Evaluating technology options to mitigate greenhouse gas emissions

IEAGHG Technical Report 2018-07

IEAGHG Modelling and Risk Management Combined Network Meeting

18th – 22nd June, 2018

EERC, Grand Forks, North Dakota, USA

An IEAGHG meeting, hosted by the EERC

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Attendees of the Modelling and Risk Management Combined Network Meeting, University of North Dakota, Grand Forks North Dakota, June 2018
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Front & Back Cover Images: Network meeting at EERC in progress (Image courtesy of EERC); View of the exposed Badlands and the Little Missouri River valley, Theodore Roosevelt National Park (Image Courtesy of James Craig, IEAGHG); Brine storage tanks at the brine extraction and pressure management test site (BEST) near Watford City, North Dakota (Image Courtesy of James Craig, IEAGHG)

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Delegates view the striking landscape of the Dakota Badlands in Theodore Roosevelt National Park (Photo Courtesy of EERC)

Summary

IEAGHG's combined Modelling and Risk Management Network, hosted by the EERC, took place in Grand Forks, North Dakota between 18th and 22nd June 2018. These meetings bring together leading experts from research and industry to discuss the latest work and developments, with over 30 speakers and 71 attendees representing 8 countries.

The theme for the meeting was 'How advances in modelling and risk management improve pressure management, capacity estimation, leakage detection and the prediction of induced seismicity'. Sessions included project updates, the application of oil and gas production experience, modelling capacity, unconventional reservoir risk assessments and active pressure management. The third day focused on conformance and regulation with a keynote presentation by Lynn Helms from the North Dakota Industrial Commission on Class VI well regulations.

Key findings from the meeting included further refinement for a global capacity estimation methodology needs to be agreed. SPE SRMS provides a solid foundation although further refinement is necessary. Geological heterogeneity still remains very difficult to simulate. The development of models based on a diversity of analogues would improve model predictability. Capillary pressure simulations can help to explain the pattern of CO_2 plume migration better than porosity/permeability simulations alone. Fluid events can now be simulated at pore-scale.

Residual Oil Zones (ROZs) potentially have significant CO_2 storage capacity but field-specific studies are needed to improve predictions. CO_2 has been tested as a fracture/production fluid to extract oil in the Bakken Formation but conformance is a major challenge and further optimisation is required.

Evidence from the Norwegian sector shows ~40% of injector wells have integrity problems. Producer wells are less prone to integrity issues. A Neural-Genetic Algorithm could be a useful method for screening wells in depleted O&G fields as storage candidates. Statistical methods have been developed to rationalize the number of variables that affect wellbore integrity. The technique has been field tested on data from fields with background data on well integrity.

Good progress has been made with CarbonSAFE projects notably the initial stages on the storage potential of the Atlantic Shelf and across Michigan. Probabilistic Risk Maps have been developed which could aid project design.

A comparative study of known leaking and sealing faults in CO_2 traps on the Colorado Plateau has shown that where CO_2 pressure exceeds the fracture gradient then seepage occurs. The research has shown that these criteria apply equally to CO_2 traps and conventional oil and gas traps. Knowledge of reservoir stress changes and fracture closure pressures adds uncertainty to predicting fault and fracture-related leakage. Sophisticated numerical modelling tools are available for predicting fluid flow at faults but building models is difficult, material properties are not well known and few have been thoroughly calibrated.

Micro-seismicity detected at Quest is at very low levels and has no correlation with injection rates or pressures. Large events are extremely unlikely and none of the events represent a risk to containment.

Decatur induced seismicity events range from -2.13 to 1.17 and 95% are 0 or less. ~85% of events are in Precambrian basement.

Pipeline risk assessment needs to include transient multiphase flow models for CO_2. Fluid and thermodynamics within pipelines are tightly coupled. Large-scale experiments (with many effects) are difficult to use for model development. When designing CO_2-transport pipelines against running-ductile fracture, the large forces that CO_2 can exert on the pipe flanks, due to the phase change occurring during decompression, needs to be taken into account.

Active pressure management at basin scale is likely to become an essential tool for carbon storage operations. A single study has shown central injection and pressure management using brine extraction, concentrated in the centre of a basin, may be easier to manage than onsite injections dispersed across the basin. A single study has shown that approximately the same volume of brine needs to be produced as the volume of CO_2 being injected. Consequently large volumes of brine would need to be treated or re-injected in other formations.

Smart reduction in model complexity can gain valuable efficiency without sacrificing accuracy. Integration of geological modelling and simple dynamic pressure simulation are necessary for understanding where to invest in detailed characterization and simulation.

Recommendations from the meeting included: the development and application of more appropriate constitutive models such as anisotropic cap-plasticity models with creep; more research on the relationship between pressure increase and the effects elsewhere on fractures; and further modelling on hydrate formation in or near wellbores if water is present in CO_2.

Session Overviews

Session 1: Welcome

Welcome and Introduction - Thomas Erickson, EERC & James Craig, IEAGHG

Thomas Erickson, the CEO of EERC, opened the meeting by welcoming everyone to North Dakota. He highlighted North Dakota's attitude towards energy resources as an "all of above" strategy which includes wind, hydroelectric power, oil and coal. Thomas also described the role CCS and that it "is critical to the world" and outlined how shale oil production in North Dakota was changing global energy dynamics.

James Craig from IEAGHG outlined the meeting theme of how advances in modelling and risk management improve pressure management, capacity estimation, leakage detection and the prediction of induced seismicity. James thanked EERC for hosting the meeting and all the sponsors for their generous financial contributions.

Session 2: Modelling Capacity at Reservoir and Formation scale — *Chair: Owain Tucker*

Testing the SRMS on Real World Storage Estimates - Owain Tucker, Shell & OGCI

The Society of Petroleum Engineers (SPE) published the CO_2 Storage Resources Management System (SRMS) in 2016 as a modification to the petroleum equivalent Petroleum Resource Management System (PRMS) which is an industry standard system. A variety of authors were involved including Shell with funding from the Oil and Gas Climate Initiative (OGCI).

Modelling capacity is vital to predict storage capacity at reservoir and formation scale. There is currently a need to better understand the micro and macroscopic processes during CO_2 injection and how these impact capacity estimations. Detailed and reliable capacity estimates are required by stakeholders and investors to instil confidence. Currently a variety of methods have been used to calculate various storage capacities at different scales globally. These variations in technique mean comparison between estimates is very difficult. Given the global application of the PRMS the development of the SRMS offers a standardised methodology and an industry standard for CO_2 storage capacity estimations. The SRMS is based on the PRMS and is therefore a two axis system that compares geological uncertainty with maturity in terms of commercial development.

The work included a review by Pale Blue Dot of over 900 storage options already published calculating storage resource. A total of 12,000 Gt was recorded but with varying definitions and different assumed storage efficiency factors. In summary, the SRMS has made an important start in developing categories for estimates and provides a way to differentiate between a high reliability detailed estimate and a broad brush estimate.

A Pressure-Limited Model to Estimate CO_2 Injection and Storage Capacity of Saline Formations: Investigating the Effects of Formation Properties, Model Variables and Presence of Hydrocarbon Reservoirs - Hossein Jahediesfanjan, LynxNet LLC contracted to the U.S. Geological Survey (USGS)

This study investigated the effects of formation properties (e.g. the presence of hydrocarbons in reservoirs) on CO_2 storage capacity estimations. The presentation highlighted the availability of numerous models and the range of estimates produced, due to the different factors used to calculate capacity. For example, in published literature studies of the Mount Simon Formation have a range from 5 to 254 Gt. It was therefore decided that there is a need for a model that produces capacity estimates for deep saline formations (DSFs) based on practical constraints. This study tried to develop a roadmap of how to conduct estimates that incorporated an injection plan including number of wells, their spacing, the injection rate and the brine extraction rate required for a given DSF.

Hossein outlined the USGS model developed and the assumptions used. The Decatur project (Mt Simon Formation) was then modelled. The starting point for the model assumed 1 Mt injected over three years (a cell size of 10x10km could model entire project). The model was scaled-up to represent injection across the formation over periods of 50 – 100 years. Based on this model, the entire saline formation is divided into equal areas that contain a single CO_2 injection area. Each area functions independently with closed boundaries. The centrally placed well has an injection rate that is a function of formation properties, cell size and duration of injection. An exclusion zone is created around hydrocarbon reservoirs with no CO_2 injection allowed. Brine extraction is being modelled to estimate potential additional CO_2 injection capacity using this pressure management technique. This model provides a practical roadmap to estimate each storage assessment unit's (SAU's) CO_2 storage capacity, optimum number of wells, well spacing and injection/extraction rates. This pressure limited model, with no brine extraction, has produced an estimate of 3.5 Gt for the Mt Simon Formation, compared with an earlier estimate of 5 Gt[1].

Modelling Pressure Build-Up due to CO_2 Injection in Saline Formations - Simon Mathias, Durham University

An introduction to the link between injection rate and cost demonstrated that for large numbers of wells (>40), the cost of storing CO_2 is inversely proportional to the injection rate applied to each well. Pressure build up due to injection rate was then described based on the maximum injection rate that can be sustained whilst ensuring that the pressure does not exceed a critical level. This scenario depends substantially on formation properties. Physical controls on pressure build-up were then discussed. Evaporation of residual water and dissolution of CO_2 were shown to reduce pressure build up whereas precipitation of salt increases pressure build up.

Operational storage capacity as a function of maximum allowable cost was modelled as well as the impact of capillary pressure on salt precipitation. It was concluded that CO_2 storage capacity is likely to reduce with declining CO_2 injection rate and the salt precipitate volume fraction is found to be independent of CO_2 injection rate. In conclusion, pressure build-up is reduced by brine evaporation and CO_2 dissolution but brine evaporation also leads to salt precipitation, which leads to a loss in permeability and an increase in pressure build-up. Also, low injection rates lead to counter current flow, which delivers more salt to the dry-out zone, leading to more salt precipitation.

