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Athabasca CO_2 Storage as Gas Hydrate:

identifying and addressing the key uncertainties for storage capacity

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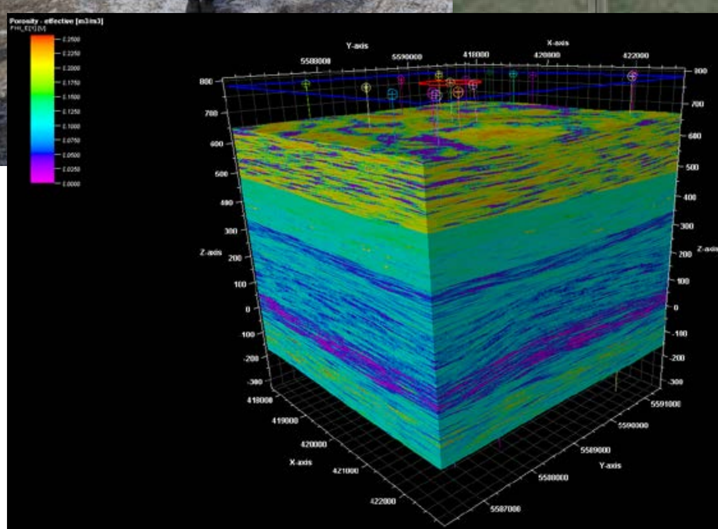
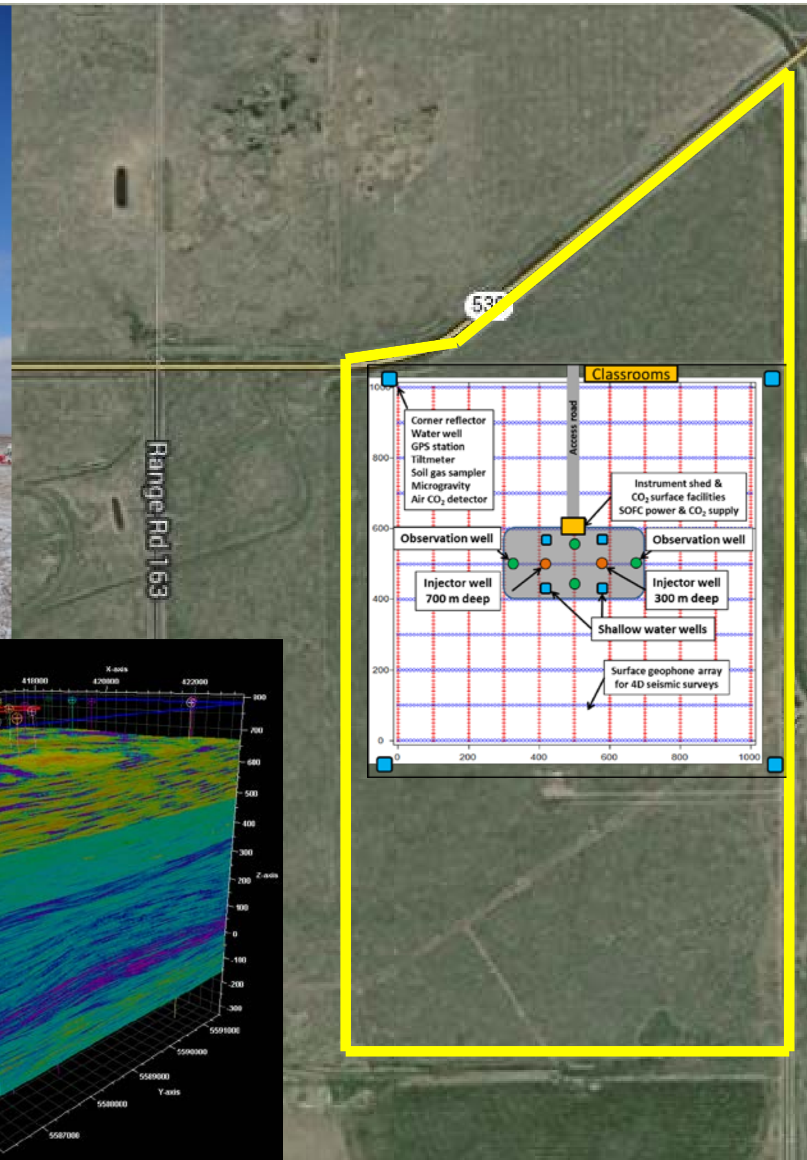
FRS News

News From the Newell County FRS, sec. 22-17-16W4





3D Seismic and 10-22-17-16W4 well completed.

Received ~$5 Million for levered S&T R&D from WED.

Applying soon for a permit to inject CO2.

Negotiating Major Scientific and Engineering programs to be co-hosted at FRS.

