilot scale/demonstration projects and are not commercial. Therefore those projects are not included in the Table. The Air Products hydrogen plant capture		

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	a source, for example Global CCS institute, and let reader go there for latest news on the few CCS projects going forward.	project was included in the Table but the text was not modified. Text has now been corrected to exclude hydrogen plants from the statement.		
4.19	p. 15, fig3-1 Some Denbury pipelines (SONAT and the one that goes east from Jackson Dome), and tiny one at Citronelle are missing. Would be wise to cite source and date this figure, as pipeline build-out continues.	Pipeline map updated and citation added		
4.20	Sec3.2 should be clarified to exclude windfall credits for facilities that were operating prior to the promulgation of this methodology. Exxon's Labarge facility for example already captures CO2. Expansions for that facility may be economically viable even without a mandate. Giving such a facility offsets would not be appropriate if market conditions dictate the reductions in the absence of offsets. Carbon capture projects in existence prior to the promulgation of this methodology should not qualify.	In Sec. 3.2, the approach to additionality is based on a performance standard approach and not on project economics, it would be unfair to exclude projects based on economic viability considerations.		
4.21	The conclusion stating "Based on these low penetration rates, it can be concluded that CCS projects meet a practice-based performance standard and can be considered additional as long as they are not required by regulation" overreaches. While this may be true for power generation at the present time in some cases, lower cost CCS options may or may not be additional. Economic viability is possible in some cases where EOR bridges the gap by itself.	See response to 4.20. In this methodology economic viability is not a consideration for project qualification. If the project is surplus to regulations and meets the performance standard, it is considered additional.		

F. Quantification methodology

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5.1	In Eq 4.17, the terms **PE** $_{S\text{-}P\text{-}CO2\ Transfer}$ and **PE** $_{S\text{-}P\text{-}Leakage,\ y}$ should be replaced by one term which is the quantity of emissions from the subsurface; i.e. any CO2 leaving the subsurface boundary in the vertical or lateral direction.	**PE** $_{S\text{-}P\text{-}CO2\ Transfer}$ term refers to CO2 intentionally transferred offsite. It's a measured quantity. The **PE** $_{S\text{-}P\text{-}Leakage,\ y}$ term refers to leakage from the geologic storage reservoir. Both terms will be retained.		
5.2	Eq. 4-18 should include a term for flaring.	Term added		
5.3	The density in Eq 4.19 should be the density of the CO2 in the blowdown chamber.	Agree-text modified		
5.4	In Eq 4.20 **PE** $_{S\text{-}P\text{-}Leakage,\ y}$ related to produced water should be explicitly only that water which leaves the project boundary.	Agree.-Text added to clarify this point.		
5.5	In Eq 4-20b, project proponents should not be "docked" for CO2 naturally occurring in the gas, oil and water in the reservoir. The mass fraction used in the calculation should be the mass fraction which is in excess of the naturally occurring mass fraction.	Agree. However, neglecting the naturally occurring mass fraction is conservative. We expect the contribution of these terms to be small compared to overall emission reductions. -		
5.6	Text discussing Eq 4.22 should be explicit in stating that this equation refers to CO2 other than that accounted	Agree-sentence added		

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	for in Eq. 4.20b.			
5.7	Section 4.2.5 needs modification to distinguish between short term leakage which can be remediated, and treated as an emission, as opposed to leakage which compromises permanence. By leakage is meant any CO2 which crosses the subsurface project boundary, defined as the boundary within which the project proponents believe the CO2 will be permanently stored. Thus, this section should be amended to note that the possibility of lateral long term leakage must also be examined. If a leak cannot be remediated, an estimate of the likely long term loss from the project will need to be made. Mitigation of leakage should be subject to 3rd party verification. Calculation of long term loss should be subject to third party verification. Estimates of short term leakage should be subject to 3rd party verification (comment on adding 10% for "conservatism" should be struck). If long term leakage is detected the proponents should consider the possibility of re-defining project boundaries. For example, lateral movement of the CO2 beyond what is predicted does not necessarily constitute a long term leak to the atmosphere. In re-defining the project boundaries the proponents assume the responsibility for assuring that there are not leak paths within that boundary which jeopardize permanence.	Distinction between injection period and post-injection period made as indicated in response to comment No. 0.1. Other suggested concepts included in Sec 5.4		
5.8	Section 4.3 needs modification to address issue of permanence for leakage from the reservoir which cannot be remediated. The methodology should address this eventuality and be consistent with the ACR Standard. One approach might be to require creation of an ERT "reserve" account, in which the project owner would deposit, as an example, 10% of project credits	Discussion of an ERT Reserve added to Section 6.3		

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	issued on an annual basis. This obligation would accrue through the initial 10 year project period, at which time a full year's worth of credits would be banked. From then on, credits would flow into the bank on a rolling basis, with the oldest tranche being "released" the same year a new 10% tranche was added to the bank. Upon cessation of the project, the "bank" would remain in place. In the event of later-detected leakage, these credits could be expired.			
5.9	Page 66: bullet points: 'Flow simulations of co2 injection….' Should add "co2 injection and oil production" since the production may affect the storage 'Identify leakage pathways' : better to say "identify potential leakage pathways and describe the assessment methods" 'Remediation of …' add 'and plans for potential mitigation' "A strategy for …" add 'surface or subsurface' I think that separate discussion of surface and subsurface monitoring is good.	The section has been revised.		
5.10	5.4.1 Page 68: "If drilling history…..cannot be documented with high .. confidence" - It would be good to give some example of how this is documented – do you just trust the available records? Maybe a letter from the local regulator of drilling oil and gas wells?	The section has been revised and shortened to exclude this detail.		
5.11	5.4.2 Page 69 "outside the confining zones and	The section has been		

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	groundwater" - This is a large task if there are multiple groundwater aquifers. Perhaps just the deepest USDW should be sampled.	revised and shortened to exclude this detail.		
5.12	5.4.3 Page 70, Change "geochemical sampling and analysis" to "fluid sampling and geochemical analysis" As above, I think that only one above zone fluid monitoring should be required, or it becomes too onerous. Paragraph 2: "or into groundwater", I suggest "or into USDW".	The section has been revised and shortened to exclude this detail.		
5.13	5.4.4 Page 71: "Pressure in the injection tubing string and annulus…..and in regions outside the confining zone…." This typically requires separate wells for sampling separate zones. Better to separate sampling of injection/production wells from sampling of above zone intervals or USDW. Change "vertical movement of co2 within the reservoir" to "vertical movement of co2 above the reservoir"	The section has been revised and shortened to exclude this detail.		
5.14	Table 5.4: Baseline: Geochem sampling: I suggest only deepest USDW zone. "Sensitivity" analysis does not seem the way to determine constituents. Operational: Geochem: "parameters that may signal leakage" – Should obviously sample for co2. If there are none, no sampling needed – this seems unlikely since sampling directly for co2 is always good. Pressure Monitoring – I suggest reported monthly. Material Balance: I suggest requiring defining "injection	The section has been revised and shortened to exclude this detail.		

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	pattern" as this can have various meanings at different sites. Post Injection monitoring: Pressure and/or …: I suggest using deepest USDW.			
5.15	5.5 page 74: "The flowmeter will be": The method selected for use should be documented/reported. "Flowmeter calibrations": A calibration schedule should be used, maybe every 1-2 years?	Text modified to report the selected standard. Calibration is discussed in Section 7 QA/QC. Calibration procedures, including frequency will be per manufacturer's specifications.		
5.16	"Functional equivalence" is in quotation marks on pages 18-19, but not on page 10. Quotation implies a specific meaning, but no definition is provided.	Quotation marks have been removed. Definition has been added.		
5.17	"Excess CO_2 emissions" is in quotation marks, but no definition is provided (page 19).	Quotation marks have been removed. Definition was included.		
5.18	"Adjustment factor" is in quotation marks, but no definition is provided (page 19).	Quotation marks have been removed		
5.19	"Output" is in quotation marks, but no definition is provided (page 22).	Quotation marks have been removed		
5.20	There are a number of equations in this section that are almost identical to equations in C2ES' *A Greenhouse Gas Accounting Framework for Carbon Capture and Storage Projects*. ACR Methodology | C2ES Report Equation #	A citation has been added in the introduction to Section 4.0		