Characterization and Capacity Estimation of Potential CO_2 Storage Sites on the Norwegian Continental Shelf - Eva Halland, Norwegian Petroleum Directorate

The Norwegian CO_2 storage atlas was published in 2014 and was conducted to inform the government on potential CO_2 storage capacity on the Norwegian continental shelf. To date a total of 27 formations have been evaluated and grouped into aquifers using the UNECE-SRMS classification system. The current status of CO_2 storage in Norway includes two active projects (Sleipner and Snøhvit) and there is the potential for full-chain large-scale CCS in the near future with the Northern Lights project.

[1]Zhou Q, Birkholzer JT, Mehnert E, Lin YF, Zhang K. 2010. Modeling basin- and plume-scale processes of CO_2 storage for full-scale deployment. Groundwater 48(4): 494–514

The Farsund and Bryne/Sandnes Formations storage capacity estimations were discussed. An example of CO_2 storage site characterisation was given using the Garne/Ile aquifer. Data quality and maturation were discussed. In total three capacity maturity pyramids have been produced for the North Sea, Norwegian Sea and Barents Sea. The largest indicative capacity has been estimated for the Utsira – Skade and Bryne – Sandnes Formations within the North Sea Basin of the Norwegian sector.

Session 2: Discussion

The biggest challenge to creating robust capacity estimates at formation and aquifer scale is defining one common system to calculate capacity and knowing how much storage is required. Another significant challenge is geological heterogeneity, especially at finer scales. Characterisation can be problematic in terms of defining what is present in the reservoir. The representation of heterogeneities in numerical models is still a significant challenge.

Defining an appropriate range of boundary conditions, especially for DSFs, for use in modelling remains a challenge (for example using open or closed boundary conditions makes a big difference). There is a need to know what the limits are and how these boundaries constrain capacity, such as the protection of fresh water sources and limits imposed by faults. For example, why do models assume open boundary conditions in the knowledge that there are limits to a reservoir. Better justifications are needed for some of the assumptions currently being made. Unevaluated prospects could have good storage potential and it should not be assumed that they lack storage capacity. Overall there is an improvement in understanding the influence of pressure but dynamic modelling and the incorporation of heterogeneities still presents significant challenges.

The distribution of capacity at a regional scale is important and there is a need to take into account non-net factors. Local calculated estimates are very different to regional estimates. The capacity pyramids also need to be handled carefully. There is not necessarily a lack of capacity, but a lack of projects. More analogues are necessary to refine predictions bearing in mind each site has unique characteristics.

Source matching and the economic viability of projects also needs to be taken into consideration when estimating capacities. These are difficult elements to incorporate but need to be taken into consideration. Areas with coal and steel reserves (and therefore the related industries) now have the majority of industrial CO_2 sources and the association of these areas that have significant storage resource needs to be understood.

Injectivity also needs to be taken into consideration, however, the vast majority of global resource (12Tt estimated worldwide) is based on limitations from plume migration and residual trapping. More analogues are needed to develop experience and to progress model development.

Session 3: Upscaling Core to Reservoir – Link to Predicting CO_2 at Reservoir Scale — *Chair: Sam Krevor*

Characterising Core-Scale Heterogeneity, Links from the Pore Scale and Implications for Larger Scales - Sam Jackson, Imperial College London

Unexplained CO_2 plume migration has been poorly predicted at several sites by conventional multiphase flow simulations. This could be attributed to small heterogeneities at nano-scale causing variations in capillary pressure leading to large variations in CO_2 saturation and therefore variations when up-scaled. Imperial College has been conducting experiments to investigate whether CO_2 can become trapped residually and by local heterogeneities by studying capillary effects.

Small heterogeneities can lead to large variations in saturation when the capillary number is very low, which is different to what would be predicted at the viscous limit case. Variation in saturation can have an impact on upscaled heterogeneity. During laboratory experiments this effect has been observed in many different scenarios.

Three UK North Sea samples (Bunter, Captain and Bentheimer) were selected and characterisation started with core flooding experiments. The second step was to establish capillary pressure heterogeneity via low rate core flood experiments. This approach can be used to parameterise imbibition with core flood observations of residual trapping.

There were implications for larger-scale projections when these processes were applied to the Captain Sandstone at Goldeneye. Capillary pressure simulations can explain patterns of CO_2 plume migration better than porosity and permeability simulations alone.

In conclusion, at a large scale, lateral plume migration speed can be enhanced by up to 20% due to layering in the capillary pressure. CO_2 total storage and efficiency is controlled by heterogeneity and hysteresis. This could explain why early breakthrough is found at several injection sites where the capillary number is expected to be low. Capillary pressure heterogeneity is not conventionally accounted for in large-scale modelling, but is the underlying cause of these phenomena.

A Data-Driven Approach to validate and Improve Pore-Scale and Implication for Larger Scales - Tom Bultreys, Imperial College London

Calculating relative permeability from pore-scale fluid arrangements can reduce measurement time and therefore reduce costs, reduce constraints on core material volume and enhance insight into why relative permeabilities behave the way they do. Relative permeabilities can have complex behaviour and at small-scales can have large impacts.

X-ray micro-computer tomography (CT) scans are used to provide images of pore-scale configurations that can be used to build models of interconnected pores. Models can then be compared with actual samples. The fluid migration can be measured and simulated at pore-scale and then fed into larger-scale predictions.

In conclusion, to reduce uncertainty a data driven approach to pore-scale modelling is required but needs to take into account the semi-stochastic microscopic properties of the fluid distributions. Connectivity needs to be taken into account during validation. Generally flow paths made good matches during drainage but not with imbibition.

Session 4: Untraditional Reservoirs and Modelling Risk — *Chair: Neil Wildgust*

Assessing CO_2 Storage and Oil Recovery Potential from Residual Oil Zones - Rajesh Pawar, Los Alamos National Laboratory (LANL)

Residual oil zones (ROZs) are defined as zones where oil exists at residual saturation, where oil has been swept naturally due to background water flow over geological time scales. ROZs are increasingly being exploited commercially using CO_2-EOR, for example there are current ongoing commercial field operations in the Permian Basin.

ROZs could potentially be used for CO_2 storage with the side benefit of oil recovery. The sites tend to have similar characteristics to saline reservoirs with thick target intervals and high porosity (so could potentially store large amounts of CO_2). The information that is needed for estimating capacities is still limited.

LANL , though US-DOE funding, have characterized CO_2 storage and oil recovery potential as well as CO_2 fate utilizing numerical simulations (using an Eclipse compositional simulator). The reservoir model was based on data from the Goldsmith-Landreth San Andreas Unit. Simulation observations showed that the CO_2 retention and oil recovery vary non-linearly with the amount of injected CO_2 and that higher CO_2 retention and oil recovery are observed with single five-spot well configurations compared to multiple five-spot distributions.

Results from the simulations concluded that ROZs are potential unconventional CO_2 storage targets although, in spite of increased commercial CO_2-EOR operations in ROZs, critical understanding needs to be developed for CO_2 storage and oil production mechanisms as well as the long-term CO_2 fate and associated risks. There is currently a lack of appropriate data and a large uncertainty still remains. Numerical simulations have been used to identify key characteristics as well as the development of empirical models for quantifying preliminary CO_2 storage capacity, and oil recovery potential, in ROZs. Overall, ROZs potentially have significant CO_2 storage capacity but field-specific studies are needed to improve predictions and predictive capabilities.

Thick Siliciclastic Brownfield ROZ: Modeling Development Strategies for CO_2-EOR and Storage - Scott Frailey, Illinois Geological Survey

A geological conceptual geo-cellular model was undertaken on the ROZ potential in the Thick Cypress Sandstone as part of a project funded by US DOE/NETL. One of the aims was to develop CO_2-EOR field strategies and look at the economic viability of using ROZs for storage.

The geological characterisation showed the sandstone was deposited as part of an incised valley system with stacked, interconnected beds. Case 1 modelled simultaneous injection into the main pay zone (MPZ) and the ROZ which is still regarded as the best scenario. Other variations allowed for CO_2 and/or oil to move.

The work concluded that CO_2 distribution is controlled by the process of oil displacing water, and water production. In the presence of a MPZ the challenge is to inject and store CO_2 throughout the ROZ and EOR zones. Also, favourable water mobility at a ROZ counters the CO_2 buoyancy, but gravity override prevails. The model also demonstrated that the oil bank has lateral and downward movement and it is a challenge to minimize its downward movement. Two water and two oil banks were formed. The first water bank is related to oil displacement, the second water bank is related to CO_2. MPZ oil recovery is similar to conventional CO_2-EOR but ROZ CO_2-EOR is 40-50% of the MPZ CO_2-EOR. ROZ CO_2 storage efficiency is 15-45% of the MPZ and ROZ net Utilization is 2-3 times the MPZ.

Identification of Residual Oil Zones in the Williston and Powder River Basins - Matt Burton-Kelly, EERC

This work was funded by the US DOE with the objective of identifying and characterizing the presence of potential residual oil zones (ROZs) in the Williston and Powder River Basins. The primary objective was to identify potential ROZs, estimate the residual oil in place, and determine the feasibility of CO_2-EOR and estimate the associated CO_2 storage potential. The development of a repeatable methodology applicable to other sedimentary basins was an additional objective.

Basin evolution modelling was undertaken (using Schlumberger PetroMod) to provide a record of the evolution of the target petroleum system. Potential ROZs identified through the basin modelling approach could yield 32–90 million barrels of recoverable oil through CO_2-EOR and 10–100 Mt of CO_2 in associated storage. Fine-scale modelling of CO_2-EOR simulation was performed on an interpreted ROZ in two Williston Basin Mission Canyon fields with known hydrodynamic influence. A 640-acre (2.6 km^2) "sweet spot" was selected from each ROZ. Primary production (with no significant oil) followed by continuous CO_2 injection into 16, 40-acre (~0.16 km^2) (five-spot patterns (16 injectors, 25 producers)).

