



Climate Change Central

CCS – Technical (First) Round Review

September 12, 2011

1pm MDT

Teleconference

Meeting called by: Alison Lennie

Note taker: C3

Invitees:

Amanda Stuparyk – C3
Tanya Maynes – C3
Kathy Penney – Shell
Robyn Kuhn – AENV
Ian Kuwahara – Leading Carbon
Hannah Simmons – Leading Carbon
John-Paul Jepp
Leah Kirkpartrick – Shell
Rich Wong
Chris – Pembina
Jorg Aarnes - DNV
Rich Wong – Pembina Institute
Hannah Simmons – Leading Carbon
Chris Severson-Baker – Pembina Institute
Barry Jessup – Enhance Energy

Shan Pletcher – Alberta Environment
Andrew Reed – DOE
Amanda Bambrick – DOE
Keith Driver – Leading Carbon
Duncan Kenyon – Pembina
Dr. Berhard Meyer - U of C
Barry Jessop – Enhanced
Jiyoung Yu - NRCAN
Malcom Wilson – U of R
Eric Beynon – ICO2N
Rachelle Forsyth – NRCAN
Ed Whittingham – Pembina Institute
Barbara Toole-O’Neil – DNV

Absent With Regrets:

Alison Lennie - Leading Carbon
Tim Crowe – Swan Hills Synfuels
Rob Lavoie – RPS Group
Oliver Bussler – TransAlta

Documents:

1. DRAFT Protocol
2. Protocol TPP
3. Protocol TSD

Agenda

1. Introductions.
2. Context.
 - a. Alberta Environment on policy.
 - b. Climate Change Central on process.
3. Protocol Overview.
 - a. Overview of document, history, context.
 - b. Section by section review (interactive) including key issues:
 - i. Protocol scope (SMR vs broader).
 - ii. Baseline and project analysis.
 - iii. Calculations.
 - iv. Measurement and monitoring.
4. Re-cap on key and outstanding issues.
 - a. Clear understanding of key issues and path to closure on issues.
5. Wrap-up and next steps.

Minutes

1. **Introductions – Protocol Developer**

2. **Introduction to the Quest Project – Kathy Penny**

Want protocol by first quarter of 2012. Project is picking up speed. Hoping to make final investment decision early in 2012. Want to begin 3 year construction period next year. Hope to be in full operation by 2015. Project will capture CO₂ from Scotford upgrader (at base plant and expansion) and use shell technology, compression onsite and within fence line at Scotford. Project will include both the upgrader, a chemical plant and a refinery. No additional compression outside the fence. Will be taking compressed CO₂ out of the site and dispose of in set number of wells (3-8 wells). Project will capture 1.2 million tonnes per year. Steam will be from onsite from cogen, offsite co-gen or from grid.

Basal Cambrian Sands (BCS) is expansive across W. Canada. Best locations determined to be 80 km N of the facility therefore 80 km pipeline. Will cross North Sask River using horizontal drilling and going under the river. Line breaks valve locations.

Quest project is based on 3-8 wells into basal Cambrian sands (BCS) >2km deep. Three salt seals above the BCS. Project area is greater than 39 townships. Extensive MMV submitted as part of submission to AENV, ERCB, AB Energy and Feds. MMV is to demonstrate containment/permanence (CO₂ will stay) and to demonstrate that CO₂ are performing as expected. Obligated to submit data from MMV every three years.

3. **Why We're Here – Alberta Policy Context – C3**

Little background information:

- Alberta Environment (AENV), on behalf of the Government of Alberta, regulates greenhouse gas emissions reductions in the province, they are the regulators and policy decision makers.
- AENV has contracted with Climate Change Central (C3), a public-private partnership, to facilitate

the protocol development process among other programs.

- AENV retains final approval for all protocols developed under the Alberta Offset System.

Touching on some background information of Alberta's Regulatory Framework.

- As of July 1, 2007 the Alberta Government has brought in a Regulatory Framework (enabled by first Climate Change and Emissions Management Act) the Specified Gas Emitters Regulation (SGER).
- This regulation lays down the framework for a compliance-based carbon market, by establishing market demand and enabling market supply:

The regulation establishes a DEMAND – Setting 12% ↓ intensity targets for LFE facilities current Threshold: emitting over 100 kt Total of GHG in Alberta (a little over 100 facilities captured)

Enabling market supply through OPTIONS FOR COMPLIANCE

- a. Internal Reductions
- b. Performance Credits (beyond reduction target intensity)
- c. Alberta Technology Fund \$15 tonne (unlimited access) —
- d. Offsets – Regulated entities can purchase verified emission reductions and/or removals (offsets) from voluntary projects that reduce GHG emissions arising from unregulated activities

Offsets – Emerging Carbon Market in AB – The Alberta Regulations define necessary eligibility criteria for generating and using emission offsets for compliance here in Alberta. Some important criteria is:

- Projects start after Jan 1, 2002 (stems from AB's first climate change plan (A Plan for Action 2002 was released), intensity reduction talks, carbon price signals, with anticipation of this signal people may have started to implement changes in regard to GHG reductions)
- Real (project must have specific and identifiable actions that reduce or remove one of main GHGs; beyond business as usual practices), demonstrable, quantifiable (GHG reductions must be calculated and measured according to scientifically acceptable methods)
- Not regulated by law – must be incremental to provincial regulations
- Clearly defined ownership (verifier will seek clear ownership) ie. Tillage projects in Alberta in last compliance – crown land, land lessees, projects where a technology service provider is installing a unit that results in emission reductions, or where multiple entities are involved
- Generated in Alberta - **investment** / project **undertaken** in Alberta
- Not double counted (only serialize on one system, used for compliance once)
- Verified by independent 3rd party (chartered account/certified engineer)

One of the key principles for development of the AB Offset System was for an administratively simple system – No validation step – like CDM and Canadian System have Pre-Validation step

Ex Poste Verification – In the Alberta Project Cycle – Gov't doesn't validate or pre-approve a project, the project is implemented and then the credits are verified. It is a back-ended system.

- In the Alberta Offset System a project cannot be considered for the generation of offset credits until a consistent approach to quantifying GHG reductions for a given project type has been approved by government.
- This is why it's important to mitigate the risk by developing a strong set of gov't approved protocols to serve as a good standard for credit creation and guidance for project developers

The Government developed the first series of 15 Quantification Protocols in Alberta were initially

developed using Good Practice Guidance and adapted from previous protocol work coordinated by federal-provincial and territorial governments from 2003 to 2006.

Bottom Line – Gov't is fostering this process to help develop strong protocols for the Alberta system.

The Protocol Development Process was opened up in late Fall 2007 to encourage industry and other interested stakeholders to share in development costs, by bringing forward new protocols.

Step 7 of 11 in the Alberta Protocol Development Process – First Round of Review - Expert Technical Review

Why we are here today, to ensure this Protocol undergoes technical review by third-parties who have not yet been part of developing the protocol (similar to scientific peer review). Expert technical review ensures transparency and helps identify potential issues early in the process. Consensus must be reached and at this stage is defined as 'no sustained objection'.

