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The University of Queensland Surat Deep Aquifer Appraisal Project (UQ-SDAAP)

Scoping study for material carbon abatement via carbon capture and storage

Supplementary Detailed Report

Methodology for assessment of dynamic capacity

30 April 2019

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Acknowledgements

This working document was prepared for The University of Queensland Surat Deep Aquifer Appraisal Project (UQ-SDAAP), a 3-year, $5.5 million project funded by the Australian Government through the Carbon Capture and Storage Research Development and Demonstration (CCS RD&D) programme, by Coal 21, and The University of Queensland

Citation

Garnett A & Underschultz J (*2019*), *Methodology for assessment of dynamic capacity*, The University of Queensland Surat Deep Aquifer Appraisal Project – Supplementary Detailed Report, The University of Queensland

Referenced throughout the UQ-SDAAP reports as **Garnett & Underschultz 2019.**

Publication details

ISBN: 978-1-74272-282-5

Disclaimer

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1. Summary

The purpose of this report is to summarise the methodology employed to estimate a calibrated estimate of dynamic storage capacity. Largely, the methodology used to assess the potential of attaining and sustaining a given plateau injection rate is generic. The degree of uncertainty is highly dependent on the type and quality of the data available to constrain the assessment. The component of the methodology that defines a future site appraisal and field development plan is site specific.

The essentials of the evaluation methodology are as follows:

1. *Units of analysis* are a defined in terms of a storage "play" and storage "container(s)". The "play" is the combination of reservoir and seal, or seal-complex. The play can be defined by common geological injectivity and containment risks across a geographic/stratigraphic region. The "container" is the 3D volume of strata within the overall play, in which a mass of CO_2 is proposed to be injected over a given time period and subsequently stored. In addition to play risks, there may be container-specific containment and injectivity risks or uncertainties
2. The evaluation of key surface development constraints (e.g. geographic limits to the placement of well sites)
3. The evaluation of key sub-surface development constraints (e.g. geographic limits to plume migration and to far-field or overburden pressure rises)
4. A focus of all subsidiary geotechnical evaluations[1] on ultimately determining trends and ranges of (i) factors which govern maximum initial injection rates; and on, (ii) factors which govern and give rise to formation pressure increases over time (transient)
5. A storage development philosophy focussed on delivering minimum containment risk (as the sole justification for carbon capture and storage (CCS) is *emissions reduction*)
6. A storage development goal of defining the nature of sustainable plateau injection rates[2] for the play or container; and, if data allows, the trade-off between plateau rate and plateau duration (at this stage it is useful to define a *minimum* rate and duration of practical interest)
7. An iterative approach to initial field development planning i.e. the interplay between field lay-out, well and completion design and initial and plateau rates

This outline (see graphical representation in Figure 1) is in essence a form of resource assessment common across a number of resources based industries. Such an evaluation may be reported in a way analogous to oil and gas resources (SPE 2016) if required i.e. based on the uncertainty assessment, which is inherently part of it.

Conceptually, the storage resource to be exploited is the available <u>pressure margin</u> not pore space.

Following this workflow and depending on the maturity of the opportunity, decision criteria for staged development decisions would need to be established (e.g. Garnett et al. 2012; Garnett and Greig 2014). Alternatively, as is the case with UQ-SDAAP, a play and container appraisal programme may be required based on risk and uncertainty analysis (Honari et al. 2019d, 2019e).

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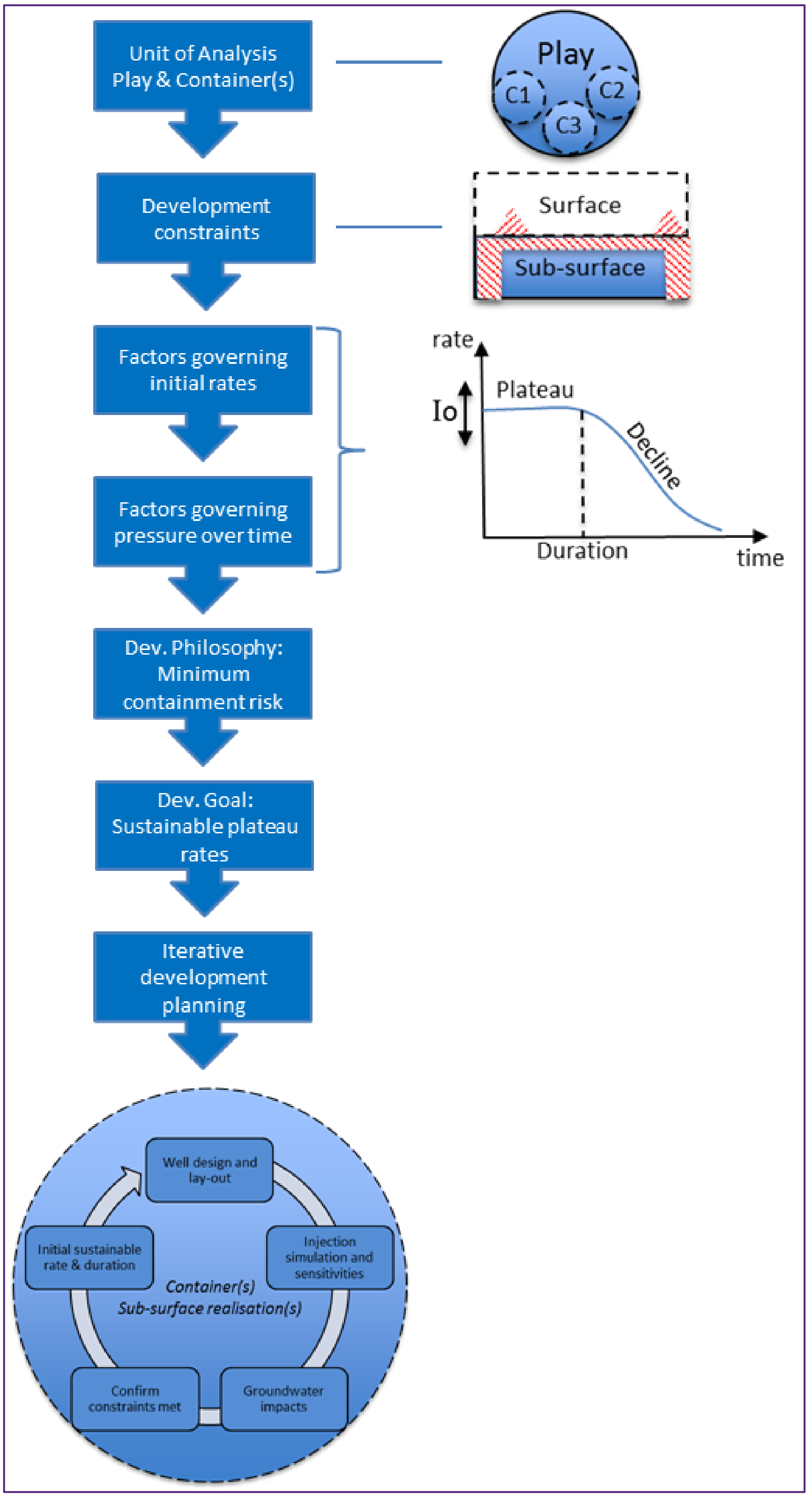
[1] The type, detail and range of these is dependent on data availability
[2] Because capture plants deliver constant rates or steps in constant rates with modular deployment

Figure 1 Simple workflow for dynamic capacity evaluation.