The study concluded that the scale and detail of input models are important and automated facies modelling (neural networks) may help attenuate purely structural hydrocarbon migration and locate stratigraphic traps. There is a tradeoff between detail and time spent building the model. PetroMod simulation time also needs to be taken into consideration with regard to finer scale modelling. The approach developed in this project will work at any scale and any type of ROZ but modelers should always be aware of the 'garbage in - garbage out' scenario. There were large effects from inputs that affect generation and migration masses and irreducible oil saturation.

CO_2 Storage and Enhanced Recovery in the Bakken Unconventional Tight Oil Formation - James Sorensen, EERC

'Tight' formations are characterised as having extremely low permeability (<0.1 mD). The vast majority of Bakken oil production is from low-permeability siltstones, sandstones and carbonates where horizontal wells and hydraulic fracturing are necessary. Modelling was undertaken to estimate the amount of CO_2 required to realise Bakken oil using EOR. A huff and puff test was modelled with injector-producer pairs and nine different scenarios.

The modelling results were then compared with field injection test results from five publically available records. The improvements in oil recovery predicted by the model were not observed in the injection tests to date and gaps still remain between the modelling and reality in the field. A better understanding of the fundamental properties affecting CO_2 interactions with "unswept" Bakken reservoir is needed.

The EERC have recently undertaken the "Bakken CO_2 Storage and Enhanced Recovery Program field injection test", which was an injection test undertaken for 5 days in June 2017 where 98 tons were injected. Injection was tested in a vertical well to generate more real world data. The field test validated observations made in the laboratory with evidence that CO_2 mobilized oil and was stored in the reservoir matrix.

Session 4: Discussion

Unconventional reservoirs, and their potential for storage, are regularly discussed within the CCS community. EERC explained that since the test in the Bakken the industry has been undertaking additional tests. The current challenges are managing the reservoir and injection conformance. There are different strategies for managing pressure for example optimising production from drill spacing units (DSUs). With injection in the right wells at the right times, to produce, soak and move fluid around within DSUs it is possible to manage reservoir pressure and fluid movement. There are suggestions this can be a very effective method having been conducted with natural gas. Fundamentally, organic-rich shales have the potential to absorb a lot of CO_2 and could, therefore, have large storage potential.

Session 5: Modelling and Pressure Management in the Near Wellbore Environment — *Chair: James Craig*

Review/Update of Near-Wellbore Flow, Thermal, and Geochemical Issues - Curt Oldenburg, Lawrence Berkeley National Laboratory

A review on near-wellbore processes was presented looking at thermal and geochemical processes and effects in the near-well region as well as near-well issues for injection versus withdrawal.

Overall, the well communicates with the reservoir through perforations, and the damage-like zone is outboard of the perforations. The near-well region is dominated by high flow rates and single-phase conditions. Expansion cooling has not been seen to be a problem for injectivity but expansion cooling during the production of CO_2 can be problematic.

Effect of Intermittent CO_2 injection on Well Integrity and Injectivity - Malin Torsæter, SINTEF

A large area of interest in Norway at the moment is the requirement for scaling up each CCS process to reach commercial scale. As wells can never be removed integrity needs to be secure for long time periods. The causes behind well failures are one of the research areas that SINTEF has focused on.

Intermittent supply of CO_2 typically caused by disrupted supply during unloading from a ship, or well intervention for repairs, has implications for well integrity. On-off injection leads to cyclical heating and cooling causing the casing to expand more than surrounding materials. This condition causes radial and hoop stresses in cement and can cause both debonding (between the cement and the casing and/or rock) or disc and regular fractures. Both of these effects can result from thermal changes. This can also have an impact on nucleation conditions (e.g. salt) and borehole deformation. Intermittent injection will affect both well integrity and injectivity. The research-based advice is to avoid extensive pressure testing of annular barriers, ensure robust well construction, and minimize thermal cycling (through choice of injection parameters and well materials/fluids). Also, salt precipitation and borehole deformation are likely to occur in injection wells. The average time for problems to occur is approximately two years if wells are being operated outside their initial design envelope. There is a strong dependence on the quality of cementation.

The Value of Real-time, Continuous Wellhead to Bottom-Hole Temperature and Pressure Measurements for Dynamic CO_2 Injection Conditions – the Aquistore Experience - Gonzalo Zambrano, University of Alberta

A summary of the Aquistore project to date (June 2018) was presented including instrumentation on the injection and observation wells and an overview of the geology.

Downhole camera observations were used to look at precipitation occurring. The camera was run in May 2017 (exposure value (EV) was run at 15 – 15 frames / second, 43 mm OD). Some of the footage recorded was shown at the meeting which revealed some areas of precipitation forming inside the casing.

Overall, Aquistore has, and will continue to contribute, significant science-based evidence in support of safe and effective implementation of the geological storage of CO_2 in association with coal-fired power generation. The project specifically and more generally shows that measurement, monitoring and verification (MMV) technologies can be effectively deployed to demonstrate injectivity, conformance and containment performance metrics under complex and dynamic operating conditions.

Session 5: Discussion

The confidence in wellbore integrity still depends on whether it is a new or an old well. For new wells there is confidence in the materials to use and how to design cement completions. The issue with old wells is the history of production and issues associated with cyclical operations. Moreover the adaptation of old wells for a different use invariably means that the original design is not optimised for its new function.

There is a reasonable amount of confidence with regards to the near wellbore processes including thermal effects and compositional flow. Discussion with regulators over these processes, and related issues, should not be an issue. However, more research is required to asses these complex processes. Fracture pressure models need further refinement.

Session 6: Leakage: Modelling and Monitoring — *Chair: Jonathan Ennis-King*

Time-lapse Cross-well Pressure Tomography for Monitoring CO_2 Plumes and Detecting Leaks: Efficient Approaches to Inversion - Jonathan Ennis-King, CSIRO

Stage 3 of the Otway Project is currently trying to reduce the cost of subsurface monitoring and increase the efficiency of new CO_2 monitoring techniques. CO2CRC aim to deliver a permanently deployed cost-effective subsurface real-time monitoring solution for industry. Three probable monitoring techniques are to be investigated: pressure tomography; cross-well seismics; and electromagnetic surveys.

There are two options for pressure monitoring, passive or active. Pressure tomography is an active technique using time-lapse detection of CO_2 from response to water injection. Modelling was undertaken to look at the potential for pressure tomography at Otway. The proposed well spacings in the model were adequate for signal detection but it was concluded that it is better if wells are outside the predicted plume for pressure tomography techniques. Early time cross-well response contains most of the information within four to five hours of water injection. Some 'quiet time' is needed between injections so cross-well responses avoid overlap. Harmonic or pulsed injection should also be tested.

Pressure tomography should be feasible for the Otway Stage 3 but the CO_2 plume is best modelled by a nonlinear hybrid model, rather than effective diffusivity or constant pressure. Efficient inversion can be done by adjoint methods (voxel based) or object models. The aim is to detect and locate the plume, not to 'image' the plume. The cost of wells implies the need to extract the greatest value for monitoring from the smallest number of wells, but more than 2 are required.

Pressure Transient Techniques for Continuous Monitoring of CO_2 Storage - Mehdi Zeidouni, Louisiana State University

Three techniques were discussed to monitor and analyse pressure in a CO_2 storage complex. The first technique is to use 2 wells to conduct an interference test. The second is to have an injection well within the plume and inject water and observe the pressure arrival time at a second and third well. The third method required just one well to conduct a pressure test.

The work concluded that the pressure influence time is inverted to obtain the CO_2 saturation on a line connecting an observation well to an active well. The pressure influence time was found to be independent of plume location. Pressure arrival times at observation wells were used to obtain average CO_2 saturation and location of the plume boundary. A single-well pressure test has been introduced to obtain the distance of a CO_2 plume from a given well.

Application of NRAP's Integrated Assessment Model to Determine Risk-Based Area of Review - Signe White, Pacific Northwest National Laboratory (PNNL)

The National Risk Assessment Partnership (NRAP) have developed a suite of tools designed for quantitative risk assessment of geological CO_2 storage. For this study existing datasets from the FutureGen 2.0 project were used to determine whether these tools can be used to develop a risk-based methodology for delineating the Area of Review (AoR) for a CO_2 storage project.

The AoR is the area surrounding the injection point for a project where other resources for example groundwater may be potentially impacted. The AoR is a project risk area which needs to monitored. The AoR is defined by the maximum extent of the CO_2 plume and pressure front over the lifetime of the project where the risks associated with both CO_2 and/or brine leakage into the overlying groundwater aquifer must be accounted for.

The pressure front is defined at the critical pressure than can cause fluid flow from the injection zone through a hypothetical conduit. This depends on whether the reservoir is under-pressurized or at a hydrostatic condition. US Environmental Protection Agency (EPA) guidance refers to the determination of "an allowable pressure increase" that causes fluid leakage. This is calculated based on multiphase numerical model design for wellbore leakage and a numerical or analytical approach to determine a threshold value above which impact to aquifers occurs.

The NRAP tool OpenIAM was used to make plume and pressure predictions for the FutureGen2.0 project. Open wellbore leakage assessment and evaluation of aquifer impact. The area of aquifer impact analysis using OpenIAM provided a risk-based AoR estimate for a geological sequestration site. The area of aquifer impact based on changes in pH was found to be equivalent to the plume footprint but the area of aquifer impact based on changes in total dissolved solids (TDS) is smaller than the large AoR determined with critical pressure of 10 psi (69 kPa). This current analysis is based on a single reservoir simulation and will be expanded to be based on all 32 reservoir simulations.

Session 6: Discussion

The application of pressure tomography could use water extraction as effectively as injection. The only caveat for the use of extraction is the location of the plume. It is possible that there is the potential for CO_2 back production if it is near the monitoring well which would change the symmetry of the system.

Another discussion explored an open well concept. Even 80-90 year old wells are left with mud still in place, but they are not regarded as open conduits. An alternative approach would be to look at the shear strength of the mud that would need to be overcome and use that parameter instead. It was agreed this could be a good approach.

