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ZEROGEN
IGCC WITH CCS
A Case History
Acknowledgements

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Editors’ Foreword

This ZeroGen Case History was initiated during the final close–down phase of the project after an end–Prefeasibility Phase stage–gate. In general, it should be expected that a large proportion of first–of–a–kind, commercial–scale CCS projects, like ZeroGen, will (and should) stop at these earlier stage–gates. Given this, a ‘stop scenario’ knowledge capture and dissemination plans should be in place and funded as part of the base case. In ZeroGen’s case this was not so. However, the project co–funders, Queensland and Australian Governments and the Australian Coal Association, remedied this and committed to this volume in a desire for greater dissemination.

This Case History is a compromise between the need to wrap–up and summarise key lessons and experiences and the need to describe the work underpinning these lessons to a level which will satisfy many different groups. The report is derived in large part from the confidential Prefeasibility Study (PFS) augmented when possible with additional material provided by former ZeroGen personnel. It is to the great credit of the co–funders as well as Mitsubishi and Shell that so much PFS material could be released in this way. While the editors have sought to document both project content and to summarise lessons learnt, there will inevitably be too much detail from some, and not enough for others. Nevertheless, the material is just the tip of an iceberg representing well over 100,000 man–hours of study. An extensive reference list is also included and while many of the reports cited are internal and confidential, they are included to further inform readers of the depth of work required to underpin such studies.

The Case History is divided into three chapters covering general project management overview material and IGCC and storage development. An attempt has been made to ‘tell the story’ rather than just provide 20:20 hindsight. Thus, each chapter has an executive summary and each chapter commences with a context and lessons learnt summary which is followed by more information. The executive summary in the first, project management overview chapter is a compilation for the whole report.

As much technical and cost data as time and confidentiality allowed are included in each of the three chapters. And, while in the storage chapter, much of the data and findings are site specific, detail has been retained better to inform the levels of analyses which might be required in other projects and also to deepen an appreciation of why the main storage resource proved unsuitable.

It is hoped that readers will recognise the importance of conducting CCS project studies at commercial scale and in real locations. Demonstration–scale projects will not adequately inform the costs and challenges of full–scale deployment, and it is not just storage that raises site–specific challenges.

Finally, to all others engaged in this endeavour to deploy low emissions, base–load power, we hope that this volume is of use and wish you the best of luck.
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Executive Summary

After having evaluated several different CCS project configurations, scales and technologies, in 2008 ZeroGen embarked upon a major Prefeasibility Study (PFS) for a nominal 500 MW Integrated Gasification Combined Cycle (IGCC) plant with carbon capture and storage (CCS) in Central Queensland. This included capture, transport and storage of some 60–90 million tonnes of carbon dioxide ($\text{CO}_2$) over a 30 year period. The commercial–scale deployment study was funded by the Queensland and Australian Governments and the Australian Coal Association, and it is a sign of these funders’ commitment to CCS that they adopted this relatively high–risk, large–scale approach. ZeroGen’s lessons from uncovering and quantifying the scale of the deployment challenges (especially in an Australian setting) are important and have assisted in moving the CCS debate into the space required if major capital project developments are to be realised.

While the project produced a high calibre, fit for purpose PFS, as recognised by an independent expert review panel, it did not progress beyond the end of the prefeasibility stage which ended in mid 2010. Many lessons emerged from the study, however in essence, the high–level reasons for project close are two–fold.

First, deploying an IGCC plant with CCS requires that an expensive, first–of–a–kind (and initially less reliable) power plant can attract investment and can operate in some way commercially in a highly competitive electricity market. ZeroGen demonstrated that this would require a degree of public funding support both in the development phase as well as in ongoing operational phases beyond that thought likely to be available. With a fully–loaded capital cost estimate for all capture, transport and storage assets of $6.9 billion and low productivity compounded by a high cost base (due to competition with large mining and CSG projects), it also became evident that Australia would be a relatively expensive location in which to attempt this.

Second, although over 70% of prefeasibility costs were consumed by the search for and appraisal of underground storage, the main and only available sub–surface resource proved not to be suitable. Other areas did become available at the end of the PFS, however, only desk–top studies were possible. A far higher level of storage confidence would be required prior to further and larger investment in the further development of the power plant and capture facility. The specific time–frame available to the ZeroGen special purpose vehicle did not allow for a recommencement of storage exploration.

From the ZeroGen experience, it is clear that in–depth, PFS at commercial scale are essential. Notwithstanding large uncertainties in storage and transport costs, capital cost estimates for the power plant with capture escalated by 46% compared to earlier ‘scoping’ studies. Approximately 26% of this escalation was due to design growth and additional scope (especially enabling infrastructure) and a further 20% was due to Australian–specific factors such as exchange rate and local productivity factors (vs international benchmarks costs).

Moving forward, it is hoped that the lessons contained in this Case History will assist others in achieving the large–scale deployment deemed necessary for CCS to contribute to GHG mitigation.
Major Lessons Learnt

**Industrial–scale, low emissions coal–fired power projects incorporating CCS are not currently economic.** Deployment and operating costs for ZeroGen were found to be at the upper limit of published ranges. The project would therefore have required significantly heavier and more ongoing government financial support than had previously been thought likely.

First–of–a–kind low emissions coal–fired power projects that incorporate CCS have very high capital and operating costs and with forecast electricity and carbon prices, will generally not be financially viable. This issue is exacerbated in the Australian context where strong levels of major project activity in the resources sector have created a skills shortage which is adversely impacting labour cost and productivity. Such low emissions coal–fired power projects must rely on large capital and operating subsidies, the majority of which governments will be required to fund. While limited funds are potentially available from strategic investors such as the coal industry and technology providers, the project team for this first–of–a–kind project identified a large funding gap which could not be closed.

**Industrial–scale is not a simple scale–up from demonstration–scale**

The ZeroGen experience indicates that CCS projects should be approached at commercial scale. It is only at this scale that significant reality checks can be made regarding schedule, cost and performance predictions, and only at this scale that the main locally–relevant deployment challenges emerge and can be understood. Desk–top analyses proved inadequate. In particular for storage, a significant acquisition and evaluation (drilling, testing and seismic) program proved to be necessary and this should have been conducted well before significant power plant engineering commenced. Such exploration and appraisal programs are, by their nature, subject to significant uncertainty as is the level of *funds at risk*. Furthermore, the scale of funds available for such programs should be flexible and large enough to provide a portfolio chance of success in line with the risk tolerance of the funders.

**Measured management of pace of ‘first’ projects is critical to wider deployment**

The first CCS projects carry the burden of ‘proof’ for follow–up wider deployment. Risk management, approaches to Environmental Impact Assessments and public consultation will need to be conservative and measured. However, this requirement runs counter to an urgent push or mandate for an early operational start date. In particular, the ZeroGen experience suggests that, at least in the case of IGCC, CCS project schedules need to be risk optimised, such that larger investment decisions in plant and capture are not taken before achieving sufficient confidence that storage (i) is present, (ii) will perform as required, and (iii) is licensable and acceptable.
Pre–FEED and feasibility risks and costs are heavily weighted to the search for storage

Prior to Front End Engineering Design (FEED) and probably prefeasibility stages for an integrated CCS project, the majority of risk and expenditure lies in finding and appraising storage resources to a sufficient level of confidence (in storage security and sustained injectivity) to justify a larger investment in plant. In ZeroGen’s case, over 70% of expenditure to end PFS was related to storage (and this was to ultimately establish the site was not appropriate)—20% to plant and capture. Forecasts to evaluate an entirely new storage area to a mature stage of characterisation would have resulted in over 90% of costs, to the end of prefeasibility, being storage related.

Storage is a natural resource, a portfolio exploration and appraisal approach is needed

Exploration and appraisal of potential storage sites requires a portfolio approach to create multiple options to allow for some sites which might be found to be ‘unsuitable’. A large amount of expensive data gathering should be expected and while success rates might be higher than in the oil and gas exploration sector, delays and escalating costs are still likely to be significant with storage exploration.

Storage exploration and appraisal data acquisition and study programs should be focused on reducing large geotechnical uncertainties. Acquiring data and conducting analyses which can quickly polarise the suitability or otherwise of a site are of highest appraisal value and may allow for a rapid reduction in the need for further exploration spending.

It is essential to develop clear storage decision criteria, with both confidence levels and performance targets, which will define whether subsequent stages of (often larger) investment in plant should go ahead.

When defining storage resources requirements it is essential to discuss the consequences and trade–offs between injection rate and/or cumulative volume objectives

Storage resources and field developments which are required to match specific injection rate requirements are likely to be significantly different from those which must only fulfil a cumulative volume target.

The former may require significant and continuous in–fill drilling and has implications for sparing, redundancy and pressure management (including aquifer off–take). The latter has implications for operational venting, the time variant carbon intensity of emitting plant. Both have implications or may set constraints on capture capex and phasing.

Appraisal of storage site and predictions of ‘reserves’ and performance must be based on long term, dynamic well testing (production or injection) and not on static–based derivations of capacity as is currently the case for most published estimates. Many published basin–wide estimates are likely not to be a useful indicator of the amount of practical storage available.

In addition to extended well tests, conceptual, engineered field development plans are essential and need to be constrained by real surface and environmental factors and potential sub–surface risk features. Development drilling sequences need to be simulated to account for static and dynamic uncertainties and show how injection rate might be installed over time and might need to be maintained by in–fill drilling or venting or development of and transport to other sites.
High front–end engineering loading is needed for first–of–a–kind

Integrating CO₂ separation technologies with power generation is not mature and there remain significant technical risks. Proponents must recognise that these projects are technically complex and it is not just a simple matter of ‘integrating well understood, proven technologies’. Such statements understate the challenges and set unreasonable expectations for project development schedule and cost and, potentially, for plant start–up performance and availability. Significant further technical development and engineering is required to provide confidence in plant design and performance.

Furthermore, if first–of–a–kind projects are to become economically viable then, notwithstanding currently immature ‘breakthrough developments’, significant developments in commercial terms and project financing as well as significant technical improvements will be required. Funding arrangements must sustain an organisation through the project reviews and decision making processes that are inevitable between phases of a project.
CHAPTER ONE
Project Management and Overview
1 Executive Summary

ZeroGen completed a PFS for an industrial-scale, low emissions coal-fired power project integrating IGCC with CCS, in July 2009. The project was to be located in Central Queensland, Australia and would utilise thermal coal from the Southern Bowen Basin.

Project decision to close

ZeroGen took a decision to close the ZeroGen commercial-scale IGCC with CCS demonstration project in November 2010 following a review of the PFS outcomes. The reasons for this decision were:

- inability of the Northern Denison Trough storage resource to accommodate the sustained injection rates or volumes of CO₂ required by the project;
- uncertainty as to the timely award of sufficient tenure and funding necessary to successfully appraise an alternative CO₂ storage resource;
- very high capital and operating costs which could not be supported by anticipated revenue streams;
- technical risks around the CO₂ capture technology and project integration; and
- lack of credible project funding opportunities to achieve financial close.

The ZeroGen Project was well supported for the scope of study activities proposed, by its owner and key funding sponsors who had a genuine stake in the success of the project. However, the funding arrangements did not allow sufficient funds or provide a basis to sustain the organisation through the project reviews and decision making process that is inevitable between phases of a project.

The project had been through a number of reconfigurations since 2004, generally to meet expectations of the owner and key funding sponsors who sought to accelerate the development cycle toward industrial deployment. There appears to have been a lack of formal risk assessment in relation to these significant changes in configuration despite the considerable elevation of project size and risk profile.

Capital and operating costs high

Extensive engineering and cost estimating studies were conducted to a relatively high level of completeness considered to at least meet ZeroGen’s standards for a PFS. These included studies specific to the power plant and CO₂ capture facilities, as well as balance of plant, enabling infrastructure costs and owner’s costs. These studies informed material elements of the final headline, fully loaded, forecast capital costs of approximately $6.9 billion (detailed in Chapter One). This headline cost is broken down approximately as follows:
CHAPTER ONE Project Management and Overview

<table>
<thead>
<tr>
<th>Main project cost area</th>
<th>AU billions</th>
<th>% Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>ZG owner’s costs</td>
<td>$ 0.30</td>
<td>5%</td>
</tr>
<tr>
<td>Enabling works</td>
<td>$ 0.62</td>
<td>11%</td>
</tr>
<tr>
<td>Power plant incl. balance of plant</td>
<td>$ 3.90</td>
<td>68%</td>
</tr>
<tr>
<td>Carbon transport and storage</td>
<td>$0.80</td>
<td>14%</td>
</tr>
<tr>
<td>Operations readiness and start–up</td>
<td>$ 0.14</td>
<td>2%</td>
</tr>
<tr>
<td><strong>Total base estimate</strong></td>
<td><strong>$5.76</strong></td>
<td><strong>100%</strong></td>
</tr>
<tr>
<td>Direct project contingency</td>
<td>$ 0.52</td>
<td>9%</td>
</tr>
<tr>
<td>Escalation</td>
<td>$ 0.65</td>
<td>11%</td>
</tr>
<tr>
<td><strong>Total fully load capital cost</strong></td>
<td><strong>$6.93</strong></td>
<td></td>
</tr>
</tbody>
</table>

At $3.9 billion, the majority (circa 68%) of the ZeroGen forecast capital costs between end–PFS and operational start up were related to power plant and capture.

It is noteworthy that significant additional costs were included in the estimate which are often missing from published non–site specific, non–Australia specific estimates. Costs in a Central Queensland setting incur significant additional ‘enabling costs’ such as infrastructure, water and transport and are also impacted by local, notably low, productivity factors. Given increased local, major projects activity and regional markets, it is also very important to consider real escalation factors and the competition for human talent.

For ZeroGen, significant engineering studies and commercial negotiations were conducted in parallel with the search for CO₂ storage. This was a reflection of the funders’ commitment to CCS deployment and to a sense of urgency. However, because of a 2015 operational timeline, mandated by the Commonwealth’s CCS Flagships program, to further progress to a feasibility stage ZeroGen would have needed to invest in excess of $400 million in engineering studies and long lead items for the power and capture facilities, while the search for storage would have been reset to the beginning in an entirely new area. The estimate to ‘sufficient storage confidence’ for those elements of the project alone was of the order of $180 million.

The operating cost estimates were also considered high and likely to exceed anticipated revenues.

Without a confirmed storage site, CO₂ transport and storage costs remained only at a scoping level of accuracy. But even with conservative development assumptions, in this setting investment in storage is likely to be less than 15% of total project capital cost.

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1 Note that references to the ‘Commonwealth’ in this document refer to the Commonwealth of Australia and the Australian Federal Government.
PFS including exploration\(^2\) cost $138 million

The total cost invested in the PFS including CO\(_2\) storage exploration and appraisal activities was approximately $138 million.

The majority (circa 73%), of the ZeroGen PFS costs were related to exploration drilling, testing and studies required to answer the key criteria defined for a ‘stop or go’ decision for CO\(_2\) storage. While storage was confirmed to be secure to a reasonable level of confidence, the area available and under tenement could not sustain the required injection rates for a commercial-scale operation.

Funding arrangements were complex

It is essential to ensure that the funders and stakeholders have access to adequate technical and decision support to understand the degree of risk and uncertainty known to the projects and that this understanding is explicitly shared. Ideally, the project proponent would be regarded as the funders’ own team—but would be distinct from any vendors or major service providers.

Multiple funding parties introduced a high degree of complexity in relation to the formation and administration of agreements and project governance. While not possible for ZeroGen due to its complex evolution, serious consideration should be given to funding bodies creating a collaboration or ‘joint venture’ agreement between themselves and a single funding agreement for the proponent to simplify the project–funder interface.

Project development approach departed from convention

There were clear departures from the conventional project development principles and from ZeroGen’s own system. These were generally justified on the basis of reducing project risk (e.g. early selection of technology vendors). However the decision to proceed with the PFS without first having a reasonable level of technical and development confidence in at least one CO\(_2\) storage resource was a very high risk strategy. ZeroGen explained to its funding stakeholders that it was necessary to take such a risk if it was to comply with the criteria set down to access critical Commonwealth CCS Flagship grants.

ZeroGen also had only one potential CO\(_2\) storage play to explore and appraise. This was also a very high-risk option that amplified the risk articulated in the preceding paragraph. However this was a constraint over which ZeroGen had no control, especially when the ZeroGen tenements represented the only Greenhouse Gas (GHG) storage exploration permit available in onshore Australia. ZeroGen did explicitly identify this risk to its owner and funding sponsors.

Environmental studies commenced prematurely

The project commenced significant studies to establish the environmental impact of the project. Environmental Impact Studies (EIS) were undertaken for two of the development proposals. The latest was in 2009–10 for the commercial-scale development. In neither case were the studies completed prior to the study work being terminated.

\(^2\) NB: this includes CO\(_2\) storage exploration activities undertaken for pre–PFS earlier project stages and configurations going back to 2006.
The project schedule which mandated start–up in 2015, had the EIS process on the critical path so that it would need to commence before the appropriate levels of definition and reduction of risks and uncertainties had been achieved. In reality, the mandated project schedule constraint could never align with regulatory approval processes. Another issue facing early–mover CCS projects is the issue of a longer learning curve for regulatory approvals and the knowledge of the regulator’s personnel. ZeroGen recommends that planning for such projects should allow (time and cost) for 20–50% longer than typical approval times.

**Stakeholder and public engagement and communications is critical**

ZeroGen had a successful stakeholder engagement and communications program until the decision to close the project. Reaction to the closure was very negative in the Queensland print media. While ZeroGen explicitly and consistently articulated the considerable risks and uncertainties associated with the project, some engagement messages were arguably optimistic given the complexity of a ‘first mover’ project. It is possible that the various processes by which project proponents compete for, and are awarded funding discourages candour or indeed can lead to a culture of over–promising. The contingent nature of any possible full project deployment needs to be a central theme of any stakeholder (especially public) engagement at earlier project study stages.

**Project finance arrangements problematic**

Industrial–scale first–of–a–kind coal–fired power plants with CCS require large sums of capital and with forecast electricity and carbon prices, there is no (financial) business case to support the investment. ZeroGen developed a conceptual project financing plan with the assistance of a recognised financial adviser. The main sources of funds were grants and or equity from governments and ACA Low Emissions Technologies Limited (ACALET). Corporate investment and debt finance are highly improbable sources of funds for first–of–a–kind CCS projects. In reality, a ‘credit wrap’ from a government entity would be required to cover the gap between projected revenue and costs of operations and debt (if any) servicing.

Informal feedback was obtained from the proposed Australian grant and equity funders that the amounts proposed exceeded their investment/risk appetite for the project.

The challenge to fund a large, integrated IGCC and CCS power project remains one of the major barriers to demonstration and deployment in Australia. This could be assisted by considering a reframing of the CCS Flagship guidelines and the *Queensland Clean Coal Act*. 
2 Project Context

This section describes the strategic rationale, project ownership, key stakeholders and the history of the project from its inception to closure.

Lessons learnt

The strategic context for the ZeroGen Project is well documented and supports the approach taken. The ZeroGen Project was supported for the scope of study activities proposed, by its owner and key funding sponsors who had a genuine stake in the success of the project.

However the funding arrangements did not allow sufficient funds or provide a basis to sustain the organisation through the project reviews and decision making process that is necessary between phases of a project. This added to the complexity of the decision to close ZeroGen.

Notwithstanding that potential flaw in the arrangements, the decision to suspend/cease the project is considered appropriate.

The project went through a number of reconfigurations, generally to meet expectations of the owner and key funding sponsors who sought to accelerate the development cycle toward industrial deployment. There appears to have been a lack of formal risk assessment in relation to these significant changes in configuration despite the considerable elevation of project size and risk profile.

2.1 Project Ownership and Funding Sponsors

The ZeroGen Project started within Stanwell Corporation, after which the company ZeroGen Pty Ltd was established as a subsidiary to a government–owned corporation (Stanwell), and then sold back to the Queensland Government. It became a government–owned entity, however it has operated under an independent board of directors with an officer of the Queensland Government as the shareholder.

In 2007, the Clean Coal Technology Special Agreement Act was brought into force with the objective of ‘accelerating the development, demonstration and widespread implementation and use of clean coal technology by encouraging collaborative investment, by the State and the coal industry, in research, development and demonstration’. This Act brought into existence the Queensland Clean Coal Council which was to provide recommendations to the Queensland Premier on the projects to be funded. The funds were to be held by ACALET and $300 million was to be reserved for an IGCC project in Queensland. The Premier had the right to determine the scope and scale of the IGCC project to be funded.
The key project sponsors and their rationale for supporting the project are as follows:

(a) The Queensland Government

The Queensland Government was the sole owner and major funder of the ZeroGen Project. It contributed a total of $102.45 million in equity which was spent on early investigations and the PFS for an industrial-scale integrated IGCC with CCS project.

84% of Queensland’s electricity is generated from conventional black coal–fired power stations and black coal is the state’s largest export earner. Accordingly, Queensland’s economic prosperity is tightly linked to the future sustainability of coal as a source of electricity generation and to its continued export and use in Asia and elsewhere.

Transitioning to a clean energy future was one of the core elements of the Queensland Government’s response to climate change. Through its ClimateSmart 2050 policy, the Queensland Government was actively pursuing the development of clean energy sources to ensure that the State plays its part in helping to achieve the national target of a 60% reduction in greenhouse gas emissions by 2050.

Queensland’s climate change policy outlined a long-term strategy to secure a clean energy future for the State, based on investing in the development and deployment of low-emission coal technologies and included:

- an emphasis on the use of low-emission coal technologies in power generation, with a direct investment (by both government and industry) for the development of these technologies in Queensland over 10 years; and
- a requirement that any new coal–fired power stations constructed in Queensland must utilise ‘newly emerging clean coal technologies, which provide for carbon capture and storage, and efficient water practices’.

As a contingency to the above, if the State demand required new electricity generation capacity before low-emission coal technologies were commercially available, coal–fired generation capacity would only be considered where the power station:

- was linked to facilities which provide a capacity for carbon capture or CCS;
- was associated with a major energy-intensive facility attracting foreign investment which might otherwise be situated in a Kyoto Protocol–participating nation that does not have binding emissions targets (i.e. developing nations), and the project adopts best–practice generation technology; and
- provided a response to a threat to security of electricity supply in Queensland (where supply cannot be economically met by alternative energy services in the relevant time frame), and the project uses best–practice generation technology.

(b) Australian Government

Like Queensland, Australia as a nation relies heavily on coal for the generation of electricity, and coal exports are the nation’s second largest export earner. The $4.5 billion Clean Energy Initiative (CEI) which was announced in the May 2009 Federal Budget, complemented the expanded Renewable Energy Target by supporting the research, development, and demonstration of low–emission energy technologies.
Funding for the CEI and associated programs included the $2 billion CCS Flagships Program. The CCS Flagships Program was established to accelerate the deployment of large–scale integrated CCS projects in Australia and was expected to fund two to four projects. The objective of the program is to deploy 1000MW of low–emission fossil fuel technologies.

The Australian Government contributed $38.5 million in grant funding to ZeroGen for the PFS for an industrial scale–integrated IGCC with CCS project.

(c) Australia’s black coal industry

Australia’s black coal industry has established the Coal21 Fund, a world first voluntary industry fund into which the coal producers pay a levy on each tonne of coal produced. This will raise over $1 billion over 10 years to fund the development and deployment of low–emissions coal technologies in Australia. This fund is administered by ACALET, which provided $47.1 million in grant funding to ZeroGen for the PFS for an industrial–scale integrated IGCC with CCS project.

2.2 Project History

The ZeroGen Project was initiated in 2003 by Stanwell Corporation, a Queensland Government owned corporation and major electricity generator. Initially Stanwell conducted desk–top studies of various technologies for low emissions coal–fired electricity generation. These studies concluded that the project proceed with a pilot scale IGCC with CCS.

In March 2006, Stanwell incorporated ZeroGen Pty Ltd as a wholly–owned subsidiary to undertake feasibility studies and other investigations to assess the technical and commercial merit of the project.

In March 2007, ownership of ZeroGen Pty Ltd and the project was transferred to the Queensland Government and an equity funding agreement completed to fund the feasibility study for the pilot scale IGCC and CCS project.

The scope of the feasibility study covered both the pilot–scale power generation facility and associated infrastructure and also included an exploration and appraisal program in the Northern Denison Trough (NDT), near Springsure approximately 300 km west of Rockhampton. The GHG exploration permits in the NDT were, at that time, the only available tenements for exploration and appraisal activities in respect of CO₂ storage potential in Queensland, or in fact, mainland Australia. The IGCC and CO₂ capture and compression facilities were to be located adjacent to the Stanwell Coal Fired Power Station approximately 80 km west of Rockhampton (Figure 2.1).
In early 2007, the project basis was reconfigured to a larger two–stage configuration including a 120MW (gross) demonstration project to be operational in 2014, followed by an industrial–scale project to be operational in 2020. This reconfiguration was driven by the Queensland Clean Coal Council, seeking to accelerate the development schedule to industrial deployment.

In late 2008, ZeroGen was approached by Mitsubishi Heavy Industries (MHI) with a proposal to proceed directly to an industrial–scale 530MW (gross) IGCC plant including CO₂ capture and compression. At the same time the key project sponsors and board of ZeroGen mandated a new mission for ZeroGen to ‘develop a fully integrated, industrial–scale IGCC with CCS project in Queensland to be operational by 2015’.

ZeroGen completed a scoping study to validate the potential merit of such a project, based on the MHI proposal, to justify the investment in a PFS. The PFS for a commercial–scale configuration (nominal locations, Figure 2.2) was funded by the Queensland Government, Australian Government, ACALET and MHI (in kind) and was completed in June 2010.
In November 2010, the management of ZeroGen recommended the closure of the project for the following reasons:

- inability of the proposed NDT storage resource to accommodate the sustained injection rates of CO₂ required by the project;
- uncertainty as to the timely award of sufficient tenure and funding necessary to successfully appraise an alternative CO₂ storage resource;
- very high capital and operating costs which could not be supported by anticipated revenue streams;
- additional design definition required around the CO₂ capture technology and project integration; and
- lack of credible project funding opportunities to achieve financial close.

It was assessed that these critical risks were unlikely to be resolved within a time frame which would allow ZeroGen to survive with its available funds or, any reasonably likely sources of additional or interim funding.

These recommendations were accepted by the board of ZeroGen and the shareholder. The decision was made in early 2011 to proceed with an orderly closure of the project and wind-up of ZeroGen Pty Ltd.
3  Project Development Approach

This section describes the project development approach adopted by ZeroGen.

Lessons learnt

ZeroGen had in place capital investment processes and systems which were robust for this type of project.

A comprehensive mapping of the complete scope of works and services for the project is considered to have delivered a robust estimate of the required capital investment, notwithstanding the technical uncertainties associated with the project.

There were clear departures from conventional project development principles and from ZeroGen’s own system. These were generally justified on the basis of reducing project risk (e.g. early selection of technology vendors). However the decision to proceed with the PFS without first having a reasonable level of technical and development confidence in at least one CO₂ storage resource was a very high–risk strategy. ZeroGen explained to its funders that it was necessary to take such a risk if it was to comply with the criteria set down to access critical Commonwealth CCS Flagship grants.

ZeroGen also had only one potential CO₂ storage play to explore and appraise. This was also a very high–risk option that amplified the risk articulated in the preceding paragraph. However this was a constraint over which ZeroGen had no control because its exploration permits were the only ones granted onshore Australia. ZeroGen did explicitly identify this risk to its owner and funding sponsors.

It is a mark of funders’ commitment to CCS that despite the relatively high–risk profile, they elected to fully fund a commercial–scale PFS.

The Commonwealth CCS Flagships Program and similar competitive processes for project funding mandate a project schedule which includes start–up dates for operational plant as a requirement for qualifying for funds. Such dates are mandated even before feasibility studies are complete and in some cases, without licensed access to resources or environmental approvals. Such start–date qualifying conditions, particularly in first–of–a–kind projects, provide a disincentive for candour from project proponents with respect to actual project maturity and cost and schedule risk. Similarly, such processes may also discriminate against those projects which are most advanced and hence have the most in–depth appreciation of delivery risks. Whilst this might be acceptable for fundamental research funding, it is very dangerous in development of large–scale capital projects. This dynamic has been previously documented for similar contexts, and should be considered by funders of large–scale, flagship–type project funds.
3.1 Generalised Staged Project Development

The ZeroGen team put in place a Capital Investment System (CIS) prior to the initiation of the scoping study phase and followed the system throughout the development to date. The CIS system utilises a hierarchical system that applies policies through the use of minimum standards for critical elements and stages of the project development cycle (Figure 3.1). The minimum standards provide structured frameworks, benchmarks, procedures and templates for various activities.

**FIGURE 3.1: PROJECT DEVELOPMENT FRAMEWORK**

It is important to recognise that the progression of a project through this development process is about systematically moving through each phase, from broad project identification (scoping study), through appraisal of the options (PFS), and onto definition (feasibility study and FEED) and delivery (project implementation). Whereas this progression is drawn as a continuum, the completion of each phase represents a decision point when the key project sponsors must decide whether to progress to the next phase or to suspend, abandon or reframe the project.

The first stage of this work was to conduct a scoping study to define, at a high level:

- the facility options;
- overarching technology approaches;
- the development pathway and its key elements;
- broader financial parameters;
- proposed development methodology to ensure the highest probability of success; and
- a high-level business case for one possible option to justify investment in the PFS.

The PFS is the phase of the development where the broad range of options are analysed and the basis for the feasibility study stage settled. It therefore follows that the PFS is the process where most of the value is added through options analysis and optimisation of the project configuration to deliver a combination of the most viable and economic approaches.
Prior to commencing that phase of work, ZeroGen developed a detailed PFS work plan, which described the scope of activities, standards, resources, schedule and cost for the study against which progress was continually measured and reported. This PFS work plan was subject to review and approval by the project’s key funders.

3.2 Departures from Conventional Project Development

ZeroGen identified two specific departures from conventional project development practice, which were arguably a departure from its own CIS guidelines. These were:

- pre–selection of a contracting strategy and technology vendor for the IGCC plant; and
- undertaking early exploration and appraisal activities on an unexplored, un–risked CO₂ storage resource, in parallel with the PFS.

The justification for these system departures is outlined in the following subsection.

3.2.1 Pre–selection of contracting strategy and technology vendor

ZeroGen argued that because of the first–of–kind nature of the technology, it was important to involve the technology providers at the PFS phase in order to ensure that the different project configurations selected to progress to a feasibility study aligned with the capabilities and technology offered by those technology providers. In particular, the integration of IGCC with pre–combustion capture technology and also compression, transport and storage added a high level of complexity and risk for which it considered the ‘buy–in’ and alignment of all technology providers to be critical.

The alternative approach would have been to engage an independent engineering firm to engineer a specific ZeroGen Project configuration.

ZeroGen also nominated a preference to engage with technology providers willing to take on a level of technical and commercial performance risk through an ‘EPC–wrap’ and/or turn–key contract forms. This was justified on the basis that ZeroGen was a special purpose vehicle with a limited capital base. Furthermore its equity, grant and debt providers were likely to cap any funding commitments which would limit the ability of ZeroGen to take on cost and performance risk.

This approach was accepted by the key project sponsors.

3.2.2 Parallel early–stage exploration and appraisal on a single GHG storage resource

Conventional project development practice would normally involve commencing a PFS only after establishing a reasonable level of confidence in the quantity and quality of critical natural resource(s) upon which the project depends.

In this case, ZeroGen was granted GHG exploration permits in the NDT only and these were at the time, the only GHG exploration tenements in Queensland or indeed onshore Australia.
This fact, coupled with the clear requirements mandated by key project sponsors to commence integrated operations by 2015 compelled ZeroGen to proceed as described.

It is clear that ZeroGen articulated the high–risk nature of this approach to its funders. It is also clear that ZeroGen lobbied the relevant authorities for early release of alternative tenure and its key funders to fund exploration and appraisal of a portfolio of independent GHG storage options.

No additional GHG storage acreage was made available by authorities and the single resource exploration risk was accepted by key project sponsors.

3.3 Project Configuration Options

The ZeroGen Project examined various project configuration options including:
- project scale;
- power and CO₂ capture technologies;
- CO₂ storage options;
- plant site; and
- coal supply.

These are outlined and discussed briefly in the following subsections. A more detailed presentation of the basis for selection of preferred options is provided in the volumes dealing with IGCC plant and CO₂ storage development.

3.3.1 Development scale

ZeroGen examined various project–scale options leading up to the decision to undertake a PFS for an industrial–scale (530 MW gross) demonstration project.

Various smaller pilot–scale projects were considered as a precursor to studying the industrial–scale project ranging from 60 MW to 120 MW gross with CO₂ storage of up to 100,000 tpa of CO₂.

One of the critical drivers for this decision was a view by ZeroGen that more prospective funding would be available, especially access to Commonwealth CCS Flagships funding which was established to support industrial–scale, fully–integrated CCS projects which could be operational by 2015.

3.3.2 Power and capture technology

(a) Low emissions coal–fired power technologies

Prior to embarking on the PFS, ZeroGen examined the three main low emissions coal–fired power platforms:
- IGCC with pre–combustion capture;
- ultra–supercritical boiler with post–combustion capture; and
- ultra–supercritical boiler with oxy firing and post–combustion capture.

ZeroGen’s engineering team concluded, based on published technology status reports (for example, by the USA’s Electric Power Research Institute, EPRI), reference projects (pilot–scale and larger) and
indicative cost and performance data from technology providers, that IGCC with pre–combustion capture represented the most mature, least risk, highest performance (in an Australian context) and lowest cost (Levelised Cost of Electricity (LCOE) basis) of the three options.

The **IGCC with pre–combustion capture** option was supported by all funding stakeholders.

(b) **IGCC technology provider**

As mentioned in Subsection 2.2.1, ZeroGen settled on a strategy to preselect an IGCC technology partner. The selection process considered:

- technical merit;
- project references;
- willingness to accept significant performance risk with material financial guarantees; and
- willingness to contribute equity to the development.

ZeroGen sought proposals from vendor AA, vendor BB, vendor CC, vendor DD, vendor EE and MHI. Proposals were received from vendor AA, vendor BB and MHI. The **MHI proposal** was judged to best align with the criteria described in the preceding paragraph.

(c) **CO₂ capture process units**

The main technologies required for the CO₂ capture process are:

- CO shift reaction to convert CO to CO₂;
- acid gas removal; and
- sulphur removal.

The preferred options were again based on technology, maturity, performance and project references.

For CO₂ shift reaction the technology options were based around the catalyst options. ZeroGen examined vendor XX, vendor YY and Johnson and Matthey. For the purposes of the PFS, ZeroGen in conjunction with MHI selected Johnson and Matthey, however the final selection was to be subject to further test work and not to be decided until the feasibility stage.

For the acid gas removal process, the technology options were based on the choice of solvent to absorb acid gasses (H₂S and CO₂). The options considered were Selexol by UOP (a physical absorption technology), another physical absorption solvent technology and chemical absorption using amines (various suppliers). **Selexol** was selected as the preferred option.

Finally, the sulphur removal process decision centres on either the production of sulphuric acid or elemental sulphur. The preferred option is again based on technology, maturity, performance and project references but this time consideration is also given to the market for by–products (elemental sulphur or sulphuric acid). In Queensland there is a ready market for sulphuric acid (98% purity) and so the **WSA (wet sulphuric acid) process by Haldor Topsoe** was selected.

3.3.3 **CO₂ storage options**

At the time of commencing the PFS, ZeroGen did not have any certainty or confidence in a CO₂ storage resource.
The project held limited exploration permits in the NDT and had conducted limited exploration activities with mixed results.

The project actively encouraged the authorities, with supporting technical work, for release of further exploration permits in different areas and developed contingency plans and portfolio exploration programs (Chapter Three, Part B of this volume) for the event that the NDT could not support the project’s storage requirements. In this event, permits were not gazetted for competitive application until the PFS was virtually complete and award could not be achieved in time for the submission of the CCS Flagships project. ZeroGen also submitted a proposal to the Queensland Government and ACALET entitled Queensland Carbon Storage Hub Project (13 August 2009). This submission proposed to create an expandable, multi-user ‘hub’ storage development including an early development scheme able to accommodate at least 2Mtpa of CO₂. The Hub development relied upon appraising a suite of potential resources, prioritising investment in the Surat basin but seeking to acquire low cost, low commitment tenements in the Eromanga and/or Galilee Basins as longer term storage insurance.

The lack of CO₂ storage options was identified by ZeroGen as a critical risk and ultimately proved to be a fatal flaw which contributed to the project cancellation.

3.3.4 Power plant site and coal supply

During the PFS, ZeroGen studied various power plant sites adjacent to established thermal coal mines. The main criteria used to evaluate site options included:

- security of long-term coal supply at reasonable pricing;
- site development cost and risk;
- proximity to NDT CO₂ storage area;
- coal quality and suitability for gasification; and
- access to supply chain infrastructure for alternative coal procurement.

ZeroGen called for expressions of interest from all Queensland coal mines and sought proposals from companies short-listed according to the above criteria.

The project ultimately nominated the Ensham Resources mine site near Emerald as the preferred site and for non-exclusive supply of coal.

It is worth noting that, ZeroGen also developed contingency plans to pipe CO₂ from the Ensham site to potential storage areas in the Surat Basin to the south as well as an alternative power plant site at Wandoan in the Surat Basin.

3.4 Project Scope and Delivery Strategy

A feature of the ZeroGen PFS was a very comprehensive mapping of the complete scope of the project being undertaken from the PFS to start-up, commissioning and hand-over of all facilities summarised in Figure 3.2. A complete listing and assessment of the contracts that would be required to be formed, executed and implemented was also established. The project team considered this to be a critical issue to fully understanding the project execution risks and to establish a robust cost estimate for the project.
FIGURE 3.2: SUMMARY OF WORK SCOPES AND PHASING FOR PROJECT DELIVERY

**POWER PLANT and TRANSMISSION PIPELINE PHASES**

1. Pre-Feasibility
   - IGCC Engineering MHI
   - IGCC BIP Engineering AECOM

2a. Feasibility & FEED
   - FEED 1 – IGCC – MHI
   - FEED 2 – CO2 storage – Surface works and pipelines, IGCC BoP and Interim Works

2b. Detailed Engineering & Early Works
   - Detailed Engineering – CO2 Transmission Pipeline; H2O Supply Pipeline and Intake Works
   - Detailed Engineering – Balance of Works

3. Construction and Commissioning
   - EPC or O&G – Power Plant Engineering, EPC, Pipeline Infrastructure and Controls
   - EPC – HV Transmission and Intake Works
   - Contractor 3 – Balance of Works, SPPA – HV Transmission and Infrastructure, SPPB – Civil Supply Infrastructure, SPPC – Social Infrastructure, SPPP – Early Construction Support works
   - Commissions Support
   - Operations Start Up

**PIPELINES WORK PACKAGE 2**

- Pipeline Studies
- Separation Studies and Framework
- HV Transmission Studies
- Coal studies and negotiations

**BALANCE OF WORKS WORK PACKAGE 3**

**OWNER’S ENABLING WORKS WORK PACKAGE 4**

**CO2 STORAGE FIELD WORK PACKAGE 4**

**CO2 STORAGE FIELD PHASES**

1. Pre-Feasibility
   - CO2 and Water Supply Projects – Reservoir modelling and Thermal Applications

A. Explore and Appraisal
   - CO2 Drilling and Testwork Campaign, Field Development Plan
   - EIS and Regulatory development with Government and Stakeholders

B. To FID
   - EIS Contract – Power Plant, Land, Water, Cultural Heritage Approvals (eg Water), Long Lead Procurement, Operational Startup Planning

C. To Construct

D. To Commission
   - Power Plant Operations (Demonstration Phase)

Includes:

- EIS Contract – Power Plant
- Land, Water, Cultural Heritage Approvals
- Long Lead Procurement
- Operational Startup Planning
- Commissioning Support
- Operations Start Up

**Timeline**

- Jul 09 to Aug 10
- Oct 10 to March 13
- Jan 12 to Feb 13
- Mar 13 to Dec 15
- Aug 15 to Aug 16
- Mar 13 to Aug 15

**Contractual Arrangements**

- Open Book/ Cost Reimbursable
- Open Book/ Cost Reimbursable
- EPC Wrap/ Lump Sum arrangements

**Participants**

- IGCC Engineering
- MHI
- Pipeline Studies
- HV Transmission
- AECOM
- Sequestration Studies and Teamwork
- IGCC BoP Engineering
- Teamwork
- Includes:
  - EIS Contract – Power Plant
  - Land, Water, Cultural Heritage Approvals
  - Long Lead Procurement
  - Operational Startup Planning
  - Commissioning Support
  - Operations Start Up
The project was broken down into five key packages. Each package was scoped and the project delivery strategy defined as follows:

Package 1  IGCC power plant with CO₂ capture with battery limits:
- outlet manifold of the CO₂ compression station;
- outlet manifold of raw water supply pipeline;
- substation mast; and
- coal stockpile.

Package 1 was to be contracted to MHI through pre–FEED, FEED, engineering, procurement, construction and commissioning support, under an ‘EPC–wrap’ contract and ultimately to a maintenance support contract.

Package 2  Pipelines including:
- CO₂ transmission line and booster stations;
- CO₂ field permanent administration and operational support facilities; and
- power plant water supply pipelines including pump station(s).

Package 2 was to be contracted to one or more specialist pipeline contractors through pre–FEED, FEED and EPC under design and construct (‘D&C’) contracts.

Package 3  Balance of works comprising:
- Site preparation and facilities:
  - power plant site earthworks, access infrastructure and temporary facilities;
  - workforce construction camp accommodation;
  - site offices (power plant and CO₂ field);
  - construction of power infrastructure;
  - construction of water infrastructure; and
  - site communications infrastructure.
- Infrastructure upgrades:
  - Gladstone port upgrades;
  - highway improvements;
  - CO₂ field supply road works;
  - coal supply infrastructure;
  - social infrastructure;
  - housing for operations staff;
  - high voltage connection works; and
  - CO₂ field well head power supply.

Package 3 works was to be contracted to multiple D&C contractors.
Package 4  CO₂ storage field development works comprising:
- drilling and completions for CO₂ injection wells;
- infield flow lines;
- injection controls; and
- measurement, monitoring and verification facilities.

These works were to be co–managed by ZeroGen and a recognised oil and gas major (e.g. Royal Dutch Shell), utilising contracted field operators, drilling contractors, etc. through FEED and full field development.

Package 5  Owners enabling works comprising:
- project environmental licenses;
- government liaison and approvals;
- operations pre–start activities including recruitment and training;
- financial close activities; and
- community engagement activities.
4 Risk Management

The purpose of this section is to review the ZeroGen risk management processes (technical, health and safety, environmental, stakeholder and commercial) in the context of the overall business risk assessment protocols.

Lessons learnt

Management efforts required to build policies and systems and implement standards were significant.


A risk assessment workshop conducted near the completion of the PFS indicated three risks which retained an ‘Extreme’ classification and 48 risks which were classified as ‘High’.

The risks having a residual risk classification of ‘High’ related to a range of technical, commercial and socio–political risks which had the potential to negatively impact project performance, cost and/or schedule.

The risks having a residual risk classified as ‘Extreme’ were considered unable to be resolved within a time frame and/or budget acceptable to ZeroGen’s owner and key stakeholders. These were:

- Northern Denison Trough GHG tenements will not support project’s CO₂ storage requirements;
- no alternative GHG storage tenements are available for exploration and appraisal; and
- high capital and operating cost estimates create an excessive funding gap.

4.1 Risk Management Overview

Mature risk management practices as typically applied in complex, major industrial projects were considered necessary by ZeroGen. As a start–up company, ZeroGen invested considerable resources in development of policies, standards, systems and processes to manage project risks in general and health, safety and environmental risk in particular.

The systems were generally found to be suitable, however a new methodology was developed in the area of technical CO₂ storage risk and uncertainty assessment.

ZeroGen developed and implemented a risk management system compliant with international Risk Management Standard ISO 31000:2009. This standard provided a structured framework to ensure that the purpose of work done was to manage risks and reduce uncertainties so as to provide more confidence in delivering project value.
The principal risk management tool was the register of risks and uncertainties. The risk and uncertainty register was dynamic and updated systematically and regularly through both formal risk assessment workshops (involving the entire team and some external stakeholders) and continually reviewed based on work done during the course of the PFS. Each item on the risk and uncertainty register was allocated an ‘owner’ within the PFS team. The register documented and tracked:

1. identification of risks and uncertainties;
2. analysis of consequence and likelihood to quantify the risk;
4. assessment of existing mitigation controls and their effectiveness;
5. development of additional mitigation controls and/or contingency plans; and
6. analysis and ranking of residual risk.

### 4.2 Residual Risks upon Completion of the PFS

The risk assessment workshop conducted near the completion of the PFS indicated three risks which retained an ‘Extreme’ classification and 48 risks which were classified as ‘High’.

The risks having a residual risk classified as ‘Extreme’ were:

- Northern Denison Trough GHG tenements will not support project’s CO₂ storage requirements;
- no alternative GHG storage tenements are available for exploration and appraisal; and
- high capital and operating cost estimates create an excessive funding gap.

The risks having a residual risk classification of ‘High’ related to a range of technical, commercial and socio–political risks which had the potential to negatively impact project performance, cost and/or schedule.

While the ‘High’ classification risks were considered manageable through further work and/or relaxation of the project schedule, the ‘Extreme’ risks were considered unlikely to be satisfactorily resolved within a time frame to support the ZeroGen Project proposition.

### 4.3 Management of HSE&C Risks in Field Operations

ZeroGen undertook a range of field operations in parallel with the PFS including seismic survey, drilling, meteorologic mast erection and injection testing with CO₂ and water, which required the development of a range of systems. To manage the health, safety, environmental and community aspects of exploration in its tenements, ZeroGen developed a Health, Safety, Environment and Community Policy.

The policy set the framework for the ZeroGen Health, Safety, Environment and Community Management System (HSE&C–MS). The HSE&C–MS set out a Plan–Do–Check–Act system to be followed.
This system was described under the following headings:

- General requirements
- Management system policy
- Planning
- Implementation and operation
- Performance assessment
- Improvement
- Management review

The HSE&C management system was required to govern all operations.

Within the management system were a number of standards which included:

- Leadership and commitment
- Organisation, accountability, responsibility and authority
- Planning objectives and targets
- Legal requirements, document control and information management
- Community consultation
- Competencies, training and awareness
- Hazard and risk management
- Carbon dioxide
- Incident management
- Reporting and performance measurement

There were a number of high risk safety issues that arose as a consequence of the exploration program which included (but was not limited to):

- Well blowout
- Vehicle travel
- Rotating equipment—rig and seismic

These risks, with control measures in place, rated as a ‘High’ risk to workers. Some other risks in the workplace that were reduced, with effective control measures, to lower levels included:

- Working at heights
- Electrical hazards
- Welding
- Confined space
- Well control event
- High winds
ZeroGen managed health and safety during field operations by implementing two main management plans:

- Safety management plan
- Emergency response plan

These plans were further backed up by a suite of procedures such as:

- Incident, accident and non-conformance reporting
- Safety behaviour
- Fire risk management
- Safe work observations
- Permit to work
- Drugs and alcohol
- Job safety and environmental analysis

Likewise, health was managed through a set of procedures which included (but not limited to):

- Occupational hygiene
- Housekeeping
- Health assessment
- Hours of work
- Critical incident recovery
- Personal hygiene
- Employee rehabilitation

ZeroGen also had a comprehensive induction process in which presentations/training packages were presented to the workforce, including (but not limited to):

- Driver fatigue awareness
- Alcohol and drugs
- Eye, hand, back, etc. and safety
- Care of cryogenics (especially for CO₂)
- Worksite rules
4.4 Management of Risk in Studies

The focus and organisational requirements for risk management for the surface project (power plant and infrastructure) were different to that for CO₂ storage. This is because the CO₂ storage project was essentially at the very beginning of the project development cycle, dealing with a single, unexplored, un–risked resource, while the surface project was completing a PFS.

For the study activities, the project team focused on identification of risks and uncertainties to deliver the project safely and within the parameters of performance, cost and schedule required to create a project of value. All risks and uncertainties were assessed in terms of impact on work scope, cost and schedule necessary to reduce project uncertainty.

Regular risk and uncertainty workshops were conducted, focusing on all areas of the project including:
- achieving plant operational performance (i.e. technical and environmental);
- increasing certainty with respect to the volume and containment of CO₂;
- engineering development and test–work;
- regulatory frameworks;
- environmental and safety performance and compliance;
- community and stakeholder development; and
- project delivery issues such as:
  - delivery strategy;
  - contractual risk allocation; and
  - market risks e.g. labour availability, infrastructure.

The risk and uncertainty register was used to inform the Project Capital Cost estimates, to develop direct contingency allowances and to scope the future work plans and contractual arrangements:

(a) Power plant and infrastructure specific studies

Management of HSE&C risks in studies included ‘operational’ risks (especially associated with travel) however managing risk in design was also critical. Activities included but were not limited to:
- Technical Hazard Study 1³;
- Technical Hazard Study 2; and
- Reliability and Maintenance Study.

³ Based on the 6 level ICI based Hazard Studies
(b) \textbf{CO}_2 \text{ storage uncertainty}

A supplementary approach to risk management was implemented for geosequestration (storage risk). It was essential that the risk management processes for sub-surface storage differentiate between uncertainty and risk. The methodology chosen should define data acquisition and study programs which would reduce uncertainty and better define risk.

This approach used Shell’s adaptation of Evidence Support Logic\(^4\) (ESL) to differentiate risk from uncertainty in the appraisal of risks relating to injectivity, capacity and containment (James et al, 2010). The approach has significant advantages over other methods as it allows proponents to focus data acquisition on those areas where uncertainty dominates the risk assessment. This will be covered in greater detail in the CO\(_2\) storage sections of this report.

\(^4\) ZeroGen implemented Shell’s ESL system based on Quintessa’s TESLA software http://www.quintessa.org/
5 Environmental

This section outlines the environmental planning and approvals processes adopted for the ZeroGen Project along with specific challenges to project permitting.

Lessons learnt

The project commenced significant studies to establish the environmental impact of the project. Environmental Impact Statement (EIS) studies were undertaken for two of the development proposals. The latest was in 2009–10 for the commercial-scale development. In neither case were the studies completed prior to the study work being terminated.

EIS studies were commenced prior to the completion of early-stage exploration and appraisal and so the storage resource contained a high level of uncertainty and poor definition of risk. The power plant and infrastructure studies also contained a significant residual technical uncertainty and risk. Under normal circumstances, it would be premature to commence a formal EIS. However the project schedule which mandated start-up in 2015, had the EIS process on the critical path so that it would need to commence before the appropriate levels of definition, and reduction of risks and uncertainties had been achieved. In reality the mandated project schedule constraint could never align with regulatory approval processes.

The competitive bidding process for CCS Flagships funding drove proponents to commit to accelerated environmental assessment schedules. Even if it were possible to accelerate the project’s environmental approvals and permits, the practice is high risk, especially for first-of-a-kind projects, because it:

(a) can cause distrust and suspicion among certain stakeholders and the community which in turn leads to wavering political support for the project and schedule risk; and

(b) requires some impacts to be considered in generic terms only leaving residual permitting and approval risks that cannot be resolved prior to the commitment of substantial project funds.

Another issue facing first-of-a-kind projects generally, and early-mover CCS projects specifically, is the issue of the learning curve required of regulators and the knowledge of regulator’s personnel. In reality, it is real development projects which provide the opportunity to fully detail and ‘road-test’ new regulations.

First-of-a-kind projects require exceptional efforts to inform and communicate with regulator’s personnel. ZeroGen recommends that planning for such projects should allow (time and cost) for 20–50% longer than typical approval times.

Furthermore while regulators typically, and understandably, prefer to retain proponents at ‘arms-length’, for these first-of-a-kind projects there may be merit in placing regulator technical staff within the project to accelerate staff development for subsequent projects.
5.1 Environmental Planning

This section provides an overview of environmental management issues which were addressed during the project.

5.1.1 Introduction

The potential environmental impacts of an IGCC and CCS development were categorised as effects on stakeholders, land tenure, and environmental aspects of hydrology, land forms, soils, vegetation and fauna.

ZeroGen developed several environmental management plans for its operations:
- Environmental Management Plan (EMP)—including water uses;
- Chemical Management Plan;
- Waste Management Plan (WMP);
- Emergency Response Plan (ERP); and
- Weed Management Plan.

5.1.2 Typical factors to be assessed

Numerous local factors influence environmental planning, including:
- climate;
- land use patterns and restrictions;
- hydrogeology/ground–water;
- designated environmentally sensitive areas;
- matters of national environmental management;
- native title;
- cultural heritage;
- water and catchment areas;
- wetlands;
- emissions types to air, land and waterways;
- noise;
- light emissions; and
- traffic patterns.

At each step of the prefeasibility discovery process it is important to investigate and define these issues in detail and depth specifically for proposed sites (not as generic issues). Local conditions are likely to impact cost and schedule significantly. Gaining timely knowledge of these site and area specific issues will be essential in any EIS or community acceptance efforts.

Local details may have significant cost (e.g. storage field location and lay–out, pipeline routes) and schedule (e.g. approvals times) implications.
Example 1: Local Climate and Topography

The climate of the area was evaluated from local meteorological stations.

The area was characterised by high daytime temperatures and summer dominant rainfall. Average maximum temperatures for the region range from 31 to 42°C during summer months to 19 to 21°C during winter months. Average minimum temperatures range from 17 to 19°C in summer months and 3 to 5°C during winter months.

The predominant prevailing wind direction (based on morning winds) varies. In spring and summer the predominant prevailing wind direction is north easterly with increasing tendency to the south and southeast as the seasons progress with the direction tending to mainly South–Easterly and Southerly in autumn and winter. Wind variability occurs throughout the year.

The mean summer monthly rainfall ranges from 74 to 97 mm and the mean winter monthly rainfall ranges from 29 to 39 mm. The annual mean rainfall for the area is 657 mm. It is important to note that especially in a Queensland setting, mean rainfall figures are not instructive. Detailed investigation of annual rainfall patterns and historic flood ranges are essential. Ironically, Central Queensland has been characterised by both prolonged period of drought and sporadic but extreme flood events.

These three examples of local weather conditions and variability require:

- engineering (especially cooling) solutions for an arid environment;
- modelling of gaseous emission plumes to examine local impacts at different times of the year; and
- lay–out to consider flood mitigation and management.

Example 2: Groundwater

In some areas of Central Queensland, ground water resources form part of the Great Artesian Basin. Rather than being a single aquifer, as the name might suggest, the basin is formed of numerous aquifers with different levels of salinity and differing levels of relative connectedness. In the peripheral areas of the basin, historic agricultural water use has depleted some aquifers. More recent Coal Seam Gas (CSG) developments are producing large quantities of saline water which pose a major utilisation and disposal issue and which may compete for pore space in deep saline aquifers which ZeroGen was considering for CO2 geosequestration.

Significant hydrogeological base–line studies and monitoring are likely to be required to establish aquifer flow and connectedness, pre–storage conditions and existing anthropogenic changes. This would undoubtedly add considerable time and cost to any project.

5.2 Environmental Impact Statement—EIS

In order to meet the 2015 deadline, ZeroGen commenced an extensive and multidisciplinary EIS for the project, which complies with both Federal and State Government statutory approvals processes and requirements. ZeroGen had almost completed another EIS for an earlier pilot–scale project configuration, prior to that project being discontinued.
The principal head legislation applicable to the project was the *State Development Public Works Organisation Act 1971*. ZeroGen was recognised by the Queensland Coordinator General as a ‘Significant Project’ and as such, was required to submit an EIS for the project in accordance with that legislation.

The methodology for the EIS process was:
- the assessment and characterisation of the existing values of the surrounding environment;
- the description of the project and potential influences (positive and negative) on the environmental, economic and social values;
- development of an understanding of the implications of the project on the values; and
- reduction of significant adverse impacts of the project.

The EIS was focused on addressing the Terms of Reference issued by the Coordinator–General, which covered an IGCC at Ensham and associated storage in the NDT. Additional studies for sequestration of CO₂ in the Surat Basin were also to be undertaken had ZeroGen secured tenures in that area.

The Terms of Reference for ZeroGen required multidisciplinary studies in at least the following areas:
- Air quality and meteorology
- Greenhouse gas
- Contaminated land
- Geology and soils
- Geosequestration
- Groundwater
- Native title and cultural heritage
- Non–Indigenous cultural heritage
- Social and community
- Economic effects
- Land use
- Hazard and risk
- Nature conservation (flora/fauna and aquatic ecosystems)
- Noise and vibration
- Surface water (quality and overland flows such as flooding)
- Transport and road/rail capacity
- Visual amenity
- Cumulative impacts
- Sustainability
- Waste

While the principal objective of the ZeroGen Project was to facilitate the development and accelerated commercial deployment of low emissions coal–fired power generation technology, the plant was also aiming to demonstrate cleaner production principles in other areas including:
- high efficiency water use;
- by–product capture and reuse; and
- source reductions in pollutant emissions.
5.2.1 Specific environmental impact issues

Most EIS–related issues are, of course, site–specific.