Based on the feedback from the first round, revised versions are circulated for comment and feedback with a final close date to gather comments. Once all comments are gathered and consensus is reached all changes should be incorporated into a final revised version of the draft protocol.

All comments and changes should be recorded and ultimately sent to Climate Change Central to post on the www.carbonoffsetsolutions.ca website for transparency purposes. Begin initiation of Second Round Reviews.

4. Principles to Guide Protocol Decisions/Development - C3

So the Alberta Government would like the technical reviewers to keep 4 main principles in mind when weighing in on the protocol:

Principals to Guide Protocol Development

1. Environmental Integrity

- Considering all GHG sources controlled, affected, and related to the project
- Process – hopefully ? that it is there
- All 3 main GHG's – but if 1 gas is so ? to quantity, and we can provide solid ? then it doesn't affect the integrity (<5% ?) then ok.

Related, Controlled, Affected definitions; Related – SS generally upstream of project - Controlled – Project developer has control over, on the site – Affected – Downstream of project activity having an impact (i.e. city offsets for transit infrastructure affected traffic congestion (less due to increased ridership) then due to that, people start driving more)

2. Usability/Practicability - reasonable level of rigour and integrity – realistic, using consistent approaches to decide what needs to be quantified in baseline and project
3. Adapting Precedents – set elsewhere, used in other systems - adapted – C3 conducted a review of protocols around the world (close to 500)
i.e. Afforestation protocol – used CDM approach of project cycles (3 cycles of 20 years) adapted
4. Streamlined Life Cycle Analysis – Completeness as outlined by the ISO 14064 framework - Cumbersome, but comprehensive. The Protocols are based on the ISO 14064 Part 2 Project level Standard. Which involves a LCA of project and baseline, and then selection and relative quantification of relevant Sources and Sinks between the two. Beginnings of project through to

aftermath

- Involves identifying emission sources and sinks upstream and downstream of the project, as well as in the baseline and project conditions
- Allows you to consider all the possible impacts on project and baseline condition
- CDM does not take that approach – dev from bottom-up – did not consider outside project boundaries – changed who financial aspects of the projects

- Good considered technical assessments
- Important SS to include and justification of inclusion or exclusion
- Gov't put effort in – others can avoid

** More on the Alberta offset system can be found at www.carbonoffsetsolutions.com

5. **Message from Regulator**

Intensive review process, this protocol is on a compressed review schedule. Will need to consider alternatives for stakeholder review for this protocol as this falls stakeholder review has been postponed until January 2012. At all stages of review we are looking for no sustained objection – if any are identified, than it is a full stop on the protocol development process. Protocols will go through technical review and build broader to include stakeholder, departmental and public. On this protocol, AENV and Energy are the most relevant.

The offset system is a market based compliance flexibility option. It is voluntary to set up an offset project, however once you choose to participate, project developers need to meet compliance level data. Increasing importance on data.

Want all protocols to be as clear as possible. Protocols are cost to develop so want to have them as broad as possible. Will be working to ensure all new protocols meet reasonable level of assurance. This is much higher than you will see in voluntary systems.

Need to ensure that additionally is met – that it's above and beyond. Need to address leakage - that emissions reductions are real and are not just shifted. Finally, permanence – need to understand that this is a permanent removal and that it isn't going to be reversed.

Additional questions are welcomed and will be addressed (via email).

Q – How will you ensure transparency ? How are sustained objections handled?

A – all notes & questions are documented and will be circulated to the group. Non attributed notes will be posted on the Carbon Offset Solutions website. Sustained objections will be handled by AENV.

6. **Introduction to the Protocol – Keith Driver**

Want to organize comments into the following

- Syntax
- Clarification
- Issues of policy
- Technical - i.e. equation

We are considering two documents today – the Protocol and the TSD

Protocol – the rules, what’s involved, methodology

TSD – a lot of the background. More in terms of examples and depth of information. Two documents are joined and will be revised to ensure consistency.

Need to have transparency, want to ensure that everyone is on the same page. Want defensible on it’s design and process.

7. Review of the Protocol - Protocol Developer

- **1.0 Offset Project Description**
- **1.1 Protocol Scope**
- How do we deal with the fact that this is for CCS (not EOR, AGI)?
- Q - are you asking if this should just be steam methane reformers or if this should be all CCS? Can this go to non-industrial process emissions?
- Do the process flows in the diagrams as presented allow for a broadening of the protocol?
- Q – why are we limiting this to IP emissions? What about gasification for the production of chemicals? Not sure why we would create an artificial distinction.
- A - Logic, the way the SGER works, there needs to be guidance from AENV.
- Comment from the Regulator - On the EOR protocol, it will be revised. There will need to be alignment between the protocol. That methodology has been problematic.
- Comment from the Regulator - In terms of IP, prefer to be as general as possible. See no benefit to narrowing to steam methane reforming or IP emissions. For the specific project being discussed, they will be left out.
- Need to be able to clearly draw boundaries between what is the project and what is the regulated facility. Don’t want overlap. Principle of the system is that offsets are beyond the facility (anything within the facility is an EPG).
- Concern echoed, an offset protocol must be additional to regulation. Concern over broadening it to include combustion sources... this takes it out of the area of offsets. Dealing with potential sources that are regulated, this is in the realm of additional guidance produce from AENV.
- Clarification - IP emissions are regulated however they don’t have a target.
- Perhaps the distinction is that if there is a target... could broaden to zero target emissions. By default, emissions with a target are excluded from an offset system.
- Q - To clarify, an EPC is separated from a protocol? A – It’s not related to offsets or protocols, it becomes identifiable upon inventory reporting. In this case, the preference is that this protocol works with different sources of emissions. Internal AENV discussion still needed as to determine how to work with targets. AENV preference is to have a broader source of CO2.
- Need guidance form AENV on non-zero target emissions.
- Would like to see extension for IP to be removed. Want to see those emissions covered through regulations. Preference is to not develop a hybrid system.
- Q - Is this an open issue for AENV? Will IP emissions have a target? A - This is the topic of

internal AENV discussion, no clear direction at this time.