Session 7: Bayesian Modelling in Risk Assessment and Management — *Chair: Rajesh Pawar*

Bayesian Method Applications in Risk Management at Geologic Sequestration Sites - Ya-Mei (Cheryl) Yang, NETL

For the first time in a network meeting, Bayesian methods applied to risk management and modelling were discussed in a series of presentations. Bayesian methods set out with a predicted statistical analysis (prior probability) and then modify predictions with the integration of observed data (posterior probability). In situations where there is limited data Bayesian methods allow existing background knowledge or judgment to be applied as a means of investigating uncertainty and risk. With new data risk assessments and the analysis of uncertainty can be adapted.

In summary Bayesian methods allow incorporation of human knowledge and judgment given limited or unavailable observations (data). The variety of applications using Bayesian methods in CO_2 storage includes the occurrence of risk events, anomaly detection, event source locating, risk-based monitoring design, system-level risk assessment and management and risk treatment evaluation. An example currently being worked on is mapping bow-tie methods into Bayesian network using Quest project data.

Improving Risk Analysis Precision for Geologic CO_2 Sequestration by Quantifying the Uncertainty Reduction Before and After Acquiring Monitoring Data - Bailian Chen, Los Alamos National Laboratory (LANL)

This first part of this study looked at monitoring design and the value of information before data is acquired. The objective is to determine the optimal monitoring strategy from a set of proposed scenarios by quantifying the expected uncertainty reduction in risk metric (which is cumulative CO_2 leakage).

Data assimilation was then addressed looking at how to effectively use monitoring data to reduce the uncertainty in predictions and risk metrics (e.g. CO_2 leakage, AoR, plume mobility, etc.). The expectation is that uncertainty within the AoR, and mobility, will be reduced by assimilating monitoring data. The impact of this approach may change the decision on field operations.

Observations from the modelling concluded that the filtering and uncertainty reduction based approach can be used as an efficient tool for selecting the optimal monitoring design. The Ensemble Smoother with Multiple Data Assimilation (ES-MDA) performs well on assimilating monitoring data to calibrate the reservoir model and reduce the uncertainty in predictions. Ongoing work includes the plan to bring in metrics (plume AoR, plume mobility, etc.) to quantify uncertainty reduction by assimilating monitoring data and to apply the method to a field example, the Rock Spring Uplift storage site in southwestern Wyoming.

Prediction of CO_2 Leakage Risk for Wells in Carbon Sequestration Fields with an Optimal Artificial Neural Network - Andrew Duguid, Battelle

The overall objective of this project was to develop a novel computer model for predicting long-term leakage risks for wells exposed to CO_2. This involved identifying likely leakage scenarios for specific wells (injection wells, producing wells, and abandoned wells) to understand the major leak mechanisms under different well conditions. Also, the development of a neural-genetic algorithm model to predict leakage risks for CO_2 – exposed wells using common well construction and operation data. Finally, the verification of model results with field sampling data including side wall cores samples, pressure testing data, and well logs for existing wells.

Well data was collected from the Oyster Bayou oilfield, Hastings West and Cranfield Fields including construction details, operation details and maintenance history. None of the wells were identified as leaking by the operator but 72 parameters were collected for each well and compiled into a database for modelling analysis. Application of the analytical and numerical stress models of the wells in the West Hastings Field and the Oyster Bayou Field allowed for identification of wells with an increased risk of leakage. In the West Hastings Field, 10 wells were identified to be higher risk due to fluid injection with over-pressure (above Maximum Permissible Pressure (MaxPP)). In addition, four wells were found in the condition of under-pressure (below Minimum Permissible Pressure (MinPP), which can cause failure of the cement sheath. In the Oyster Bayou Field, well pressures were found to be lower than the calculated MinPP for most wells. These wells are subjected to shear failure of cement sheaths and possess a high risk of leaking in dynamic injection conditions.

The Integrated Neural-Genetic Algorithm (INGA) was tested for accuracy and converging efficiency against data dimension and sample size. It was found that the algorithm was slow and unfeasible for processing the data set obtained from the 510 wells. The controlling factor is the large number of independent variables (72 well design and operating parameters affecting leak probability). A statistical model was developed using the Integrated Neural-Genetic Algorithm (INGA) with a data-dimension reduction mechanism. This mechanism makes the well leakage probability as a function of four indicators that are based on some of 72 well parameters before data processing. The developed statistical INGA model was trained with the LPI ((Leakage-safe Probability Index) which is based on an average of the four key indicators) data for the wells in the West Hasting Field and the Oyster Bayou Field. The model output matched the ample data with a relative error of 0.51%.

Combining Environmental Statistics and Marine Process Modelling to Design Monitoring Programs for Offshore CCS Storage - Guttorm Alendal, University of Bergen

Horizon 2020 have funded a STEM-CCS project (http://www.stemm-ccs.eu) which will conduct a controlled CO_2 release experiment in 2019 from within sea-floor sediments near the Goldeneye Platform.

The objectives of this work will be to develop a robust environmental baseline assessment methodology under "real life conditions". It will also implement methods for constraining the natural and anthropogenic induced CO_2 permeability of the overburden in offshore CO_2 storage sites and develop a suite of cost effective tools to identify, detect and quantify CO_2 leakage from a sub-seafloor CO_2 storage reservoir. During the release experiment the applicability of artificial and natural tracers for detection, quantification and attribution of leakage of sequestered CO_2 in a marine environment will also be assessed. STEMM-CCS will also model and assess impacts of different reservoir leak morphologies and provide decision support tools for monitoring, mitigation and remediation action.

As part of STEMM-CCS Heriot Watt have also undertaken simulations of air and CO_2 dispersion through sediments by AND2P model as a test case for demonstration. Plymouth Marine Laboratory have also undertaken pH trend modelling and collected data on background variability. There are significant challenges working with a temporal and spatially varying signal from an unknown source in a highly variable environment. The models need data for verification and validation plus quality assurance. Their outputs are essential for predicting the effects of actions and long-time trends and simulating scenarios that are difficult or beyond anticipated operational conditions. Further insight into marine processes might be gained from models with additional data. Models can assist through experimental and monitoring design, impact and risk assessments and data analysis.

In summary, assurance monitoring is an intrinsic part of any storage project. A project team needs to have a multifaceted picture of a storage site, collect data, and build a baseline. A number of process models allow for a set of footprint predictions to be made. Decision tools, with uncertainties, and metrics are required.

Session 7: Discussion

The difficulty of developing a good baseline was discussed. There is a lack of good baseline conditions in marine environments where pH conditions fluctuate spatially and temporally. Attribution of pH, and other properties, needs to be distinguished to determine whether it relates to a genuine leak or a natural source. There was a consensus that many different measurements of different parameters will be needed to compile a baseline, for example, changes in oxygen levels. Different chemistry and the effects of currents need to be taken into account. For example the ability to make a distinction between a CH_4 bubble from a CO_2 bubble.

The development of an ocean global baseline dataset is currently being explored and the different ways of compiling it. Data sharing is highly beneficial. CCS projects should make used of other experts and previous baseline data. The possibility to ask other experts to collect information which could be shared for CCS purposes is being considered.

Sharing probability estimates with regulators was also discussed. Uncertainty and probability are not widely understood or appreciated. Some stakeholders react to a single metric without considering the concept of uncertainty or levels of uncertainty. There is a necessity to develop ways to communicate uncertainties and risks especially to regulators and other key stakeholders.

Evaluating Risks for CO_2 Storage for Early Stage Projects - Neeraj Gupta, Battelle

Two examples of early stage projects were presented. The goals for risk assessments at early stages are: to assess suitability of a reservoir for CO_2 injection at industrial scale, rates and volumes; assess storage security to ensure CO_2 is contained within the intended reservoir volume; screening out high-risk areas; identify performance and safety risk items; evaluate key regulatory issues; provide guidance on injection system design, monitoring and develop stakeholder; and produce a public acceptance strategy.

The first was a pre-project stage assessment from the Mid-Atlantic US Offshore Carbon Storage Resource Project which focused largely on the identification of sources of risk during the regional assessment stage. The seismic and wellbore data collected and characterisation methods were discussed the results of which will serve as inputs for prospective storage resources and storage efficiency calculations.

The second example was a pre-feasibility stage assessment for the CarbonSAFE projects which performed a qualitative risk analysis and evaluated the capability of NRAP tools. A site screening analysis was performed and the evaluated risk factors included AoR, wellbore integrity and above-ground access issues.

Risk analysis activities definitely help focus system design, the monitoring program and site characterization for early stage carbon storage projects. Site specific data and field testing allows for more realistic risk analysis.

Overview of Various Methods for Treating Uncertainties and Guiding Decision Making in the Early Stages of a CO_2 Geological Storage Project - Thomas Le Guénan, BRGM

At BRGM, work has been conducted on various tools for managing low volumes of data and large uncertainties. With the objective of "keeping the models as objective as possible". There are several challenges, and thus several tools to face these challenges. The first challenge is dealing with subjectivity of experts and finding a way to aggregate expert opinions on modelling options. The concept of possibility and comparison of it to probability is introduced. Possibilities can be understood as a sort of "envelope" for all possible probability distributions. The second challenge lies in the representation of the uncertainties without making too strong hypotheses. Here again the focus will be on what possibilities can provide. The third challenge is propagating these uncertainties from the input of the model to the output. Possibilities are less known than probabilities but there are ways to propagate this kind of uncertainty in combination with probabilities. Finally once these large uncertainties have been ascertained the next challenge is to handle them in decision making.

There are some practices where it is possible to make decisions in the presence of large uncertainties and some of these will be reviewed. If the decision consists in prioritizing the subsequent characterization campaigns, then the correct tool in this context is sensitivity analysis. Given model outputs the input criteria which are most important and should be preferentially selected for characterisation.