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	Equation #				
	4.1 (page 21)	2			
	4.2 (22)	3			
	4.3 (page 23)	4			
	4.4 (page 24)	5.0			
	4.5 (page 25)	5.1			
	4.5a (page 26)	5.1.A			
	4.5b (page 26)	5.1.B			
	4.5c (page 27)	5.1.C			
	4.6 (28)	5.2			
	4.7 (page 31)	5.3			
	4.7a (page 31)	5.3.A			
	4.7b (page 32)	5.3.B			
	4.7c (page 33)	5.3.C			
	4.8 (page 35)	6.0			
	4.9 (page 36)	6.1			
	4.10 (page 37)	6.2			
	4.10a (page 37)	6.2.A			
	4.10b (page 38)	6.2.B			
	4.11 (page 39)	6.3			
	4.17 (page 43)	7.0			
	4.18 (page 44)	7.1			

<table>
<tr><th></th><th>1st Review</th><th>Response</th><th>2nd Review</th><th>Response</th></tr>
<tr><td></td><td><table><tr><td>4.19 (page 45)</td><td>7.2</td></tr><tr><td>4.20 (page 47)</td><td>7.3</td></tr><tr><td>4.20a (page 48)</td><td>8.3.A</td></tr><tr><td>4.20b (page 49)</td><td>8.3.B</td></tr><tr><td>4.21 (page 50)</td><td>8.4</td></tr><tr><td>4.22 (page 51)</td><td>8.5</td></tr><tr><td>4.23 (page 53)</td><td>9</td></tr></table>If the equations were pulled from the C2ES report, than the methodology should cite the C2ES report.</td><td></td><td></td><td></td></tr>
<tr><td>5.21</td><td>The equation numbering jumps from 4.11a (page 40) to 4.17 (page 43).</td><td>Agree. This will be modified in the final draft to avoid confusion in understanding changes made in response to comments in this document.</td><td></td><td></td></tr>
<tr><td>5.22</td><td>On page 21, it would be helpful to clarify that the performance standard being reference is a rate-based standard. Performance standards are not necessarily expressed in the form of an emissions rate. For example, Section 111 of the Clean Air Act permits “design, equipment, work practice, or operational standards” as an alternative to a rate-based performance standard. Clean Air Act, Section 111(h), 42 U.S.C. § 7411(h); See, e.g., Standards of Performance for Petroleum Refineries, 40 C.F.R. § 60.103a.</td><td>Clarification added.</td><td></td><td></td></tr>
<tr><td>5.23</td><td>The methodology does not provide a temporal unit for the calculation of the projection-based baseline on page</td><td>In the projection-based baseline, the actual total</td><td></td><td></td></tr>
</table>

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	19. Specifically, over what time period is the “actual CO_2 produced by the primary process” summed or averaged?	CO2 emissions produced by the primary process for that year are taken and adjusted for any excess emissions and functional equivalence as indicated in Equation 4.1		
5.24	The methodology does not provide a temporal unit for the calculation of the standards-based baseline on page 21. Specifically, over what time period is the “actual output of the primary project’s process” summed or averaged?	The actual output is the aggregate over the year for which CO2 emission reductions are being calculated (i.e. total annual).		
5.25	Given the definition of the “physical boundary” as “demarcat[ing] the GHG emission sources included in the project and baseline emissions calculation,” the discussion of an unqualified boundary of the capture site for the CO_2 capture calculation is confusing (page 23). The boundary “encompasses the source of CO_2 capture and compression systems” and “extends to the point at which CO_2 is transferred to the pipeline operator” and, therefore, delineates physical dimensions (page 23). Yet “physical boundary” as defined seems to encompass more than the boundary described. Also, why are the spatial dimensions of the capture site described but not methods or transportation or the storage site?	See response to comment No. 3.5		
5.26	It would be helpful to clarify that the “CH_4[/N_2O] emission factor for combustion of fossil fuel” is an emission factor for stationary source combustion which varies by fuel type (page 26).	Clarification added		

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5.27	It is not clear what the "capture boundary" is (page 27).	See 5.25		
5.28	Abbreviation of cogeneration as "cogen" may be confusing (page 33). Recommend using "cogeneration."	Change has been made		
5.29	Methodology states that "[a] mass balance method is not appropriate in situations where the uncertainty of the measured values is greater than the magnitude of the quantified emissions" (page 38). It would be helpful to explain how to determine whether the uncertainty of the measured values is greater than the magnitude of the quantified emissions.	Footnote added		
5.30	Methodology states "[m]obile source emission for CO_2 transport by barge, rail, or truck are calculated by aggregating the ton-miles transported by each mode and multiplying the individual totals by an appropriate mode-specific emission factor." Recommend clarifying that "mode" refers to the listed modes of transportation.	Clarification added		
5.31	Suggest a better transition to the sub-section on calculation of emissions "transferred outside if the project boundary" on pages 50-51. Emissions transferred outside the project boundary are not mentioned in the roadmap for the section on page 42.	The section has been reorganized to improve transition. Offsite transfer is mentioned in the roadmap under 4.2.4.		
5.32	The methodology states that "[w]hile CO_2 transferred out of the project boundary is not necessarily an emission to the atmosphere, project proponent should nevertheless *not account* for it as if it were sequestered from the atmosphere." (page 50) (italics added). This should be made clearer by stating that project proponents should account for emissions transferred	Clarification added		

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	outside the project boundary?			
5.33	The methodology advises that project proponents should develop a "project monitoring plan" that "include[s] a strategy for detecting and quantifying any surface CO_2 leakage. In the event of containment failure, a simplified estimation to conservatively determine maximum leakage can be used, rather than requiring rigorous quantification" (page 52-53). Because unaccounted for leakage could lead to a failure of a regulated entity buying offsets to comply with a regulation to meet permit conditions, the "project monitoring plan" should include a duty to report leakage from the Reservoir to ACR.	Leakage from the reservoir will be estimated and reported under Eq. 4.23. A requirement to report leakage to the ACR has been added.		
5.34	Section 4.2.3, p. 40. I am not a pipeline expert, but my experience and from literature, the accuracy of metering is around 1%, and metering at two points sums the error. Pipelines are inspected using pressure, no? then follow up methods like Seeper Trace to find any leakage points. If CO2 leaks from pipeline, it will flash to gas with a big volume increase, so that small volume supercritical leaks typically make a large signal (noise, condensation). A mass balance approach to pipeline leakage seems low probability of being better than inspection.	A mass balance method is not being proposed as a replacement to visual inspection or other methods that companies routinely use to ensure pipeline integrity. In the US, USDOT Part 195 covers those requirements. Mass balance or component count methods are accounting tools to account for any losses in the system. If a leak is determined through visual or other inspection means, then it should be quantified		

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		and reported		
5.35	Section 4.2.4, P. 51, table 4.22. The volume in the equation needs to be at standard conditions, not actual volume of supercritical or liquid CO2.	Agree. Clarification added		
5.36	Section 4.2.5, p. 51. “as discussed in Section 2.2, leakage shall be monitored during the entire project term…” Section 2.2 does not describe how leakage shall be monitored. Furthermore, this phrase sets up an expectation that a number will be somehow magically measured at the land/air interface and reported here. The following three paragraphs are superficial, full of "coulds", and are not harmonized with lengthy section 5. Suggest that this whole section be abbreviated to “Methods of estimating and reporting annual atmospheric release from storage are described in section 5.”	Text has been modified. Section 4.2.5 has been modified to focus on the accounting equation. Key concepts from this section are included in Section 5.4		
5.37	Section 4.2.5, p. 52, Para 1. “Project proponents should select and locate monitoring equipment and establish CO2 detection thresholds to calibrate monitoring systems in a manner that provides confidence in the monitoring program’s ability to accurately confirm the effectiveness of the CO2 storage complex.” This is an important key performance-based statement that should be used to guide chapter 5. “Storage complex” is an EU phrase not defined in this document and not really suitable for EOR.	This concept has been added to Sec 5.4. Reference to storage complex has been removed		
5.38	Section 4.2.5, p. 52, para 3. “for a CO2 storage site in compliance with its injection permits, the value of the CO2 term in equation 4.23 should be zero” is somewhat sensitive to what permits are included, but UIC, even Class II, does not in most cases tolerate flow from	The text has been removed		

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	reservoir to surface. Permits do not deal with the issue of long term storage permanence except for Class I "no migration" which is not applicable.			
5.39	If the terms conformance and assurance monitoring are set up, they should be used in section 5. I am unconvinced that these terms have a place in a carbon registry, as "assurance monitoring" in some usage is for public assurance, and linked to environmental and resource protection, not part of an accounting framework.	These concepts have been excluded		
5.40	Section 4.2.5,p. 53, para 2. This is good: "subsurface monitoring systems indicate will enter the atmosphere . Might add over short and long timeframes.	Text in Sec 4.2.5 has been modified		
5.41	"Functional equivalence" is discussed but not defined, nor are rules or principles laid out for determining functional equivalence. It should not be left to each individual application to argue and calculate what "functionally equivalent" is. It should be made clear throughout that any parasitic energy use for the CCS system and its associated GHGs should NOT be included in the calculation of offset benefits. The ultimate goal is CO2 reduction, not the running of inefficient systems that generate more CO2 and then capture/sequester it.	A definition for functional equivalence has been added. We agree that parasitic energy used for the CCS system should be accounted for and any CO2 captured and stored that is attributable to this parasitic load should not be credited. This is a main reason to include affected elements of the primary process within the project boundary.		
5.42	Eq. 4.1 What is the rationale for subtracting non-	If primary processes are run inefficiently leading		