- Can't have two parallel streams of discussion – where we are considering an IP only source and a broader source. Will discuss this protocol in terms of IP. Worry about the policy overlay of broadening gas streams after the fact.
- Clarification: Where is the definition of Acid gas? Is there a definition where the AGI protocol ends and this protocol start? A - the AGI protocol only applies to unregulated facilities.
- There is a need to expand the glossary of terms – clearly define when the EOR, AGI, and CCS protocol are eligible. To build in guidance. **Terms and references to be sent to Protocol Developer.**
- Why not put a value on the gas composition as a distinction between the three protocols? It's not necessarily the composition of the gas, but also the source of the emissions. **To be clarified in the protocol and background.**
- Clarify that this is not just steam methane reforming (SMR)... do the process flow diagrams capture scenarios beyond SMR? Concern over adding additional SS's. **Flagged for discussion.**
- Q - First Paragraph – Can we expand beyond saline geological formation – want to see something closer to 'non-hydrocarbon producing wells'. Still closed site. A - Concern over expanding this may open up more discussion of permanence. Site selection discussion section in MMV plan should address that. Beauty of saline aquifers is that the form of sequestration is different and the risks associated with reversals is different.
- Q - Is there a technical reason why saline may be different from non-hydrocarbon? A - With a depleted O&G reservoir, over time you will get saline water flush back into reservoir. The key is that there is no risk associated with recirculating within the formation. (pp 7). The main question is what do you consider permanent storage? **Needs to be clarified in the document.** The term permanent storage, must be detailed. Many thing mineral storage is the only permanent solution. There is no reason to re-enter and go after reserves in a saline aquifer, whereas in a depleted O&G reservoir, there may be.
- **Definitions - Non hydrocarbon producing reservoirs, permanent storage, depleted reservoirs and other formations with hydrocarbons within where resources are non-accessible (i.e. very deep gas).** Important distinction. Definitions will need to address over time.
- Department Energy will be considering tenure requests, it forms a good distinction between saline storage projects and EOR. Issuance of that license could be beneficial. **E-mail Keith more information on the concept.**
- Need to have the proper rationale for why deep saline was chosen. If that's the appropriate approach than that's fine, but need to understand what has been considered. **To be clarified.**
- 1.1 and throughout the document, quantification approach is referenced, needs to be clarified throughout the document – net GHG quantification approach. To be clarified.
- **1.3 Flexibility provisions**
- **Point 1 – no longer a valid FM.**
- Q - Question on cogen. Understand that cogen is given full credit for use towards reduction requirements is not based on how much goes to grid, but how much is

generated. A - AENV to defer. Onsite cogen is quite beneficial but can't speak to quantification. **To follow up with John.** Concern if 100% of credits are given to LFE, the environmental benefit has now been claimed. Concern of downstream claim of co-gen could result in double counting.

- Clarification that it errs on the side of caution. **To follow-up to ensure interpretation is correct.**
- **Submit terms via e-mail** - Ian has a copy of the document produced by SK. Extensive glossary in that document. Please ensure that definitions align with industry accepted definitions.
- **Clarify definition of primary product** – generify.

- **2.0 Baseline Condition**

- Dynamic projection based baseline. The big assumption is that the sources and sink in the baseline condition is based on the assumption that the amount of CO₂ put into the reservoir is put into the reservoir. Need to ensure we are considering the net emissions.
- Will need to do a final wash to ensure that the syntax matches the final decision on IP.
- Section 2.3 of the TSD – concern over “alternative technologies”. Definition is pretty close to Best available technology economically achievable (BATEA). Should be the best available technology for the circumstances available. Don't want to credit BAU. If there is a lower efficiency generally accepted technology we may need to look at excluding that as a valid capture technology. Recent discussion of membrane technology... concern that wording in the TSD don't limit the technology to the most efficient technology but allows broader technology (i.e. a 80% efficient technology rather than a 95%). Want to ensure we don't preclude technologies with wording that leads to one technology. **Word flagged is “lowest” at bottom of PP.3 in TSD. Propose to change to ‘lower’.** In additionally we don't have to be BATEA. **Clarification requested on “comparable level of service”... ensure meaning is clear.**
- Concern over the assessment in baseline – should likely be more SS's. In the Shell project, yes, it's likely the one. Can't predict the changes without project specific information. Reference to the EOR protocol, there are relevant SS's. In the project plan, you can exclude identified SS's and justify exclusion. Needs to be built out. Concern over including an SSR, you can't just say to include, need to provide an equation. Difficult to provide this for all perms and combs of different project. In general, to put a protocol together for all the various capture and processes, various storage scenarios is going to be difficult, it will be too broad you can't capture all the ss's.
- Worry that putting too broad a scope, will weaken. Prefer to keep narrow scope. Without it, there will be limited confidence in the methods. To date the limited scope has had a lot of research and supporting documents.
- What about looking at a FM that would broaden the scope?
- Still concern that a different capture technology might not be reflected in the quantification.
- Example: WRT Figure 3. An example of putting capture technology on coal plants. If you build a capture ready plant, it depletes the performance of the plant y 5-10%. By decreasing the efficiency of the plants, you may be creating a problem of leakage. Don't

know how the inputs would change. To put it in the protocol as an SS, you need to give sufficient guidance to project developers as to what needs to be measured and quantified.

- Could Figure 4 be adapted to baseline? Not really, too different. Could look at EOR Protocol for some SS's. They are affected but not controlled and should be identified.
- Concern over the lumping of process emissions into one – should be expanded for transparency.
- We are working with the reality that this is an offset protocol that applies to regulated facilities. The reality is we need to be able to differentiate between the facility and need to identify the baseline condition and the project condition.
- Identification of SSs isn't transparent. Not substantive to the review of this protocol. Need to sort out with AENV.
- **To be continued offline as a separate discussion.**

- **3.0 Project Condition**

- From pp13, process flow. Need to ensure that all the SS's are captured. Is there additional that may be identified if broader scope?
- Primary process box could incorporate the hydrogen production. The definition the primary process box could include Hydrogen production? Is it better to have 'secondary process'.
- First two boxes, hydrogen production doesn't make any difference how it is made. Adding secondary production works too to make more generic to other technologies.
- If the host facility falls under the SGER, emissions will be captured in facility reporting. Not the case in a non-regulated facility. Perhaps the distinction needs to be identified and addressed? Concern that this is an offset protocol and if you are counting on a regulated facility, you are by definition now saying that the project is ineligible for this protocol.
- **Pp 11 – very uncomfortable with a number of terms used. Needs to be reviewed systematically and put in a more geological context. For example, formation has a specific meaning in geology and it's being misapplied here. To be taken off line.**
- **Footnotes are incomplete – pp11 – put full references.**

- **4.0 Quantification**

- To come back to

- **4.1 Quantification Methodology**

- **5.0 Data Management**

- **5.1 Project Documentation**

- **5.1 Project Documentation**

8. **Next Steps - Protocol Developer/Climate Change Central (if desired)**

- Need further discussion of scope – smaller group to hash out
- Hope to reconvene the broader group next week.
- On the material we've covered, please send syntax, etc. issues. Please drop a note ASAP up until Second 4.
- Sections 4 & 5 are open, please identify high priority issues.
- We are working towards no sustained objection and will work diligently towards that.