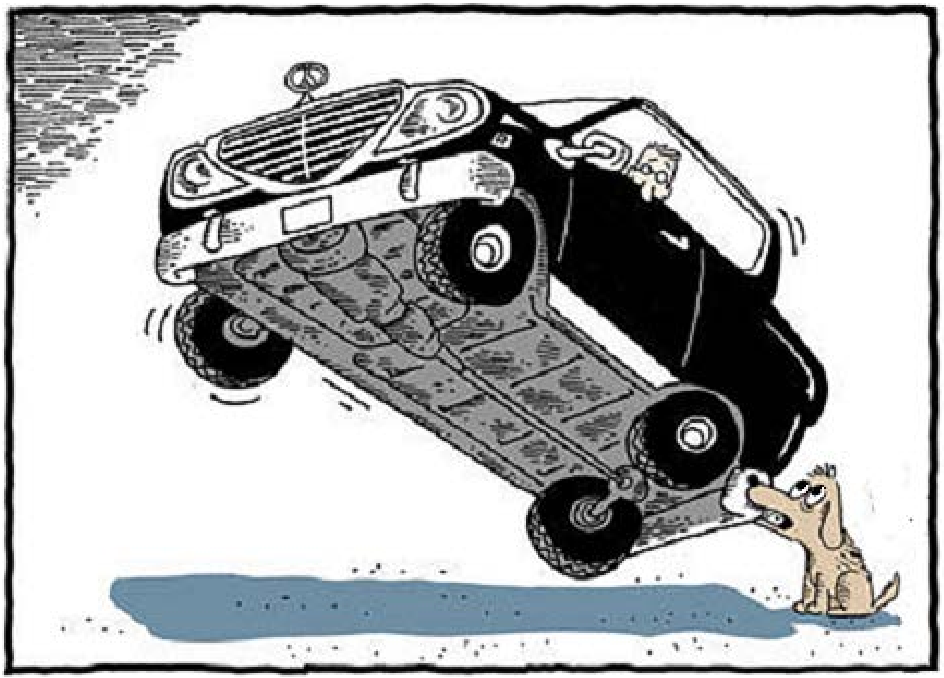
CSPG Field Trip and core presentation at Geoconvention.

A Risk CSPG Cont. Ed. Course to come soon.

Outline

- Motivations to Explore Athabasca Region CO_2 Gas Hydrate Storage Capacities and Technologies.
- Basics about gas hydrate properties and occurrences.
- Athabasca CO_2 Gas Hydrate Storage Review.
- Long-Term CO_2 Gas Hydrate Containment.
- Recent Advances in Alaska.
- Conclusions.

CO_2 Capture without Storage is like:



- "**Canada is committed to reducing greenhouse gas emissions** by 17% from 2005 to 2020 and Alberta's Climate Change strategy calls for a reduction of 200 million tonnes of CO_2 by 2050. CCS is expected to account for about 70 per cent of that reduction". (from: https://www.shell.ca/en/aboutshell/our-business-tpkg/upstream/oil-sands/scotford-upgrader.html)
- How can we manage the **storage component costs and risks** of CCS?
- Dogs (Engineers) like to chase cars (capture CO_2), but what does the dog (engineer) do once it catches it (CO_2)?
- Pipelining construction costs are ~$1 Million/Km and compression is need every ~100 km
- There are aquifer containment issues for Athabasca region reservoirs.
- **Novel, local Athabasca shallow storage as CO_2 gas hydrate is a potential cost and risk mitigation strategy.**

Solid Secure CO_2 Storage & Other GH Themes

•***Secure Carbon Storage*** **of natural or anthropogenic CH_4 and CO_2.**

•**"Inclusion-based" materials technologies, including *manufactured cap rocks* for the in situ solvent extraction of bitumen .**

•**CO_2 utilization in *water purification technologies* (e.g. potable water from plant effluents).**

•**Flow-assurance issues for pipeline transportation.**

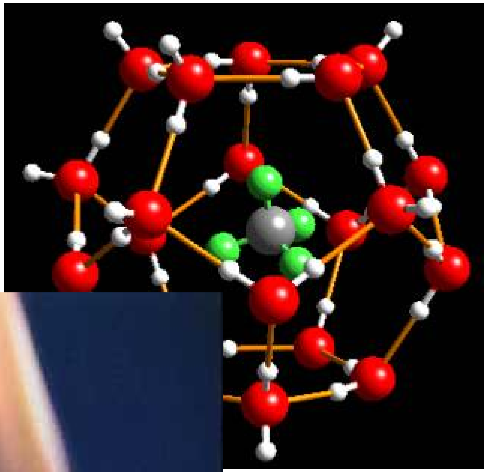
•**A potential geohazard to seafloor and permafrost facilities.**

•**A potentially commercial or strategic petroleum resource.**

•**A potential environmental change agent (e.g. the clathrate gun hypothesis).**

•**A natural gas transportation mechanism that is potentially cheaper than LNG (~21 shipping days).**

GH Structure & Energy Content



•GH is an ice-like solid (clathrate) composed of gas (guest) molecules in a cage of water (host) molecules that forms at low temperature and moderate pressure (shallow depths).

•Secure Storage as a stable solid. Like ice, GHs require energy input to dissociate, which also is the source of “self-preserving” characteristics.