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	permitted emissions from the baseline?	to increased CO_2 emissions then credit should not be given to the excess CO_2 emissions that are generated and sequestered.		
5.43	Eq. 4.2 A project may perform better than the emissions mandated by a standard. The use of this equation would reward a project unduly. This should be corrected.	Projects performing better than an applicable standard should be allowed to claim reductions. This would incentivize other projects to improve their performance.		
5.44	Neither eq. 4.1 or 4.2 discuss how representative output levels and years are to be chosen.	See response to comment 4.8		
5.45	Eq. 4.5 includes CO_2 transferred off site, but it is implicitly assumed that this CO_2 is sequestered. This is not valid.	In Eq. 4.5, the CO_2 transferred term only acknowledges that the CO_2 enters the pipeline at the capture site. In the process of transport, injection and storage, some of this CO_2 may leak, may be vented, or intentionally transferred out of the project boundary. These emissions are deducted as applicable by		

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		appropriate equations described in those sections.		
5.46	Eq. 4.5b and elsewhere: global warming potentials from AR4 should be used, or the methodology should reference globally determined potential values by ACR.	Per the ACR Standard, the second assessment report 100-year GWP values have been retained. ACR recognizes IPCC has updated the GWP numbers, but current ACR policy is to retain the 2nd Assessment Report values for consistency and fungibility of credits across years.		
5.47	4.2.2 and 4.2.3 The Component Count method and the use of emission factors for components should only be allowed where reliable emission factors exist. EPA has documented extensively in the context of methane leaks from producing wells and infrastructure that the true extent of losses are not known and that existing empirically estimated emission factors likely grossly underestimate the problem. Only emissions factors that are based on measurements and have a strong validity basis can be considered sufficient. The same applies for 4.2.3	Emission factors are continually being refined and updated by regulatory bodies (e.g., EPA) and industry groups (e.g, API). The methodology recommends the use of the most recent version of emission factors published by recognized bodies.		

G. **Data collection and monitoring**

6.1	**This section generated a very large volume of comments from the reviewers (detailed below), many of which questioned both the details and/or the overall tone and content. We believe that the number of comments and the specific details in the comments indicate an inadequacy of this section that requires a full revision and rewrite. We believe this section can be shortened with fewer specific monitoring details, but, most importantly, it needs to capture these larger concepts:** **1) The monitoring plan needs to have site specific details, not meet generic requirements set in this document.** **2) This methodology needs to provide for a specific third party review of the monitoring plan, and criteria for selection of the third party. A third party should verify the plans and review the results at select intervals. This third party is likely to need separate expertise from the 'verifier' (section 1.3, 5.1) for emissions.** **3) The review of data collection and monitoring plans should include comparison to existing protocols and regulations as guides.** **4) The idea of permanence within a defined area or 'box'. For permanence, no projection of known processes (natural or industrial) would cause release from the subsurface. This time period for permanence may be set by ACR or others, but the concept should be part of the monitoring plan.**	Section 5.4 has been rewritten to exclude references to specific monitoring tools, while including many of the concepts suggested in the comments. A requirement for the development and review of the Plan by qualified personnel has been added. Verification requirements to require comparison of Project Plan with existing protocols and regulations as guides has been added. The ideas of permanence have been clarified	Qualifications of personnel acting as 3rd party reviewers should include proven knowledge, experience and expertise in the geologic storage of CO_2 and the methods used. A minimum of three persons should be specified to avoid self interest, and requirements for their impartiality and independence included.	

	If a full rewrite is not completed (which is not a course of action that we advise) then the specific comments below need to be addressed.			
6.2	Text should incorporate idea of 3rd party verification of the subsurface monitoring plan and the data. 3rd party verification of data should occur on a yearly basis initially, perhaps less frequently later.	3rd party verification of the MRV plan has been added		
6.3	Page 87: “Confidence in the location…..increases over years…” This may be true, but there is uncertainty. “associated hazards can be well recognized” – Not necessarily, I suggest “ hazards may be recognized”.	Agree and uncertainties must be addressed. This reference to hazards has been deleted		
6.4	Page 88 paragraph 1: The discussion of oil industry liability and trespass is informative but not a methodology.	The issue of CO2 migration outside the boundaries does not necessarily constitute Trespass and liability is relevant to the discussion.		
6.5	Though Blue Strategies states in its response the Clean Air Task Force comments that “it is not the intent of the methodology for projects to require RR certification,” It may be helpful to note that the Greenhouse Gas Reporting Rule requires development of an MRV plan and highlight the difference between reporting required under the Greenhouse Gas Reporting Rule MRV plan and the MRV beginning recommended. 78 C.F.R. 19,802 (Apr. 2, 2013); 77 C.F.R. 48,072 (Aug. 13, 2012).	Similarities highlighted		
6.6	Table 5-5 (page 76-85) is almost identical to table 2 in the Center for Energy and Climate Solutions’ (C2ES)	Citation added		

	report, *A Greenhouse Gas Accounting Framework for Carbon Capture and Storage Projects*. If the equation was pulled from the C2ES report, then the equation should cite the report.			
6.7	It is not clear whether the listed components of the MRV plan are derived from the model rules of the IOGCC task force or recommendations from DOE (pages 66-67).	Clarification added		
6.8	Include citation to referenced DOE recommendations (page 66).	Citation added		
6.9	Methodology states that "[r]ather than being overly prescriptive, the Task Force has recommended that the Model Rules and Regulations require the operator to submit a comprehensive monitoring plan that is tailored to the specific characteristics of the site" (pages 65-66). Prescriptive recommendations are not exclusive from tailoring plans to specific sites. Recommend revising sentence to read: "[r]ather than prescribing uniform monitoring plan requirements, the Task Force has recommended that the Model Rules and Regulations require the operator to submit a comprehensive monitoring plan that is tailored to the specific characteristics of the site".	NA		
6.10	It's unclear how the MRV framework components (pages 66-67) match up with the site characterization and the CO_2 monitoring (baseline, operation, and post-injection) (pages 69-73). It might be helpful to include a graphic of the physical project boundary that identifies monitoring components at each phase/location.	Text modified (NA)		
6.11	Blue Strategies' response to the Clean Air Task Force recommendation to suspend injection if there is risk or	The CATF suggested that the EOR operator		

	indication of an atmospheric leak, was "[s]hould atmospheric leakage occur, then the leakage will be estimated and deducted from the qualified credits for the project. As long as the operator's permit is not violated, we believe there is no need to suspend injection operations." Recommend clarifying what "operator's permit" is being referenced. As noted above, mitigation of leakage could include utilizing offsets/allowances held in a reserve bank for contingencies such as leakage.	suspend operations if leakage is detected. The methodology cannot require the EOR operators to suspend operations. The operator's injection permit will dictate what constitutes an emergency to require suspending operations. The methodology will mitigate the leakage through accounting or insurance/reserve mechanisms.		
6.12	The MRV plan identifies monitoring and verification requirements, but does not provide detail on reporting requirements. As noted above, it may be useful to include minimal reporting requirements, especially regarding any reservoir leakage.	Reporting requirements have been added		
6.13	Table 5.1 p. 62, table row 2. A performance standard is set, this is good: "For properly selected, operated, and closed CO2 storage operations, atmospheric leakage of CO2 emissions from the geologic reservoir do not normally occur. Should it occur then emissions shall be calculated on a site-by-site basis according to a reasonable engineering approach. For CO2 storage, the project monitoring plan would include a strategy for detecting and quantifying any surface CO2 leakage – i.e., leakage	This is in Table 6.2; the methodology has been modified.		