Action Item	Person Responsible	Deadline
✓ Guidance to be built into the protocol to guide project developers between the EOR, AGI and CCS Protocols	Leading Carbon	Complete
✓ Additional discussion on expanding scope of the protocol to continue offline	Shell, AENV, Leading Carbon	Complete
✓ 'permanent storage' to be clarified	Leading Carbon (with input from Bernard Mayer)	Complete
✓ Definitions to be revised including: non-hydrogen producing reservoirs, permanent storage, depleted reservoirs, other formations, primary product	Leading Carbon (with input from experts)	Complete
✓ Department of Energy Tenure request re: distinction between EOR and CCS	Andrew R	Complete
✓ Review treatment of co-gen to ensure quantification errs on the side of caution	Robyn	Complete
✓ Bottom of pp 3 in TSD – propose to change lowest to lower. Clarify 'comparable level of service	Leading Carbon	Complete
✓ Identification of SS's to be continued offline	Shell, ABENV, Leading Carbon	Complete
✓ Pp11 Put in full references	Leading Carbon	Complete

Part II – September 30, 2011 1:00-4:00

Edmonton

Amanda Stuparyk
Tanya Maynes
Amanda Bambrick
[Andrew Read](#)
Ian Kuwahara
Robyn Kuhn
Shan Pletcher
Jon-Paul Jepp
Duncan Kenyon

Calgary

Hannah Simmons
Keith Driver,
Jorg Aarnes
Barry Jessup
Ronnie Yu (TransAlta)
Sol Cifuentes (Shell)
Eric Beynon
Ed Whittingham

Via Telephone

Malcolm Wilson
jiyoung.yu@nrca-rnca.gc.ca*
Rich Wong
Rachelle Forsyth
Alyssa Haunholter (enhanced Energy)
Rob Hamaliuk, AENV

9. Welcome Back

10. Summary of issues from last session:

- a. See AENV presentation. - Industrial process vs. Non IPE
 - i. In AB under the SGER, all LFE's report all emissions including emissions sent offsite as IP or non IP. This means if emissions were to leak downstream, they are already accounted for. This is the same for stationary combustion emissions or IP. If stationary, they have a 12% target that is taken into account, while IP does not have a target.
Q – confusion about IP. A – IP emissions have no target applied but are accounted in the compliance report. In section B1 of compliance report they are booked as IP emissions but backed out of target. Clarification of COGEN. No credit is given but they are 'generously treated'. Q – if cogen is given a factor for putting on the grid, how is that credit given to the large final emitter. A – it's within the calculation of the compliance report. Discussion to be taken offline.
 - ii. (AENV Presentation) Incremental emissions (yellow) are captured in the project. The lifecycle approach used in the offset system ensures that all incremental emissions are accounted for. All fugitive emissions or vented emissions are already booked at the facility. Note that in the QUEST project, there is no midline topping up. No field compression for that project.
 - iii. Injectors will have invoices and contracts that outline the exact volume of injected CO₂ – can be accounted for and verified. Could account for some emissions with an emission factor (midstream pumping and compression).

AENV would like this flexibility built in. Q – Issues is IP vs. Non-IP emissions (see slide 2) – don't need to specify IP vs. non-IP because by the time they have left the site it doesn't matter as they have been taken care of. There is no difference as how it is treated in the project. All crediting is accounted for in inventory. No special treatment required. AENV would like to remove the requirement of IP emissions as it is treated as a separate facility. I.e. Scotford already reports that all emissions going to a pipeline as an emission. There will be no impact on the project if AENV down the road places a 12% target on IP emissions. Q – think it makes sense but what about if a natural source of CO₂ or recycled CO₂ from EOR field. A – to be answered in a few slides. Q – will injection be measured – not shown in the image? A – yes. Q – What about potential for double counting if facilities request a restatement of baseline? I.e. if Scotford would to ask for a restatement of baseline that accounts for injected CO₂ – this would be double counting. A – to be taken offline – a thought of process. Desire to have a transparent process. CO₂ emissions are being emitted and in the project year they are captured. Therefore there will not be a restatement of baseline. Must be clear in terms of boundaries. Any change at the facility (i.e. building cogen) are accounted for and there is a boundary issue. Emissions from the capture facility are not on Scotford but will be accounted for in the project – in the QUEST project, they would not be accounted for on Scotford's reporting. There is no reason to restate the baseline. **To be clarified in the protocol.** Suppose CO₂ from a coal fired power plant, would this be

prorated to account for parasitic load. Yes if you can prorate it appropriately – it's a parasitic load.

Need to be very clear on project boundaries and facility boundaries.

b. Saline vs. non-producing hydrocarbon reservoirs

i. AENV suggested wording for sequestration reservoir:

Includes:

- *Deep saline aquifers,*
- *depleted oil and gas reservoirs,*
- *depleted oil and gas reservoirs following tertiary recovery (i.e. CO2 EOR may have already occurred and so no further EOR will take place), and*
- *coal seams (which may also be deep saline aquifers); however coal seam specific MMV plans are required*

Does not include:

- *Reservoirs where CO2-EOR may be later pursued*

Tied to Alberta Energy's Carbon Sequestration Tenure Regulation and ERCB's Disposal Approval Directive 65

Question – the requirement of reservoirs where CO2-eor will not be pursued – this can't be verified. Is this acceptable language for permanent sequestration?

Tenure regulation requirement is that EOR cannot be used. If this requirement is required in the Reg, this can be tied to Tenure. Also can tie to ERCB. Dir 65 is actually set up to encourage EOR. If you get tenure, you cannot go back for oil within the first 15 years. Can tie to carbon sequestration lease and Dir approval.

A little concerned about using present day technology and definitions of what is 'non-recoverable resource'. Are we going to give out leases today that would be considered recoverable in the future? A – this is liability.

In the big picture Alberta (GOA) is taking on that liability. Yes, AB does have a high amount of rigour. Normally we handle permanence by discounting credits based on the likelihood of reversal. The risk of reversal must be accounted for. This is a risk for the program as a whole.

Q - yes there is a permanence issue, how do you tie it together? what about a set aside – to give incentive to keep it there. This starts to be a discussion with other resources – this is a function of time.

Can't tell 20 years down the road where the opportunity is. If someone is going into a reservoir with stored carbon, put the liability on them to ensure it stays there. Still give 100% of reductions upfront. That is one option. Could also figure out what the risk of reversal is – i.e. tillage discount factor to set aside to cover liabilities. Unsure of this applicability. Also with the afforestation conservation protocol, there is a requirement for a commitment period – could go down a similar avenue.

Protocol proponent has gone to a tremendous effort to ensure permanence. A holdback (even small) has a large impact due to the scale. The concept of a holdback or similar concept is not a desired approach. Looking at p20 – if anything escapes from the container, tie to MMV plan. Protocol proponent does not support this approach.

Comfortable with four categories?