A Risk Map Methodology to Assess the Spatial and Temporal Distribution of Leakage into Groundwater from Geologic Carbon Storage - Erica Siirila-Woodburn, LBNL

The aim of this work is to develop a risk-based approach to determine the area of review (AoR) but building on a 3-tier methodology to define the AoR proposed by Birkholzer et al. (2014)[2]. Tier 1: CO_2 leakage risk; Tier 2: Open borehole brine leakage risk; Tier 3: plugged and abandoned (P&A) wellbore brine leakage risk. The goal is to understand and quantify brine leakage risks from P&A wells to define Tier 3 AoR. Risk definitions are based on an adverse change of underground sources of drinking water (USDW) water quality due to brine leakage based on a metric of water quality. Finally, the work aimed to define the adverse impact on water quality in the USDW by an increase in brine concentration above background level or some other limit. Then, either a volume or an area of impacted water (Vimp) above some threshold is used to determine the probability of risk.

[2]A tiered area-of-review framework for geologic carbon sequestration. Jens Birkholzer, Abdullah Cihan, Karl Bandilla. Greenhouse Gases Science and Technology, Wiley Online Library, 2014

The work has been summarised with a probabilistic methodology to compute "risk maps" of Tier 3 (P&A wellbores brine leakage). This approach balances fidelity and computational cost. An example demonstration shows that the importance of well permeability distribution dramatically affects the risk of brine leakage through P&A wells in Tier-3 zones. The next steps include continued sensitivity analyses and utilization of the methodology in a more complex system (e.g. at the Kimberlina site) and the integration of USDW heterogeneity.

Session 8: Discussion

The discussion centred on how risk assessment methods can be approved by using approaches that are more computationally efficient compared to the conventional 'monte carlo' approach. Economic factors are another key to the decision making process in the early stages of projects and efficiency and time savings are important to that.

A key element is how to test advanced risk assessment methods with regulators and other stakeholders and determining how should this be implemented. For example should these methods be tested at a workshop for regulators?

The value of information is a key consideration. It is an important element to consider and contributes to managing risk. Work still needs to be undertaken on how this needs to be integrated into the decision making process and the value of new data versus the cost of collecting it.

Session 9: Risk Management Approach for Fault Properties & Induced Seismicity *Chair: Thomas Le Guénan*

Effective Stress Constraints on Vertical Flow in Fault Zones: Learnings from Natural CO_2 Reservoirs - Steve Naruk, Shell

Loss of containment along faults is a major study area for CO_2 storage projects as well as conventional oil and gas production. Critically stressed faults have been observed to both leak and seal in the field. The Cusiana El 330 is an example of major fields trapped by sealing active faults. A comparative study of known leaking and sealing faults in CO_2 traps on the Colorado Plateau was conducted. It was concluded that fault leakage requires two elements: firstly a network of interconnected fractures; and secondly an elevated fluid pressure equal to the minimum horizontal stress. The results are consistent with analyses of leaking faults in oil and gas accumulations.

The current state of understanding is that fault gouges can seal cross-fault flow. Trap geometry (crest and spill points) is known from outcrop and well data. Drillers' reports have indicated that CO_2 occurs as a free-phase gas cap and the upper portions of faults are sealing to lateral flow. Also, seeps occur only along faults and only in crestal areas. There are also a series of assumptions that are currently made during modelling including CO_2 gas-water-contacts, vertical stress as a function of depth, the minimum horizontal and aquifer (brine) fluid pressure.

Potential Impact of Faults on CO_2 Leakage: Evidence from the Petroleum Industry - Quentin Fisher, Leeds University

This talk outlined the current understanding of fault-related fluid flow and the requirements for fault leakage within the petroleum sector. The oil and gas industry already has a standard fault seal analysis procedure of mapping faults, estimating fault rock properties, estimating clay content of faults, calculating the fault transmissibility multiplier and finally assimilating data into a simulation model.

Fault movement requires the in-situ stresses to overcome the strength of either pre-existing faults or the intact rock. Observations from well bores have showen that faults that are critically stressed act as conduits for flow. Theories of fault properties have been developed from observations in hard rocks but have been extensively applied to all rock types (including very soft high porosity rocks). Faults need to remain dilated to allow for fluid flow but there is currently a poor understanding of the fracture closure pressure in shales as they are known to be self-sealing. More data is required on the conditions that cause this phenomenon as it is currently an area of uncertainty.

In general, fault-related leakage seems far less common than is often assumed. Bench mark examples, for example, Eugene Island, turn out to be incorrect interpretations for CO_2 storage and there are no higher incidents of dry traps in areas that are very seismically active. Evidence so far seems promising but there is a need for more documented case studies, especially with regards to gas. Sophisticated codes for modelling these processes are now available to couple flow and geomechanics that can then be history matched to seismic data. Water tight geometries for finite element modelling are still extremely time-consuming to generate, which limits sensitivity studies. Also, there are still a few cases of codes being successfully history matched to reservoir stress path data. Many studies of reservoir geomechanics currently use inappropriate constitutive models (i.e. those conditions applied to hard rocks) and it is recommended that more appropriate constitutive models are used such as anisotropic cap-plasticity models with creep. The key issue is that far more experimental data are required to populate these models.

Measuring flow properties of shale caprocks is still extremely difficult and great uncertainties exist, particularly for multiphase flow properties for example stressed porous plate and mercury injection (MICP) indicates massive underestimation of sealing capacity. The importance of processes such as pathway dilation are still not fully understood, the knowledge of reservoir stress changes and fracture closure pressures adds considerable uncertainty to predicting fault and fracture-related leakage. Horizontal stress and pore pressure coupling means that it may be difficult to drill and complete new wells in highly depleted reservoirs. Sophisticated numerical modelling tools are available but building models is difficult, material properties are not well known, models are time consuming to run and few have been thoroughly calibrated. Evidence for fault-related fluid flow in petroleum-bearing sequences is probably not as strong as is often thought.

Quest Microseismic: Observations after 2.5 million Tonnes of CO_2 Injection - Simon O'Brien, Shell

To date, more than three million tonnes of CO_2 have been stored at Quest in the first 32 months of operation. So far operating costs are lower than expected, and there has been excellent injectivity which is comparable to high case scenarios. Deployed MMV multiple technologies indicate that the CO_2 is where it is expected to be. Only two wells have been required to date which has contributed to significant well and MMV savings.

The pre-injection baseline monitoring at Quest was important to understand the regional seismicity and to optimize the parameters for the operating environment. The short-term average / long-term average (STA/LTA) triggering parameters were revised to optimize the event detection based on the observed noise floor. Baseline recording of microseismic data began in November, 2014, and injection began in August 2015. The majority of the trigger files generated are related to surface, automatic and noise triggers. No locatable events were detected in the baseline monitoring period. The first locatable event was recorded nine months after the start of injection in July 2016, and three locatable events were detected by December 2016.

A number (104) of locatable events occurred in the AoR in 2017. Most events were measured in the first quarter and the 'new normal' is roughly 1-2 events per week. Neither frequency nor magnitude of the events seem to be correlated to changes in downhole pressure and all events are located below the Basal Cambrian Sandstone (BCS) in the Precambrian Basement.

In summary there is no correlation to injection rates or pressures and the Guttenberg-Richter plot indicates that a large magnitude event is extremely unlikely. None of the events represent a risk to containment.

Illinois Basin – Decatur Project Microseismic Observations - Robert A. Bauer, Illinois State Geological Survey

As part of the Midwest Geological sequestration Consortium (MGSC) one million metric tons of supercritical CO_2 was injected to a depth of 2.1km at a rate of 1,000 metric tons per day in the Illinois Basin from 17th Nov 2011 – 26th Nov 2014. 1.5 years of pre-injection monitoring was undertaken starting in May 2010. In total 7,894 events were detected, 86% of which related to drilling and well activities. There were 1,100 distant events recorded most related to distant quarries in southern Illinois and eight local events unrelated to drilling and well activity were observed. Analysis of these events showed that the first clustering of events (Cluster 1) formed first about 1,800 feet (~550 m) from CCS1 before Cluster 2 at an average of 1,160 feet (~350 m) from CCS1. Pre-existing fractures close to 30° from the maximum horizontal stress direction are optimally oriented in the direction expected for strike-slip movements.

The observations at the site show that were that stratified pressures and a maximum pressure difference of 5.2% increase below the mudstone baffle. The maximum CCS1 down-hole pressure was at 73% of fracture pressures. Low permeability thin mudstone baffles, present 100m above injection, hamper pressure increases upward and confines microseismic development to 365m below Eau Claire caprock. Micro-seismic events form distinct clusters along previously undetected pre-existing faults and fractures. About 85% of events are in the Precambrian basement.

Session 9: Discussion

Conveyance of seismic information to the public was discussed. For Quest a community advisory panel who meet twice a year was set-up which included representatives from universities, schools, county councils and local communities. There is a continuous dialogue with the advisory panel about what to expect with the project. In reality the events were below anything that could be felt so the urgency of the message to the public is reassurance. Rob Bauer explained that ISGS (Illinois State Geological Survey) have an advisory board and occasional town hall meetings about Decatur to update local people.

The prospect where seismic events could definitely be attributed to natural causes or induced by injection or whether they were always going to be inferred was discussed. Direct attribution is going to be unlikely as it is difficult to prove exactly what causes these events. For Quest, a better knowledge of the basement would be ideal but it would be expensive to get data of the basement structure.

Session 10: Forecasting and Managing Risk at CO_2 Surface Facilities: Likelihood and Mechanistic Modelling

Chair: Curt Oldenburg

Have You Identified All the Risks? The Whole Story Framework in a CCS Surface Context - Ken Hnottavange-Telleen, GHG Underground LLC

This research focuses on the very first stage of risk management, identifying risks. Unidentified risks can cause big challenges and can be highly detrimental. This research aims to address whether all the risks have been identified for a project. Other frameworks were discussed but with a new proposal to use a journalistic framework based on how to answer '6 Ws', "Who, What, When, Where, Why and How?" This approach would be a good starting point.