	to atmosphere estimated based on monitoring and measurements completed as part of the MRV plan.” After this, a lot of prescriptive detail is provided, however the link between the requirements and the performance standard is weak to non-existent. Reviewing this section line-by-line is undertaken, however a more comprehensive restructuring of the concept is needed. If the performance standard remains “detecting and quantifying any surface CO2 leakage”, then a great detail can be dropped. If the standard includes likelihood of long term storage, it needs repair.			
6.14	P 63, figure 5-1 P. 64. Table 5-5. This figure and table is overly prescriptive, incomplete, not compatible with the rest of the document, and obscures, not illuminates the complexities and sources of error. It shows two capture facilities going to one field. In many scenarios, the number of fields will be larger than the number of capture facilities. Accounting and allocating at a system scale needs to be dealt with, as for example the amount of offtake may vary year to year, and input may also as dispatch varies. 3&4 say flow-meters are to deal with fugitive losses or venting, this is a poor tool as described in my comment above on Section 4.2.3, p. 40. Commercial pipelines now meter at plant gate and at off take, not in between, is this not adequate? Position 5 and 6 comingle the tools needed for within-field tracking with the accounting framework. A bad idea. The simple tables in the accounting section are perfect: Injection mass – (mass emitted from surface+	Figure 5.1 and Table 5.3 (assuming the reference is not to Table 5.5) have been removed and some of the information included in other parts. Agree that the information in the other tables covers much of the data. The intent of the figure was not to indicate that all of the measurement points have to be monitored but as an example of typical locations where monitoring may already be occurring.		

	mass emitted from subsurface) = stored. But when we zoom in a level to calculate mass emitted from surface and mass emitted from subsurface, this is not good. We know, from Chuck Fox's report, that the surface emissions are tiny, need to get them from an inventory of venting events etc. not from meters. Then to get the mass emitted from subsurface we need a fit-to-purpose monitoring plan. In some situations, injection/withdrawal ratio (IWR) may be important, for this one needs to get accurate enough data on injection rate at each injector and production at each producer. Details that matter, in particular accuracy and frequency of metering, purity of metered fluids must be fit-to-purpose. Without enough specificity, the guidance gives a false sense of approval. Position 1-7 Sampling, is prescriptive and guilty of both over-kill and inadequacy. Sample for what and to what standards? Sample frequency needs to be tied to variability. If all the release occurs during day-long upsets, once a month is a total waste. Plus why on earth sample at both ends of the same pipe? Sample fit-to-purpose to adequately capture average and changing composition.			
6.15	5.4 P. 65 I think co-mingling credits and protecting health safety and the environment is not a good place to go for this document. We know from experience that leakage of brine is the main tertiary recovery risk; this is not dealt with in this document. I recommend stay with GHG accounting, and fix class II as needed in a separate effort.	Text modified- NA		
6.16	5.4 p. 66. Bulleted list is an under constrained, ill-	Text modified		

	informed, and prescriptive list with no clue as to the performance metrics to be attained. Needs a total rethink. Some of these activites might be done as part of obtaining performance metrics, but without a clear statement of goals these activities waste effort. What is the standard for static model? How do you deal with uncertainty. Simulation has to meet a standard of calibration with relevant data, then predictive is a very high (unattainable) standard. Models are very useful, but need to be fit-to-purpose. "Identify and remediate leakage pathways". I know that some regs say this, but by the time the project is permitted, all known pathways will have been remediated, allow a project proponents to say that no pathways were identified, therefore no monitoring is needed. What is needed is scenarios that show the range of uncertainty, including unknown or missed conditions that could make the project fail. Only then can a monitoring strategy be designed to increase certainty in short and especially long term retention. Major leakage risk in EOR is accidental production by out-of-pattern producers not on recycle. Baseline level of CO2 in an EOR setting can be a risky way to work, as naturally microseepage hydrocarbon signal combined with historic spills and a highly modified landscape can result in high temporal and spatial variability. Any technique proposed should be shown to be effective, in terms of identifying and quantifying leakage signal and in terms of avoiding large amounts of false signal that might damage the project's reputation.			

	EOR goals might be: Operators goals focus on project economics: produce sufficient oil at sufficient rate and be efficient in use of CO_2 and water to obtain a good rate of return on capital investment. This drives their surveillance. In spite of different intent, operator surveillance may provide some key data to the storage monitoring program. Storage monitoring goals: Demonstrate effective retention of injected anthropogenic CO_2 during short and long term periods. This will likely be done somewhat indirectly. For example comprehensive inventorying of failure scenarios, modeling the indicators that show that each failure scenario is or is not occurring or likely to occur in the future, testing, monitoring or sampling at times, locations, frequencies with techniques and analytic process that are sensitive to the failure/non-failure determination, and reporting the outcome of failure /non-failure determination. In reality, more intermediate steps are likely needed. For example, collection of existing subsurface data, assessment of material data gaps, collection of additional data, reassessment of gaps, additional modeling to create a comprehensive failure scenario inventory. Or failure /non failure may involve reaching a trigger of concern. However, additional data collection is likely needed and must be in budget to determine if the failure is occurring or may occur. If failure has occurred further evaluation may be needed to mitigate, and further assessment needed to estimate the losses.			
6.17	5.4.1. p. 68 para 1. Need information on cement on any wells that penetrate through the injection zone to	Text modified -NA		

	deeper horizons, also management of any such wells drilled in the future. Need robust data to determine how high cement was lifted (caliper logs and cement volume), and formally evaluate uncertainty.			
6.18	5.4.1. p. 68 para 2. Conversion of bad wells to monitoring is a terrible idea. Plug them. Wells get worse with time, idle monitoring wells are at high risk.	Text modified -NA		
6.19	5.4.1. p. 68 para 3. Needs complete rewrite. This is a weak description of reservoir characterization and inadequate to support the expectation placed on "model matching" (which are likely unrealistic even under the most rigorous conditions, see below). Reservoir characterization needs to feed a risk or uncertainty assessment that seeks uncertainties that may have a material negative impact of project goals. See above, under "storage monitoring goals" Some tough questions need to be dealt with properly, such as miscibility, defining CO2 plume size, interact action CO2 with oil and other fluids, reservoir heterogeneity, barriers and thief zones, unknown connectivity, pressure history, and planned production, injection, and pressure management in reservoir. Characterize intermediate zone above the reservoir and below USDW, ownership, pressure history, planned other uses. Seismicity risk and management. USDW characterization, past history, future uses. Wells were dealt with in previous paragraphs, don't need them in this one.	Text modified -NA		
6.20	5.4.1. p. 69 para 1. Needs major rewrite. A simulation cannot assess out of pattern migration, unless	Text modified -NA		

	uncertainty is put into the simulation. For storage modeling, model construction has to go beyond the normal uses of assessing likely outcomes, and consider possible negative outcomes, which is not usually done for commercial EOR. Simulations should include leakage scenarios, to test if monitoring is suitable for detection of leakage. A big step of normal modeling is also missing, history match the static model with the past production data. This, if done properly, can constrain uncertainty.			
6.21	5.4.2. p. 69. Needs complete rewrite. Baseline does not exist at fields that are ready for CO2-EOR. They have been geologically perturbed by introduction of oil, then very strongly perturbed by extraction of oil and other operations for many decades. Most of them will be strongly changed again to prepare for CO2 flood, pressure increased toward miscible, patterns changed, surface infrastructure reworked, new roads, berms and ditches put in, old features remediated. Every parameter in the system is dynamic. The protocol should not recommend collecting data and expecting to do a simple subtraction to find change. What should be done, with significant investment, is to measure ambient conditions, including temporal and spatial variability, to determine how change can be detected in this high noise setting.	Text modified -NA		
6.22	5.4.3 Operational Monitoring para 1. Needs complete rethink. Why geochemical sampling? Very hard to identify leaked CO2 chemically. It is 1) everywhere already, 2) buoyant low viscosity fluid can move along narrow preferential flow paths, without much impact on adjacent flow units 3) dissolves and is diluted. Current best practice in subsurface is to use pressure as the main	Text modified -NA		

	tool. Pressure increase is the primary signal that drives leakage, pressure change is easy to detect far from the leak point.			
6.23	5.4.3 Operational Monitoring para 2. Needs work. Off lease and out-of-pattern need to be discussed as main targets. How to do it: it is correct to seek field-specific methods. Surveillance of producers that could receive CO2, geophysics in various geometries, sentential monitoring wells are possible.	Text modified -NA		
6.24	5.4.3 Operational Monitoring para 3. Needs complete rethink. Reservoir pressure monitoring sneaks in a sentence under MIT, to which it is not related. Semi-annual USDW pressure monitoring is almost guaranteed to be totally worthless, because recharge and pumping are seasonal and impact water levels strongly. This is where the revised section formerly known as baseline is needed, to do characterization such that monitoring can be designed that is sensitive to leakage signal above variability.	Text modified -NA		
6.25	5.4.4 Post injection monitoring. Most of this seems to have sneaked in from saline and should be ousted with a do-over. Tracking the CO2 plume and pressure front could only be mentioned by someone who has never seen an EOR pattern flood. The flood saturation and pressure map is covered by plumes and sinks, which coalesce. To find the unswept zones in between is the unattained target of all operators, so it is quixotic of the MVA plan to strive for this. The end of the EOR flood has not happened much in our experience, so one must speculate here. Will the operator cut back CO2 purchase as oil declines - probably, and likely in some parts of the	The idea of monitoring the plume is not to identify and track individual plumes or find unswept zones but to understand the farthest reach of the CO2 across the reservoir. Plumes near the lateral boundary pose risk for leakage and the monitoring strategy can		