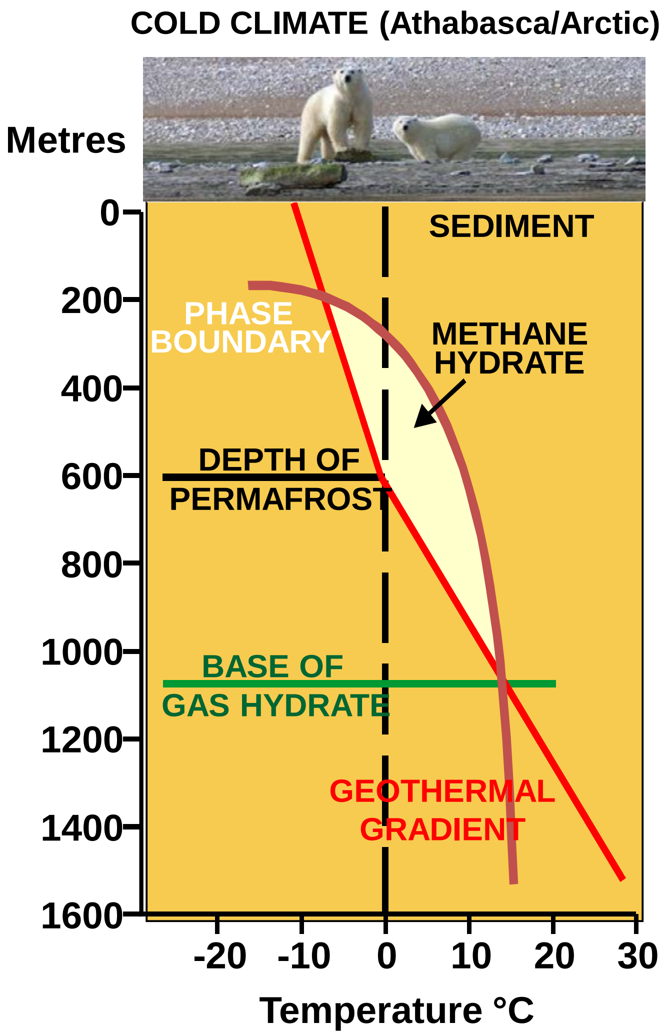
•CH_4 and CO_2 are the common, but not the only guest molecules.

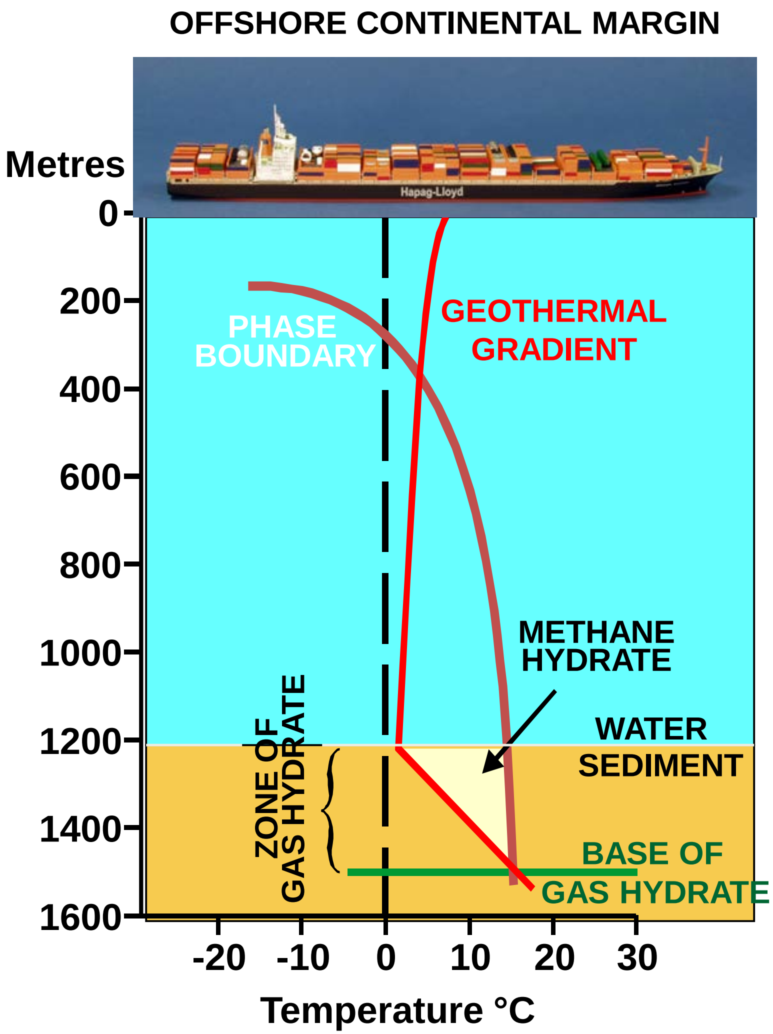
•High storage capacity at shallow depths.

•1 m^3 of GH $\rightarrow$ 164 m^3 of methane gas, equivalent to a dry gas reservoir at 16 Mpa, or a gas pool at 1.6 km depth. Gas hydrate has an energy content comparable to bitumen and tar sands. Energy content in SCF/ft^3 of rock:

- Gas Hydrate: 40 – 50
- Coal Bed Methane: 8 –10
- Tight/Shale gas: 5 –10

GH Stability Conditions





Modes of Gas Hydrate Natural Occurrence

Terrestrial Sub-Permafrost Accumulations

- Common in Arctic regions and identified by drilling.
- Commonly part of a thermogenic petroleum system.
- Thickest, richest, most accessible, potentially associated or co-located with conventional natural gas in porous and permeable reservoirs.
- Preferred North American production target.