The early identified critical issues for proposed sites in Queensland related to the management of salt derived from cooling waters and questions about the fundamental nature of an EIS for storage operations

- Disposal of zero liquid discharge plant effluent (brine concentrate).

Given the zero liquid discharge constraint placed on the plant design, and the nature of the processes that produce the salt, long–term storage and disposal presented a significant challenge. The total tonnage by the end of such a project’s life would be in the order of 65,000 tonnes. The concentrate is hygroscopic, caustic, and must be sealed in an airtight container to avoid liquefaction upon prolonged exposure to ambient moisture.

- Definition of a subsurface EIS

The process and methods for definition and assessment of the environmental impact of surface activities were well understood. However geosequestration of greenhouse gases is new in Queensland (and more generally) and the methodology for assessment is immature.

In order to meet the 2015 mandated schedule and given the amount of work involved in preparing an EIS for such a project, an EIS was commenced during the exploration phase of the project. Until the exploration is complete, and the field engineering studies are undertaken, locations, types and numbers of wells are not available. This lead to an approach whereby impacts were assessed for a number of ‘standard’ well configurations, and pipeline scenarios, and management plans derived for those scenarios. The ultimate design would consist of a mix of these standard (and assessed) scenarios. As a result a larger potential storage area had to be assessed than the final plan might have covered—increasing the costs of the process in order to meet the time constraints.

5.3 Regulatory Interfaces

5.3.1 Overview

As a first–of–a–kind project, ZeroGen had the task of liaising with and educating a range of regulatory stakeholders on the technology it proposed. This was particularly difficult in the context of new and developing regulation and the learning curve required. As the Greenhouse Gas Storage Act was being developed, ZeroGen was one of the bodies consulted on the impacts of the proposed legislation.

Furthermore, since 2008, there have been several major industrial project developments proposed in Queensland, and this served significantly to increase the workload of regulatory staff.
The two main regulatory stakeholders in this arena in Queensland were:

- the Department of Environment and Resource Management (Environmental Authorities); and
- the Department of Mines and Energy (GHG tenements).

Early in the life of the project when the concept of CCS was a topic not discussed outside academic circles, the level of knowledge within the regulators (at the proponent interface level) on carbon sequestration was low.

ZeroGen estimates that, for first–of–a–kind projects, the challenges to inform and communicate with regulator’s personnel in advance of approvals and permitting can add 20–50% to typical approval times.

5.3.2 Regulatory interface issues

ZeroGen Project personnel rapidly became the technical experts in the field, generally surpassing expertise held within the regulator. One way of alleviating this issue would be for the regulators to actively engage with first–of–a–kind project proponents. While regulators typically, and understandably, prefer to retain proponents at ‘arms–length’, for these first–of–a–kind projects there may be merit in placing regulator technical staff within the project to accelerate staff development for subsequent projects. ZeroGen was able to assist in overcoming some of the issues faced as follows:

Technical ‘isolation’ of the regulator’s staff

Regulator staff (who were responsible for the issuance of permits), were not initially equipped to understand the new risks and issues that might arise from the activity. Understandably, they adopted a conservative approach.

ZeroGen was able to assist by hosting intra–departmental workshops and phone conferences on the topics to ensure that the field officers received sufficient support.

Developing regulatory frameworks

Detailed regulatory development requires real development projects to facilitate development and to ‘road–test’ regulatory processes.

ZeroGen contributed to the developing regulatory framework, through providing project perspectives. This included the Greenhouse Storage Act and regulations, discussions on the Carbon Pollution Reduction Scheme, and development of Environmental Permits. It is vitally important that the regulatory frameworks are formed with real projects in mind.
6 Stakeholder and Community Engagement

This section outlines the ZeroGen approach and experiences with regard to stakeholder identification and engagement including community and public relations.

Lessons learnt

The ZeroGen Project identified early in its project life that consultation with the community and other key stakeholders would be an important aspect in the development of their project. This was particularly true because the project is concerned with developing new and commercially unproven technology.

Applications from the ZeroGen experience which may be relevant and applicable to other low emission coal projects include:

- the need for a stakeholder analysis to identify those stakeholder groups with the potential to have the greatest impact on the project, either positive or negative;
- appropriate communication activities to then engage the prioritised stakeholder groups;
- champions within the influential groups that can help to raise awareness of the benefits of the project—particularly for government, investors and insurance agencies;
- the use of community liaison groups, to provide the community with a voice, to meet regularly with the project team;
- proactive engagement with the local media to advertise project developments, public meetings and present the latest information about project developments; and
- applying the principles of honesty, transparency and respect in all interactions.

The contingent nature of any possible full deployment stages needs to be a central theme of any stakeholder (especially public) engagement at earlier project stages. A PFS is not an indication that there ‘will’ be a full project development.

While ZeroGen explicitly and consistently articulated the considerable risks and uncertainties associated with the project, some engagement messages were arguably optimistic. It is possible that the various processes by which project proponents compete for and are awarded funding discourages a detailed exposure of risk indeed can lead to a culture of over-promising.

As a result, significant negativity arose with the decision not to proceed with the project.
6.1 Stakeholder Identification

ZeroGen identified its initial range of stakeholders by drawing on the knowledge base, network and experience of its management team. The list of stakeholders was then increased following an extensive stakeholder engagement program involving community meetings, briefings and proactive communications and engagement, such as presentations to national and international conferences and membership of various CCS related industry forums.

6.1.1 Stakeholder issues and prioritisation

Stakeholders were grouped and mapped as to their ability to influence each other and the project outcomes. Table 6.1 is an analysis of those groups and ZeroGen’s perspective of known and potential issues of interest or concern.
<table>
<thead>
<tr>
<th>Stakeholder group</th>
<th>Ability to influence Project outcomes</th>
<th>Issues</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Federal Government</strong></td>
<td>High</td>
<td>Policy, Funding development of low emissions technologies, Leadership, CCS, International collaboration, Exploration incentives, Funding recommendations, EIS approvals, Employment, Great Artesian Basin, Public awareness and understanding, Pre-competitive exploration programs, Standards</td>
</tr>
<tr>
<td><strong>State Government</strong></td>
<td>High</td>
<td>Policy, Funding, Leadership, Coal industry (exports), CCS, International collaboration, Regional development, EIS and planning approvals, Infrastructure, Roads, transport, safety, Employment, Skills development, Housing, Energy security, Local impacts, Great Artesian Basin, Reputation, Public awareness and understanding</td>
</tr>
<tr>
<td>Stakeholder group</td>
<td>Ability to influence Project outcomes</td>
<td>Issues</td>
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<tr>
<td><strong>Local Government</strong>&lt;br&gt;• Central Highlands Regional Council&lt;br&gt;• Isaac Regional Council&lt;br&gt;• Rockhampton Regional Council</td>
<td>High</td>
<td>• Regional development&lt;br&gt;• EIS and planning approvals&lt;br&gt;• Infrastructure&lt;br&gt;• Roads, transport, safety&lt;br&gt;• Water&lt;br&gt;• Employment&lt;br&gt;• Skills development&lt;br&gt;• Housing&lt;br&gt;• Energy&lt;br&gt;• Local and cumulative impacts&lt;br&gt;• Public awareness and understanding of safety and permanence of CCS&lt;br&gt;• Cumulative impacts</td>
</tr>
<tr>
<td><strong>Project partners</strong>&lt;br&gt;• Queensland Government&lt;br&gt;• ACALET&lt;br&gt;• Federal Government</td>
<td>High</td>
<td>• Funding&lt;br&gt;• Leadership&lt;br&gt;• International collaboration&lt;br&gt;• Commercialisation of CCS&lt;br&gt;• Safety and permanence of CCS&lt;br&gt;• Infrastructure&lt;br&gt;• Workforce&lt;br&gt;• Coal industry (exports)&lt;br&gt;• Energy&lt;br&gt;• Local impacts&lt;br&gt;• Reputation&lt;br&gt;• Public awareness and understanding</td>
</tr>
<tr>
<td><strong>Environmental NGOs</strong>&lt;br&gt;• WWF—Australia&lt;br&gt;• Queensland Conservation Council&lt;br&gt;• Capricorn Conservation Council&lt;br&gt;• Mackay Conservation Group</td>
<td>Medium to High</td>
<td>• Deployment of low emissions technologies&lt;br&gt;• Pace of change&lt;br&gt;• Greenhouse emissions from use of fossil fuels&lt;br&gt;• CCS (safety, permanence)&lt;br&gt;• Continued use of coal as an energy source&lt;br&gt;• Energy mix&lt;br&gt;• Cumulative local and regional impacts of coal mining and energy projects&lt;br&gt;• Environmental management, biodiversity conservation&lt;br&gt;• Water&lt;br&gt;• International collaboration&lt;br&gt;• Great Artesian Basin</td>
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<tr>
<td>Stakeholder group</td>
<td>Ability to influence Project outcomes</td>
<td>Issues</td>
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<td>------------------------------------------------------------------------</td>
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<tr>
<td><strong>Industry associations</strong></td>
<td>Medium</td>
<td>• Funding</td>
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<td></td>
<td>• Leadership</td>
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<td></td>
<td></td>
<td>• Demonstration of CCS</td>
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<td></td>
<td></td>
<td>• International collaboration</td>
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<td>• Infrastructure</td>
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<td>• Workforce</td>
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<td>• Overlapping rights</td>
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<td></td>
<td>• Industry position on CCS exploration and storage</td>
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<td>• Skills development</td>
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<td>• Coal industry (exports)</td>
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<td>• Energy</td>
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<td>• Reputation</td>
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<tr>
<td></td>
<td></td>
<td>• Public awareness and understanding</td>
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<tr>
<td><strong>Research organisations</strong></td>
<td>High</td>
<td>• Deployment of low emissions technologies</td>
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<tr>
<td></td>
<td></td>
<td>• Pace of commercialisation</td>
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<tr>
<td></td>
<td></td>
<td>• International collaboration</td>
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<td></td>
<td></td>
<td>• Knowledge sharing</td>
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<tr>
<td></td>
<td></td>
<td>• Greenhouse emissions from use of fossil fuels</td>
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<tr>
<td></td>
<td></td>
<td>• Continued use of coal as an energy source</td>
</tr>
</tbody>
</table>

- Australian Coal Association
- Queensland Resources Council
- National Generators Forum
- Carbon Capture and Storage Association
- Australian Petroleum Production and Exploration Association (APPEA)
- Minerals Council of Australia
- World Coal Institute
- Environment Business Australia
- NSW Minerals Council
- AgForce Queensland
- Global CCS Institute
- CO2CRC
- National Low Emissions Coal Research Centre
- CSIRO
- Geoscience Australia
- CSLF
- International Energy
- Japan Coal Energy Centre (JCOAL)
- Ministry of Economy, Trade and Industry (METI), Japan
- International Energy Agency Clean Coal Centre
- Research Institute for Innovative Technology for the Earth, Japan
## Stakeholder group

<table>
<thead>
<tr>
<th>Stakeholder group</th>
<th>Ability to influence Project outcomes</th>
<th>Issues</th>
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</thead>
<tbody>
<tr>
<td>Agency Greenhouse Gas</td>
<td>• Asia Pacific Partnership on Clean Development and Climate</td>
<td>• International collaboration</td>
</tr>
<tr>
<td>Electric Power Research Institute (EPRI)</td>
<td>• New Energy and Industrial Technology Development Association (NEDO)</td>
<td>• Knowledge sharing</td>
</tr>
<tr>
<td>Intergovernmental Panel on Climate Change (IPCC)</td>
<td>Engineering Advancement Association Japan (ENAA)</td>
<td>• Demonstration of CCS</td>
</tr>
<tr>
<td>Central Research Institute for Electric Power (CRIEPI)</td>
<td>• Agency Greenhouse Gas</td>
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## CCS projects

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<thead>
<tr>
<th>CCS projects</th>
<th>Ability to influence Project outcomes</th>
<th>Issues</th>
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</thead>
<tbody>
<tr>
<td>Global CCS Institute</td>
<td>• Callide–A Oxy–Fuel Project</td>
<td>• International collaboration</td>
</tr>
<tr>
<td>FutureGen</td>
<td>• CO2CRC Otway Basin Project</td>
<td>• Knowledge sharing</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>• Demonstration of CCS</td>
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<tr>
<td></td>
<td>Medium</td>
<td>• Infrastructure</td>
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</table>

## Unions

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<tr>
<th>Unions</th>
<th>Ability to influence Project outcomes</th>
<th>Issues</th>
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</thead>
<tbody>
<tr>
<td>CFMEU</td>
<td>• ETU/CEPI</td>
<td>• Infrastructure</td>
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<tr>
<td>Australian Workers Union</td>
<td>• AMWU</td>
<td>• Workforce</td>
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<tr>
<td></td>
<td>Medium</td>
<td>• Employment opportunities</td>
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<tr>
<td></td>
<td></td>
<td>• Skills development</td>
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<tr>
<td></td>
<td></td>
<td>• Coal industry (jobs, exports)</td>
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<td></td>
<td></td>
<td>• Energy supply</td>
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</tbody>
</table>

## Potential investors

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<thead>
<tr>
<th>Potential investors</th>
<th>Ability to influence Project outcomes</th>
<th>Issues</th>
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</thead>
<tbody>
<tr>
<td>Coal companies</td>
<td>• Institutions</td>
<td>• Funding</td>
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<tr>
<td>Technology providers</td>
<td>• Ethical investment funds</td>
<td>• Project time frames</td>
</tr>
<tr>
<td></td>
<td>High</td>
<td>• Commercialisation</td>
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<td>• Reputation</td>
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<td></td>
<td></td>
<td>• Climate change</td>
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<td></td>
<td></td>
<td>• Demonstration of CCS, safety and permanence</td>
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<tr>
<td>Stakeholder group</td>
<td>Ability to influence Project outcomes</td>
<td>Issues</td>
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<tr>
<td><strong>Local community</strong></td>
<td>High</td>
<td>- Infrastructure</td>
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<tr>
<td>- CLGs</td>
<td></td>
<td>- Workforce</td>
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<tr>
<td>- Landholders</td>
<td></td>
<td>- Coal industry (jobs)</td>
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<tr>
<td>- Regional Development</td>
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<td>- Energy</td>
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<tr>
<td>Corporations</td>
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<td>- Regional development</td>
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<tr>
<td>- Chambers of Commerce</td>
<td></td>
<td>- Planning approvals</td>
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<tr>
<td>- Golden Triangle</td>
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<td>- Water</td>
</tr>
<tr>
<td>Community Group</td>
<td></td>
<td>- Great Artesian Basin</td>
</tr>
<tr>
<td>- Schools</td>
<td></td>
<td>- Roads, transport</td>
</tr>
<tr>
<td>- Individual residents</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td><strong>Issues</strong></td>
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<tr>
<td></td>
<td></td>
<td>- Prime agricultural lands</td>
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<td></td>
<td></td>
<td>- Employment</td>
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<td>- Skills development</td>
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<td>- Housing</td>
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<td></td>
<td></td>
<td>- Local impacts (environment, social and economic)</td>
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<td></td>
<td></td>
<td>- Public awareness and understanding of safety and permanence of CCS</td>
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<td></td>
<td></td>
<td>- Timing</td>
</tr>
<tr>
<td><strong>Indigenous</strong></td>
<td>Medium</td>
<td>- Land Use Agreements</td>
</tr>
<tr>
<td>- Kangoulu</td>
<td></td>
<td>- Native Title</td>
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<tr>
<td>- Kairi</td>
<td></td>
<td>- Cultural heritage management plans and protection</td>
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<tr>
<td>- Bidjara</td>
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<tr>
<td>- Iman</td>
<td></td>
<td><strong>Issues</strong></td>
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<td></td>
<td></td>
<td>- Cultural sensitivities</td>
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<td></td>
<td></td>
<td>- Employment opportunities</td>
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<tr>
<td><strong>Service providers</strong></td>
<td>Medium</td>
<td>- Project certainty</td>
</tr>
<tr>
<td>- Pipelines</td>
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<td>- Reputation</td>
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<tr>
<td>- Contractors</td>
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<td>- Employment</td>
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<td><strong>Issues</strong></td>
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<tr>
<td></td>
<td></td>
<td>- Skills</td>
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<td></td>
<td></td>
<td>- Housing</td>
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<tr>
<td><strong>Coal suppliers</strong></td>
<td>Medium</td>
<td>- Coal supply</td>
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<td>- Competitive prices</td>
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<td><strong>Issues</strong></td>
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<td></td>
<td>- Low emissions technologies</td>
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<td></td>
<td></td>
<td>- Timing</td>
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<tr>
<td><strong>Potential customers</strong></td>
<td>Medium</td>
<td>- Commercial viability</td>
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<td>- Cost of power</td>
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<td><strong>Issues</strong></td>
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<td>- Reputation</td>
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<tr>
<td>Stakeholder group</td>
<td>Ability to influence Project outcomes</td>
<td>Issues</td>
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<td>-------------------</td>
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</tr>
</tbody>
</table>
| **Landholders**   | Medium                                | • Regional development  
|                   |                                       | • Roads, transport  
|                   |                                       | • Water  
|                   |                                       | • Great Artesian Basin  
|                   |                                       | • Prime agricultural lands  
|                   |                                       | • Employment  
|                   |                                       | • Local impacts (environment, social and economic)  
| **Media**         | High                                  | • Knowledge  
|                   |                                       | • Climate change  
|                   |                                       | • Need for low emissions technologies  
|                   |                                       | • Regional development  
|                   |                                       | • Local impacts (environment, social and economic)  
|                   |                                       | • Public awareness and understanding of safety and permanence of CCS  
|                   |                                       | • Timing  
|                   |                                       | • Land access  
|                   |                                       | • Easements  
|                   |                                       | • Compensation  

- International media  
- National media  
- State media  
- Local media  
- Trade media (international, national)  
- Academic journals
6.2 Engagement and Communication Process

Generally, ZeroGen took the approach of open and face-to-face community consultation as a key element of stakeholder engagement and to secure support for the project.

ZeroGen was proactive over a number of years in informing the communities in which the project was to be based about technology development, scale of the project, the environmental impact study, CO₂ storage exploration programs and timing.

ZeroGen used the following methods, as a minimum, to engage with stakeholders:

- regular meetings and briefings with stakeholders;
- community meetings;
- community liaison groups;
- newspapers, radio and television—articles, news and project announcements;
- conference participation, speeches, forums and seminars;
- community events;
- project fact sheets; and
- project website.

The ZeroGen Stakeholder Analysis and Communications Plan was a ‘living document’, which was revised at key project milestones to ensure it continued to meet needs and address any new issues that could arise during the life of the project.

The plan was developed after an identification and analysis of ZeroGen’s key stakeholders and recognises that different stakeholders have different issues and information needs. The plan outlined strategies for communicating with different categories of stakeholders—from those that require a high-level of engagement to those who are more passive observers of the project.

Each stakeholder category was defined as follows:

<table>
<thead>
<tr>
<th>Category</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Strongly supportive</td>
<td>Have openly indicated to ZeroGen, other third parties and/or the media, their strong support of the project—also includes project partners.</td>
</tr>
<tr>
<td>Moderately supportive or opposed</td>
<td>May not have openly or publicly communicated their opinion towards the project and require further information and relationship-building efforts to shift into the ‘supportive’ or ‘strongly supportive’ categories.</td>
</tr>
<tr>
<td>Strongly opposed</td>
<td>Have indicated to ZeroGen, other third parties and/or the media, that they are either opposed to the ZeroGen Project, climate change initiatives or low emission coal technologies.</td>
</tr>
</tbody>
</table>
6.3 Public Perceptions

As a general comment, ZeroGen’s wide stakeholder and community engagement activities were well received during the course of the project. Numerous levels and types of public engagement on the nature and impact of the project were positively recognised by local, national and international groups. Experiences with ZeroGen with respect to community engagement have been published previously and the following references provide a useful guide to the lessons learnt from the ZeroGen approach to engagement:


6.3.1 Issues arising for community groups

Being in the prefeasibility stage, the ZeroGen Project had limited exposure to divisive issues and incidents which might cause public concerns. However, notwithstanding the early stage of the project, ZeroGen established a network of contacts within the community and a website through which feedback could be provided or issues raised for consideration and timely response.

Several public information sessions were held at Emerald, Comet, Springsure, Biloela and Rockhampton to increase awareness of the project and low–emissions technologies. These sessions were used as a forum to identify, respond to and manage potential community issues. Community feedback was encouraged at public meetings. Community comment and input was actively sought for inclusion into the Terms of Reference for the EIS. The public meetings and stakeholder communications conducted by ZeroGen in March and April 2010 confirmed continued widespread support for the project.

These meetings were attended by representatives of Queensland Government departments and agencies, local government councils, police, regional development corporations, chambers of commerce, the Indigenous community, schools and education facilities, coal mining companies, environmental NGOs, landholders, retirees, and individual business owners and operators.

Engagement with representatives of the Indigenous communities in the study area was positive, and issues raised were effectively managed and communicated for inclusion in the project planning process. Indigenous people were engaged to assist ZeroGen, ensuring the identification and protection of items of cultural significance in its study and exploration activities.

Based on the various interactions and communications with community groups, key community issues were:

- regional development potential;
- employment opportunities;
- skills development—need and potential;
- housing;
- roads and transport;
• infrastructure development potential;
• indigenous and historic cultural heritage management;
• business opportunities and expansion;
• water supply;
• carbon capture and storage—permanence and safety; and
• cumulative impacts of mining, exploration, development in Regional Central Queensland.

### 6.3.2 Impacts and issues from exploration activities

ZeroGen worked closely with landholders and the community to minimise issues arising from field exploration activities.

Key issues identified and resolved included:

- early and open communications with all landowners potentially impacted by ZeroGen operations;
- recognising the limited availability of landowners during business hours and being available to consult and discuss issues after hours;
- understanding stock movement plans and managing site access accordingly;
- minimising damage to local roads and responding quickly to undertake repairs and maintenance after wet weather damage;
- ensuring all land was rehabilitated to the same or better standard than existed prior to ZeroGen operations; and
- community support and participation including sponsorship of sporting and other local community activities and events.

Ashworth et al., (2010) undertook local stakeholder interviews and reported specific successes including:

- overcoming communication barriers with a landholder. This was done by acknowledging the landowner’s rights to manage access to his land, using respectful engagement practices such as ensuring permission for all entry onto the landowner’s property, providing compensation as relevant, and where possible engaging the landowner in activities that might otherwise have been carried out by contractors—for example, building a road and platform on the landowner’s property: and
- speedy and professional response to complaints received from landowners and residents after an incident where a contractor damaged a local road after accessing the property. The road had only recently been graded. ZeroGen was noted to react swiftly to the local council’s request to repair the damage to the road; a response that was perceived by some stakeholders as a positive measure of the developer’s good intentions towards the local community.
6.3.3 Media response to project closure

Since the decision to close the project, media engagement had to be discontinued. Certain print media has been negative in response to the closure decision, suggesting that the project was a ‘failure’ and that the significant investment ‘wasted’.

The development and operation of any major project, such as this integrated IGCC plant with CCS, is always contingent on the findings from studies and ultimately contingent on a positive investment decision. In fact most projects which enter scoping phases will not continue all the way through to a positive investment decision. The purpose of funding (scoping, prefeasibility and feasibility) studies is to reduce the uncertainty of value being derived from a larger future capital investment and to avoid investing capital in projects which do not deliver value for investors. Notwithstanding this reality, some stakeholders clearly held the perception that the project would definitely go ahead. This is likely to be partly based on ZeroGen’s messages to stakeholders.

While ZeroGen explicitly and consistently articulated the considerable risks and uncertainties associated with the project, some engagement messages were arguably optimistic. It is possible that the various processes by which project proponents apply for and are awarded funding discourages a detailed exposure of risk and could lead to a culture of over-promising.
7 Intellectual Property Management

This section outlines the Intellectual Property ownership, rights and knowledge management processes adopted and issues faced by the project.

Lessons learnt

Knowledge capture and sharing from CCS demonstration projects is widely considered important to accelerate the global deployment of CCS.

CCS projects are complex and require knowhow and background Intellectual Property (IP) from a variety of sources and the development of improvements to background IP.

Management of the ZeroGen Project and background IP required considerable effort to encode various requirements into formal agreements. Funders of the ZeroGen Project saw some of their ‘return’ taking the form of project or arising IP.

However, much of the technology IP was the property of the various vendors and considered to be commercial–in–confidence. It becomes challenging and to define even more challenging to value the delta between project and background IP.

Technology providers understandably were concerned at the potential ‘leakage’ of background IP that might occur as a result of disclosure or commercial exploitation of project IP arising during the course of the ZeroGen Project. Management of this issue resulted in a web of confidentiality agreements and various conditional rights accrued by parties associated with funders. At the same time, vendors naturally required on–going controls on disclosure of IP which potentially added to project management complexity.

7.1 General

Knowledge capture and sharing from CCS demonstration projects is widely considered important to accelerate the global deployment of CCS.

Similarly, the careful management of the project and third–party intellectual property associated with the power generation, carbon capture and carbon storage facilities, is paramount to project proponents and technology providers.

During the ZeroGen PFS, a range of processes and negotiations relating to IP and technology rights were undertaken, and this lead to various confidentiality and IP management principles being encapsulated in a range of documents, as shown in Table 7.1.

Management of the ZeroGen Project and background IP required considerable effort to encode various requirements into formal agreements. Some funders of the ZeroGen Project saw their ‘return’ taking the form of project or arising IP. However, much of the technology IP was the property of the various vendors and considered to be commercial–in–confidence.
TABLE 7.1: STATUS OF AGREEMENTS COVERING IP MANAGEMENT OBLIGATIONS

<table>
<thead>
<tr>
<th>Agreement</th>
<th>Counterparties</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project Development Agreement</td>
<td>MC and MHI</td>
<td>Executed and effective</td>
</tr>
<tr>
<td>Project Funding Agreement</td>
<td>ACALET</td>
<td>Executed and effective</td>
</tr>
<tr>
<td>Project Funding Agreement</td>
<td>Commonwealth of Australia</td>
<td>Executed and effective</td>
</tr>
<tr>
<td>Licence Agreement</td>
<td>UOP</td>
<td>Executed and effective</td>
</tr>
<tr>
<td>Licence Agreement</td>
<td>Haldor Topsøe</td>
<td>Executed and effective</td>
</tr>
<tr>
<td>Various supplier agreements</td>
<td>All providers of goods and services to the ZeroGen Project</td>
<td>Executed and effective</td>
</tr>
<tr>
<td>Development Agreement</td>
<td>Shell Global Solutions</td>
<td>Draft and under negotiation</td>
</tr>
<tr>
<td>Shareholders Agreement</td>
<td>State of Queensland, MC and MHI</td>
<td>Draft and under negotiation</td>
</tr>
<tr>
<td>UJV Agreement</td>
<td>State of Queensland, ACALET, MC, MHI and others</td>
<td>Draft and under negotiation</td>
</tr>
<tr>
<td>EPC Contract</td>
<td>MHI</td>
<td>Draft and under negotiation</td>
</tr>
</tbody>
</table>

With regard to IP management, these agreements encompass the management of background IP and developed IP, where background IP is the intellectual property that an organisation brings to the project, and developed IP is the intellectual property that is created on and during the performance of the project.

It was ZeroGen’s intention that during the Feasibility Study stage, outstanding agreements (currently in draft form) and other necessary arrangements are completed and executed, such that the IP rights are protected and the intent to commercialise the technology is structured in a manner to provide assurance of future exploitation for successful outcomes.

7.2 IP Ownership and Licensing

In the development of the range of agreements referenced in Table 7.1, there is express recognition that the parties each bring IP to the project that they developed without the involvement of the other parties, and/or developed prior to the current project arrangements. This IP is referred to as background IP.

Such background IP is understood to have strategic and commercial significance to each organisation, and the parties agreed that each party retained the full ownership rights to this IP, and that such IP shall be kept confidential within the constraints defined by the various agreements.

Developed IP on the other hand, arises out of the conduct of the project’s development and commercialisation activities, and thus remained the property of ZeroGen. ZeroGen granted an irrevocable, royalty–free, non–exclusive worldwide licence to that IP to ACALET and other grant providers.
In the case of MHI plant IP, MHI remained the sole owner of IP developed within the battery limits of its EPC contract scope. MHI granted an irrevocable, royalty-free, non-exclusive worldwide licence to that IP separately to ZeroGen and to ACALET and other grant providers for projects developed by ZeroGen or by ACALET members provided that MHI would be contracted to supply the technology under an Engineering Procurement and Construction (EPC) style contract.

Background IP access rights were to have an access time restriction of 20 years from the date of the relevant agreement. In the event that the project did not proceed past the PFS phase, the background IP providers were to provide a non-exclusive, royalty-free, worldwide, non-sub-licensable right to use the background IP for further studies and investigations for at least 15 years.

Each of the participants in the project provided their IP to the ZeroGen Project at no cost, provided that they continue to be a participant in the project as intended by the range of agreements. The parties agreed that while they granted a royalty-free, irrevocable one-off licence for the use of the IP to ZeroGen, ZeroGen was not permitted to allow access to such IP by any competitor of the IP owner without prior approval of the IP owner.

Third-party technology providers, which were not project participants (such as UOP or Haldor Topsoe) provided their IP under arms-length licence agreements to ZeroGen.

Even though these third-party technologies were to be incorporated into the MHI plant scope, ZeroGen held the IP licence directly, and were obliged to pay licence fees directly to the provider. MHI then engaged the technology providers under engineering agreements to ensure the integration of technologies was achieved.

### 7.3 Commercialisation of IP

#### 7.3.1 ZeroGen Project participants

With the overarching objective of the project being the global commercialisation of low-emissions coal fired power generation (with CCS), the ZeroGen Project was required to ensure other parties would have access to the IP of the project.

This was achieved by expressly committing each party, by way of contract, to cooperate with ACALET, the Australian Government, ZeroGen and/or other grant providers, to work with such parties and potential facility owners to develop like projects for the further commercialisation of the technology. The agreements between the relevant parties imposed positive obligations on the parties to make such background and developed IP available for other participants to access on reasonable commercial terms, while enabling the IP owners to protect their commercial interest from competitive exposure.

In the case of MHI plant IP, MHI granted an irrevocable, royalty-free, non-exclusive worldwide licence to that IP separately to ZeroGen and to ACALET and other grant providers for projects developed by ZeroGen or by ACALET members. That licence was provided on the basis that MHI is contracted to supply the technology under an EPC style contract and would be obliged to demonstrate by way of ‘open-book pricing’ that margins excluded IP licence fees.
Where such positive obligations were found not to be honoured, it was agreed that ZeroGen could step in and access such background and developed IP for the purposes of assisting other participants to develop like projects in alignment with the overall strategic objectives.

These obligations were intended to be fair and commercial, while ensuring that the pricing for such technology access is no less advantageous than for the current ZeroGen Project. Demonstrating the absence of IP licence fees within the cost estimate of a complex EPC project is however, likely to be challenging in practice.

### 7.3.2 Global commercialisation

There was also a positive obligation on MHI to exploit the IP globally, but in cases other than those projects involving ACALET, the Australian Government, ZeroGen and/or other grant providers, MHI was entitled to put a price on the IP.

Where ZeroGen, or other project sponsors (such as ACALET), reasonably consider that the IP owner is not acting in accordance with their positive obligations to exploit the technology, then ZeroGen and such sponsors could elect to step-in and access the IP and use such IP as if it was the IP owner.

To help facilitate global exploitation, the parties agreed that they would share information on potential further commercialisation opportunities and improvements to the background IP for a period of no less than 10 years.

It was also agreed that should the project not proceed past the PFS, the background IP providers would provide a non-exclusive, royalty-free, worldwide, non-sub-licensable right to use the background IP for further studies and investigations for at least 15 years.
8 Operations and Management Systems

This section describes the approach and the work done to define the operational and management system frameworks that were to be applied to the ZeroGen Project.

Lessons learnt

CCS demonstration projects must prepare robust estimates of capital and operating cost estimates as well as the financial models necessary for a commercial evaluation.

This requires an understanding of the business structures, organisational frameworks and management systems required to support projects from studies through construction and into operations.

8.1 Operations Framework

ZeroGen developed a preliminary operational framework under which the completed Power Generation and CO₂ Capture (PGC) plant and Carbon Transport and Storage (CTS) assets, would be operated by separate companies formed for these specific purposes. This framework was prepared to provide a robust basis for estimating of capital (pre start-up operational) and operating costs, as well as the project schedule.

Figure 8.1 reflects the organisational and contracting arrangements inherent in the proposed operational framework.

The companies were to enter into a contract for the transport and storage of CO₂ from the power plant. This contract was to be a ‘send or pay’ contract to ensure that the CTS company remained solvent notwithstanding the power plant performance and availability.
Chapter One: Project Management and Overview

**Figure 8.1: Proposed Ownership and Operational Framework for the ZeroGen Project**

- **ZeroGen Pty Ltd**
  - O&M Contract
  - Connection and Access Agreement
  - Network Provider

- **ZeroGen Generation**
  - UJV Agreement
  - UJV Partner #2 (Equity)
  - UJV Partner #3 (Equity)
  - PPA Contract
  - Carbon Permit Contract
  - NEM ‘Generator’ Trader
  - NEM Customers

- **ZeroGen Sequestration Pty Ltd**
  - CO₂ Sequestration Contract
  - CO₂ Transport Contract
  - XYZ Pipeline Co

- **Major equipment maintenance**
  - Pulversers
  - CCGT
  - Gasifier
  - ASU

- **Chemicals and Catalysts etc**
  - Electrical Services
  - HR Services
  - Plumbing Services
  - Audit Services
  - IT Services
  - etc

- **Fuel Supplier**
  - Fuel Contract

- **Water Supplier**
  - Water Contract

- **Other Suppliers**
  - Other Contracts

Notes:
1. Carbon permits are procured by the trader, and surrendered by the operator on behalf of the owners.
2. Carbon permit/PPA contract are interactive to optimise outcome – the trader takes the permit price risk based on a set carbon intensity. The owner is responsible for the target intensity variation from the set point (cost or benefit).
3. PPA contract needs to reflect actual operating costs and operating limits.
The time frame to establish the companies to the point where they were trained and ready to take control of operating assets at the end of commissioning meant that the companies’ formation, recruitment activities, training and systems development would need to happen well in advance of start-up.

Both operating companies were to be organised to ensure compliance with best industry practice in the areas of:

- health and safety management;
- asset management;
- environmental management; and
- community/stakeholder management.

The organisational structures also gave consideration to the need to optimise design and operations and to capture lessons learnt for future CCS projects.

In the case of the power generation company, recruitment activities were planned to commence in parallel with the construction of the plant commencing in order to have the required business, operating, maintenance, safety and environmental systems in place prior to plant operations (commissioning) commencing.

In the case of the carbon storage operating company, ZeroGen proposed that it be formed coincident with the commencement of the Feasibility Stage of the project. This was in part to facilitate early investment, but also in acknowledgement that exploration and appraisal activities were in fact ‘operational’.

ZeroGen developed a high-level recruiting strategy that considered:

- current power industry and oil and gas sector practices;
- work cycles and resident versus commuter (e.g. FIFO) arrangements, based on local demographics; and
- availability of local support services.

The proposed manning levels of the businesses were intentionally above the minimum sustainable level during the commercial proving period (first five years) and forecast to fall as plant reliability improved, and issues were resolved. This reflected the technical risks and uncertainties associated with the first-of-a-kind project.

The initial manning levels are noted in Table 8.1.
TABLE 8.1: INITIAL MANNING LEVELS PROPOSED FOR PROJECT OPERATIONS

<table>
<thead>
<tr>
<th>Category</th>
<th>ZeroGen PGC</th>
<th>ZeroGen CTS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shift operations</td>
<td>41</td>
<td>10</td>
</tr>
<tr>
<td>Operation and maintenance (days)</td>
<td>42</td>
<td>13</td>
</tr>
<tr>
<td>Technical and system support</td>
<td>23</td>
<td>7</td>
</tr>
<tr>
<td>Commercial and administrative support</td>
<td>27</td>
<td>14</td>
</tr>
<tr>
<td>Management</td>
<td>6</td>
<td>6</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>139</strong></td>
<td><strong>50</strong></td>
</tr>
</tbody>
</table>

An important impact of the ZeroGen operations plan was a significant early investment in ‘operational readiness’ both during construction and to a lesser extent during the Feasibility Study phase and therefore, to inflate both feasibility study and capital costs.

There is little doubt that this was a prudent and appropriate proposal given that ZeroGen would in fact be a start–up company undertaking a complex first–of–a–kind project to a mandated and very tight schedule.

8.2 Management Systems Framework

In conjunction with the operational framework outlined above, ZeroGen developed a preliminary management systems framework required to ensure all required applications and underlying technical infrastructure would be available for use as required for the applicable business and/or project team.

This framework is represented at a high level in Figures 8.2 and 8.3 and was used to provide the basis for scoping and estimating the investment in management systems during the feasibility study, construction, start–up and operations phases.

As with the investment in operational readiness, this framework anticipated a significant early capital investment in management systems both during the Feasibility Study phase and construction. This was also considered a prudent and appropriate proposal.
FIGURE 8.2: OPERATIONS—INFRASTRUCTURE
FIGURE 8.3: OPERATIONS—FUNCTIONAL APPLICATION MAP
Figure 8.3 Legend:

- **Function (Application)**: Large Packaged System—Part of an ERP or packaged software with 40 or more users.

- **Function (Application)**: Medium Packaged System—Integrated, off-the-shelf software with less than 40 users.

- **Function (Application)**: Small Packaged System—Independent, off-the-shelf software with typically less than 5 users. Noted exceptions are the SGE desktop applications.

- **Function (Application)**: Out of Scope—Systems which have been completely addressed or will be addressed in a later phase or by a different business entity.

- **Function (Application)**: A dashed line indicates that an application will be deployed during the phase indicated by the drawing title.
9 Independent Peer Reviews

ZeroGen developed an Independent Peer Review (IPR) process to inform its board and funding stakeholders and thereby assist with and validate the basis for decision making. At the completion of the PFS an IPR was prepared according to that process.

Lessons learnt

IPRs are a valuable governance tool at various stages of the development of complex projects such as integrated CCS demonstration projects.

ZeroGen selected a very high–calibre IPR panel of experts from various parts of the world, covering all of the technical and commercial disciplines necessary to address whether, through the PFS, the project had:

- gained a sufficient understanding of the project;
- characterised the risks and uncertainties appropriately; and
- formulated a plan that would effectively address the remaining issues in the next phase at a cost that is appropriate.

ZeroGen chose to trial DNV’s CO2QUALSTORE as the basis to review its storage plans.

The panel concluded, in general agreement with the ZeroGen Project leadership that:

- the decision to cease work on the NDT is supported;
- plans for exploration and appraisal of the Surat and Galilee Basins are supported;
- further expenditure on the project was high risk because of uncertainties in relation to the award of future exploration tenements and the consequent technical and approval risks to the development of an adequate storage resource;
- the forecast ‘funding envelope’ required to develop and construct the project along with the net present value of the proposed Power Purchase Agreement (PPA) represented a total of $10 billion which would be extremely challenging;
- even with a Commonwealth Government ‘credit wrap’ proposed by ZeroGen, the proposed terms of debt and equity are ambitious, and would require several market firsts;
- the forecast cost of electricity from the project is very unlikely to ever be economic even with a price on carbon; and
- the 2015 mandated schedule is high risk and sticking to that schedule would likely set the project up for failure.

Investment in IPRs was over $1 million but was considered worthwhile to ‘assure’ the project and to enhance decision making especially around whether to continue or cease investing in a project.
9.1 Intent and Purpose of IPRs

IPRs were proposed to inform the ZeroGen board and Project Steering Committee (comprising board members, shareholder representatives and funding body representatives) on the appropriateness of proceeding to the next stage of development of the project. The Project Steering Committee would in turn make recommendations to the ZeroGen board and other stakeholders.

ZeroGen’s Capital Investment System (CIS) mandated that any significant project be developed in stages, for the purpose of pacing financial commitment to the level of development and understanding of the project. An IPR would examine all of the deliverables in a particular stage (including Health, Safety and Environment (HSE), commercial, technical, stakeholder relationships, etc) and determine if the project team has:

- gained a sufficient understanding of the project;
- characterised the risks and uncertainties appropriately; and
- had a plan that will effectively address the remaining issues in the next phase at a cost that is appropriate.

Based on these analyses the IPR team makes a recommendation to the board and Project Steering Committee as to whether they should accept the project team report and proceed to the next stage, request additional work or stop development of the project.

IPRs can also be convened at times other than a stage–gate boundary if, in the opinion of the Project Director, CEO or the Project Steering Committee, an issue emerges that warrants such a review. ZeroGen developed an IPR Manual to guide the conduct of the IPR.

**FIGURE 9.1: TIMING OF INDEPENDENT PEER REVIEW**

- When a progress report indicates an unfavourable KPI or as requested by the Project Director
- 40% engineering design
- Project controls implemented
- Commencement of construction works
- 100% engineering design
- Procurement of most of the equipment and bulk materials
- Civil works nearing completion
- Start of mechanical installation
- Completion of the definitive estimate
9.2 Timetable and Process for PFS IPR

The Project Director nominated a date for the IPR, giving at least six weeks’ notice, upon the completion of a mature draft of the PFS report.

The draft PFS and supporting documents (the pre–read material) was distributed to all IPR team members three weeks before the study team was scheduled to meet at the ZeroGen offices. A self–assessment of the project status by the project team was also provided.

During the period between receipt of the pre–read document and arrival at the review location, members of the review team were free to contact the project team with questions for clarification as part of their preparation.

The IPR team was made up of three smaller teams covering:
• CO₂ storage and transport;
• power plant; and
• commercial and integration.

On arrival at the review site the IPR team was given brief presentations by project team members that summarised the status of the work and allowed for questioning as a review team group.

The IPR team then made an assessment of the interviews that they wished to conduct and scheduled these meetings with the project team. The IPR team determined the composition and format of the interviews. The IPR team was on site for five days.

The IPR team made a short presentation to the Project Director (members of the Project Steering Committee also had the option of attending) at the end of the visit with a summary of their key findings.

The formal report detailing the IPR team findings was provided to the board and Project Steering Committee approximately two weeks after the end of the site meetings.

9.3 Composition of the IPR Team

Due to the complex nature of the ZeroGen Project and the breadth and depth of technical issues, the IPR team was quite large.

The minimum qualification of an IPR team member was personal direct experience in several major process plant and/or subsurface reservoir related projects as project manager or discipline lead.

The team members were also:
• not employed by ZeroGen or any other project stakeholder;
• experienced in the use of ‘stage–gate’ project management processes;
• experienced in conducting other similar project reviews;
• a balance of technical and commercial skills (across the team) that covers the full range of project disciplines;
available to return for subsequent projects to give some degree of consistency and familiarity;
• able to enter into confidentiality agreements to the satisfaction of ZeroGen and the various
technology suppliers; and
• had an understanding of project development in an Australian context.

For the ZeroGen PFS, the Project Director recommended the following panels of recognised
international experts for the IPR as detailed in Table 9.1. These panel members were accepted
by the ZeroGen board and Project Steering Committee.

<table>
<thead>
<tr>
<th>TABLE 9.1: RECOMMENDED EXPERT PANEL—PREFEASIBILITY REPORT</th>
</tr>
</thead>
<tbody>
<tr>
<td>Name</td>
</tr>
<tr>
<td>------</td>
</tr>
<tr>
<td><strong>Power and Capture Project</strong></td>
</tr>
<tr>
<td>Christopher Higman</td>
</tr>
<tr>
<td>Jeffrey Phillips</td>
</tr>
<tr>
<td>Ron Schoff</td>
</tr>
<tr>
<td>Dan Kubek</td>
</tr>
<tr>
<td>Carlo Wolters</td>
</tr>
<tr>
<td>Nick Jukes</td>
</tr>
<tr>
<td><strong>Carbon Transport and Storage</strong></td>
</tr>
<tr>
<td>Mike Carpenter</td>
</tr>
<tr>
<td>Jens Petter Tronskar</td>
</tr>
<tr>
<td>Reinoud Blok</td>
</tr>
<tr>
<td>Peter Oswald</td>
</tr>
<tr>
<td>Susan Struthers</td>
</tr>
<tr>
<td><strong>Integration and Commercial</strong></td>
</tr>
<tr>
<td>Brad Nowland</td>
</tr>
<tr>
<td>Lewis Jeffrey</td>
</tr>
</tbody>
</table>
9.4 Areas to be Reviewed

The ZeroGen IPR Manual provided a list of the major deliverables from each project stage. The IPR team reviewed each of those deliverables to form a view of the completeness and accuracy of the work and an assessment of the interpretation of this work by the project team.

The IPR team also provided an assessment of the overall package of deliverables and in particular, whether some important issue had been missed.

The IPR team provided their advice on the basis that it was to be used by the board and Project Steering Committee to have confidence that:

- there is at least one project configuration (commercial and technical) that meets the project objectives;
- configuration options that would be worth exploring further are identified;
- the estimated level of commitment (financial and reputational) required to complete the next stage is robust; and
- the estimated level of commitment required to complete the entire project if it proves viable is within the accuracy levels nominated by the project team.

9.5 Report Contents

The main purpose of the review is to provide the board and Project Steering Committee with the information needed to decide if expenditure on the next stage of the project is an appropriate investment. The report therefore must address the uncertainties that remain in the project, the work plan to address these risks and the cost of this plan.

The structure for summarising the assessment of the IPR team is included as Figure 9.2.

Each of the key deliverables specified for the PFS were assessed by the IPR team and classified according to that structure.
The horizontal axis of the chart seeks to describe the uncertainty and the probability of an event. Estimating probability requires an in-depth understanding of the issue. Incomplete understanding means increased uncertainty and is considered to be additive to risk for the purposes of this chart.

Positioning of each point required considerable expertise from the IPR team to make judgements about the level of definition that they consider appropriate. An item placed in the area ‘fatal flaw’ is an assessment that a practical and economic solution to a specific issue is not likely to be found. It was advised to the Project Steering Committee Governance Board that the project, as it is currently conceived, was not considered viable by the IPR team.
9.6 Key Findings from the ZeroGen PFS IPR

The IPR team made a number of recommendations for additional work and organisational strengthening to be undertaken prior to moving to a feasibility study, but their general conclusions in relation to the project may be summarised as follows:

- the decision to cease work on the NDT is fully supported;
- plans for exploration and appraisal of the Surat and Galilee Basins are supported;
- further expenditure on the project is high risk because of uncertainties in relation to the award of future exploration tenements and the consequent technical and approval risks to the development of an adequate storage resource;
- the forecast ‘funding envelope’ required to develop and construct the project along with the net present value of the proposed PPA represents a total of $10 billion which will be extremely challenging;
- even with an Australian Government ‘credit wrap’ proposed by ZeroGen, the proposed terms debt and equity are ambitious, and would require several market firsts;
- the forecast cost of electricity from the project is very unlikely to ever be economic even with a price on carbon; and
- the 2015 mandated schedule is high risk and sticking to that schedule would likely set the project up for failure.

These findings were aligned with the views of ZeroGen’s Project team. Given that ZeroGen faced very limited funding to sustain it while the critical issues of accessing alternative GHG exploration tenements and no clarity that the 2015 mandated schedule would be relaxed, the IPR findings reinforced the decision to cease operations.

9.7 Comments on the use of CO2QUALSTORE for Storage Review Purposes

Significant efforts have been undertaken to develop guidelines to assist developers and regulators in the governance of CCS projects. ZeroGen sought to contribute to this through its IPR process.

The CO2QUALSTORE guideline (DNV, 2010) was used as a basis for assessing the storage elements of the ZeroGen Project. The guideline provides a generic Capital Value Process for CCS projects, based on upstream oil and gas developments, which is designed to qualify geological storage ‘reserves’ by iterative cycles of risk and uncertainty reducing measures. The stage–gated process contains features which appear to be a common trend amongst emerging regulations and guidelines for CCS in various countries.

The guideline was published in early 2010 by DNV following a two–year Joint Industry Project with upstream and power utility companies. The partners were: Arup, BG Group, BP Alternative Energy, Det Norske Veritas (DNV), DONG Energy, Gassco, Gassnova, IEA GHG R&D Programme, Petrobras, RWE Dea, Schlumberger, Shell, Statoil and Vattenfall. The project was coordinated by DNV.
For the ZeroGen IPR, DNV with other members of the IPR team, tested the guidelines as a first application in a project review setting. Subsequently DNV reported the following findings for this Case History.

It was concluded that the guideline offers a robust basis for performing independent project reviews. The generic capital value process and stage–gate structure that is described in the guideline is flexible enough to be adapted to individual corporate and project models. Modifications to the guideline will likely be required on a project by project basis in order to account for differences in stage–gate criteria and project structure. This is a straightforward process, but should be carried out by the project in conjunction with an external body in order to ensure the integrity of the review.

Two main areas for modification were identified, based on work ZeroGen had undertaken but were not covered by the guidelines. These were (i) reservoir uncertainty analyses and the importance of dynamic–based assessments, and (ii) wells and conceptual field development planning. For the former, a suggested addition to CO2QUALSTORE in the Assess and Select Stage might be as follows:

Data and models should be analysed and the quality summarised by error bounds. The following items should be calculated and presented as a high, most likely and low case (say P20/P50/P80).

- total storage volume;
- an assessment of the seal thickness and fracture pressures;
- maximum allowable injection pressure;
- volume of any compartments in the reservoir and connectivity between them; and
- of the storage site at expected project injection rates.

Sensitivity of the reservoir performance to errors in the available data should be analysed to determine priorities for additional data acquisition.

With respect to wells and field development planning DNV made the following comments:

Well engineering considerations are not treated in any detail in the initial CO2QUALSTORE guidelines and this may represent the biggest lesson from the IPR trial. As a result of the ZeroGen experience, it is recommended that the guideline now require additional information from the Assess and Select Stage relating to an Injection and Operations Plan for conceptual development based on the results of Reservoir Characterisation studies. Such plans should consider constraints to development and the locations, numbers and types of well to be drilled. The plan should consider the following for the P20/P50/P80 cases in the Reservoir Characterisation:

- conceptual layout of the wells over the storage site including an evaluation of surface and other environmental constraints or containment risk features;
- preliminary well design details;
- injection rate and well count expected for the proposed project; and
- injection rate decline and ongoing drilling program in the operational phase of the proposed project.
In addition to the plan, a Drilling and Completions Uncertainty Statement should analyse possible variations in the delivery and performance of the wells described by the Injection Plan. Such a report should include:

- estimated drilling time and cost for each well;
- the estimated ‘learning rate’ or improvement in well delivery time as the campaign progresses;
- number and type of drilling rigs in use;
- expected variation in delivered well flow performance;
- P20/P50/P80 drilling program costs for the various cases described in the Injection Plan;
- challenges and opportunities created by any existing wells in the area; and
- an estimate of the workovers that will be required on existing wells.

One reason for this addition may be that the original guideline did not envisage such a level of detail being required prior to submitting a storage permit application (at milestone M4). There now appears to be two main reasons for updating this area of the guideline:

a) detailed well engineering plans are essential for predicting capacity and injectivity; and

b) well construction will represent a large proportion of capital expenditure.

The first reason is fundamental to project viability and could be scrutinised by regulators as well as the project developer. The second is a commercial consideration, but given the level of public funding of CCS projects could also be expected to be open to scrutiny by regulators and funding bodies.
10 Project Development Costs and Funding

The purpose of this section is to present an approximate breakdown of costs incurred on the PFS for development of the MHI industrial-scale IGCC with CCS integrated project. The relevant period is mainly from late 2008 when the scoping study commenced, to end July 2010 with the submission of the PFS.

Lessons learnt

The total cost invested in the PFS including CO₂ storage exploration and appraisal activities was approximately $138 million.

The majority (circa 73%) of the ZeroGen PFS costs were related to CO₂ storage exploration drilling, testing and studies required to answer the key criteria defined for a stop or go decision for storage. While storage was confirmed to be secure to a reasonable level of confidence, the area available and under tenement could not sustain the required injection rates for a commercial-scale operation.

Had the project history been different and had it started in 2008 with a clean-sheet (rather than against a back-drop of several project scope changes) to investigate the possibility to storing 60–90 million tonnes at an injection rate of 2–3 Mtpa, the exploration program would have been smaller and more focused on dynamic testing. Such a tailor-made program, had it been allowed to be conducted on a whole campaign basis might have been less costly. However the results would not have been different.

It is essential to ensure that the funders and stakeholders have access to adequate technical and decision support to understand the degree of risk and uncertainty known to the projects and that this understanding is explicitly shared. Ideally, the project proponent would be regarded as the funders’ own team.

Multiple funding parties introduced a high degree of complexity in relation to the formation and administration of agreements and project governance. While not possible for ZeroGen due to its complex evolution, serious consideration should be given to funding bodies creating a collaboration or ‘joint venture’ agreement between themselves and a single funding agreement for the proponent to simplify the project-funder interface.
10.1 General
The ZeroGen Project evolved through five earlier project configurations before the end of 2008, when a commercial-scale configuration was settled upon. Prior to the end of 2008, significant plant technology and engineering studies from earlier project phases had been carried out, some of which possibly contributed knowledge to the commercial-scale project. This is excluded from the analysis of prefeasibility costs.

In terms of CO₂ storage, six of the 12 exploration wells relied upon for evaluating the CO₂ storage potential were drilled prior to the end of 2008, and so it is appropriate that their estimated costs are included in the analysis of prefeasibility costs.

Finally, the PFS was submitted at the end of July 2010. However, the project had significant extra costs to close studies and contracts, and the corporate vehicle. Of these post-July 2010 costs, only those related to CO₂ storage wells and decommissioning of environmental monitoring installations are carried in this analysis.

10.2 Scoping Study Cost
The scoping study was undertaken during the fourth quarter of 2008 and early 2009. This study examined at a very high level most of the issues to be assessed in the PFS with the following limitations:

- all studies were desktop with no test work undertaken;
- no specific work was undertaken in relation to plant siting with a generic Central Queensland coal mine being anticipated;
- no engineering was performed, and the MHI concept was accepted as providing a workable basis;
- MHI provided an EPC estimate of the plant costs which was not subjected to any detailed scrutiny by ZeroGen;
- owner’s costs and enabling infrastructure costs were factored based on typical project benchmarks;
- the CO₂ storage field and facilities was based on a generic field concept with 50 simple wells, located within 100 km of the power plant; and
- very high level concepts were prepared in terms of HSEC, Environmental Approvals and Stakeholder Engagement plans.

The scoping study cost was approximately $2.5 million.

10.3 PFS Cost
Prior to commencement of the PFS, ZeroGen invested approximately $49 million in engineering, drilling and data interpretation for exploration activities in the NDT. These costs have been added to the CO₂ storage costs actually incurred during the PFS phase.
All costs within the PFS were controlled within a detailed Work Breakdown Structure (WBS) and investments released according to the PFS Work Plan.

The PFS was completed and submitted at end July 2010. Several contracts extended beyond this time and some work was still undergoing completion. With the exception of well closures, which were completed in July 2011, most other PFS costs were complete by September 2010.

The total costs for the PFS and CO₂ storage exploration program are broken down into major cost groupings in Table 10.1.

TABLE 10.1: ZERGEN PFS—MAJOR COST GROUPINGS

<table>
<thead>
<tr>
<th>Cost group</th>
<th>Estimated cost (all millions)</th>
<th>% of total</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂ storage</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Prior to PFS period (6 wells)</td>
<td>$48.0</td>
<td></td>
</tr>
<tr>
<td>PFS period (6 wells)</td>
<td>$53.6</td>
<td>73.5%</td>
</tr>
<tr>
<td>Power plant with capture</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Engineering</td>
<td>$14.71</td>
<td></td>
</tr>
<tr>
<td>Coal studies and testing</td>
<td>$2.43</td>
<td></td>
</tr>
<tr>
<td>Site selection</td>
<td>$1.87</td>
<td></td>
</tr>
<tr>
<td>Operations and maintenance studies</td>
<td>$0.26</td>
<td>13.9%</td>
</tr>
<tr>
<td>Environmental studies</td>
<td>$2.68</td>
<td>1.9%</td>
</tr>
<tr>
<td>Stakeholder engagement</td>
<td>$0.81</td>
<td>0.6%</td>
</tr>
<tr>
<td>Commercial studies</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Capital and operating cost estimates</td>
<td>$0.31</td>
<td></td>
</tr>
<tr>
<td>Power revenue and trading</td>
<td>$0.20</td>
<td></td>
</tr>
<tr>
<td>Financial modelling</td>
<td>$0.35</td>
<td></td>
</tr>
<tr>
<td>Financing studies</td>
<td>$0.40</td>
<td>0.9%</td>
</tr>
<tr>
<td>Project management and controls</td>
<td>$4.08</td>
<td>3.0%</td>
</tr>
<tr>
<td>Corporate administration, financing studies, etc</td>
<td>$8.6</td>
<td>6.2%</td>
</tr>
<tr>
<td>Total study expenditure</td>
<td><strong>$138.3</strong></td>
<td></td>
</tr>
</tbody>
</table>
10.4 Discussion of Costs by Cost Group

The following subsections provide a discussion of the major cost groups in order of the quantum expended.