	flood long before other parts. One could recommend that parts of the field that were taken out to of the flood would be good study sites to provide information about the long term fate of the whole system (this is research and not part of this document). Will the area of the flood be left pressure depleted? If so, how long will recovery take? What are the risks of unexpected migration? If the flood area includes the top of the structure, probably many material uncertainties have been resolved. However, if in the last year, the field is injected full of CO2 for storage, and the top of the structure has not been tested, is 5 years enough? But do not change to 50 years! I think what is needed here is a plan for full build-out and abandonment scenarios, and then a series of tests during the active part of the flood to reduce uncertainties, so that end of injection allows abandonment. If some uncertainties require measurements to be made post-closure, the type and duration of such measurements should be planned and budgeted.	be built to detect for leakage across the boundary. We believe that in many cases five years is enough. However, 2-yr increments have been added since each project is different and there may be site-specific issues that may warrant an extended period of monitoring.		
6.26	Table 5-4 Page 73.This table needs an almost complete rethink: Baseline sampling of aquifers and USDW above the reservoir. Suggest instead a much less prescriptive requirement to design a water sampling plan that provides information to the project about the value of water sampling in monitoring. As written, this is a big job for little value. The method is under-prescribed to detect leakage. Can be dozens of separate aquifer zones. Installing wells to sample them all will make a mint for	Table removed -NA		

	Westbay. Standards for sampling are critical because the question is dissolved gases which can easily be lost. Why monthly for deep aquifers – will they change? Where are the wells located - upgradient and down gradient is standard. They need to be completed to detect gases. We think that transport is limited by gradient and by reaction along the flow path – need to have very high sample density to catch leakage. We think it is important in characterization to react aquifer rock, water and CO_2 in the lab or field and make a determination of the sensitivity of chemical sampling. Report findings, input to monitoring plan.			
6.27	Table 5-4 Page 73 Baseline Why are MIT's here? Is this supposed to be an assessment of well risk, including P&A and lost wells? Report findings, input to monitoring plan	Table removed -NA		
6.28	Table 5-4 Page 73 Baseline pressure sounds like our recommendations! report findings, input to monitoring plan	Table removed –NA- Although pressure monitoring has been retained.		
6.29	Table 5-4 Page 73 Operational geochemical sampling. What if there is a signal, but it is weak and hard to detect above noise? Suggest non prescriptive "operate groundwater geochemical sampling plan optimized to provide assurance of no loss of CO_2 and no impact to USDW" report findings, follow up on any anomalies.	Table removed -NA		
6.30	Table 5-4 Page 73 Operational Injection rate. Does this methodology really plan to get reports monthly? Seems to not parallel the other reporting, which is annual. Need to specify that rate is collected so that it can be converted to mass. Need to separate CO_2 from water	Table removed -NA		

	injection, and separate new purchase from recycle.			
6.31	Table 5-4 Page 73 Pressure testing. This key model match parameter seems to drop to every five years, and be tied to regulatory requirements. Very weak. Suggest non prescriptive "operate pressure surveillance plan optimized to provide assurance of no loss of CO_2" report findings. Follow up on any pressure anomalies as needed to quantify 1) current and 2) future possible leakage. Need some teeth. Suggest predetermined thresholds of concern linking injection rate to expected pressure increase. Where do we find out about out-of-zone and out of pattern migration? Any CO_2 accidentally produced and released? Report findings. Follow up on any anomalies, and report as needed to quantify 1) current and 2 future possible leakage.	Table removed -NA		
6.32	Table 5-4 Page 73 Material balance. This is the workhorse of EOR flood optimization, and in the hands of a talented operator and a well-known field may be everything you need to show the flood is conformant. However, during the early decade of a flood and where many changes are made, and at the edges, material balance can provide little to no information about retention. Therefore material balance is not enough. Need to collect the data needed to robustly document that CO_2 migration that could lead to project fail to retain CO_2 is not occurring. The double negative is required, to show this is hard to do. Report, follow up on any anomalies. Suggest predetermined thresholds of concern	Table removed –NA. Material balance has been retained as a recommendation		

6.33	Table 5-4 Page 73 post injection. Plume tracking – no! see previous discussion	Post-injection has been retained with less prescription, although pressure measurements have been recommended.		
6.34	Table 5-4 Page 73 If above- zone monitoring will be conducted, it needs to be during operation. Starting at project end is not likely to provide anything interpretable. Suggest predetermined thresholds of concern.	Table removed –NA.		
6.35	5.5 p. 74, para 1. What accuracy is needed for flow meter? They need to measure mass, if they just measure volume without provision for conversion, this is not Ok.	Per USEPA Code of Federal Regulations. 40 CFR Part 98.3(i), the accuracy required is 5 percent or better. This is included in Section 7 QA/QC		
6.36	5.5 p. 74, para 2 Standards for gas or liquid composition. This is so general as to have no value. There are many standards by which fluids are sampled, stabilized, transported and analyzed. The one selected must be fit the designed purpose. Sampling multiphase fluids from high pressure and hot, deep environments requires a lot of thought about how to conserve the information needed.	The options are 1) either an appropriate standard method or 2) an (appropriate) industry standard practice. These cover the range of acceptable methods without being overly prescriptive. The operator will select the method that best fits the purpose (i.e., appropriate).		

6.37	Table 5-5, p. 82, first row comment column. When measurement of gas is given in volume it is important that the volume be corrected, using good quality measurement, to standard temperature and pressure. Lower cost meters collect volume only, and pressure and temperature are assumed, which results in significant measurement errors. Alternatively require reporting of gas in mass (but this would require adjustment of the formulas).	The methodology does not restrict operators to use volumetric flowmeters. Mass flow meters can be used and reported as such. See Eq. B-1 in Appendix B, as an example. Ultimately the verifier will review and determine whether the data are of acceptable quality		
6.38	Table 5-5, p 84. Fourth row of table. Mass fraction of CO2 in water. CO2 is dissolved in water and ionized to H2 CO3, HCO3 – and CO3-- -. Asking for dissolved Inorganic carbon is a way to capture all the species. The method should include head-space gas.	Text modified		
6.39	Table 5-5, p 85. Second row of table, comments. "examples of leakage pathways are faults and fractures, not fugitive from wells. This is not correct. Leakage in the subsurface related to wells, such that CO2 migrates through geologic environments should be counted here. The phrase about Equation 4.2.3 is unclear, it does refer to geologic environments. Leakage from wellheads, however, is not part of this quantification, it is in equation 4.20 with other equipment.	Text has been modified		
6.40	"Reasonable engineering approach" to be determined on a case-by-case basis is inadequate. Either details need to be given or this section needs to point to other relevant sections in the methodology.	It would not be possible to provide a calculation approach for various leakage events. The approach used will be		

		verified by a competent verifier who will review the assumptions and methods used for the estimate.		
6.41	p. 66. The approach of the reservoir boundary including the CO2 plume + some buffer is flawed. First, identifying the extent of plume with accuracy may not always be possible or desirable. Second, the order of guessing the buffer and then identifying potential leakage pathways in the buffer is backwards – the buffer needs to be determined based on the presence of potential leakage pathways.	The text has been modified.		
6.42	5.4.1 What is needed here is not a suite of options for site characterization, but criteria and requirements for what an operator claiming offsets should do. Class II regulatory requirements are very likely not sufficient, given how sparse they are.	The section has been modified		
6.43	5.4.2 Baselines in EOR settings are likely already highly perturbed. This section should discuss this and address ways around it.	The section has been modified		
6.44	5.4.3 This section is extremely weak and does not discuss monitoring strategies, upsides and downsides, limitations or options. A successful operational monitoring regime is central to the credibility of the emission reductions. This section needs a major rethink and substantiation.	The section has been modified. However, many of the details of individual monitoring techniques have been removed to make it less prescriptive per the overarching comments.		
6.45	5.4.4 The rationale of equilibration is extremely	Text has been modified.		