No comments

AENV wording of eligibility (3)

- **Require that CO2 must come from a Large Final Emitter (LFE) to Protocol – this can easily be handled – take out IP, put this in.**
- **All Incremental emissions must be accounted for in the project to account for lifecycle approach.** Q – Is there something that is being left out? A – Just making it clear that every source and sink is accounted for.
- **Storage Reservoir must have both**
 - a Alberta Energy's Sequestration Lease, and an ERCB Disposal Approval - Directive 65

A few concerns on well inventory on leases. Clearly you have to inventory injection wells. Unclear on abandoned wells and other wells. This is a potential permanence issue – not specific to QUEST. This is a bigger issue for the protocol as applied to other projects. Any changes to directives are upto ERCB and outside AENV's control. Loopholes or gaps that can affect a protocol need to be considered. Don't count on Directive to change fast enough. Could cover in monitoring requirements of the protocol and state that DIR X and additional monitoring requirements A, B, C. Q – what about abandoned wells that haven't been signed off of. There is a chance of leakage that may not be captured in a MMV. This is not an issue for QUEST. **This needs to be taken offline. Phone call with Mike Fernandez at ERCB (Duncan, JP and ENV). There are gaps and this protocol can address that. This can be handled at a later time.** Don't want to hold up the protocol with this as it is not applied to QUEST. AENV to consider monitoring and D65 issue more and consider developing wording to cover some of the risks for

other projects. There may be a spot in the MMV section down the road.

Barry J – Q – Eligibility from LFE? If there is a case where emissions are not a LFE – is there another protocol? A – AENV wants this to come from LFE – it might be that it could be a flexibility mechanism but would definitely need AENV approval. Uncertain of economics of small sources. Clear that the CO2 must come from a source that would have been emitted to the environment. Natural and recycled sources will not be eligible. This will need to be clear – from an industrial facility in the applicability section.

AENV flexibility mechanisms:

Mid pumping or compression must be accounted for either:

- *Directly in Project*
- *Prorated in Project*
- *If the system is too complex, a pumping/compression emission factor would be applied*

Q – the third bullet, is it like a grid intensity factor? A yes - determine an emission factor for the entire system. This is a good placeholder. Would like to see wording that any development of an emission factor is a stakeholder driven transparent process. AENV wants a placeholder for future complex situations.

Derek – Q on the public process - what does this mean? How is it different than the rest of the protocol? A – would like to see a technical review that is transparent. In AB, we have the NERP protocol, there is identified gaps in the protocol which will be reviewed upon review.

- c. SMR vs. Other - Propose to leave as is – it is SMR. Propose to have a FM that says if you can prove that you should be included (to AENV), than you can use this protocol.

Proposed wording:

For projects that do not include steam methane reformers (SMR) as the source of the carbon dioxide for the CCS project, these project proponents must receive approval from Alberta Environment that the scope of sources and sinks included within this protocol cover all aspects of the project. The review to support the Alberta Environment approval should be transparent such that stakeholders, including a third-party auditor, has reviewed to confirm conformance.

AENV needs to take this internal. Not ready to make a decision yet. Director has indicated that this will need to be moved up the line. AENV still fundamentally doesn't agree with this approach. Will be speaking to the ADM as to the route.

Q – are any other CCS (non EOR) projects far enough down the road to comment on this? A – With Enhanced (EOR) can identify the ss's for the project but haven't gone beyond that to envision what may or may not be there down the road. One source from fertilizer plant and one yet to be build upgrader gasification. Good handle on those but not on other possibilities.

Q – on the upgrader example, it is not an SMR – do you see that the boundaries of that project would fit in? **Would your process description map onto what is presented in the protocol?** Also note that the EOR protocol will be reviewed and is flagged for review. Same question to TransAlta. **Would your process description map onto what is presented in the protocol?** Think gasification would fit under this protocol as it is coming out of the bubble of the facility and going into a project – will need to follow-up.

Clarification – can we say broadly that this protocol captures the SMR technology and other technologies as well? It would appear that the FM that has been proposed are on the right track. Question on opportunity for further input? And Process? This input will be included in a subsequent draft, circulated and polled for sustained objection. AENV will be the mediator for any unresolved issues. Note that validation is optional in this system. At the same time we don't want a protocol that is so specific we need to develop a new protocol for every project. The factor is an issue identified for further work for complex projects. **To be parked. Protocol proponent is concerned about having a broad protocol that may not accurately accounting**

AENV formal request? How are we going to seek this input? Previous discussions have identified post combustion capture. This is an unknown 'box' or source... but using the words 'such as' with a flexibility of another box is ideal. The ISO standard, you need to identify all the ss's upfront. There is no president to add. Protest noted. Shell has concern over this as this is concern that there will be many additional boxes... also could be substantial differences in baseline. Desire for transparency on feedback and a speedy return (end of next week). C3 to lead the collection of feedback (TransAlta, Enhanced and Swan Hills)

- d. New project boundary – because of discussion to date, there is a revised project boundary in the protocol. Exclusion of SS's that are onsite as they are reported. This boundary line captures the discussion on IP vs. Non-IP.

11. Continued Review of Protocol

• **4.0 Quantification**

Pp 19 – Table of inclusion and exclusions.

- Sol – P11 is included? Yes, even though negligible
- Q – a number of activities are excluded that I thought would be included? I.e. P4 – production and materials used in CO2 capture process (assuming amine). Justification for exclusion is that emissions are negligible compared to other sources? How did you come to the decision that it was negligible? What is the justification? AENV seconds this approach. Negligible emissions

must be justified to the AG. Need rough estimates and quantifications to support this statement. Technical seed document has references to this. Pp 52 of the TSD – Appendix A2 provides explanation. Came from estimates early on in project by Shell on production of Amines. For all exclusions, P4, P21, P2, P1, P3, there is analysis of Appendix A of TSD to provide analysis of why they are negligible.

- Can we do this for P11 to demonstrate truly negligible? Yes, but keep in mind that this is future looking.
- In project plan, if p11 is negligible, it can be excluded, but it must be included in projects where it isn't negligible.
- Concern that the 5% of materiality text for this project is perhaps not a good tool given the magnitude of this project. Note that 5% materiality is for a 3rd party verifier to assess the accuracy of the project against an approved methodology. This is consistent with financial practices. For LFE's, AENV uses a facility threshold of 1000 tonnes or ~2% on a 100K baseline for consideration of negligible emissions. Accuracy and conservativeness are different issues all together. Need to understand the accuracy around the conservativeness. Need to have parameters. For offset projects in general we are crediting small projects and therefore a negligible emissions threshold that we use in LFE's won't work. Offset projects themselves through quantification do not have negligible limits. We are giving credits for reductions that could be negligible at an LFE scale. In the past we have excluded some very small and very difficult sources to quantify – typically we try to include.
- This protocol is not using the 5% materiality. They are being excluded because they are so small (i.e. p21) – assume that all amine gets combusted. The reason that the fugitives are excluded is because they are measuring downstream. It is only the net number that is being credited.
- Non-regulated facilities BAU is non-regulated fugitive emissions, therefore if they are capturing emissions, it's captured from their process and it's a reduction from their BAU. Fugitive emissions are released to atmosphere in a non-regulated BAU practice.
- Q – why P19 is excluded and p20 is included – where is the boundary? Clarify with JP. Multiple well heads and multiple metering. There is a discrepancy as to the metering at the well head and storage complex. How would you rectify the situation? Leakage out of the casing would be detected but not nec. in p20. Perhaps there is a component of the leakage detection that should be included. Should Include P19.

Clarification on the definition of P19 and a clarification of Table 6.