10.4.1 CO₂ storage costs

The majority of the PFS costs (73.5%) were on the extensive CO₂ storage exploration drilling and testing program. These costs cover the 12 wells drilled in total by ZeroGen, as well as the design and fabrication of bespoke CO₂ injection equipment, three CO₂ injection tests, seven water injection tests and all related CO₂ sub-project management, study and laboratory costs.

The CO₂ storage sub-project expenditure was broken down approximately, as shown in Table 10.2. Note that this breakdown is based on the expenditure during the PFS period as the WBS and project controls prior which applied to exploration activities prior to the PFS were less rigorous.

TABLE 10.2: ZEROGEN PFS—CO₂ STORAGE COSTS

<table>
<thead>
<tr>
<th>Cost area within CO₂ storage exploration</th>
<th>% of CO₂ costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project management, data and special IT</td>
<td>6%</td>
</tr>
<tr>
<td>Wells (management, civil, drilling, completions and P&amp;A)—12 wells</td>
<td>52%</td>
</tr>
<tr>
<td>Well specific geotechnical studies</td>
<td>4%</td>
</tr>
<tr>
<td>ZG–11 CO₂ test (facilities EPC, operate and CO₂ costs—excl. ZG11 drilling)</td>
<td>18%</td>
</tr>
<tr>
<td>2D seismic (acquisition, processing, interpretation)</td>
<td>1%</td>
</tr>
<tr>
<td>Water injection tests (four wells)</td>
<td>6%</td>
</tr>
<tr>
<td>Geotechnical studies, sub–surface and facilities, synthesis and FDP</td>
<td>10%</td>
</tr>
<tr>
<td>Studies of alternate basins and tenements</td>
<td>2%</td>
</tr>
</tbody>
</table>

Geotechnical studies include, well log and test interpretations, core studies, laboratory tests (Routine Core Analysis (RCAL) and Special Core Analysis (SCAL)—including CO₂ SCAL) geological characterisation studies, petrophysical studies, geological modelling, reservoir engineering, in–field layout and preliminary field engineering.

After completing a large number of individual investigations, the final technical and engineering syntheses of all studies required to address the key PFS question (total costs per tonne of CO₂ sequestered, including unit development costs and operational costs) was in excess of $850,000.
10.4.2 Power plant costs

The total power plant related costs were approximately $19.3 million (almost 14%) of the total prefeasibility costs. They included power plant (including CO₂ capture) engineering studies, site selection and layout studies, coal evaluation and testing and, operations and maintenance studies.

The power plant engineering studies defined the main IGCC plant complete with CO₂ capture.

Broadly speaking these costs divide in two categories:
- Power plant and capture proper $12.5 million (85%); and
- Balance of plant $2.21 million (15%).

Power plant and capture engineering study costs ($12.5 million) included:

<table>
<thead>
<tr>
<th>Study cost breakdown for power plant with capture ($12.50 M)</th>
<th>% of PP&amp;C costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Engineering studies and study management (ZG and MHI)</td>
<td>34%</td>
</tr>
<tr>
<td>Basis of design, coal, technology and process selection and design (incl. heat and mass balances and water optimisation studies)</td>
<td>32%</td>
</tr>
<tr>
<td>Preliminary engineering (gasification, water shift, acid gas removal, sulphur processing, gas turbine, steam turbine (and auxiliaries), civil, structural and building, piping, electrical, instrumentation and controls)</td>
<td>16%</td>
</tr>
<tr>
<td>Estimating, next phase planning and implementation</td>
<td>18%</td>
</tr>
</tbody>
</table>

Balance of plant engineering study costs ($2.21 million) included:

<table>
<thead>
<tr>
<th>Study cost breakdown for balance of plant ($2.21 M)</th>
<th>% of BoP costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Management and techno–socio–economic trade–off studies</td>
<td>28%</td>
</tr>
<tr>
<td>Materials handling</td>
<td>11%</td>
</tr>
<tr>
<td>Site selection/development/civil engineering studies</td>
<td>41%</td>
</tr>
<tr>
<td>General site infrastructure</td>
<td></td>
</tr>
<tr>
<td>Reporting and estimating</td>
<td>15%</td>
</tr>
<tr>
<td>Process modelling</td>
<td>5%</td>
</tr>
</tbody>
</table>
10.4.3 Other power plant related costs

Related to the abovementioned power plant engineering costs are ‘coal supply’, ‘plant site selection’ and ‘operations and maintenance’ study costs.

**Coal supply** study costs comprised over $2.43 million of costs related to engineering trade–off studies, characterisation and testing to assess options along with a pilot–scale gasification test burn by MHI. This work also covered commercial procurement negotiations relating to various coal supply options.

**Plant site selection** study costs comprised $1.87 million techno–commercial engineering trade–off studies and commercial negotiations associated with identifying and evaluating potential sites for the plant and including survey and meteorological monitoring. Five potential sites were studied in detail before narrowing down to one preferred NDT site and a contingent Surat Basin site. In order to make this selection, many studies were repeated for comparative purposes across these sites. The study costs included management and studies related to water supply, water pipelines, HV power, CO₂ pipelines and natural gas pipelines.

**Operating and maintenance** study costs comprised $260,000 of studies related to the likely frameworks for operations and maintenance, including management systems that would be required to operate the integrated CCS project.

10.4.4 Corporate administration

At approximately 10% of total costs, these represent costs incurred by the ZeroGen special purpose corporate vehicle to support the project.

ZeroGen Pty Ltd was a special purpose vehicle incorporated under the Corporations Act in Queensland. Project administration costs are dominated (40%) by staff and management costs, but include significant elements for audit and accounting, IT infrastructure and support, office costs, and legal and insurances. Legal costs were significant at $1.5 million with a plethora of complex funding and development agreements with the project funders and MHI, along with many but less complex licensing, confidentiality and services contracts.

It is of interest to note that the project had to work under government funding processes within which it was required to produce high quality project documentation. In June and July 2010, this took the form of five GHG Tenement Application documents, a complete five volume PFS and a Commonwealth CCS Flagships Submission (and supplementary submission). Graphics and reproduction costs alone for these were in excess of $500,000.

10.4.5 Project management and controls

At approximately $4.1 million (5%) of total costs, this represents the Project Director’s office, project commercial function, overall project controls, project reporting and independent peer reviews.

These costs are predominantly staff and management costs. However, over $1 million was applied to the independent project reviews. This is in addition to in–house and contractor reviews which were an integral part of the power plant and CO₂ storage work programs.
10.4.6 Environmental

These costs of $2.85 million (2.2%) related to the creation of terms of reference for an EIS and commencement of those studies. As discussed in Section 4, EIS studies had to commence in this period (prematurely perhaps) because of the mandated schedule to commence operations by 2015 under the CCS Flagships Program.

These costs included management and studies related to the screening and pre–EIS work for several potential plant sites and covered land use and tenure, noise monitoring, meteorological baseline monitoring as well as EIS compliance costs. The costs also included procurement and installation of base–line weather monitoring towers at two of the potential plant sites.

Note that for CO₂ storage there was also a significant ‘environmental’ spend included in geotechnical studies, which included ground water issues and storage monitoring and verification studies.

10.4.7 Commercial studies

These costs of $1.26 million ( > 1%) related to the acquisition and analysis of data, preparation of estimates, development of models and interpretation of design and operational regimes necessary to establish a robust financial model for the project, along with development of a project financing concept proposal. They included:

**Capital and operating cost estimates** ($310,000) developed and verified utilising in–house estimators as well as a range of contractors and suppliers.

**Power revenue and trading** studies ($200,000) comprised studies on possible entries into the electricity markets as well as modelling projected electricity and carbon prices.

**Financial modelling** studies ($350,000) comprised the creation of a special purpose financial evaluation model able to support various trade–off studies and also to determine the financial viability and ‘commercial gap’ for the project under various operational and commercial scenarios.

**Financing plan** preparation ($400,000) covered the engagement of Queensland Treasury Corporation and other financial advisers to assist with the development of a project financing concept covering possible grant, equity and debt mixes, along with operational subsidies.

10.4.8 Stakeholder engagement

Stakeholder engagement costs of $810,000 (0.6%) included management of community and external engagement, as well as costs related to Cultural Heritage and Native Title searches and clearances. It should be noted that an additional $720,000 in the Corporate Administration costs were of a similar nature and could possibly be better classified as external/stakeholder engagement costs.
10.5 Funding the Development Costs

Public and industry (i.e. ACALET) non–recourse grant and equity funding was essential to these development activities because at no point since its inception in 2004 did the project ever present a business case that suggested it could proceed without significant financial subsidies. As the preceding section shows, development costs are extremely significant and high risk and funders understandably prefer to share the risk. This typically leads to the involvement of multiple funding bodies.

The presence of three funding bodies with different objectives and controls produced some management and governance challenges. A significant amount of funders’ and the ZeroGen executives’ time was spent negotiating and facilitating the various funding agreements required.

For the latest development phase there were four major agreements:

- Equity funding: State of Queensland Equity Funding Agreement;
- Grant funding: Commonwealth Government Funding Agreements;
- Grant funding: ACALET Funding Agreements; and
- Technology Supplier: Mitsubishi Project Development Agreement.

In addition to management time, ZeroGen’s share of third–party legal costs for the project up to March 2011 was approximately $1.5 million, mostly on facilitating these agreements. It is likely that each counterparty also had significant costs in this regard.

10.5.1 Funding agreement discussions

Until the commencement of the PFS for the industrial–scale CCS project, the Queensland Government and ACALET were the main funding bodies. After the project had converted to a commercial–scale proposal in 2009, the Australian Government also became a grant funder under a new agreement.

The challenges in ensuring that equity and grant funding stakeholders are fully informed and understand project risks and uncertainty are significant. As in any venture, multiple parties with differing levels of expertise and engagement and differing sensitivities to various outcomes will increase complexity and management effort. The following is a discussion of issues and observations made by ZeroGen.

Multiple funders

Where several funding bodies may wish to invest in a project, alignment of funding agreements can be very complex for the project proponent and may be seriously distracting from the core purpose of project delivery.

Funders control versus corporate governance

Each of the major funders sought to govern their investment by ensuring that they were consulted and had ‘steering’ rights with respect to the major project decisions (both with regard to scope and investment levels). This was achieved ultimately with the formation of a project steering committee which comprised representatives of the shareholder, grant funding bodies, ZeroGen board and Mitsubishi Corporation.
In a situation with a mix of equity and grant funding, equity parties carry most risk and often in the case of CO₂ storage exploration, an uncapped liability. The relationship between project company and its grant funders is one of critical dependency. This creates a potential dilemma for a project proponent unless the perception and understanding of risk, as well as tolerance for risk, is well aligned between company and its ‘steering’ bodies.

**Communication of risk and uncertainty or confidence**

Public versus private funders may have a different tolerance for risk and uncertainty. In some situations, messages replete with cautionary statements and caveats, while properly communicating a project developer’s opinion, may be uncomfortable for the public sector trying to justify its investment or additional funds. Concepts based on levels of confidence and the communication of uncertainty, require sophisticated conversations.

**Intellectual Property**

A more detailed discussion of IP issues is covered earlier in Section 7, Chapter One of this document and in any case is project, funder and vendor specific. But it should be noted that management of project and background IP requires considerable effort to encode and administer the various requirements in formal agreements. In the case of ZeroGen, some funders saw part of their ‘return’ taking the form of project or arising IP. However, most of the basic technology IP was the property of the various vendors and considered to be commercial in confidence. Management of this issue resulted in a web of confidentiality agreements and various rights accrued by parties associated with funders. At the same time, vendors naturally required ongoing controls on disclosure of IP which potentially added to project management complexity.
11 Capital and Operating Cost Estimates

This section describes the formation of capital and operating cost estimates prepared for the ZeroGen Project and provides an analysis of those estimates.

Lessons learnt

ZeroGen developed relatively detailed capital and operating costs consistent with an American Association of Cost Engineers (AACE) Class 3 estimate for the IGCC power plant and Class 3/4 for the gas processing (CO₂ capture) and CO₂ pipeline and storage. A significant engineering effort went into both the IGCC and the capture plant however, at the time of submitting the PFS (aligned with CCS Flagships requirements), ZeroGen had not settled on a final preferred CO₂ capture process configuration.

In terms of the CO₂ pipeline and storage capital costs, because ZeroGen was ‘resetting’ the search for storage, the field location, development, well depths, well spacing and well count were unknown and so these costs and infrastructure costs (surface facilities) thus could not be specified to any great degree and are based on a generic concept.

ZeroGen estimates that work-load involved in the process of compiling cost estimates for in-house, contractor and an independent review was of the order of 42 man-months. This was in addition to approximately 500 man-months of engineering undertaken in relation to the power generation and CO₂ capture process facilities. These effort levels are essential to properly specify the scope of projects and reduce uncertainty levels of cost estimates.

Key outcomes include:

- the headline capital cost for the project was estimated at $6.93 billion inclusive of $1.2 billion in contingency and escalation allowances. This is up from the scoping study estimate of $4.2 billion;
- the power plant including CO₂ capture was $3.9 billion up from the scoping study estimate of $2.25 billion;
- enabling infrastructure costs which were excluded from the scoping study were $620 million;
- a conservative estimate of $800 million was allowed for a CO₂ pipelines and storage field development and surface facilities concept; and
- local cost and productivity factors add significantly to the cost of projects deployed in the Queensland mining provinces with a total cost—productivity ratio (compared with US Gulf Coast) of 1.56 determined.
11.1 General Commentary on Cost Estimates

A capital cost base line estimate was prepared in accordance with the ZeroGen Estimating Guidelines, where scope and pricing has been developed using:

- preliminary engineering design to identify all major plant and equipment (and performance specifications) and associated bulk materials (e.g. concrete, structural steel, piping, etc.);
- specific budget quotations from Australian contractors for works and services including:
  - site civil works (permanent and temporary);
  - pipeline construction (CO₂ and water);
  - ready mix concrete and quarry products supply;
  - permanent buildings—design and construction;
  - logistical costs; and
  - construction support services such as camp operations, charter services, etc.
- budget quotations from the major equipment manufacturers based upon the project’s equipment lists and performance specifications; and
- historical project cost data to estimate a benchmark price for specific elements of the ZeroGen Project.

Design growth allowances were included in the base estimate to cover the level of engineering completeness. These allowances were discipline–specific and based upon historical industry benchmarks that provide for the increased work specification as design is detailed during subsequent phases. On individual engineered costs, levels of accuracy (excluding CTS costs) were typically –15% to +25%.

Escalation and contingency amounts were not included within the base estimate. Contingency was developed using Monte Carlo simulation techniques linked directly into the risk register. Escalation was estimated based on historical data for a recent period of high engineering and construction activity in the Australian resources sector. Note the purpose of including contingency and escalation estimates in the headline capital cost estimate is to reflect the likely limitations on funding from government and industry associations. The funders have typically considered the contributions to be capped on a nominal basis.

Operating cost estimates were, as is customary at PFS phase, based on benchmark information from like facilities. However, because of the first–of–kind nature of this project, ZeroGen did attempt to improve the confidence in estimates by broadly reconciling benchmarks with first principles estimates for fuel, operating labour, maintenance, catalysts and chemicals, consumables etc.

Operating cost estimates were considered to have a level of accuracy of approximately –15% to +35%.

ZeroGen estimates that work–load involved in the process of compiling cost estimates for in–house, contractor and an independent review was of the order of 42 man–months.
Figure 11.1 summarises the data composition and review process followed by ZeroGen to build a robust capital cost estimate.

**FIGURE 11.1: ILLUSTRATION OF THE STRUCTURE OF ZEROGEN COST ESTIMATES**

![Diagram showing the process of ZeroGen cost estimates]

- **Define outcome and constraints**
  - ZeroGen PFS Workplan
  - ZeroGen Project schedule
  - ZeroGen basis of design
  - ZeroGen estimating guideline

- **Engineering, study, planning and detailed estimate build up**
  - ZeroGen estimates
    - Typical owner’s/sponsors cost such as: manning, administration, insurances etc.
  - PFS – study consultants
    - Estimations
  - EPC contractors
    - Detailed proposal estimations: MHI, AECOM, Hatch, Fluor
  - Vendors
    - Equipment budget quotations
  - Australian contractors
    - Works and services budget quotations

- **Check, review and correct**
  - ZeroGen Price book
  - ZeroGen Risk and opportunity register
  - Market/Industry escalation assessment

- **First principles review**
  - 1. Scope and boundaries
  - 2. Quantities
  - 3. Rates
  - 4. Durations and work productivities
  - 5. Schedule alignment
  - 6. Forex conversions

- **Baseline estimate**
  - Monte Carlo Modelling
  - Monte Carlo model target project outcome cost

- **Final element/area cost review**
  - Final overhead review
  - Independent review

- **Final estimate sign-off**
  - Project financial modelling

- **Review and adjust with originator**
  - Summary of changes
11.2 Capital Cost Estimates

The ZeroGen overall capital cost estimate was $6.9 billion, inclusive of direct contingency and escalation based on the project being delivered during the period 2011 to 2017. This covers estimated costs from the end of PFS to completion of commissioning, demonstration and handover, including the remaining project development costs estimated for the Feasibility Study, FEED and achievement of FID.

Excluding contingency and escalation, the headline estimate was $5.8 billion which was allocated to five main project cost areas as detailed in Table 11.1.

TABLE 11.1: ZEROGEN PROJECT CAPITAL COST ALLOCATED TO MAJOR PROJECT COST AREAS

<table>
<thead>
<tr>
<th>Main project cost area</th>
<th>Billions</th>
<th>% Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>ZG owner’s costs</td>
<td>$0.30</td>
<td>5%</td>
</tr>
<tr>
<td>Enabling works</td>
<td>$0.62</td>
<td>11%</td>
</tr>
<tr>
<td>Power plant incl. balance of plant</td>
<td>$3.90</td>
<td>68%</td>
</tr>
<tr>
<td>Carbon transport and storage</td>
<td>$0.80</td>
<td>14%</td>
</tr>
<tr>
<td>Operations readiness and start–up</td>
<td>$0.14</td>
<td>2%</td>
</tr>
<tr>
<td>Total base estimate</td>
<td>$5.76</td>
<td>100%</td>
</tr>
<tr>
<td>Direct project contingency</td>
<td>$0.52</td>
<td>9%</td>
</tr>
<tr>
<td>Escalation</td>
<td>$0.65</td>
<td>11%</td>
</tr>
<tr>
<td>Total fully load capital cost</td>
<td>$6.93</td>
<td></td>
</tr>
</tbody>
</table>

11.2.1 Key assumptions

The key underpinning assumptions to the capital cost estimate included:

- the initial and subsequent inter–phase review and approval periods defined in the project schedule would not be extended or delayed;
- foreign exchange rates are:
  - AUD 1.00 = USD 0.800 (specified in Commonwealth Flagships guidelines)
  - AUD 1.00 = Euro 0.605
  - AUD 1.00 = Yen 79.402
  - AUD 1.00 = RMB 6.323
- access to the port facilities and the required logistic infrastructure upgrades on existing major roads will be approved by the relevant third–party authorities; and
- all dollar values are Australian dollars at May 2010 values and exclude Goods and Services Tax (GST) unless otherwise noted. Foreign currency amounts were estimated at:
Where specific assumptions posed an inherent risk (e.g. the assumed labour rate was based on current major project enterprise agreements and would be potentially at risk in the volatile construction labour market predicted to exist from 2011 on), then it was quantified and included within the project’s direct contingency calculation.

11.2.2 Escalation

With the majority of capital costs to be incurred over the period 2012 to 2017, escalation of the capital cost budget was considered likely to be very significant.

Key influences on escalation were seen as:

- significant increases in new resource sector projects within Australia and near Pacific neighbours. Specifically, several planned Liquified Natural Gas (LNG) projects would require a similar highly skilled trade workforce to that required by ZeroGen, as well as utilising common infrastructure facilities (such as Queensland ports and roads);
- any slack in the Australian skilled workforce was likely to be taken up over 2010–2011;
- recent historical performance predicted that trade, engineering and management skill shortages will increase, labour productivity and industrial relations worsen and wages increase as fly-in fly-out (FIFO) and overtime increases;
- the supplying Asian economies will continue to strengthen leading to increased costs for manufactured equipment and material; and
- domestic construction wages and building material costs did not fall during the global financial crisis.

For these reasons ZeroGen calculated an escalation envelope using actual escalation indices from the 2006 to 2008 period (i.e. prior to the global financial crisis). Examination of historical rates gave rise to the following indices.

<table>
<thead>
<tr>
<th>Example indices</th>
<th>Annual growth</th>
<th>Modelled as</th>
</tr>
</thead>
<tbody>
<tr>
<td>Private construction wages</td>
<td>5.46%</td>
<td>0% to 6%</td>
</tr>
<tr>
<td>Equipment—mechanical</td>
<td>12.05%</td>
<td>1% to 12%</td>
</tr>
<tr>
<td>Equipment—electrical</td>
<td>4.83%</td>
<td>3% to 5%</td>
</tr>
<tr>
<td>Materials—cement/concrete</td>
<td>4.32%</td>
<td>3% to 5%</td>
</tr>
<tr>
<td>Materials—pipes/tubes</td>
<td>15.23%</td>
<td>3% to 15%</td>
</tr>
<tr>
<td>Materials—fabricated steel</td>
<td>10.26%</td>
<td>3% to 10%</td>
</tr>
</tbody>
</table>
11.2.3 Comparison—productivity factors

This subsection is included to assist non–Australian readers in cost comparisons since most other published costs and studies assume US base–line costs.

The following figures are based on Australian heavy industry sectors and widely applied to Australian projects:

• work production: 1 US man–hour (Gulf Coast) = 1.2 Australian man–hour;
• cost: 1 US man–hour = US$45 = AU$56.25 vs Australian Enterprise Bargaining Agreement (EBA) average rate of $73/hr; and
• hence the wage productivity factor is 1.30.

Hence the US Gulf Coast to Australia total productivity factor is 1.56 (i.e. 1.2 x 1.3). It is worth noting that this productivity factor may actually be even higher for regional mining zones in Queensland and Western Australia, where activity levels are much higher and skills shortages exacerbated.

11.3 Discussion of Capital Costs by Cost Group

11.3.1 ZeroGen owner’s costs

ZeroGen owner’s costs were estimated at $300 million (5% of total), and includes the full cost with overheads of the owner’s project team and its professional advisers to provide review and oversight throughout the course of the project.

11.3.2 Enabling works

In contrast to most published cost estimates and benchmarks, ZeroGen’s engineering assessments found that site specific ‘enabling’ costs were likely to be significant, especially in an Australian context. A total of $620 million or 10.7% of the total (unescalated) base cost was estimated in this area and is broken down as follows.

<table>
<thead>
<tr>
<th>Enabling works costs</th>
<th>% of base capital cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Land, EIS, and cultural heritage and native title</td>
<td>0.58%</td>
</tr>
<tr>
<td>Water rights and infrastructure</td>
<td>0.86%</td>
</tr>
<tr>
<td>Camp supply, operations and charter costs</td>
<td>4.32%</td>
</tr>
<tr>
<td>Logistics management and infrastructure</td>
<td>1.36%</td>
</tr>
<tr>
<td>Social infrastructure</td>
<td>2.10%</td>
</tr>
<tr>
<td>HV transmission infrastructure</td>
<td>0.72%</td>
</tr>
<tr>
<td>Communications infrastructure</td>
<td>0.18%</td>
</tr>
<tr>
<td>Construction power</td>
<td>0.57%</td>
</tr>
<tr>
<td><strong>Total enabling works</strong></td>
<td><strong>10.69%</strong></td>
</tr>
</tbody>
</table>
11.3.3 Power plant including balance of plant

The majority of engineering, procurement and construction costs were directly related to the power plant with capture, estimated at $3,900 million or 67.7% of the total base cost. These costs were to be expended under an ‘EPC wrap’ contract by MHI as described in Section 3.2. In addition to direct costs, these naturally attracted contractor margins. For the purposes of this document, these have been distributed across the five sub–groups.

<table>
<thead>
<tr>
<th>Power plant EPC wrap</th>
<th>% of base capital cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Engineering</td>
<td>7.0%</td>
</tr>
<tr>
<td>Plant and equipment supply</td>
<td>21.9%</td>
</tr>
<tr>
<td>Construction labour</td>
<td>15.6%</td>
</tr>
<tr>
<td>Subcontract construction and installation</td>
<td>17.7%</td>
</tr>
<tr>
<td>Balance of plant</td>
<td>5.5%</td>
</tr>
<tr>
<td><strong>Total power plant capital cost</strong></td>
<td><strong>67.70%</strong></td>
</tr>
</tbody>
</table>

‘Engineering’ includes the provision of engineering, procurement, project management and construction supervision by MHI (IGCC plant), subcontracted technology and engineering firms (associated with the carbon capture technology) and balance of plant engineering.

‘Plant and equipment’ was the permanent plant and equipment to be procured and delivered to site.

‘Construction and installation’ was the on–site works for construction, erection and installation of the main IGCC with CO₂ capture facility (civil, structural, mechanical, piping, electrical and controls) which MHI planned to subcontract to a major Australian construction contractor.

‘Balance of plant’ covered the plant areas to be provided by third–party design and construction contractors for items such as raw and waste water treatment, on–site storage of supplementary fuel and reagents, Zero Liquid Discharge and so on.

11.3.4 CO₂ Transport and Storage (CTS) costs

Due to the lack of site definition, the estimate for CTS costs is significantly less robust than those for other engineered elements in the table above. For this cost case, a distance from power plant (Ensham site) to a notional Surat storage site of circa 420 km was assumed for a 3 Mtpa capacity line which would require 2–3 booster compressor stations. This pipeline and compression configuration was estimated at over $350 million in third–party EPC costs. However, given pipeline length uncertainty was –50 to +200 km, the uncertainty around this estimate was significant.

Furthermore, for the field development, well depths, well spacing and well count were unknown and so well costs and infrastructure costs (surface facilities) could not be specified to any great degree. The remaining costs therefore represent a conservative allowance which covers ZeroGen CTS team costs for the whole period as well as an allowance drilling between six and 40 wells—including some exploration wells that after drilling are assessed to be unusable.
11.3.5 Operational readiness

This cost of $140 million, just under 2% of the base cost estimate, included the recruitment, salary and on–costs and training of the management and operational staff progressively during development, engineering, construction and commissioning of the various facilities such that the project owner(s) are ‘operations ready’ at the time of start–up.

11.4 Operating Costs

For any first–of–a–kind plant, the estimation of operating costs comes with significant uncertainty. As with Capital Cost estimates, Operating Cost estimation included known Australian–specific factors including the effects of a skills shortage.

The power plant operation and maintenance cost considered the operating costs in terms of materials (e.g. chemicals, coal, diesel etc.), operations labour (and their mobile plant, vehicles and equipment) and plant area maintenance.

Detailed operating cost estimates allowed for different operating costs in an initial five year ‘proving’ phase. In an attempt to account for maintenance and replacement schedules, a plan to replace mobile plant and vehicles every six to eight years were included, as well as a rolling program of catalyst/chemical replacements over two, three and six year cycles.

Total average annual operating costs were estimated to be $177 million as follows:

<table>
<thead>
<tr>
<th>O&amp;M cost element</th>
<th>% total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Plant materials</td>
<td>55.0%</td>
</tr>
<tr>
<td>Operations labour and plant</td>
<td>6.1%</td>
</tr>
<tr>
<td>Gasification and ASU</td>
<td>1.8%</td>
</tr>
<tr>
<td>Maintain gas clean up</td>
<td>3.5%</td>
</tr>
<tr>
<td>Maintain power block</td>
<td>10.8%</td>
</tr>
<tr>
<td>Maintain other process element</td>
<td>3.9%</td>
</tr>
<tr>
<td>Maintain BoP</td>
<td>3.6%</td>
</tr>
<tr>
<td>Management and indirect costs</td>
<td>9.5%</td>
</tr>
<tr>
<td>O&amp;M contingency</td>
<td>5.9%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>100%</strong></td>
</tr>
</tbody>
</table>
12 Financial Modelling

The purpose of this section is to summarise the financial modelling work and outcomes developed by ZeroGen for the industrial-scale integrated IGCC with CCS project.

Lessons learnt

ZeroGen developed a detailed financial model based on various assumptions (e.g. revenue, costs, performance, time) to produce financial forecasts for the Feasibility Study, construction, commercial proving and commercial operations phases of the project. The purpose of the forecasts was to assess the project’s cash flows and other financial information, necessary levels of equity, grant and debt funding and indicative prices for the PPA to be sought from the Australian Government.

Electric Power Research Institute (EPRI) has estimated the Levelised Cost of Electricity (LCOE) for an nth-of-a-kind plant for various major low emission technologies. The LCOE of IGCC with CCS compares favourably with other technologies particularly when considering its ability to generate significant and consistent base-load power.

ZeroGen’s assessed LCOE was much higher than expected revenues for a commercial project and the EPRI published benchmarks. However, ZeroGen was a first-of-a-kind plant and, as such, ZeroGen’s costs include:

- costs usually omitted from benchmark costs such as necessary infrastructure (e.g. pipelines for water and CO₂, HV transmission lines), remote location construction costs (e.g. workforce housing and travel, project management buildings, communication), logistics infrastructure, land acquisition, CO₂ storage exploration and appraisal, legal services and corporate costs. For ZeroGen these were estimated to be in excess of $1 billion; and
- significant capital and (potentially) operating cost premiums associated with its position in the development/demonstration phase of the technology’s maturity cycle.

The ZeroGen model developed may be a useful tool for other Australian low emissions coal-fired power projects utilising CCS.

12.1 Revenue Estimates

12.1.1 CCS Flagships guidelines

Revenue and costs are influenced by two market forces. The CCS Flagships guideline proposed these be set as follows:

Carbon price

The base case as supplied in the CCS flagship proponent guide stipulates the carbon price at $25/tonne in 2014 rising linearly to $50/tonne in 2030 (based in 2005 dollars).
Escalation of the carbon price to 2010 dollars at the prescribed inflation rate brings this up to $28.29/tonne and $56.57/tonne respectively.

Electricity price
The stipulated electricity price in 2010 dollars rises linearly from $38 per MWh in 2014 to $75 in 2030.

12.1.2 Market considerations
The ZeroGen Plant needed to operate as a generator in the Australian National Electricity Market (NEM). The market is centrally co-ordinated by The Australian Energy Market Operator (AEMO) which assembles offers and bids from all generators greater than 30MW, and all centrally dispatchable loads in the wholesale market, to form an aggregate supply function at five-minute intervals.

The growth in demand for electricity was forecast to outstrip supply in 2015/16, supporting the entry into the market of the ZeroGen Plant at that time.

As a single unit operator in the NEM, ZeroGen examined different business models. The business model defines the market risk profile for the plant owners, and defines the roles and responsibilities for the participants. The following models were discussed and assessed.

- Pool generator;
- Pool generator plus financial market;
- Tolling plant; and
- Power Purchase Agreement (PPA).

The PPA model was recommended as the most appropriate to manage the market, when facing risks of a first of a kind plant such as ZeroGen.

For a range of technical reasons the ZeroGen Plant would perform most efficiently and with lower operating risk as a base-load plant. In the NEM, base load plants ‘self select’ based on their variable cost of operation, with the lowest variable cost plants being the base load facilities. The ZeroGen Plant could not have competed as a base-load plant in the market which has not attributed a very significant value to the emissions of CO₂. As a result there existed a significant ‘commercial gap’ for the deployment of a first of a kind plant.

Three different electricity and CO₂ price path scenarios were projected, and the viability assessed of the current first-of-a-kind plant, and an assumed 2030 build which would have taken advantage of the lessons learnt from the earlier ZeroGen Plant and other similar early mover projects to deliver design and technology improvements and reduced costs of operation.

The future viability of the technology for the 2030 build was also benchmarked against competing technologies using an EPRI benchmarking study as the basis for that assessment. It was concluded that a mature IGCC with CCS technology could benchmark well against other low-emissions technologies. It is also noted that most benchmarking studies such as these omit consideration of site specific costs and as a result understate the costs of the technology, relying on the user of the information to make the necessary adjustments.
12.2 Financial Model

A detailed financial model was prepared to inform business case decisions and to compare project configurations for different scenarios.

The model presents the discounted cashflows over the life of the project. These were based on the design, operations and estimating outcomes developed in the PFS.

A key feature of the model was a PPA, which was designed to keep the participating businesses solvent and not dependent on electricity and carbon market prices. The PPA is also an availability PPA, meaning the project was not financially dependent on being dispatched. During the first five years, the project was also not taking availability risk due to the first–of–kind risks.

The key metrics for evaluation of the project were the LCOE and the value of the PPA which is required by the project.

The financial model was run for the recommended development option (power plant at Ensham with storage in the Surat Basin) under two scenarios:

Scenario 1 ZeroGen first–of–a–kind costs and performance
Scenario 2 ZeroGen Project nth–of–a–kind costs and performance in 2030

The LCOE for each scenario is presented in Figure 12.1.


![Levelised cost $/MWh](image_url)
The PPA required for the preferred development option is also presented in Figure 12.2.

FIGURE 12.2: PROPOSED POWER PURCHASE AGREEMENT PAYMENTS OVER THE LIFE OF THE ZEROGEN PROJECT

A second configuration was considered with the power plant located in the Surat in close proximity to the CO₂ storage field. The capital and operating costs were equivalent or higher for this case so there was no financial merit in such a configuration.
13 Project Financing

This chapter describes the conceptual financing plan prepared for the ZeroGen Project, including IGCC plant with CCS, along with associated owner’s costs, enabling infrastructure and pre-FID development costs. A financing plan was a requirement for CCS Flagships submissions.

Lessons Learnt

ZeroGen developed a conceptual project financing plan with the assistance of a recognised financial adviser. A financing plan was a requirement under the CCS Flagships program.

Industrial-scale, first-of-a-kind coal fired power plants with CCS require large sums of capital and with forecast electricity and carbon prices, there is no (financial) business case to support the investment. In fact a ‘credit wrap’ from a government entity would be required to cover the gap between projected revenue and costs of operations and debt servicing.

In general ZeroGen’s financing plan, while of academic interest in terms of the issues raised and structures proposed, was not tested with the proposed funders. Informal feedback was obtained from the proposed Australian grant and equity funders (Australian and Queensland Governments and ACALET) that the amounts proposed exceeded their investment/risk appetite for the project.

No genuine investment appetite was observed for corporate investors with the exception of Mitsubishi who had conditionally offered up to $300 million to be invested as equity with priority dividend arrangements.

Debt finance is highly unlikely to be sourced from commercial lenders. ZeroGen proposed a large export credit facility with Japan Bank for International Cooperation (JBIC). While the Japanese Government did indicate a strategic intent to support CCS deployment, the amount required for ZeroGen of $2.5 billion would be JBIC’s largest export credit loan to a first world country and a first in terms of lending in Australian dollars.

The challenge to fund a large, integrated IGCC with CCS power project remains one of the major barriers to demonstration and deployment in Australia. A reframing of government incentive programs and associated statutes may need to be considered.

13.1 Concept Capital Financing Plan

The plan incorporated funding levels and time frames, funding requirements (covering funding options, principles, sources and mix), project participants, ownership structure, financial forecasts (including levelised costs) and key funding risks with mitigation measures.

ZeroGen engaged Queensland Treasury Corporation as financial adviser to assist with the development of the financing plan.
The total funding level for the project’s future development is $6,936.4 million (nominal dollars) including a contingency of $522.9 million and cost escalation of $649.0 million as shown in Table 13.1.

**TABLE 13.1: REQUIRED FUNDING LEVELS**

<table>
<thead>
<tr>
<th>Funding requirement</th>
<th>Amount (AUS$ million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power generation and carbon capture (PGC)</td>
<td>4,848.9</td>
</tr>
<tr>
<td>Carbon transport and storage (CTS)</td>
<td>915.6</td>
</tr>
<tr>
<td>Total of PGC and CTS</td>
<td>5,764.5</td>
</tr>
<tr>
<td>Contingency</td>
<td>522.9</td>
</tr>
<tr>
<td>Escalation</td>
<td>649.0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>6,936.4</strong></td>
</tr>
</tbody>
</table>

Because the project was a first–of–a–kind plant with significant development and construction costs, the funding sources and mix could not follow the standard financing approach for power generation projects. Accordingly, the financing plan was conceptual only, and focuses on a mix of grant, equity and debt funding from a range of public and private sector stakeholders with a strategic interest in the successful long–term commercialisation of IGCC with CCS technology.

The funding mix and funding sources were not negotiated or tested with the various stakeholders. However, potential breakdowns of the conceptual funding mix that were proposed by ZeroGen and QTC are shown in Table 13.2.

**TABLE 13.2: POSSIBLE (CONCEPTUAL) FUNDING MIX**

<table>
<thead>
<tr>
<th>Funding mix</th>
<th>Power generation and capture (AU$M)</th>
<th>Carbon transport and storage (AU$M)</th>
<th>Total (AU$M)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>%</td>
<td>%</td>
<td>%</td>
</tr>
<tr>
<td>Grants</td>
<td>2,050.0</td>
<td>400.0</td>
<td>2,450.0</td>
</tr>
<tr>
<td>Equity</td>
<td>1,230.0</td>
<td>386.7</td>
<td>1,616.7</td>
</tr>
<tr>
<td>Debt</td>
<td>2,487.4</td>
<td>382.3</td>
<td>2,869.7</td>
</tr>
</tbody>
</table>

As has been indicated earlier in the report, the project, being a first–of–a–kind, had inherent risks in its deployment. The funding concept therefore, proposed an additional supplementary funds allowance of $423.3 million be available. This was considered prudent to provide a P<sub>80</sub> probability that the project would be completed within the available funding and would only be drawn down under special approval from the project funders. It was proposed that the funding allowance be accommodated by way of contingent equity contributions from equity investors.
13.2 Potential Funding Contributors

Whilst potential funding contributors were identified, no funding agreements (neither indicative nor binding) were concluded. ZeroGen was attempting to engage in a dialogue on conceptual funding arrangements with the Queensland, Australia and Japanese Governments, ACALET, suppliers such as Mitsubishi Corporation and MHI, coal suppliers and a CO₂ storage partner, however these did not progress to any genuine level of engagement. Further, initial engagement from the JBIC, Nippon Export and Investment Insurance (NEXI), via Mitsubishi Corporation, other commercial lenders and strategic investors, such as power generators and pipeline operators, to secure the required funding levels was planned but not commenced. Participation from institutional investors was considered highly improbable until after the commercial proving phase was completed and the risks of completion and performance had been eliminated.

The conceptual financing plan proposed the mix of funding sources in Table 13.3 after taking into consideration what is currently known about possible contributions and the estimated economic value of the project. This analysis reveals a funding gap (shown in Table 13.3 as other grants and other equity) totalling $948.5 million. Potential sources of this additional funding could include ACALET, the Queensland Government, the Japanese Government and additional equity from strategic investors from the private sector. No strictly commercial funding sources were considered prospective.

**TABLE 13.3: HYPOTHETICAL FUNDING SOURCES**

<table>
<thead>
<tr>
<th>Hypothetical funding sources</th>
<th>Power generation and capture (AU$M)</th>
<th>Carbon transport and storage (AU$M)</th>
<th>Total (AU$M)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Commonwealth Government (grant)</td>
<td>1,100.0</td>
<td>300.0</td>
<td>1,400.0</td>
</tr>
<tr>
<td>ACALET (grant)</td>
<td>219.0</td>
<td>35.0</td>
<td>254.0</td>
</tr>
<tr>
<td>Japanese Government (grant)</td>
<td>350.0</td>
<td>—</td>
<td>350.0</td>
</tr>
<tr>
<td>Other (grant)</td>
<td>381.0</td>
<td>65.0</td>
<td>446.0</td>
</tr>
<tr>
<td>Queensland Government (equity)</td>
<td>170.0</td>
<td>27.5</td>
<td>197.5</td>
</tr>
<tr>
<td>MC/MHI (equity)</td>
<td>330.0</td>
<td>—</td>
<td>330.0</td>
</tr>
<tr>
<td>Strategic investor (equity)</td>
<td>300.0</td>
<td>286.7</td>
<td>586.7</td>
</tr>
<tr>
<td>Other (equity)</td>
<td>430.0</td>
<td>72.5</td>
<td>502.5</td>
</tr>
<tr>
<td>JBIC (loan)</td>
<td>2,487.4</td>
<td>—</td>
<td>2,487.4</td>
</tr>
<tr>
<td>Commercial lender (loan)</td>
<td>—</td>
<td>382.3</td>
<td>382.3</td>
</tr>
<tr>
<td><strong>Total funding</strong></td>
<td><strong>5,767.4</strong></td>
<td><strong>1,169.0</strong></td>
<td><strong>6,936.4</strong></td>
</tr>
</tbody>
</table>
ZeroGen noted that some or all of the grant funding would have been subject to taxation under a National Tax Equivalent Regime (NTER) which would have been payable to the Queensland Government. ZeroGen proposed to seek a commitment from the Queensland Government to ‘recycle’ these tax payments as equity contributions to the project. The total NTER payments are estimated to be as high as $719 million, although the actual liability could be less depending on the taxability of the various grants, available tax deductions and carry forward tax losses.

Although the final ownership structure had to be negotiated and agreed amongst all current and prospective project participants, it was proposed that the project vehicle best suited to accommodating different levels of participation from various investors would have been an unincorporated joint venture for each of the major components of the project (i.e. one for Power Generation and Carbon Capture (PGC) and another for Carbon Transport and Storage (CTS)). Further, it was suggested that ZeroGen would incorporate two subsidiaries to represent ZeroGen’s interests in each of the joint ventures and to facilitate additional project investment.

13.3 Financial Support during Operations

ZeroGen’s financial assessment of the project concluded it would be extremely unlikely for wholesale electricity prices to reach a level that would provide adequate revenue for the project, and consequently some level of ongoing support would be necessary. ZeroGen reviewed various financing options including incentives utilised or proposed in Australia or other developed countries for low emission technologies. These options varied in terms of public–private sector responsibility for financing and risks.

ZeroGen ultimately considered that, for a first–of–a kind plant, a mix of public and private sector funding and a PPA with the Australian Government (covering operating expenses, debt servicing and equity distributions and including some risk sharing) was the most appropriate mechanism to provide sufficient assurance to lenders and investors that the project can generate adequate cash flows to meet its obligations.

ZeroGen did not ‘test’ this proposal with the Australian Government, but was aware this proposal differed from other programs, such as the Mandatory Renewable Energy Target (MRET) and Solar Flagships Program. However it considered a higher level of support was appropriate given the first–of–a–kind nature of the project. Further, this use of a mixed public–private sector model for commercial–scale, first–of–a–kind CCS projects was supported by the international bodies charged with implementing the G8 CCS objectives, including the International Energy Agency (IEA) and the Carbon Sequestration Leadership Forum (CSLF) Task Force.

13.4 Funding Schedule

Meeting the mandated CCS Flagships schedule to achieve successful, commercial–scale operations by 31 December 2015, was critical to access a large amount of essential grant funding. That program implied unusually accelerated scheduling of activities and consequently critical funding dates within that time frame were:
30 September 2010  finalise funding for, and commence the Feasibility Study.
31 December 2011 finalise funding for, and commence Detailed Engineering, Early Procurement and Early Development (DEEPED).
31 March 2013  finalise funding for, and commence Procurement, Construction and Pre-commissioning (PCP).

ZeroGen would have needed to get the necessary approvals and develop the project through the phases listed in Table 13.4.

<table>
<thead>
<tr>
<th>Phase</th>
<th>Indicative dates</th>
</tr>
</thead>
<tbody>
<tr>
<td>Concept/scoping study (completed)</td>
<td>September 2008 to May 2009</td>
</tr>
<tr>
<td>PFS (completed)</td>
<td>June 2009 to July 2010</td>
</tr>
<tr>
<td>Feasibility Study</td>
<td>October 2010 to December 2011</td>
</tr>
<tr>
<td>Engineering, Procurement and Construction (EPC)</td>
<td>January 2012 to November 2015</td>
</tr>
<tr>
<td>Detailed Engineering, Early Procurement and Early Development (DEEPED)</td>
<td>January 2012 to March 2013</td>
</tr>
<tr>
<td>Procurement, Construction and Pre-commissioning (PCP)</td>
<td>April 2013 to December 2015</td>
</tr>
<tr>
<td>Demonstration and Commercial Proving Phase</td>
<td>December 2015 to September 2020</td>
</tr>
<tr>
<td>Commercial Operations Phase</td>
<td>From 2020</td>
</tr>
</tbody>
</table>
CHAPTER TWO
Integrated Gasification Combined Cycle Power Plant
1 IGCC Power Plant Overview and Scope

1.1 Executive Summary (IGCC Power Plant)

The technical and engineering specification of the nominal 530MW (gross), nominal 400MW (net) ZeroGen Project power plant section and associated systems was completed to a Prefeasibility Study (PFS) definition level.

ZeroGen conducted the PFS in accordance with its Capital Investment System (CIS). The CIS defines the minimum standards, which were to meet the requirements of a PFS.

These minimum standards provided the framework for the specified and balanced level of definition, quality and assessment criteria for the project, as well as the structure, format and content for the PFS.

The final selection of technology vendors, configuration of the flow sheet, the engineering performance and plant costs were a series of sequential and iterative processes.

Overall, ZeroGen evaluated that, when compared with other gasification technologies, the Mitsubishi Heavy Vehicles (MHI) gasifier and IGCC offered a solution that provided better prospects of meeting the future requirements for the Australian power generation sector in a hot and arid context, and offered the potential to be adapted to meet future technology enhancements.

The MHI IGCC was developed with the operating and maintenance culture of the conventional coal–fired power industry in mind, building on already mature, proven pulverised coal–fired technology aspects where possible, hence making the plant simpler to operate and maintain and importantly, minimising risks of the first–of–a–kind integration. This approach was expected to result in enhanced availability through avoiding the need for many of the complex systems found in other IGCC designs.

Early in the evolution of the ZeroGen Project there was a view among some of the stakeholders that integration risk was not too significant. This mirrored the ‘conventional wisdom’ of the day, namely that all the individual elements of the process were proven at commercial scale and could be utilised in their current form in an integrated process, and easily fast tracked. The addition of capture, for all technology choices, created an entirely different (not ‘bolt–on’) integrated process design.

The ZeroGen experience across all the development phases of the project was that a strong owners team presence was required to guide and coordinate the technology providers and licensors as well as provide the context for the Australian environment (market, regulatory, locational constraints, etc.). In most cases, facilitation was required between the design battery limits as technology providers took an approach in respect to their respective technologies and not necessarily to the overall project outcomes.
Integration risks are material for first–of–a–kind projects, even if individual plant element operations have been proven as part of another application. Through its design process, the ZeroGen Project responded to these first–of–a–kind challenges as follows:

- rigorous assessment of technology options to identify preferred technologies;
- early involvement by the key technology vendors in the PFS, especially in settling the design basis, functional specification and trade–off studies in order to optimise the project configuration;
- negotiate sharing significant engineering, procurement and construction performance risk, as well as critical integration risk with the technology provider; and
- balancing front–end loading with appropriate project definition and judicial application of value improvement process and engineering best practices.

In conjunction with the inherent risks from a first–of–a–kind plant, IGCC with carbon capture brought a further unique dynamic challenge between desired stable process operation and preferred dynamic electricity market responsiveness.

1.2 Top Five IGCC Power Plant Lessons Learnt

**Industrial scale is not a simple scale–up from demonstration–scale**

An industrial–scale project PFS is not a simple scale–up of a demonstration–scale study. The decision to move to a commercial–scale study significantly improved the understanding of deployment issues. Major implementation and deployment lessons arise from addressing the challenges of this larger scale at real and relevant locations.

**Budgets for first–of–a–kind studies is a process of discovery**

In a first–of–a–kind technology, where there has been no previous engineering to define the process requirements, it is probably not possible to reach the required accuracy class without significantly more engineering/testing. Study work plans/budgets need to reflect this requirement. Understanding the budget requirements for first–of–a–kind studies is a process of discovery.

**Externally imposed timeframes negatively affect cost accuracy and/or risk**

It is highly unlikely that scoping and prefeasibility studies for first–of–a–kind projects will follow a simple, linear process and so this should not be the basis for project planning. At least one major iteration (within a stage such as prefeasibility but not across stages) should be in the base case. An externally imposed time–frame, rather than a bottom up schedule build can only either decrease cost accuracy and/or increase development risk.

**High front–end loading needed for first–of–a–kind**

Despite the fact that ZeroGen followed a rigorous CIS process, there is a case that an even higher level of front–end loading would have been appropriate. Designs for a first–of–a–kind IGCC with carbon capture are at such an early stage of development that further in depth studies are required to optimise the technology and evaluate the risks of any proposed configuration. There is a strong requirement for very high front end loading for this complex first–of–a–kind project. High levels of front end loading should be considered as the key deployment risk mitigation strategy.
Early phase integrated teams to include key vendors

‘Vendors’ need to be integrated partners. The forming of an integrated team during this early phase is essential to allow the best communication between all major participants. ZeroGen developed an excellent working relationship with Mitsubishi.

1.3 Overview

The technical and engineering specification of the nominal 530MW (gross), nominal 400MW (net) ZeroGen Project power plant section and associated systems was completed to a PFS definition level.

ZeroGen conducted the PFS in accordance with its CIS. The CIS defines the minimum standards, which were to meet the requirements of a PFS.

These minimum standards provided the framework for the specified and balanced level of definition, quality and assessment criteria for the project, as well as the structure, format and content for the PFS.

The final selection of technology vendors, configuration of the flow sheet, the engineering performance and plant costs were a series of sequential and iterative processes.

The work leading up to the conclusion of the PFS consisted of three phases:

1. Preliminary work conducted between the conclusion of the scoping study and the commencement of the PFS. This included the short listing of respondents to an expression of interest for the provision of a project site and long–term coal supply agreement, as well as a sensitivity assessment of coal parameters on power plant capital and operating costs.

2. Initial work conducted for the first half of the PFS of which there were three principal activities;
   • site evaluation process to select the preferred site and coal;
   • selection of the third party technology providers; and
   • initial engineering to conduct calculation of the energy, mass and water balance (with assumed Central Queensland Reference site and coal specification).

3. PFS conclusion that consisted of:
   • engineering studies for the preferred site (Ensham) and alternative site (Surat);
   • engineering studies for the power plant by MHI, UOP, Haldor Topsøe;
   • side studies and optimisation of the flow sheet by MHI and ZeroGen;
   • test burn of the Ensham Coal at MHI’s test facility in Nagasaki, Japan;
   • performance adjustment to the Reference Case for side study outcomes and specification coal (Ensham); and
   • identification of outstanding work activities to be completed prior to commencing FEED.

To support the PFS, significant engineering studies and designs were completed across a range of subjects.

Figure 1.1 illustrates the project development work plan that was followed to progress the project to its status and Figure 1.2 provides the timing and production of studies required to prepare the PFS.
IGCC
technology
selection
process

Site selection
process

Coal suppliers
expressions of interest

Nov 2008

Dec 2008

Feb 2009

Scoping
Report

Jan 2009

ZeroGen/MHI

MHI gas turbine type

MHI IGCC technology
selected

Technology
selection

8 sites selected
from 15 EOIs

MHI

Mar 2009

Apr 2009

May 2009

ZeroGen/MHI

CO shift
Wet Sulphuric Acid
Acid gas removal
Zero liquid discharge
MHI gas turbine class

Third party technology review

Preparation of project functional
specification
(project design basis)
ZeroGen

Project functional
specification

Opex and capex sensitivity
to coal

Coal sensitivity study

4 sites selected

NPV trade off analysis

June 2009

Site selection

July 2009

Coal test burn 30kg sample
at MHI R&D

MHI

Study options

Aug 2009

Sept 2009

MHI

Coal test burn

Oct 2009

Nov 2009

Dec 2009

Preferred Site
Selected

Jan 2010

AECOM

MHI

Feb 2010

Mar 2010

• CO shift
• Water usage
• CO2 purity
• Equipment margins
• Fluor AGR optimisation

Optimisation

• Ensham site
• Ensham coal
• 98% CO2 purity
• Hybrid cooling
• CO Shift catalyst—
Johnson Matthey
• UOP selexol AGR

Configuration

Final power plant
configuration

• Ensham (Preferred)
• Surat (Alternate)

PreFEED engineering
(AECOM)

100t Ensham (preferred coal)
sample test burn at MHI R&D
facility, Nagasaki

Site Study/Optimisation Process

Relax CO2 spec
Water/air cooling trade–off
CO shift catalyst—sud chemie/Johnson Matthey

Sud chemie
Haldor topsoe
Selexol
Veolia/HPD

Third party technology assessment

(Reference site and reference coal)

MHI preliminary design

• Ensham (Preferred)
• Wandoan
• Blackwater
• Callide
• Rolleston

Site risk assessment

Multivariable criteria analysis

• Transmission line
• Marginal loss factors
• CO2 pipeline
• Water supply
• Coal supply

NPV Delta Analysis

Apr 2010

May 2010

June 2010

PreFEED

Aug 2010

Oct 2010

Commence
FEED

Sept 2010

Bridging
work plan

ZeroGen, MHI,
Fluor

July 2010

Pre feasibility
Report

Prefeasibility
Report

Preferred case
ZeroGen, MHI, AECOM, ROAM, RLMS, Hatch

Prefeasibility Study

Options assessment
ZeroGen, MHI, AECOM, ROAM, RLMS,
Hatch

Commence
Prefeasibility
Study

Risk assessment for the site and coal supply

Site shortlisted process

ZeroGen, MHI

ZeroGen

Candidate
site ranking

Prefeasibility Study
Prework

Scoping Study

Figure 1.1: Project Development Work Plan

CHAPTER TWO Integrated Gasification Combined Cycle Power Plant

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### Prefeasibility Study Prework

<table>
<thead>
<tr>
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<td>June 2009</td>
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### Prefeasibility Study

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<td>Equipment performance</td>
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### Central Queensland site selection

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### Site shortlisting

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### Surat basin benchmark site study

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<td>NEM connection and access</td>
<td>ROAM</td>
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</table>
1.4 Options Considered

1.4.1 Gasification and associated technologies

ZeroGen explored a number of options for the project’s technical configuration. The ZeroGen Project proposed to use a Mitsubishi Heavy Industries (MHI) air–blown gasifier combined with a MHI 701G series gas turbine. This decision was undertaken prior to the commencement of the PFS.

Early in the PFS, MHI proposed the use of a G class gas turbine instead of the F class originally proposed. ZeroGen accepted this proposal but required full flow combustor testing at the specified syngas conditions.

The early selection of the third–party technology platform was instrumental in allowing the process design and integration design to proceed and allow the proper design coordination with all key technology providers to mitigate integration risk.

The acid gas (H2S) and CO2 capture technology chosen was the Selexol process from UOP after extensive assessment and evaluation. The selected CO shift technology was Johnson Matthey, subject to performance verification testing. Both technologies have been used extensively in the petro–chemical/fertiliser industries and have long established credentials.

The project would produce sales grade 98% sulphuric acid using Haldor Topsøe’s wet gas sulphuric acid technology.

1.4.2 Site

The selection of the power plant site was made during the PFS and followed an expression of interest (EOI) to 15 organisations to provide a host site, coal supply and to potentially become an equity participant in the project. Registrations of interest were received from companies located in the Bowen, and Callide Basins in Central Queensland, the Tarong Basin and Surat Basin.

The Ensham Mine in the Bowen Basin was chosen as the preferred site for the power plant after an extensive evaluation process. Once the Ensham site was selected, it became the focal point for PFS engineering.

Since selecting Ensham as the preferred power plant site and coal supplier, indicative–term sheets were signed for the supply of coal for the project and for the purchase of the power plant site land from Ensham Resources Pty Ltd.

An alternative power plant site located in the Surat Basin was also studied to serve as a benchmark basis in the event that the project may relocate due to better CO2 storage prospects.