Sub-sea Marine Accumulations

- Common to continental shelves and slopes and detected using Bottom-Simulating-Reflections (BSR's).
- Commonly part of a biogenic petroleum system.
- Typically hosted in silt and shale dominated lithofacies.
- Asian production target.

Seafloor Accumulations

- Discrete rich seafloor outcrop accumulations.
- Not well characterized.
- Not persistent due to concentration effects.
- Possible Korean alternate production target.

The potential advantages of Athabasca CO_2 gas hydrate storage include:

- **Lower costs (shorter transport, fewer wells, more efficient storage)**
  - Proximity to the capture facility (<100 km, avoid compression).
  - Using existing gas fields (already environmentally impacted sites).
  - More efficient storage (~120-160 m^3 per $1 m^3$ pore volume) compared to compressed gas (>3 times the initial natural gas volume in-place).

- **Safer and more secure storage as a thermodynamically stable solid** substance resistant to dissociation (avoidance of cap-rock issues for storage, resistant to climate change).

- **Potential collateral technological benefits** that could result
  - engineered hydrate cap-rocks for solvent-based in situ projects,
  - water purification technologies that consume CO2 and reduce tailings ponds sizes.
  - contribution to carbon dioxide-methane hydrate gas production technologies ensuring abundant natural gas supplies for bitumen operations.

- Large potential storage capacity, possibly as much as ~6-7 Gt, or more, of which 3-11 individual gas pools can provide >10 Mt CO_2.

Key Studies Pertinent for Athabasca CO_2 storage as gas hydrate include:

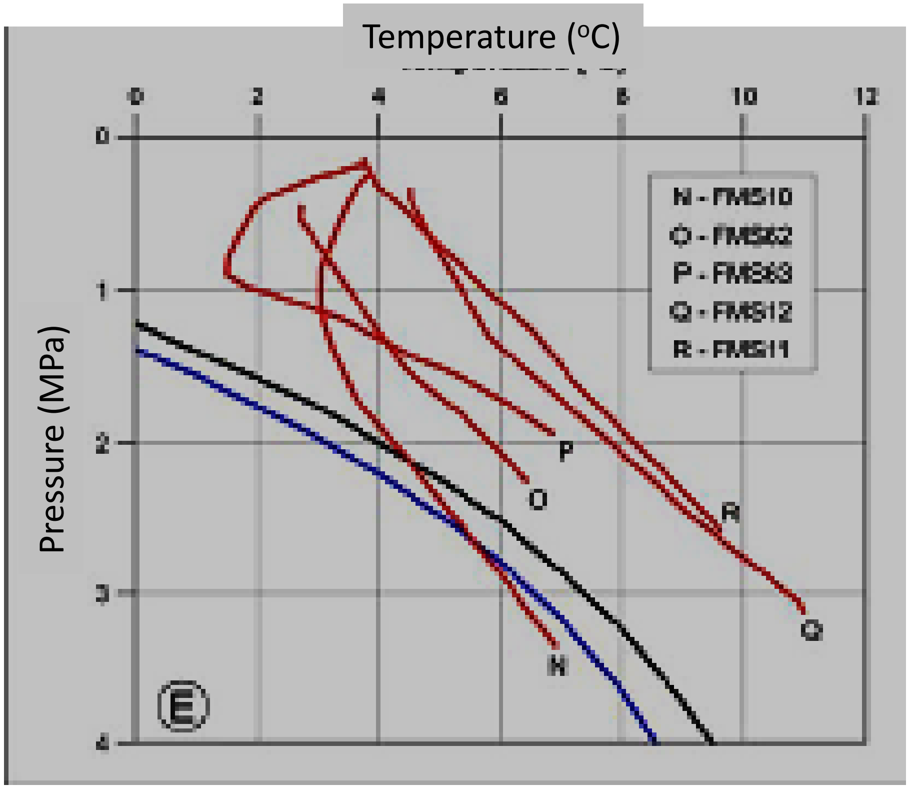
- Potential Gas Pool Storage Potential (Shaw, 2004);
- Regional Aquifer Storage Potential (Cote and Wright, 2010, 2013);
- Reservoir Numerical Modeling of Athabasca Gas Pool Storage (Zatsepina and Pooladi-Darvish, 2012, 2013),

The 3 key studies relevant to CO_2 gas hydrate storage in the Athabasca region have fundamentally different: purposes, data sources and methods, that were used to identify and characterize different Alberta CO_2 hydrate storage options.

The key studies are irreconcilable because the goals, focus and methods of the three studies are so different. Care should be exercised regarding the results of the reservoir model as it did not produce a gas production history match using observe pool parameters.

Key Data for understanding hydrate storage capacity: Temperature profile

- Porous volume within or promotable to the CO_2 gas hydrate stability zone.
- The pore space resource within the CO_2 GHSZ.
- The achievable gas hydrate saturation (S_{gh}) within the pore space that is within or promotable to the CO_2 GHSZ.