2. Introduction

2.1 The emissions abatement problem is a *rate* problem

Discussions on storage "capacity" have traditionally centred on the quantification of static, corrected pore volume calculations for certain basin or plays or segments thereof (e.g. Bachu et al. 2007; DOE 2007; Bachu et al. 2008 and Bradshaw et al. 2011). Capacity in this paradigm is a function of pore space with some discount defined by a storage 'efficiency factor'. More recently this has been modified to be analogous to resource and reserves definitions to the petroleum resources management system (e.g. SPE 2016). However, it has been noted that static-based capacity calculations have limited benefit in estimating dynamic 'practical capacity' (e.g. Garnett et al. 2012 pp 353-441; Allinson et al. 2014).

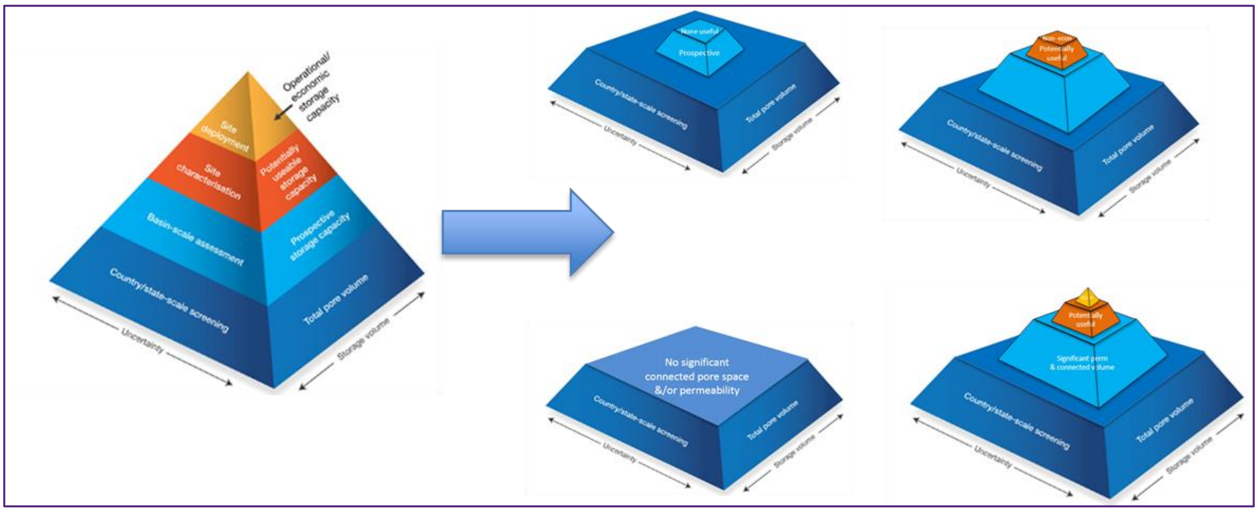
The historic corrected pore volume approach represents largely a fallacy of construction. The methodology is derived from approaches applied to exploration volumetrics in the oil and gas business, where recoverable volumes (and thereafter value) is estimated by establishing an "oil in place" estimate. Typically, this includes an uncertainty distribution, which is then transformed into an estimate of recoverable reserves by convolving it with an estimate of recovery factor. This is a first-pass, seemingly rate independent, methodology. However, (i) the volume to value transformation is typically play-dependent and rate is inherently included in this; and (ii), the difference in value between production this year versus the next is simply the deferred value of sales, not a loss of volume. The analogy is wholly inappropriate for carbon storage because there is no equivalent to '*deferred'* production in CO_2 injection.

So, for any proposed sequestration site or sites, the challenge at hand is not to sequester a given *volume* of CO_2 but to sequester a given *rate* for a sustained, defined period. This falls from the higher-level need to reduce global emissions *within a given time frame*, in order to maintain a limit on global temperature rises (IPCC 2018). Static methods either fail to recognise that mitigation is a rate-governed challenge and/or make implicit assumptions that large static capacities can support a large sustained injection rate, and that somehow sustainable injection rate is mainly a function of capacity. Furthermore, not until the rate governing features of a storage play have been evaluated, can a basis of design (scale and rate) for capture facilities be determined.

Kaldi & Gibson-Poole 2008, building on Bachu et al. 2007, suggested what is a now commonly used "resource-reserves" pyramid (see pyramid on the left side of Figure 2). While this may have been a useful communication tool to explain that rate "matched" capacities are significantly lower than "theoretical capacities", the model can be misleading. It appears to suggest that there is some scaled relationship between different resource levels. This can lead to a significant overestimation and overconfidence in the available, useful storage. In turn this can lead to a focus on capture (and Hub) design, well in advance of available information required to size and design such schemes.

A more nuanced view of the relationship between theoretical (static) capacities and "useful" or "rate-matched" capacities can be represented as per Figure 2.

Figure 2 Modified view of storage resource pyramid (Garnett 2017, modified after Kaldi & Gibson-Poole 2008).



When evaluating a "rate matched" (c.f. dynamic capacity) requirement, the size of a theoretical static capacity is not indicative the dynamic potential. Permeability rather than porosity dominates. The pyramid model is therefore limited. A new language and set of concepts is required to discuss dynamic capacities.

2.1.1 Dynamic capacity – concepts and communicating uncertainty

While not capturing the full complexity, for the purposes of communication, dynamic capacity can be usefully discussed in terms of **a rate that can be sustained over a defined period of time** (rather than a simple cumulative volume or mass). As noted by previous authors (e.g. Allinson et al. 2014) and demonstrated by others (e.g. Garnett et al. 2012), this dynamic capacity is a function of geology *and* an engineered field development plan (FDP).