1.4.3 CO2 transport

Options were studied to transport CO2 from the Ensham power plant site to the Northern Denison Trough (NDT) in Central Queensland (approximately 25 km) or to a location in the Surat Basin (approximately 370 km). These options were studied in case the NDT storage prospect did not deliver the required storage objectives. The NDT was subsequently proven as an unviable storage location.
1.4.4 Fuel

The primary feedstock for the plant is black coal. Coupled with the site evaluation, a key inclusive element was the fuel source to be provided by the host mine. The evaluation process for the coal was for each of the shortlisted respondents to provide an initial 30 kg screening sample to MHI for testing. MHI provided an initial assessment of the gasification properties of each of the coals. MHI also provided sensitivity analysis of coal parameters on the cost and performance of the gasifier, which was subsequently used to feed into the NPV relativity analysis for the site assessment. The Ensham thermal coal was shown to be suitable for gasification. A 100t sample of Ensham coal was sent to Nagasaki for a gasification test burn in MHI’s 24t/d test facility. This test was successful and confirmed the selection of the Ensham site and the primary fuel source.

In addition to Ensham providing the coal supply to the project, the project design also allowed for the future installation of a spur rail loop and train unloader to supply coal to the site from other mines if required.

1.5 PFS Final Configuration

The ZeroGen Project was designed to be located adjacent to the entrance of the Ensham coal mine.

Raw water would be sourced from the Nogoa–Mackenzie Water Supply Scheme with water allocations from the Fairbairn Dam being drawn from the Bedford Weir located to the east of the Ensham Mine.

A coal supply non-binding indicative term sheet was executed with Ensham Resources for the supply of up to 1.4Mt/annum of coal for the operating life of the project, currently projected to be 30 years beyond commissioning and commercial proving. Coal would be delivered by truck from the existing mine coal handling plant.

Following the MHI gasification testing of the 100t coal sample at their Nagasaki test facility, the Ensham coal would not require the addition of a fluxing agent to facilitate slagging within the gasifier.

The power plant would connect to the National Electricity Market (NEM) and transmission system at the Lilyvale substation located to the north west of the site. This is the strongest NEM connection point and allows the project to export the maximum amount of net electricity generated whilst minimising transmission marginal loss factors.

Extensive studies were completed to optimise the pipeline routes for water to the site, and CO₂ transport to the Surat CO₂ storage location.

The overall project configuration showing the plant location in relation to the water supply, transmission connection point and Surat CO₂ storage location is shown on the following map Figure 1.3. The major technology elements within the project are shown in Figure 1.4, with the majority of the power plant facility with carbon capture being delivered by MHI under an ‘EPC wrap’. 
FIGURE 1.3: OVERVIEW OF PROJECT LOCATION

FIGURE 1.4: MHI PROCESS CONFIGURATION AND SCOPE OVERVIEW

Mitsubishi Heavy Industries EPC scope

- ASU MHI managed
- Coal grinding and drying (and bunkering) MHI
- Gasifier and syngas cooler MHI
- CO shift Johnson Matthey
- Selexol AGR and CO2 removal UOP
- CCGT power block MHI
- Waste water treatment (ZLD) MHI managed
- Water treating and utilities
- Wet sulphuric acid plant Haldor topsoe
- Slag handling
- Solid waste handling
- Raw water
- Sulphuric acid handling
- Substation MHI
- Water supply
- CO2 compression and dehydration MHI
- CO2 pipeline
- CO2 storage

MHI EPC Scope

- Coal handling
- MHI technology
- Related works

This map sourced from Google Earth.
Due to the site and fuel supply selection being conducted in parallel with the studies for the power plant, a reference case was selected for MHI based on a notional Central Queensland site and Bowen Basin coal specification. The energy and mass balance was based on this data and adjusted for each of the subsequent changes from the initial Central Queensland reference case through to the final Ensham and Surat site project parameters created as a result of a number of optimising side studies.

Table 1.1 summarises the key performance elements for the Ensham site.

**TABLE 1.1: ENSHAM SITE PERFORMANCE INDICATORS**

<table>
<thead>
<tr>
<th>Performance indicator</th>
<th>Units</th>
<th>Value (Ensham site conditions)</th>
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<tbody>
<tr>
<td>IGCC plant output—gross</td>
<td>MW</td>
<td>524.8</td>
</tr>
<tr>
<td>IGCC plant output—net</td>
<td>MW</td>
<td>390.9</td>
</tr>
<tr>
<td>IGCC net thermal efficiency—HHV</td>
<td>%</td>
<td>31.3</td>
</tr>
<tr>
<td>Carbon captured</td>
<td>%</td>
<td>65</td>
</tr>
<tr>
<td>IGCC plant availability</td>
<td>%</td>
<td>85*</td>
</tr>
<tr>
<td>Power block main stack SO(_x) emissions</td>
<td>ppmv</td>
<td>&lt;4</td>
</tr>
<tr>
<td>Power block main stack NO(_x) emissions</td>
<td>ppmv</td>
<td>&lt;25</td>
</tr>
<tr>
<td>Power block main stack dust loading</td>
<td>mg/Nm(^3)</td>
<td>&lt;50</td>
</tr>
<tr>
<td>Load change ramp rate</td>
<td>%/min</td>
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<tr>
<td>Plant turndown—thermal input</td>
<td>%</td>
<td>60*</td>
</tr>
<tr>
<td>Coal feed rate (as received)</td>
<td>TPD</td>
<td>4279</td>
</tr>
<tr>
<td>Flux addition</td>
<td>TPD</td>
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</table>

* Target design values

### 1.5.1 MHI technology selection

ZeroGen undertook an extensive evaluation of gasification and IGCC technologies over the period 2005 to 2010, involving commercial EOI processes, PFS, Feasibility Studies, due diligence site inspections and coal validation test work. ZeroGen actively engaged directly with technology providers as part of this process.

Overall, ZeroGen evaluated that, when compared with other gasification technologies, the MHI gasifier and IGCC offered a solution that provides better prospects of meeting the future requirements for the Australian power generation sector in a hot and arid context, and offered the potential to be adapted to meet future technology enhancements.
The MHI IGCC was developed with the operating and maintenance culture of the conventional coal–fired power industry in mind, building on already mature, proven pulverised coal–fired technology aspects where possible, hence making the plant simpler to operate and maintain and importantly, minimising risks of the first–of–a–kind integration. This approach was expected to result in enhanced availability through avoiding the need for many of the complex systems found in other IGCC designs.

A MHI IGCC employs a combination of dry fed, membrane wall, air blown technologies with complete char recycle which ZeroGen assessed would make the plant simpler to operate and maintain, relative to other oxygen–blown commercial IGCC configurations. This resulted in enhanced IGCC plant availability and thermal efficiency.

The MHI design has the following key features:
- simpler plant start–up/shutdown;
- a single inert mineral residue (slag) product, without complex fly ash handling, and without complex water recirculation and treatment systems;
- a consistent gas turbine fuel (diluted syngas), without complex syngas and nitrogen blending systems and associated risks to gas turbine availability; and
- a reduction in the number of shift operators/maintainers required to safely and effectively operate the plant, which is more consistent to the approach of the power industry than other commercially available IGCC designs.

The slurry fed gasifiers appear to have been developed primarily for the chemical and hydrocarbon processing industries using a low ash feedstock such as petroleum coke, resulting in a plant which is more complex to operate and maintain, especially when coal is used as the feedstock instead of petroleum coke. They appear to be less robust during start–up, which is a necessarily lengthy operation to avoid damage to the gasifier internal refractory lining. The use of a refractory lining rather than a membrane wall can add up to tens of hours to the warm up of the gasifier.

An oxygen blown gasifier supplying shifted fuel to a gas turbine requiring large quantities of pre–blended nitrogen diluents, has significant potential for compromising the availability of the gas turbine.

### 1.5.2 Demonstration history

The progress of the MHI IGCC technology (without capture) demonstration was an important input for the ZeroGen Project, as the demonstration plant allowed the study team to assess the technology from an operations standpoint and allowed lessons learnt to be fed into the design process for the gasifier and Combined Cycle Gas Turbine (CCGT) technology.

The United States–based Electric Power Research Institute (EPRI) concluded that in the first year, the Nakoso IGCC facility has achieved the best operational results to date of all the coal–fired IGCC demonstration plants. Table 1.2 summarises the results.
ZeroGen undertook two separate site visits to the Nakoso IGCC facility in order to explore lessons learnt and results achieved from the Nakoso facility. In summary, the findings of the ZeroGen site visits confirmed the good performance achieved at Nakoso with no significant adverse findings to date.

### 1.5.3 Design philosophy

The design philosophy of the power plant has been described in a ‘functional specification’ prepared by the ZeroGen study team. The functional specification focuses on plant performance and cost in the context of ambient conditions for a Central Queensland site, minimising water consumption and maximising water recycling/reuse, adopting technologies which are robust and fit for the purpose, and adopting beneficial reuse of waste streams where practical and economic. It was planned that the plant would have a high degree of automation. To ensure a consistent approach to automation and data management, ZeroGen prepared a control and operation philosophy, which would be used across the project.

For the purpose of the PFS, MHI prepared its design basis for the power plant with carbon capture based on the ZeroGen functional specification. ZeroGen engaged AECOM Engineers to prepare the balance of plant design to support the power plant. The balance of plant was comprised of civil works, water supply, fuel and chemical delivery systems, building, coal stockpiles, residue storage facilities and other miscellaneous systems. AECOM prepared a design basis for their design activities.

For critical sections of the plant, where performance was dependent on feedstock or process conditions, it was planned that testing would be completed to validate performance expectations in these key areas prior to completion of the feasibility study. These areas were coal feed, CO shift and gas turbine combustor test at the specified syngas composition.
The ZeroGen Project had an objective to achieve as much beneficial use of waste streams as practically possible. The ZeroGen IGCC facility would have allowed virtually all the sulphur in the coal feed to be converted into a 98%, high purity, market saleable sulphuric acid product. It was also intended that the power plant would treat and recycle process water on site and there would be zero process water discharge to the environment.

Although individual elements of the technology used in coal–integrated IGCC and carbon capture exist, there were no coal–fired IGCC facilities with carbon capture in operation anywhere in the world at the time of the ZeroGen study. Therefore, ZeroGen was going to be developed in the context of being a first–of–a–kind project. First–of–a–kind projects often experience surprises during project delivery, including delays, capital cost over–runs, under–performance and/or extended ramp–up times.

Integration risks are material for first–of–a–kind projects, even if individual plant element operations have been proven as part of another application. Through its design process, the ZeroGen Project responded to these first–of–a–kind challenges as follows:

- rigorous assessment of technology options to identify preferred technologies;
- early involvement by the key technology vendors in the PFS, especially in settling the design basis, functional specification and trade–off studies in order to optimise the project configuration;
- negotiating sharing significant engineering, procurement and construction performance risk, as well as critical integration risk with the technology provider; and
- balancing front–end loading with appropriate project definition and judicial application of value improvement process and engineering best practices.

In conjunction with the inherent risks from a first–of–a–kind plant, IGCC with carbon capture brought a further unique dynamic challenge between desired stable process operation and preferred dynamic electricity market responsiveness.
2 Overview of IGCC Power Plant Knowledge Reports

ZeroGen undertook a PFS for the development of a commercial–scale, low emission, coal–fired power project in Queensland. The project would have delivered the integration of IGCC and CCS technologies. Carbon storage would be based on geosequestration in deep sandstone reservoirs.

A series of knowledge products covering the IGCC power plant aspect of the ZeroGen PFS were developed from the range of studies and reports developed as part of the ZeroGen Project. It was necessary to be selective in regards to which aspects the knowledge products provide coverage on. In this context, the knowledge products developed are in reference to the following aspects:

- IGCC power plant status of studies;
- IGCC power plant technologies selected;
- IGCC power plant approach to design;
- IGCC power plant (main process);
- IGCC power plant (balance of plant); and
- IGCC power plant site selection.
3 Status of Studies

3.1 Context

The PFS required a work plan to be prepared. The work plan for the ZeroGen Project defined the scope of studies, deliverables, resources, schedule and cost to complete the PFS for a nominal 530MW (gross) IGCC with CCS project in Queensland, based on a MHI 701G series CCGT.

This section describes the study work undertaken to achieve the broad objectives of the study in relation to the power plant, the carbon capture and compression facility, plus the necessary infrastructure required for the power plant, namely:

- water supply;
- coal supply;
- network connection;
- land suitability and location as PFS deliverables; and
- CO₂ pipeline and infield distribution.

The specific objectives which were studied in relation to the power plant and infrastructure are highlighted in the following Table 3.1.

**TABLE 3.1: PFS WORK PLAN OBJECTIVES**

<table>
<thead>
<tr>
<th>Technical/engineering outcomes</th>
<th>Preliminary engineering design and specifications for an integrated IGCC plant with CCS, following trade–off studies to determine the impact of processing technology options, coal properties, location and site conditions, and level of CO₂ capture.</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Preliminary specification of infrastructure requirements and facilities including CO₂ pipelines, CO₂ reservoir surface infrastructure, water supply, start–up fuel supply, high voltage grid connection, waste disposal, coal supply infrastructure, sulphuric acid sales and slag storage.</td>
</tr>
<tr>
<td></td>
<td>Selection of the project site by the optimisation of key inputs, outputs, infrastructure and services.</td>
</tr>
<tr>
<td>Commercial outcomes</td>
<td>Establishment of a project delivery plan including work breakdown structures, contracting strategies and term sheets for major supply contracts.</td>
</tr>
<tr>
<td></td>
<td>Selection of preferred coal source and term sheets for long term coal supply agreements.</td>
</tr>
<tr>
<td></td>
<td>Preparation of capital cost estimates with an accuracy of ±25% and operating cost estimates with an accuracy of ±20%.</td>
</tr>
<tr>
<td></td>
<td>Determination of revenue projections and trading protocols.</td>
</tr>
</tbody>
</table>
### Commercial outcomes (cont.)

- Development of ‘ready for award’ contract agreements for key feasibility phase works (e.g. power plant and balance of plant FEED studies, storage resource appraisal studies, storage FEED studies, etc.).

### Project deployment/commercialisation outcomes

- Comprehensive risk assessment process in accordance with AS4360.
- Proposals for the ownership structure and legal framework to deliver the project from the study phase through to construction, demonstration and operation phases.
- Development of preliminary Operations Plan describing organisational requirements, Industrial Relations (IR) strategies, spare parts management, procurement of services and consumables.
- Establishment of preliminary Health And Safety Management Plans.
- Preliminary outline of management systems required for implementation through construction, commissioning and operations.
- Establishment of the future work plans with specific detailed focus on the Feasibility Study work plan.
- Establishment of project management systems, protocols and procedures.
- Preparation of financial models and assessment of the project’s financial viability under a range of potential scenarios and identification of requirements for support/concessions.
- Development of a Funding Plan for the Feasibility Study, construction, demonstration and commercial operation phases, including grant funding, strategic investors, institutional investors and lenders.
- Development of an IP Management Plan which will allow the IP and know how generated through the project to be identified, documented and protected for future commercialisation opportunities.
- Establishment of project governance protocols and steering committee functions.
- Preparation of a final PFS Report with contents consistent with ZeroGen’s CIS guidelines.

### 3.2 Lessons Learnt

The key lessons learnt arising from undertaking the IGCC plant design studies are as follows.

The type and description of studies noted in this document can be used by proponents of similar projects to guide them (as a checklist) in planning for and undertaking required studies.

The ZeroGen team put in place a CIS at the initiation of the scoping study phase and followed the system throughout the development to date. A CIS delivers a staged development process with sufficient front end loading to ensure that the major decisions are adequately informed.
From the start, the CIS should include a branch at the end of any stage gate which allows for knowledge capture and dissemination, such that if a ‘no go’ decision is reached on the project proper, resources are available for wrap up. In a project–resourcing plan, consideration should be given to internal, embedded technical writing resources to support publications.

The exit strategy and budget from each phase should include not only a close–out report, but also the production of sufficient reports and conference papers to ensure that the lessons are adequately communicated to the CCS community.

In a first–of–a–kind technology, where there has been no previous engineering to define the process requirements, it is probably not possible to reach the required accuracy class without significantly more engineering/testing. Study work plans/budgets need to reflect this requirement. Understanding the budget requirements for first–of–a–kind studies is a process of discovery.

It is highly unlikely that scoping and prefeasibility studies for first–of–a–kind projects will follow a simple, linear process and so this should not be the basis for project planning. At least one major iteration should be in the base case. An externally imposed time–frame, rather than a bottom up schedule build can either decrease cost accuracy and/or increase development risk.

A clear decision criteria needs to be developed well in advance of each stage–gate, such that decisions to go forward, recycle or stop can be as swift as possible.

Despite the fact that ZeroGen followed a rigorous CIS process, there is a case that an even higher level of front–end loading would have been appropriate. Designs for a first–of–a–kind IGCC with carbon capture are at such an early stage of development that further in depth studies are required to optimise the technology and evaluate the risks of any proposed configuration. There is a strong requirement for very high front–end loading for this complex first–of–a–kind project. High levels of front–end loading should be considered as the key deployment risk mitigation strategy.

An industrial–scale project PFS is not a simple scale–up of a demonstration–scale study. The decision to move to a commercial–scale study significantly improved the understanding of deployment issues. Major implementation and deployment lessons arise from addressing the challenges of this larger scale at real and relevant locations.

Early in the evolution of the ZeroGen Project there was a view among some of the stakeholders that integration risk was not too significant. This mirrored the ‘conventional wisdom’ of the day, namely that all the individual elements of the process were proven at commercial scale and could be utilised in their current form in an integrated process, and easily fast tracked. The addition of capture, for all technology choices, creates an entirely different (not ‘bolt–on’) integrated process design.

The manufacturer, whilst having detailed knowledge of the components that they might supply, will need to have completed significant additional design work to confirm the viability of an integrated design. If that cannot be produced and validated then the study work scope will need to also include this design work. Base plans should include as an expectation that significant additional work is needed, even at scoping and PFS phase, for integrated designs.
First-of-a-kind plants such as ZeroGen’s were complex and required significant detailed study (front-end loaded) to establish accurate assessments of performance and cost in a timely manner. To conduct scoping, Prefeasibility and Feasibility/FEED Studies is costly and requires considerable development time.

The ZeroGen experience across all the development phases of the project has been that a strong owners team presence is required to guide and coordinate the technology providers and licensors as well as provide the context for the Australian environment (market, regulatory, locational constraints, etc.). In most cases, facilitation is required between the design battery limits as technology providers take an approach in respect to their respective technologies and not necessarily to the overall project outcomes.

In order to provide a level of definition that is acceptable within a capital investment process, for a new technology, ZeroGen consider it essential to select the preferred technology vendor and involve that vendor, in depth, in the earliest stages of the process. It is therefore critical that the technology providers be selected early in the project lifecycle, with the preference being no later than at the end of scoping phase. This allows the prefeasibility to properly assess the design merits and issues of each of the major elements on a whole of project basis and to optimise this across the entire project and not just within the individual elements.

‘Vendors’ need to be integrated partners. The forming of an integrated team during this early phase is essential to allow the best communication between all major participants. ZeroGen developed an excellent working relationship with Mitsubishi.

Consideration should be given to the available offering of commercial-scale plant compared to the size of smaller-scale demonstration or reference plant. A full technical risk assessment is required to confirm scale-up risk is within acceptable limits.

### 3.3 Status of Studies

#### 3.3.1 Summary of studies

The following studies detailed within Table 3.2 were conducted for the power plant, infrastructure and CO₂ transport and CO₂ field distribution to a standard that meets the requirements of a PFS. The study scopes meet the specific objectives of the ZeroGen PFS.
### TABLE 3.2: SUMMARY OF STUDIES

<table>
<thead>
<tr>
<th>Central Queensland/Surat Power Station site documentation/study area</th>
<th>Focus area</th>
<th>Consultant/originator</th>
<th>Status of study work</th>
<th>Outcomes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Site selection (Central Queensland)</td>
<td>CQ</td>
<td>ZeroGen</td>
<td>Complete</td>
<td>Ensham site recommended for PFS as preferred Central Queensland site.</td>
</tr>
<tr>
<td>Water Resource Assessment Study Central Queensland</td>
<td>CQ</td>
<td>4T Consultants</td>
<td>Complete</td>
<td>Water resource identified as Fairbairn Dam. Water to be drawn from Bedford Weir downstream of Fairbairn Dam. Quantity expectation is 3000ML per year.</td>
</tr>
<tr>
<td>Preliminary Flood Risk Assessment</td>
<td>CQ</td>
<td>4T Consultants</td>
<td>Complete</td>
<td>Ensham site cleared of major flood potential.</td>
</tr>
<tr>
<td>Flood Harvest Study</td>
<td>CQ</td>
<td>4T Consultants</td>
<td>Complete</td>
<td>Potential alternate water resource identified through purchase of flood harvest allocation.</td>
</tr>
<tr>
<td>Water Allocation Availability Study</td>
<td>CQ</td>
<td>4T Consultants</td>
<td>Complete</td>
<td>Possible options to acquire required water allocations.</td>
</tr>
<tr>
<td>Screening Plume Rise Assessment for the proposed power generation facility near Blackwater</td>
<td>CQ</td>
<td>PAE Holmes</td>
<td>Complete</td>
<td>Assessment of Obstacle Limitation Surfaces for operational aircraft. Ensham site cleared. Alternate Blackwater west site requires two 50% flares to remain within limits.</td>
</tr>
</tbody>
</table>
### TABLE 3.2: SUMMARY OF STUDIES (CONT.)

<table>
<thead>
<tr>
<th>Central Queensland/Surat Power Station site documentation/study area</th>
<th>Focus area</th>
<th>Consultant/originator</th>
<th>Status of study work</th>
<th>Outcomes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Potential Coal Supplier Resource Evaluation</td>
<td>CQ</td>
<td>Wood Mackenzie.</td>
<td>Complete</td>
<td>Evaluation of Ensham and Rolleston coal mines’ capacity to deliver the required coal quantities for the project life.</td>
</tr>
</tbody>
</table>
| Infrastructure Corridors Study for three potential sites for an Integrated Coal Gasification and Combined Cycle Power Station | CQ | RLMS | Complete | Determination of potential corridor routes for powerline, natural gas, water and CO₂ pipelines for the three sites:  
• Calide  
• Rolleston  
• Blackwater. |
| Infrastructure Corridors Study Supplementary Report—Ensham entrance site | CQ | RLMS | Complete | Update of corridor route study for the Ensham site. |
| Rail Corridor Study for Ensham entrance site | CQ | RLMS | Complete | Additional study for rail loop into Ensham site. |
| Generation Development and Grid Connection Strategy | CQ | ROAM Consulting/Hill Michael and Associates. | Complete | Study into powerline connection to the 275kV network for each of the proposed sites using the routes from the RLMS corridor study. |
| High Voltage Connection and Access Study | CQ | ROAM Consulting. | Complete | Study into the long term Marginal Loss Factors (MLF) for each of the proposed connection points. |
## TABLE 3.2: SUMMARY OF STUDIES (CONT.)

<table>
<thead>
<tr>
<th>Central Queensland/Surat Power Station site documentation/study area</th>
<th>Focus area</th>
<th>Consultant/originator</th>
<th>Status of study work</th>
<th>Outcomes</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂, Natural Gas and Water Pipelines Study Central Queensland options</td>
<td>CQ</td>
<td>Hatch</td>
<td>Complete</td>
<td>Prefeasibility engineering and costing for the natural gas, water and CO₂ pipelines using the routes from the RLMS corridor study.</td>
</tr>
<tr>
<td>IGCC CO₂ Sequestration Pipeline Prefeasibility Phase HAZARD Study 1</td>
<td>G</td>
<td>Hatch</td>
<td>Complete</td>
<td>ICI Hazard Study 1 workshop to investigate health, safety and environmental issues that need to be considered during Feasibility Study phase.</td>
</tr>
<tr>
<td>CO₂ Compression and Pumping Study</td>
<td>CQ</td>
<td>Hatch</td>
<td>Complete</td>
<td>Preliminary optimisation study for the requirement and location of CO₂ compression booster pumps for an Ensham site located project.</td>
</tr>
<tr>
<td>Central Queensland Site Evaluation Study Report</td>
<td>CQ</td>
<td>AECOM</td>
<td>Complete</td>
<td>Engineering trade off study for selection of the Central Queensland site.</td>
</tr>
<tr>
<td>Bowen Basin PFS Report</td>
<td>CQ</td>
<td>AECOM</td>
<td>Complete</td>
<td>Prefeasibility engineering and costing for the Ensham site.</td>
</tr>
<tr>
<td>Operating Overview Report (Ensham)</td>
<td>CQ</td>
<td>Minserve</td>
<td>Complete</td>
<td>Detailed mine operating model for the Ensham mine.</td>
</tr>
<tr>
<td>Central Queensland/ Surat Power Station site documentation/ study area</td>
<td>Focus area</td>
<td>Consultant/ originator</td>
<td>Status of study work</td>
<td>Outcomes</td>
</tr>
<tr>
<td>---</td>
<td>---</td>
<td>---</td>
<td>---</td>
<td>---</td>
</tr>
<tr>
<td>Ensham Waste Disposal Terms Sheet for dispose of Gasifier Slag in mine voids</td>
<td>CQ</td>
<td>ZeroGen</td>
<td>Draft terms. Further negotiation during the Feasibility Study.</td>
<td>Term Sheet under discussion for Ensham to take ZeroGen gasifier slag and use it for bulk fill into mine voids.</td>
</tr>
<tr>
<td>Xstrata Coal Supply Terms Sheet—Rolleston Coal</td>
<td>CQ</td>
<td>ZeroGen</td>
<td>Draft terms. Further negotiation during the Feasibility Study.</td>
<td>Term Sheet under discussion for coal procurement.</td>
</tr>
<tr>
<td>Operating Overview Report (Rolleston)</td>
<td>CQ</td>
<td>Minserve</td>
<td>Complete</td>
<td>Detailed mine operating model for the Rolleston mine.</td>
</tr>
<tr>
<td>Coal Rail Transport Indicative Terms Sheet</td>
<td>CQ</td>
<td>QR National</td>
<td>Draft terms. Further negotiation during the Feasibility Study.</td>
<td>Term Sheet for rail transport services.</td>
</tr>
<tr>
<td>Sulphuric Acid Sales</td>
<td>G</td>
<td>ZeroGen internal memo</td>
<td>Preliminary market assessment completed.</td>
<td>Conclusion that sulphuric acid produced from the plant can be readily sold. Market to be formally approached during the Feasibility Study.</td>
</tr>
<tr>
<td>Ensham Local airports</td>
<td>CQ</td>
<td>ZeroGen internal memo</td>
<td>Complete</td>
<td>Investigation into local airstrips and air services and potential impact to the project.</td>
</tr>
</tbody>
</table>
### TABLE 3.2: SUMMARY OF STUDIES (CONT.)

<table>
<thead>
<tr>
<th>Central Queensland/ Surat Power Station site documentation/ study area</th>
<th>Focus area</th>
<th>Consultant/ originator</th>
<th>Status of study work</th>
<th>Outcomes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Screening Level Investigation into Impact on Radio–communications Systems Operations</td>
<td>CQ</td>
<td>SpecCom</td>
<td>Complete</td>
<td>High level investigation into the potential for the project structures to impact on radio–communications networks in the plant locality.</td>
</tr>
<tr>
<td>Screening Plume Rise Assessment for Flares near Blackwater</td>
<td>CQ</td>
<td>PAE Holmes</td>
<td>Complete</td>
<td>High level screening study of the potential impact of a tower flare located near Blackwater.</td>
</tr>
<tr>
<td>Site Selection (Surat Basin)</td>
<td>S</td>
<td>ZeroGen</td>
<td>Complete</td>
<td>Wandoan site recommended as the benchmark site for a Surat Basin site location.</td>
</tr>
<tr>
<td>High Voltage Connection and Access Study for Wandoan Site</td>
<td>S</td>
<td>ROAM Consulting</td>
<td>Complete</td>
<td>Study into powerline connection to the 275kV high voltage network using the routes from the RLMS corridor study.</td>
</tr>
<tr>
<td>Transmission Costing Study for Wandoan Site</td>
<td>S</td>
<td>ROAM Consulting</td>
<td>Complete</td>
<td>Cost estimate for the Wandoan connection.</td>
</tr>
<tr>
<td>Water Resources Assessment Study for a potential site (Wandoan) for a commercial–scale demonstration plant utilising IGCC and CCS</td>
<td>S</td>
<td>4T Consultants</td>
<td>Complete</td>
<td>Water resource assessment for the Surat region.</td>
</tr>
<tr>
<td>CO₂, Natural Gas and Water Pipelines Study, Wandoan Option Study</td>
<td>S</td>
<td>Hatch</td>
<td>Complete</td>
<td>Prefeasibility engineering and costing for the proposed Surat power plant option using the routes from the RLMS corridor study.</td>
</tr>
<tr>
<td>Infrastructure Corridors Study Wandoan Site</td>
<td>S</td>
<td>RLMS</td>
<td>Complete</td>
<td>Determination of potential corridor routes for powerline, natural gas, water and CO₂ pipelines for a potential Wandoan site.</td>
</tr>
<tr>
<td>Modified Routes for Revised Wandoan IGCC Site</td>
<td>S</td>
<td>RLMS</td>
<td>Complete</td>
<td>Revised water, natural gas, CO₂ pipelines and high voltage powerline corridors for an alternative Wandoan site.</td>
</tr>
</tbody>
</table>
### TABLE 3.2: SUMMARY OF STUDIES (CONT.)

<table>
<thead>
<tr>
<th>Central Queensland/Surat Power Station site documentation/ study area</th>
<th>Focus area</th>
<th>Consultant/originator</th>
<th>Status of study work</th>
<th>Outcomes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Surat Basin Site PFS Report</td>
<td>S</td>
<td>AECOM</td>
<td>Complete</td>
<td>Prefeasibility engineering and costing for the proposed Surat power plant option.</td>
</tr>
<tr>
<td>Surat Basin Coal Supplier/Mine Screening Study</td>
<td>S</td>
<td>Wood Mackenzie</td>
<td>Complete</td>
<td>Assessment of Surat Basin coal mines.</td>
</tr>
<tr>
<td>Xstrata Coal Supply Term Sheet—Wandoan Coal</td>
<td>S</td>
<td>ZeroGen</td>
<td>Draft terms. Further negotiation during the Feasibility Study.</td>
<td>Term sheet under discussion for the provision of coal from the proposed Xstrata Wandoan coal mine.</td>
</tr>
<tr>
<td>Inter–Basin Carbon Dioxide Pipeline Corridor Study</td>
<td>G</td>
<td>RLMS</td>
<td>Complete</td>
<td>Corridor study for the transport of CO₂ from the Ensham site to a Surat–based CO₂ storage site and from a Surat power plant to the Denison Trough.</td>
</tr>
<tr>
<td>CO₂ Cross–Basin Pipelines Study</td>
<td>G</td>
<td>Hatch</td>
<td>Complete</td>
<td>Prefeasibility engineering and costing for transporting CO₂ from the Ensham site to a Surat–based CO₂ storage site and from a Surat power plant to the Denison Trough using the routes from the RLMS corridor study.</td>
</tr>
<tr>
<td>ZeroGen: Control and Operating Philosophy</td>
<td>G</td>
<td>ZeroGen</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>Control System Report</td>
<td>G</td>
<td>ZeroGen</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>Control System Gap Analysis</td>
<td>G</td>
<td>ZeroGen</td>
<td>Complete</td>
<td></td>
</tr>
</tbody>
</table>
### TABLE 3.2: SUMMARY OF STUDIES (CONT.)

<table>
<thead>
<tr>
<th>Central Queensland/ Surat Power Station site documentation/ study area</th>
<th>Focus area</th>
<th>Consultant/ originator</th>
<th>Status of study work</th>
<th>Outcomes</th>
</tr>
</thead>
<tbody>
<tr>
<td>ZeroGen: Design Control Plan</td>
<td>G</td>
<td>ZeroGen</td>
<td>Issued for use</td>
<td>Design Control Plan prepared by ZeroGen for use by MHI and AECOM in preparation of their PFS reports.</td>
</tr>
<tr>
<td>ZeroGen: Coal Specification (Ensham)</td>
<td>CQ</td>
<td>Ensham Resources</td>
<td>In progress</td>
<td>Coal specification for design/evaluation purposes.</td>
</tr>
<tr>
<td>ZeroGen: Coal Specification (Wandoan)</td>
<td>S</td>
<td>Xstrata Coal</td>
<td>In progress</td>
<td>Coal specification for benchmark design/evaluation purposes.</td>
</tr>
<tr>
<td>PFS Report</td>
<td>G</td>
<td>MHI</td>
<td>Complete</td>
<td>Prefeasibility engineering and costing for the proposed Ensham and Surat power plant options. Incorporates studies of all technology providers in the context of the optimal plant configuration.</td>
</tr>
<tr>
<td>PFD/HMB Simulation Validation Study</td>
<td>G</td>
<td>ZeroGen/ PROCOM</td>
<td>Complete</td>
<td>Project–developed tool for the confirmation of process modelling across gasification and power block for heat and mass balance data and plant performance. Initially used as independent verification of MHI HMB. However, can be used for option assessment and engineering.</td>
</tr>
</tbody>
</table>
### Table 3.2: Summary of Studies (Cont.)

<table>
<thead>
<tr>
<th>Central Queensland/Surat Power Station site documentation/study area</th>
<th>Focus area</th>
<th>Consultant/originator</th>
<th>Status of study work</th>
<th>Outcomes</th>
</tr>
</thead>
<tbody>
<tr>
<td>MHI: Nagasaki Gasification Facility — Design Coal Test Burn Report</td>
<td>CQ</td>
<td>MHI</td>
<td>Complete</td>
<td>Report on the test burn of 60 tonnes of Ensham coal for the purpose of providing the definitive design basis for Ensham coal. The results will be used to progress the process design during the Feasibility Study.</td>
</tr>
<tr>
<td>ZeroGen: Nagasaki Gasification Facility—Design Coal Test Burn Report</td>
<td>CQ</td>
<td>ZeroGen</td>
<td>Complete</td>
<td>Report on the test burn of 60 tonnes of Ensham coal for the purpose of providing the definitive design basis for Ensham coal. The results will be used to progress the process design during the Feasibility Study.</td>
</tr>
<tr>
<td>ZeroGen: Nakoso Site Visits Due Diligence Report</td>
<td>G</td>
<td>ZeroGen</td>
<td>Complete</td>
<td>Summary of site visit conducted by ZeroGen to assist in confirming performance of Nakoso IGCC with independent operator of this facility.</td>
</tr>
</tbody>
</table>
| ZeroGen: MHI Site visit November 2009/ Nagasaki, Hiroshima, Takasago | G          | ZeroGen                | Complete             | Summary of site visit conducted by ZeroGen to assist in confirming:  
  - R&D and analysis capability of MHI for gasification trials, and confirm MHI capability for gasifier and steam turbine technology delivery.  
  - MHI capability for compressor technology delivery.  
  - MHI capability for gas turbine technology delivery. |
### TABLE 3.2: SUMMARY OF STUDIES (CONT.)

<table>
<thead>
<tr>
<th>Central Queensland/ Surat Power Station site documentation/ study area</th>
<th>Focus area</th>
<th>Consultant/ originator</th>
<th>Status of study work</th>
<th>Outcomes</th>
</tr>
</thead>
<tbody>
<tr>
<td>ZeroGen: Tamar Valley Site Visit Report</td>
<td>G</td>
<td>ZeroGen</td>
<td>Complete</td>
<td>Summary of site visit conducted by ZeroGen to assist in confirming MHI capability for control systems technology delivery.</td>
</tr>
<tr>
<td>Application for Registration as an Intending participant in the NEM</td>
<td>G</td>
<td>ZeroGen</td>
<td>Complete</td>
<td>Application to AEMO for ZeroGen to be an intending participant in the National Electricity Market. Needed to access data for Feasibility Study design work.</td>
</tr>
<tr>
<td>Confirmation of ZeroGen Registration as an Intending participant in the NEM</td>
<td>G</td>
<td>AEMO</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>TCLP Analysis of Gasifier Slag Product</td>
<td>G</td>
<td>ALS Laboratory Group</td>
<td>Complete</td>
<td>Leachate test report on Nakoso gasifier slag product.</td>
</tr>
<tr>
<td>Salt Storage Report</td>
<td>G</td>
<td>AECOM</td>
<td>Complete</td>
<td>Assessment of process zero liquid discharge plant salt stream disposal methods.</td>
</tr>
<tr>
<td>Cooling Systems Options Report</td>
<td>G</td>
<td>SigmaMSc</td>
<td>Complete</td>
<td>Assessment of current power plant and process cooling system and technology.</td>
</tr>
<tr>
<td>Gasification Technology Comparison Report</td>
<td>G</td>
<td>ZeroGen</td>
<td>Complete</td>
<td>Technology comparison.</td>
</tr>
</tbody>
</table>

Key:  
- **CQ** = Central Queensland  
- **S** = Surat Basin Alternative  
- **G** = General Report

The site selection study investigated power plant sites at the following locations:  
- Ensham;  
- Rolleston;  
- Blackwater;  
- Blackwater West; and  
- Callide.
A site selected adjacent to Xstrata Coal’s proposed Wandoan Coal mine was also studied as a benchmark power plant site for a Surat Basin located power plant. Further work is required to optimise a power plant location in the Surat Basin. The following Table 3.3, Table 3.4, Table 3.5 and Table 3.6 show the engineering studies completed for the ZeroGen Project referenced against each site.

**TABLE 3.3: COMPLETED ENGINEERING STUDIES—SITE SELECTION SCREENING STUDIES FOR CENTRAL QUEENSLAND**

<table>
<thead>
<tr>
<th>Study</th>
<th>Ensham</th>
<th>Rolleston</th>
<th>Blackwater</th>
<th>Blackwater West</th>
<th>Callide</th>
</tr>
</thead>
<tbody>
<tr>
<td>Site Selection Screening Studies for Central Queensland</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Water Resource Assessment Study Central Queensland</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Water Allocation Availability Study</td>
<td>✓</td>
<td>✓</td>
<td>Not req’d</td>
<td>✓</td>
<td>Not req’d</td>
</tr>
<tr>
<td>Water Supply Strategy Report</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>Not req’d</td>
<td></td>
</tr>
<tr>
<td>Preliminary Airspace Assessment for Blackwater Airport</td>
<td>Not req’d</td>
<td>Not req’d</td>
<td>✓</td>
<td>✓</td>
<td>Not req’d</td>
</tr>
<tr>
<td>Potential Coal Supplier Resource Evaluation</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Queensland Domestic Coal Market Assessment</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Infrastructure Corridors Study for three potential sites for an Integrated Coal Gasification and Combined Cycle Power Station</td>
<td>✓</td>
<td>✓</td>
<td></td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Generation Development and Grid Connection Strategy</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Draft Logistics Survey Report</td>
<td>✓</td>
<td>✓</td>
<td></td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>High Voltage Connection and Access Study</td>
<td>✓</td>
<td>✓</td>
<td></td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>CO2, Natural Gas and Water Pipelines Study Central Queensland Options</td>
<td>✓</td>
<td>✓</td>
<td></td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Screening Plume Rise Assessment for the proposed power generation facility near Blackwater</td>
<td>✓</td>
<td>✓</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Central Queensland Site Evaluation Study Report</td>
<td>✓</td>
<td>✓</td>
<td></td>
<td>✓</td>
<td>✓</td>
</tr>
</tbody>
</table>
### TABLE 3.4: COMPLETED ENGINEERING STUDIES—CENTRAL QUEENSLAND (ENSHAM) ENGINEERING STUDIES

<table>
<thead>
<tr>
<th>Study</th>
<th>Sites</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Central Queensland (Ensham) Engineering Studies</strong></td>
<td></td>
</tr>
<tr>
<td>Flood Harvest Study</td>
<td></td>
</tr>
<tr>
<td>Infrastructure Corridors Study Supplementary Report—Ensham Entrance Site</td>
<td></td>
</tr>
<tr>
<td>Rail Corridor Study for Ensham Entrance Site</td>
<td></td>
</tr>
<tr>
<td>CO\textsubscript{2} Compression and Pumping Study</td>
<td></td>
</tr>
<tr>
<td>Ensham Entrance PFS Report</td>
<td></td>
</tr>
<tr>
<td>Ensham Coal Supply Term Sheet—Ensham Coal</td>
<td></td>
</tr>
<tr>
<td>Ensham Terms Sheet for Land Procurement</td>
<td></td>
</tr>
<tr>
<td>Ensham Waste Disposal Terms Sheet</td>
<td></td>
</tr>
<tr>
<td>Xstrata Coal Supply Terms Sheet—Rolleston Coal</td>
<td></td>
</tr>
<tr>
<td>Coal Rail Transport Indicative Terms Sheet</td>
<td>✓ ✓ ✓</td>
</tr>
<tr>
<td>Central Queensland Local Airports</td>
<td>✓ ✓ ✓</td>
</tr>
<tr>
<td>ZeroGen: Coal Specification (Ensham)</td>
<td></td>
</tr>
<tr>
<td>MHI: Nagasaki Gasification Facility—Design Coal Test Burn Report</td>
<td></td>
</tr>
<tr>
<td>ZeroGen: Nagasaki Gasification Facility—Design Coal Test Burn Witness Report</td>
<td></td>
</tr>
<tr>
<td>Screening Level Investigation into impact on Radio-communications Systems Operations</td>
<td></td>
</tr>
<tr>
<td>Preliminary Flood Risk Assessment</td>
<td>✓ ✓ ✓</td>
</tr>
<tr>
<td>Screening Plume Rise Assessment for Flares near Blackwater</td>
<td>✓ ✓ ✓</td>
</tr>
<tr>
<td>IGCC CO\textsubscript{2} Sequestration Pipeline Prefeasibility Phase HAZARD Study</td>
<td></td>
</tr>
</tbody>
</table>
### TABLE 3.4: COMPLETED ENGINEERING STUDIES—CENTRAL QUEENSLAND (ENSHAM) ENGINEERING STUDIES (CONT.)

<table>
<thead>
<tr>
<th>Study</th>
<th>Sites</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mine Operating Overview Report (Ensham)</td>
<td>✓</td>
</tr>
<tr>
<td>MHI PFS Report¹</td>
<td>✓ ✓ ✓</td>
</tr>
<tr>
<td>Mine Operating Overview Report (Rolleston)</td>
<td>✓</td>
</tr>
</tbody>
</table>

Note ¹: The MHI PFS Report covers the Ensham, Blackwater West and Wandoan sites.

### TABLE 3.5: COMPLETED ENGINEERING STUDIES—SURAT BASIN (WANDOAN) ENGINEERING STUDIES

<table>
<thead>
<tr>
<th>Study</th>
<th>Surat Site</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Surat Basin (Wandoan) Engineering Studies</strong></td>
<td></td>
</tr>
<tr>
<td>Site selection (Surat Basin)</td>
<td>✓</td>
</tr>
<tr>
<td>SunWater Water Supply Proposal and Terms Sheet—Surat/Wandoan</td>
<td>✓</td>
</tr>
<tr>
<td>High Voltage Connection and Access Study for Wandoan Site</td>
<td>✓</td>
</tr>
<tr>
<td>Transmission Costing Study for Wandoan Site</td>
<td>✓</td>
</tr>
<tr>
<td>Water Resources Assessment for a Potential Site (Wandoan) for a Commercial—Scale Demonstration Plant Utilising IGCC and CCS</td>
<td>✓</td>
</tr>
<tr>
<td>CO₂, Natural Gas and Water Pipelines Study, Wandoan Option Study</td>
<td>✓</td>
</tr>
<tr>
<td>Infrastructure Corridors Study Wandoan Site</td>
<td>✓</td>
</tr>
<tr>
<td>Modified Routes for Revised Wandoan IGCC Site</td>
<td>✓</td>
</tr>
<tr>
<td>Wandoan PFS Report</td>
<td>✓</td>
</tr>
<tr>
<td>Surat Basin Coal Supplier/Mine Screening Study</td>
<td>✓</td>
</tr>
<tr>
<td>ZeroGen: Coal Specification (Wandoan)</td>
<td>✓</td>
</tr>
<tr>
<td>Xstrata Coal Supply Term Sheet—Wandoan Mine</td>
<td>✓</td>
</tr>
</tbody>
</table>
### TABLE 3.6: COMPLETED ENGINEERING STUDIES—NON SITE–SPECIFIC STUDIES

<table>
<thead>
<tr>
<th>Study</th>
<th>Ensham (CQ Selected Site)</th>
<th>Surat Site</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Non site–specific studies</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO₂ Cross–Basin Pipelines Study</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Inter–Basin Carbon Dioxide Pipeline Corridor Study</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Coal Supply Risk Matrix</td>
<td>Non site–specific report</td>
<td></td>
</tr>
<tr>
<td>ZeroGen: IGCC Functional Specification</td>
<td>Non site–specific report</td>
<td></td>
</tr>
<tr>
<td>ZeroGen Control and Operating Philosophy</td>
<td>Non site–specific report</td>
<td></td>
</tr>
<tr>
<td>ZeroGen: Design Control Plan</td>
<td>Non site–specific report</td>
<td></td>
</tr>
<tr>
<td>PFD/HMB Simulation Validation Study</td>
<td>Non site–specific report</td>
<td></td>
</tr>
<tr>
<td>ZeroGen: Hazard Study #1 Report</td>
<td>Non site–specific report</td>
<td></td>
</tr>
<tr>
<td>ZeroGen: Hazard Study #2 Report</td>
<td>Non site–specific report</td>
<td></td>
</tr>
<tr>
<td>ZeroGen: Nakoso Site Visits Due Diligence Report</td>
<td>Non site–specific report</td>
<td></td>
</tr>
<tr>
<td>ZeroGen: Nagasaki Site Visit Due Diligence Report</td>
<td>Non site–specific report</td>
<td></td>
</tr>
<tr>
<td>ZeroGen: Hiroshima Site Visit Due Diligence Report</td>
<td>Non site–specific report</td>
<td></td>
</tr>
<tr>
<td>ZeroGen: Takasago Site Visit Due Diligence Report</td>
<td>Non site–specific report</td>
<td></td>
</tr>
<tr>
<td>ZeroGen: Tamar Valley Site Visit Report</td>
<td>Non site–specific report</td>
<td></td>
</tr>
<tr>
<td>Control System Report</td>
<td>Non site–specific report</td>
<td></td>
</tr>
<tr>
<td>Control System Gap Analysis Report</td>
<td>Non site–specific report</td>
<td></td>
</tr>
<tr>
<td>Confirmation of ZeroGen Registration as an Intending Participant in the NEM</td>
<td>Non site–specific report</td>
<td></td>
</tr>
<tr>
<td>Application for Registration as an Intending Participant in the NEM</td>
<td>Non site–specific report</td>
<td></td>
</tr>
<tr>
<td>ZeroGen: TCLP Analysis of Slag Product</td>
<td>Non site–specific report</td>
<td></td>
</tr>
<tr>
<td>Salt Storage Report</td>
<td>Non site–specific report</td>
<td></td>
</tr>
<tr>
<td>Sulphuric Acid Sales</td>
<td>Non site–specific report</td>
<td></td>
</tr>
<tr>
<td>Cooling Systems Options Report</td>
<td>Non site–specific report</td>
<td></td>
</tr>
<tr>
<td>Gasification Technology comparison Report</td>
<td>Non site–specific report</td>
<td></td>
</tr>
</tbody>
</table>
3.4 Further Information on Studies

3.4.1 Overview of the key study consultants and engineers

The consultants and engineers engaged by ZeroGen performed the study work in accordance with the specific scopes of work established by the ZeroGen Project team.

The following subsections describe the key roles each of the study consultants and engineers undertook during the PFS.

3.4.2 IGCC with carbon capture

Mitsubishi Corporation/Mitsubishi Heavy Industries (MC/MHI) was selected as the technology partner during the scoping study in order to reduce the project design and technology risk. As part of its business model, MHI designs, fabricates, erects and commissions significant power facilities internationally, such as the demonstration IGCC plant at Nakoso, Japan.

For the ZeroGen Plant, MHI designed a significant amount of the process plant equipment in–house, including the key components of the gasifier and power block.

MHI was engaged under a Service Agreement to provide the necessary prefeasibility design and costing detail for the PFS Report. MHI and ZeroGen selected the following third–party technology providers as detailed within Table 3.7.

<table>
<thead>
<tr>
<th>Technology</th>
<th>Selected third–party provider</th>
</tr>
</thead>
<tbody>
<tr>
<td>Acid gas removal (AGR) plant (a combined H₂S and CO₂ removal process)</td>
<td>UOP</td>
</tr>
<tr>
<td>Wet sulphuric acid plant (conversion of H₂S to sulphuric acid)</td>
<td>Haldor Topsøe</td>
</tr>
<tr>
<td>Water treatment</td>
<td>Veolia/HPD</td>
</tr>
<tr>
<td>Zero liquid disposal (ZLD)</td>
<td>Veolia/HPD</td>
</tr>
<tr>
<td>CO shift catalyst</td>
<td>Johnson Matthey (JM)</td>
</tr>
</tbody>
</table>

The broad areas covered in the MHI PFS are:

- process design basis;
- plant performance under base case and turndown cases;
- process flow diagrams;
- process descriptions;
- water balance;
- plant arrangements and layouts;
• control systems configuration;
• operations and maintenance;
• lessons learnt; and
• preliminary RAM study.

MHI also engaged Fluor Engineers in the USA to conduct a further optimisation of the Acid Gas Removal plant.

### 3.4.3 Balance of plant

Under the Project Development Agreement with MC and MHI, MHI was responsible for the balance of plant for the IGCC with carbon capture.

However, MHI had not worked extensively in Australia, and at the start of the PFS, was not familiar with the local engineering consultants capable of performing this work.

ZeroGen agreed to engage an appropriate Australian engineer to manage this portion of work, with MHI responding to interface management issues as required.

ZeroGen subsequently prepared a scope of work and approached the consulting engineer market on a competitive basis.

AECOM Engineers was selected to perform this work.

### 3.4.4 Infrastructure corridors

The infrastructure corridor work was completed on a sole source basis. Resource and Land Management Services (RLMS) had previously been engaged on a competitive basis for the ZeroGen Project, and was familiar with ZeroGen’s requirements. RLMS has also worked extensively in Queensland as a land management consultant and agent for many large industrial pipeline projects.

RLMS was responsible for identifying alternative routes for each of the pipelines (CO₂, natural gas, and water), from the power plant to the nominated connection points. RLMS was also responsible for identifying an appropriate transmission line corridor to the nominated national electricity market connection point.

RLMS studied corridors for both the Ensham and Surat sites, and investigated the connection of the Ensham site to the Surat Basin for the transport of CO₂.

The resulting reports identified land tenure, constructability, and environmental constraints as components of the preferred corridor route assessment.

### 3.4.5 Water resources

4T Consultants, a water resource consultancy local to Central Queensland, performed the work for the scoping study. The organisation is familiar with the local water market and water resource availability, and was consequently re–selected to perform the water resource assessment for the PFS.
4T Consultants were also required to nominate an appropriate connection point for the water supply pipeline and assist with the development of a water procurement strategy and a fatal flaw flood risk assessment for the Ensham site.

### 3.4.6 Transmission connection

ROAM Consulting performed work for the scoping study. A niche network and electricity market modelling consultancy, ROAM Consulting is very familiar with the NEM, the transmission network, and the modelling of the transmission network, and has provided an independent market modelling analysis service recently for the Australian Government. ROAM Consulting was re-selected to perform additional work for the PFS.

ROAM Consulting was required to provide and assess which was the most appropriate connection point for each of the shortlisted sites. ROAM Consulting also provided the data on the Marginal Loss Factor (MLF) for each of the sites. Once the preferred site was selected, ROAM Consulting, in conjunction with Hill Michael and Associates, provided a capital cost estimate for the high voltage power line and the modifications required at the Powerlink substation for connection into the electricity network.

ROAM Consulting also provided an assessment of the long-term MLF impacts at the connection point to ensure that the ZeroGen Plant would not be impacted by large changes in the MLFs in the future.

As MLF is largely dependent on load and generation flows, this work was an estimation only, based on ROAM Consulting and ZeroGen’s current knowledge of the market, industrial developments, and potential future additional generation projects.

### 3.4.7 Pipelines (CO₂, natural gas and water)

Under the Project Development Agreement with MC and MHI, ZeroGen was responsible for the provision of project infrastructure.

A key component of the infrastructure was the CO₂ main trunk pipeline. There are no CO₂ pipelines of any significance in Australia, and the local engineering consultants are limited in their capability.

OSD had performed work for the scoping study and had some international experience. However, given the level of detailed study work required for the PFS, it was decided to competitively bid this work to the local engineering consultants with a strong requirement that pipeline experience, and specifically high pressure CO₂ pipeline experience.

Hatch was awarded this work on the basis of its pipeline and project experience, but more importantly, on their ability to tap into experienced CO₂ pipeline design and operations resources in Canada. The Hatch Canadian office included personnel who had performed various works for Weyburn and Encana CO₂ injection for Enhanced Oil Recovery (EOR).
Once the pipeline corridors were identified by RLMS, Hatch was responsible for providing prefeasibility class engineering and costing for the CO₂, water and natural gas pipelines.

Hatch was also responsible for identifying the potential for existing natural gas infrastructure to supply the ZeroGen Project as an alternative auxiliary fuel to diesel.

### 3.4.8 Supporting studies

A number of supporting studies were completed to provide additional information for the main studies for the PFS.

Primarily, these additional studies relate to risk assessments, background information and reviews, including:

- Wood Mackenzie is a specialist consulting organisation in the energy sector, and has absorbed the coal and resource areas of Barlow Jonkers, a well-known coal market analysis organisation. The organisation was engaged to provide advice on the domestic coal market in Queensland, cost of production at various mines, resource assessment of mines, and market outlook for coal and energy;
- Minserve is a specialist consultant to the mining industry, engaged by ZeroGen to provide advice on mine production costs for negotiation purposes;
- PAE Holmes is a consultant group involved in air monitoring and climate data monitoring and assessment. It provided advice on the impact of the plant flare under full flare relief conditions on domestic aircraft space intrusion (OLS and PANS OPS) at the Blackwater airport; and
- WorleyParsons is a large consulting organisation in the energy and process industries. It provided independent facilitation of Hazard Study 1 and 2 reviews, reliability, availability and maintainability overview analysis, and lessons learnt.

### 3.4.9 Engineering man–hours

Table 3.8 provides an indication of the man–hours expended by each of the consulting groups to complete the study work. In some cases, the work was performed on a lump sum basis, so the estimates have been based on an approximation of the man–hours related to lump sum costs and hourly charge rates.

This level of effort was considered consistent with the required effort for this scope element of the PFS.
TABLE 3.8: CONSULTANT MAN–HOURS FOR STUDY WORK

<table>
<thead>
<tr>
<th>Consultant/organisation</th>
<th>Scope of work</th>
<th>Approx. effort level</th>
</tr>
</thead>
<tbody>
<tr>
<td>ZeroGen</td>
<td>Project management/technical oversight.</td>
<td>15,000</td>
</tr>
<tr>
<td>MHI</td>
<td>Technical studies for IGCC/CC.</td>
<td>50,000</td>
</tr>
<tr>
<td>Procom Engineers</td>
<td>Development of Aspen Model for process verification.</td>
<td>1,000</td>
</tr>
<tr>
<td>AECOM</td>
<td>Balance of plant engineering for the Ensham power plant and Surat power plant.</td>
<td>14807</td>
</tr>
<tr>
<td>Hatch</td>
<td>Pipeline engineering for CO₂, natural gas, water for the Ensham site and Surat site. Compressor optimisation study. Cost estimates.</td>
<td>2675</td>
</tr>
<tr>
<td>4T Consultants</td>
<td>Water resource assessment for Central Queensland, Callide and Surat sites.</td>
<td>537</td>
</tr>
<tr>
<td>ROAM Consulting/HMA</td>
<td>Network studies and MLF assessment.</td>
<td>450</td>
</tr>
<tr>
<td><strong>Total (estimated)</strong></td>
<td></td>
<td><strong>Approximately 84,500</strong></td>
</tr>
</tbody>
</table>

3.4.10 Additional requirements prior to Feasibility Study

Certain results and elements of the completed work raised additional items, which needed to be completed prior to commencement of the Feasibility Study and were generally planned as part of bridging activities.

These works are generally described as:

Rework of heat and mass balance—was to be carried out by MHI. This incorporated the coal specification from Ensham and results of the gasification test. Studies to optimise water consumption and maximise power output were to be incorporated. This work was expected to include an update of the plot plan.

The Acid Gas Removal (AGR) plant is complex, costly and power intensive. A further study of the AGR plant was to be conducted by Fluor in USA to confirm that ZeroGen had selected the best technology configuration.

The MHI report identified a number of improvements to the final plant configuration to enable a net–power output increase from the plant. These will be further assessed and either rejected or incorporated into the final configuration.

Inspections of the Selexol Plant at Coffeyville in the USA were to be conducted if necessary.

The technology selection and testing for the CO Sour Shift Catalyst was to be closed out.