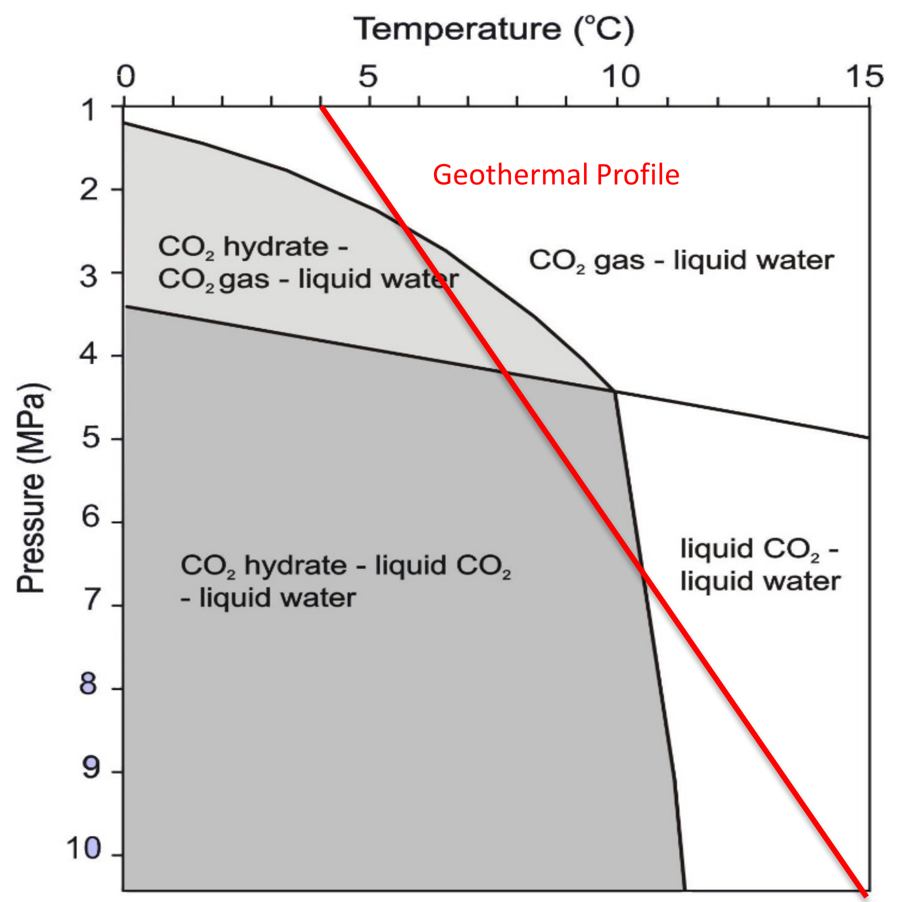
High Precision Athabasca Temperature Logs in a region *where CO_2 gas hydrates were inferred unstable using well log temperatures*. One of the wells indicates ~300 m of CO_2 gas hydrate stability (data from Jacek Majorowicz pers. comm. 2010).

Key Data for understanding hydrate storage capacity: pore space in GHSZ

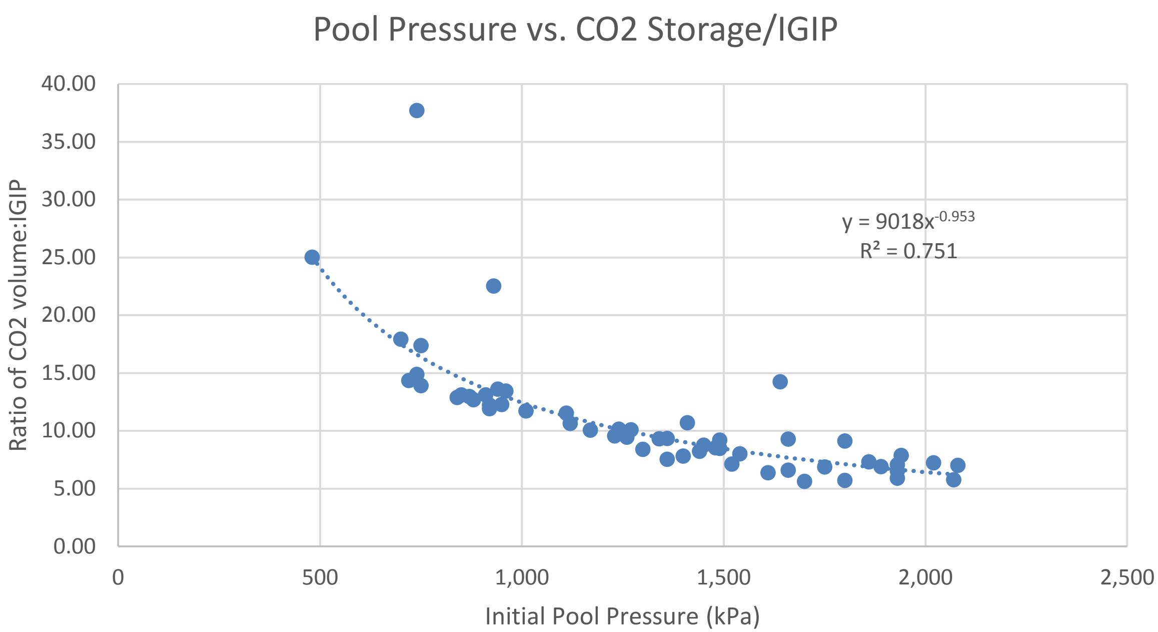
- Earth volume within or promotable to the CO_2 gas hydrate stability zone.