	simplistic and not credible. A simplified, textbook case is very unlikely to correspond to a real project with complex parameters and geology. The 5yr period is arbitrary. This section needs a major revision.	See response to comment 3.13 on 5-yr period.		
6.46			Sec. 5.4 , p. 72 typo, "injected period" should read "injection period".	
6.47			p. 73 " the storage volume is a confined region" confined is not the right terms, confined means something else and region is 2-D, not a volume . How about "the rock volume planned to contain the injected CO_2 is defined as the storage volume. " The top of the storage volume should be set at a defined surface above the uppermost acceptable fluid migration. I would set the lateral boundaries likewise at	

			the limits of acceptable CO2 migration. Note that for an EOR project, the volume that is prepared for CO2, in the active flood area will be only part of the area to ultimately store CO2. During early stages of the flood, it is important to not let the CO2 migrate beyond the area prepared for the current patterns.	
6.48			p. 73. “Potential leakage pathways” will have been eliminated during characterization or by remediation. What is needed is an assessment of unexpected but possible leakage mechanisms that would result in unacceptable leakage	

			to the atmosphere. Here and following discussions, the monitoring program cannot expect to detect leakage at zero; the best that can be done is to negotiate or set what leakage is considered negligible (at the sensitivity of detection). For the purposes of this methodology, the minimum rate and volume of leakage categorized as unacceptable and which monitoring must be set to detect should be stated in the MRV plan. In my opinion, examples of EOR-specific flaws in order to likelihood and impact: 1) unexpected but possible CO2 migration laterally to parts of the reservoir	

			which are not prepared for EOR and may be in production not linked to recycle, 2) unexpected but possible CO2 migration vertically up flawed wells, including wells which were not prepared for the flood because they were unknown or had lost records and wells that had flaws that were not found during characterization and mitigation, 3) unexpected but possible CO2 migration up faults and fractures (fissures is not the right word) because of CO2 migration out of the part of the reservoir that contained hydrocarbons, or because the fracture permeability was	

			changed by pressure change.	
6.49			The section on fluid flow model on page 76 is still weak and meaningless. It is difficult to determine if a model is sufficiently relevant to the question ask to provide a correct answer.	
6.50			p. 79: “Permanence is assured […] permanently”. This is tautological.	
6.51			p. 71: The identification of leakage pathways should be in addition to those identified in characterization. Also, if MRV finds pathways, they are probably no longer 'potential'. Remediation should be its own category or part of operations, MRV identifies the	

			need for remediation and assesses success. For example, plugging a well is different skill set than identifying an unknown well. The "buffer region" should be made both vertical and lateral, and it should be a requirement, rather than a suggestion.	
6.52			p. 72: "assessing for potential leakage pathways is an important part of a monitoring program" - change to "assessing for unidentified leakage pathways......"	
6.53				

H. Emissions ownership and quality

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7.1	Page 91 paragraph 2: “calibration error … shall not exceed 5 percent” How did you determine this, it seems arbitrary. Similarly for the 2% used for the CE value of	Values are per EPA requirements in 40CFR Part 98.3 which is cited	OK	

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	each transmitter in paragraph 3. If these are standard values, please provide a citation.	in paragraph 1. Another footnote has been added at end of paragraph 2 indicating this reference. Additional context included in response to comment 8.4		
7.2	The methodology states that "[t]he project proponent shall attest annually that all emissions reductions occur on the property owned and/or controlled by the project proponents" (page 86). As noted above, we believe that focusing on emissions source is a poor approach, and that a methodology focused on the CO2 sink will create a more streamlined and effective methodology that (i) reduces project complexity and costs (ii) does not create disincentives to improve operational/combustion efficiency at the CO2 source (iii) recognizes that the EOR/pipeline company/owner may not have any relationship with the CO2 producer, apart from a contract to take the captured CO2, and (iv) integrates better with CCS projects that involve multiple carbon capture locations.	The project proponent can be the CO2 supplier, transporter, EOR site operator, or another 3rd party who has clear title to the emission reductions. A clear title to the project's ERs will be required by the registry, and therefore, a contract should be in place among the parties indicating who has Title to the ERs. As indicated in response to comment 1.3, completely ignoring the primary process would not allow certain emissions attributable to the capture of CO2 to be fully accounted.	We do not advocate "ignoring" CCS-related emissions but instead accounting for tem without including the primary process in the project boundary, because in many instances the CO2 source has no direct corporate relationship (apart from an off-take contract) with the sequestering entity. As a result, the project proponent may not (and usually does not in the case of EOR) "own or control" the emissions source, which is the focus of this comment. Some	

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			reviewers believe that particular issue remains unaddressed and that the methodology fails to account for situations where the CO2 generator is not a project "proponent." Thus, this approach is over-inclusive.	
7.3	The methodology states, "During the operational phase, documentation that traces the chain of custody of CO_2 as it is transferred from parties involved in the capture, transport, and sequestration shall be established" (page 86). Recommend clarifying this recordkeeping requirement. Who maintains and updates the records? How long do the records need to be maintained after the CO_2 is stored?	Documents indicating date (month/yr) and CO2 volumes received, transferred, sold, etc. among the parties. The documents are maintained by the project proponent and provided during verification. Documents are retained for a period of 3 years following verification.	OK. The text has not been modified to clarify this point - perhaps add a clarifying note or internal cross-reference.	
7.4	The methodology makes the general statement that leakage is an "unlikely event." (page 87). The probability that atmospheric leakage will occur depends on many factors – the geologic formation, maintenance of wells, proper closure, etc. A general statement that leakage is unlikely should be clarified or qualified by the inherent	Text has been modified	OK	

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	assumptions.			
7.5	The methodology states, “Trespass is a liability that can occur during operations or post-operations. It is the migration of the CO_2 plume into areas or outside the reservoir that initial modeling did not anticipate or was not tracked by MRV techniques.” (page 88). Recommend not defining trespass, as this is highly state-law specific, and stating that migration of plumes might qualify as trespass or nuisance under state law.	Text has been modified	OK	
7.6	6.3, p. 88. Para 1 “trespass” has to do with pore space ownership, not “inside or outside the reservoir” . ... ”original modeling” or ‘not tracked by MVA”. See previous comment on definition of project boundary.	Paragraph has been modified	OK	
7.7	Provide citation for Texas Railroad Commission v. Manziel case referenced (page 88).	Citation added	OK	
7.8	Provide definitions for “out-of-zone” and “off-lease” migration (page 88) or using different terms that better convey the meaning.	Text has been modified	OK	
7.9	Provide explanation for statement, “While out-of-zone or off-lease migration could imply that modifications to the project’s MRV are necessary, these events should not qualify or affect the project’s emissions reductions as long as there is no leakage to the atmosphere.” (page 88). If migration occurs across state boundaries, is it possible that emission reductions could not be credited because emissions are regulated intrastate, not interstate?	The effect of migration beyond the State boundaries should not automatically disqualify the project’s emission reductions based on the individual State regulations. The ER would be disqualified if the State where the CO2 source is located has	OK	

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		regulations requiring the capture of CO2 or other performance metric that invalidates the project's ERs. This is discussed in Section 3.2		
7.10	Methodology states, "If a CO_2-EOR project has a leak which causes damage, the operator will be liable in criminal or civil courts." (page 88). Change "will be" to "may be" – whether to not a project proponent is liable for a leak is a legal question subject to litigation. Additionally, a distinction between organizational/corporate liability and personal liability may be appropriate.	Text has been modified	OK	
7.11	Methodology states, "Case law has built up around claims associated with subsurface injection and liabilities can be managed through the tort system." (page 88). We recommend replacing "tort system" with "existing legal system," as much of this law is being developed by state legislatures, oil and gas commissions, state environmental agencies, etc.	Text has been modified	OK	
7.12	Methodology states, "To cover liability of leakage, project proponents can purchase private insurance." (page 88). "Liability of leakage" is vague phrase and again confuses "Leakage" with "Atmospheric Leakage" and sub-surface migration. Atmospheric or subsurface migration can violate particular statutes and regulations or give rise to a tort claim. However, these releases do not automatically or conclusively generate liability. In addition, insurance policies may not apply to cover regulatory liability, as opposed to liability to a third-	Sentence modified for clarity. We agree that liability is not automatic. From a GHG credits perspective, if the leakage is accounted for either through a deduction from the current year or future year's total there is no	OK	

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	party.	liability. However there may be insurance products for atmospheric leakage.		
7.13	The methodology states that "[Insurance] policies could be short-term policies that are renewed periodically over the project term." (page 88). What is the justification for stating that insurance policies be short-term?	Since liability coverage for CCS projects is relatively new to insurance companies, they are more comfortable initially with providing short-term coverage, which they renew based on the project's past performance and their increased confidence in future performance. This may change over time as insurance companies gain more confidence in CCS projects and develop long-term insurance products.	OK	
7.14	The methodology discusses insurance coverage in very certain terms (i.e. "insurance company would cover obligations"). However, insurance coverage is not automatic and typically contains exclusions. Recommend re-phrasing the discussion of insurance to emphasize that insurance may be designed to cover damages associated with releases, including in third-party liability and those resulting from lost or negated	Text has been modified	OK	