- **Additional comment on P19 – take away faulty seals. Take out example**
- The only opportunity to meter it is at the wellhead. Need to estimate any losses indirectly by MMV results. Can't measure directly whereas on PP 38 you say you will measure. However depending on what actually causes the leakage is difficult to do with some degree of precision. Lengthy discussion in Europe. Some discussions on how to handle this uncertainty. Suggest additional discussion on how to handle this uncertainty.

h

Question – the MMV plan that went in to AE, provided a mechanism for measuring those emissions for Government. ERCB have accepted and AE, can we go back to this approach? Estimate the leakage in the unlikely. Not sure exactly what the number is. ETS and Pew are supporting the identification of uncertainties within a certain limit and penalizing outside of that. In AB, we don't have some of the issues that are identified elsewhere. If it's in the MMV,

we are fine, if it's not than we need to add. Discussion needed on how to handle uncertainty. Where could we find this language? **MMV by EUETS or Pew Centre.**

Suppose a leakage event from a storage project. Measuring a small difference in pressure could signify an event and have the appropriate mechanism in place to handle that. If we are tying this to a carbon sequestration lease, the lease has an associated MMV plan. Look for these particular terms to tie the MMV as a trigger for this. Shell is supportive of this approach to minimize uncertainty. This would apply to p20 – need to examine if it applies to p19. **Keith to examine this further – esp. application to p19 and p20. This will be an appendix.** This could be a trigger or mechanism to put a non-zero term into those boxes – the percentage for uncertainty would require commenting from subsurface team. The idea here is that as a project proponent, you must test your MMV to know if you break a specified uncertainty threshold. In that event, a true-up would be required the year as you went outside limits. In the event of a leakage during the crediting period, they would true up the following year.

Only applies if there is an event. Analysis around uncertainty, if it's not within the accepted bounds, than a penalty is applied. **AENV to review to ensure approach is consistent and acceptable.**

- Q – what if an event triggers the calculation of leakage. How is the monitoring of the underground plume carried out? Is that information and data used in quantification? Leakage is only quantified when an event has occurred. Data is captured at the wellhead and assume that all tonnes are stored. Unless your MMV shows otherwise. Injected gas is monitored. If a MMV program identifies a finding, it will trigger reporting in those project sources and will show up in quantification of that year.
The MMV program requires reporting each year, so any non-zero number would trigger the leakage calculations/quantification.
- To what degree are these MMV plans apply to sequestration side of things. For example, if we are injecting into a smaller reservoir – are we monitoring the same? This is uncertain. Yes, think you need the same type of MMV in the detection plan regardless of the reservoir. If a CCS project, you need to demonstrate containment regardless. Need to have a trigger mechanism to identify a possible leakage. AE – linking it to the CCS tenure will tie it to the MMV and make it a requirement. Smaller projects should have a MMV plan of equal rigor. A MMV plan is required as a part of a sequestration application. **No required content on what must be in MMV. AENV will be following up on.** Concern that this is a liability and permanence issue to take this out of the protocol and put it in an unknown document.
<<Break>>
- Table 6 – P4 – **one minor change** – p19?
- The circulated draft is written from a LFE perspective, does this table change (i.e. exclusion of fugitive emissions) if the facility is unregulated? Fugitive emissions would still occur in the base case, the table doesn't change.
- Construction and decommissioning is convention to exclude.
- P4, P7 & P21 are excluded with explanation in the appendix. All other exclusions are based on the fact that they are accounted for elsewhere. What about a technology below the 100 threshold.

They could capture and store. Is this a problem? No, emissions would have occurred with no penalty.

- Q – pp 15 – p10 separate heat from power. Should also separate onsite from offsite? I.e. offsite cogen could be at LFE or elsewhere. Offsite and onsite is captured. Combining H&P is to be consistent with harmonize approach with AENV approach. Could go either way. Q – how does p8 fit in – this is generation of electricity on the grid (offsite upstream). Couldn't we just apply the cogen factor? A – Mimicked how cogen was done. This is a way of allowing to account for emissions.
- Q – process flow diagram – and include/exclude. In the process flow diagram, there is no heat and electricity at the injection site. Future projects may have this? Is there potential to have more intense heat and electricity at injection site? Also, on monitoring equipment, where is the electricity for the equipment captured? A – all fuel and power that will be consumed by project is represented. A data capture unit would need to be plugged in. Energy sources p7, p8 and electricity should also come into injection wells as well. **Need to adjust the definition of 10, 9, & 8 to capture emissions at the injection site.** Q – what if a different fuel is used at the injection site? A – Quest is able to identify the use of fuel, but no SSR identified. **P11 captures any (pp37) volume of fuel for the inspection and maintenance at the site... can expand to include operation. Change the title in the definition.** Q – in adjustment to p11 to include operation (allowing for NG energy for compression to be included) – should this be applied for the transport as well? **Change way diagram is formatted and...change the definition.** Q – Monitoring? How energy intensive? Is it captured? A. Project has identified the power draw involved. Want to ensure it is captured.
- P18 – should probably be looked at in conjunction with p19 in terms of measurement. They should be defined as either upstream or downstream. **Clarification required.**

4.1 Quantification Methodology

- Won't get through the full suite of equations in the balance of this meeting.
- Can we flag issues with existing equations?
- All feedback will be considered and will be revisited.

5.0 Data Management

- Comments have been rec'd via e-mail. Vocabulary inputs have been rec'd to ensure vocabulary is adequate.
will need wording around the legislation and reference (AE or E to send?)
- Comment on Section 5.5 – liability. Need to clearly detail who has liability of the CO2 throughout the process. Transfer of liability from the developer to the Province. Useful to detail how this will be done. Is there a diagram or text somewhere that we draw for guidance on this?

A – Initial thought is that we would likely need to reference legislation. Original intent was to download responsibility of revoked credits for tillage. Also useful to talk about what information needs to be disclosed to the registry to check for double counting. Do we need to track well sites? Can there be double counting? The protocol is agnostic to the transfer of liability. Liability is an issue identified worldwide. AB needs to address appropriately as they are a leader in this area.

5.1 Project Documentation

- Require placeholder in protocol for minimum requirements of content of MMV plans per work of regulatory group (RFA Working group)
- What is being done within MMV working groups on CCS – sounds like guidance is being done but is not yet finished. It would be good to reference within the protocol that the MMV must follow guidance – a place holder for minimum requirements. The regulatory framework assessment (Energy on that Group) group is waiting for CSA Standard (Jorg) public hearing in the next month. Should be out by end of October.