The final selection process for the water treatment and Zero Liquid Discharge (ZLD) process was to be closed out.
ZeroGen was going to submit the Connection Enquiry to Powerlink once the status of the
PFS was announced and recommended site, Ensham was approved.

ZeroGen commenced discussions with Powerlink regarding the construction of a 275kV power
line from the Powerlink substation to the power plant.

The PFS identified that in addition to the MHI Diasys control system being used, a separate
vendor was required for the provision of the plant dynamic modelling, simulation platform
and plant historian. It was desirable that this vendor was established before the Feasibility
Study commenced.

The test procedure and costs associated with gas turbine combustor testing needed to
be confirmed.

The ZLD system needed to be optimised, and the salt disposal options and testing confirmed.

The water strategy paper indicates that ZeroGen needed to enter the water market to secure
water allocations from Fairbairn Dam by procuring allocations from the market. SunWater does
not hold water allocations out of Fairbairn Dam. SunWater has also provided a preliminary water
supply proposal for the supply of coal–seam gas water to a Surat Basin power plant project.
Meetings were planned to start prior to the commencement of the Feasibility Study to firm up
the availability of water from SunWater, and prior to ZeroGen entering water discussions directly
with the various water producers.

Non–binding and indicative term sheets for the procurement of the Ensham site from Ensham
Resources, the freehold land owner, were executed and discussions commenced for the
development of a Land Procurement Agreement between ZeroGen and Ensham Resources.
Further discussions were needed to progress the development of the agreement.

Discussions with Ensham Resources regarding the disposal of slag into the mine voids.
Transport 2t of slag from the Nagasaki gasification test burn of Ensham coal to Australia
for storage and future testing.

The work package and scopes of work for Feasibility Study were to be developed.
4 Technology Selection

4.1 Context
This section introduces the various gasification processes available and the basis for selecting the MHI gasification process. It also provides the basis for selecting the key associated technologies/technology providers for the IGCC facility, namely CO shift, acid gas removal and sulphur recovery.

ZeroGen undertook an extensive evaluation of gasification and IGCC technologies between 2005 and 2010. This included commercial EOI processes, prefeasibility studies, feasibility studies, due diligence site inspections and working actively with technology providers as part of this process.

4.2 Lessons Learnt
The key lessons learnt arising from provision of this overview of the ZeroGen IGCC power plant based on the MHI gasification process are as follows.

The information contained in this knowledge product can be used by other proponents as a checklist for similar project technology selection processes.

ZeroGen decided that when compared with other gasification technologies available, the MHI gasifier and IGCC best met its requirements.

MHI has developed its IGCC technology with the operating and maintenance culture of the conventional coal–fired power industry in mind, building on already mature, proven pulverised coal–fired technology aspects where possible, making the plant simpler to operate and maintain when compared with other gasification technologies, and importantly, minimising risks of the first–of–a–kind integration. This approach was expected to result in enhanced availability through avoiding the need for many of the complex systems found in other IGCC designs.

A MHI IGCC employs a combination of dry fed, membrane wall, air blown technology with complete char recycle. ZeroGen assessed that this will result in enhanced IGCC plant availability and thermal efficiency based on MHI information.

Clean Coal Power (CCP) has installed a MHI 250MW air blown IGCC demonstration plant at Nakoso in Japan, which commenced operation in 2007. In September 2008, the Nakoso plant achieved over 2,000 hours of continuous operation. This was achieved in the first year of operation of the IGCC facility and has been arguably the most successful coal–fired IGCC demonstration when compared against the performance of other coal–fired IGCC demonstrations.
4.3 Gasification Technology Comparison

Gasification is a chemical process by which carbonaceous (hydrocarbon) materials (coal, petroleum coke, biomass etc.) are converted into a synthesis gas (syngas) by means of partial oxidation with air, oxygen, and/or steam.

Modern gasification technologies use hydrocarbon feedstock, which is fed into a high-pressure, high-temperature chemical reactor (gasifier) containing steam and a limited amount of oxygen to produce syngas.

The syngas is primarily a mixture of hydrogen and carbon monoxide, and is cleaned using commercially available and proven systems that remove particulates, sulphur, and trace metals (e.g. mercury).

The syngas can then be used in highly-efficient combined cycle electric power plants or to make many products presently made from natural gas, including ammonia fertilisers, methanol-derived chemicals, and clean-burning synthetic fuels.

Gasifier technologies fit into three primary technology types:

- **Moving bed** The carbonaceous fuel is dry-fed through the top of the reactor. As the fuel slowly descends, it reacts with the gasifying agents (steam and oxygen) flowing in a counter-current through the bed. The fuel goes through the various stages of gasification until it is ultimately consumed, leaving only syngas and a dry or molten ash. The syngas has a low temperature (400–500°C) and contains significant quantities of tars and oils.

- **Entrained flow** The fuel and gasifying agents flow in the same direction (and at rates in excess of other gasifier types). The feedstock, which may be dry-fed (mixed with nitrogen) or slurry-fed (mixed with water), goes through the various stages of gasification as it moves with the steam/oxygen flow. The gasifier may be lined with an internal membrane wall or refractory lined. Operating temperatures are in the vicinity of 1,200–1,600°C. The gasifier may be fed with oxygen (oxygen blown) or air (air blown).

- **Fluidised bed** The fuel, introduced into an upward flow of steam/oxygen, remains suspended in the gasifying agents, while the gasification process takes place. Since the operating temperature of the reactor (800–1,050°C) is less than the temperature at which the ash from the fuel melts, these can be removed either in dry form or as an agglomerate.

An important development for the power industry was the development and construction of four international coal based IGCC demonstration projects to generate electrical power (without carbon capture) in the early to mid-1990s. More recently, MHI built an air blown demonstration IGCC at Nakoso. The IGCC projects, technology suppliers and respective technologies are listed in Table 4.1.
4.4 IGCC Selection Overview

ZeroGen undertook an extensive evaluation of gasification and IGCC technologies between 2005 and 2010. This included commercial EOI processes, PFS, feasibility studies, due diligence site inspections and working actively with technology providers as part of this process.

4.4.1 Gasification technology selection activities (early 2005)

As part of the gasification technology evaluation conducted in 2005, ZeroGen commissioned an independent consultant to assist a review of available technologies. Detailed EOIIs were issued to major entrained flow–gasification technology providers listed in Table 4.1 in late December 2004, and an assessment of the responses below (Table 4.2) commenced in early 2005.
The evaluation followed a pre-determined evaluation procedure and used selection criteria and weightings, which were determined prior to opening the responses to the EOI.

An independent probity auditor who provided a probity audit report indicating his satisfaction with the process oversaw the evaluation.

An independent technical gasification expert reviewed the evaluation and confirmed their satisfaction with both the process and the conclusions of the evaluation process.

The evaluation process determined that the Vendor E submission matched the evaluation criteria better than the submission provided by Vendor C. The main areas of difference included plant performance and operating flexibility.

The evaluation concluded that:

- A membrane wall gasifier is preferable to a refractory wall gasifier, due mainly to issues affecting plant availability, operability and maintenance costs:
  - Membrane wall demonstrated operating life of ten years versus refractory wall demonstrated life of two years, requiring an outage period of many weeks to fully refurbish the refractory.
  - Refractory wall requiring a plant outage each year to effect repairs to the refractory.
  - Refractory wall gasifiers are more susceptible to refractory damage due to operational upsets, requiring a shutdown for repair, whereas a membrane wall ‘self heals’ a loss of solid slag on the wall, by liquid slag solidifying at the point of damage/loss allowing operations to continue.
  - Refractory wall gasifiers take significantly longer to start up due to the need to carefully control refractory temperature ramp profile to avoid refractory damage.
  - Refractory wall gasifiers take significantly longer to shut down due to the need to carefully control refractory temperature ramp profile to avoid refractory damage.

- For power plant technology, ZeroGen has concluded that a dry feed gasifier is preferable to a slurry feed gasifier, due mainly to issues affecting plant availability, range of suitable coal feeds, operability, operating complexity and maintenance costs:

### TABLE 4.2: RESPONDENTS TO GASIFICATION EOI

<table>
<thead>
<tr>
<th>Technology provider</th>
<th>Response</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vendor A</td>
<td>A partial EOI was submitted covering the gasification process only.</td>
</tr>
<tr>
<td>Vendor B</td>
<td>Declined to submit a response.</td>
</tr>
<tr>
<td>Vendor C</td>
<td>A complete EOI was received, including the overall process design and the gasification process.</td>
</tr>
<tr>
<td>MHI</td>
<td>Declined to submit a response.</td>
</tr>
<tr>
<td>Vendor E</td>
<td>A complete EOI was received, including the overall process design and the gasification process.</td>
</tr>
</tbody>
</table>
– The slurry feed injection/burner arrangement requires frequent replacement of the burner tip, and equates to an outage period of more than several hours to effect the change. The dry feed injection/burner arrangement can operate for more than two years without replacement, increasing availability relative to the slurry feed design.

– The slurry feed system is less suitable for coals with higher ash and moisture content relative to a dry feed system.

– The slurry feed system requires regular repair and replacement of feed pumps and other wearing parts as a result of the abrasive coal/water slurry.

– The slurry feed gasifier produces slag with a significantly higher carbon content than slag/ash produced by a dry feed gasifier, which negatively impacts the thermal efficiency.

Study work conducted by ZeroGen during the subsequent Stage 1 design studies and due diligence activities (focused on a further review of operational sites deploying the different gasification technologies) confirmed these conclusions.

4.4.2 ZeroGen Stage 1 design studies (2005–2008)

ZeroGen undertook a series of design studies as part of its Prefeasibility and Feasibility Studies using a dry feed, membrane wall gasifier as the core technology element.

ZeroGen also continued to review the development of other gasification and related technologies to assess potential impacts on IGCC technology deployment. The ongoing technology review along with the assessment of the chosen technologies and changes in the market ensured that the ZeroGen technology aspects remained current.

The following sections highlight key outcomes of the work conducted through the design studies.

Slurry feed versus dry feed

Further comparison between slurry feed and dry feed gasifiers concluded that dry feed remained preferable to slurry feed, due mainly to:

• the slurry feed system, in combination with a wet particulate scrubbing system, resulted in excessive quantities of water in unshifted syngas relative to the water required for the sour shift reaction using commercially available CO shift catalysts, resulting in a significant reduction of thermal efficiency; and

• the slurry feed system, if higher carbon conversion is targeted, required a complex plant to separate the high carbon slag for recycling from the low carbon slag for disposal.

Elimination of fly ash product

At ZeroGen’s request, study work was undertaken by the selected gasification technology provider in 2005 to identify technology options for the elimination of fly ash as a product (only a non–leaching slag product to be produced), potentially reducing complexity and capital cost.

The conclusion from this work was that this configuration was not a viable option.
Quenching alternatives

The selected gasification technology provider independently proposed a modified quench system in 2006, with the intent to significantly decrease gasifier capital cost, and achieve higher water content in the unshifted syngas for the CO shift process, with the intent of tailoring the selected gasification technology for a carbon capture IGCC facility. The modified quench system proposed for deployment at demonstration scale or larger was at the design stage and therefore had not been observed in an operating facility beyond pilot facility scale. A pilot-scale deployment of the technology was previously undertaken at their research facility.

The conclusion from study work was that there was no benefit from quenching syngas using the proposed modified technique.

Syngas Wobbe Index control

Studies undertaken by ZeroGen and WorleyParsons (2008) (under an Engineering Services contract) identified that the control of syngas Wobbe Index was critical in ensuring stable operation of contemporary gas turbine shifted syngas combustion systems, and to achieving high plant availability by avoidance of gas turbine trips.

The proposed approach for syngas Wobbe Index control for an oxygen–blown gasifier involved the blending of nitrogen diluent to low CO₂ highly shifted syngas. This requires the availability of large quantities of high purity nitrogen from an air separation unit, the use of heaters to significantly raise the fuel temperature, and a complex blending control system to ensure the syngas Wobbe Index could be controlled within a tight range. This diluent blending system has never been demonstrated for low CO₂ highly shifted syngas and nitrogen within an operating plant, but to date, has only been demonstrated in a batch system under tightly controlled laboratory conditions for a single gas turbine combustor.

The potential for significant variations of Wobbe Index at the gas turbine combustor, and the inability to optimise the design to minimise this variance, represented additional risk for ZeroGen. It was recognised that further study work was required to quantify expected diluent–conditioned syngas Wobbe Index variation for an oxygen–blown gasifier. ZeroGen and WorleyParsons initiated study work involving dynamic simulation of the critical Stage 1 IGCC systems at appropriate stages of design development in order to mitigate this risk.

Confidential discussions between ZeroGen and another IGCC project team confirmed ZeroGen’s view that inadequate mixing of low CO₂ highly shifted syngas with high purity nitrogen diluent could result in significant transient variations in syngas Wobbe Index at the gas turbine combustor, and that careful attention to the design of the blending system was necessary to minimise this risk. WorleyParsons confirmed both the risk and the approach for mitigation of the risk.

The conclusion from these findings was that an oxygen–blown gasifier may present design challenges for stable operation of a gas turbine. These challenges centre on the provision of a highly shifted, low CO₂ syngas (with diluent) having a suitably stable Wobbe Index to allow high availability under expected operating conditions. Based on these findings, an alternative approach
may provide the required performance at lower risk. This MHI air blown approach for gasification with the production of a well-blended shifted syngas and diluents mixture appears to reduce this risk, substantially.

4.4.3 ZeroGen commercial-scale IGCC technology evaluation (end 2008)

In undertaking the commercial-scale IGCC with CCS scoping study, ZeroGen re-evaluated the status of commercial IGCC technologies and confirmed that there were six recognised IGCC technology providers with coal-fired demonstration experience.

In October 2008, ZeroGen invited proposals from each of these organisations to participate in the ZeroGen commercial-scale project. In addition, ZeroGen sought responses in relation to the critical issues highlighted previously. Of the six invited organisations, three submitted proposals.

**TABLE 4.3: TECHNOLOGY PROVIDERS APPROACHED FOR EOI FOR COMMERCIAL SCALE PLANT**

<table>
<thead>
<tr>
<th>Technology provider</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vendor AA</td>
<td>Formal proposal received</td>
</tr>
<tr>
<td>Vendor BB</td>
<td>Formal proposal received</td>
</tr>
<tr>
<td>Vendor CC</td>
<td>Declined to submit bid</td>
</tr>
<tr>
<td>Vendor DD</td>
<td>Declined, but interested at another time</td>
</tr>
<tr>
<td>Vendor EE</td>
<td>Declined to submit bid</td>
</tr>
</tbody>
</table>

MHI’s initial proposal was used for the evaluation of the MHI technology.

ZeroGen received comprehensive proposals from the three respondents and held interviews with each organisation to understand their submissions better including requesting clarification of any omissions or uncertainties. An independent probity auditor provided process oversight. ACALET also commissioned a peer review by EPRI.

A comprehensive review of the MHI, Vendor AA and Vendor BB technologies concluded that all of the technologies were capable of satisfying the requirements for an IGCC facility with carbon capture in a hot, arid Australian context, fuelled by typical Queensland coal. While the review identified advantages and disadvantages with each technology, ZeroGen concluded that the MHI proposal was significantly more attractive than Vendor AA and Vendor BB.

During the course of previous studies and investigations, ZeroGen had identified a number of technical features that could be deployed to enhance the IGCC technology from an operations perspective. These included:

- elimination of fly ash product;
- quenching of syngas; and
- control of syngas Wobbe Index (for gas turbine combustion stability).

The MHI gasification process successfully addressed these aspects.
While each of Vendor AA, Vendor BB and MHI technologies could work, ZeroGen concluded that the MHI technical proposal was superior in terms of efficiency, robustness, operability and maintainability.

Table 4.4 lists the benefits of the MHI gasifier relative to other entrained flow gasification technology.

**TABLE 4.4: MHI GASIFICATION TECHNOLOGY BENEFITS**

<table>
<thead>
<tr>
<th>MHI technology benefit</th>
<th>Key assessment elements</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lower plant complexity</td>
<td>• Air blown gasifier with no syngas/diluents blending.</td>
</tr>
<tr>
<td></td>
<td>• Simpler water treatment circuits.</td>
</tr>
<tr>
<td>Higher plant availability</td>
<td>• Membrane wall gasifier which is ‘self–healing’ versus refractory wall which develops ‘hot spots’ (requiring a shutdown to fix) on loss of protective lining.</td>
</tr>
<tr>
<td>Significantly higher continuous on–stream days</td>
<td>• Nakoso IGCC (MHI) ~ 2000 hours maximum continuous run hours achieved.</td>
</tr>
<tr>
<td>Lower operating costs</td>
<td>• Less maintenance on simpler water circuits.</td>
</tr>
<tr>
<td></td>
<td>• No gasifier refractory requiring replacement approximately every two years.</td>
</tr>
<tr>
<td></td>
<td>• Higher efficiency—lower–fuel cost.</td>
</tr>
<tr>
<td>Higher thermal efficiency</td>
<td>• MHI assessment of air–blown versus oxygen–blown IGCC with and without carbon capture.</td>
</tr>
<tr>
<td>Simpler treatment of scrubbing waters</td>
<td>• No black and grey water systems due to use of a high temperature high pressure filter for solids removal from syngas.</td>
</tr>
<tr>
<td>Very high carbon conversion</td>
<td>• Slag carbon content less than 0.1% due to recycling of hot dry char and flyash to extinction.</td>
</tr>
<tr>
<td></td>
<td>• Dry coal feed versus slurry feed.</td>
</tr>
<tr>
<td>Environmentally inert, very low carbon slag product with no tars</td>
<td>• Recycling of hot dry char to extinction in the gasifier to form a vitrified inert glassy slag.</td>
</tr>
<tr>
<td></td>
<td>• No full water quench of solids and syngas.</td>
</tr>
<tr>
<td></td>
<td>• No mixing of slag with syngas scrubbing waters.</td>
</tr>
<tr>
<td>Fewer more manageable waste streams</td>
<td>• Production of a single environmentally inert slag product rather than slag and fly ash.</td>
</tr>
<tr>
<td></td>
<td>• Use of a high temperature high pressure filter for solids removal from syngas to avoid producing solids contaminated grey and black water streams containing hydrocarbons.</td>
</tr>
<tr>
<td>Significantly higher number of coals suitable as feedstock</td>
<td>• Dry coal feed allows more coals (such as high ash, sub–bituminous types) to be processed versus slurry feed approach.</td>
</tr>
</tbody>
</table>
A MHI IGCC employs a combination of dry fed, membrane wall, air blown technologies with complete char recycle which will make the plant simpler to operate and maintain, relative to other oxygen–blown commercial IGCC configurations. This will result in enhanced IGCC plant availability and thermal efficiency.

The MHI design avoids the use of many complex systems found in other IGCC designs, allowing for:

- simpler plant start–up/shutdown;
- a single inert mineral residue (slag) product, without complex fly ash handling, and without complex water recirculation and treatment systems;
- a consistent gas turbine fuel (diluted syngas), without complex syngas and nitrogen blending systems and associated risks to gas turbine availability; and
- a reduction in the number of shift operators/maintainers required to safely and effectively operate the plant, which is more consistent to the approach of the power industry than other commercially available IGCC designs.

The slurry fed gasifiers, for example, appear to have been developed primarily for the chemical and hydrocarbon processing industries using a low–ash feedstock such as petroleum coke. This has resulted in a plant, which is more complex to operate and maintain, especially when coal is used as the feedstock instead of petroleum coke. These gasifiers appear to be less robust during start–up, which is a necessarily lengthy operation, to avoid damage to the gasifier internal refractory lining. The use of a refractory lining rather than a membrane wall can add up to tens of hours to the warm up of the gasifier. The use of complex–fuel composition control for low CO₂ highly shifted syngas increases risks of the first–of–a–kind integration.

Overall, ZeroGen has evaluated that when compared with other gasification technologies, the MHI gasifier and IGCC offers a solution that provides better prospects to meet the future requirements for the Australian power generation sector for a hot and arid context, and offers the potential to be adapted to meet future technology enhancements.

In addition, MHI is able to offer a project delivery wrap for the delivery of an integrated IGCC facility with carbon capture, including integrating third party technology providers/licensors as part of the overall delivery wrap.

### 4.4.4 Evaluation of IGCC demonstrations

The MHI IGCC technology (without carbon capture) has commenced an extensive demonstration program at Nakoso in Japan. The results of the program to date have been very encouraging and formed an important part in the technology selection process for the gasifier. The Nakoso demonstration (Clean Coal Power R&D Co. LTD 2005) is the result of over 20 years of research into gasifiers in Japan.

The development path of the MHI gasifier is illustrated in Figure 4.1.

In September 2008, the Nakoso IGCC achieved over 2000 hours of continuous operation (Ishibashi 2008). This was achieved in the first year of operation of the IGCC facility. This has been arguably the most successful coal–fired IGCC demonstration project when compared against the performance achieved by other coal–fired IGCC demonstration projects.
ZeroGen undertook two separate site visits to the Nakoso IGCC facility in order to fully explore lessons learnt and results achieved from the facility. Mitsubishi provided full and open support and findings of the ZeroGen site visits confirm the excellent performance achieved at Nakoso with no significant adverse findings to date.

ZeroGen has also undertaken several site visits to other IGCC demonstration facilities in order to understand lessons learnt from these demonstrations. These units have confirmed some of the difficulties other projects and technologies have had, which have contributed to the performance outcomes achieved over the operating periods of the demonstrations.

### 4.4.5 CO shift technology

In order to recover carbon from the gasification process, it is necessary to convert the CO in the syngas to CO\(_2\). This is achieved by using a shift catalyst that converts the CO in the syngas to CO\(_2\) by reaction with water (steam). For each molecule of CO consumed, there is a corresponding yield of one molecule of hydrogen (H\(_2\)).

\[
CO + H_2O \rightarrow CO_2 + H_2
\]

In the ZeroGen IGCC facility, this processing step is known as a ‘sour CO shift’ (as the shift reaction occurs in the presence of hydrogen sulphide (H\(_2\)S) using a catalyst that is unaffected by the presence of H\(_2\)S and other sulphur compounds). The syngas is known as ‘shifted syngas’ after treatment in the CO shift process.
The CO₂ produced by the shift is extracted from the syngas in an Acid Gas Removal (AGR) process, leaving the H₂ in the syngas for use as fuel in the gas turbine.

The CO shift reaction is an essential ingredient for an IGCC flow scheme incorporating the capture of CO₂.

Studies conducted as part of ZeroGen Stage 1 PFS work undertaken by the gasification technology provider and their engineer, recommended the use of sour shift (high sulphur) technology in preference to sweet shift (low sulphur) technology, for a dry fed gasifier with dry particulate removal. Major drivers were lower capital and operating cost, as well as reduced process complexity.

WorleyParsons (2010), engaged by ZeroGen as the engineer for the ZeroGen Stage 1 Feasibility Study work, also recommended the use of sour shift technology.

The process layout from MHI included sour shift for the proposed air blown gasifier case. This approach, when backed by appropriate test work during the PFS is consistent with the findings of ZeroGen’s earlier work, and supports technology based on improved outcomes for the key performance drivers of capital cost and operating cost for the overall syngas treatment system.

For quench type gasifiers, recent external studies have confirmed sour shift is preferred to sweet shift (Kubek 2007). Some recent external studies have concluded that for syngas cooler (non-quench) gasifier configurations (such as the MHI technology), the preferred CO shift configuration is not clear, however other studies have marginally favoured sour shift over sweet shift (Grol et al. 2009 and Huang et al. 2007).

MHI initially selected a Vendor XX catalyst for the CO shift unit for the IGCC facility. MHI subsequently requested commercial proposals from Vendor YY and Johnson Matthey for the supply of catalyst for the CO shift unit. MHI evaluated the expected performance of the IGCC facility with the Vendor YY and Johnson Matthey CO shift catalysts, and concluded that the use of the Johnson Matthey catalyst would provide improved IGCC net power performance and improved (lower) overall capital cost outcomes. The improved performance was chiefly a result of the reduced steam/syngas ratio required at the inlet to the CO shift reactor with the Johnson Matthey catalyst.

In order to validate the performance of the Johnson Matthey CO shift catalyst in the proposed service, MHI is proposed to conduct pilot-scale tests at the MHI Nagasaki R&D facility as part of pre-FEED activities.

### 4.4.6 Acid gas removal

CO₂ and hydrogen sulphide can be removed from the shifted syngas using an AGR process. The technology selected for the ZeroGen IGCC facility was the physical solvent-based Selexol process licensed by UOP.

The Selexol solvent is a physical solvent that does not rely on a chemical reaction with the acid gases to remove them. The Selexol solvent is a mixture of the dimethyl ethers of polyethylene glycol (DMPEG). The Selexol solvent has the advantage in that it does not degrade with use.
In the Selexol process, the Selexol solvent dissolves (absorbs) acid gases (CO\textsubscript{2} and H\textsubscript{2}S) from the syngas at relatively high pressure. The rich solvent containing the acid gases is then let down in pressure and/or steam stripped to release and recover the acid gases.

The Selexol process can operate selectively to recover H\textsubscript{2}S and CO\textsubscript{2} as separate streams, so that the H\textsubscript{2}S can be sent to a Wet Sulphuric Acid (WSA) unit for conversion to sulphuric acid while, at the same time, the CO\textsubscript{2} can be prepared for carbon storage by drying and compression.

Figure 4.2 depicts a typical Selexol process flow scheme for removal of H\textsubscript{2}S and CO\textsubscript{2}.

**FIGURE 4.2: TYPICAL SELEXOL PROCESS FLOW SCHEME FOR REMOVAL OF H\textsubscript{2}S AND CO\textsubscript{2}**

Studies undertaken as part of ZeroGen Stage 1 PFS work by the gasification technology provider and their engineer, recommended the use of physical solvent AGR technology in preference to chemical solvent AGR technology, for a dry feed gasifier with dry particulate removal.

In addition to the above work, WorleyParsons (2010), as the engineer for the ZeroGen Stage 1 Feasibility Study work, also recommended the use of physical solvent AGR technology. WorleyParsons further recommended the use of Selexol physical solvent as the AGR technology based on technology maturity, parasitic power, capital cost, technology complexity and technology fit drivers.

In the scoping study phase of the commercial-scale ZeroGen IGCC, MHI and ZeroGen considered the use of various solvent AGR technologies. After joint review by ZeroGen and MHI, Selexol solvent AGR technology was selected over alternative AGR technology based on improved outcomes for the key performance drivers of capital cost and operating cost for the overall syngas treatment system.
MHI and ZeroGen concluded Selexol technology was preferred to technology used in other projects, particularly in the context of the hot and arid climate in which the technology is to be deployed, as well as achieving significantly lower concentrations of solvent in the CO₂ product (considered an undesirable contaminant in sequestration).

Further, while the Hydrogen Energy California (HECA) project selected an alternative physical solvent technology when comparing the same two technologies, a significant driver was the environmental requirement in California for the extremely low levels of sulphur in treated syngas (ultimately flue gas). This particular extreme regulatory requirement does not exist in Queensland and ZeroGen will remove 99.9% of sulphur in incoming coal. In addition, HECA also concluded the Selexol and alternative physical solvent life cycle costs, including CO₂ compression, were similar (HECA 2009).

### 4.4.7 Sulphur removal

Studies undertaken by ZeroGen, as part of ZeroGen Stage 1 PFS work, highlighted that regulatory issues associated with the transport of CO₂ by pipeline combined with potential geological issues arising from H₂S levels in CO₂ (for sequestration) greater than 100ppmv required that a sulphur by–product would be necessary from the IGCC facility.

WorleyParsons (2010) engaged by ZeroGen as the engineer for the ZeroGen Stage 1 Feasibility Study work, investigated technologies for the recovery of sulphur by–product, with major drivers being environmental, marketability, technology maturity, as well as capital and operating costs. WorleyParsons and ZeroGen concluded that the production of sulphuric acid represented the best outcome for the Central Queensland context. ZeroGen conducted a preliminary market assessment for sulphuric acid sales and confirmed that 98% purity sulphuric acid could be effectively sold into the Central Queensland market.

Studies identified two sulphuric acid production technologies and associated vendors for further review. ZeroGen conducted due diligence meetings with both technology providers and visited key facilities deploying one of the shortlisted technologies. ZeroGen concluded that the wet gas sulphuric acid technology process licensed by Haldor Topsoe was preferred.

During the scoping study phase of the commercial–scale ZeroGen IGCC, MHI also concluded that the sulphuric acid technology process licensed by Haldor Topsoe was the preferred sulphuric acid production technology.
Annex 1—Technology Selection Evaluation Criteria (Gasification Technology Provider)

The following commercial and technical criteria was used in the development of an EOI sent to candidate gasification technology providers, and the evaluation of EOIs received from gasification technology licensors.

**Commercial evaluation criteria**

- Experience, operating history, and construction history
  - Experience list
  - Operating history
  - Construction history
  - Experience list—ammonia manufacture
- Completion warranties and guarantees
  - Wrap guarantees and extent provided by EPC contractor
  - Completion warranties and guarantees
  - Performance tests—LSTK total plant performance
  - Licensor limitation of liability
  - Licensor limitation of liability—procedures to ‘make work’
  - Liquidated damages
  - Warranty and guarantee references
  - Standard performance and completion guarantees
  - Performance measures
  - Proprietary equipment and materials—extended warranties
- Approved EPC contractors
- Commercial licensing
  - Fees and schedule
  - Proprietary equipment and materials
  - Joint development agreement example
- Research and development
  - Processes commercially available, proven technology, no further development work required
  - Commitment to gasification technology
  - Commitment to CO₂ separation, injection or sequestration
- Engineering support services
- Proprietary equipment and materials—listing
- References
• Company information
  – Credit rating
  – Corporate structure
  – Financial statements
  – Commitment to gasification technology
  – Lobbying strength
  – Resources for operation of plant facility
  – Strategy fit to licensee
  – Flexibility to meet licensee customer needs

Technical evaluation criteria
• Plant design and performance
  – Typical equipment list
  – Thermal efficiency
  – Plant performance reports (with/without CO₂ capture)
  – Plot plan
  – Process flow diagrams
  – Energy and mass balances (with/without CO₂ capture)
  – Condensate and steam balances
  – Utility requirements
  – Start-up utility requirements
  – Flux requirements
  – Oxygen consumption per unit of feed
  – Ability of plant to operate in CO₂ capture and non–CO₂ capture modes

• Plant long run marginal cost
  – Initial capital and operating costs
  – Information to allow and Reliability, Availability and Maintainability (RAM) analysis to be undertaken
  – Comment on CO₂ recovery and any cost breakpoints
  – Optimisation and trade–off studies

• Operations support
  – Engineering support services
  – Qualified operations and maintenance service providers
  – Support for operations startup
• Plant reliability
  – Capacity factor
  – Availability
  – Reliability
  – Syngas block—annual capacity factor
  – Power block—annual capacity factor
  – Overall plant—annual capacity factor
  – Minimised integration of plant components
  – Commercially available components demonstrated by licensor
  – Level of integration required between syngas and power blocks
  – Gasifier lining life
  – Gasifier feed system life
• Plant operating expense
  – Typical operating and maintenance costs
  – Annual catalysts, chemicals, other consumables
  – Recommended staffing plan
  – Annual maintenance costs, including maintenance capital and spares replacement
• Plant capital cost
  – Asian basis, broken down into major plant sections; further broken down into equipment supply and installation costs
  – Other costs
• Plant operating flexibility
  – Ability to feed non–fossil solid fuel
  – Ability to process high fusion ash
  – Ability to process high ash coal
  – ASU size for design coal
  – Ability to process coals with >2% sulphur and >20% ash
• Plant environmental performance
  – CO₂ emissions considering economic impact
  – Water usage
  – Environmental performance air and noise
  – Flaring frequency
  – Emissions and effluents
  – Emissions and effluents treatment options
  – Slag, fly ash, filter pressings properties and hazardous classification
• Plant engineering compliance
  – Compliance of structures to wind loading
  – Compliance to Australian electrical standards

**Economic model**

An economic model was developed based on inputs from commercial and technical evaluation information collection. The economic model was established to compare technologies on a whole of life basis and used as part of the overall evaluation process.

**Risk assessment**

Technologies were compared to see if they could be differentiated on a risk basis. A comparison was made to determine whether the choice of gasification technology provider would make a material difference to the risk profile of the project.
Annex 2—Partner Selection Evaluation Criteria (Commercial–Scale Plant)

The following criteria was used in the selection of a preferred partner for provision of investment funding, technology, and project delivery capability for the IGCC power plant for the ZeroGen Project. The scope of provision included the design, supply, construction, integration guarantee and some equity investment for a commercial-scale IGCC with CO₂ capture.

Evaluation criteria

- **Funding**
  - Equity funding (committed and probability)
  - Commercial basis
  - Ownership of intellectual property
  - Project costing basis

- **Technical capabilities¹**
  - Plant performance
  - Environmental
  - Power generation industry fit

- **Project delivery²**
  - Risk allocation
  - Design management/integration/configuration
  - Construction expertise and responsibility

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¹ These areas were subdivided and ranked with weightings to reflect the importance of particular engineering/technical requirements of the ZeroGen Project, including but not limited to such areas such as plant efficiency and availability, IGCC experience, water usage, plant emissions and byproducts, responsiveness to market demands, and cultural fit (refer to Appendix 1 for examples of detailed technical evaluation criteria).

² The enquiry sought information on third party contractors, warranties and guarantees, risk arrangement and schedule surety. ZeroGen placed emphasis on the allocation of risks as well as Australian construction experience and management expertise.
5 Power Plant Approach To Design

5.1 Context

This section describes the key aspects of the approach to the IGCC plant design (design basis, design philosophy, approach to process design) developed to frame the design activities for the IGCC facility.

5.2 Lessons Learnt

The key lessons learnt arising from undertaking the IGCC plant design are as follows.

It is vital for project proponents to have a skilled owner’s team. As well as develop a comprehensive design philosophy, functional specification and design basis for the proposed facility, and to continually refine/challenge this in consultation with engineering contracting organisations engaged to undertake the design development.

The information contained in this knowledge product, in regards to design philosophy, functional specification and design basis can be used by other proponents as a checklist for design development for similar projects.

The forming of an integrated team during the early phase of study work is essential to allow the best communication between all major participants. ZeroGen developed an excellent working relationship with Mitsubishi.

Basecase plans should include a number of iterations as an expectation and considerable (more than conventional) time and schedule contingency should be allowed for. Base plans should include as an expectation that significant additional work is needed, even at scoping and PFS phase, for integrated designs.

Integrated project proponents need to be aware that the manufacturer, whilst having detailed knowledge of the components that they might supply, will need to have completed significant additional design work to confirm the viability of an integrated design. If that cannot be produced and validated then the study work scope will need also include this design work.

The addition of capture, for all technology choices, creates an entirely different (not ‘bolt–on’) integrated process design. The level of engineering and process development required is very significant and for ZeroGen was still incomplete at the end of its prefeasibility stage.

Use of pilot–plant facilities to evaluate the suitability and performance of the MHI gasification process using the selected coal over a continuous three day operating period was considered important to minimise the technical risk.

ZeroGen concluded that approximately 98% CO$_2$ purity resulted in the best optimised cost of electricity for the ZeroGen context. The expected concentration of the non–CO$_2$ constituents in the CO$_2$ product was confirmed by the ZeroGen CO$_2$ storage team to be acceptable for CO$_2$ transport and storage.
ZeroGen conducted its own independent process design model verification exercise. This is based on the use of widely deployed, universally accepted, industry-reputed computer simulation packages. This validation work is a major project risk mitigation measure ensuring that the integration issues associated with the plant are able to be addressed early in the project’s design life.

ZeroGen examined gasifier slag from the MHI gasification process using the TCLP methodology (using hydrochloric acid as the leach medium) and the material is regarded as inert.

A series of process waste–water treatment studies were undertaken in order to optimise the capital and operating costs of the ZLD facility in combination with water reuse opportunities within the IGCC facility. The studies included testing of key waste–water streams from the Nakoso IGCC facility which highlighted the relative ease of treating wastewater streams from the MHI gasification facility.

5.3 Introduction

The plant design will be based around the MHI air blown gasifier, which has been installed at Nakoso, Japan as part of a demonstration-scale IGCC facility (no carbon capture).

The ZeroGen Plant will be scaled to approximately double the output of Nakoso, and will be fitted with a carbon capture process.

ZeroGen prepared a project specific functional specification for the IGCC plant including carbon capture facility. MHI subsequently prepared its own design basis using the requirements of the functional specification.

The following subsections provide details of the major design parameters and values.

5.4 Basis of Design

5.4.1 Design basis—key elements

The design basis and design philosophy of the power plant has been described in a functional specification prepared by the ZeroGen study team. The functional specification focuses on plant performance and cost in the context of ambient conditions for a Central Queensland site (hot and arid context), minimising water consumption and maximising water recycling/reuse, adopting technologies which are robust and fit for the purpose, and adopting beneficial reuse of waste streams where practical and economic.

It was planned that the plant would have a high degree of automation. To ensure a consistent approach to automation and data management, ZeroGen prepared a control and operation philosophy which was to be used across the project.

For the purposes of the PFS, MHI prepared its design basis for the power plant with carbon capture based on the ZeroGen functional specification. ZeroGen engaged AECOM Engineers to prepare the balance of plant design to support the power plant. The balance of plant was
comprised of civil works, water supply, fuel and chemical delivery systems, building, coal stockpiles, residue storage facilities and other miscellaneous systems. AECOM prepared a design basis for their design activities.

The design bases cover the following topics:

- project drivers;
- design philosophy;
- project functional objectives;
- scopes of work;
- performance requirements and expectations;
- technology selections and interactions;
- plant and systems design and operational requirements;
- design parameters for each unit and/or system;
- specification for all feedstocks, products and by-products;
- auxiliary fuel specifications;
- utility specifications;
- chemicals specifications;
- battery limit conditions for each process unit, package and/or system;
- site conditions;
- environmental requirements;
- waste materials limits;
- codes and standards;
- materials selection criteria;
- units of measurement; and
- numbering and naming conventions.

The key design elements for the purpose of the PFS are summarised below.

**Design coal**

Several candidate coals were investigated and a Central Queensland blended coal was selected as a design or reference coal at the commencement of the PFS and this was the basis of the reference Energy, Mass and Water Balance (EMWB), also referred to as the heat and mass balance (HMB). The reference coal is categorised as a bituminous coal with less moisture and higher heating value (HHV) compared to a sub-bituminous coal.

**Reference site characteristics**

The reference site location was assumed to be in Central Queensland, Australia, and the site was assumed to be greenfield, clear and levelled, with a site elevation of 260 m above mean sea level.
Air cooling
To minimise water usage, air cooling was considered as the primary medium for the main steam condenser, as well as process cooling for the PFS.

Design temperature
The design ambient temperature was set at 23°C, following an evaluation of annual variations of the ambient temperature at the proposed site location and its impact on power production, as well as the relative value of power between summer, winter, day and night. This also coincided with the annual average ambient temperature for the site.

CO₂ purity
To satisfy the CO₂ pipeline requirement, CO₂ purity was initially set as 99.7% for the PFS. Subsequently this was revised to 98%.

Capture rate
A carbon capture rate of 65% was selected, however a future retrofit to 90% was also investigated.

Water reuse
To achieve optimum process water–reuse, a Zero Liquid Discharge (ZLD) system was included in the power plant.

5.4.2 Design philosophy—key areas
In selection of technology options for deployment in the process flow sheet, ZeroGen undertook a detailed review of technology options.

In order to achieve the project objectives and engineering requirements, the project design philosophy focuses on a number of key areas detailed below.

Risk reduction
Technology risks were minimised to the extent possible by the selection of technologies and equipment that has a proven record. Technology partners would have been selected based on a proven history of successful delivery and a reference list of their technology. This has been shown on similar projects to significantly reduce operational issues.

Engineering standards
Up–to–date engineering standards and international practice were adopted for the project engineering design. This has been shown on similar projects to significantly reduce operational issues.
Beneficial reuse

ZeroGen undertook a selection and configuration of the technologies approach that maximised beneficial reuse of waste streams and high value inputs. The MHI gasifier converts all of the ash contained in the coal to a vitrified product capable of reuse as an aggregate. Sulphur is captured and converted to sulphuric acid for sale. This approach provided the best value to the project.

Automation

The plant was controlled on an integrated control system platform to allow sophisticated start–up, shut–down and upset controls for the operators. The control system allowed seamless integration of the control requirements across the technology boundaries. A high fidelity dynamic simulation model would be developed for process verification, engineering design and operator training. Uses of these types of models have been proven to reduce design and commissioning of these types of facilities.

Water usage

ZeroGen implemented a design standard of achieving a zero process water discharge and this design choice then influenced other aspects of project design. To achieve zero process water discharge, ZeroGen planned to minimise the intake of water and used all waters entering the plant to the maximum extent practically possible. The plant would have been designed to segregate process waters to maximise the reuse potential of residual salt cakes and minimise potentially contaminated salts, which needed to be disposed of on site. ZeroGen adopted a mixture of water and air cooling largely through the selection of hybrid wet/dry cooling systems. Furthermore, ZeroGen took the opportunity to examine the intake water quality and was able to utilise relatively poor quality intake waters, which could have facilitated water harvesting from incident rainfall on the site and the reuse of industrial sources. This would have optimised plant performance within available water supply constraints and limits waste disposal issues.

Emissions reduction

The plant was designed to achieve a significantly better emissions profile than the current pulverised fuel coal–fired power stations.

Efficiency

The approach to the design is to achieve a plant efficiency, which will meet the requirements of the power industry for a first–of–a–kind plant.

Key technologies

In the case of the ZeroGen Project, although elements (or unit operations) of the technology used in coal–fired IGCC and carbon capture exist, there was no coal–fired IGCC facilities with carbon capture in operation anywhere in the world.

ZeroGen was therefore being developed in the context of a first–of–a–kind project.

Integration risks are material for first–of–a–kind projects, even if individual unit operations have been proven as part of another application.
IGCC with carbon capture brings a further unique dynamic challenge between desired stable process operation and preferred dynamic electricity market responsiveness.

ZeroGen was responding to these first–of–a–kind challenges as follows:

- rigorous assessment of technology options to identify preferred technologies;
- early involvement by the key technology vendors in the PFS, especially in settling the design basis, functional specification and trade–off studies in order to optimise the project configuration;
- negotiate sharing significant engineering, procurement and construction performance risk, as well as critical integration risk with the technology provider; and
- seek must–run, base–load power generation status.

As part of this and earlier studies, ZeroGen undertook a rigorous pre–selection of technologies/ vendors using independent review.

ZeroGen was then involved with the selected vendors early in the PFS, especially in the roles of settling the design basis, functional specification and trade–off studies in order to optimise the project configuration.

MHI has provided the integration role in conjunction with the relevant third–party technology providers.

5.5 Process Design

5.5.1 Approach used

Based on the above design conditions and philosophies the process design for the PFS was carried out. This included technical studies and engineering activities that lead to the development of the HMB, water balance, equipment design and sizing for the normal steady state operation of the plant as well as for the design case, the rating case and the maximum turndown case.

Development of heat and mass balance

As an initial activity for the PFS, the overall plant HMB was prepared, based on the design conditions specified in the design basis, and by integrating the different technology elements and aligning the individual interface conditions.

Development of water balance

An overall water balance was developed, based on the mass balance of process plant, utilities and balance of plant (BoP) requirements.

Design margins

An evaluation of the key project drivers and operating philosophy of the plant as well as the variability in the key design basis parameters were also carried out. This led to the development of design margins, which were then to be applied to the sizing of plant and equipment.
Equipment design and sizing

Based on the operating parameters obtained from the HMB and water balance calculations, the design and sizing of each equipment item was conducted.

Performance calculation

The estimated plant performance derived using the specified parameters in the functional specification, was significantly lower than that achieved at the conclusion of the scoping study. MHI and ZeroGen embarked upon a significant campaign of side studies to derive improved performance from the plant. Design basis conditions, assumptions and philosophies were challenged and these lead to the following focus areas for potential performance improvement:

- review of process cooling philosophy and the introduction of optimised water cooling for Power Block Portion, Gas Clean Up Units and Main Condenser—Parallel Condensing System (PAC);
- relaxation of the CO₂ specification from 99.7% to 98.0%;
- investigation of alternative CO shift catalysts in order to potentially reduce the steam requirements and improve power plant output;
- gas turbine performance improvement;
- improvement of large compressor efficiency; and
- ASU auxiliary power reduction.

Impact of different coals

For the purpose of the PFS, a Central Queensland blended coal was selected as a design or reference coal from the initial screening test work. However, to review the impact of different candidate coals, an analysis for Ensham and Wandoan coal was conducted. From this analysis adjustments were made to the reference case calculations to predict plant performance for the Ensham coal at the Ensham plant site as well as for the Surat Basin coal for a plant located in the Surat area of Central Queensland Basin.

Coal testing and pilot plant studies

As a part of the PFS activity, 30kg sample coal analysis for the range of candidate coals was performed to confirm the coal properties and provide an initial assessment of the suitability of the candidate coals for gasification.

In addition, a 100t suitably prepared representative sample of the Ensham coal was shipped to Nagasaki for testing in their 24t/d pilot plant coal gasification test unit. In April 2010, approximately 60t of Ensham coal underwent a gasification test using a gasifier representative of the MHI air blown gasifier. ZeroGen representatives witnessed this test.

The aim of this test was to evaluate the suitability and performance of the MHI gasification process using Ensham coal over a continuous three day operating period and thereby minimise the technical risk.

As a result of the coal gasification test, it was confirmed that the Ensham coal was well suited for the MHI air–blown gasifier and that its operation was well within the appropriate operating conditions. These tests confirmed the process design for the facility.
ZLD process development

A series of process wastewater treatment studies were undertaken by the technology provider HPD in order to optimise the capital and operating costs of the ZLD facility in combination with water reuse opportunities within the IGCC facility.

The studies included testing of key wastewater streams from the Nakoso IGCC facility, which highlighted the relative ease of treating wastewater streams from the MHI gasification facility. The conclusions from this test work were incorporated into the process design of the ZLD facility.

5.5.2 Reference case, base case and alternate case

At the commencement of the PFS, ZeroGen selected a reference site and reference coal, which would be the basis of the HMB calculations. As ZeroGen had always planned to conduct a competitive site and coal selection process through the front end of the PFS, the final performance assessments of the site and coal was done using a sensitivity adjustment. The results using this methodology are normal engineering practice and sufficiently accurate for the PFS.

Using the reference case conditions, MHI prepared a complete HMB with calculation closure of sufficient accuracy on all the key process streams. In parallel with the work being conducted by MHI for the HMB, ZeroGen developed its own independent process model using Aspen Plus and Thermoflex to validate the MHI HMB.

The ZeroGen model and MHI results aligned, confirming competency in the calculations and additionally providing ZeroGen with valuable expertise and a locally developed gasification modelling tool which was used for the purpose of the project.

Once the results of the reference case were obtained, a series of side studies were concluded to further optimise the performance of the plant.

The specific data from the selected site, selected fuel and gasification test, was assessed against the reference case and adjustments made to arrive at the base case result which was specific to the selected site. In this case, the preferred site was Ensham coal mine in Central Queensland. However, an alternative Surat Basin site was also studied for the purpose of benchmarking a Surat Basin alternative power plant location.

Finally, MHI commissioned a further high–level review and optimisation of the gas treating plant by Fluor Engineers in the USA. The Fluor review and optimisation indicated a further potential improvement on the plant performance.

5.5.3 Design trade–off studies

ZeroGen conducted extensive trade–off studies associated with fuel and water supply, power plant location, plant layout and configuration, transmission connection and access, infrastructure corridor routes for transmission lines, water and CO₂ pipelines and auxiliary fuel supply options.

These studies were used extensively in the site selection process to determine the optimum power plant location in Central Queensland and for the Surat Basin benchmark site adjacent to the Xstrata Coal proposed Wandoan coal mine. They were also used extensively to arrive at the process element configuration for the power plant.

Figure 5.1 shows the energy mass and water balance overview.
Energy and Mass Balance Overview

Calculation Results

Reference Case Side Studies and Optimisation / Base Case Coal Applied

<table>
<thead>
<tr>
<th>Study/Configuration</th>
<th>Result</th>
<th>Reference Case</th>
<th>MHI Side Study results for Reference case</th>
<th>Fluor Assessment for Reference Case</th>
<th>Ensham with Fluor Assessment for Reference Case</th>
<th>Surat with Fluor Assessment for Alternate Site</th>
</tr>
</thead>
<tbody>
<tr>
<td>Additional 8.0 MW net</td>
<td></td>
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<td></td>
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<td>Additional 10.3 MW net</td>
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<tr>
<td>Base Case Ensham site with Ensham Coal</td>
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<tr>
<td>All Case Surat with Wandson Coal</td>
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</tbody>
</table>

Power Plant Performance

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Unit</th>
<th>Reference Case</th>
<th>MHI Side Study results for Reference case</th>
<th>Fluor Assessment for Reference Case</th>
<th>Ensham with Fluor Assessment for Reference Case</th>
<th>Surat with Fluor Assessment for Alternate Site</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross Plant Output</td>
<td>MW</td>
<td>507.4</td>
<td>531.8</td>
<td>529.8</td>
<td>524.8</td>
<td>509.8</td>
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<tr>
<td>Net Plant Output</td>
<td>MW</td>
<td>345.6</td>
<td>357.6</td>
<td>400.6</td>
<td>399.0</td>
<td>388.4</td>
</tr>
<tr>
<td>Net Plant Efficiency</td>
<td>%</td>
<td>28.3</td>
<td>31</td>
<td>32</td>
<td>31.3</td>
<td>32.1</td>
</tr>
<tr>
<td>Carbon Capture</td>
<td>%</td>
<td>65</td>
<td>65</td>
<td>65</td>
<td>65</td>
<td>65</td>
</tr>
</tbody>
</table>
Cooling options

MHI conducted extensive trade–off studies regarding the impact of different cooling options on the net power output for the IGCC facility.

As a result of these studies, ZeroGen and MHI selected hybrid (wet) cooling for the AGR (Selexol) refrigeration compressor, the CO₂ compressor and for key systems on the gasification unit (listed as the power block portion in the table). The selected options also individually and collectively reduced the overall capital cost of the IGCC facility.

MHI also completed a study on the use of a parallel condensing system for the steam turbine condenser on the power block. MHI concluded that the improvements in net–power output were insufficient to justify the increase in overall water consumption and increase in overall capital cost for the IGCC facility. This was consistent with an independent report by SigmaMSc commissioned by ZeroGen to review parallel condensing systems.

Start–up fuel supply

The purpose of the gas turbine start–up is to secure the air supply for the gasifier. The gas turbine cannot be started on syngas since it contains a significant amount of hydrogen, which due to its properties, would cause unstable combustion conditions on start–up. The gas turbine is therefore started on a suitable auxiliary fuel, such as natural gas or diesel, and the fuel supply is switched over to syngas at approximately half load.

Similarly, on load reduction the fuel supply is switched over from syngas to auxiliary fuel at half load, when the IGCC unit is being shut down (such as for a planned maintenance outage).

For the ZeroGen PFS, diesel was selected as the start–up fuel.

Sufficient on site storage facilities were provided. They were sized to allow a number of cold starts and take into account the logistics of diesel supply in the region.

Investigations into the use of natural gas instead of diesel were carried out assuming the same total quantity of energy is required. Options reviewed included supply by gas pipeline, as well as in liquid form.

A financial comparison between diesel and natural gas fuels, based on assumed capital and operating costs, indicated that the payback period to use natural gas supplied by pipeline instead of diesel is approaching ten years.

This result is due to difficulties with the supply of natural gas since:

- suppliers are reluctant to provide a relatively small total quantity of gas at random times to suit unplanned start–ups. The gas would need to be sourced from a main distribution pipeline, which will be supplying a major customer such as an LNG plant;
- the price of gas may be assumed to be at least equivalent to the export price, and probably significantly greater, due to the intermittent nature of ZeroGen’s requirement; and
- the quantity of gas needed for a start up over a 24 hour period necessitates that the supply pipeline be much larger than the simple flow requirement, since it must act as a ‘storage bottle’. Therefore, the capital cost of the gas supply infrastructure was significant and poorly utilised.
The initial design allowed for equipment based on the use of diesel as the auxiliary fuel for plant start-up. A further financial comparison between diesel and natural gas at an appropriate time as the project proceeds prior to final equipment selection was proposed.

**Further work prior to FEED**

Additional activities were required to be completed before the commencement of the FEED, in order to ensure that an optimised single plant configuration and design basis is carried into the FEED and included the following:

- the CO shift catalyst testing;
- optimisation of the CO shift, gas clean-up and carbon capture sections of the power plant;
- rework of the CO shift, gas clean-up and carbon capture sections of the power plant layout;
- rework of the HMB on the final design coal; and
- optimisation of bottoming cycle.

These studies were proposed to be completed as ‘bridging activities’.

**5.5.4 CO₂ product—optimisation of specification**

The CO₂ purity specification for the project was initially set at 99.7% as a result of geological storage contamination concerns. During discussions with MHI and UOP, and after receiving the results of the reference HMB, it was evident that improved performance could be achieved by slightly relaxing the purity specification.

Studies undertaken by ZeroGen on CO₂ content in recovered CO₂ for sequestration (with the main driver being cost of electricity produced), concluded that if the CO₂ purity dropped much below 98%, then the cost of electricity produced would rise. The increased cost is a result of overall capital and operating cost increases associated with the production of additional syngas components (namely hydrogen and carbon monoxide) which would be sequestered with the CO₂ product. If the CO₂ purity increased much above 98%, then the cost of electricity produced would again rise as a result of overall capital and operating cost increases associated with production of higher purity CO₂ by the Selexol AGR plant. ZeroGen concluded that approximately 98% CO₂ purity resulted in the best optimised cost of electricity for the ZeroGen context. The expected concentration of the non-CO₂ constituents in the CO₂ product was confirmed by the ZeroGen CO₂ storage team.

CO₂ is captured, dehydrated and compressed prior to leaving the power plant. It is compressed to a pressure greater than the critical pressure (7.4MPag) for CO₂ such that it is a supercritical fluid since this condition is the most economical way to transport CO₂ by pipeline.

The design pressure of CO₂ at the exit of the power plant is influenced by the equipment selection for the CO₂ transport system and the requirement of the geosequestration site:

- it was designed to be 15 MPag;
- the maximum temperature of the CO₂ at the exit of the power plant is 55°C;
- the composition of the CO₂ mixture at exit from the power plant is detailed within Table 5.1; and
- the purity level of the CO₂ has been set by the geological requirements for CO₂ storage.
TABLE 5.1: CO₂ PRODUCT SPECIFICATIONS

<table>
<thead>
<tr>
<th>Constituent</th>
<th>Design case</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂ purity (% vol)</td>
<td>98.0 min</td>
</tr>
<tr>
<td>Total sulphur (ppm)</td>
<td>&lt; 10</td>
</tr>
<tr>
<td>CO (% vol)</td>
<td>&lt; 0.90</td>
</tr>
<tr>
<td>N₂ (% vol)</td>
<td>&lt; 0.80</td>
</tr>
<tr>
<td>H₂ (% vol)</td>
<td>&lt; 0.80</td>
</tr>
<tr>
<td>HC (as CH₄) (% vol)</td>
<td>&lt; 0.06</td>
</tr>
<tr>
<td>Moisture (ppmv)</td>
<td>&lt; 311</td>
</tr>
</tbody>
</table>

These CO₂ product specifications are preliminary estimates. These were to be reviewed during detailed design.

5.6 Plant Design—Approach and Division of Responsibility

The ZeroGen Project PFS design has been broken up into a number of major components. The main process plant and power island work was to be carried out by MHI, with the BoP work being awarded to the engineering consultancy group AECOM following a national competitive tendering process.

In broad terms, the MHI component included:
- the Air Separation Unit (ASU);
- coal bunkering, preparation and feed to the gasifier;
- gasifier flux system;
- the gasifier, char and slag systems;
- the gas clean-up unit;
- the CO shift, AGR and sulphuric acid plants;
- the power block including sub-station;
- CO₂ compression and dehydration system;
- the ZLD facility;
- the associated steam, condensate, water, nitrogen, plant air, instrument air and chemical systems; and
- the main control room and associated control systems.

BoP component designed by AECOM included:
- the coal, raw water and process chemicals delivery and flux delivery systems, coal stockpile and receival system as well as the coal feed to the MHI facility;
- raw water and demineralised water treatment;
- site wide earthworks including on-site raw water dams, wastewater systems and stormwater retention systems;
• site access and security, buildings, sewerage systems and treatment;
• on–site storage of the inert vitreous slag and the process water ZDL plant salts and all catalysts and chemicals;
• fire systems, process distribution piping systems; and
• recommendation for construction camp facilities, construction power and water provision.