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	credits, but that a purchased policy does not necessarily guarantee coverage in the event of a release			
7.15	The methodology refers to “small” releases that could be handled through accounting and “large” releases that could be handled by deducted credit in future years (page 88). Recommend explaining what qualifies as a “small” or “large” release and whether the releases are acute events or ongoing for an extended period of time. Also, as noted above, the ACR buffer pool or a credit “bank” may be one way to handle this eventuality and “true up” credit accounting in the event of Atmospheric Leakage.	Text modified to qualify “small” release”. “Large release” was already defined. The concept of an ERT reserve Account has been included.	OK	
7.16	The methodology proposes to account for Atmospheric Leakage by deducting the amount of credits associated with the release from current or future year’s total qualified credits and/or compensating for the loss of credits through liability insurance (page 88). The proposal assumes that there are no ramifications from the loss of credits beyond loss of the funds paid for the credits. If an entity was relying on the credits for compliance with an emissions reduction required by a permit condition and/or regulation, the permit or regulation may require compliance through actual emissions reduction rather than financial compensation. The entity also may be subject to penalties for violating the permit condition or regulation. To address such situations, consider including a mechanism to provide for actual emissions reductions in the case of leakage (e.g., reserve of emissions credits) and clarify whether the CCS project proponent is liable for only the cost of the credit or any penalties or other costs that may result from the credit not being valid (i.e., special damages). A	Some insurance policies (see 7.17) have an option to compensate in kind. Also the option of contributing to an ERT Reserve account, if the right type of insurance policy is unavailable, has been added to the methodology.	OK	

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	credit bank is one way to facilitate this, with a credit banking floor requirement (i.e. 10%) to account for uncertainty over long timeframes.			
7.17	It would be helpful to clarify how the insurance proposed for ACR credits compares to the Parhelion California Air Resource Board Offset Credit Invalidation Insurance. See, Parhelion Underwriting, Ltd., www.parhelion.co.uk.	The Parhelion Insurance currently applies to invalidation of offsets from Ozone Depleting Substances and Livestock projects and is specific to the CARB invalidating criteria. The policy can settle in cash based on the market value of offsets at date of invalidation or actual replacement costs. Alternatively the policy could be written to provide replacement offsets. The policy is short-term (up to 3 years from date of offset issuance) as mentioned in response to 7.12 and 7.13, a similar approach could work for CCS projects if the insurance companies can replace offsets invalidated due to reversals to meet regulatory requirements	OK	

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		and renew policies to cover the longer-term coverage that will be required for CCS projects.		
7.18	The methodology states, “In many States, no clear property right to use pore space has been assigned to surface property owners covering the injection of fluids into deep geological formations, and such injection under the underground injection control (UIC) program goes on without approval from surface land owners except for those on whose property the injection well is located.” (page 89). Recommend breaking into two sentences for clarity.	Sentence modified for clarity	OK	
7.19	The methodology states, “These cases appear to have adopted the “inverse rule of capture” rule that determines in effect that the subsurface rights vest in whoever is able to assert them physically on a first-come basis.” (page 89). Recommend breaking into two sentences for clarity. Recommend clarifying what “these cases” are. Provide citation (or example citations) for “these cases” and the “inverse rule of capture.” Recommend re-phrasing ““inverse rule of capture” rule” because current phrasing is awkward.	Clarifications have been added	OK	
7.20	The methodology states “there is no uniformity in the way in which [state] rights to inject fluid into deep pore space are currently being handled.” (page 89). Recommend re-phrasing to reflect that state laws governing pore space are not uniform rather than “no uniformity in the way . . . being handled.” Provide examples of divergent state laws to support and help	Text modified. However, no additional examples included since the sentences that follow are examples highlighting the non uniformity.	OK	

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	clarify the statement (although detailed citations are not necessary).			
7.21	Methodology states, “In case of storage in non-EOR projects, some states, including Montana, Wyoming, and North Dakota have assigned pore space ownership to surface owners.” (page 89). Omitted “the” before “case.” Omitted a comma after “North Dakota.”	Text modifications added.	OK	
7.22	The methodology states, “In Wyoming and Montana, that ownership may be severed and assigned to the mineral owner.” Clarify that the “ownership” at issue is pore space ownership.	Text modified for clarity	OK	
7.23	The methodology states, “In Texas, where mineral rights are severed from surface rights, there is no clear ownership of pore space between surface and mineral owners, although it is likely owned by surface owners.” (page 89). Correct dangling modifier (“although it is likely owned by surface owners) by clarifying what “it” is. Recommend re-phrasing sentence so that there are fewer clauses to make the sentence less awkward.	Sentence modified	OK	
7.24	The methodology states, “Therefore the right to use an oil reservoir for the associated storage of CO_2 during the operation phase of a CO_2 EOR project would be permissible under an oil and gas lease. “ (page 89). Omitted comma after “therefore.” Is this statement true with regard to all state laws? If uncertain, recommend qualifier here.	This is true of all oil and gas leases involving CO2 injection for EOR.	We question this conclusion as a legal matter, as such leases and state oil & gas laws are highly variable. The right to use CO_2 for EOR is different from storage that is supposed to be permanent.	

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7.25	The methodology states, “However, there is a need for the continued monitoring activities for the remainder of the project term to assure permanence.” (page 90). Suggest re-phrasing for clarity: “However, monitoring after the end of hydrocarbon extraction activities is needed as part of assuring permanence.” Provide citation with support for the statement – could reference earlier sections addressing permanence.	Text modified for clarity and appropriate section referenced.	OK	
7.26	The methodology states, “These are capital-intensive projects that may require environmental assessments. If an Environmental Assessment (EA) or an Environmental Impact Statement (EIS) is required, that document or a summary thereof shall be provided to the ACR and provided to the validation/verification body on request.” (page 90). Recommend clarifying that “these . . . projects” are CCS projects. Recommend clarifying that there are different state and federal laws, regulations and guidance that require an EA and/or EIS for certain governmental actions, such as the federal National Environmental Policy Act and state analogues.	Text has been modified and clarification added.	OK	
7.27	The methodology states, “Project Proponents shall document in the GHG Project Plan a mitigation plan for any foreseen negative community or environmental impacts, and shall disclose in their annual Attestations any negative environmental or community impacts or claims (by community members only, not external stakeholders) of negative environmental and community impacts.” (page 90). It is not clear what is included in “claims” from community members – are these legal claims, public comments submitted during a permitting action, public comments on an environmental impact statement, or informal complaints from community	Text has been added to clarify the nature of “Claims”. The exclusion of external stakeholders’ claims has been removed.	OK	

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	members? It is not clear how a project proponent could distinguish between "claims" from a community member and external stakeholders. For example is an environmental non-profit organization working with community members an external stakeholder? Further, what is the justification for not reporting claims from external stakeholders to ACR and why is this policy prudent?			
7.28	6.3, p. 87. Para1. Consider clarifying that modeling must be fit-to-purpose and designed specifically for the relevant project. Also clarify the use of monitoring data to test the correctness of the key model assumptions. Modeling alone may not adequately demonstrate permanence. As written, the methodology appears to allow the operator to produce a model and a model match that look completely OK and credible while the site was leaking CO2 at a significant rate. For example, most models assume a no-flow boundary at the top of the injection zone. If the injection rate and observed pressure increase are not as predicted, the classic modeler response is to change the model characteristics to better approximate the observations. However, a mismatch with the assumptions is the way that a leak would appear also. Only if a model is built specifically to test for leakage out of the reservoir zone, and carefully designed data are collected and input into the model, can the leakage signal be extracted from a model. Modeling is a powerful and important tool, however it has to be designed correctly to serve the intended role.	This idea has been included.	OK	
7.29	6.3, p. 87. Para3. Delete "In spite of projects' MVA".	Text modified	OK	