12. Process – Key Issues Identified

- a. SMR and Non SMR discussion lead by AENV
- b. One further meeting to discuss changes to date and calculation approach.
- c. Chapter 4 for future discussion – comments appreciated in advance of

Action Item	Person Responsible	Deadline
✓ Require that CO2 must come from a Large Final Emitter (LFE) to Protocol – this can easily be handled – take out IP, put this in.	Leading Carbon	Complete
✓ SMR vs. Other	AENV	Complete
✓ Clarify with TransAlta, Enhanced and Swan Hills if the process description map presented in the protocol is reflective of their process	C3/AENV	Complete
✓ AENV to review to ensure approach of ‘accepted bounds’ (page 17 of minutes) is consistent and acceptable.	AENV	Complete
✓ No required content on what must be in MMV. AENV will be following up on.		Complete
✓ Provide feedback on 4.1 and Data Management	All	Complete

Tuesday, November 15, 2011

Edmonton

Tanya Maynes
Amanda Bambrick
Ian Kuwahara
Robyn Kuhn
Shan Pletcher
Jon-Paul Jepp
Duncan Kenyon
Kathy Penny

Calgary

Hannah Simmons
Keith Driver
Barry Jessup
Chris Severson-Baker – Pembina Institute
Sol Cifuentes (Shell)

Via Telephone

jiyoung.yu@nrcan-rncan.gc.ca
Richard Wong, Pembina

Minutes:

Welcome – Shell

1. Update on Scope
 - a. CO₂ source: an industrial facility operating a primary process where:
 - i. Primary process includes any type of process that manufactures a primary product such as H for bitumen upgrading
 - ii. Primary product is a core product by the primary process and is used to determine functional equivalence
 - b. Capture technology is a chemical solvent (ex. Amine regeneration)
 - c. Co₂ storage is a deep saline aquifer

2. Protocol Overview

Q – is the definition of an industrial facility operating a primary process – what if CO₂ is not from a waste stream but an industrial source – can they get credit if they are producing co₂ from a biological process? A – Definition is designed to preclude this – can't pull from an aquifer and use. IP from cement production is eligible? Any example? Greenhouse growers create Co₂ from NG but it's used for growth and wouldn't be used. Also NOVA, Airliquid create food grade co₂. Q – where do they source their co₂ from? Entirely out of scope for these companies.

Value of co2 is too high it won't be used as such. Not a lot of wells do produce co2.
Anthropogenic is a key and is stated in the protocol.

Since the last discussion, AENV has had discussions with PD. New version of protocol drafted – incorporating comments to date. Malcolm Wilson provided written comments as he is unable to join us today.

See presentation.

Issue of what about a complex network – mentioned by AENV last time. Appendix C added to provide additional guidance on this. Once we get to that point, AENV approval will be required.

Shell would like revisions to this:

Intent is that:

1. If co2 streams are split between two downstream sinks (eg. Saline aquifer and to an EOR), that the GHG emissions are proportionally per molecule. Not attach all GHG liabilities to the molecule. GHG emissions applied equally amongst molecules according to where they go.
2. In the case of multiple source, multiple sink scenario, if proponents can show figures for each SSs and can fully quantify through the project condition, then those numbers can be used OR the proponent could elect to use a system factor upon AENV approval. This is a project specific basis.

AENV wanted a place holder in case there was a need of a system factor. Discussed at meeting two weeks ago. Concern over developing an emissions factor is significant enough to trigger a protocol review. It won't change the protocol, but it would likely trip a review. **To be word smithed to reflect that a revision may be triggered.** Discussions with industry have indicated that there is sufficient information available to have complete accounting. If the proponent is going for the whole network, then all is included. When considering a proportion, it's more difficult. Any proponent should know what is going into the network given appropriate instrumentation. If there is an interconnection case in the future, this is being proposed.

One last scrub for glossary of terms to ensure adequate. A number of terms have been added to this draft.

Terms:

- Disposal
- Storage

And organize alphabetically

Still taking suggestions for definitions

Are storage and disposal different?

ERCB define them as different. Preference is to stay with those definitions. Should reflect common industry accepted definitions.

What about moving disposed co2 from one reservoir to another? We've excluded formation co2, what if co2 is being moved from one formation to another? That is concerning as the value of co2 could increase. Concern that co2 could be moved and ultimately generate additional credits from CCS or EOR.

The title reflects "Permanent Storage". Any recycling of CO2 should be handled through an EOR activity. To be tied to disposal operating permits from the ERCB.

On the front end, the CO2 source is from industrial source. Concern that co2 could be temporarily stored and moved. Need a D65 approval and sequestration lease – these aren't done easily. D65 is specifically about disposal and co2 storage. These are required for using these protocols. Not likely to have this scenario play out.

If a D65 operating permit is rescinded, what are the outcomes? CO2 might be a commodity at some point and this protocol is trying to limit that possibly.

What about if CO2 was 'directly from an industrial facility' – does this limit this? **Yes, could provide some clarity.**

In the US, there are examples of cycling co2 multiple times in EOR. They move from oil field to oil field.

To be parked. Agree that we don't want this type of gaming to happen, to come back to this.

See presentation

Discussion of baseline and project condition

Propose: "it is anticipated that there are no co2 emissions from the storage facility" – at bottom of page 11 – Storage in Deep saline Aquifers

Q – re: P11 – what is the new definition? Definition is on page 17 – includes all equipment that will be used. Broadened the scope to include operation as opposed to the initial definition that was 'maintaining'. To capture any activity that doesn't fall into any other activity.

Q – trucks – do we need to meter the tail pipe of trucks? Is there an expectation that all fuel be tracked? The version of the protocol is to include this?

Concern that this is dangerously broad.

This includes mobile sources. Venting captures the equipment to vent. If they were to pump the CO2 out of that pipe to another? Yes, it would be captured under venting. Operations would be broad – include all vehicles associated with supporting MMV.

AENV needs to check this against other protocols. There are protocols who need to track this – eg. Wind.

For industrial facilities, they don't capture the movement of people. Capture movement of the product. For the offsets, the accounting tends to be more onerous. Would need to be tracked and justified/defended.

To be defined further to narrow.

Mobile – very difficult to track

Stationary – very easy to track

Concern that this would include MMV wells, servicing MMV wells, traffic. To measure all of this won't happen. MMV plan is extensive and includes a broad range of monitoring activities – including planes, remote sensing, etc. Is it expected to be tracked?

Note that these emissions would be negligible compared to the size of the project. AENV would need to see calculations as to what negligible means. **This needs follow-up – need to revisit other protocols.** Would help to have some clarity as to what is included in this box. Will view expectations in other protocols.

Q – P5 – arrow goes to p9 – should it perhaps go to p10? Yes, **P5, p6 & p7 have all shifted to the right and will be corrected.**

For simplicity can combine 5,6,7 into one box. Will consider consolidation.

Previous discussions on p9 – concern over cogeneration. Why is cogeneration included in p9 and p10 – H&P might be sourced from something other than cogeneration. **To remove 'co' from 9 & 10.**

Revise: Generation of H and/or Power – could accommodate the different possibilities. Cogen spits between two things, if one size is zero, it attributes all emissions to the non-zero.

Want to keep P8 – as it allows PPA – a power purchase agreement. The inclusion of p8 and p9 are intended to accommodate different fossil fuel intensities. EX: drawing from the grid for power would be p8. If they buy power specifically from a wind farm it is captured from p9.