- The pore space resource within the CO_2 GHSZ.

- The achievable gas hydrate saturation (S_{gh}) within the pore space that is within or promotable to the CO_2 GHSZ.



CO_2 gas hydrate storage: uncertainties (S_{gh} is really important)



- We can infer much about the size of the GH storage container, especially considering none of the data were collected with even the remotest though of GH storage.
- The largest uncertainty is the achievable pore space gas hydrate saturation, Sgh. Natural systems reach 90%, but the only available reservoir simulation suggests 15%, using a rudimentary injection technology in a model that did not replicate gas production using known reservoir parameters (i.e. don't take too much from this model).
- Can we do better? Most probably yes and the recent well tests in Alaska suggest why.

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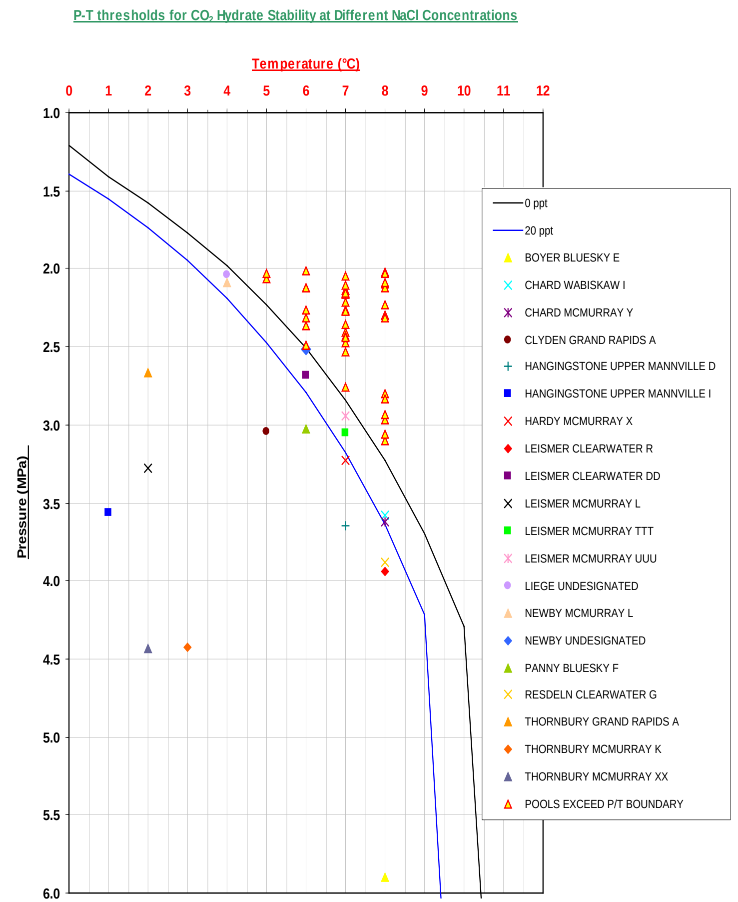
GH Storage

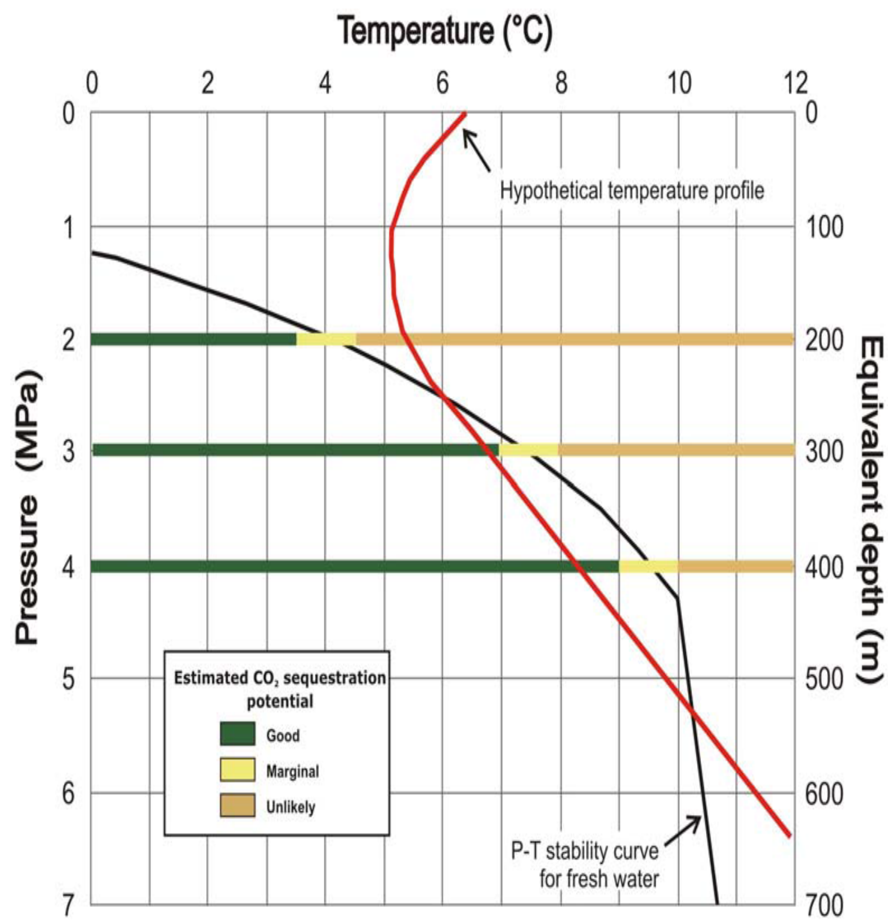
Athabasca CO_2 gas hydrate storage in gas pools:

- 18 Athabasca gas pools are in the CO_2 gas hydrate stability zone (GHSZ) and 38 more could be promoted to GHSZ @ >p.
- Capacity depends on achievable gas hydrate saturation (S_{gh}), which is poorly constrained to be 15%-90%.
- Average CO_2 storage capacity is 3X IGIP @ 15% S_{gh}, but 11 X IGIP @ 54% S_{gh}.
- Depending on S_{gh} the capacity of 56 candidate gas pools is 79-472 Mt CO_2 (284 Mt at 54% S_{gh}).
- The 10-15 largest gas pools contain 81% to 91% of total storage. capacity.
- There are 3-11 gas pools with individual capacities >10 Mt CO_2 if S_{gh} is 15%-90%.



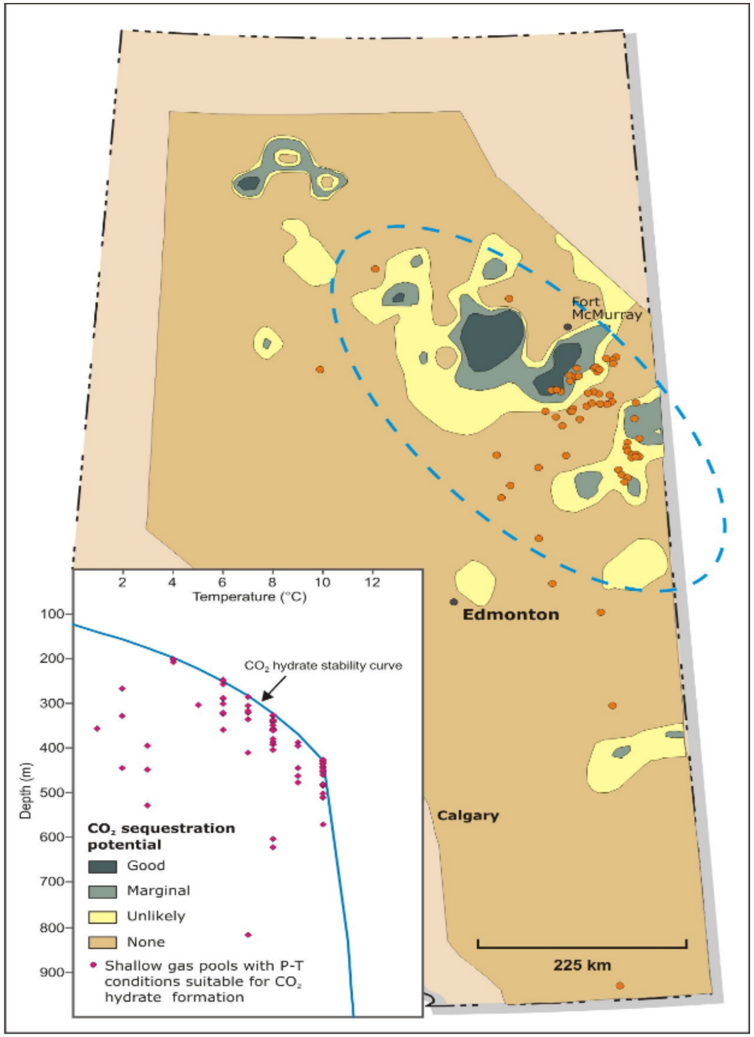
Gas Pools water-leg associated CO_2 gas hydrate storage:

- Typically the thickness of the GHSZ is >200 m if the temperature is > 1-2° C lower than the GHSZ phase.
- Athabasca Mannville gas pool net pays are typically on average individually ~2.5 m thick and average net pay at any location would be ~7.5 m, assuming all three zones are present.
- Athabasca candidate gas pool net pays are 4.1 m net pay and all the candidate gas pools are <10 m thick.
- Most of the GHSZ extends below or on the fringe of the gas pool.
- Associated gas pool water-leg storage is uncharacterized, but knowledge of it could:
  - augment gas pool storage capacity significantly,
  - change the storage size rank of individual gas pools, or
  - it might increase the number of gas pools with >10 Mt CO_2 storage capacity.



Aquifer CO_2 gas hydrate storage:

- Areas of aquifer GHSZ were inferred as a function of "corrected" surface temperature and geothermal gradient. Not a robust analysis.
- Areas appear to be regionally consistent with GHSZ indications from gas pools and petroleum well data, but high precision temperature logging indicates significant aquifer GHSZ, up to 300 m thick, outside of the regions inferred to have storage potential.
- Cote and Wright (2013) inferred 61 Gt of potential storage in aquifers. This equals Alberta saline aquifer storage capacities. They significantly overestimated the available reservoir thickness and so it is more likely that aquifer storage is 6-7 Gt.
- Even so discounted the majority of storage is in aquifers not in gas pools.
- A topic for future study as much storage (maybe ~.5 Gt) is available in gas pools proper.