Value improvement

The plant designs were driven by a number of value improvement initiatives, including:
• reviewing functional objectives (project value objectives) including reliability, availability, quality expandability, degree of automation, life of facility, flexibility and scale–up issues;
• setting design margins and sparing philosophy to ensure that the plant and equipment were designed to the agreed margins and that further margins were avoided;
• agreeing on project standards for engineering early in the design process to prevent the use of excessive and unnecessarily conservative design standards and to ensure commonality across the plant units and systems, especially BoP;
• using process simplification extensively to both derive and then independently validate the plant design;
• evaluating preliminary reliability and availability including identification of issues, concerns and mitigations provided by the current design; establishing the preliminary operations and maintenance philosophy; and
• developing a Lessons Learnt Register and Risk Register and applying it to the designs.

Although a formal front–end loading assessment was not carried out, the approach to plant design was consistent with the guidelines for front–end loading appropriate to a PFS.

Safe design practices

The safe design practices were geared towards delivering inherent safety, i.e. the elimination of hazards through design and included risk assessments and hazard studies. Where elimination was not feasible, hazard reduction was driven by the ALARP principle (as low as reasonably practical).

Safe design practices addressed personnel safety, plant and equipment integrity as well as business economics where appropriate. Safety in design also addressed construction hazards as well as start–up, normal operation, normal shutdown and emergency shutdown to the level appropriate to a PFS.

Hazard studies based on the ICI methodology were carried out during the PFS. Hazard Study 1 (Hazard Identification) was carried out at the concept block diagram level and Hazard Study 2 (Hazard Assessment and Mitigation) was carried out at the PFD level. Both studies were independently facilitated.

These studies ensured that all hazards to personnel, equipment and the environment, both inside and outside plant boundaries were identified, evaluated and either reduced to or suitably documented for reduction to ALARP levels by subsequent design and/or procedural means during the FEED stage.
Plant layout—overall site layout

AECOM were provided with a generic MHI plant layout drawing and arranged this on the site to integrate with the plant infrastructure, which was designed and arranged by AECOM. This infrastructure included buildings, car parks, fuel and chemicals storage facilities, slag and salt storage, truck loading and unloading access requirements, as well as water treatment, storm water and fire water management and site security considerations.

Typical considerations that drove the overall site layout included:

- the relationship between the power plant and the coal supplier and the coal supply requirements of ZeroGen for the planned 30–40 year operating life of the project. To this end, the Ensham site would have coal delivered by truck from the mine coal handling plant to the on-site stockpile from the north, with the option of developing a rail loop from the Blackwater Main Line if needed at some stage in the future;
- direction of prevailing wind and the location of coal stockpiles, hazardous chemicals storages and habitable buildings;
- the topography of the site to minimise bulk earthworks and to meet the flood design criteria;
- the location of existing roads and other infrastructure such as export power connection points; and
- the location of any specific vegetation.

The MHI plant layout

The MHI plant layout was developed as a generic layout. Inter-relationships with the BoP facilities, habitable buildings and other site-specific constraints including site geometry have lead to some changes to the orientation of some of the major plant blocks in relation to the generic layout.

The generic IGCC power plant layout was developed based on the following considerations:

- interrelation between the various units in terms of process flow, pressure drops, interfaces and nature of the process within the units;
- access requirements for maintenance and erection of facilities;
- arrangement of plant roads for appropriate accessibility to facilities and to manage any major traffic movements such as the removal of slag by truck;
- selection of the flare type and its location to minimise connected piping ensuring compliance with occupational health and safety requirements;
- location of the Air Cooled Condenser (ACC) to mitigate the impact on adjacent units such as the gas turbine and any habitable buildings from diffusion of hot air from exhaust fans of the ACC, considering the predominant wind direction;
- arranging the pipe rack to minimise the length of piping, particularly large bore piping;
- planning likely terminal points with other parties to minimise the overlapping of work areas;
- locating the gas clean-up system to minimise large bore piping;
- locating the CO₂ vent stack to provide a sufficient exclusion zone;
• locating the switchyard to minimise the length of the transmission line and also considering the arrangement of a future second unit;
• locating the coal bunkers to minimise the length of the coal conveyor taking account of the location of the coal stock pile and rise angle constraints;
• minimising impacts to adjacent facilities from fire, explosion and possible emissions of hazardous materials from an inadvertent loss of containment;
• location of air intakes to minimise the likelihood of contamination from adjacent units such as coal stockpiles and any atmospheric vents from fuel storage facilities;
• future retrofit of a second unit and/or reinforcement of the carbon capture unit are/is considered in the current plot plan; and
• EPRI recommendations provided in the User Design Basis Specification (UDBS) were not fully implemented at this stage, however this will be completed during the next phase.

The MHI plant layout was expected to undergo considerable further development during the bridging activities leading up to the FEED, as well as design activities during the FEED as additional information and definition becomes available.

Finally, as an integral part to further optimisation studies, detailed Quantitative Risk Assessment (QRA) exercises would be required in the subsequent FEED phase. These would need to examine the likely impacts of fire, explosion and dispersion of toxic gases during emergency conditions.

5.7 Validation of Performance—Approach

MHI has calculated HMB information for all major process units in the plant.

These MHI HMBs were based on (Figure 5.2):
• MHI’s gasification test data and coal analyses;
• experience at the Nakoso demonstration plant and other test facilities;
• performance information obtained from different technology providers. In particular, this is relevant to the performance of process units such as the CO Shift, Selexol, WSA, ZLD, and ASU; and
• experience on pulverised coal-fired power plants for the coal grinding and drying process.

For certain areas of the plant, MHI also used its proven computer simulation techniques to predict plant performance.
ZeroGen conducted its own independent model verification exercise. This was based on the use of widely deployed, universally accepted, industry–reputed computer simulation packages. ZeroGen used Aspen Plus for chemical process modelling and ThermoFlex for power block modelling.
The modelling work, while validating and verifying the HMB data provided by MHI and other technology providers, also provided ZeroGen with a tool. The tool had the appropriate enhancements, to conduct further case studies such as optimisation, technology comparison and performance rating on different coal feedstocks and different ambient conditions. This would be required during pre- FEED and FEED activities.

Key expertise and know how had been developed by the ZeroGen engineering team through the validation modelling work to allow informed process decisions to be made in the future. Additionally, the HMB validation work is a major project risk mitigation measure ensuring that the integration issues associated with the plant could be addressed early in the project’s design life, Figure 5.3.

ZeroGen identified key aspects of dynamic process performance for validation during the early part of FEED activities. An overall dynamic model was considered key for the validation of detailed designs during the FEED stage.

ZeroGen, in conjunction with MHI selected technologies associated with the plant to reduce resource use, minimise emissions and improve plant efficiency.

5.8 Site Conditions

The PFS assessed two sites for the power station location, being:

- selected site, adjacent to the Ensham coal mine in Central Queensland; and
- alternative site, adjacent to the proposed Wandoan coal mine in the Surat Basin.

The following nominal site data, shown in Table 5.2, are provided to give a general indication of the typical site conditions.

### Table 5.2: Ensham Site Conditions

<table>
<thead>
<tr>
<th>Site elevation</th>
<th>160m</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rainfall</td>
<td>684mm</td>
</tr>
<tr>
<td>Mean annual</td>
<td></td>
</tr>
<tr>
<td>Mean no. of rain days</td>
<td>71 per year</td>
</tr>
<tr>
<td>Design storm based on</td>
<td>1000 year period</td>
</tr>
<tr>
<td>Temperature</td>
<td>29.6°C</td>
</tr>
<tr>
<td>Mean daily maximum</td>
<td></td>
</tr>
<tr>
<td>Mean daily minimum</td>
<td>12.9°C</td>
</tr>
<tr>
<td>Maximum recorded</td>
<td>44.5°C</td>
</tr>
<tr>
<td>Minimum recorded</td>
<td>–6°C</td>
</tr>
<tr>
<td>Relative humidity</td>
<td>Average 9:00 a.m</td>
</tr>
<tr>
<td>Average 3:00 p.m</td>
<td>41%</td>
</tr>
<tr>
<td>Design site conditions for plant performance</td>
<td>23°C and 55% relative humidity and 99.589 kPa(a) pressure (design to include evaporative cooler)</td>
</tr>
</tbody>
</table>
TABLE 5.2: ENSHAM SITE CONDITIONS (CONT.)

<table>
<thead>
<tr>
<th>Condition</th>
<th>Specification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind loading</td>
<td>All engineering and design must be based on Australian standards for wind loading and design, including AS 1170, Part 2</td>
</tr>
<tr>
<td>Seismic design criteria</td>
<td>Site Class D, no liquefaction to be considered</td>
</tr>
<tr>
<td>Soil design criteria</td>
<td>Foundations to be designed to suit geotechnical survey data</td>
</tr>
<tr>
<td>Other conditions for design</td>
<td>Design maximum ambient temperature for air compressors$^1$ 40°C</td>
</tr>
<tr>
<td></td>
<td>Design humidity value for air compressors$^2$ 25%</td>
</tr>
<tr>
<td></td>
<td>Design maximum ambient temperature for air coolers$^3$ 40°C</td>
</tr>
<tr>
<td></td>
<td>Design humidity value for air coolers$^4$ 25%</td>
</tr>
<tr>
<td></td>
<td>Design wet bulb temperature (for cooling towers) 23.6°C</td>
</tr>
<tr>
<td></td>
<td>Design minimum ambient temperature$^5$ –6°C</td>
</tr>
</tbody>
</table>

1. This represents the 99th percentile of the maximum ambient temperature.
2. This represents the value coincident with the maximum ambient temperature.
3. This represents the 99th percentile of the maximum ambient temperature.
4. This represents the value coincident with the maximum ambient temperature.
5. This represents the absolute lowest reading ever recorded.

5.9 Emissions Criteria

ZeroGen commenced an EIS for the project. This process would have resulted in the final licensing of parameters for the project. Elements of an EIS for the power plant and capture and associated enabling infrastructure could be relatively well defined. Note, that since no CO$_2$ storage site (and hence pipeline route) had been fixed, EIS aspects relating to these could not be addressed.

5.9.1 Carbon dioxide

When operating with the anticipated low CO$_2$, highly shifted syngas, the plant would be required to remove carbon from the syngas stream so that the overall facility CO$_2$ intensity would be less than natural gas combined cycle power generation without carbon capture, approximately 350kg/MWh (net power exported accounting for electrical power for CO$_2$ compression).

The proposed level of CO$_2$ capture to achieve this requirement was approximately 65%.

5.9.2 Other emissions

The emissions guidelines for the total plant were made up of those from the entire facility.

This includes normal steady state emissions, fugitive emissions, and emissions released under upset and transient conditions.
In addition to fugitive emissions, emissions from the following point sources were considered:

- Heat Recovery Steam Generator (HRSG) stack;
- wet sulphuric acid plant;
- coal dryer;
- flare;
- other vents and purges to atmosphere; and
- auxiliary boiler stack.

Pollutants that required special consideration included oxides of nitrogen (NO\textsubscript{x}) and sulphur (SO\textsubscript{x}). These issues were considered in the development of the process scheme. The expected frequency of process flaring during both the commissioning phase and in actual operation were considered when determining the emissions.

For the plant as a whole, the emissions limits to atmosphere were expected to be equivalent to those expected for a gas fuel fired combined cycle power plant, some of which are defined in Table 5.3.

**TABLE 5.3: ATMOSPHERIC DISCHARGE LIMITS**

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Units</th>
<th>Maximum limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO\textsubscript{x}</td>
<td>ppm</td>
<td>25ppmvd at 15% O\textsubscript{2}\textsuperscript{1}</td>
</tr>
<tr>
<td>SO\textsubscript{x}</td>
<td></td>
<td>Assumed 98% (min) sulphur recovery\textsuperscript{2}</td>
</tr>
<tr>
<td></td>
<td></td>
<td>20 g/sec at combined stack outlet</td>
</tr>
<tr>
<td>PM\textsubscript{10}</td>
<td>mg/m\textsuperscript{3}(n)</td>
<td>50\textsuperscript{3}</td>
</tr>
<tr>
<td>Hg</td>
<td>ppb</td>
<td>Not yet confirmed\textsuperscript{4}</td>
</tr>
<tr>
<td>Volatile Organic Compounds (VOCs)</td>
<td>ppm</td>
<td>Not yet confirmed\textsuperscript{5}</td>
</tr>
<tr>
<td>Odours</td>
<td>OU</td>
<td>No nuisance odours\textsuperscript{6}</td>
</tr>
</tbody>
</table>

1. Syngas firing.
2. Sulphur compounds sequestered with the CO\textsubscript{2} stream are taken as ‘recovered’, and therefore comprise part of the 98% recovery.
3. Subject to negotiation with EPA; by ZeroGen.
4. Subject to negotiation with EPA; by ZeroGen; not expected to require Hg removal bed.
5. Subject to negotiation with EPA; by ZeroGen; not expected to require VOC control for the coal dryer.
6. During the CO\textsubscript{2} venting case, no nuisance odours are to occur under worst case odour modelling at nearby sensitive locations.

**5.9.3 Noise emissions**

The plant was required to meet environmental standards for noise emissions as required by the Environmental Management Plan (EMP).
5.9.4 Environmental noise impact

The plant was required to comply with an Environmental Authority (EA) for noise emissions such that no nuisance noise occurs.

Preliminary background noise measurements indicate that the plant should be designed to achieve a sound pressure level of 28dB(A) at sensitive locations in the vicinity of the plant.

5.9.5 Occupational health and safety noise impact

The plant was required to comply with occupational health and safety regulations for noise emissions. The limit is a maximum of 80dB(A) for eight hours.

5.9.6 Wastewater discharge specification

The plant was designed to be a zero process water discharge site.

5.10 By–Products

The ZeroGen IGCC facility was designed to take advantage of opportunities to produce by–products which have the potential for direct sale into existing markets, or which have the opportunity for beneficial reuse.

5.10.1 Sulphuric acid

A market study by ZeroGen established that the proposed quantities of 98% purity sulphuric acid product would be readily absorbed into the Central Queensland sulphuric acid market.

The sulphuric acid would have been able to be used internally within the power plant in applications such as water treatment, thus eliminating the need to purchase sulphuric acid. The power plant would be designed to allow off–specification sulphuric acid (with purity less than 98%, balance being water) to be used within the power plant, or to be reprocessed by the sulphuric acid process.

The 98% purity sulphuric acid product, a corrosive material, would need to be stored in a dedicated on–site sulphuric acid product tank capable of holding 10 days of acid production at full IGCC load.

5.10.2 Slag

The power plant would convert nearly all the ash in the coal feed into a non–leachable, extremely low carbon, environmentally inert glassy and granular slag.

The slag (and any associated moisture) was found to be non–hazardous, but the quantities that are produced necessitate the use of large–scale transportation equipment such as trucks. Upon filling of an individual on–site slag storage area, the filled area would be capped with an impervious layer of capping material (preventing ingress of rain or other sources of water) and suitably surfaced, landscaped and revegetated to prevent erosion of the capping layer.
ZeroGen investigated the use of the slag in a number of beneficial use applications. One potential application is to use the slag as fill material in the adjacent coal mine, as it is environmentally inert and a structurally competent material. This would assist in the rehabilitation of the mine voids.

Another application is the use of the slag as an aggregate-type material in road bitumen surfacing materials, thereby reducing the amount of aggregate that needs to be extracted by quarrying operations. IGCC slag has already been successfully used in Europe and Japan in road bitumen surfacing materials for many years.

Toxicity Characteristic Leaching Procedure (TCLP) is an analytical procedure, which examines the mobility of potential contaminates through soil and other materials. It was developed by the United States Environmental Protection Agency (USEPA) (and published as Method 1311 and 1312). The test is based on the well-understood principle that acids can mobilise compounds and result in environmental release.

The process varies slightly between laboratories but usually involves challenging a sample with an acid for a fixed period. Analysis of the leachate provides an indication of the ability of the sample to retain contaminates. Inert materials will have low levels of contaminates in the leachate.

ZeroGen examined gasifier slag using the TCLP methodology (using hydrochloric acid as the leach medium) and the material is regarded as inert.
6 Power Plant (Main Process)

6.1 Context

This section provides an overview of the ZeroGen IGCC Power Plant based on the MHI gasification process, including key subsections not included in balance of plant. It importantly defines the scope and extent of these facilities. This forms the basis for development of the capital and operating cost estimates for the IGCC power plant (excluding balance of plant facilities).

6.2 Lessons Learnt

The key lessons learnt arising from provision of this overview of the ZeroGen IGCC Power Plant based on the MHI gasification process are as follows.

The information contained in this Case History can be used by other proponents as a checklist for facility scope for similar projects.

In order to deliver a representative capital and operating cost estimate at the prefeasibility stage of project development, it is vital to establish the scope of what constitutes the IGCC power plant.

A key means of identifying the scope of what constitutes the IGCC power plant is the development by the owner of a well defined functional specification and design basis; this requires engagement of suitably skilled owner resources at the beginning of the prefeasibility stage; note this also applies to the balance of plant, and infrastructure scopes of work.

In hot arid climates such as Australia it will likely be necessary to develop IGCC with CCS projects to be zero process water discharge facilities, which aim to minimise demand on external water supplies where possible. It is important for project proponents and their engineering contractors to carefully classify and utilise water streams and integrate these into the IGCC power plant scope to minimise costs and optimise water reuse.

6.3 IGCC Power Plant

A single gasification train was proposed for the ZeroGen IGCC facility.

The gasification plant components are as follows:

- coal feed bunkers;
- coal mills (with flux addition capability);
- gasifier vessel;
- Syngas cooler;
- high temperature high pressure filters;
• air separation unit;
• air booster compressor; and
• coal feed bunkers.

Figure 6.1 shows a schematic arrangement of the gasification facility.

**FIGURE 6.1: TYPICAL GASIFICATION PLANT PROCESS FLOW DIAGRAM**

6.3.1 Coal feeding

**Coal feeding system**

With reference to Figure 6.2 which is representative of a coal feed system (showing coal bunker structure), for each gasifier, three sets of coal storage bunkers, coal feeders and associated pulverisers were provided. After the coal drying and pulverising process, pulverised coal is separated by bag filters, stored in the pulverised coal storage bin then enters the pulverised coal distribution hoppers. From the pulverised coal distribution hoppers, coal is transported into the gasifier using nitrogen gas provided by the Air Separation Unit (ASU).
Coal bunker and feeder
Raw coal is transported by the coal conveyor to the coal bunkers and stored for daily operation of the unit. Coal is extracted from the bottom of the coal bunkers, where coal flow is measured continuously by weight at the coal feeders and fed to the coal pulverisers.

 Flux handling system
Limestone (CaCO₃) is used as a flux to lower the melting temperature of the ash and improve the slag discharge process from the combustor.
Flux is stored and supplied from a flux bunker and then mixed with coal.

Pulveriser
With reference to Figure 6.3, which illustrates the MHI Coal Pulveriser, the purpose of the pulveriser is to dry and grind the raw coal to the specified fine particle size prior to gasification.

The pulveriser is of the vertical shaft type, with three rollers made of abrasion resistant material, and is furnished with a built-in fixed separator.

Raw coal is fed to the pulveriser by a coal feeder through the centre feed pipe. Coal is ground between the three grinding rollers and the rotating table in the pulveriser. During this process, coal is dried simultaneously, and exits the pulveriser from the top side of the pulveriser.
There are a total of three pulverisers installed, of which two pulverisers to be in operation and one on stand–by while operating the gasifier at the design conditions.

Pulverisers that are not in operation are purged at all times by a minimum flow of nitrogen gas to avoid accumulation of volatile matter in the pulveriser, which can be generated from coal particles remaining in the pulveriser.

**FIGURE 6.3: MHI COAL PULVERISER**

Pulverised coal collector

The bag filter is installed at the downstream of the coal pipe to separate pulverised coal particulates from the coal drying gas. The bag filters have blow back systems using nitrogen gas that are operated periodically for cleaning. The coal drying gas and the nitrogen gas used for blow back are exhausted to the stack by the pulverised coal–drying blower.

Pulverised coal feeding system

Major components of the pulverised coal feeding system are the pulverised coal storage bin and the pulverised coal distribution hopper.

Pulverised coal storage bin

The pulverised coal storage bin stores the pulverised coal under atmospheric pressure. The weight of the stored pulverised coal is continuously measured by gravimetric sensor (load cells). Pulverised coal is discharged intermittently from the bottom of the bin and directed to one of the distribution hoppers.
Pulverised coal distribution hopper

The pulverised coal distribution hopper receives the pulverised coal under atmospheric pressure. Once the receiving process is complete, the hopper can be pressurised using nitrogen gas.

After pressuring is complete, the pulverised coal can be discharged from the hopper and transported to the gasifier using nitrogen gas as the transport media. The three pulverised coal distribution hoppers are operated sequentially.

Dried coal is pneumatically conveyed using drying gas into one of three feed hoppers operating in parallel. These are pressurised sequentially with nitrogen from the ASU and used to feed the gasifier. While one is being filled, another is feeding the gasifier, and another is depressurised ready for filling.

Dryer off gas passes through a particulate filter to remove any coal dust and is then ducted into the main stack for discharge to atmosphere with the gas turbine exhaust gas from the heat recovery steam generator.

6.3.2 Syngas production

Features of the MHI gasifier

The major features of MHI’s gasification system include:

- air blown gasification (high efficiency);
- two-stage gasification—combustor/reductor configuration—(increased flexibility);
- char recycling system (high efficiency);
- dry feed (high efficiency, flexible operation with a wider range of coals);
- membrane waterwall design (high reliability and low maintenance);
- annular space (safe operation);
- clean slag treatment (clean and easy handling, environmentally friendly); and
- fouling free syngas cooler (high availability).

Air blown gasification

The MHI air blown gasifier takes air from the gas turbine compressor that is boosted to gasifier pressure by the booster air compressor. Excess oxygen produced as a by-product by the ASU is added to provide enrichment of the air feed.
Two–stage gasification—combustor/reductor configuration

The MHI gasifier design features an up–flow, two–stage configuration that consists of two chambers, a lower combustor chamber and an upper reductor chamber, illustrated in Figure 6.4.

In the combustor stage, coal and recycled char are fed into the combustor chamber and mixed with the oxygen–enriched air on a relatively high air/fuel ratio. Combustion is established in the combustor section.

In the reductor stage, more coal is fed to the hot–gas stream flowing upwards into the reductor with no additional air. Reduction reaction takes place in the reductor section.

By having the two–stage coal feed process, it is possible to maintain a high temperature atmosphere at the combustor stage. The majority of the ash in the coal is melted and discharged as molten slag, while allowing the reduction reaction to occur at the second stage. The gasified product is chemically quenched at the second stage and the remaining ash is cooled to minimise ash accumulation on the heating surfaces at the syngas cooler. The chemical quench at the second stage also avoids the use of water injection or quench gas injection that would otherwise reduce the efficiency of the process.

The feed ratio between the two coal feed stages, as well as the air/fuel ratio are controlled to achieve the optimum temperature in the gasifier. This allows the gasifier to use a wide range of coals with different properties.
CHAPTER TWO Integrated Gasification Combined Cycle Power Plant

FIGURE 6.4: OPERATING PRINCIPLE FOR THE MHI AIR–BLOWN TWO–STAGE ENTRAINED–BED GASIFIER

Char recycling system

The char recycling system consists of a cyclone, a set of porous filters, storage bin and distribution hoppers. This system separates all of the char included in the syngas and recycles it back into the gasifier. This improves efficiency by eliminating unburned carbon exiting the gasifier and avoiding generation of black water, that poses water treatment challenges.
Dry feed

The dry coal feed design eliminates the need for mixing the pulverised coal feedstock with water as would otherwise be required by slurry feed designs. Less water in the coal feed reduces evaporation heat loss and improves efficiency of the gasifier. Dry feed also allows stable combustion and use of high moisture coals that cannot be fired and used in slurry feed designs because of the high moisture content.

Membrane waterwall design

The gasifier has a ‘membrane waterwall’ configuration that eliminates the need for a refractory lining. An initial start–up consumable refractory lining is applied only on the inner surface of the combustor waterwall for protection until it is gradually replaced by a solid state slag layer created by the ash in the coal feedstock.

The membrane waterwall design has been used in conventional boilers for many years and has a proven record of high reliability and long life, thus avoiding the need for a spare gasifier. Refer to Figure 6.5, Figure 6.6 and Figure 6.7 for membrane wall examples.
Annular space

The MHI gasifier is designed for maximum safety. An important aspect of the pressure vessel design is to minimise the possibility of having hot spots caused by hot gases leaking from the gasifier. The membrane waterwall design provides a highly secure structure to minimise failures with additional backstop by maintaining a slightly higher pressure using an inert gas at the annular space between the gasifier waterwall and the pressure vessel. This will prevent hot gas from leaking out of the gasifier through any cracks in the gasifier wall and avoid hot gases exiting the pressure vessel from any loose flange connections.

On the other hand, a refractory lined gasifier solely relies on the refractory for protecting the pressure vessel from hot spots. Any failure of the refractory may lead to overheating of the pressure vessel wall, with further concerns of hot gases leaking from any loose flanges on the pressure vessel. Extensive optical heat detection systems would be required to monitor the temperature throughout the pressure vessel surface, however these detection systems have been known to be complicated and difficult to maintain. The MHI gasifier design avoids such concerns. This feature is illustrated in Figure 6.8.

**FIGURE 6.8: COMPARISON OF REFRACTORY LINED GASIFIER VERSUS GASIFIER WITH WATERWALL AND ANNULAR SPACE**
Clean slag treatment

The gasifier features a clean, low volume and low unburned carbon slag discharge system described in Figure 6.9.

The molten slag flows down from the bottom of the combustor chamber, where it is quenched in water. The slag is removed from the bottom of the water bath through a slag lock hopper system and transported by a feeder and slurry pumps to dewatering tanks.

The slag is recovered in the form of a glassy bead–like by–product with less than 0.1% unburned carbon. Since the slag has minimum unburned carbon content, the slag water is not black, and is easily treated for beneficial reuse within the IGCC facility, see Figure 6.10.

The glassy slag contains virtually no leachable trace elements and has a relatively high density, which reduces the volume of the slag to roughly half that of fly ash from a conventional pulverised coal plant.

This slag has possible commercial applications as road paving materials or as a fine aggregate for concrete.

FIGURE 6.9: SLAG DISCHARGE SYSTEM
Fouling–free Syngas Cooler

In addition to the two-stage gasification that minimises ash accumulation at the Syngas Cooler (SGC), the heat transfer surfaces in the SGC are equipped with high pressure soot blowers for on-line cleaning.

These soot blowers operate automatically on preset intervals during normal operation.

Similar systems have been in use in conventional boilers and are proven highly effective in improving availability and minimising any manual cleaning during outages.

Gasifier island facilities

A schematic diagram of the gasifier island is shown in Figure 6.11. There are three major systems, these include the gasifier system, the coal feeding system and the char recycling system.
FIGURE 6.11: GASIFIER ISLAND SCHEMATIC DIAGRAM

Coal feeding system

Coal bunker

from HRSG exhaust gas

Coal pulveriser

Pulverised coal collector to Stack

Pulverised coal storage bin

Pulverised coal distribution hopper

Gasifier system

Gasifier SGC

Char recycling system

Porous filter

Cyclone

Char bin

Char distribution hopper

Slag disposal

FIGURE 6.12: ASSEMBLY OF SYNGAS COOLER AT NAKOSO IGCC
Air Separation Unit (ASU)

For the MHI air–blown gasifier, the majority of the gasification agent is supplied as air extracted from the gas turbine compressor. Nitrogen is used for both pulverised coal and char transportation. Therefore, a relatively small quantity of oxygen is generated as a by–product from the ASU, so it is utilised as an additional gasification agent.

As a result, the ASU is significantly smaller in terms of size and auxiliary power than the much larger units needed for oxygen–blown gasifier design, and consequently has lower capital and operating costs. Nitrogen is also required for pneumatic coal feed to the gasifier from the distribution hoppers.

One relatively small capacity–air separation unit is provided to supply oxygen and nitrogen for the gasifier. Ambient air is compressed, cooled and dried by molecular sieves. By expansion and cooling, the temperature is lowered and the air is partially liquefied. The air is then distilled in a distillation column.

This process produces oxygen of 95% purity and high purity of nitrogen (<0.1% O₂). The oxygen is fed to the gasification unit to supplement the air. The nitrogen and oxygen are fed to the gasifier from the ASU by high pressure. A liquid nitrogen and oxygen system with gaseous storage is provided as a backup for the ASU.

Typical ASU facilities are shown in Figure 6.13.

FIGURE 6.13: AIR SEPARATION UNIT AT NAKOSO IGCC (FOREGROUND)
Gasification air booster

Air is provided to the gasifier for the combustion processes by an electric motor driven air booster. The air is supplied to the booster from extracted air from the gas turbine compressor. One 100% booster is provided to feed the gasifier.

6.3.3 Syngas treatment

HCN hydrolysis

Syngas from the High Temperature High Pressure (HTHP) filter enters a Hydrogen Cyanide (HCN) hydrolysis unit with a low–pressure drop, square pitch ‘honeycomb’ tube catalyst arrangement. Here, HCN is converted to ammonia. The use of this HCN hydrolysis step avoids significant issues in downstream scrubbing water treatment caused by cyanide containing compounds, such as Prussian Blue.

Wet scrubbing

The syngas is then passed through a venturi scrubber, which is used to remove acid halide gases (such as hydrogen chloride) and ammonia from the syngas. The wet scrubber works on the principle of contacting water with the syngas, which removes both acid gases and any residual particulates.

A scrubber wash–water blowdown stream is drawn from the venturi scrubber to remove salts scrubbed out of the syngas. Scrubber wash–water blowdown is treated with caustic soda to liberate ammonia and other light gases, and is evaporated to recover water for reuse in the gasification plant, as well as concentrate the salts in the scrubbing water, so as to reduce the cost and size of the ZLD plant from treatment of the concentrated scrubbing water.

The use of HTHP filters upstream of the venturi scrubber ensures that the scrubber wash water does not contain particulates. This eliminates the requirement for a dedicated solids removal system for fly ash, thereby reducing capital cost.

The scrubbing process also humidifies and cools the syngas.

Consequently, a series of heat exchangers are used prior to the scrubber in order to extract as much heat as practical from the syngas at this point, and transfer it to the final syngas as pre–heat for the gas turbine, which then improves the efficiency of the plant.

CO shift conversion unit and shifted syngas washing

After water scrubbing of the syngas, the syngas is mixed with steam from the power block, preheated against shifted syngas and sent to a CO shift unit to produce hydrogen and CO$_2$.

The presence of nitrogen in the syngas allows lower levels of steam addition to be used for the shift reaction. This in turn lowers the condensate recovery capital costs of downstream equipment.
The hot shifted syngas is then cooled against incoming syngas, and is also used to raise steam from recovered shift condensate. This produced steam reduces the quantity of steam that must be supplied for the CO shift reaction from the power block. The warm shifted syngas is then used to preheat demineralised water, which is subsequently de-aerated and used to raise steam. The cooled shifted syngas is then cooled in an air cooler to recover shift condensate. Excess shift condensate is then treated to extract hydrocarbons and ammonia to enable reuse of the recovered water.

Air cooled shifted syngas is sent to a gas washing column where residual ammonia is removed from the shifted syngas prior to the removal of H₂S and the capture of CO₂. Additional shift condensate recovered from the gas–washing column is sent to hydrocarbon extraction and ammonia stripping.

**Acid Gas Removal (Selexol)**

The shifted syngas from the gas–washing column is sent to an Acid Gas Removal (AGR) unit, which utilises the Selexol process developed by UOP. This process removes the CO₂ and H₂S from the shifted syngas.

The H₂S–rich acid gas stream, produced by the Selexol process, is sent to the WSA plant to recover the sulphur as sulphuric acid.

The high purity CO₂ product, produced by the Selexol process, is sent to the CO₂ compression and dehydration unit to prepare a single supercritical CO₂ product suitable for pipeline transport and subsequent geological storage.

The Selexol unit used in the ZeroGen Project is comprised of a sulphur control section, a CO₂ control section and a solvent regeneration section.

The solvent used in the Selexol unit is a mixture of dimethyl ethers of polyethylene glycol, otherwise known as DMPEG is considered low–toxicity solvent and is used in products such as household cleaners.

Figure 6.14 illustrates an example process flow diagram for a Selexol Plant (not ZeroGen specific).
The Selexol unit relies on a refrigerant chilling system using propane as the chilling fluid to ensure that the required purity of CO₂ and H₂S–rich acid gas are achieved.

### 6.3.4 Combined cycle gas turbine

#### Overview

The power block equipment is arranged in a combined cycle configuration with the gas turbine, steam turbine, electric generator and the Heat Recovery Steam Generator (HRSG) as the major components.

Optimising the power block thermodynamic cycle offers a higher combined cycle efficiency, while lowering the life cycle costs. The design also considers the need for meeting the target reliability and availability, while allowing for flexible operation.

The power–producing component of the combined cycle power block consists of one single shaft gas turbine, a dual casing steam turbine, and the electric generator coupled along a single shaft line. Besides being suited for base load operation, this single shaft configuration allows for faster start–ups, allows the use of a single electric generator and related electrical equipment and reduces the power block footprint, as compared to a multi–shaft arrangement.

The order of the equipment line–up along the shaft line consists of the gas turbine, axial compressor, HP–IP steam turbine, LP steam turbine and generator. Considering the size of the generator, a static start–up system is provided. This uses the electric generator as a motor to start the gas turbine, and eliminates the need for separate starting devices.
The heat recovery bottoming cycle is selected to offer high efficiency, while enabling heat transfer to certain streams to the gasification plant. Steam to the CO shift comes from the bottoming cycle. The following subsections provide additional details of the major power block components.

**Gas turbine assembly**

**Gas turbine**

The MHI M701G is a 3,000rpm heavy duty gas turbine designed to serve the 50Hz power generation sector. It is a robust unit with a successful operating history. As of May 2010, MHI has sold 11 M701G units with natural–gas firing.

The latest version M701G gas turbine design has evolved on the extensive experience acquired by operating numerous M501G, M501F and M701F gas turbines, and the steam cooled combustor and advanced aerodynamics of the H–technology design. Thus, this gas turbine represents the latest and proven offering within the whole gas turbine portfolio.

The MHI M701F combustion turbine is in operation on natural gas using MHI’s dry low NOx combustors and in operation on low BTU gas using diffusion combustors.

As of 2010, there are 28 units operating on low BTU gas with over 1,500,000 total operating hours.

At least 11 of these gas turbines utilise fuels with heating values of 4 MJ/Nm³ or lower. Several of the low–BTU gas turbines have been designed to fire dual fuels, which include liquid fuels as well.

Figure 6.15 illustrates MHI’s operational experience of hydrogen–rich syngas firing gas turbines, with hydrogen content of 20% volume or higher.
Based on the operational experience of the figure 6.15 hydrogen–burning gas turbines and other low–BTU gas turbines, MHI supplied a M701F gas turbine to Negishi Refinery of Nippon Oil Refining Company in 2003. The gas turbine was for operation in hydrogen–rich syngas service with a capacity of 431MW. At that time, it was the world’s largest gas turbine in this duty.

The gas turbine design would also utilise the operational knowledge gained by operating the M701DA gas turbine at the 250 MW IGCC Demonstration Plant at Nakoso.

Although there are no MHI 701G gas turbines currently operating on syngas, MHI is in a position to utilise its body of experience using low BTU fuels, hydrogen rich fuels and operational data from the full scale 250 MW IGCC demonstration plant at Nakoso as the basis for deploying the M701G gas turbine in hydrogen–rich syngas service.

In addition, the deployment would be based on the results of a comprehensive development testing program using techniques such as full–scale combustion testing and advanced computer modelling and design techniques. This is based on actual test work proposed by MHI on a single combustor to support the validation of gas turbine combustor performance on the range of expected shifted syngas compositions. These tests were proposed to be performed during the Feasibility Study.
Combustion system

The combustion system is designed for operation on shifted syngas and conventional start-up/backup fuel.

For operation on syngas, the diffusion type combustion system—modified from the typical steam cooled dry low NO₅ type used on G class gas turbines firing natural gas is installed. There is also a separate backup fuel nozzle.

The combustion system can achieve 35 ppm (volume, dry) NOₓ emissions at 15% O₂ without steam or water injection when operating on syngas. NOₓ emissions at the stack outlet are able to be reduced to 25 ppm (volume, dry) NOₓ at 15% O₂ by a Selective Catalytic Reduction (SCR) system installed in the HRSG. The requirement for this will be studied during the Feasibility Study.

Although NOₓ emissions at the gas turbine outlet can be further reduced through the separate addition of diluent at the combustor or by saturating the syngas with water/steam addition, this design instead aims to maximise plant performance.

Air integration

When the MHI M701G GT is integrated with air–blown gasifier, extracted air from the gas turbine compressor is introduced into the gasifier. The pressure of the extracted air is increased in a booster for admission into the gasifier as a gasification agent. All the air required for gasification is supplied only by this means, and can be termed as ‘full integration’. This process has worked successfully at the 250MW Nakoso IGCC plant, and it would be applied for the commercial plant using the larger MHI M701G gas turbine. The air extracted from the gas turbine would not be sent to an ASU.

This would avoid issues that have occurred at other oxygen blown IGCC facilities which have integrated air extraction fully with ASUs. At these facilities, changes in the extracted air pressure have caused problems in the ASU with regard to product gas quality, particularly with nitrogen, resulting in IGCC trip on nitrogen gas quality.

The ASU at the proposed ZeroGen facility would not be integrated with the gas turbine air extraction, and therefore, would not have been subject to nitrogen quality disturbances/fluctuations.

Steam turbine

HP and IP turbines are combined into one cylinder, thus forming a compact overall steam turbine. The MHI combined HP–IP turbine was designed to eliminate excessive thermal stress and thermal distortion during start up and load change.

Generator assembly

Turbine generator for gas turbine and steam turbine would be designed and manufactured based on the following basic conditions:

- horizontally mounted cylindrical rotor, rotating field type with explosion proof structure;
- stator winding and core are hydrogen cooled type, and rotor winding is also hydrogen
cooled type;
  • generator excitation system is static type; and
  • hydrogen sealing is vacuum–treating–type seal oil system.

Heat recovery system

Heat Recovery Steam Generator (HRSG) with SCR

An HRSG would be connected to the exhaust of the gas turbine, and the exhaust of the HRSG is connected to a stack. Hot–flue gas exhausted by the gas turbine passes through the HRSG.

The HRSG would be unfired, two–pressure level, reheat, natural circulation type with vertical–gas flow and horizontal fin tubes in all sections.

If required, the HRSG could be equipped with a Selective Catalytic Reduction (SCR) system for NOX emission control. The SCR unit would be for control of NOX emissions from the gas turbine.

The bottoming cycle uses an ACC for rejecting the residual low–grade heat to the environment, after the steam has expanded through the steam turbine.

The use of an ACC significantly reduces water consumption as compared to a wet–cooled condensing system. The main functions of ACC are to condense the exhaust steam from the
6.3.5 CO₂ processing

After capture in the Selexol facility, the CO₂ is compressed by two CO₂ compression systems (trains), each of which has sufficient capacity to produce a total flow rate corresponding to a 65% carbon capture rate for the plant.

Each CO₂ compression system consists of a booster compressor (for low pressure CO₂ from the Selexol plant), gearbox and variable speed drive motor, followed by a multi-stage compressor (combining the boosted low pressure CO₂ from the Selexol plant with the medium pressure CO₂ from the Selexol plant), gearbox and variable speed drive motor.

A typical CO₂ compressor arrangement is illustrated in Figure 6.17.

The number of stages of compression would have been selected after the design is finalised.

**FIGURE 6.17: CO₂ COMPRESSOR**

A heat exchanger would be installed between each stage of the compressor to reduce the CO₂ temperature and power consumption.

In addition, a dehydration unit (utilising Triethylene Glycol (TEG) Dehydration Technology) would be installed part way through the compression system to permit the amount of moisture in the CO₂ to be limited to an acceptable level. This would enable a less costly construction material to be used for the main CO₂ transport pipeline.

An optimisation study was completed to determine the configuration of the CO₂ compression system. The recommended configuration consisted of the compression of CO₂ to a sufficiently
high pressure such that it changes phase from a gas to a liquid or supercritical fluid and then further increasing the pressure by means of a pump.

The study indicates that the combination of a compressor and pump will minimise the system power consumption and capital cost.

**6.3.6 Sulphur recovery**

The H₂S–rich acid gas from the solvent regenerator column in the Selexol plant, the ammonia and other light gases from the ammonia stripping column and the H₂S–rich gases from the unshifted syngas sulphur removal system, is sent to a sulphuric acid production unit. The production unit utilises the Wet Gas Sulphuric Acid (WSA) process developed by Haldor Topsøe to produce a high purity 98% sulphuric acid product.

The WSA process is environmentally sustainable and highly energy efficient. Key features include:

- no generation of waste materials;
- efficient heat recovery ensures the best possible energy economy and maximum export of superheated steam at desired pressure;
- very low consumption of cooling water; and
- no consumption of chemicals.

The WSA unit also has the capability of being able to reprocess off-spec sulphuric acid (as confirmed by Haldor Topsøe).

To avoid NOₓ emissions when handling feedstocks containing nitrogen compounds, an SCR DeNOₓ system is installed as part of the WSA plant.

Hot air generated in the WSA condenser may be used as preheated combustion air to ensure optimal energy efficiency.

Figure 6.18 illustrates the WSA Flow Diagram.

**FIGURE 6.18: WSA FLOW DIAGRAM**
6.3.7 Wastewater treatment

Central to the project’s philosophy of operating in the arid Australian environment, water reuse is compatible with the cleaner production hierarchy. Consequently, the treatment of wastewater aims for a Zero Liquid Discharge (ZLD) of process water from the plant.

Wastewater is generated by a number of processes around the plant. A sample of these sources includes gas scrubbing wastewater, purge water, excess slag bath water, demineralisation wastewater and blowdown from judicious use of wet cooling.

Wastewater is collected from sources within the process plant, and treated in a ZLD wastewater treatment plant.

This approach produces a distillate of water for reuse within the plant, leaving only a relatively small quantity of solids for disposal.

**FIGURE 6.19: ZERO LIQUID DISCHARGE FACILITY (PER HPD)**

The gasification scrubbing blow down water is pumped to a ZLD facility, where it is processed in a multiple effect brine crystalliser utilising low-grade steam as the heating medium. This process evaporates the water fraction of the water stream for recycling to the gasification plant, leaving concentrated salt slurry, which is fed to a belt press filter. The belt press filter separates the concentrated salt slurry into a salt cake, and concentrated caustic brine, which is recycled to the gasification plant to recover the caustic component.

The evaporated water is recycled to the gasification plant for use in production of high quality water applications. The concentrated brine from the forced circulation brine concentrator is sent to the multiple effect brine crystalliser described earlier for further processing.
Testing has confirmed that slag water from the MHI gasifier is of a high quality requiring minimal treatment for beneficial reuse. Excess water from the slag water system is filtered to remove suspended solids, and is then sent to the cooling tower as make-up water. The small amount of collected solids is either sent to slag disposal, or, if environmentally inert, can be disposed of with raw water suspended solids.

The design considered options for producing segregated salt products, however salt quantities are minimised through the combination of brines from cooling water blow down, demineralised water treatment and the gasification plant.

This approach also optimises the operating and capital costs of the ZLD facility, and minimises the addition of chemicals in the ZLD facility.

The salt cake produced by the belt press filter has a low moisture content of approximately 5% (by weight).

The salt cake is formed (using purpose-built equipment) into bales and transported by dedicated truck to an on-site double lined storage cell (with removable cover and leak detection) that will cater for long-term on-site storage of these gasification salts.

Upon filling of an individual on-site salt storage cell, the filled area is capped with an impervious layer of capping material (preventing ingress of rain or other sources of water) and suitably surfaced, landscaped and revegetated to prevent erosion of the capping layer.

6.3.8 Utilities

Nitrogen systems

The IGCC plant uses nitrogen for a number of functions, including:

- purging;
- blowback;
- pulverised coal pressurising; and
- pulverised coal conveying.

Liquid nitrogen storage was included, facilitating decoupling of the ASU and plant operation preventing minor ASU upsets calling for a plant shutdown, and affording a store of nitrogen for restart from planned shutdowns.

Flare/relief system

The flare system was used to relieve syngas to atmosphere (after it has been combusted) during plant start-ups, shutdowns and upsets.

Instrument air

The function of the instrument air system would be to supply air to pneumatic control valves, dampers, and other duties. The instrument air must be suitably dry and oil free to a level suitable for consumer operation.
Plant air

Plant air would be provided to supply pneumatic tools, general purpose cleaning, repairs and maintenance.

Auxiliary steam

The auxiliary steam system supplies steam to a variety of steam users.

User demand can be prior to start-up, during start-up, and during normal plant operation.

Refrigeration systems

The AGR process requires lower temperatures than available through use of air cored coolers, and evaporative cooling towers.

The use of mechanical refrigeration would be included in the design to provide the temperature difference necessary to achieve these lower temperature processes.

Demineralised water

The power plant would use demineralised water for a number of purposes, including make up to the steam cycle, and for gas treatment use, such as CO shift.

Process cooling system

Process cooling would be provided through a number of techniques. The mixed approach applies cooling to remove process heat, recovering heat where appropriate, and rejecting where necessary.

For extracting non-recoverable heat from the process, a variety of utilities would be employed depending on the process conditions required, including:

- air cooled exchangers enable moderate temperature cooling, while not adding to water consumption. An example of this is the air cooled condenser as part of the steam cycle in the combined cycle power station;
- cooling water from evaporative cooling would be used to provide lower temperatures where needed, and through judicious use, consume limited water; and
- mechanical refrigeration supplies cooling to low process temperature duties, notably in the AGR section.

Electrical systems

Electrical power would be distributed to all site consumers by the electrical power distribution system. Consumers include process equipment, exterior lighting, emergency lighting, and general light and power for all buildings.

The electrical systems would be designed to comply with the relevant Australian standards.
6.3.9 Process control and automation systems

The ZeroGen Plant would be a first–of–a–kind plant integrating complex technology processes. This would require very close attention to the design of an integrated process control system for the plant.

Being a first–of–a–kind facility requires additional instrumentation and monitoring than that required for a plant, which has been designed and delivered many times. A specialist team was required to deliver this element of the project.

Central control

All unit and station plant would be started, controlled and monitored from the Central Control Room (CCR) to the extent possible.

Field local control rooms and control panels would be limited to the minimum required for safe operation, and would normally only be required when equipment requires interaction with a local operator, e.g. truck loading.

Field operator stations may be required to support minimum manning levels into commercial operation.

The design of the IGCC includes minimal process storage of fuel gas, CO₂ and intermediate gas products. The continuous operation of the power station therefore requires coordinated transport and sequestration of the CO₂, and integration of the process plant and power block.
7 Power Plant (Balance of Plant)

7.1 Context

This section provides an overview of the ZeroGen IGCC power plant balance of plant facilities. It importantly defines the scope and extent of these facilities, which are required to support the operation of the IGCC facility and provide the interface with supporting infrastructure. It also identifies options for key items of balance of plant along with those selected as preferred. This forms the basis for development of the capital and operating cost estimates for balance of plant facilities (which have been known to be inadequately defined on first-of-a-kind projects through inadequate scope definition and option selection).

7.2 Lessons Learnt

The key lessons learnt arising from undertaking the balance of plant scope of work are as follows.

In a first-of-a-kind technology, where there has been no previous engineering to define the process requirements, it is probably not possible to reach the required accuracy class without significantly more and new engineering and testing. Study work plans and budgets need to reflect this requirement. Understanding the budget requirements for first-of-a-kind studies is a process of discovery.

In order to deliver a representative capital and operating cost estimate at the prefeasibility stage of project development, it is vital to establish the scope of what constitutes balance of plant, as the balance of plant scope contributes significantly to the make-up of the overall capital and operating costs; note this also applies to the infrastructure scope of work.

A key means of identifying the scope of what constitutes the balance of plant is the development by the owner of a well defined functional specification and design basis; this requires engagement of suitably skilled owner resources at the beginning of the prefeasibility stage; note this also applies to the infrastructure scope of work.

A key means of defining the scope of what constitutes the balance of plant is the engagement of a suitably qualified engineering contractor with specific skills in engineering and cost estimation of balance of plant scope. The owner and engineering contractor need to be continually revising and enhancing the functional specification for the balance of plant scope to ensure alignment; note this also applies to the infrastructure scope of work.

EPC contractors and other project delivery organisations for IGCC projects may not include the balance of plant within their scope of delivery; the items listed in this document provide a check-list for proponents (owners) for what needs to be considered.

In hot arid climates such as Australia it will likely be necessary to develop IGCC with CCS projects to be zero process water discharge facilities, which aim to minimise demand on external water supplies where possible. It is important for project proponents and their engineering contractors to carefully classify and utilise on-site water streams (such as collected runoff, wastewater and leachate) to minimise costs and optimise water reuse.
7.3 Balance of Plant (BoP)

The BoP consists of the following:

- raw coal handling;
- ancillary fuel;
- chemicals handling;
- water systems;
- buildings;
- plant drainage, sanitation and wastewater;
- solid waste management; and
- site works.

7.3.1 Raw coal handling

Coal stockyard

Coal stockpiling at the power plant needs to provide both a dry coal store and a storage buffer to protect against disruptions to supply of coal.

A covered store capacity of up to five days of coal consumption, plus an uncovered storage capacity of up to four weeks of coal consumption at full burn rate should be provided.

Additional long-term compacted stockpile for emergency purposes can be considered depending upon specific circumstances.

Stockpiling and stockpile management options for consideration are detailed in Table 7.1.

**TABLE 7.1: COAL STOCKYARD CONFIGURATION OPTIONS**

<table>
<thead>
<tr>
<th>Option</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>Conical stockpiles created by fixed cantilevered boom conveyor or overhead stacking conveyor, with underground reclaim tunnels below the stockpile. Dozers are used to push coal to the reclaim outlets.</td>
</tr>
<tr>
<td>B</td>
<td>Slot bunker with plough reclaimers in reclaim tunnel</td>
</tr>
<tr>
<td>C</td>
<td>Travelling slewing boom stacker, and portal scraper reclaimers.</td>
</tr>
<tr>
<td>D</td>
<td>Stacking and reclaiming via boom bucket wheel stacker–reclaimers.</td>
</tr>
</tbody>
</table>

A study of the capital costs and operability of the above options concluded that the travelling slewing boom stacker, and portal scraper reclaimer was preferred (option C).
Key features of this arrangement include:

- a covered roof over part of the stockyard provides the dry storage;
- a slewing boom stacker travelling on rails down the centre of the stockyard for its full length;
- the stacker is also capable of travelling under the covered roof two portal scraper reclaimers travelling on rails parallel to the stacker rails, one on either side of the stacker;
- one of the portal reclaimers will be capable of travelling under the covered roof structure to reclaim the dry coal store; and
- the portal reclaimers operated automatically via the control system:
  - stacking conveyor feeding the stacker;
  - reclaim conveyors for receiving coal from the reclaimers; and
  - tramp collection magnets on both and to capture ferrous waste materials in the coal stream. Removal of this waste metal helps prevent damage to downstream equipment, particularly conveyor belts.

Conveyors would be fitted with rip detection devices to detect early damage to the belts. These devices signal an alarm to the operator or shut down the conveyor, depending on the severity of the damage and the type of detector used.

**Coal plant feed**

Coal is transported from the stockyard to the coalbunker via the plant feed system. The plant feed system consists of:

- plant feed conveyor receiving coal from the reclaim conveyors and discharging to the bunker feed conveyor;
- online coal analyser obtaining continuous values of coal composition, ash and moisture content;
- bunker feed conveyor which has a reversible direction and can feed to either of the bunkers; and
- enclosed superstructure over the bunker feed conveyor and head end of conveyor.

Elevated sections of plant feed conveyor and the bunker–head house superstructure would be fully enclosed in galleries to prevent dust emission from the conveyor and eliminate the risk of falling objects to work areas below.

**7.3.2 Ancillary fuel**

**Fuel farm**

Fuel for start–up and shutdown was required. The quantity and type will vary with technology and plant location.

The preferred fuel is natural gas since it has a lower carbon foot print than both diesel and LPG and is lower in cost. However, start–ups, and to a lesser extent shutdowns, consume orders of magnitude greater quantities than normal operations and contracting such a supply can be
difficult unless line pack can be economically arranged with the supplier. Even then, sufficient fuel for several plant start/shutdown cycles is required and storage capacity needs to consider supply chain reliability and delivery batch size if a liquid fuel was selected.

Where a liquid fuel is selected this should based on a single fuel preferably diesel and all engine driven equipment including light vehicles should be based on its use. Depending upon location a minor quantity of unleaded petrol could be stored in a self–bunded wrap tank.

### LPG unloading and handling

All fuel storage and handling facilities are purpose designed and built to all the relevant codes and standards. Handling of fuels also requires stringent safety systems and documented procedures as well as training of personnel.

Where liquefied gaseous fuels are used, vaporiser and accumulator/knock–out pot together with a suitable heat source was also required. If LNG is used, it must be noted that it is a constant boiling liquid requiring a significant downstream user or re–liquefaction facilities that can make this option unattractive.

The facility would need to include:
- purge nitrogen supply;
- vent piping to the flare system;
- fire detection/fire protection;
- static gas detection;
- safety showers; and
- area lighting is required for safe operation.

All fuel piping can be carbon steel and installed aboveground in pipe racks.

### 7.3.3 Chemicals handling

Chemicals are required for:
- syngas treatment including caustic soda for chloride control and ammonia for NOx control;
- water treatment;
- general clean–up; and
- pest and weed control.

Substantial users such as water treatment and syngas treatment would have bulk handling and storage facilities in dedicated bundled areas. Smaller quantities will require storage in a purpose designed and built covered hazardous chemicals store.

### Ammonia storage and distribution

NOx emissions from, the gas turbine exhaust gases can be reduced by means of a Selective Catalytic Reduction (SCR) process using ammonia as the reagent.
Anhydrous ammonia is stored in bullets similar to LPG and similar systems for vaporisation and handling as described above for LPG would be required to convert the liquefied gas into vapour. Ammonia is typically present in syngas and depending upon local economics may be recovered. However, depending upon emission licensing conditions an independent source may be required.

**Sulphuric acid**

Sulphur is liberated from coal in the gasification process as H₂S, which can then be selectively removed from the product syngas.

The captured H₂S can be converted to a high-grade sulphuric acid in a Wet Sulphuric Acid (WSA) plant.

Tankage to store both product acid and off spec acid for reprocessing together with handling and safety equipment is required.

**Water systems and management**

A schematic of the water types and their typical sources are shown in Figure 7.1.

**FIGURE 7.1: WATER TREATMENT SCHEMATIC**

- **Recycled water**
- **Demineralisation**
- **Demin water**
- **Clarification**
- **Service water**
- **Raw water**
- **Sterilisation**
- **Potable water**
- **Fire water**

**Raw water**

Raw water may be from a supplier such as a Water Authority or a natural water source. The raw water clarification and filtration system would be required where the supply is from a river, lake or dam. This employs a system of coagulation and flocculation to produce a clarified water stream with a turbidity of ≤ 1 NTU.

**Potable water**

Potable quality water requires further treatment by way of sterilisation typically using UV ozone or chlorine. For effective sterilisation the water needs to be free of organics and low in turbidity. Potable water would be used to supply drinking water to the buildings and amenities on site and the site—safety shower ring main.
All water systems need to take into account their full range of usage patterns, as well as the hierarchy. Specialist vendors provide customised treatment packages as well as on-going technical support if required.

**Demineralised water**

The two most common technologies used to produce demineralised water are:

- reverse osmosis followed by mixed bed polishing; and
- ion exchange.

Selection would depend largely on the clarified/filtered water quality and treated water specification requirements. Water treatment vendors are best placed to advise on technology selection.

**Service water**

Service water would be reticulated throughout the facilities and is required to be clearly marked as ‘not suitable for human consumption’.

All distribution piping within the plant would be carbon steel and installed aboveground in pipe racks.

**Recycled water**

The raw water supply can be supplemented from time-to-time with water collected on site by the clean-plant drainage system. The run-off from roofed, paved and unpaved areas could be collected and stored separately. Water from paved areas may need to be treated separately with an oil separator (if necessary) and discharged to the clean water dam if to an acceptable quality. Water from unpaved areas may need treatment in sediment traps prior to transfer to the clean water dam.

Recycled water would be pumped from the clean water dam into the raw water clarifier for treatment.

The recycled water system (subject to suitable water quality) would include provision of a standpipe to enable filling of water trucks to be used for dust suppression across any unsealed haul roads and slag/ash placement areas.

**Water storage**

Storage capacity of the various water types depends upon their criticality, usage patterns and upstream system reliability.

**Firewater and distribution**

Firewater could be stored within a segmented section or tiered part of the raw water dam to ensure that a dedicated maximum design quantity of firewater is always available.