To clarify – for removing 'co' from p10 – is it now redundant with p11? P11 is intended to capture smaller point sources whereas p10 is intended to capture the magnitude – large. **To clarify via language.**

Q – using the Grid factor at 0.88 – is this locked in? The NIR number increased last year.

A – it will be revisited when we the grid factor.

Q – energy use at injection well is now carbon capture storage and facility operation? This is flagged for review.

Quantification

Table 7

Most equations are taken from other protocols

Any questions about specific sources or sinks?

Re: p20 – the definition is under review with shell sub surface team. This is attempting to quantify tonnage that would come out of formation in the case of reversal. How exactly to quantify. There is a very robust MMV plan in place that would be able to ID this and would be able to quantify. Equipment will be in place to MMV and want to tie that information to this box.

Question re: p12 and p13 & p19 – thought previous discussions said to not exclude? Any venting in the pipeline would not be captured in the well. These are showing up in the well head quantification. Anything that didn't make it to the meter doesn't matter.

What about p19- emissions at injection well sites. The meter is between p19 and p20. In p20 the name includes sub surface equipment. Question is the meter is on figure 3 is in the wrong spot then?

Exclusions are based on numbers – need further justification.

Fugitives can't be measured... venting can be measured. There are ways of estimating fugitive emission – other protocols and ERCB have methods. **To review p19.**

Also should consider intentional vs. unintentional. If p18 and p20 are included, why isn't p19?

Any other protocols for estimating fugitives? Any methods for estimating? What does MMV plan say about that? MMV system is designed and intended to ID any co2 emissions from geology. If the co2 were to come out of the storage the MMV plan is to id this.

For facility compliance – they use a fitting count to estimate fugitive emissions.

Critical to this is where the meter is. Understanding is that the meter is downstream to all the hardware and is the last thing prior to the CO2 hitting the geology. To be clarified.

Line of site monitoring is to detect any fugitive co2 emissions. This uses laser to ID as part of MMV program. Unsure if it can quantify volumes, but it can detect.

P20 – include “and vented”? Thinking that if maintenance is occurring and there are emissions? P20 is meant to be from the geology. Those emissions would be captured in p18

Q re: table 6

Calculations to justify exclusion – can we put reference to justifications as a footnote with full information in TSD.

Cogeneration Equations (p9) – equations 2 & 3 – can measure this directly as opposed to using formula's 4 & 5. Total volume of FF consumed can either be calculated or directly measured. **Proposal to split this SS into measured and calculated methodology. This will give the option to use a direct measurement where data is available. Is there language that says when data is available, you must use direct measurement. When not available, you can use alternative method.**

Measured, metered, and quantified are all quite different. Engineers will be quick to point out that measured will denote a meter – not always feasible or advisable. Quantification is an alternative when not available. Question over non-advisable – what does this mean? Economically advisable? Not really, but just too complex and too much work involved. Using a mass balance is an alternative.

Any steam or power consumed by CCS facility will be determined by mass balance. Can clearly identify fuel destination in some instances and it's more accurate.

AENV supports the use of the most accurate method of determining number in facility reporting. This isn't always used in the offset system. In the offset system, we are always trying to look for the most accurate method available. Direct metering while preferred is not always feasible. When site specific information is available and generic factors are being applied, this would be a flag. Ultimately the approach needs to be justified to prove that it is the most accurate method available.

Q – in a cogen facility where X natural gas goes in to the facility to produce H&P. Can measure directly the amount of NG and can segregate the portion that is used to quantify the GHG associated with H and the GHG associated with P by using mass balance.

Cogen produces power through the turbine and the heat is extracted through the flue gas. There is a huge excess of hot flue gas which goes into a heat steam recovery generator.

With cogen you are almost always duct firing. There is always a value in the steam portion.
Discussions to take place off line to ensure all possibilities are covered.

P8 – pp 29 – grid emission intensity factor – this value is the pulled grid average (not the 0.65).
To ensure it's clear – update table A4 to include emission intensity for electricity generation in AB (.88) and the custom factor.

If power is purchased from wind, it's a zero GHG footprint. **Clarify the treatment of PPA – update in table A4.**

Q – back to cogen formulas. Curious if the credit under the SGER given to co-gen facilities (presently cogen facilities have a 'generous credit'). Is it possible to get a further explanation of treatment?

Assumes boiler is 80% efficient and that electricity generation uses a NG electricity generation factor.

Suppose a cogen generates 35 MW a year. Concern over double counting of co-gen. AENV considers cogen to be more efficient than grid.

Suppose a facility reports cogen. It accounts for the use of this fuel on site. They get a generous treatment in their inventory for the use of this fuel. Concern that if H&P is shipped offsite, is it counted a second time by the CCS facility?

Cogen is captured under the regulated facility compliance reporting and the current allocation will not result in double counting of cogen credits between the facility and offset project.

Slides to be circulated.

Section 5.5 – liability

This liability transfer does not include climate liability. The project proponent retains liability for all climate obligations resulting from activities and events occurring during project execution and after closure. Please refer to Alberta Environment policy for guidance on dealing with liability.

Concern over this language – it's fully inaccurate. **This is an item that needs to be parked – discussions need to occur with energy. AENV needs to understand liability – whose it is. This is still parked.**

Liability is set out per legislation. Transfer of liability is not determined as of yet. At what point in project life transfer occurs isn't determined and therefore how potential reversals are addressed at different points of the life are not handled yet.

The “statues amendment act” does state that liability applies to the crown. However there is no mechanism to accept this. This is concerning as we are giving credits and counting of long term disposal. The mechanisms of how government accepts the liability is not determined.

To get a credit you have to prove that it is a permanent disposal. After 35 years, the GOA takes liability and has no system in place to ensure the permanence. Government has no legislation as to how to accept the liability. Credits are predicated upon permanent removal. After handover of liability, it's a black box and how can you ensure permanence. Unsure of what the GOA will do to monitor liability. Nothing exists that empowers GOA to accept liability – the legal framework currently doesn't exist.

Proposed revision

The project proponent retains liability for all climate obligations resulting from activities and events occurring during project execution and during the closure period prior to issuance of the closure period.

Accepted revision

This will be part of the government review. The other items will be addressed at a later time.

Pp 45 – “In general, thesupersede...” it doesn't supersede... it's in addition to

Add directives into glossary for clarity

Next Steps:

1. Other than the issues discussed, it's generally to go forward. Will work on corrections and clarifications to review. To revise and recirculate.
2. Normal process is stakeholder review followed by public comment. Proposing a reversal of process to do a 30 day public posting prior to stakeholder – for inclusion at January. Concern over the lack of clarity of liability. Liability will be built in but need to keep moving forward.

Require a final draft by Feb 1.

Concern that comments may be raised during stakeholder commenting that may require substantial changes.

If there is a sustained objection or a major flag there is a concern that it may necessitate a second public posting. This is a risk at each point of that this could happen. The technical review process has been very thorough. Hope is that in the next couple of weeks, meetings with AEW and AE will occur.

DRAFT