Dynamic capacity is *constrained* by:

- ✓ By geology (e.g. permeability, thickness and reservoir volume which contribute to rate and pressure constraints); *and*
- ✓ By the developable area (e.g. surface constraints); *and*
- ✓ By in-field architecture, field lay-out and well spacing (e.g. cross-well interference): *and*
- ✓ By interference with other subsurface users (e.g. pressure rises for other uses or water quality changes or use of a pressure margin required by others such as MAR users); *and,*
- ✓ By regulatory limits, (e.g. as licence boundaries and pressure build-up limits, environmental conditions or similar monitoring and verification (M&V) indicators)

It can also be *economically* constrained. For example, if optimised on the unit technical cost (UTC)[3], more injection might be possible in a given FDP, but there are diminishing incremental sustainable-injection returns (lower rates and durations) for incremental capital investment (drilling more wells). UQ-SDAAP sought to establish technical rather than economic feasibility of large-scale injection and therefore has not applied an economic limit. However, such a limit or UTC target has been recommended as a decision test (e.g. Garnett et al. 2012 pp 346) at the end of field appraisal. Further discussion on unit costs can be found in Garnett 2019a and Garnett & Greig 2014b.

A methodology to estimate dynamic capacity requires the evaluation of surface and geological constraints, a "container" defined, specific sites identified and an appraisal and development philosophy set. Within this, it

[3] Unit technical cost, UTC = discounted sum of capex + opex divided discounted sum of injection rates. This is an estimate of a constant real terms, pre-tax, carbon price which a storage operator would need to receive to break-even.

is then possible evaluate the impact of different injection scenarios in the ‘high graded sites on other resources, such as groundwater. These evaluations then inform engineered FDP options which lead to a holistic estimate. With this approach in place, any calculated dynamic capacity is then specific to the parameters, constraints, definitions and engineering solutions. Additionally, any assessment of dynamic capacity carries uncertainty. This is especially true of early stage assessments, such as those undertaken by this research.

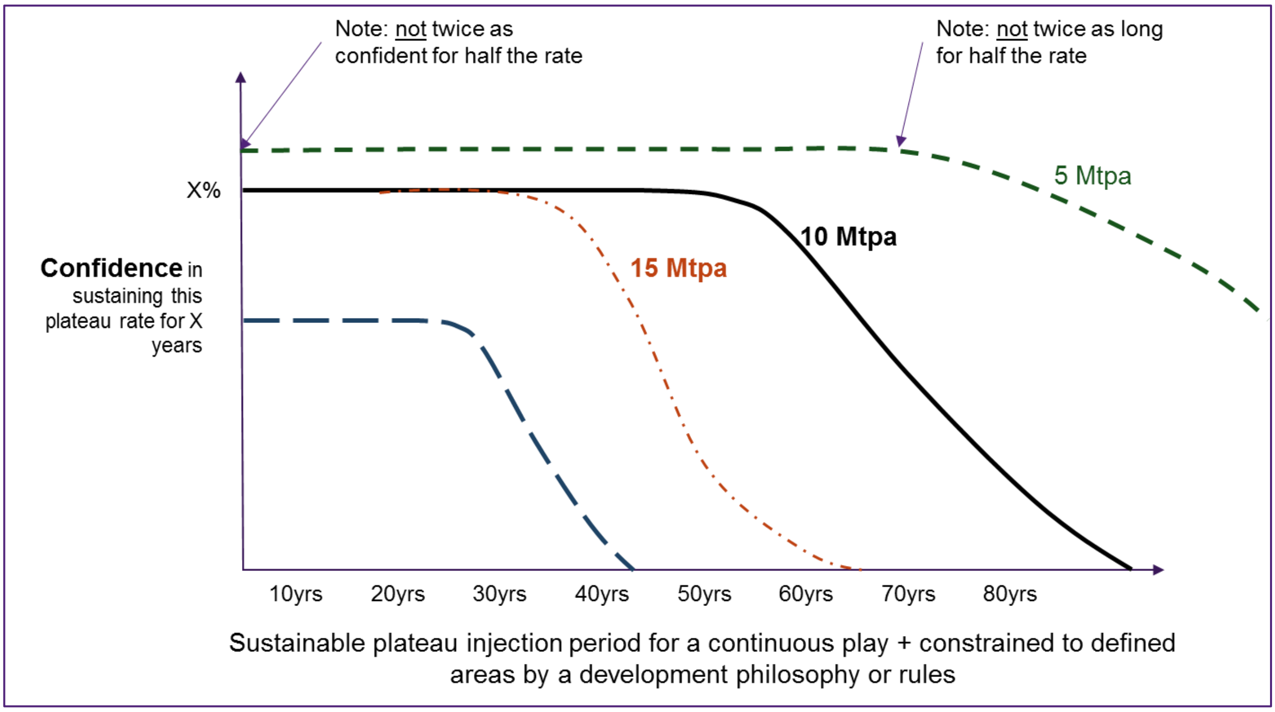
Communicating uncertainty is important because when designing capture plants and deciding on their capacity (Mtpa), the ideal would be to retrofit a capture-rate that can be utilised to its maximum extent, but does not become limited by declines in storage injection potential during its useful lifetime. To install too much capture is to waste significant capex if it becomes rate constrained by the dynamic capacity. Note that the capex required for capture is far greater than the cost of establishing greater confidence in sustainable injection rates.

The basis of design (BoD) for capture rate in a CCS hub is constrained by confidence in storage potential, its plateau rate, and how long it can be sustained.

Three models for discussing dynamic capacity uncertainty are discussed herein. Figure 3, shows a schematic of confidence in sustaining different plateau rates (Mtpa) for different durations. These can be estimated from FDP specific models for a given play, location, development philosophy and constraints. There is clearly a higher confidence level for lower rates in general. Furthermore, for higher plateau rates, confidence in sustainable plateau time is lower. **Confidence is lower for higher plateau rates and also confidence decreases for longer sustained plateaus.**

In such a discussion, for given play and area constraints, the differences between the sustainable rate curves are caused by different field development choices (mainly well count, type and spacing). Higher rates and longer durations would lead to higher total costs and unit costs.

Figure 3 Diagramatic model for discussing confidence in dynamic capacity.



An alternative way of considering uncertainties, especially in an early stage development requiring further site appraisal, is shown in Figure 4. In this figure, different subsurface realisations (all consistent with the data) result in different plateau durations when considered with a given FDP. There are several reasons that the injection rate can fall off, including:

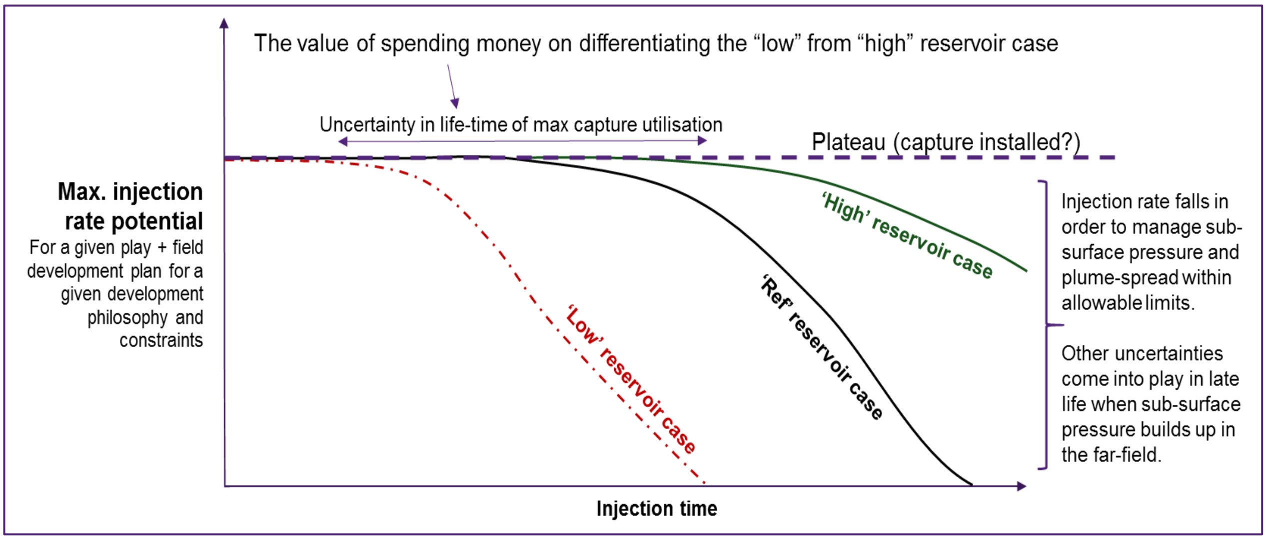
- Near well bore scaling or fines migration
- Far-field reservoir architecture (channels or faults)
- Far-field changes to reservoir permeability due to precipitation of minerals
- Pressure interference between CO_2 injection wells or between these wells and other injection operations such as MAR
- Regulatory pressure rise constraints (including far-field) e.g. imposed due to impact on water bores
- Managed reduction in rate in response to unexpected monitoring and verification information e.g. if plume migration is further than forecast

The main uncertainty is geological. The impact of BoD for capture can be significant. There is a risk of long periods of time when installed capture capacity is under-utilised. For this reason, investment in an appraisal plan to reduce geological uncertainty can be important prior to FID on capture plant options.

Even when a field development plan can be constructed that can attain the required injection rate, significant uncertainty in the onset of injection decline is driven by the (uncertain) reservoir case.

It is important to invest in differentiating the 'low' from the 'high' reservoir case for the play to maximise the abatement potectial of CCS in the focus area (Figure 4).

Figure 4 Model for discussing uncertainty in dynamic capacity.

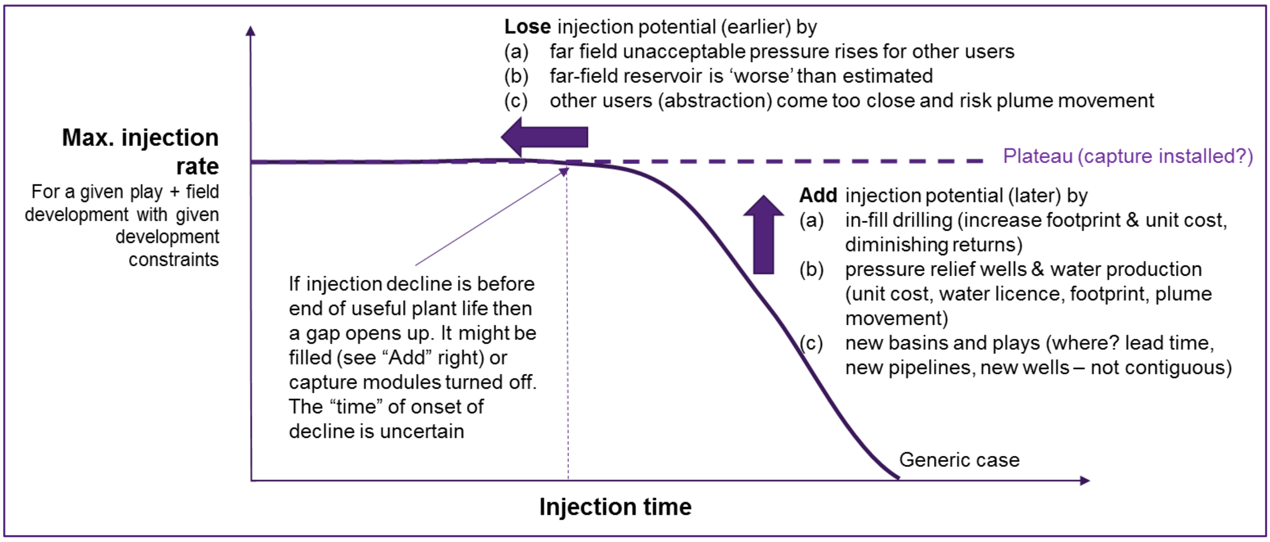


With reference to Figure 5, development options may exist which in later field life can extend a plateau. This includes in-fill drilling in areas with remaining, un-used pressure margin; or water abstraction for reasons of pressure reduction (margin increase). Conversely, the factors which give rise to fall-off in injection rate (bullet points above) could also act to reduce *expected* plateau times and cause early onset decline.

There may also be an option in future to in move to non-contiguous storage locations in different basins and plays with the added cost of new injection site infrastructure development and transport infrastructure. Similarly, unforeseen future events can cause injection potential to be "lost", thus reducing plateau durations.

For a given reservoir case and FDP, there are additional technical and non-technical uncertainties which also impact onset of decline and rate of decline, both positively and negatively.

Figure 5 Model for discussing late-life uncertainties in dynamic capacity.



These models may be useful to consider an evaluation methodology for plays and future projects.

3. Evaluation methodology (dynamic calibration)

3.1 Containment

A descriptive summary of methods to attain containment confidence is not included in this report. This report primarily concentrates on how to estimate a sustained rate of injection for a play or play segment.

In essence, the approach UQ-SDAAP used to build containment confidence was as follows:

- ✓ Map and avoid to the maximum extent (distance) all known potential leakage features (especially wells and faults)
- ✓ Avoid to maximum extent (distance) other sub-surface operators/users
- ✓ High-grade areas with likely thickest and 'tightest' seal (deeper, geologically more distal, basin centre locations)
- ✓ High-grade areas with minimum structural dip
- ✓ Construct an internally consistent (sequence stratigraphic) interpretation of the Transition Zone and Ultimate Seal and use this to guide lateral prediction away from data control to the high-graded areas
- ✓ Collate independent evidence of sealing potential, including:
    - o Lithology, core description and permeability
    - o Continuity, thickness and structure (seismic data)
    - o Hydrochemistry (differences in formation water composition within and across the Transition Zone and Ultimate Seal)
    - o Hydrostatic gradients (differences within and across the Transition Zone and Ultimate Seal)
    - o Hydrocarbon accumulations (presence of independent hydrocarbon columns in the Blocky Sandstone Reservoir and Transition Zone sands)
- ✓ Design the proposed operations and field lay-out to:

- Constrain allowable maximum injection bottomhole pressures to within 90% of the thermally adjusted fracture gradient of the Transition Zone
- Constrain bottomhole pressure build up to be significantly below estimated fault reactivation pressures (Rodger et al. 2019a)
- Minimise the number of new seal penetrations (wells) within the modelled CO_2 plume area by maximising injectivity per well within the defined pressure constraints (above)

The main issue is the absence of data for the sites, rather than specific evidence of leakages. In a typical oil and gas subjective assessment, the probability of success (Ps) and failure (Pf) is where:

$$Ps = 1 - Pf \qquad \text{(Eq. 1)}$$

Using this concept, if we consider "containment" only, we are obliged to assign some small, but finite Pf in the case of UQ-SDAAP because there are indications of high angle low offset faults on the seismic in the area and because there is some indication that the Ultimate Seal and Transition Zone may become more sand-prone and thinner to the south. These discrete risks are discussed in Honari et al. 2019e and applied to "value of appraisal" discussions in Garnett 2019a.