The proposed firewater system design and sizing is normally based on the National Fire Protection Association US codes and standards or equivalent Fire Protection Association of Australia standards (where these exist).
7.3.4 Plant drainage

Stormwater

Stormwater management would be site specific, and considered:

- natural topography of the site;
- the site layout;
- average recurrence interval (ARI) flow data; and
- design criteria—typically ARI 100 for pipes and channels, ARI 1,000 year runoff for flood inundation of buildings or plant facilities.

Stormwater drainage design is in accordance with Australian rainfall and runoff methods for hydrology components and the DMR Guidelines and QUDM for both hydrology and hydraulics.

All stormwater dams are typically sized by catchment generation of flows at 100% runoff for containment volume. Erosion control and sediment traps were required where necessary.

Dirty water

Dirty water from the following would be directed to a sump collection dam:

- paved plant areas;
- bunded areas;
- tanker loading/unloading bays; and
- equipment wash-down areas.

Clean water dam

The clean water dam was designed to contain runoff from uncontaminated areas of the plant including roads, roof runoff from buildings, and areas adjacent the plant but not at risk of contamination.
The clean water dam would also contain approved discharges from the sump collection dam and the sediment collection dams.

**Drainage systems**

Provisions were made throughout the site for surface and underground stormwater drainage systems designed to suit catchment runoff. The basics of the systems will be:

- open channel drains, cross road culverts, underground pipe drainage systems along roadways where open channels may provide a safety hazard or prevent access to verges. Sanitation and sewerage; and
- a standalone sewage treatment plant caters for the operations workforce, with on site effluent disposal by irrigation or recycling for watering of landscaped areas.

The sewage collection system for the plant and BoP areas would consist of a gravity collection system to cater for most of the adjacent buildings draining to a package pump station for pumping to the package plant for treatment.

**Oily water/oily waste system**

The oily waste produced by the process plant is pumped to an oily–water separator making the water phase suitable for discharging to the clean water dam for recycling.

Waste oil from the oil–water separator would be removed from site by a waste oil contractor.

API–standard oil collection sumps would be located within bunded storage or process areas having a high possibility of oily runoff (e.g. diesel storage area, workshops).

### 7.3.5 Solid waste management

**Slag and ash handling**

The slag and/or ash produced by the gasifier depend on the gasification technology and the mineral matter in the coal feed.

Slag and ash handling and disposal systems also depended upon the characteristics and relative quantities of these materials. Typically, these included:

- bins, hoppers tanks;
- transfer is by conveyors/pumps/trucks and haul roads;
- stacking may be wet or dry or a combination of both;
- disposal is in ash dams or mine voids depending upon location;
- some beneficial reuse may be possible but is very case specific;
- the dumping area is typically lined with clay or HDPE and includes a drainage layer which also protects the liner; and
- runoff can be collected and recycled through the sediment dam clean water dam via the sediment dam.
Ash/slag placement areas would need to be designed for rehabilitation. Typically, general clay sealing material with returned topsoil cover for support of grasses and low shrubs on a free draining surface and defined drainage pattern were envisaged.

**Raw water treatment sediment cake**

These solids are collectively referred to as suspended solids.

The suspended solids removed during raw water treatment are typically collected and dewatered by a belt.

The sediment cake is benign and is disposed of in an unlined landfill site designated by the local Shire Authority or combined with the slag/ash for convenience. The filtrate is suitable for recycling to the raw water clarification plant.

**Salt cake**

The salt cake produced by the ZLD plant could be disposed to a hazardous waste facility or alternatively this waste material can be formed (using purpose–built equipment) into bales and transported by dedicated truck to an on–site double lined storage cell (with removable cover and leak detection) that would cater for long-term, on–site storage of these water treatment salts.

Upon filling of an individual on–site salt storage cell, the filled area would be capped with an impervious layer of capping material (preventing ingress of rain or other sources of water) and suitably surfaced, landscaped and revegetated to prevent erosion of the capping layer.

### 7.3.6 Buildings

Buildings would be air–conditioned, with standard office fit out. The plant and site facilities would have included the following.

**Visitor and induction building**

Consideration was given towards a location outside the secured site with a view over the facility. The visitor centre would have been provided with a separate access road and a separate drop off and parking area to cater for coaches (used by tours), as well as light vehicles. The proposed facility included:

- entry to give a clearly defined entry point that orientates the visitor centre within the building;
- display area;
- theatrette;
- storage space for temporary equipment such as chairs, tables and supplies;
- small office space for on site management and staff;
- staff room and kitchen—small space for eating and informal meetings; and
- external recreation space/courtyard.
Administration, operations and technical services

Building would have included:
- private offices, open offices, meeting room ablutions, kitchen, and general facilities;
- muster room—general meeting space for 40 persons. The room will be separated by accordion door (sound proof) and will have a retractable projection screen; and
- external covered awning for large gathering (full work force) includes BBQ facilities, table and bench seating and landscaping.

Laboratory

The laboratory and sample preparation facility and test equipment would be a single story building with 3.5 m wall height, with steel sheet trusses roof and an approximate area of 450 m². A fire fighting sprinkler/deluge system would be required.

Gatehouse

The gatehouse building would have been based on a brick on slab structure with sheet steel roof, air-conditioning and, standard office fit out and include an induction room.

Emergency services

The First Aid Room would have provided an external covered area for two vehicles, a small emergency/fire truck and ambulance. A helipad for emergency use, was recommended outside the security fence but adjacent to the gatehouse. The helipad would be a sealed landing area with standard markings only, with a sealed pathway for stretcher transfer from the first aid room to the helipad.

Workshop and warehouse

A single workshop or separate workshop buildings for gas cleanup and power plant maintenance teams would have been required, with each approximately 1,500 m².

Typical construction would be steel framed portals with heavy duty concrete floors in trafficable areas. Lightweight steel partition rooms would be provided for office, crib and toilet facilities as required.

The workshop would have housed and facilitated mechanical repairs of vehicles and equipment, with welding bays and an area for electrical maintenance, tool store, and general marshalling.

Additional facilities associated with the warehouse and store included the following:
- outdoor compound attached to the warehouse—generally unsealed medium-duty gravel pavement with secondary security fencing;
- undercover unloading area; covered hardstand—nominally 20% of the concrete hardstand (225 m²) area will be provided with steel frame and roofing typically five metres high; and
- the compound would include a concrete hardstand typically 1200 m² concrete surface area, nominally 0.25 m thick.
Hazardous storage building

Typically steel framed portal type construction with concrete floor and concrete block dividers, nominally 100 m², with specially designed segregation and spillage controls as well as safety systems and equipment.

Weighbridge

A weighbridge typically controlled by the gatehouse security crew would be provided. Typically, a commercially available weighbridge suitable for B–Double trucks would be considered. The facility would be located on concrete footings and with approach and departure concrete ramps off a plant access road.

Wash–down bay

The wash–down bay would have comprised of the following:

- heavy concrete slab approx 10 m x 30 m to suit the largest mobile equipment on–site, with drainage to a sediment trap and overflow to oil trap, then flow on to dirty water drain system;
- high pressure wash–down equipment—nominally four monitors, hose reels and high pressure, low flow spray and detergent applicators;
- provision of elevated walkways on each side to provide access to high equipment;
- potable water supply and safety shower/eyewash; and
- wash–down water recycling system.

7.3.7 Site works

Site–specific civil, structural and building work was required. Work needed to cover:

- site preparation including clearing of vegetation and stripping of topsoil, grubbing sand bulk earth works;
- formation of site access and in–plant roads designed to local standards including at least a 10 m wide sealed formation with centre and edge lines, guide posts and signage as required;
- in–plant roads are typically bitumen sealed heavy duty pavements with or without kerb and channel to suit the area of plant;
- heavy manoeuvring areas typically require concrete pavements and bunded truck loading and unloading bays also need to be in concrete; and
- unsealed gravel access roads are provided along plant conveyors, around the perimeter of the coal stockyard, along the overland conveyor and around the entire perimeter of the plant. These roads typically have a 6 m wide earthworks formation with side drains and low flow culverts or ford drainage crossings, and will be provided with a 4 m wide 100 mm thick gravel pavement.
Haul roads
A haul road was required to link the slag/ash handling facility with the slag dump area. The design vehicle for the haul road was either a Caterpillar 730E or 740E articulated 6x6 drive dump truck.

The road width would need to be set in accordance with local coal mining guidelines, which specify road widths to be 3.5 times the design vehicle width (12.25 m for a Cat 740) or twice the width for a one–way section such as the drive–through below the truck–loading hopper.

A water standpipe and a water truck for dust suppression watering may be required. Provision of a vacuum truck for ‘dry cleaning’ roads throughout the plant with disposal of dry waste to the slag storage may be an appropriate operating procedure to minimise run–off pollution issues.

Structural steel
Commonly available Grade 300 steel is used for structures, as high strength steel is normally not necessary.

Footing system design
Geotechnical data is normally not sought during the early phases of a project. Although site–specific geotechnical data has a significant impact on the type and overall cost of the foundation systems the use of generic assumptions based on the typical geology in the area and local site knowledge is normally sufficient for the level of definition required for early stages of project development. Allowable bearing capacity of 200 kPa to 250 kPa for all foundations is generally acceptable in the absence of more definitive information. A design criteria based on using wide pad footings provided a more conservative approach.

The major risk being the presence of a large area of soft alluvium, however this presents a risk skewed towards larger structures, such as the coal stockpile machines where the rail runway beams cover a large footprint. Initial estimates for small footprints were based on bored piers or piles as an alternative where soft ground is expected. Alternatively, pre–loading or excavation and replacement with engineered materials were considered.

Concrete, used for footings and slabs and structures typically use Grade N32 except where higher durability is required (trafficable areas for example) where Grade N40 is suggested. There was no advantage in the use of higher strength concretes within the BoP design.

Perimeter security fencing
Heavy–duty steel framed with, grated crossings of drainage paths security fencing along the facilities perimeter including, the slag/ash storage area is normally provided.

The main entry gate would be a steel framed, automatic sliding gate 10 m wide, and will be monitored and controlled by security/emergency staff at the gate house.

Secondary gates in the perimeter fence would be paired swing gates nominally 10 m opening.
Secondary gates would be located to suit access requirements, including:

- access to the coal truck dumping facility;
- as required to provide access for firebreak maintenance equipment; and
- any custody transfer points.

Access to the administration area from the main car park would be outside the secure zone. Personnel gates with swipe card operation or gatehouse over-ride was suggested.

**Secondary security fencing**

Secondary security fencing within the main perimeter would be provided to segregate certain areas from the key plant areas.

This fencing would be a chain wire and barb strand or razor wire fence to 2.4 m total height.

Areas segregated by secondary fencing are:

- special zones for drivers and their vehicles to access the unloading bays without entering the main plant area. Normally locked, swinging gates would be provided at several access points into the bulk liquids storage tank area and any other hazardous areas. These gates would be fitted with alarmed emergency escapes and normally only be opened for maintenance activities; and
- main high voltage sub-station.

**Rural fencing**

Depending upon plant location allowance for rural fencing and gates along existing roadways and site access roads external to the main perimeter fencing would be suggested to enable utilisation of external areas for other activities such as grazing.
8 Power Plant Site Selection

8.1 Context

The selection of a power plant site is an optimisation of potentially competing elements. The major items are:

- available land;
- land tenure;
- topography and flood levels;
- coal supply and quality;
- water supply, availability and cost;
- transmission network connection and marginal loss factor;
- location of CO₂ sequestration field;
- available infrastructure corridors;
- local infrastructure and services;
- proximity of potentially incompatible land use or services e.g. dwellings, schools, airports and air space;
- accessibility for transport of heavy/large plant components;
- proximity/availability of waste disposal sites;
- local and regional socio economic, permitting and political factors;
- proponents’ prior experience in similar projects; and
- special factors such as funding or other significant incentives.

8.2 Lessons Learnt

The key lessons learnt arising from undertaking site selection (for a greenfield IGCC development with carbon capture) are as follows.

In order to effectively conduct a site selection process, it is important for a proponent to have a well-structured process/methodology. The details below can be used by project proponents to develop a fit-for-purpose site selection process.

The process of site selection is by necessity a lengthy process requiring the proponent to engage suitably qualified resources to manage the process; this requires a combination of commercial and technical skills.

The early focus of site selection activities is to establish any fatal flaws to minimise cost/time resources being devoted to sites with fatal flaws.
It should be noted that the site evaluation process may utilise broad factored costs that may not be suitable in the development of the actual capex budget for the preferred site since the selection process is relative rather than absolute.

A significant factor is defined as one that has the potential to differentiate the sites. All common factors such as CO₂ capture rates, CO₂ field distribution piping and sequestration costs are ignored unless different sequestration sites are also being considered.

Non financial, intangible factors are compared using Multi-Criteria Analysis (MCA). This entails tabulation of all significant factors, determining their weighting and calculating a relative score.

Sensitivity studies are required to ensure that assumptions are not skewing the results. A range analysis and high-level probabilistic approach should be used to check the results.

In the ZeroGen specific case, it was the infrastructure requirements (i.e. power transmission lines/corridors, water supply pipelines/corridors) rather than IGCC facility requirements which were the significant factors differentiating the sites.

### 8.3 Site Selection

#### 8.3.1 Approach

Major influencing factors and trade-offs in selecting sites include:
- mine mouth vs load centre;
- coastal vs inland;
- proximity to sequestration sites;
- coal quality and supply factors; and
- site elevation.

Other lower level differentiating factors include:
- site elevation has a significant bearing on gas turbine output;
- competitive pricing of coal, including access to multiple independent sources of coal;
- longevity and security of coal supplies;
- coal quality can have a significant impact on capital cost due to parameters such as grindability and gasification properties; and
- for mine mouth sites coal supply logistics, truck vs conveyor vs rail where typically capacity and availability of existing facilities drive costs (i.e. loading/unloading, turning loops can be significant).

Site selection process is a combination of:
- fatal flaws analysis;
- financial factors;
- non financial (intangible) factors;
- sensitivity analysis; and
- risk.
Fatal flaws criteria were established and any sites that meet these criteria were eliminated from further consideration.

Tangible (financial) factors were determined by estimating relative costs for each significant factor for each site and comparing them in terms of NPV. The NPV analysis considers coal supply, plant configuration and infrastructure costs to provide relativity between sites.

A significant factor was defined as one that has the potential to differentiate the sites. All common factors such as CO₂ capture rates, CO₂ field distribution piping and sequestration costs were ignored unless different sequestration sites are also being considered.

Non-financial, intangible factors were compared using MCA analysis. This entailed tabulation of all significant factors, determining their weighting and calculating a relative score. Weightings can either be determined by a panel or by applying a paired criteria analysis approach. This entailed evaluating criteria relative to each of the other criteria and determined the overall relative importance of that criterion. This study utilised the paired criteria approach.

Sensitivity studies are required to ensure that assumptions are not skewing the results. A range analysis and high-level probabilistic approach should be used to check the results.

A conventional risk assessment approach was used to determine a risk score for each site.

The candidate sites were ranked for financial, non-financial and risk and the site that has the highest overall score is selected. A further weighting could have been applied if the scores are close.

### 8.3.2 Power plant location

#### Site selection process overview

Typical power station site selection processes are normally based on a series of optimisation studies, taking into account coal supply price and quality, power plant options and location, water availability and quality, land availability, transmission connection and access, transmission line length, and the availability of social infrastructure.

In the case of carbon capture projects, an additional dimension is in the form of a CO₂ transport system and sequestration costs.

A further consideration for the project, and a distinguishing feature of the gasification and carbon capture process compared to a conventional pulverised coal power station, was that the plant may be classified as a ‘major hazard facility’ under legislation that now exists in most Australian states. This legislation applies to large chemical processing plants such as oil refineries, chemical plants and large fuel and chemical storage sites where large quantities of hazardous materials are stored, handled or processed. This has the potential to increase costs due to the development of a safety case and its flow-on effects on plant design and operation.
TABLE 8.1: WORK SCOPES OF ENGAGED CONSULTING ENGINEERING FIRMS

<table>
<thead>
<tr>
<th>Consultant</th>
<th>Role</th>
</tr>
</thead>
<tbody>
<tr>
<td>Balance of plant</td>
<td>Determine the preferred option for coal transport, site layout, site infrastructure and access as well as water treatment and slag disposal.</td>
</tr>
<tr>
<td>Environmental</td>
<td>Determine the best option for an infrastructure corridor route for CO₂, water and possibly natural gas pipelines as well as a high voltage transmission route to the nominated NEM connection point.</td>
</tr>
<tr>
<td>Coal pricing</td>
<td>Provide a coal market analysis and pricing and coal resource assessment for each mine.</td>
</tr>
<tr>
<td>Connection and access</td>
<td>Determine the best option for the NEM connection point with regard to power flows and MLF as well as capital and operating costs for high voltage connection and access including the transmission line following the route provided. Provide an assessment of the impact of the project on other NEM generators in the region.</td>
</tr>
<tr>
<td>Pipeline</td>
<td>Determine CO₂ transport, water and natural gas pipeline capital and operating costs based on route selections provided.</td>
</tr>
<tr>
<td>Water supply</td>
<td>Determine an assessment of water availability and cost.</td>
</tr>
<tr>
<td>Gasification technology</td>
<td>Candidate coal evaluations and capital cost impacts of varying coal qualities.</td>
</tr>
</tbody>
</table>

NPV analysis

Site related issues are allocated to a capital and operating cost, which when added into the project financial model used for the Business Case, produce an NPV for each site.

The NPVs were then compared to each other for relativities rather than absolute values.

The site–specific aspects requiring financial examination included:
- CO₂ transmission pipeline capital and operating costs including any intermediate pumping costs;
- transmission connection and access locations including the cost of developing a transmission line and sub–station to the best connection point;
- Marginal Loss Factor (MLF) at the connection point;
- site preparation, general site works and bulk earthworks;
- site layout and its impact on costs;
- coal supply costs;
- coal transport means and distance from mine infrastructure and the plant site;
- capital and operating cost impacts from coal quality variations relating to total ash and flux quantities, total coal moisture, calorific value and sulphur content;
- flux cost of flux transport to site;
ZeroGen IGCC with CCS A CASE HISTORY

- Plant output based on site elevation (the plant net output changes at 1.5% for every 100 m elevation change);
- Water supply costs including alternatives such as source locations, costs of transport and relative water quality;
- Cooling means and temperature as well as having a capital costs impact can have a major impact on plant efficiency;
- Coal supply costs and quality impacts on plant performance and capital costs;
- Estimated cost of land based on publically available sales information for the area and local land agent background advice;
- Waste disposal;
- Permitting cost impacts;
- Revenue from any by-products e.g. sulphuric acid; and
- Logistics costs of transporting equipment to site. Plant and equipment is typically larger and heavier than in conventional power stations and depending upon location large costs may be involved in upgrading existing roads or relocating existing infrastructure. Alternatively significant additional construction costs may be involved if knock-down used as means of overcoming transport logistics limitations especially if vessel diameter is the issue.

Both capital and operating costs for each element need to be determined and entered into the financial model. It should be noted that the site evaluation process could have utilised broad factored costs that may not be suitable in the development of the actual capex budget for the preferred site since the selection process is relative rather than absolute.

An independently developed financial model was developed for the NPV analysis. This model was version controlled, and the official master version was held by the independent developer, who is the only person authorised to change the functionality of the model.

Coal supply

A number of site related options were assessed to determine the optimum site option for layout and coal transport. This uncertainty of coal supply was addressed in the risk assessments by allowing in the design for the installation of a future rail spur and unloading facility.

Water supply

Other options considered for each site included access to ground water, surface water harvesting, access to excess mine pit or wash plant wastewater, and water channel lining projects to free up water currently being lost due to evaporation and into the groundwater.

These latter options were considered potential future opportunities to reduce water costs, but were not sufficiently secure for the project base case.
Transmission connection and access

Studies to determine the optimal connection point into the NEM are conducted to ensure that the project output, and hence revenue, would be maximised. These studies examined load flows and MLF over the life of the project operations at a number of potential connection points and at various voltage levels.

A number of options were evaluated based on the project net output, the capacities of the various substations in the areas, and the voltages for connection. Any capacity constraints at the connection points were used to eliminate voltage options.

Sensitivity analysis

The financial model was used to carry out a number of sensitivity studies to determine whether a significant change to a key assumption change the ranking of the sites.

The base assumptions of the financial model for all locations included:

- CO$_2$ in–field distribution piping is the same for each location and is based on a fixed number of wells (noting that marginal changes in CO$_2$ production due to variations in plant output resulting from plant elevation were not considered significant);
- carbon capture is the same for all sites;
- connection and access requires the same equipment regardless of site location;
- electricity revenue pricing is common for all sites; and
- coal price is linked to export parity pricing for all sites apart from one, which is a domestic mine and so is de–linked from export parity pricing. A flat $/GJ has been used for coal pricing for all sites apart from one, which has been modelled at a $/GJ reflective of a domestic mine.

Risk assessment

In addition to the NPV relativities, a risk assessment was carried out on three critical aspects of the sites.

A comprehensive risk assessment for each of the sites needed to be conducted.

The following risks needed to be considered and assessed:

- inability to obtain sufficient high priority water allocation;
- inability to secure a long–term coal supply;
- no commitment from hosting company to participate in the project;
- local community does not accept the project because of visual impact, land use, potential noise impacts and impact on current social infrastructure;
- cultural heritage issues on the power station site stop or delay the project;
- cultural heritage and/or native title issues on the infrastructure corridors stop or delay the project;
- inability to acquire the project site;
- site and access road prone to flooding;
- inability to obtain all project environmental approvals from state and federal authorities;
- inability to obtain airspace approvals due to plume rise impacts (this is only applicable if the site is in proximity of an airport);
- lack of skilled workforce and construction workforce accommodation;
- inability to procure electricity transmission easement;
- inability to procure CO₂ pipeline easement;
- inability to procure water pipeline easement;
- inability to transport alternative coal supply to the site;
- inability to take coal deliveries due to mine operational constraints;
- difficulties with construction of the power plant on the site; and
- timing risks including:
  - coal not being able to be delivered to the project to meet the commissioning date;
  - water not being able to be delivered to the project to meet the commissioning date; and
  - insufficient definition and confidence to toll gate the study into the next phase especially around coal and water supply.

These risks needed to be assessed using the proponents risk assessment process.

In addition to these higher-level risks, and as part of the Site Evaluation Study, a comprehensive risk assessment for each site and each site option needed to be conducted.

**Multi-criteria analysis of non-financial site factors**

An assessment of the non-financial factors of a power station site were assessed and ranked using a MCA. The MCA process compares these non-financial factors with each other to provide a preference weighting for each aspect. Each site was then assessed for its ability to deliver each of the non-financial factors to produce a ranked score.

The non-financial factors considered were:
- access to social infrastructure;
- satisfactory relationships with the traditional owner groups;
- integration of the project and personnel into the local social fabric;
- access to local skilled labour and engineering capability;
- close working relationship with the host mine;
- ability to permit the site (community support and no objections from neighbours);
- ability to attract a workforce;
- political, stakeholder, local government support for the project site; and
- access to multiple coal sources.

The factors that attracted the highest weightings were related to political, stakeholder and local government support for the project site, and the ability to permit the site with no objections from neighbours and with community support.

The methodology and factors considered are shown in Figure 8.1.
## ZeroGen Non-financial Site Selection Criteria

### Paired Criteria Evaluation

<table>
<thead>
<tr>
<th>A. Access to social infrastructure</th>
<th>2B</th>
<th>0</th>
<th>1A</th>
<th>2E</th>
</tr>
</thead>
<tbody>
<tr>
<td>B. Satisfactory relationships with traditional owner groups</td>
<td>2B</td>
<td>2B</td>
<td>2B</td>
<td>1B</td>
</tr>
<tr>
<td>C. Integration into social fabric</td>
<td>1D</td>
<td>2B</td>
<td>2E</td>
<td>2F</td>
</tr>
<tr>
<td>D. Access to local skilled labour/engineering capability</td>
<td>2D</td>
<td>1E</td>
<td>1B</td>
<td>2F</td>
</tr>
<tr>
<td>E. Close working relationship with host mine</td>
<td>2F</td>
<td>2F</td>
<td>1G</td>
<td>2H</td>
</tr>
<tr>
<td>F. Ability to permit site (neighbours &amp; community support)</td>
<td>2F</td>
<td>1G</td>
<td>2H</td>
<td>2H</td>
</tr>
<tr>
<td>G. Ability to attract workforce</td>
<td>2F</td>
<td>2G</td>
<td>2H</td>
<td>2H</td>
</tr>
<tr>
<td>H. Political/stakeholder/local gov. support for site</td>
<td>2F</td>
<td>2G</td>
<td>2H</td>
<td>2H</td>
</tr>
<tr>
<td>I.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>J.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Maximum

<table>
<thead>
<tr>
<th>Alternative Analysis</th>
<th>Raw Score</th>
<th>Importance - normalised out of 10</th>
<th>Total</th>
<th>Rank</th>
</tr>
</thead>
<tbody>
<tr>
<td>Callide</td>
<td>3 4 2 4 4 4 4 3 4</td>
<td>6.4</td>
<td>62</td>
<td>4</td>
</tr>
<tr>
<td>Rolleston</td>
<td>4 2 4 4 4 1 3 3 1</td>
<td>12.2</td>
<td>68</td>
<td>2</td>
</tr>
<tr>
<td>Ensham</td>
<td>4 2 3 3 4 4 3 4 4</td>
<td>10.5</td>
<td>69</td>
<td>1</td>
</tr>
<tr>
<td>Blackwater West</td>
<td>4 2 3 3 4 4 3 4 4</td>
<td>10.5</td>
<td>69</td>
<td>3</td>
</tr>
</tbody>
</table>

Excellent = 5  
Very Good = 4  
Good = 3  
Fair = 2  
Poor = 1

How well does each site deliver the criteria.
Storage Evaluation

Executive Summary (Storage)

Lack of adequate storage resource was one of the major reasons for the cessation of the ZeroGen Project. For historic reasons, the project could not develop a portfolio of exploration prospects and was required to take resource exploration risk in parallel with significant expenditure on IGCC plant studies. In effect, this put all Prefeasibility Study (PFS) funds significantly more at risk than in similar projects and entirely dependent on a single area of geology proving to be suitable.

The available Northern Denison Trough (NDT) area had been selected based on the capacity needs of an earlier demonstration scale project with a 20 times smaller storage requirement. Significant reservoir performance risk had been identified, however, this smaller scale was considered to be within the bounds of possibility. In late 2008, the funders’ committed to accelerated deployment and to increase to commercial scale. This commitment was with full realisation that this would ‘steepen the risk curve’. It was a necessary decision. While always risking hindsight criticism, without this commitment, the robust view which ZeroGen developed of the real challenges and costs of commercial–scale deployment in a real setting would simply not have been possible. Many of the cost, schedule and storage resource estimates available in current literature are likely to be over–optimistic.

ZeroGen’s PFS work program included significant exploration drilling and dynamic well testing (over 70% of PFS cost). In the end, the critical resource risk eventuated and geological properties were found to be at the very low end of expectations. It was a core purpose of the exploration program to discover this prior to making much larger investments in an IGCC plant.

The NDT area is not suitable for commercial–scale CO₂ storage at the injection rates and within the time frame which the ZeroGen Project and Commonwealth CCS Flagships program demanded. The required rates could not be sustained and unit costs of injection and transport alone would be of the order of $150/t.

Going forward, a balanced exploration portfolio could have been built in the Galilee and Surat Basins which would have been well removed from large areas of potential resource conflict (particularly related to coal mining and Coal Seam Gas (CSG) in the Surat Basin). Preliminary geotechnical indications in the Surat Basin were positive; secure storage might be possible at commercial rates and at costs of less than $40/t. However, this view was based only on desktop analyses. Uncertainty, caused by lack of site specific, modern data dominates current evaluations. Between $90 and $180 million and two to four years would be required, applying ZeroGen lessons, to acquire new well, test and seismic data to establish suitability or otherwise of high graded areas. There would remain a discrete chance that the areas would not prove technically (or otherwise) suitable.
Virtually all promising areas for GHG storage in Queensland are within geology which is an integral part of the Great Artesian Basin (GAB), as defined in various state and federal statutes. However, there are significant and large areas which are well removed from existing users and significantly deeper than current abstraction points where ground water residence times are estimated to be in excess of one million years. It would be essential to establish a sound geotechnical basis and new data with which to evaluate whether or not there would be any impact of any significance on groundwater usage or users from commercial-scale CO₂ injection. Extra cost and complexity would need to be included in draft exploration programs to account for this.

In the context of Queensland and the GAB, it was considered strategically essential to conduct these exploratory storage studies as soon as possible because without a confirmed, licensable storage resource the State’s pathway to low carbon emissions would have to be significantly different.

While further scientific investigations are essential, they are not sufficient. If preliminary evidence continues to be favourable for secure, commercial-scale storage, then socio-political aspects of developing CCS projects in the GAB regions and in tandem with other major resource projects are likely to be complex and necessarily time consuming. A first-of-a-kind Environmental Impact Statement (EIS) process might be expected to take two to five years and time from commencement of exploration drilling to start up of an integrated IGCC plant with CCS might reasonably be expected to be 10 or more years with significant potential for slippage.

Without firmer geotechnical evidence and scientific investigation, notwithstanding issues relating to absence of adequate project financing, ZeroGen’s management recommended that further investment in IGCC plant should be paused until greater confidence in storage could be achieved.

**Top Five Storage Lessons Learnt**

**Industrial scale is not a simple scale-up from demonstration scale**

For efficient investment in storage exploration, CCS projects including storage must be approached at commercial scale. It is this scale that, in and of itself, increases confidence and enforces significant reality checks on schedule, cost and performance predictions. Desktop analyses are inadequate, it is likely that a significant (drilling, testing and seismic) program will be required and these will be *funds at risk*.

**Measured management of pace of ‘first-of-a-kind’ projects is critical to subsequent wider deployment**

The first CCS projects carry the burden of ‘proof’ for follow-up wider deployment. Risk management, approaches to Environmental Impact Assessments (EIA) and public consultation will need to be conservative and measured—this requirement runs counter to an urgent push to create a first-of-a-kind development.

CCS project schedules need to be risk optimised, such that larger investment decisions in plant and capture are not taken before achieving sufficient confidence that storage (i) is present, (ii) will perform as required; and (iii) is licensable/acceptable.
Pre–FEED and feasibility risks and costs are heavily weighted to the search for and appraisal of storage

Prior to Front–End Engineering and Design (FEED) and probably Prefeasibility stages for an integrated CCS project, the majority of risk and expenditure lies in finding and appraising storage resources to a sufficient level of confidence (in storage security and sustained injectivity) to justify a larger investment in plant. In ZeroGen’s case, over 70% of expenditure to end PFS was related to storage (and for a failed resource)—20% to plant and capture. Forecasts to get an entirely new storage area to storage maturity would have concluded with over 90% of costs to end PFS being storage related.

Storage is a natural resource, a portfolio exploration and appraisal approach is needed

Storage exploration and appraisal requires a portfolio approach with more than one option to allow for ‘failures’. A large amount of expensive data gathering should be expected and while success rates might be higher than in the oil and gas exploration sector, failure rates and costs and delays are likely to be significant.

Storage exploration and appraisal data acquisition and study programs should be focused on reducing large geotechnical uncertainties. Evidence (data and analyses) which can polarise storage risk assessment is of highest appraisal value and may allow for a rapid cessation of exploration spend.

It is essential to develop a clear storage decision criteria, with both confidence levels and performance targets, which will define whether subsequent stages of (often larger) investment in plant should go ahead.

When defining storage resource requirements it is essential to discuss the consequences and trade–offs between injection rate and/or cumulative volume objectives

Natural storage resources and field developments which are required to match specific injection rate requirements are likely to be significantly different from those which must only fulfil a cumulative volume target.

The former may require significant and continuous in–fill drilling and has implications for sparing, redundancy and pressure management (including aquifer off–take). The latter has implications for operational venting, the time variant carbon intensity of emitting plant. Both have significant implications or may set constraints on capture capex and phasing.

Appraisal of storage site and predictions of ‘reserves’ and performance must be based on long-term, dynamic well testing (production or injection) and not on static–based derivations of capacity as is currently the case for most published estimates. Many published basin–wide estimates are likely not to be a useful indicator of the amount of practical storage available.

In addition to extended well tests, conceptual, engineered field development plans are essential and need to be constrained by real surface and environmental factors and potential sub–surface risk–features. Development drilling sequences need to be simulated, account for static and dynamic uncertainties and show how injection rate might be installed over time and might need to be maintained by in–fill drilling, venting or development of and transport to other sites.
Part A
Northern Denison Trough
1 NDT Storage Review Structure

1.1 Context

ZeroGen undertook two main types of storage evaluations. The first, centred on the Northern Denison Trough (NDT), involved extensive drilling, testing, core analyses and modelling. The second type centred on the younger Surat Basin and essentially comprised only desktop studies in preparation for GHG tenement applications, which were made possible almost at the end of the Prefeasibility period.

The NDT exploration program commenced in 2006, before the transition of the ZeroGen Project from a demonstration–scale project (several configurations were considered) to a commercial–scale project. The area was selected, and became the only area licensed for GHG exploration, based on a much smaller storage requirement. The first six wells were intended to find mature sufficient storage for around 3 million tonnes at around 100,000 tpa. The commercial–scale configuration (from late 2008 onwards) required 60–90 million tonnes of storage at 2 to 3 Mtpa.

The following NDT chapters refer to licensed, technically mature acreage with an extensive data–set. This work required a screening investment of around $130 million. In contrast, subsequent chapters relating to possible new tenements in the Surat Basin represent an investment of less than $2 million.

1.2 Lessons learnt

It is critical to define stage–gate decisions in terms of confidence levels and performance requirements for a storage resource. These require discussions on risk tolerance with funders and should guide when ‘ready’ to invest further (and more) in associated plant and capture developments and when work on a resource should cease.

It is essential to define the vertical and lateral boundaries of the sub–surface ‘container’ which is the unit of analysis for exploration and appraisal efforts. It is only with reference to container boundaries that seepage or leakage can be evaluated and that capacities can be discussed.

Storage assessment starts with as complete a geological description of the resource as possible. Such a description should note all geological uncertainties and ambiguities. Exploration and appraisal data acquisition plans should focus on those uncertainties which have the greatest potential impact on storage performance and on stage–gate decisions.
1.3 Storage and the Post–prefeasibility Decision

In the context of ZeroGen’s Capital Investment System (CIS) and its commercial–scale PFS, the storage exploration and appraisal work was designed to inform the end–PFS decision:

- Should the project as a whole continue to Feasibility, should it cease or should it do additional appraisal work before revisiting this decision (and if the latter, what work would be required)?

The decision to continue would have required an investment of additional funds at risk of over $400 million in Feasibility Studies and early procurement.

1.3.1 Original storage performance and confidence criteria

To address this decision, an assessment of (i) the expected performance of the appraised storage resource and (ii) the level of confidence in that assessment was required.

For the end of the PFS phase ZeroGen devised a three level performance test as follows:

**TABLE 1.1: ZEROGEN ORIGINAL NDT STORAGE DECISION CRITERIA**

<table>
<thead>
<tr>
<th>Ref</th>
<th>Original decision criteria for progression of NDT as the storage location after PFS—under the schedule driven project</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>To at least a <strong>P50 level of confidence</strong>.</td>
</tr>
<tr>
<td>1.1</td>
<td>The site can <strong>store securely</strong> 60–90 mln tonnes in sites and under operating conditions in which containment can be assured.</td>
</tr>
<tr>
<td>1.2</td>
<td>The site can accept <strong>sustained injection</strong> of 2–3 Mtpa in sites and under conditions in which containment can be assured.</td>
</tr>
<tr>
<td>1.3</td>
<td>Site <strong>unit development costs</strong> for carbon transport and storage will be less than $50/t (full–life cycle).</td>
</tr>
</tbody>
</table>

All three tests were required because:

- **Natural resource limit**  
  It might simply be that the naturally occurring geological resource (connected, accessible pore space) was inadequate.

- **Pressure constraints**  
  It may be possible that 60 (84) million tonnes of storage was in place, but it might not be able to be filled at sustained rates which matched the capture rate of 2 (3) Mtpa, for example, due to safety pressure constraints such as avoidance of fracturing the seal or interference between closely spaced in injection wells.

- **Cost constraints**  
  The resource may have been in place and it may have been technically possible to inject at sufficient and sustained rates for the required project life, but costs, for example well engineering or drilling, might have been prohibitive.

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1 In effect, this is assured via a set of reviewed dynamic flow and mechanical models which are constrained by site–specific data acquired during the exploration and appraisal phases.
For ZeroGen, the early exploration and appraisal efforts were conducted in parallel with PFS efforts for IGCC with capture (the Plant). The project was schedule driven.

### 1.3.2 Risk optimised storage performance and confidence criteria

ZeroGen management developed and proposed an alternative decision pathway as follows.

> It was suggested that exploration should ideally progress to a P50 level of performance confidence in parallel only with Scoping level Plant studies. Contingent on confidence, a circa $50 million Plant PFS could continue in parallel with subsequent storage site appraisal. However, the larger, $460 million Plant Feasibility/FEED phase should not go forward until a far higher level of storage confidence is attained.

A revised test was articulated as follows.

**TABLE 1.2: ZEROGEN RISK OPTIMISED STORAGE DECISION CRITERIA, PRE-FEED**

<table>
<thead>
<tr>
<th>Ref</th>
<th>Revised and recommended decision criteria for progression of a storage location in a risk optimised project into an (expensive) FS/FEED phase.</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>To at least a <strong>P75 level of confidence.</strong></td>
</tr>
<tr>
<td>1.1</td>
<td>The site can store securely 60–90 mln tonnes in sites and under operating conditions in which containment can be assured².</td>
</tr>
<tr>
<td>1.2</td>
<td>The site can accept <strong>sustained injection</strong> of 2–3 Mtpa in sites and under conditions in which containment can be assured².</td>
</tr>
<tr>
<td>1.3</td>
<td>Site <strong>unit development costs</strong> for CTS will be less than $50/t (full-life cycle).</td>
</tr>
<tr>
<td>2</td>
<td>A completed, independently reviewed <strong>Field Development Plan</strong> (FDP) for CTS (which is required to fulfil, see 1.3 above).</td>
</tr>
<tr>
<td>3</td>
<td>An approved and/or independently verified <strong>Environmental Impact Statement</strong> relating to storage and transport.</td>
</tr>
<tr>
<td>4</td>
<td><strong>A Storage Lease</strong>—which requires assurance of containment, 1.1; an initial FDP, 2 and some surety of supply, 3 above.</td>
</tr>
<tr>
<td>5</td>
<td><strong>Coordination Agreements</strong> with overlapping tenements rights holders.</td>
</tr>
<tr>
<td>6</td>
<td><strong>Surety of CO₂ supply.</strong> The FEED investment decisions for CTS and IGCC are mutually dependent. If storage proceeds in advance of IGCC, then if an <strong>integrated funding, integrated development or a supply agreement</strong> with the IGCC project would be required.</td>
</tr>
</tbody>
</table>

However, for the purposes of this Case History the NDT storage resource was evaluated (and failed in any case) against the looser, original three level (P50) test.

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² In effect, this is assured via a set of reviewed dynamic flow and mechanical models which are constrained by site–specific data acquired during the exploration and appraisal phases.
1.4 Structure of this NDT Evaluation

Exploration of the NDT commenced in 2005/6 and continued until late 2008. The target of that work was to discover and develop storage of circa 3 million tonnes total (100,000 tpa). This is some 20 times less than the later commercial-scale project would require. Consequently, while significant amounts of data had been obtained (including six wells), the evaluation of the storage performance and confidence had not been with reference to commercial scale.

While integrating previous data, a new drilling, testing and study work program was constructed in early 2009 to address the original three level test by mid 2010. It is this last program which is largely described herein.

The basic ‘container’ under analysis is first defined. The construction of geologic models and synthesis of geological understanding is then described leading to an understanding of static properties and their predictive uncertainty (Section 3). A series of dynamic well tests are next described which calibrated the emergent geological models, in-situ and at bulk scale (Section 4).

A rich, internally consistent geological model of the container, calibrated by dynamic flow tests was then the basis for storage performance assessment in terms of injectivity, containment, and capacity (Sections 5, 6 and 7). Constraints to development were investigated in depth and the cost and performance of a notional field development concept was investigated (Section 8) to arrive at well count and unit cost estimates (Section 9). A discussion on storage ‘reserves’, (Section 10), suggests that there is no useful quantification of practical storage resource from static volume calculations commonly reported and that dynamic tests are essential.

A final (geotechnical) risk and uncertainty analysis (Section 11) showed little remaining chance of a development which would satisfy the required sustained injection rate and unit cost targets.

1.5 Unit of Analysis—The Container

The size and extent of a ‘container’ available for CO₂ storage (Shell–ZeroGen, 2010b), had to be defined as follows:

- within a licensed tenement;
- within named sequestration reservoirs; and
- beneath a defined cap–rock or rocks.

ZeroGen’s tenement holdings comprised two GHG Exploration Permits EPQ1 and EPQ2. The further areas QLR2010 1–7 (also referred to as DAQ–1) could have been available in an altered tenement licensing round (Figure 1.1).

With reference to Figure 1.2, the main reservoir of interest (based on earlier data acquisition) was the Permian, Catherine Formation Sandstones. Within the total licensed area of EPQ–1 and EPQ–2, the available area with supercritical conditions in the main Catherine Reservoir was 481 km² out of 886 km² (this figure still includes environmentally sensitive areas, areas of restricted access and other possible exclusion zones).
The top of the container was taken to be the top of the Black Alley Shale. This shale is the regional seal to the potential CO₂ storage reservoirs in the storage complex and is proven to seal gas in the same contiguous formations in gas–fields next to the ZeroGen tenements.

Within the storage complex the proposed main reservoirs for CO₂ storage were the Upper Aldebaran Sandstone, the Freitag Formation and the Catherine Sandstone—with the main focus being the Catherine Sandstone, due to its generally higher permeability.
An overlying formation, the Mantuan Formation, might have been an additional, potential injection reservoir within the storage complex. Initial assessment of the reservoir characteristics indicated that the formation has moderate and highly variable poro–perm characteristics. However, its depth over most of the key ZeroGen tenements was less than 740 m bGL. For this reason characterisation and testing of this unit was not a primary consideration during the PFS, though it was considered as upside (subsection 9.5).

The shale intervals of the Peawaddy and Ingelara are the primary seals for the Catherine and Freitag and have fairly consistent thickness in this area.

Overall, the lateral extent of the container was defined by the tenement boundaries (less some margin to allow for migration). The vertical extent for injection was defined by virgin pressures which allows for supercritical storage and the Black Alley Shale.

A schematic cross section (Figure 1.3) shows that EPQ2 covers a synclinal area with gas fields up dip to the West formations shallowing to outcrop in the East. EPQ1 to the South covers this same syncline and the smaller, shallower syncline to the West of the gas–fields.

**FIGURE 1.2: SIMPLIFIED STRATIGRAPHIC COLUMN OF THE NDT**

![Figure 1.2: Simplified Stratigraphic Column of the NDT](image)

*Note: Showing possible injection horizons and ultimate top seal (Black Alley Shale).*
FIGURE 1.3: A WEST EAST CROSS-SECTION OF ZEROGEN’S NDT HOLDING, SHOWING APPROXIMATE POSITION OF TENEMENT

Note: Showing the extent of the potential GHG storage complex.
2 Geologic Framework and PFS Modelling

2.1 Context

A major geological integration exercise was undertaken to understand the depositional environment, define a sequence stratigraphic correlation framework and ascertain the palaeogeography of the area. This was with a view to creating predictive models. Importantly the work involved geologists with extensive local knowledge as well as a larger team from Shell’s centre of excellence for CCS in Bangalore.

Fundamental geological work, (Shell–ZeroGen, 2010) formed the framework for all subsequent performance (and risk) analyses which are summarised in this document.

The benefits, in terms of decision confidence, of successfully creating deterministic predictive models could be large. In particular, ZeroGen sought an improved understanding of:

i. how depositional systems analyses might help predict better the permeability of main Catherine Sandstones, particularly those with a NE provenance; and

ii. how depositional and digenetic analysis might inform views on heterogeneity and reservoir continuity.

While many of the findings are specific to the sites investigated, a series of technical discussions are included hereunder to illustrate the extent to which project developers might expect to undertake fundamental geological exploratory research, even in relatively mature areas. The type of analyses undertaken are expected to be similar to many onshore coal basins elsewhere in the world.

2.2 Lessons Learnt

The requirement for significant well–based and regional geological studies may be extensive. Costs for well drilling and logging may represent only around 50% of total exploration costs with around 25% of costs for program management and studies.

The Permian sequences of the NDT, had historically been characterised largely in the context of gas production from nearby anticlines. However, appraising site–specific complex depositional environments and digenetic history, required a significant amount of additional data and geological analyses in the synclinal areas which were mooted for storage.

Extensive characterisation of the potential reservoir sequences indicated a very complex digenetic history. Vitrinite reflectance data indicated a maximum paleo–depth of burial of 5 km to 6 km at which time geothermal gradients estimated to be as high as 5°C per km, existed in the NDT.

3 Example: ZeroGen’s Geotechnical Manager, Nick Hall, Vic Ziołkowski (stratigrapher) and Dr Julian Baker (petrology) each with well over 20 years’ experience in these Queensland basins.
Multi–cyclic deposition, large paleo–burial depths, high–temperature gradients and very complex diagentic effects lead to a likely high degree of vertical heterogeneity as seen in the cores. It is also likely that small scale–lateral heterogeneity in these types of systems is also high. This means that while deposition trends and facies might be predicted in a gross sense, no predictive model is possible, which might guide field development and optimisation.

Conditions were conducive to quartz overgrowth cementation and this is the main digenetic effect in the cleaner sandstones in all potential reservoirs (Aldebaran, Freitag Formation, Catherine Sandstone and Mantuan Formation).

This silicification has severely overprinted the control of depositional environment and, more specifically, texture on porosity and permeability. Accordingly, relationships between porosity/ permeability and depositional facies are not strong.

Preservation of porosity and permeability in the NDT is complex and other than gross regional trends based on deposition and provenance arguments, no predictive model was found useful for deterministic reservoir modelling—though it did drive the direction of the exploration program to the North.

Evidence indicated that the more labile (immature) ‘dirty sands’ such as the distributary facies may be better exploration targets than the clean quartz rich sands of middle to upper shoreface facies. Furthermore, these sands were more likely to be coarse grained and feldspar rich the closer they are to the sediment provenance area. Provenance studies were essential.

Moderate to high permeability in the Catherine Sandstone in ZG–5 can be attributed to the presence of authigenic grain–coating clay, coarse grain size and, particularly where the channel section is very coarse grained, relatively high feldspar content.

Rock typing showed that the Catherine Sandstone is the dominant contributor to well k.h in most of the ZeroGen wells and that the Catherine core derived, rock–type k.h, improves towards the north and west of the tenements.

Geomechanical and geochemical (reactivity) issues were also researched and were on the whole favourable to storage. With high rock strength and fracture gradients and a low proportion of reactive mineralogies.

Finally, Routine Core Analyses (RCA) indicated that overburden corrected brine permeabilities were of the order of 65% of the initially measured ambient air permeabilities. Importantly, this reduction did not allow for in–situ, bulk property effects of reservoir scale heterogeneity. Only dynamic test data could calibrate these scale effects. However, fundamental geological analyses are still required in addition to well tests to increase confidence on interpretations and the degree of lateral applicability of these.
2.3 Geological Deposition

2.3.1 Depositional environment

The Permian sequence of the NDT was deposited in a wave dominated deltaic system flowing into a NE–SW orientated shoreline. Sedimentation off the shoreline was controlled mainly by eustatic events with sedimentation rates less than 100 m per million years. Due to the gentle slope of the continental margin minor rise or fall in sea level shifted the coastline to large distances as evidenced by thin extensive coastal sediments and marine siltstones which can be correlated over many kms.

The wave dominated delta system can be divided into three major sub–environments, demonstrated in Table 2.1.

<table>
<thead>
<tr>
<th>Sub–environment</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lower Delta Plain</td>
<td>Lower Delta Plain is characterised by Distributary Channels, over bank Coastal Plain facies and Coastal Mire. This sub–environment includes the best reservoirs in this area.</td>
</tr>
<tr>
<td>Distributary Channels</td>
<td>Based on the description of the ZeroGen core these Distributary Channels in the area are believed to be low sinuosity braided in character. They are mostly multi–storeyed with net thickness of channel fill about 5 m–15 m. Individual channels are medium to coarse grained cross bedded sandstones with blocky or fining upward log motifs. Most commonly the channels begin with a pebble lag followed by coarse to medium grained feldspathic sandstone and terminates as fine grained sandstone or siltstones.</td>
</tr>
<tr>
<td>Coastal Plain</td>
<td>Coastal Plain facies are interbedded mudstone and siltstone with occasional burrows and rootlets. Siltstones are fine to medium grained parallel laminated or ripple laminated sandstones with serrated log profile.</td>
</tr>
<tr>
<td>Coastal Mire</td>
<td>Coastal Mire is characterised by coal, coaly shales and carbonaceous shales. Coals are typically a few tens of cm thick but thicken up to a meter in the north (EQP–2).</td>
</tr>
<tr>
<td>Delta Front</td>
<td>Delta Front can be divided into four facies. These are moderate to poor reservoirs.</td>
</tr>
<tr>
<td>Proximal Delta Front</td>
<td>Proximal Delta Front (Upper Shoreface) is the landward part of the Delta Front. It is characterised by fine to medium grained well sorted sandstones with coarsening upwards log motifs. These are mostly quartzose in nature and tight due to quartz cementation.</td>
</tr>
</tbody>
</table>
Distal Delta Front (Lower Shoreface) is the seaward part of the Delta Front. These are characterised by interbedded sandstones and shaly heterolithics with a coarsening upward trend.

Distributary River Mouth is defined as the distal part of a channel where it meets the Delta Front.

Mouth Bar is the wave reworked distributary river mouth facies. These are oriented parallel to the shoreface and the geometry is controlled by wave action.

Offshore facies is characterised by thick marine shales deposited on a marine shelf. These include the non reservoirs shales.

Log facies were sub-divided and simplified into above geological facies.

### 2.3.2 Sequence stratigraphy

A revised sequence stratigraphic framework of the NDT was determined from the detailed facies and ichnological description of the cores and analysis of well logs. A complete sequence wherever preserved would include the Highstand, Lowstand and Transgressive system tracts. The extensive core database which was established (circa 7 km from 12 wells) allowed depositional sequences to be analysed in detail.

For the former, flooding surfaces at a well are identified by locating the point of maximum separation between the neutron and density porosities with the lowest shale resistivity values as it represents the purest shale. In cores they are recognised as the boundary between the ravinement surface and the overlying highstand unit.

Lowstand system tracts were present in all of the wells as far south as ZG–5 and were correlated to thin channels in the most distal well ZG–4. The base of these tract is usually marked by erosive channel sands which could be recognised from cores from the pebble lag at the channel base but were difficult to identify in well logs.

Transgressive systems tracts consist of gravel lags that are bioturbated and pass rapidly into holomarine siltstones containing crinoids, phycosiphon traces and shell debris. This change occurs within several meters vertically and suggests a gently dipping shelf with deep penetration (incursion) landwards of the coastline in response to sea level changes.

All major sequence stratigraphic markers, such as the flooding surfaces and sequence boundaries, were identified from the cores in the ZG–3 to ZG–12 and the correlation was extended by correlating with the well logs in the non cored wells. This sequence stratigraphic framework was used in the full field static modelling to subdivide formations into different zones.

A type log showing different system tracts and log signature of the facies is shown in Figure 2.1.
2.3.3 Palaeogeography

A palaeogeographical understanding was based on the analysis of palaeocurrent data from image logs and facies proportion pie plot for each of the lowstand units. During the highstand almost all of the area was under marine influence. At other times the delta setting and relative position of the facies remains the same but the shoreline moves forward and backwards based on rise or fall in the eustatic sea level.

Palaeocurrent directions from the tabular cross beds were identified from image logs and rose plots were drawn for each lowstand unit. Pie plots for the facies proportions at each well were analysed together with the rose plots to delineate the location and extent of the different sub environments. An example of this for two lowstand Units in the Catherine Formation is shown in Figure 2.2.

In overview, three main elements of the NDT palaeogeography are likely to control reservoir distribution.

Location and geometry of the shoreline

Bann and Fielding (2004) suggest a regional palaeoshoreline orientation of SSW–NNE. The same gross trend was used to model the shoreface in the ZeroGen static model. It was however, difficult to determine the location of the shoreline with certainty, due to only few well penetrations all located along a linear NW trend.
Catherine Lowstand Unit 2 (CS2-CF2)

Facies
- OFF
- DDF
- PDF
- MB
- CH
- RM
- CP
- CM

Depositional Environment
- Lower Delta Plain
- Delta Front
- Offshore

Figure 2.2: Location and extent of the delta during the Catherine Lowstand 1 and 2
Channel orientation and geometry

Palaeocurrent orientation data were used to give the major palaeocurrent flow direction towards south–east. Based on the petrographic analysis, the Retreat granite to the NW was considered as the provenance for the Catherine channel sands. Hence the major palaeocurrent flow direction modelled was taken as northwest to southeast with a spread of 20°. The area is located less than 100 km from the main provenance (Figure 2.3). Channels were considered to be of braided character with low sinuosity.

The Freitag and Aldebaran Sandstone facies penetrated in ZG–6 (in the west of the area) are considered to be more proximal compared to ZG–5. The permeability of these facies is higher compared to the permeability seen in other wells. This raises a possibility of an additional eastward channel orientation locally towards the west, sourced from the basin margin. Therefore, the provenance map for Catherine Sandstone (Figure 2.3) also shows an eastward flow.

An upper Permian isopach (Figure 2.3) illustrates a variation in thickness with a thickening along the (present–day) western bounding fault. This axial thickening of the Denison Trough shoals towards the northwest and it is along this axis that the bulk of the sediments entered the basin.

**FIGURE 2.3: CATHARINE PROVENANCE AND TRANSPORT DIRECTIONS**
Channel belt width

A low sinuosity braided, stacked character suggests a mobile channel belt with many small erosional based sand bodies that are laterally and vertically stacked to comprise bar form deposits and bed load sheets. This is consistent with nearby Aldebaran Sandstone outcrops where several stacked channel sands can be seen eroding the lower channel deposits (Figure 2.4).

The thickness of the multi–storeyed channel belts encountered in the well penetrations ranges from 1 m–15 m. A Shell proprietary geometric modelling tool for channels was used to inform the ‘thickness to width’ ratios. The search for global analogues indicated that the channel belt width for a 10 m channel belt height can range from a few tens of metres to a few kilometres in this type of geological setting. Both this degree of uncertainty and potential heterogeneity were significant impediments to building predictive flow models.

Water injection in ZG–11 in the Catherine Sandstones indicated the presence of parallel boundaries consistent with the channel model. The width of the channel estimated from the well test lies at the lower end of the estimated range from the Shell channel database (subsection 4.4.5, Chapter Three, Part A). However, boundaries estimated from the well test were an average boundary for the injection interval, defined by a change in permeability of an order of magnitude and not by geological facies or known geometries.

Thus, the static modelling workflow was informed by global analogues, outcrop studies and well tests to set channel widths and variogram ranges for property modelling. Channel widths used for modelling range from 500–100 m. A minor range of 300 m and major range of 1500 m was used in the variogram for property modelling in channels to restrict properties within the range seen in the well test.

FIGURE 2.4: GEOMETRY OF STACKED CHANNEL AND MOBILE CHANNEL BELTS IN THE ALDEBARAN FORMATION
2.4 Petrology

Petrological analyses were a fundamental tool in ZeroGen’s attempts to build predictive models, to assess flow–property uncertainty and to screen any potential reactive flow issues (note that a further important function was to assess drilling risks caused by interaction with drilling fluids and swelling clays).

Analyses included fine–fraction X–ray Diffraction (XRD), Scanning Electron Microscopy (SEM), Energy Dispersive Spectrometry (EDS) and thin–section analysis to determine composition, diagenetic effects and porosity characteristics.

Expertise in local geology was essential. All petrological work was conducted by Dr J Baker of Reservoir Solutions Pty Ltd. Detailed results were documented in specific analysis reports (Baker, J.C. 2006 to 2009) which have since been filed in the Queensland Government’s exploration data base, QDEX as appendices to ZeroGen’s Well Completion Reports.

2.4.1 Clay mineralogy

To the South of the main area, in the ZG2 well, all formations have clay minerals that include kaolinite, illite/mica and mixed layer illite/smectite. The Mantuan and Catherine samples also contained a trace to minor amounts of chlorite.