In order to put this to work for the purpose of identifying project risks, each one of the 6 W's is mapped onto a separate project breakdown system, each of which is intended to be complete and comprehensive in its own right. "WHO" is mapped to the complete set of actors responsible for carrying out a project. "WHAT" maps to the project's complete set of functional components. "WHEN" maps to the project's time periods or phases. "WHERE" maps to the set of project physical locations. "WHY" maps to the complete set of project objectives; and "HOW" maps to the complete set of a project's planned activities. So the first step in risk identification would be to tailor each breakdown system to the specific project being reviewed. Some elements might be added, subtracted or redefined. After identifying all the elements, risks would be identified pertinent to each element of each system. Using the 6W's Whole Story Framework the project is examined from six independent points of view that inherently overlap. This minimizes the chance of an important risk being overlooked.

Pipeline Transport of CO_2: Mechanistic Modelling of Dynamics Related to Safety and Operation - Svend T. Munkejord, SINTEF

CO_2 is different to transporting natural gas or oil as there is a tighter coupling between thermo- and fluid dynamics. There is also a lack of relevant flow experimental data for example propagating ductile pipe fractures. Existing semi-empirical models do not work well for CO_2.

An overview of the modelling process was presented looking at homogeneous equilibrium model versus two-fluid model and heat conduction. Depressurization of a long pipe and tubes, running-ductile fracture and a 3D simulation of a CO_2 jet were also discussed.

It was concluded that for safety and operational considerations, transient multiphase flow models for CO_2 are needed. Large-scale experiments (with many effects) are difficult to use for model development. For short (near-isentropic) depressurizations a homogenous equilibrium model (HEM) gives good results (dependent on the equation of state (EOS)) and experimental results suggest non-equilibrium effects. For longer depressurizations it is important to include transient heat transfer and the possible occurrence of solid CO_2. There is no clear 'winner' between a two-fluid model (TFM) and HEM. For running-ductile fractures CO_2 induces larger forces on the opening pipe than natural gas and 3D 'direct' simulation of multiphase CO_2 flows can be achieved.

Modelling of Well and Pipeline Failure Processes and Consequences for Risk Assessment - Curt Oldenburg, Lawrence Berkeley National Laboratory (LBNL)

The potential hazards associated with CO_2 pipelines were discussed, including rapid catastrophic rupture, large-scale CO_2 leakage displacing oxygen and becoming toxic at high concentrations and CO_2 migration into low-lying topography or basements of buildings even at slow leakage rates. Potential causes of leakage are corrosion or other material failure, flaw in construction, error in operation (over-pressurizing), impact breach (vehicle and aircraft), loss of support (landslide, subsidence, and support failure), earthquake (shear or tensile failure, tornadoes or flood currents). How the CO_2 pipeline hazard varies along the length of pipeline was discussed and how this compares to the hazards of a point source in one location, for example a well. A framework has been developed looking at distance along the pipe, variation in population, downstream safety radius and changes as along the length of the pipe.

The Aliso Canyon gas storage blow-out was used as a case study for risk assessment of wells although it is not directly related to CO_2 handling. A relief well eventually had to be drilled at the site to kill the well.

The overall conclusions regarding pipelines and wells were that estimating CO_2 concentration as a function of space and time from leaks is needed for completing the risk assessment. There are several ways of estimating the concentration at different points in space and time. Process models are needed for detailed estimates. Uncertainty and variability in the consequences need to be considered when a role for reduced order models (ROMs) is created. The sensitivity of results to various properties of the pipeline or well system can be used to focus risk mitigation efforts.

Session 10: Discussion

The presentation on pipe-line risk discussed the consequences of pipeline failure and the steps needed to be taken to prevent damage to pipelines. Usually the cause is corrosion or third party impact. Although corrosion can be researched and mitigated within the pipeline design, third party involvement is harder to prevent. For example, the reworking and resurfacing of land can often make the recorded locations of buried pipelines inaccurate although the usual specifications are usually sufficient.

The current standards and requirements in place for CO_2 pipelines are considered satisfactory, the main issue is in scaling up pipelines and meeting the required specifications. Some operators, for example, Equinor are currently looking at these pipeline models and fracture calculations for the pipeline scales required to develop a full-scale CCS project.

Introduction to BEST Project - Ryan Klapperich, EERC

The session began with an introduction to pressure management and the brine extraction test project (BEST) in North Dakota currently being undertaken by the EERC. Several investigations have shown the potential of brine extraction to enhance CO_2 storage operations, however there are some technical challenges and opportunities that need to be considered. Chief among these are overall cost increases and potential disposal strategies for the extracted brine. The silver lining is that brine disposal tends to be more accessible and generally quicker, easier, and less costly to implement compared to dedicated CO_2 storage. An alternative or possibly parallel strategy is treatment of the extracted brine. If effective treatment strategies can be developed, there is a broad range of potential applications for the extracted water that can provide both social and economic benefits to a project operator and local stakeholders.

The EERC BEST field site is located near Watford City in western North Dakota. A slipstream of the extracted brine will be used as one of several water supply sources for the brine treatment test bed facility. One of the challenges faced is that the expected composition of the extracted brine will evolve over the test period. To compensate the test bed is designed with the capability to generate tailored brine compositions by blending the extracted water with either high salinity produced water or fresh water available on-site depending on the level of salinity. The water will also be pre-treated in advance of the technology demonstrations so that the water will be representative of water qualities anticipated at dedicated CO_2 storage sites. The footprint will allow for additional technology specific pre-treatment as necessary.

Active Pressure Management for Industrial-Scale Deployment of Geologic Carbon Storage in the Illinois Basin - Karl Bandilla, Princeton University

A numerical vertically-integrated model was developed to look at pressure management in the Illinois Basin which includes six aquifers. The model was separated by five aquitards and had a 1.67 x 1.67 km grid spacing with approximately 108,000 cells per aquifer with spatially varying aquifer parameters. The model aimed to look at the most efficient injection pressure and the resulting pressure impact across the reservoir.

The model showed a pressure plume of 200,000 km^2 as the AoR. This meant the pressure plume to CO_2 plume ratio was 16:1. Brine extraction for injection wells across the basin (200 wells) was then modelled which showed that the AoR can be cut down dramatically (4.5:1) with active pressure management but very large volumes of brine would need to be produced. If brine extraction levels were reduced from a 100% extraction to a 75% extraction level the AoR would increase from ~18,000 km^2 to ~ 60,000 km^2.

The study concluded that active pressure management is likely an essential tool for geological CO_2 storage operations. Central injection may be easier to manage than onsite injections and approximately the same volume of brine needs to be produced as that of CO_2 being injected. Therefore large volumes of produced brine need to disposed or utilized. Further information on this study can be found in K. W. Bandilla & M. A. Celia (2017) Active pressure management through brine production for basin-wide deployment of geologic carbon sequestration, International Journal of Greenhouse Gas Control, 61, pp. 155-167.(doi.org/10.1016/j.ijggc.2017.03.030)

Development of Robust Pressure Management Strategies for Geologic CO_2 Sequestration - Dylan Harp, Los Alamos National Laboratory (LANL)

It is currently assumed that a seismically-derived permeability field provides a good estimate of the spatial distribution of permeabilities and a nominal estimate of permeability magnitudes. There is uncertainty regarding the magnitude of these permeabilities. The goal of this study was to select a pressure management strategy that is robust against failing to achieve performance criteria given the uncertainty in the permeability magnitude. The method evaluated the effect of the nominal permeability magnitudes being wrong on the performance criteria.

The goal of the pressure management strategy needed to: avoid induced seismicity; inject desired CO_2 quantity, limit the volume of brine extraction and achieve the desired extraction efficiency. The approach is designed to deal with situations where there is a lack of underlying data.

In summary, the approach evaluates how wrong nominal estimates of permeability can be but still meet performance criteria, allow multiple performance criteria to be evaluated simultaneously, include multiple sources of uncertainty can be considered uses a non-probabilistic uncertainty model and does not optimize performance but instead analyses and facilitates management of risk.

Dynamic Pressure Simulation of Large-Scale Injection on the Norwegian Continental Shelf - Sarah Gasda, Uni Research CIPR & University of Bergen

Centralised storage in the North Sea requires large volumes of injected CO_2 in 'focused' regions. Regional planning and investments decisions and infrastructure development need to be based on confidence that predicted capacity can be achieved. The challenges are that the scales are enormous, the time-scales can be long and data will certainly be uncertain.

For large-scale dynamic simulation the decision making relies on a series of information coming together within a workflow or structure. The dynamic simulation takes in data, often with uncertainty, and delivers predictions to the larger workflows. Uncertainty leads to multiple realizations of parameters which means there is a requirement for lots of simulations. The aim is to try and make models as simple as possible by smart modelling choices that reduce complexity. There needs to be a focus on geology and mechanics that have the largest impact at large scale and to work out where the most added value is gained.

Three case studies were chosen to highlight large-scale challenges and issues, the Utsira formation, the Skade (and overlap with Utsira) and the Smeaheia. The models looked at surface deformation as an indicator of pressure migration, CO_2 properties impact on near-well injectivity, regional and stacked connections for large-scale pressure migration and how faults may affect and be affected by pressure build-up in reservoirs. The results of the simulation optimised injection rates for nine of the cases studied.

In summary regional planning and risk assessment require specialized simulation tools. Some processes, parameters and other data neglected at local scale may become important for large-scale pressure migration, while local pore-scale phenomena control plume migration. Smart reduction in model complexity can gain valuable efficiency without sacrificing accuracy and the integration of geological modeling and simple dynamic pressure simulation are necessary for understanding where to invest in detailed characterization and simulation.

EPRI Brine Extraction Storage Test at Plant Smith - Robert Trautz, EPRI

The EPRI BEST project (supported my US DOE-NETL funding) is located in Florida and has the objectives to develop cost-effective pressure control, plume management and produced water strategies for: managing subsurface pressure; and validating treatment technologies for high salinity brines. The project began Phase I in 2015 which was a feasibility study that looked at five different power stations (across the south-eastern US) as potential host sites. Geological and well data was also collected as part of Phase I and a wide range of data was available.