An alternative conceptualisation has been suggested by other authors using evidence based logic (QLE 2015) built around a features, events and processes (e.g. QLE 2010) and an evidence "tree" evaluation structure (e.g. Garnett et al 2012; Tucker et al 2013; Jagger & Drosin 2013).

A detailed evidence-tree based assessment has not been undertaken for the UQ-SDAAP evaluation because as this is an initial scoping study, project development is not being proposed. However, an illustration of confidence levels is included in Figure 6.

Figure 6 Illustration: level of evidence in support of confidence in containment (green) vs. absence of evidence (white) vs. evidence against containment (red)

	0%	100%	
Containment	*positive 'green' evidence from distance from possible leak features,regional geology, lithology, core MICPs, hydrogeology, HC accumulations, modelling of TZ response, very low regional dip (and constraints within FDP pressure choices)*	*white space' exists because of lack of specifc data at sites (main concern is faults and high NTG TZ - considered unlikely)*	*no driect 'red' evidence of containment related risk features at the sites*

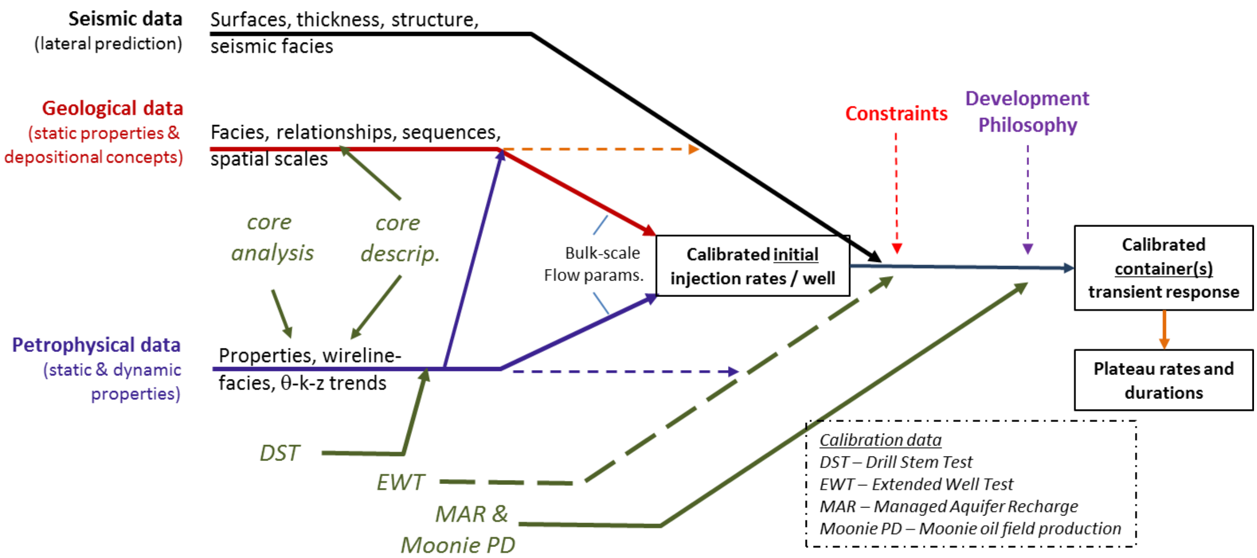
3.2 Sustained injectivity – calibrated dynamic capacity

The evaluation of sustainable injectivity (plateau) and duration has been undertaken via a series of discrete work packages in UQ-SDAAP, the results of which were synthesised in the main UQ-SDAAP Project Report (Garnett et al. 2019d). This has been done within the context of a defined container and within a defined development philosophy.

Garnett et al. 2019d, section 4, describes the detailed work-done in producing a dynamically calibrated assessment for the Blocky Sandstone Reservoir. As discussed, the detailed work program was a function of data availability. However, a generic information flow can be used (Figure 7) to illustrate the main areas where "dynamic calibration" has been achieved[4].

[4] For simplicity, the geomechanical and geochemical response to CO2 injection is included under the 'dynamic' term

Figure 7 Information flow for calibration of dynamic capacities.



With respect to Figure 7, the three main data types are shown (seismic, geological and petrophysical data) along with the main function of those data. The main data types for calibration are shown in *green*. For the UQ-SDAAP project, there was no data geographically located within the notional injection sites. Therefore, data from surrounding areas was extrapolated into the area of interest using various sophisticated techniques described in Gonzalez et al. 2019a; La Croix et al. 2019a, b; and Harfoush et al. 2019a, b and c.

In order to move between measured porosity and permeability data (core analysis and petrophysical analysis) and parameterisation of the dynamic model cells an upscaling process is required that is calibrated with available dynamic reservoir data. This includes the following steps:

- ✓ Various analyses yielded poro-perm, relative permeability, mercury injection capillary pressure, CO_2-water-rock reactivity and geomechanical data. Core analysis data calibrated poro-perm estimates from petrophysics (Harfoush et al. 2019b, Rodger et al. 2019b, 2019a, Pearce et al. 2019)
- ✓ Drill Stem Test (DST) data was used to calibrate the geological/wireline assessments of poro-perm at a larger scale. This data, together with geological and wireline facies, calibrated well “initial rate” estimates (Honari et al. 2019a)
- ✓ Newly collected extended well test (EWT) data was initially planned as part of UQ-SDAAP. However, the key wells identified became unavailable (Garnett 2019b). The collection of this is data has been planned as part of the site-specific appraisal plan (Honari et al. 2019c and 2019d). In line with previous work (Garnett et al. 2012), well tests at sites of interest are considered the main method to acquire the information required for confidence in long duration, plateau injection (Garnett et al. 2012)
- ✓ Managed aquifer recharge (MAR) and Moonie oil field production data, was not fully available when the project was initiated. However, their use for large-scale, long-duration dynamic calibration, together with major advances in geological conceptualisation, mitigated the loss of the intended EWTs (Hayes et al. 2019a, 2019b; Sedaghat et al. 2019; Honari et al. 2019b)

3.3 Summary

Calibration of dynamic flow from small (core), to well (DST), to large area scale is essential to increase confidence in forecasting the pressure transient of a play and container within it. Of these, the most valuable is the extended well test (or long-term oil and gas production or water injection data). One of the 'most valuable' outcomes in these terms is '*in establishing confidence that a plateau rate of injection can be sustained for a long period of time*'. Ultimately, confidence is rooted in the amount of site and play specific data, and constrained by the willingness to invest 'funds at risk' in appraisal activities (Figure 8 and Garnett 2019a).