Containment wasn't always the problem it has become.

<u>It is now avoid</u> this:

Primrose Lake Bitumen Seepage

Photo: CNRL website

<u>It used to be find</u> this:

Atlantic No. 3,

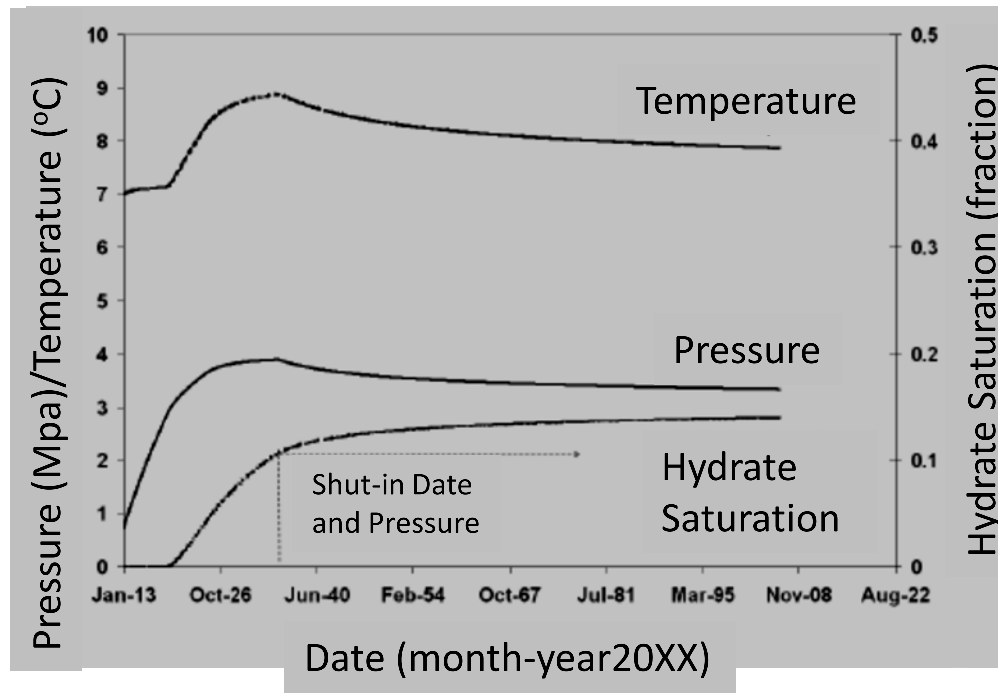
On March 8, 1948 Atlantic No. 3 blew out, flowing oil at up to 15,000 barrels/d for the next 7 months. A historical success, and arguably the most important well drilled in Alberta.

Photo: www.albertaoilmagazine.com/2010/09/

The two examples illustrate the need to discern data categories that identify information pertinent to the risk assessment intended.

Post-injection fate of manufactured CO_2 GHSZ:

- Centennial-scale models indicated that pressure increases from 0.7 MPa to 3.9 MPa resulting from the injection of 0.2 Mt CO_2 per year for 23 years.
- After injection terminated, gas hydrate continues to form during the 71 year shut-in period modelled.
- After shut-in, reservoir pressure declines to 3.3 MPa and the temperature declines by 1.1° C.
- Pressure declines during shut-in in part due to the formation of an additional 247 X 10^6 m^3 gas hydrate.
- As a result S_{gh} increase from 0.10 at the end of injection to 0.14 a century after the project beings.
- Other less detailed calculations suggest millennium-scale stability even if the climate warms (Cote and Wright, 2013).



Long-term (century scale) gas hydrate stability behavior at an Athabasca gas pool as modelled by Zatsepina et al. (2013, their Figure 16).

2011/2012 Ignik Sikumi #1, Alaska

- Flow assurance studies provide much knowledge of hydrate inhibition and promotion using chemical mixtures.
- After 14 days of injecting a mixture of roughly three-quarters nitrogen and one quarter carbon dioxide (as suggested by a Norwegian study) the Ignik Sikumi #1, the produced gas, mainly methane that also contained a higher nitrogen/carbon dioxide ratio than the injected gas.
- Not all of the injected carbon dioxide injected could be produced back indicating that either, primary carbon dioxide hydrate formed in the reservoir, or that carbon dioxide replaced methane in existing hydrate, or both.
- It suggests that the inferred carbon dioxide hydrate is much more stable than methane hydrate and that it is strongly resistant to dissociation.

Next Steps: Recommendations

- Revise the estimates of the pore space resource in the GHSZ using recent data, including a geographic characterization and consideration water-leg augmentations and try to improve the high precision temperature log data set.

- Address the issue of achievable pore space gas hydrate saturation using:
    - Validated and benchmarked reservoir model(s).
    - Consider possible inhibition/promotion technologies either chemical or physical.
    - Conduct a physical pilot to ground-truth the models and test the preferred technology.

- Begin to address the regulatory and public acceptance issues of shallow unconventional storage to prepare for eventual pilots and projects, possibly by joining the CMC Field Research Station program, which also operates at shallow depths.

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Questions