Water is to be injected as a proxy for CO_2 and all sites studied had the large volumes required available on site. Plant Smith was the site chosen as it was interested in hosting a project and was able to commit. Phase II will be the field demonstration stage where passive relief wells and active extraction will be undertaken. The project will have a salt Eocene injection zone which has sea water salinities. 500,000-1M gal/day (1.9 M – 3.8 M litres/day) will be injected. Initial modelling demonstrated that a passive relief well alone can reduce extractive volume by 40% which is the reasoning behind the strategy.

Life cycle analysis of treating the brine and the cost-effectiveness on CO_2 storage will be part of the project's assessments. There are additional CO_2 penalties that need to be taken into account for treating the brine because of the thermal technology required for the treatment of the brine. The overall purpose of project will be to provide background information if brine treatment was required as part of a pressure management strategy.

Session 11: Discussion

Carbonation mostly occurred above the reservoir at Cranfield, however the rate and volume of alteration to the cement within the annulus is unknown. Other measurements at Cranfield, for example pressure measurements, did not indicate movement of CO_2 out of the reservoir. Geomechanical stress on the casing will also affect its integrity. The evidence of stress on the casing at this site needs to be considered because it could have influenced its durability.

The ability to constrain CO_2, and its potential to migrate through the annulus of wells, needs to be ascertained. There is no evidence here of measurable quantities of CO_2 reaching the surface. It should also be stressed that the risk of installing a control line at this site was taken because this is an experimental field site. This action has benefited from the acquisition of large quantities of useful down-hole data. Control line installation would not necessarily apply elsewhere. Industry experience shows that over 40 years of casing log inspection suggests the extent of cementation will prevent significant fluid migration up an annulus.

Session 12: Modelling and Risk Assessment: Industry and Regulatory Perspectives

Panel Discussion - How can Conformance Modelling Address Regulatory Requirements and what Advancements in Modelling are Required to get Closer to that Objective?

The final day of the meeting had a conformance and regulation focus, where the following questions were addressed:

- What questions are important to regulators?
- What information / tools help regulators make balanced decisions?
- Site closure – demonstrating stabilisation to regulators

Keynote Presentation

Class VI Specifications - Local North Dakota Regulator Insight - Lynn Helms, North Dakota Industrial Commission

North Dakota has secured Class VI[3] primacy[4]. The process was a nearly 5-year journey from application to final approval. The IOGCC (Interstate Oil and Gas Compact Commission) developed a couple of principles, which guided the development of North Dakota's CO_2 storage regulations:

1. That it is in the public interest to promote the geologic storage of CO_2 to reduce anthropogenic CO_2 emissions; and
2. The state's pore space should be regulated and managed as a resource under a resource management philosophy.

CO_2 is treated as a resource in North Dakota, and as such, will be handled very differently compared to waste. Waste is entirely the responsibility of a waste generator whereas a resource opens the door to public/private partnership. A unique feature of land ownership in the US is the inclusion of mineral rights and pore space beneath the surface. 95% of all pore space in North Dakota belongs to a private individual, and therefore not the state or federal government. As the space occupied by a reservoir is owned by private individuals, project operators and regulators need to know the CO_2 plume's distribution in the subsurface, whose pore space might be affected, and how potential adverse impacts could be handled. In North Dakota, if 60% of private stakeholders agree to a storage project, state law allows the other 40% to be amalgamated into the agreement, however, they must be equitably compensated. Owner compensation presents an interesting challenge, and could be implemented on an annual per acre basis. A per tonne payment would likely be difficult to establish since the exact volume of CO_2 stored beneath each property would be virtually impossible determine. Generally, those with the CO_2 plume directly below their property would get more compensation than those only affected by the pressure front.

[3]this is a US Federal regulation that specifically relates to the disposal of CO_2 via wellbores
[4]a US Federal regulation formerly implemented by a Federal agency, in this case the US Environmental Protection Agency (EPA), and transferred to a state authority

Site characterisation is the most important part of any project to ensure that it is well-planned and avoids failure. Consequently, it is important for a regulator to know what assumptions have been made and built into predictive models.

Long-term liability of injected and stored CO_2 is just as important as monitoring during injection and operation. North Dakota has a unique feature built into its storage legislation for the state to assume this liability. Provided that a CO_2 storage project operator can demonstrate that the injected CO_2 is stable (i.e., the plume's movement is negligible or predictable) for 10 years following the cessation of injection, the state can assume long-term liability for the stored CO_2.

QUEST Regulator Experience - Jeff Duer, Shell

Shell's communication strategies and experience with regulators during the Quest project was outlined with the overview aim of being consistent, clear and concise. An example of where Shell's consistent work aided their communication with regulators was how the company intended to monitor the Cooking Lake Formation. Shell's initial application was rejected as monitoring was not seen as necessary for the Quest site but through persistence and consistency the plan was finally approved. This decision allowed a suitable pressure baseline to be established for the site.

An appropriate level of detail is necessary for project implementation. Overloading a regulator with excessive detail that is not necessarily useful to them and also makes the application process longer for everyone involved. Instead a successful strategy makes the detail clear, sets out what is involved and how progress will be achieved and how the plan will lead to a successful outcome. Shell did not initially overload the regulator with an excessive application. The company aimed to only include what the regulator needed to know and eventually the project got approved.

The MMV components of a project are designed for a specific purpose. Different approaches can be taken for example is it best to always adapt an existing model or should another model be developed from start for the same purpose. At Shell, just for the leak path alone, five models were created. Honest history matching must be conducted. At Quest the well injection showed rapid departure from the original model. The models could have been matched but the basis for doing so was weak. The results were honestly communicated to the board showing a disparity between the model and the monitored observations. After one year the injection models did fit without any adjustment. The processes that caused deviations early on are still not fully understood and research is ongoing. In general it is difficult to force a good match in the early stages of injection and long-term trends may well still be applicable. The purpose of models is to forecast not curve fit.

It is important to ensure there is a good communication strategy that is focused on what is needed from the regulator and not just how good any model is. In summary the Quest project shows that it can be too easy to dive into the science and lose focus on the goal whilst communicating on a project.

Session 13: Conformance and Concordance
Chairs: Curt Oldenburg (LBNL), Dylan Harp (LANL), Owain Tucker (Shell) and Jonathan Ennis-King (CSIRO)

Curt Oldenburg: Meanings of Conformance, and a Recommendation for Definition of Conformance in the Geologic Carbon Sequestration Context

The motivation for this talk comes from the multiple uses of the term 'conformance' currently being used. The multiple definitions are currently causing confusion. To reservoir engineers the word has a very specific meaning but it also has an everyday meaning and is similar to concordance and compliance. Its inconsistent use within CCS and regulation documents could become problematic. This presentation proposed a definition of the term conformance and how it should be used.

In the context of a comparison between conformance and conformity, there is good reason to retain the term conformance. The main reason is that the term is already in use in the CCS community. The second reason conformance is strongly preferable to conformity is that the lack of conformance, i.e., non-conformance, would be called nonconformity which has a very specific and totally different meaning in geology. In the CCS context, the main components of conformance are in the areas of model agreement with observations and system performance where performance encompasses CO_2 containment with acceptable environmental impacts. The same logic was used by Chadwick and Noy in their 2015 article in Greenhouse Gases in which they proposed the need to combine performance measures with quality modelling forecasts to make a case for conformance.

The proposed definition is that conformance of a CCS system is the condition under which there is acceptable concordance and performance; a forecast of conformance requires a forecast of continued acceptable performance. Note that there are subtle implicit temporal components in this definition. Concordance and performance rely on agreement with observations so are only relevant in past or present tense. Because of this, conformance requires an ongoing evaluation and is spoken of in the past or present tenses, as in, "…the CCS system has been and continues to be in conformance by virtue of excellent concordance with models and performance as constrained by an effective monitoring system." But conformance can be forecasted on the basis of forecasts of acceptable performance.

Dylan Harp: Handling Uncertainty in Concordance Assessments

Currently there is a big focus in literature on the term concordance but the meaning does not necessarily relate directly to conformance. For example, how is "good" verses "bad" conformance decided and what decisions should be made when confronted with inadequate data or data anomalies. Where concordance is useful is in terms of future performance. Metrics of concordance are always going to be uncertain and concordance uncertainty must be accounted for.

A simple pressure monitoring example was used to look at robustness over time for different critical pressures of a model. Concordance is only useful in its implications for future performance and concordance uncertainty must be accounted for. Concordance metrics should capture increased confidence in models over time as more measurements are obtained.

Jonathan Ennis-King: History of Static and Dynamic Models

The modelling and simulation process undertaken by CO2CRC was outlined showing that four realisations of the geological model were simulated, and matched to the following data: location of GWC (gas-water contact) before and after production; wellhead pressure during production; and downhole pressure gauge data at CRC-1 during injection. Predictions were then made for gas composition (CO_2 and tracers) at monitoring well and change in groundwater composition over time. The iterations were:

- SM0/DM0: conceptual 'hand-made' geological model. TOUGH2 (2004-5)
- SM1/DM1: detailed geological model (Petrel) but with one well in the formation and no core, history match to gas field production and pressure. (Eclipse, 2005-6)
- SM2/DM2: After CRC-1 injection well drilled and characterized, revised geological model. (Eclipse, TOUGH2, 2007-8)
- SM2/DM3: When field data was available (as test proceeded), beginning of history match to downhole P,T data, and geochemical sampling data. (Eclipse,TOUGH2) (2008-10)
- SM2/DM4: Final history matching phase as repeat RST logs and other field data are available (TOUGH2, iTOUGH) (2011-2012)

In the case demonstrated the regulators needed to be convinced that the CO_2 would remain within the lease boundary, and not leak into the shallow groundwater. All the generations of models predicted containment and refilling of the depleted gas field, which is what happened. Model predictions are crucial to approval, design, operation and monitoring, and to data interpretation and assimilation.