Figure 8 Illustration of progress on confidence in sustained injection rate vs. data types, funds and time (static corrected pore volume calculations do not reduce uncertainty).

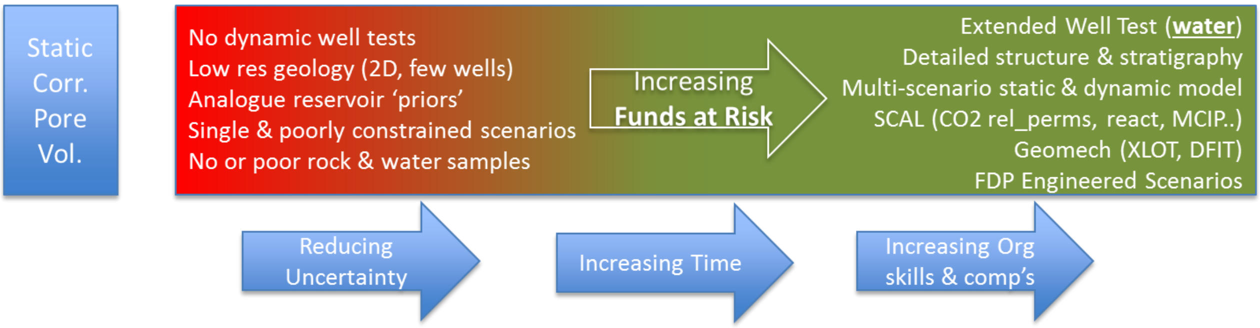
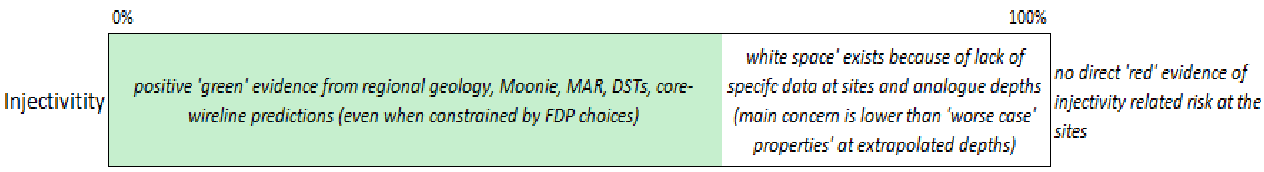


Figure 9 Illustration: level of evidence in support of confidence in containment (green) vs. absence of evidence (white) vs. evidence against containment (red).



4. The UQ-SDAAP container-specific dynamic capacity

UQ-SDAAP aimed to establish whether or not material carbon abatement was feasible in the Surat Basin in southern Queensland via large-scale CCS. The project sought to establish if *adequate* dynamic capacity was present or not. At this initial scoping stage, the project was not focussed on assessing the ultimate potential.

"Material" abatement was taken to mean *at least* the emissions of the remaining technical lifetime of one of the large supercritical power stations (nominally greater than 5 Mtpa for more than 20 years); and if possible, the majority of emissions of all three modern supercritical plants in the area. A working plateau rate of ~13 Mtpa was used as a reference case, representing the full retrofit of Millmerran and Kogan Creek and a partial retrofit at Tarong North. UQ-SDAAP assumed technical retirement dates of the power stations in the mid-2050s, an injection period of 20+ years, and all systems implemented for collection and injection to commence ~2030). All reservoir models were run for longer than this, accounting for surplus dynamic capacity across the three notional injection sites. The main limit to the plateau rate of ~13 Mtpa is the low surface footprint development philosophy. There is scope for maximisation (though not without additional data).

At the conclusion of the technical analyses, there remains a finite possibility that the play and selected sites are found not to be suitable. This can only be established with further site-specific appraisal (Honari et al. 2019d).

The *main* geotechnical risks are:

i. That there are fault barriers or leaking faults in the area which limit the reservoir volume and pose a pressure constraint risk

ii. That the reservoir is poorer (lower bulk permeability and/or thinner) than the "low case" e.g. due to depth induced diagenesis posing an infectivity and bottomhole pressure constraint risk

iii. That the Transition Zone and Ultimate Seal are found to be more sand-prone than modelled which would pose an unforeseen leakage risk

These risks are all considered to be relatively low.

If the chance of these occurrences are independently, say 20%, 10% and 10% respectively, then the combined chance of failure[5] is 35% and the a-priori probability of technical success is 65%, where "success" then has a range of "material" outcomes (all bigger than the minimum "materiality" criteria of 5 Mtpa for 20 years).

With reference to Figure 4 and Figure 5 (plateau rate vs. time uncertainties), illustrations of time-limited retrofit capture and current estimates of injection potential are shown in Figure 10 and Figure 11. The CCS deployment scenarios are those described in Gamma Energy Technology 2019.

The injection potential, uncertainty and capture profiles vary across three notional injection sites (North 1 and South 1 and 2).