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	MVA will not remove atmospheric leakage risk, if it exists. Well-designed monitoring storage, followed up by mitigation actions when appropriate, can reduce the likelihood of significant CO2 loss.			
7.30	6.3, p. 87. Para3. Remove "seismic disturbance" see R. Juanes, B. H. Hager and H. J. Herzog. No geologic evidence that seismicity causes fault leakage that would render large-scale carbon capture and storage unsuccessful. Proceedings of the National Academy of Sciences of the U.S.A.,109(52), E3623 (2012), doi:10.1073/pnas.1215026109	Text modified	OK	
7.31	6.3, p. 87. Para3 "Financial failure… social instability" The risk factors listed are not the ones that would lead to reversal. Need here to focus on risk of failure of storage, shore and long term. Also recommend discussion of potential financial and legal risks associated with reversals.	Text modified	It is still unclear what "social instability" means or how it creates project risk. Recommend removing this term since it seems overly-broad and subsumed by regulatory risk for all practical purposes.	
7.31	6.3, p. 87. Para 4 financial responsibility of injection wells "shows you will have sufficient financial resources to close, plug, and abandon your wells properly at the end of their useful life" http://www.epa.gov/r5water/uic/forms/ffrdooc2.pdf. "Safe operation" is also regulated by UIC, but different part of permit than financial responsibility. "Confidence in location of the plume increases over years" is not especially true, however uncertainties can be reduced by	Text modified	OK	

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	a well-designed monitoring program operated over time. Delete “hazards”, injection under hazardous conditions would not be permitted.			
7.32	6.4, p. 90 para 1. Add to “surface use rights” a qualifying phrase such as “needed surface use rights.” Surface access typically is limited to the access “necessary” for a given activity. For example, collecting seismic data may require separate leasing or surface rights than well pads.	Text modified	OK	

I. QA/QC

	1st Review	Response	2nd Review	Response
8.1	3rd party verification is needed for subsurface.	A requirement for qualified personnel on project proponent and verification teams has been added.		
8.2	Page 93: paragraph 6: “The uncertainty… is dependent on ….MRV plan”. The MRV plan may also help to reduce the uncertainty over time. “uncertainty…. is considered low” This is not quantitative, rarely is uncertainty actually assessed, and EOR operations do not generally worry about uncertainty in monitoring leakage – they just fix leaks if/when they find them.	Text has been modified		
8.3	Recommend adding a section on certification procedures.	Verification requirements specific to the Project’s MRV plan has been added. Certification of the		

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		overall project follows ACR Standard requirements		
8.4	Recommend providing some context on the QA/QC requirements of 40 C.F.R. § 98.3(i) that are referenced on page 91.	Context has been added		
8.5	The methodology states, “Calibration records should be maintained and made available to 3rd party verification.”(page 91). Recommend consistent abbreviation or spelling out of ordinals.	Text modified as suggested		
8.6	It is not clear whether the calibration procedures and calculations listed on pages 91-92 are from 40 C.F.R. § 98.3(i). If so, provide citation. If not, clarify that this recommendation is specific to the methodology.	Citation has been added.		
8.7	It is not clear whether the data collection procedures and periodic review on page 92 are from 40 C.F.R. § 98.3(i). If so, provide citation. If not, clarify that this recommendation is specific to the methodology.	Clarification has been added		
8.8	The methodology states, “The MRV program to detect and asses subsurface leakage (if any) should include quality checks on the data, models, etc., and report on significant deviations from expected values” (page 92). This raises the question of where the QA/QC procedures would reside – within the MRV plan or a project plan. Clarify QA/QC documentation procedures.	Clarification added.		
8.9	p. 93 para 5. Is this section trying to require “meticulous logs” it should say so. Because CAA section UU does not use this terminology and has a cut off.	Clarification added		
8.10	8.0, p. 94 para 1 “”many of which are currently being	Text modified		

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	utilized" is true, but not "to meet state regulations". Tools are currently used to optimize production and make money.			
8.11	Table 8.1, p. 95- table line 6 "oil or other hydrocarbon production values are based on continuous measurements" is incorrect. Some measurements made at central facility are continuous, others are daily, and some such as production from individual wells or well patterns are sampled monthly. Allocation is used to widely to estimate where and when production occurred.	Text modified		
8.12	Table 8.1, p. 96- table line 2. I am not sure low uncertainties can be assigned to "detecting and estimating" leakage. One can say that the probability of large volume undetected leakage occurring is low.	Based on the monitoring plan goals of modeling potential failure scenarios and developing a monitoring plan that is aimed at reducing uncertainty, the uncertainty in detecting and estimating leakage is greatly reduced.		

J. Uncertainties

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9.1	The methodology advises that the uncertainties in calculations should be addressed "in the project document." (page 93) What project document is being referenced?	The project proponent has to submit a project plan that is specific to the project, which indicates how the		

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		project conforms to the methodology requirements. Project document has been replaced by Project Plan.		
9.2	The methodology states, "The uncertainty in these parameters is considered low since site operators are currently required to report these data to the USEPA as part of their reporting requirements under Subpart WW." (page 93). It would be helpful to clarify what the reporting obligations of subpart WW are. Use consistent abbreviation of USEPA and other government agencies.	Footnote has been added for clarification		
9.3	The methodology states, "Based on this, the uncertainty in detection and measurement of leakage is considered low for EOR sites" (page 94). It is unclear what "this" is – the experience of the oil and gas industry? Recommend clarifying.	Clarification added		
9.4	It would be helpful to clarify what the requirements of "USEPA per Subpart W" are. (page 95).	See response to 9.2		

K. Appendices

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10.1	A.0 this overview is devoid of citations, which is troubling. Add some. Perhaps take out a lot of the miss-stated and somewhat irrelevant information in favor a tight review with a lot of citations. Found this same blurb repeated by several sites e.g. http://energy.gov/fe/science-innovation/oil-	The appendix is meant to serve as a general description of EOR processes and in particular CO2-EOR. A citation for the		

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	gas/enhanced-oil-recovery. All I can say is don't believe everything you read on the web.	description has been added.		
10.2	A.0 p. 97 para 1. 30-60% of OOIP is too high for EOR. http://www.netl.doe.gov/technologies/oil-gas/publications/EP/CO2_EOR_Primer.pdf says a " successful CO2 EOR project could add another 5 to 15 percent of OOIP to the ultimate recovery."	Reference to the 30-60 percent has been removed.		
10.3	A.0 p. 97 para 4. "Gas injection" this paragraph is sloppy, considering it is the topic of interest. Repair using a credible source, for example textbook of Lake.	Reference has been made to the rest of the Appendix for a more detailed description		
10.4	A.0 p. 98 para 1. Why only "some CO2" is separated? Sometimes lots of CO2 is produced. All the produced CO2 is separated. Important point for this text, should be fixed.	The text did not mean that only some CO2 is separated but that the produced fluid contains some CO2 which is separated at the surface. Nevertheless the word some is removed from the text to avoid this confusion.		
10.5	A.0 p. 99 para 2 is not correct as written. CO2 is injected at the surface at a pressure that is sufficient to displace fluids in the reservoir, otherwise the injection will not occur. However, the surface pressure is way below the reservoir pressure, because the fluid column in the well counts to produce pressure at reservoir depth. The goal of the overall operation may be to build pressure in the reservoir such that the CO2 is miscible with oil. Or it may get only to partial miscibility,	Text has been modified to address these comments.		

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	it still works. The firm numbers for how much of the CO_2 is in what phase is absurd, although the list of phases is OK. Big differences occur over time and space in distribution of CO_2 dissolved in oil, dissolved in brine, trapped by capillary process, and mobile, see models by Chris Doughy for a good calculation. Important fact: in a properly selected and managed reservoir, it is all trapped. If one produces or vents a well, all the phases will move and transform one into one another along hysteretic curves. The amount of each phase will depend on a large number of variables, and it is absurd to make a global statement. The way many fields are currently operated, the amount of CO_2 produced and recycled can supply 1/3 to 2/3 of the amount injected. However this number is elastic and depends on how field is operated, it does not belong in a fundamentals description. Although it usually does get quoted, I suggest do not do it, it confuses the issues. Also, quoted but not important: no matter how hard you try, it is not possible to extract all the CO_2; something like 1/3 will be stuck by capillary process. But, this number is not the same 1/3 as was not recycled, one is a near-steady state annualized flow, the other is endpoint saturation. The bit about “geochemically absorbed in the reservoir rock” is both misstated and wrong, even though everyone says it. CO_2 can be included in minerals that precipitate, it also, by separate process, can be adsorbed on materials like coal. However, the process is rock specific, and many sites have essentially no mineral			

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	trapping, which is why natural CO2 accumulations exist. Mineral precipitation can take days, also never occur. Minerals that form, like carbonates, can be dissolved, like carbonates, so it is not fundamentally more or less permanent than other kinds of trapping.			
10.6	B.0 p. 100 Need to make clear throughout that gas volume is at standard pressure and temperature.	On page 100, Eq. B-1 is a calculation based on mass flowmeters measurement. Where volume flowmeters are used (e.g., Equation B-2), gas volume measured at standard conditions is indicated.		