[5] R.A. Chadwick, D.J. Noy. Underground CO_2 storage: demonstrating regulatory conformance by convergence of history-matched modelled and observed CO_2 plume behaviour using Sleipner time-lapse seismics. Greenh. Gas Sci. Technol., 5 (2015), pp. 305-322, 10.1002/ghg.1488.

Owain Tucker

Owain raised the point during the discussion regarding the shape of the CO_2 plume and conformance/ concordance is not what a CCS project should be focussing on. The focus should be about risk and where is the CO_2 going to be distributed. In the oil and gas industry the focus is on running scenarios which might have two or three geological realisations and each model will behave differently. There are difficulties trying to run with those scenarios and outline the range of uncertainty.

In CO_2 storage projects it is important to demonstrate that stored CO_2 remains within a range of uncertainty within specified boundaries and does not leak. Therefore what is the level of confidence that the CO_2 plume distribution can be predicted and none of the modelled scenarios will lead to a leak. Each site should evolve to a state of stability and risks diminish with time noting that every geological system is different.

Session 13: Discussion

The definitions of concordance and performance conformance presented were well received.

The overall aim is to demonstrate stabilisation of the plume and determine that it is not moving. There will be a point after closure where the pressure has dropped off and there are no drivers but the plume will still be present. There is also the question of when concordance in a plume is achieved.

Experience from the Otway Stage 2C shows good seismic images that match model outputs. If forward predictions show plume stability within expected confines then there is evidence of stabilisation. In contrast history matching at Sleipner and Ketzin revealed poor matches.

Overall trying to demonstrate conformance all comes down to risk. Elements of the model and parameters are likely to be wrong but the performance criteria might still be met. The key question to ask is "How wrong would predictions have to be not to meet performance criteria?" This approach comes down to decision analysis that involves risk. For example, how extreme do model changes have to be to 'break' - that is go beyond a known parameter such as permeability. Is there evidence of conditions that might explain some model predictions. At Goldeneye even when altering the fault permeability it was not possible to force the model to exceed the limits of plume migration.

The Sleipner case study was also discussed with the plume migration occurring faster than was predicted by modelling. There is an argument that the early Sleipner models were very simplified and it would have been hard to accurately predict pre-injection. Looking at Otway, plume movement was certainly within the predicted range of uncertainty. The model has been increasingly constrained over time but there will always be factors that will not match although this probably does not matter in the end.

The point that sometimes bad data can be worse than no data was also raised for example pressure gauges can have signal deviations and are effected by temperature. This is definitely going to be considered by NRAP. The pressure observations always have noise and uncertainty. The Otway experience with multiple pressure gauges revealed times when one of the four gauges would have a much greater drift than the other three. More gauges would allow for a better calibration. Only having one gauge makes monitoring vulnerable to failure. The rationale for taking each measurement should be clear, why it is necessary and how it contributes to risk evaluation.

Conclusions and Key Messages

Modelling CO_2 Migration from Pore-Scale to Reservoir-Scale

- Further refinement for a global capacity estimation methodology needs to be agreed. SPE SRMS provides a solid foundation although care needs to be taken when applying the SRMS to defining discovered resources in unstructured saline aquifers and addressing vertical and lateral containment.
- Geological heterogeneity is very difficult to simulate. Development of models to simulate plume migration patterns based on more analogues would be beneficial.
- Small heterogeneities in capillary pressure can lead to large variations in CO_2 saturation.
- Capillary pressure simulations can help to explain the pattern of CO_2 plume migration better than porosity/permeability simulations alone. This phenomenon could explain why early breakthrough is observed at several sites.
- Fluid events can now be simulated at pore-scale
- Residual Oil Zones (ROZs) potentially have significant CO_2 storage capacity but field-specific studies are needed to improve predictions. ROZs could be optimised for oil production or CO_2 storage, but prioritisation will need to be decided.

CO_2 Utilisation and Storage Associated with Unconventional Reservoirs

- CO_2 has been tested as a fracture/production fluid to extract oil in the Bakken Formation. Conformance is a major challenge. Model predictions for produced oil are not observed in tests. There is potential for enhancing CO_2 use by using horizontal wells in optimized configurations.

Wellbore Integrity

- Evidence from the Norwegian sector shows ~40% of injector wells have integrity problems. Producer wells are less prone to integrity issues. The pattern of cyclical thermal loads can have detrimental effects on cement and casing.
- If casing is not centralized then there is a stronger probability of defects. For CO_2 injection wells the quality of casing and cement emplacement is very important.
- A Neural-Genetic Algorithm could be a useful method for screening wells in depleted O&G fields as storage candidates.

Bayesian Methods Applied to CCS Risk Management

- Bayesian methods can be applied in CCS to evaluate occurrence of risk events, anomaly detection, event source location, risk-based monitoring design, system-level risk assessment and management and risk treatment evaluation.
- Statistical methods have been developed to rationalize the number of variables that affect wellbore integrity. The technique has been field tested on data from fields with background data on well integrity.
- The STEMM-CCS project (**http://www.stemm-ccs.eu**) will generate data on controlled CO_2 release beneath the North Sea. This project will use data to validate a series of models that can feed into longer-term environmental monitoring.

Progress with Modelling Regional-Scale Storage Potential

- Good progress has been made with CarbonSAFE projects notably the initial stages on the storage potential of the Atlantic Shelf and across Michigan.
- Collaboration has provided opportunities to learn more about the capabilities of the NRAP Tools. For example, area of aquifer impact analysis using OpenIAM provides a risk-based AoR estimate for a geological storage site.
- Probabilistic Risk Maps have been developed which could aid project design – but their use needs to be carefully communicated to stakeholders unfamiliar with modelling.

Fluid Flow and Faulting

- A comparative study of known leaking and sealing faults in CO_2 traps on the Colorado Plateau has shown that where CO_2 pressure exceeds the fracture gradient then seepage occurs. Fault damage zones provide networks of interconnected fractures which can act as conduits for fluid migration. The research has shown that these criteria apply equally to CO_2 traps and conventional oil and gas traps.

- Knowledge of reservoir stress changes and fracture closure pressures adds uncertainty to predicting fault and fracture-related leakage.
- Horizontal stress – pore pressure coupling means that it may be difficult to drill and complete new wells in very depleted reservoirs.
- Sophisticated numerical modelling tools are available for predicting fluid flow at faults but building models is difficult, material properties are not well known and few have been thoroughly calibrated.
- Evidence for fault-related fluid flow in petroleum-bearing sequences is probably not as strong as is often argued.

Induced Seismicity at Demonstration Sites

- Micro-seismicity detected at Quest is at very low levels and has no correlation with injection rates or pressures. Large events are extremely unlikely and none of the events represent a risk to containment.
- Decatur induced seismicity events range from -2.13 to 1.17 and 95% are 0 or less. ~85% of events are in Precambrian basement.

Risk Assessment Associated with Pipelines and Wellbores

- Pipeline risk assessment needs to include transient multiphase flow models for CO_2. Fluid and thermo-dynamics within pipelines are tightly coupled.
- Large-scale experiments (with many effects) are difficult to use for model development.
- 3D 'direct' simulation of multiphase CO_2 flows can be achieved.
- For running-ductile fractures CO_2 induces larger forces on the opening pipe than natural gas.

Pressure Management at Basin Scale

- Active pressure management at basin scale is likely to become an essential tool for carbon storage operations.
- A single study has shown central injection and pressure management using brine extraction, concentrated in the centre of a basin, may be easier to manage than onsite injections dispersed across the basin.
- A single study has shown that approximately the same volume of brine needs to be produced as the volume of CO_2 being injected.
- Large volumes of produced brine need to be disposed or utilized.
- Smart reduction in model complexity can gain valuable efficiency without sacrificing accuracy.
- Integration of geological modelling and simple dynamic pressure simulation are necessary for understanding where to invest in detailed characterization and simulation.
- Results from the BEST test injection projects are expected in 2019 - 2020.

Areas for Future Research

- Capacity estimates need to be distinguish between formation and basin storage. The storage efficiency of a hydraulic unit needs to be defined.
- CO_2 storage estimates need to differentiate between a detailed estimate based on high reliability and a broad brush estimate.
- There is a need to define capacity and limits of aquifers.
- More analogues are necessary to refine predictions bearing in mind each site has unique characteristics.
- ROZs have significant potential CO_2 storage capacity, but field-specific studies are needed to improve predictions.
- Standardised monitoring, verification and performance metrics for CO_2 storage sites need to be developed and agreed.
- Data in the form of environmental measurements already acquired for other purposes could be shared with the CCS community to bridge limited data on sea water quality. Multiple function autonomous underwater vehicle (AUV) probes that analyse and record data on the marine environment could be shared and would be highly beneficial to the wider scientific community and other interested stakeholders.

Challenges

- Material properties, particularly of shale caprocks undergoing creep, are poorly understood.
- Geological heterogeneity is still very difficult to replicate in mathematical simulations.
- Appropriate boundary conditions need to be defined and include a justification for the boundary. The predicted pressure plume should be contained within the boundary limits but not exceed it.
- If ROZs are considered as a future CO_2 storage option should they be optimised for oil production or CO_2 storage?
- A field test to evaluate CO_2 injection for EOR and storage in unconventional reservoirs associated with organic-rich oil producing formations has shown that there are gaps between the modelling and field observations. A better understanding of the fundamental properties affecting CO_2 interactions with the "unswept" Bakken reservoir is needed.
- Uncertainty and probability are not widely appreciated – some stakeholders have a propensity to react to a single metric. There needs to be a better understanding of the concept of uncertainty and levels of uncertainty.
- How should advanced risk assessment methods be explained and tested with regulators and other stakeholders? Should risk assessment methods be tested at workshops organised for regulators?

Recommendations

- Develop and apply more appropriate constitutive models such as anisotropic cap-plasticity models with creep.
- More research on the relationship between pressure increase and the effects elsewhere on fractures.
- Further modelling on hydrate formation in or near wellbores if water is present in CO_2.

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