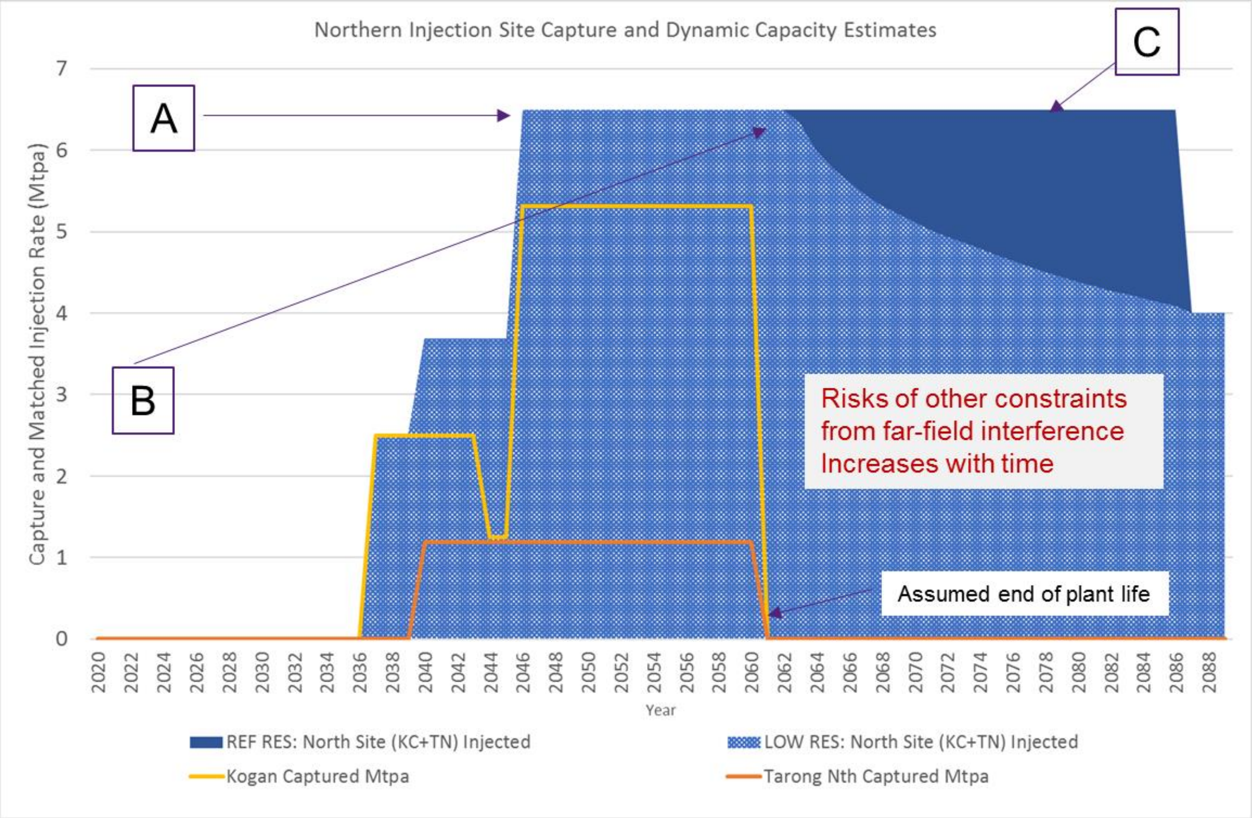
Northern site. With reference to Figure 10, the roll-out scenario (Gamma Energy Technology, 2019) leads to a notional ramp-up of injection rate matched to the capture development. The FDP and capture have been *engineered* to match at a maximum rate operated at maximum flowing bottomhole pressure (point A). It may be possible to modify the reference case FDP within the set philosophy and constraints to support a slightly higher rate (e.g. to complete the retrofit of Tarong North or to add CCGT emissions), but this *may* be at the cost of reduced plateau durations. Figure 10 shows a potential injection profile, with light blue representing a "low" or poor reservoir case and a "ref" or reference reservoir case shown in dark blue). If the low case is encountered, then the site could accommodate the captured emissions (> 6 Mtpa) just beyond the assumed

[5] For three independent failure case probabilities Pf1, Pf2, and Pf3, the probability of success = (1-Pf1) x (1-Pf2) x (1-Pf3)

end of plant life (point B). If the reference reservoir case is encountered, then there would be potential to continue injection at high rate for an additional ~25 years (point C).

There may be sufficient storage injection potential to support significant plant extensions, new builds or the later "plumbing in" of CCGT capture plants in the high-graded area.

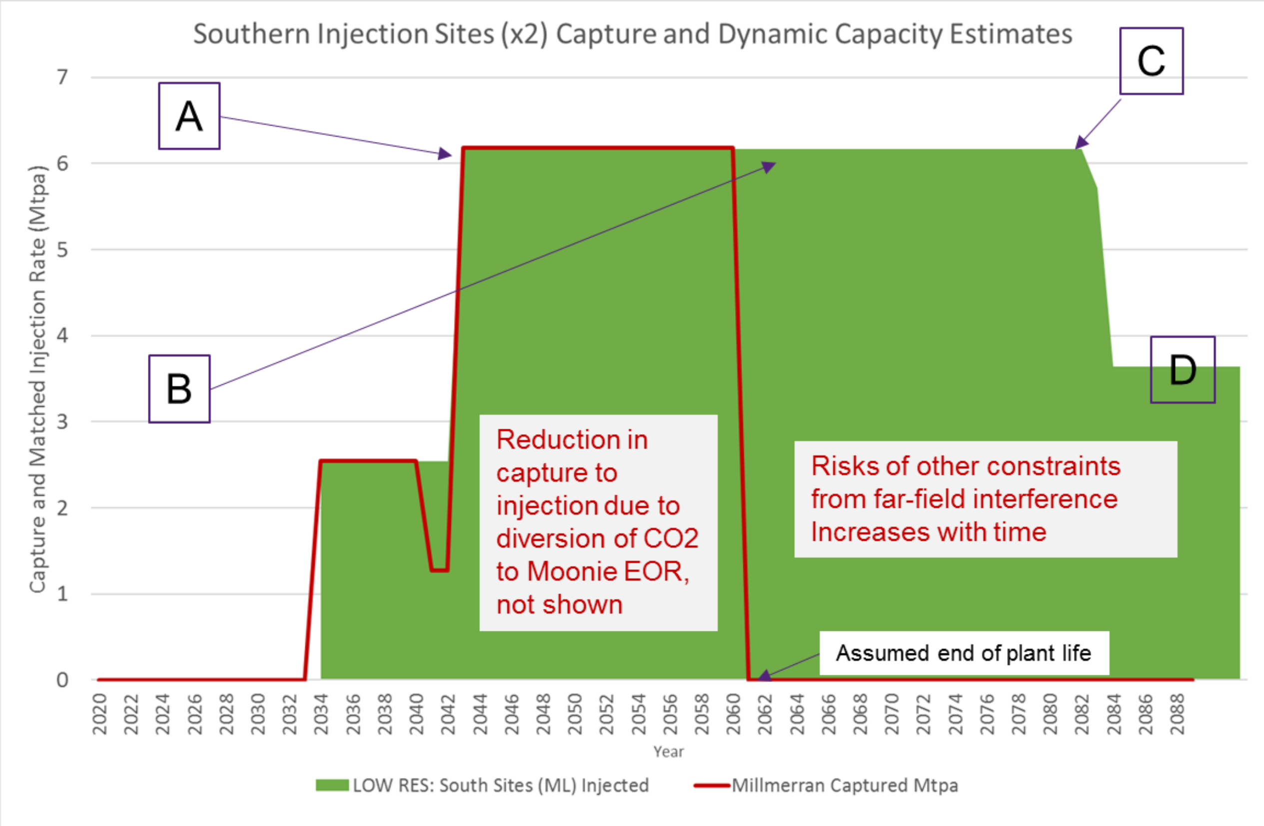
Figure 10 Injection potential, uncertainty and capture profiles for northern site (scenario 1, nominal dates).



Southern sites. With reference to Figure 11, a notional capture deployment ramp up is shown. Again, the FDP and capture have been *engineered* to match at a maximum rate operated at maximum flowing bottomhole pressure (point A). In the south, it is more difficult to attain a ~6 Mtpa rate. Two injection pads are required due to poorer reservoir quality in the reference case than in the north (though this could give some potential for additional wells within the footprint constraint). The solid green in Figure 11 shows injection potential profiles for a "low" or poor reservoir case. A reference reservoir case is not shown in this figure because low and reference case reservoirs are similar in this area. In this low case, the FDP has included additional wells on the same pads. Beyond this, options for in-fill drilling to manage decline would be limited under the development constraints, and expansion to the south is thought to be limited due to increasing seal risk. Nevertheless, even in the low reservoir case, there is still potential for a major plant emissions abatement for around 20 years *beyond* the assumed life of existing plants (point B).

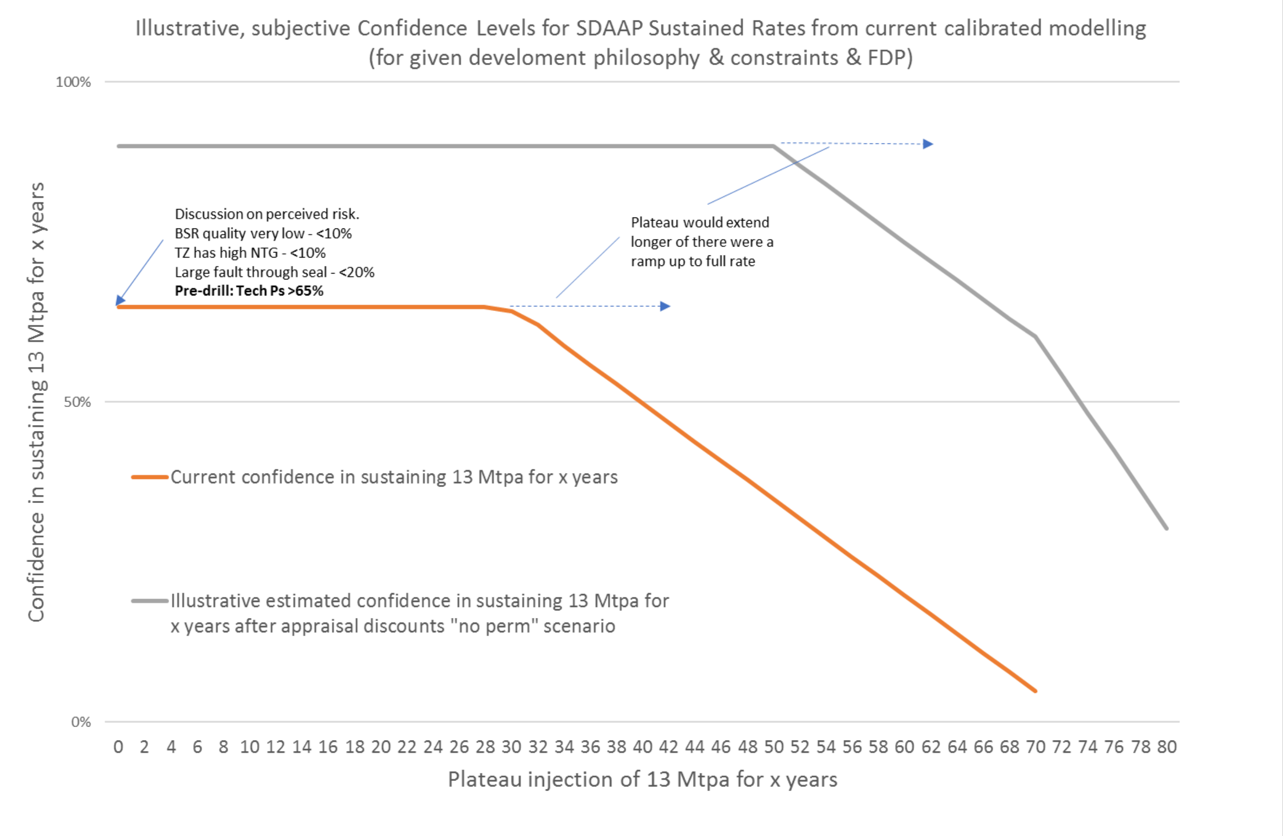
Towards the end of the plateau (point C), the reservoir dynamic is influenced by interference between the two pads and decline would be relatively rapid after this. Note that the apparent "levelling off" of injection potential at point D is an artefact.

Figure 11 Injection potential, uncertainty and capture profiles for southern two sites (scenario 1, nominal dates).



As a whole, the dynamic capacity evaluated by UQ-SDAAP is approximately 13 Mtpa for at least 30 years, and possibly up to 40 years or longer. An illustration of current views and confidence levels is given in Figure 12.

Figure 12 Illustration: confidence in ~12.7 Mtpa now and (est.) after appraisal (20 to 40 years). It is expected that confidence in longer plateau periods would be influenced by the appraisal activity and early operations with M&V.



5. Summary

For any proposed sequestration site or sites, the challenge at hand is not to sequester a given *volume* of CO_2 but to sequester a given *rate* for a sustained, defined period. This comes from the higher-level global need to reduce global emissions *within a given time frame*, in order to maintain a limit on global temperature rises (IPCC 2018).

Historical static methods either fail to recognise that mitigation is a rate-governed challenge and/or implicit assumptions are made that large static capacities can support a large sustained injection rate and that somehow sustainable injection rate is mainly a function of capacity.

UQ-SDAAP developed a generic methodology for delivering a useful “rate-matched” capacity with uncertainty that can be used to design a targeted appraisal plan followed by a more constrained field development plan. This analysis, and the defined rate governing features of a storage play, serves as a basis of design (scale and rate) for capture facilities.

Key take-away messages from this work include:

- The basis of design for capture rate in a CCS hub is constrained by confidence in storage potential, its plateau rate and how long it can be sustained
- Confidence is lower for higher plateau rates and confidence decreases for longer sustained plateaus
- Even when a field development plan can be constructed that can attain the required injection rate, significant uncertainty in the onset of injection decline is driven by uncertainty in the geology

- Geological uncertainty is quantifiable as a part of the upscaling process required to translate measured geological data (core analysis and petrophysical analysis) into dynamic model parameterisation calibrated against dynamic reservoir information (drill stem tests, extended well tests and field production/injection response)
- For a given reservoir case and FDP, there are additional technical and non-technical uncertainties that also impact onset of decline and rate of decline, both positively and negatively
- In the case of UQ-SDAAP notional injection sites, there is sufficient injection and dynamic storage potential to support the reference case of ~13 Mt/yr for 30 years and may support additional significant plant extensions, new builds or the later “plumbing in” of CCGT capture plants in the high-graded area

END

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6. References

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