<table>
<thead>
<tr>
<th>Plug no.</th>
<th>Depth (m)</th>
<th>Unit</th>
<th>Ka</th>
<th>I</th>
<th>I/S</th>
<th>Sm</th>
<th>Chl</th>
<th>I/S Illite %</th>
</tr>
</thead>
<tbody>
<tr>
<td>6A</td>
<td>719.11</td>
<td>Mantuan Fm</td>
<td>M</td>
<td>M</td>
<td>M</td>
<td>–</td>
<td>m</td>
<td>70–80</td>
</tr>
<tr>
<td>93B</td>
<td>750.98</td>
<td>Mantuan Fm</td>
<td>M</td>
<td>m</td>
<td>m</td>
<td>–</td>
<td>–</td>
<td>70–80</td>
</tr>
<tr>
<td>143A</td>
<td>901.4</td>
<td>Catherine Sst</td>
<td>A</td>
<td>m</td>
<td>m</td>
<td>–</td>
<td>T</td>
<td>70–80</td>
</tr>
<tr>
<td>241A</td>
<td>1108.15</td>
<td>Freitag Fm</td>
<td>m</td>
<td>A</td>
<td>A</td>
<td>–</td>
<td>–</td>
<td>70–80</td>
</tr>
</tbody>
</table>

*Ka = kaolinite; I = illite/mica; I/S = mixed–layer illite/smectite; Chl = chlorite. A = abundant; M = major; m = minor; T = trace.*

Catherine Sandstone samples from ZG–5 and ZG–10 (the wells with the highest permeability Catherine) contained clay that is authigenic kaolin (kaolinite, dickite) and subordinate authigenic illite and illitic mixed–layer illite/smectite that result from alteration of micaceous/argillaceous grains and feldspar.

Tuffs and mudrocks from the (sealing) Peawaddy and Ingelara in ZG–7 were also examined by XRD analysis, see (Table 2.3).
**2.4.2 Sandstone mineralogy**

Sandstones were analysed from the three potential reservoir formations in eight of the ZeroGen wells. Thin-section point counting to estimate rock compositions has been performed on several samples. Table 2.4 shows percentage compositions for six samples from the Catherine Sandstone in ZG–5 (the well with the best Catherine permeabilities).

**TABLE 2.4: ROCK COMPOSITION % FROM POINT COUNTING ZG–5 CATHERINE SANDSTONE**

<table>
<thead>
<tr>
<th>Sample no.</th>
<th>31</th>
<th>24</th>
<th>25</th>
<th>26</th>
<th>27</th>
<th>28</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth (m)</td>
<td>854.54</td>
<td>915.35</td>
<td>920.22</td>
<td>943.21</td>
<td>943.76</td>
<td>945.10</td>
</tr>
<tr>
<td>Quartz (monocrystalline)</td>
<td>60.7</td>
<td>47.2</td>
<td>51.2</td>
<td>56.1</td>
<td>58.9</td>
<td>58.4</td>
</tr>
<tr>
<td>Quartz (polycrystalline)</td>
<td>3.3</td>
<td>15.0</td>
<td>3.8</td>
<td>5.5</td>
<td>3.4</td>
<td>4.6</td>
</tr>
<tr>
<td>Quartz overgrowths</td>
<td>4.0</td>
<td>2.7</td>
<td>8.4</td>
<td>9.1</td>
<td>6.4</td>
<td>8.6</td>
</tr>
<tr>
<td>Chert</td>
<td>0.3</td>
<td>–</td>
<td>0.3</td>
<td>0.7</td>
<td>0.7</td>
<td>0.3</td>
</tr>
<tr>
<td>K–feldspar</td>
<td>5.0</td>
<td>14.9</td>
<td>13.0</td>
<td>7.8</td>
<td>10.7</td>
<td>8.8</td>
</tr>
<tr>
<td>Plagioclase</td>
<td>0.7</td>
<td>3.9</td>
<td>4.5</td>
<td>2.1</td>
<td>2.7</td>
<td>3.3</td>
</tr>
<tr>
<td>Granitic rock fragments</td>
<td>0.7</td>
<td>1.7</td>
<td>1.4</td>
<td>0.7</td>
<td>–</td>
<td>0.3</td>
</tr>
<tr>
<td>Volcanic rock fragments</td>
<td>0.7</td>
<td>–</td>
<td>2.2</td>
<td>0.7</td>
<td>0.7</td>
<td>1.1</td>
</tr>
<tr>
<td>Metamorphic rock fragments</td>
<td>1.1</td>
<td>0.3</td>
<td>–</td>
<td>0.3</td>
<td>0.3</td>
<td>1.7</td>
</tr>
<tr>
<td>Sedimentary rock fragments</td>
<td>1.1</td>
<td>–</td>
<td>–</td>
<td>1.1</td>
<td>1.1</td>
<td>2.1</td>
</tr>
<tr>
<td>Mica</td>
<td>–</td>
<td>0.3</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>0.3</td>
</tr>
<tr>
<td>Heavy minerals</td>
<td>0.3</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>Organics</td>
<td>–</td>
<td>0.3</td>
<td>–</td>
<td>0.3</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>Ankerite</td>
<td>0.7</td>
<td>–</td>
<td>0.3</td>
<td>0.3</td>
<td>–</td>
<td>–</td>
</tr>
</tbody>
</table>

*Ka = kaolinite; I = illite/mica; I/S = mixed-layer illite/smectite; Chl = chlorite. A = abundant; M = major; m = minor; T = trace.*
Almost all sandstones analysed from the ZeroGen wells were subarkose to arkose in composition. Figure 2.5 is a Quartz–Feldspar–Rock Fragments (QFR) ternary plot for the Catherine samples analysed in ZG–5, and is a sample from ZG–2 Aldebaran sandstone which is a sublitharenite.

Subsequent reactive transport modelling indicated that the rock composition is benign in terms of reaction with CO₂ and this is discussed in Subsection 2.9, Chapter Three, Part A.

Samples analysed from the ZeroGen wells are typical of those described by Anthony (2004). However, two samples, both from ZG–9 with unusual mineralogy were also point–counted. These are a highly micaceous fine grained sandstone from the Freitag formation and a pyritic granule conglomerate from the Aldebaran Sandstone to determine mineralogy, provenance and diagenetic effects. Although not typical of the coarse grained permeable sandstone intervals, very micaceous laminae in fine grained poorly permeable sandstones are fairly common in wells north of ZG–5 and indicate proximity to a granitic provenance area (Figure 2.5).

This was a key finding which indicated the possibility of a relatively high permeability play–fairway to the north of ZG5.
2.5 Diagenesis

Understanding diagenetic mechanisms and controls on permeability preservation was a critical step in ZeroGen’s understanding (i) the direction in which better permeabilities might be discovered (NW, proximal), and (ii) that significant and largely unpredictable degrees of heterogeneity were likely.

Cementation by quartz overgrowths was found to be the key diagenetic effect which occurs in the cleaner sandstones of the Permian in the NDT (Figure 3.6). The degree of silicification is a function of maximum burial temperature and, therefore, maximum burial depth. Quartz cementation starts at around 80–100°C.

Vitrinite Reflectance (VR) of 0.98 corresponds to a Tmax of around 140°C. VR data from coals in ZG–9 (Aldebaran level) and ZG–10 (Catherine level) are 0.67 and 0.69 respectively. This corresponds to a Tmax of 114°C. VR data indicate that paleo–geothermal gradients as high as 5°C per km existed in the NDT.
Silicification peaked during the early to middle Triassic, when the Aldebaran Sandstone reached a maximum burial depth of about 5000 m to 6000 m. The high degree of silicification has severely overprinted the control of depositional environment and, more specifically, texture on porosity and permeability. Accordingly, there are no clear relationships between porosity/permeability and depositional facies.

In the ZG–5 Catherine samples, porosity reduction was due to quartz overgrowth cementation, grain contact dissolution/microstylolitisation, authigenic clay formation and ductile grain/authigenic clay compaction to form pseudomatrix (Baker, 2008).

Anomalous intergranular porosity where present is the result of authigenic grain–coating illitic clay having inhibited quartz overgrowth cementation. In the deeper sandstones, permeability is controlled mainly by grain size, reflecting not only the intrinsic grain size control on permeability, but also the decreased effectiveness of quartz overgrowth in eliminating porosity in the coarser lithologies. The two coarsest samples (915.35 m, 920.22 m) are relatively feldspathic, which further decreased the susceptibility of these samples to porosity destruction. Grain contact dissolution/microstylolitisation locally reduced permeability.
Moderate to high permeability in the Catherine Sandstone in ZG–5 (and ZG–10 and ZG–12) can be attributed to three discrete mechanisms:

- authigenic grain–coating clay;
- coarse grain size; and
- relatively high feldspar content, where very coarse grained.

Thus, the preservation of porosity and permeability in the NDT is complex.

The more labile (immature) ‘dirty sands’, such as the distributary facies, may be better exploration targets than the cleaner facies. Furthermore, these sands are more likely to be coarse grained and feldspar rich the closer they are to the sediment provenance area.

In short, areas with depositionally less favourable reservoir development (smaller, proximal, poorly sorted, ‘dirtier’ channels) were likely to have the best post–diagenetic poro–perms. But lateral and vertical heterogeneity would likely be high.

### 2.6 Rock Typing

Finely–spaced horizontal fractures (‘biscuit fractures’) were very common in cores recovered from the Denison Trough as in other Australian Permian Basins (Flottmann et al. 2004).

Reservoir MicroAnalysis© was used in zones that were heavily biscuit fractured and could not be characterised by Routine Core Analysis (RCA) or probe–permeametry. The technique (Rushing et al., 2008) discriminates rocks (both core and cuttings) into distinct groupings or types according to their properties as observed under a high power binocular microscope. This is based on the quantitative observation of key visual attributes, which can then be calibrated to core measurements, as follows:

<table>
<thead>
<tr>
<th>Type</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Type 1</td>
<td>Rocks are capable of gas production without natural or artificial fracturing. They are sub–divided into four classes 1A (&gt;100 mD), 1B (10–100 mD), 1C (1–10 mD) and 1D (0.5 to 1 mD)—Figure 2.7.</td>
</tr>
<tr>
<td>Type 2</td>
<td>Rocks are capable of gas production when interbedded with Type 1 rocks or with natural and/or artificial fracturing. Permeability range is 0.07–0.5 md.</td>
</tr>
<tr>
<td>Type 3</td>
<td>Rocks are too tight to produce at commercial rates. Permeabilities are generally less than 0.07 md.</td>
</tr>
</tbody>
</table>

Photo micrograph examples of a selection of these rock types from ZG–5 can be seen in Figure 2.7.
Permeability values used (Kav) are geometric mid–point values taken from rock type permeability ranges (Rock Type Permeability Values (Ambient Air Permeability)). These are ambient air permeability values. A blind test comparison was performed between RCA and rock typing, estimates were found to be similar.

**TABLE 2.5: ROCK TYPE PERMEABILITY VALUES (AMBIENT AIR PERMEABILITY)**

<table>
<thead>
<tr>
<th>Rock type</th>
<th>Geometric mid–point</th>
</tr>
</thead>
<tbody>
<tr>
<td>1A</td>
<td>316 mD</td>
</tr>
<tr>
<td>1B</td>
<td>31.6 mD</td>
</tr>
<tr>
<td>Hi 1C</td>
<td>7.3 mD</td>
</tr>
<tr>
<td>1C</td>
<td>3.16 mD</td>
</tr>
<tr>
<td>1D</td>
<td>0.707 mD</td>
</tr>
<tr>
<td>2</td>
<td>0.187 mD</td>
</tr>
<tr>
<td>2–3</td>
<td>0.07 mD</td>
</tr>
<tr>
<td>3</td>
<td>&lt; 0.07 mD</td>
</tr>
</tbody>
</table>

The thickness estimate was more subjective, rock type samples were taken at visual changes in rock type and the distance between samples measured.
Rock typing was used on all core recovered from wells ZG–7 to ZG–12. Some wells were drilled deeper than others and intersected thicker sections of Lower Aldebaran Sandstone (ZG–9 and ZG–10, for example). All wells sampled a similar Catherine thickness.

Figure 2.8 shows rock–type, k.h by formation for each well. The Catherine Sandstone is the dominant contributor to well k.h (except for the case of ZG–7 where the Freitag Formation and Aldebaran Sandstone are significant).

**FIGURE 2.8: ZEROGEN K.H ESTIMATES FROM ROCK TYPING**

![Rock typing Kh comparison graph]

<table>
<thead>
<tr>
<th></th>
<th>Lwr Aldebaran</th>
<th>Uppr Aldebaran</th>
<th>Freitag</th>
<th>Catherine</th>
</tr>
</thead>
<tbody>
<tr>
<td>ZG 12</td>
<td>0</td>
<td>117</td>
<td>608</td>
<td>935</td>
</tr>
<tr>
<td>ZG 10</td>
<td>1</td>
<td>45</td>
<td>52</td>
<td>1170</td>
</tr>
<tr>
<td>ZG 9</td>
<td>7</td>
<td>108</td>
<td>8</td>
<td>204</td>
</tr>
<tr>
<td>ZG 8</td>
<td>42</td>
<td>42</td>
<td>31</td>
<td>618</td>
</tr>
<tr>
<td>ZG 7</td>
<td>249</td>
<td>249</td>
<td>71</td>
<td>71</td>
</tr>
</tbody>
</table>

Note: Ambient–air permeability multiplied by thickness.

Rock Typing analysis also suggested that the Catherine improves moving towards the North and West of the tenements (i.e. ZG–8 to ZG–10) as was expected from provenance concepts. However, while permeability and k.h. evaluations were fairly consistent with RCA values, they were uncalibrated by dynamic well tests and subject to errors inherent in up-scaling.

### 2.7 Routine Core Analysis (RCA)

Approximately 7200 m of core were acquired from the ZeroGen wells and approximately 1200 horizontal and 75 vertical RCA plugs were analysed for porosity and permeability base parameters (ambient air). All RCA measurements were made by Weatherford Laboratories in Brisbane.
Several sample cleaning experiments, such as miscible flush clean, critical point drying, soxhlet clean, humidity and oven drying were performed on ZG–2 core plugs to determine the best sample preparation method. A sub–set of all analyses underwent an independent quality review. The details of sample procedures, experiments and results can be found in QDEX.

2.7.1 Ambient air permeability

Figure 2.9 shows all ZeroGen RCA data sorted by formation respectively. The porosity–permeability relationships were not straightforward (similarly when sorted by depth) as expected and factors such as grain–size, composition and diagenesis are significant.

FIGURE 2.9: AMBIENT AIR POROSITY VS AMBIENT AIR PERMEABILITY BY FORMATION

Ambient air porosity vs ambient air permeability by formation

2.7.2 Overburden air permeability measurements

All plugs with horizontal air permeabilities greater than 5 mD were CT scanned to check that they were homogenous and un–fractured and the competent plugs were retested under stressed conditions to measure simulated overburden porosity and permeability. Confining pressure applied to each plug was based on the regional pressure gradient established from the geomechanical and pressure datasets.

Cross–plots indicated that overburden pressure corrected air permeabilities were typically some 89% of ambient air permeabilities.

Klinkenberg permeability analysis was also undertaken.
Cross plots indicated that Klinkenburg permeability were typically 93% of overburden corrected air permeabilities.

2.7.3 Brine permeability measurements

Ambient brine permeability was measured on 33 horizontal core plugs to establish a relationship between ambient air and ambient brine permeability.

Cross plots indicated that of the ambient brine permeabilities were typically some 69% of ambient air permeabilities with a good fit for air permeabilities less than around 800 mD. Above this letter correlation between the two was significantly poorer.

Seven core plugs were also tested under overburden pressure conditions, the applied confining pressure was selected from the pore–pressure depth relationship established from the geomechanical and observed pressure datasets.

Cross–plots indicated that overburden corrected brine permeabilities were some 94% of ambient brine permeabilities.

2.7.4 Summary of RCA permeabilities

The analyses carried out were highly selective in that the ‘best and highest’ non–fractured core plugs were selected for analyses. This produces greatest confidence in calibration factors.

Ambient brine permeability is some 69% of ambient air permeability. Overburden brine permeability is some 94% of ambient brine permeability and 65% of ambient air permeability.

These are core–scale measurements and do not account for bulk–scale, in–situ, vertical and lateral injectivity. A further correction factor would be needed to correct for bulk, in–situ conditions. This had to be derived from dynamic well testing (subsection 3.4, Chapter Three, Part A).

2.8 Petrophysics

Petrophysical analyses were employed to create a core–calibrated, continuous, poro–perm profile for each formation in each well.

2.8.1 Introduction

Well log response of the downhole porosity devices (neutron, density) were calibrated to the overburden and brine corrected core porosities. All wells in the ZeroGen Project were evaluated using TechLog™, an interactive multi well deterministic petrophysical analysis tool marketed by Schlumberger.

The Volume of Shale (VSH) was calculated with a GR curve as input using a linear method and a shale cut–off (Vsh) of 0.4 was used to discriminate between reservoir and non–reservoir rock. The cut–off valued was determined by sensitivity analysis. A consistent method was followed in determining total porosity based on density. No cut–off was applied to porosity.
Water saturations were determined using the ‘Archie relationship’. Within this, a fixed cementation exponent value of \( m = 2.0 \) was used together with a saturation exponent (\( n \)) of 2.0. The tortuosity factor ‘\( a \)’ in Archie equation, which is meant for correction to variation in compaction, pore structure and grain size, was taken to be unity (1).

Some uncertainty remained in formation water salinity. Data from offset wells which do not have residual hydrocarbon fluids, suggest water salinity (NaCl equiv) between 5500 ppm to 6500 ppm. Water sample analysis from ZG–6 and ZG–11 gave a water salinity of 7692 ppm and 4400 ppm respectively. A unique value of formation water resistivity (\( R_W \)) could not be used across the whole set.

Picket plots (deep resistivity vs porosity v/v) of the 100% water wet sandstones in the Catherine Formation for each well showed a range of \( R_W \) from 0.3 to 1.4 \( \Omega \text{m} \).

### 2.8.2 Permeability characterisation from NMR logs

CMR–Plus (combinable magnetic resonance tool) measures the petrophysical properties of rocks and formation fluids using Nuclear–Magnetic Resonance (NMR) imaging technology. It was run in ZG–11 and ZG–1.

Six sandstone core–plug samples from ZG–2 were also analysed by CSIRO\(^4\) using nuclear magnetic resonance spectroscopy CPMG–T2 methods to determine porosity characteristics and to define moveable fluid cut–offs. Fluid T1/T2 was determined on synthetic brine supplied by ZeroGen T2 input parameters derived from NMR measurements made on ZG–2 core.

Results from magnetic resonance spectroscopy CPMG–T2 (to determine porosity characteristics and to define moveable fluid cut–offs) were used to calibrate the tools. Permeability was computed using the ‘Coates equation’ to yield in–situ permeability.

An example comparison with overburden corrected brine permeability from RCA is shown in Figure 3.10. The NMR tool successfully predicted the core–scale brine permeability in ZG1 and the key well ZG–11 where hole was in gauge. The RCA data points, permeability transform and the NMR permeability almost overlie each other in ‘good hole’. **The importance of good drilling practices is highlighted by this impact on data.**

However, while NMR allows core results to be applied to non–cored areas, these results do not fully inform bulk–scale lateral and vertical heterogeneity.

### 2.8.3 Petrophysical workflow for estimating (upscaling) poro–perms for models

The RCA, porosity–permeability (\( \Phi–k \)) plot from ten wells (Figure 3.12) shows a relatively weak ‘linear’ relationship if considered across the whole data set and facies. There is a wide range of permeability for a constant porosity (e.g. porosity, \( \Phi=10\% \) corresponds to a \( k \) variation of three orders of magnitude).

There is a depth trend seen in the RCA permeability data (Figure 2.11). From 400 m to 1900 m, (i.e. from Catherine to Aldebaran), RCA permeability decreases by four orders of magnitude with depth (1000 mD to 1 mD).

It had been determined from petrology that there was a fundamental geological control on poro–perm preservation and this is linked to diagenetic effects. However, even given this, three facies based poro–perm classes could be defined (Figure 2.12) for the purposes of flow modelling, each with its own $\Phi$–$k$ transform.

**FIGURE 2.10: PERMEABILITY DERIVED FROM NMR, RCA AND TRANSFORM IN CATHERINE SANDSTONE OF ZG–11**
CHAPTER THREE Storage Part A—Northern Denison Trough

FIGURE 2.11: DEPTH TREND IN PERMEABILITY FROM ZEROGEN CORE PLUGS

FIGURE 2.12: THREE FACIES BASED PORO–PERM CLASSES AND LEAST SQUARES LINE FIT TO EACH
Facies logs were generated for all wells and the three facies based poro–perm transforms were used to calculate permeability from facies and corresponding log derived in–situ porosity. A further discussion of the use of facies as flow–zone indicators is included in Salunke et al. (2010).

The RCA–derived ambient, core–air permeabilities to overburden brine permeabilities transform was then flexed to honour the individual well, facies permeability data points and to develop a well brine permeability log.

A Vsh cut–off of 0.4 was used to obtain a net brine permeability log which is used for up–scaling. Up–scaling was based on vertical heterogeneity in permeability. Layering was selected based on vertical heterogeneity with similar permeability values captured within a particular layer. In the absence of permeability data the GR log was used to establish these layers.

Petrophysical parameters: Net sand, net to gross, average porosity and brine permeability were evaluated and are summarised in Table 2.6 (shown here for key wells and formations only). An example well log panel showing the basic open hole logs and interpreted VSH log for ZG–8 is shown in Figure 2.13.
Note that there were anomalously high permeability values in the ZG–10 and ZG–11 Catherine (some 30 km apart). Without these, the average ambient air and overburden brine permeabilities would be 1.9 and 0.4 mD respectively across the other wells. Furthermore, the postulated higher permeability Catherine play, extending north from ZG–5 was clearly not consistent or continuous (as evidenced by well, ZG8 in–between).

### TABLE 2.6: PETROPHYSICAL SUMS AND AVERAGES FOR KEY ZG WELLS

<table>
<thead>
<tr>
<th>Wells</th>
<th>Zones</th>
<th>Top (m)</th>
<th>Bottom (m)</th>
<th>Gross (m)</th>
<th>Net (m)</th>
<th>NTG</th>
<th>Av.net porosity (v/v)</th>
<th>Ambient air permeability (mD)</th>
<th>Overburden brine permeability (mD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A–ZG–3</td>
<td>Catherine Sandstone</td>
<td>800</td>
<td>941</td>
<td>141</td>
<td>40.39</td>
<td>0.29</td>
<td>0.11</td>
<td>1.71</td>
<td>0.32</td>
</tr>
<tr>
<td>A–ZG–3</td>
<td>Aldebaran Sandstone</td>
<td>1177</td>
<td>1275</td>
<td>98</td>
<td>53.34</td>
<td>0.54</td>
<td>0.09</td>
<td>0.66</td>
<td>0.09</td>
</tr>
<tr>
<td>A–ZG–6</td>
<td>Catherine Sandstone</td>
<td>818</td>
<td>955</td>
<td>137</td>
<td>48.62</td>
<td>0.35</td>
<td>0.09</td>
<td>4.19</td>
<td>0.88</td>
</tr>
<tr>
<td>A–ZG–6</td>
<td>Aldebaran Sandstone</td>
<td>1183</td>
<td>1300</td>
<td>117</td>
<td>84.43</td>
<td>0.72</td>
<td>0.10</td>
<td>0.73</td>
<td>0.15</td>
</tr>
<tr>
<td>A–ZG–8</td>
<td>Catherine Sandstone</td>
<td>959</td>
<td>1113</td>
<td>154</td>
<td>73.00</td>
<td>0.47</td>
<td>0.10</td>
<td>4.19</td>
<td>1.08</td>
</tr>
<tr>
<td>A–ZG–8</td>
<td>Aldebaran Sandstone</td>
<td>1367</td>
<td>1547</td>
<td>180</td>
<td>117.04</td>
<td>0.65</td>
<td>0.07</td>
<td>0.06</td>
<td>0.01</td>
</tr>
<tr>
<td>A–ZG–10</td>
<td>Catherine Sandstone</td>
<td>860</td>
<td>1036</td>
<td>176</td>
<td>85.65</td>
<td>0.49</td>
<td>0.11</td>
<td>18.74</td>
<td>5.25</td>
</tr>
<tr>
<td>A–ZG–10</td>
<td>Aldebaran Sandstone</td>
<td>1268</td>
<td>1619</td>
<td>351</td>
<td>213.48</td>
<td>0.61</td>
<td>0.07</td>
<td>0.16</td>
<td>0.02</td>
</tr>
<tr>
<td>A–ZG–11</td>
<td>Catherine Sandstone</td>
<td>844</td>
<td>998</td>
<td>154</td>
<td>53.80</td>
<td>0.35</td>
<td>0.10</td>
<td>42.04</td>
<td>20.13</td>
</tr>
<tr>
<td>A–ZG–11</td>
<td>Aldebaran Sandstone</td>
<td>1233</td>
<td>1280</td>
<td>47</td>
<td>34.59</td>
<td>0.74</td>
<td>0.10</td>
<td>0.39</td>
<td>0.13</td>
</tr>
</tbody>
</table>
2.8.4 Reservoir property analysis for static modelling

A sector model was built using Schlumberger’s Petrel™ software to include all existing ZeroGen wells with coarse horizontal and very fine vertical gridding. It was used to integrate detailed geological descriptions of the core, palaeocurrent data, Special Core Analysis (SCAL) and core–calibrated, well log properties so that various cross plots, pie plots maps and histograms could be examined to understand whether the controls on reservoir properties could be usefully mapped.

The objectives of the integration exercise were to:
- constrain the conceptual geological model with hard data;
- identify trends in reservoir quality;
- establish controls on reservoir properties; and
- investigate predictive utility of any full field model.

Reservoir quality trends and controls

The question of scale is connected fundamentally with the measurement process. Some significant (to injection operations) types of heterogeneity are not measurable from log and core data alone. However, the likelihood of these ‘bulk–scale’ phenomena, as key injectivity risk factors, can be informed by core, log and outcrop analyses integrated within a consistent geological framework.

In the potential injection formations of the NDT, it was found that:
- poro–perm relationships are weak;
- reservoir quality deteriorates with depth;
- core–scale permeability in the Catherine ranges from 0.1–1000 mD;
- core–scale permeability in the Aldebaran ranges from 0.1–10 mD (Figure 2.14);
- a facies control on permeability is only likely to still be visible in the Catherine Sandstone (Figure 2.14); and
- depositionally ‘poorer’, less continuous, probably smaller, more proximal Catherine channels are likely to have the best preserved permeabilities, but this is not consistently so from the ZG–5 well to the north.

Based on this analysis three porosity–permeability relationships were established and used in the static modelling:
- Catherine channel sands;
- Catherine other facies; and
- Freitag and Aldebaran all facies.
2.8.5 Summary of static modelling issues

The core description and data analysis exercise confirmed the pre–drill geologic hypothesis of more proximal facies (including more channels) northwards in the Catherine with a granitic provenance.

Integrating facies interpretation with the petrophysical properties resulted in improved facies based poro–perm transforms for the ZeroGen wells and confirmed that the better Catherine Formation channel sands would be required to contribute the vast majority of the required injectivity.

However, while updated geological model allowed better understanding of the paleo–shoreline, para–sequence stacking pattern, channel dimensions and orientation and so on, large uncertainties in the geology still remain. The location of any better persevered permeabilities could not be determined e.g. for targeting new wells.

Significantly, ZeroGen’s understanding of diagenetic controls on porosity and permeability indicated that heterogeneity is likely to be large. This is entirely consistent with the results of the dynamic well tests.

Deterministic realisations were considered inadequate to characterise reservoir performance—no deterministic predictive model were likely possible for confident predictions.

**Modelling for performance assessment required stochastic assessments of injection performance.**
2.9 Additional Special Data Analyses

In addition to the more or less conventional series of core and log analyses and geological modelling discussed above, ZeroGen undertook additional investigations required for the appraisal of a potential storage site, as follows.

2.9.1 Geomechanical data acquisition

Geomechanical factors primarily influence containment. Considerable effort was undertaken to establish in–field stress and rock strength constraints. The following data set was acquired. The XLOTs are considered the most valuable information in terms of their impact on confidence in establishing pressure constraints (Rao et al. 2010).

<table>
<thead>
<tr>
<th>Data</th>
<th>Wells</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>HMI image log</td>
<td>ZG–1, ZG–7 (acoustic scanner image log)</td>
<td>Used for predicting the maximum horizontal stress direction</td>
</tr>
<tr>
<td>Extended leak off test [XLOT]</td>
<td>ZG–2, ZG–5, ZG–6, ZG–7, ZG–8, ZG–9 and ZG–10</td>
<td>9 x successful extended LOTs</td>
</tr>
<tr>
<td>Full–wave sonic log</td>
<td>ZG–7, ZG–9</td>
<td>Young’s Modulus and Poisson’s ratio values estimated from logs</td>
</tr>
<tr>
<td>NMR log</td>
<td>ZG–11</td>
<td></td>
</tr>
<tr>
<td>Rock testing (lab)</td>
<td>ZG–2, ZG–7</td>
<td>Subsection 3.9.4</td>
</tr>
</tbody>
</table>

2.9.2 Aquifer water sampling

Formation water sampling was required for well–bore scaling (impairment) studies and for reactive flow and transport studies. Significant difficulties were encountered in recovering clean samples from the tight formations in the area. No samples were obtained under–pressure and so dissolved gas analysis remained problematic. However, two water samples from ZG–11 Catherine Sandstone were recovered, the following analyses were run:

<table>
<thead>
<tr>
<th>No.</th>
<th>Test</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>TPH (C10—C36) in water by GC</td>
</tr>
<tr>
<td>2</td>
<td>Dissolved metals in water by ICP/MS</td>
</tr>
<tr>
<td>3</td>
<td>Dissolved metals in water—ICP/AES</td>
</tr>
<tr>
<td>4</td>
<td>Total metals in water by ICP/AES</td>
</tr>
<tr>
<td>5</td>
<td>Dissolved mercury in water by FIMS</td>
</tr>
<tr>
<td>6</td>
<td>Sodium absorption ratio in water</td>
</tr>
</tbody>
</table>
### No. Test

<table>
<thead>
<tr>
<th>No.</th>
<th>Test</th>
</tr>
</thead>
<tbody>
<tr>
<td>7</td>
<td>pH in water</td>
</tr>
<tr>
<td>8</td>
<td>Conductivity in water</td>
</tr>
<tr>
<td>9</td>
<td>Resistivity in water</td>
</tr>
<tr>
<td>10</td>
<td>Dissolved oxygen in water</td>
</tr>
<tr>
<td>11</td>
<td>BOD(5) in water</td>
</tr>
<tr>
<td>12</td>
<td>Suspended solids in water</td>
</tr>
<tr>
<td>13</td>
<td>Dissolved solids in water</td>
</tr>
<tr>
<td>14</td>
<td>Anions in water by IC</td>
</tr>
<tr>
<td>15</td>
<td>TOC in water by analyser</td>
</tr>
<tr>
<td>16</td>
<td>Free carbon dioxide in water</td>
</tr>
<tr>
<td>17</td>
<td>Alkalinity in water</td>
</tr>
<tr>
<td>18</td>
<td>Ion balance in water by calc</td>
</tr>
<tr>
<td>19</td>
<td>Oil and grease in water by gravimetry</td>
</tr>
</tbody>
</table>

These resultant data were used in geochemical studies of possible interactions between CO₂ and formation waters (Subsection 3.9.5, Chapter Three, Part A).

### 2.9.3 Seismic and Vertical Seismic Profile (VSP) program

A repeat borehole seismic survey plan consisting of two rig source VSPs, an offset VSP and four Walkaway VSP surveys was designed (by Schlumberger Oilfield Services) for monitoring acoustic changes due to CO₂ injection in the vertical ZG–11 well. By using Walkaway VSP lines with several different azimuths a minimal acquisition footprint was achieved (compared to a 3DVSP scenario), while still obtaining spatially orientated information.

Ground conditions and processing challenges were significant and details of this program were published elsewhere (Dalhuis et al., 2012, in prep)⁵.

However, that paper concludes that, for a 440 tonne cumulative CO₂ injection test, ... *time–lapse changes in acoustic response in the injection interval were observed on all available borehole seismic datasets. The processed offset VSP and Walkaway VSP images also provided estimates of lateral extent and orientation of these anomalies.*

However, the causal mechanisms behind the time–lapse changes were not clear and the authors go on to say that ... *detection of time lapse changes in such a small injection test requires an investigation into the underlying causes such as fluid and pressure effects.*

---

⁵ Dalhuis et al. (in prep for ASEG 2012). Onshore Time–Lapse Borehole Seismic Project for CO₂ Injection Monitoring
2.9.4 Special Core Analysis (SCAL)

Relative permeabilities

The relative ease with which CO₂ can be injected into brine–filled reservoirs is significantly influenced by relative permeability.

With the objective to establish suitable relative permeability curves specific to ZeroGen conditions, ZeroGen contracted Hycal Energy Research Laboratories Ltd. laboratories in Calgary to conduct experimental work for SCAL under the technical supervision of Shell Technology and Projects (Shell–ZeroGen, 2010c).

The study comprised:
1. Single phase permeability measurements on the permeability class of 1–10 mD.
2. Unsteady State (USS).
3. Steady State (SS) two–phase relative permeability experiments.
4. Capillary pressure measurements.
5. Dry CO₂ end point measurements. Phase 2 study comprises of the same work on the remaining permeability classes 0.1–1 mD, 10–100 mD, 100–1000 mD, 1000 mD+.

Experiments were complex and many experimental lessons were realised (Weatherford, 2010). However, unsteady state relative permeability experiments did provide an estimate of formation specific CO₂–brine relative permeability curves, which were used in dynamic modelling (subsection 5.3, Chapter Three, Part A).

Geomechanical core analysis

NDT formations are relatively (unusually) stiff and strong making system compressibility difficult to assess. Specialists at CSIRO conducted a series of confined and unconfined rock mechanics tests on cores from ZG–2 (Amanullah et al. 2007) and ZG–7 (Maney, 2010)—for the ZG–7 samples (Catherine Sandstone) typical results were as follows:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>UCS</td>
<td>50–60 MPa</td>
</tr>
<tr>
<td>Young’s modulus</td>
<td>10–25 GPa</td>
</tr>
<tr>
<td>Poisson’s ratio</td>
<td>0.2–0.7</td>
</tr>
<tr>
<td>Friction angle</td>
<td>circa 40 degrees</td>
</tr>
<tr>
<td>Cohesion</td>
<td>12.5–13.5 MPa</td>
</tr>
</tbody>
</table>
Seal quality core analysis for CO₂

Ordinarily, in conventional oil and gas operations, seal quality (the pressure at which fluids can be forced into a seal matrix) is measured by mercury injection. It was uncertain how representative this would be for CO₂. Therefore, mercury injection seal capacity was measured on two samples from the ultimate seal, the Black Alley Shale (BAS) in ZG–2 by ACS Weatherford (ACS, 2008) and with CO₂ by experimenters at Aachen University (Aachen, 2010). All experiments indicated extremely low permeability. The BAS samples, consisting of quartz, illite, smectite and kaolinite, when exposed to CO₂ could only be exposed for several days. This did not affect the mineralogy, though the exposure time was probably too short. The absolute permeability values for both cap–rock samples were in the range of 0.7 to 1.3 nano–Darcy.

A CO₂ breakthrough experiment on sample one (initial pressure difference was set to 11.3 MPa) was stopped after approximately two weeks because no pressure changes were detected i.e. there was no CO₂ volume flow (transport of a distinct gas phase) up to this limit of capillary pressure.

2.9.5 Geochemical analysis

This section contains a brief discussion on the results of the geochemical modelling work carried out by the CCS Team, Shell Technology India on behalf of ZeroGen (Shell–ZeroGen 2010d and Gupta, 2010).

The objective was to identify the risks of reactivity of injected CO₂ stream with the aquifer mineralogy of the basin. Due to geochemical reactions of the injected CO₂ with the host rock, mineral dissolution or precipitation could occur. As a result, the reservoir properties near the wellbore might be altered and could potentially result in injectivity reductions in the short–term from scaling and storage capacity reduction in the longer term.

The conclusions from geochemical analyses were (Figure 3.15):

- Reactivity in the sample consisting of quartz as a major component was insignificant. The majority of NDT is composed of quartz dominant mineralogy and it was interpreted that severe field–wide reactions would not be expected during CO₂ injection. The presence of pyrite in the mineralogy does not cause any unexpected reactivity.
- Chemical reactivity was largely governed by the presence of illite and albite. The higher the percent of these minerals in the basin, the higher the overall reactivity and hence increased reduction in effective porosity/permeability.
- Studies on CO₂ injection stream sensitivity, primarily with varying concentrations of N₂ but similar concentrations of other components were undertaken to see any possible impact of changing the CO₂ spec at the IGCC plant in a drive to increase power efficiency. Injection performance reduction through adverse chemical reactions is insensitive to minor quantities of other components in the injection stream such as H₂S and H₂ did not trigger or make a large impact on overall chemical reactivity.
- Impact of other gas components like CO and CH₄ were not evaluated due to the lack of reactions database for these components.
The results obtained from this study were thought to be representative of the mineralogy of the core samples tested. Given the widespread mineral heterogeneity the results might not be fully representative of the entire basin.

The timescale of the reactions could not be determined. For dynamic models additional information would be required such as rate constants of various mineral reactions under aquifer conditions of temperature and pressure, grain–size of the rock and CO₂ injection rate.

**FIGURE 2.15: MINERAL DISSOLUTION/PRECIPITATION VS CO₂ INJECTION ALDEBARAN SANDSTONE**

![Graph showing mineral dissolution/precipitation vs CO₂ injection for Aldebaran Sandstone](image-url)

**CO₂ injected per metre³ of formation (100 x moles)**

- **Quartz**
- **Albite**
- **Calcite**
- **Kaolinite**
- **Illite**
- **K-feldspar**
- **Dolomite**
- **pH**

Mineral change (100 x moles)/pH

CO₂ injected per metre³ of formation (100 x moles)
3 PFS Program Dynamic Testing

3.1 Context

The previous section described fundamental geological analyses and work required to understand the range of uncertainties and ZeroGen’s attempt to produce predictive models.

The data described thus far were all evaluated at small, local or core-scale only. It was recognised that in-situ, bulk-property calibration factors would be needed for both effective determination of initial injectivity, as well as to investigate reservoir connectivity and time-dependent pressure build-up in the reservoir.

Water injection and (more expensive) CO₂ injection were employed to achieve this. Investigation of boundaries away from the well required testing for a period of time—a function of the effective, in-situ permeability (lower permeabilities require longer testing times for the same radius of investigation). The significantly lower permeabilities encountered in the tests meant that the final radii of investigation were typically less than planned, less than 600 m. However, sufficient data were acquired to significantly down-grade expectations of full-field injection performance.

The sections hereunder are intended to illustrate to potential developers the degree of testing and analyses which might be required in analogue fluvial settings and the relative importance in general of dynamic well testing at bulk (not core) scale.

Further discussions on test design can be found in Kumar et al. 2010.

3.2 Lessons Learnt

Dynamic well tests in addition to conventional Drill Stem Tests (DSTs) are likely to be a significant element of exploration costs (approximately 25% in ZeroGen’s case).

Bulk-scale, long-term, dynamic tests are essential to calibrate core results and to examine bulk-scale k.h and reservoir connectivity. However, these need not be injection tests in the first instance, water production tests are likely to have fewer ambiguities and lower costs.

Dynamic tests should be employed as soon as possible to discount areas on economic and cost grounds due to pressure build-up or to guide development options towards active pressure management.

Dynamic tests should be conducted for long enough to investigate radius of investigation large enough to inform well injection rate decline, spacing and hence well count and economics.

Once CO₂ rel-perm effects are calibrated, dynamic tests with water/brine can be used to forecast injection performance. This calibration might be achieved with very small scale in-situ injection complimented by laboratory work.
Well testing is unlikely to calibrate or evaluate long time-scale reactivity issues. These will require lab characterisation to enable acceleration of reactions.

Injection well test data in ZeroGen wells led to a major discrepancy between core-log derived transmissivity (k.h) and effective in-situ k.h with the latter being an order of magnitude lower. This could not be accounted for by formation damage or skin. The conclusion was that the discrepancy was a result of severe lateral and vertical heterogeneity. This was consistent with expectations from fundamental geological analyses.

Furthermore, while radii of investigation were lower than anticipated (due to the lower in-situ k.h), some channel-type flow barriers were evidenced. Partial compartmentalisation, as well as severe heterogeneity was evident.

The fundamental geological analyses and research together with dynamic tests and the internal consistency between the two, gave a high confidence that injectivity would be considerably poorer than required (rather than some artefact of testing or of analysis).

While dynamic flow tests are critical, interpretive ambiguities remain. Therefore, dynamic tests are not a replacement for basic geological analyses. Decision confidence is greatly enhanced when dynamic results and geological understanding produce an internally consistent set of performance risk factors and predictors.

### 3.3 Introduction to the PFS Testing Work Program

In late 2008, the scale of the storage required changed from 3.3 to 60 million tonnes. Previous data acquisition phases had been undertaken for the smaller project. Following the discovery of a potential higher permeability in Catherine, play-fairway in ZG–5, a new PFS work program was designed which ultimately comprised:

- drilling a further five continuously cored wells (ZG–7, 8, 9, 10 and 12) to the north of ZG–5 to pursue that higher permeability play;
- drilling a dedicated CO₂ and water injection test well close to ZG–5 (ZG–11);
- injection testing wells ZG–7, 8 and 9 and 10 with water (though they were not drilled or designed for this purpose); and
- significant extra experimental work and studies on previously acquired data to investigate relative permeabilities and attempt to build a predictive model (as discussed in Section 3).

At the start of the commercial-scale PFS study, it was specifically recognised and communicated to stakeholders that the expansion in project scope in the absence of any diversification of storage portfolio, resulted in a very high-risk profile.

Therefore a key aim of the PFS program was to make direct measurements of injectivity with CO₂ and H₂O injection tests. The full objectives of the campaign included:

- Further appraisal drilling of core wells to:
  - test a geological model whereby the geologic environment becomes more proximal northwards, moving into EPQ–2 with improving reservoir quality;
– gain greater understanding of reservoir heterogeneity, in particular controls on permeability; and
– better delineate the reservoir architecture through detailed core description.

• CO₂ and H₂O injection tests (this section) to:
  – evaluate bulk–property CO₂ injectivity and the possibility to calibrate water injectivity as an alternative appraisal method and to determine practical capacity and well count; and
  – obtain clear, formation water samples.

• Special core experiments (Subsection 2.9.4) to:
  – determine seal strength through geomechanical and capillary pressure measurements; and
  – measure CO₂–brine relative permeability behaviour for input to dynamic modelling of CO₂ injection.

• 2D seismic acquisition and experimental VSP program (Subsection 2.9.3) to:
  – investigate whether seismic imaging of the reservoir could be improved; and
  – investigate whether a time–lapse response to CO₂ injection could be seen.

### 3.4 PFS Dynamic Testing

Of the six new wells drilled, ZG–7, 8, 9, 10 and 12 were drilled with mud and continuously cored. These wells had been designed planned based on earlier objectives (and with a more limited budget). While sub–optimal from a drilling and completion perspective, the first four were nevertheless converted for water injection testing purposes.

In contrast, well ZG–11 was drilled as a dedicated CO₂ injection well. It was drilled underbalanced with air to minimise the problem of formation damage that was thought may have contributed to earlier poor injectivity results in ZG1.

Only a subset of the all the tests run (Shell–ZeroGen, 2010e) are described hereunder.

### 3.4.1 Objectives of the CO₂ and H₂O injection tests

An Environmental Authority was obtained to allow injection of up to 3000 tonnes of CO₂ under a testing permit. The objectives of the CO₂ and H₂O injection tests were to:

• de–risk supercritical injectivity by establishing CO₂ initial injection into low permeable reservoir sequence as found in the Freitag Formation and Aldebaran Sandstone (core perms of 0.1–4 mD);

• de–risk supercritical injectivity by establishing CO₂ initial injection into a more permeable (core perms of 40–520 mD) Catherine Sandstone interval which had been encountered and recovered in ZG–5;

• understand CO₂ subsurface behaviour by providing data for the calibration of dynamic reservoir models of CO₂ injection and associated pressure increase;

• compare and calibrate CO₂ injection with water injection;

• evaluate dynamic k.h i.e. the effective behaviour of the in–situ reservoir at bulk–scale; and
evaluate potential reservoir boundaries to mitigate against possible rapid decline of injection rate with time (which would require increased well count).

The injected CO$_2$ was heated to avoid ambiguities of interpretation, which might be caused by thermal fracturing caused by cooling of the near well bore—a potential risk indicated by a scoping study by Shell technology India (Singhal, 2010).

### 3.4.2 CO$_2$ sourcing and injection facilities design

ZeroGen (through AGR Asia Pacific) developed proprietary CO$_2$ test–injection facilities and capabilities, designed for short on–off, as well as long duration tests, at a location next to ZG–5. The design process was unique and produced a transportable, expandable, controllable test facility, which the Queensland Government has retained for future test and research purposes.

The final design was for delivery of 10 to 150 tonnes per day (tpd) and up to 1400 tonnes of CO$_2$. However, after initial testing further modifications were made to reduce the minimum rate to 1 tpd.

#### Summary of CO$_2$ injection plant capability

**TABLE 3.1: SUMMARY OF CO$_2$ INJECTION PLANT CAPABILITY**

<table>
<thead>
<tr>
<th>Capability</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum pressure capability of plant</td>
<td>180kW</td>
</tr>
<tr>
<td>Design electrical maximum demand</td>
<td>350 KVA @ 0.9 pf</td>
</tr>
<tr>
<td>On–site CO$_2$ storage capability</td>
<td>180 Tonnes</td>
</tr>
<tr>
<td>Pump capacity pumps 1A to 1D</td>
<td>38 tpd</td>
</tr>
<tr>
<td>Maximum design flow rate of plant</td>
<td>150 tpd</td>
</tr>
<tr>
<td>Minimum design flow rate of plant</td>
<td>1 tpd</td>
</tr>
<tr>
<td>Maximum supercritical CO$_2$ outlet temperature at full flow rate</td>
<td>32°C</td>
</tr>
<tr>
<td>Electric heater rating</td>
<td>180 kW</td>
</tr>
</tbody>
</table>

**FIGURE 3.1: HIGH LEVEL PROCESS DIAGRAM FOR CO$_2$ INJECTION TEST**

- **CO$_2$ Supply & Transport**
- **Pump**
- **Liquid CO$_2$ Storage**
- **Electric Heater**
- **ZG11 Well**

<table>
<thead>
<tr>
<th>CO$_2$ State in Storage</th>
<th>CO$_2$ State after Pump</th>
<th>CO$_2$ State After Heater</th>
</tr>
</thead>
<tbody>
<tr>
<td>Temp: -20 deg C</td>
<td>Temp: -18 deg C</td>
<td>Temp: +32 deg C</td>
</tr>
<tr>
<td>Pressure: 2,000 kPa</td>
<td>Max Pressure: 20,000 kPa</td>
<td>Max Pressure: 20,000 kPa</td>
</tr>
</tbody>
</table>
3.4.3 CO₂ and water injection testing in ZG–11

The injection well ZG–11 was 30 m north–west of the existing ZG–5 cored well. It was a completed open hole across the Catherine, Freitag and upper Aldebaran injection intervals 878 to 1269 MGL.

A wide range of core permeability was encountered in the key formations of ZG–5 (Section 2). Hence, the injection well ZG–11 allowed CO₂ initial injectivity to be investigated in varying permeability ranges. The modelling work carried out for designing the injection test in ZG–11 was based on the petrophysical properties of the cores analysed in ZG–5.

Injection testing in ZG–11 included three CO₂ injection tests and one water injection test. The sequence of the tests conducted was as follows:

- Test 1 Partial well CO₂ injection test in the interval 943 to 1269 mGL—lower Catherine, Freitag and Upper Aldebaran (Figure 3.4)
- Test 2 Catherine CO₂ injection test in the interval 902 to 941 mGL
- Test 3 Catherine water injection test in the interval 878 to 941 mGL
- Test 4 Aldebaran CO₂ injection test in the interval 1231 to 1269 mGL.

3.4.4 ZG–11 Test 1—Partial well CO₂ injection

In this test, a total 154 tonnes of CO₂ was injected at an average rate of 8–10 tpd. The rate and pressure history during the entire test period is shown in Figure 3.2.

FIGURE 3.2: RATE AND PRESSURE HISTORY PLOT FOR ZG–11 PARTIAL WELL CO₂ TEST
Several observations may be made from Figure 3.2.

- Reservoirs were normally pressured. Initial pressure of 1620 psi measured at gauge depth of 3748 ft (1143 m) from surface was consistent with hydrostatic gradient;
- Matrix injection was achieved. The first three injection periods were under matrix conditions. The rate was extremely low (1.25 tpd);
- Fractures were initiated and propagated. During the injection under fracture condition, injection pressure remained constant with continued injection. The rates achieved during fracture injection mode ranged from 8–10 tpd; and
- Supercritical, dense phase injection was achieved. During injection, the gradient in the tubing measured was 0.31 psi/ft which gives CO\textsubscript{2} density of 700 kg/m\textsuperscript{3}.

Figure 3.3 and Figure 3.5 respectively show pressure derivatives during the initial shorter matrix injection falloffs, as well as final and longer fracture injection falloff.

**FIGURE 3.3: PRESSURE DERIVATIVE PLOT OF MATRIX INJECTION FALLOFFS FOR ZG–11 PARTIAL WELL CO\textsubscript{2} TEST**
FIGURE 3.4: ZG–11 COMPLETION SCHEMATIC FOR PARTIAL WELL CO₂ TEST
Conclusions based on the analysis of injection and falloff data of partial well CO₂ injection test are:

- the k.h for CO₂ derived from the test was less than 1/3rd the brine k.h from RCA maximum k.h of 18 mD.ft was interpreted from the well test from the final falloff after fracture injection. The k.h of the whole interval from RCA–brine measurements was 62 mD.ft;
- a fracture propagated from the well. The fracture half length interpreted from the final falloff was approximately 125 ft; and
- CO₂ was injected into several intervals. Resistivity (induction) logs post injection have shown CO₂ saturation of 10–20% in the following intervals:
  - Aldebaran—1237 m–1243 m, 1258 m–1263 m (MD); Catherine—946 m–949 m (MD);
  - the radius of investigation from the final falloff was 250 ft; and
  - no potential boundaries were observed within 250 ft.

### 3.4.5 ZG–11 Test 2—Catherine CO₂ injection test

A total 163 tonnes of CO₂ was injected, at sub–frac pressures, into the (best ‘core’ quality) Catherine interval 902–941 m MD, with peak rate achieved at 150 tpd for 14 hours. Injection during the entire test was under matrix conditions. The rate and pressure history during the test is shown in Figure 3.6. During injection the gradient in the tubing measured was 0.12 psi/ft, which gives CO₂ density of 270 kg/m³ (also validated by PLT fluid density data).
Based on the analysis of injection and falloff data:

- the k.h for CO\textsubscript{2} from the test was of order 1/8\textsuperscript{th} the brine k.h from RCA, a k.h of 230–250 mD.ft was interpreted from the well test. The k.h from RCA–brine measurement was 2000 md.ft;
- in–situ, bulk–property permeabilities are considerably lower than those derived from RCAs. Injection was considered to be into 5 m (921–926 m MD) of sand based on PLT during injection, then average effective permeability from well test analysis was 14–15.4 mD;
- the average permeability derived from well test was lower by a factor of 10 compared to the brine permeability calculated from RCA air permeability measurement;
- negligible skin was interpreted from the well test; and
- boundaries were detected. Effects of potential boundaries can be seen from the pressure response (increasing derivative) at late–time in the final falloff. A u–shape boundary (channel) model, with three boundaries 200, 600 and 500 ft from well gives the best match.

3.4.6 ZG–11 Test 3—Catherine water injection test

A total of 1420 units of brine (5000 ppm, KCl) was injected during this test with peak rate achieved of 380 bbls/d.

The pressure and rate history during the test and pressure derivative plot of the final falloff are shown in Figure 3.7 and Figure 3.8 respectively.
FIGURE 3.7: RATE AND PRESSURE HISTORY PLOT FOR ZG–11 CATHERINE H₂O TEST

FIGURE 3.8: PRESSURE DERIVATIVE PLOT OF FINAL FALLOFF FOR CATHERINE H₂O TEST
Based on the analysis of water injection and falloff data of this H₂O injection test:

- a k.h of 210–240 mD.ft was interpreted from the well test;
- injection was considered to be into 5 m of sand based on PLT during injection, then average brine perm from well test analysis was 12.8–14.3 mD;
- the average permeability derived from well test was lower by a factor of 10 compared to the brine permeability calculated from RCA air permeability measurement;
- negligible skin was interpreted from the well test;
- the radius of investigation from the test in the last falloff was 2000 ft; and
- effects of potential boundaries can be seen from the pressure response (increasing derivative) at late–time in the final falloff, with two boundaries 150 and 750 ft from the well.

### 3.4.7 ZG–11 Test 4—Aldebaran CO₂ injection test

A total of 38 tonnes of CO₂ was injected with rate ranging from 2–2.5 tpd during initial matrix injection and about 20 tpd during fracture injection. The complete rate and pressure history is shown in Figure 3.9. Three matrix injection attempts were made before fracture injection. During injection the gradient in the tubing was 0.31 psi/ft indicating a CO₂ density of 720 kg/m³.

![Figure 3.9: Rate and Pressure Plot for ZG–11 Aldebaran CO₂ Injection Test](image)

Several observations were made as follows:

- Aldebaran reservoirs were normally pressured. The initial pressure of 1875 psi measured at gauge depth of 3946 ft (1203 m) from surface was consistent with a hydrostatic gradient;
- matrix injection was achieved. The first three injection cycles were under matrix injection condition with maximum pressure gradient of 0.95 psi/ft observed in third injection cycle;
fractures were initiated. The fourth injection cycle was under fracture injection conditions and a pressure gradient of 1.12 psi/ft during injection and a fracture closure pressure gradient of 1.04 psi/ft during falloff were recorded;

- the maximum rate achieved during fracture injection was 20 tpd; and

- the pressure decline rate after fracture closure was 4 psi/hr.

Conclusions based on the analysis of injection and falloff data of Aldebaran CO₂ injection test were:

- a k.h of 6 mD.ft was interpreted from the well test;
- a very low permeability of 0.045 mD was interpreted based on 131 ft of net injection interval;
- the average Aldebaran permeability derived from well test was lower by a factor of 2 compared to the brine permeability calculated from RCA air permeability measurement;
- negative skin of –2 was obtained from well test; and
- the radius of investigation from the test was 300 ft.

Additional injection tests in continuously cored wells

Water injection tests were conducted in the Catherine Sandstone in four other wells, ZG–7 to ZG–10. Matrix injection was achieved in ZG–8 and ZG–10, whereas injection could be carried out only in fracture mode in ZG–7 and ZG–9, mainly because of low matrix injection potential. Furthermore, those fractures retained their charge and did not readily bleed off into the surrounding matrix.

3.4.8 Water injection testing in ZG–8

With reference to location map Figure 2.1, ZG–8 was drilled near the western boundary of EPQ–2 license area of the NDT, about 14 km north–west of ZG–7. The well also intersected thick channel sand facies of the Catherine Sandstone but the reservoir quality was poorer than expected and significantly poorer than the equivalent section in ZG–5.

A water injection test in ZG–8 was undertaken in an 18 m (1065–1083 m bGL) thick open hole interval with a net sand thickness of 13.44 m. The test interval was in a fluvial channel facies in the lowermost sequence of Catherine Sandstone.

The average ambient air permeability of the test interval obtained from the RCA measurements was 4.05 mD and average brine permeability was 0.96 mD. Brine k.h for the test interval was calculated to be 12.9 mD.m (42.3 mD.ft).

Each water injection test was followed by a falloff and was conducted in three stages:

1. Initially, matrix injection was carried out at the rate of 5 STB/d for four days.
2. Then, injection under fracture conditions was carried out for four days at the rate of 240 STB/d. To test the hypothesis that drilling damage could cause a skin, a perforation job was also run.
3. Finally, after stimulating a part of the test interval by perforating, another injection test under matrix condition was carried out for two days at the rate of 14 STB/d.
A history of pressure vs rates during the injection test period in ZG–8 is shown in Figure 3.10.

Observations from the ZG8 test were:

- Reservoirs were normally pressured. The initial pressure of 1493 psi, measured at a gauge depth of 3442 ft from surface, was consistent with a hydrostatic gradient;
- Operational problems made interpretation complex. There were several injection and shut-in periods of very short duration in between the major phases of injection test as described above;
- Matrix injection rates were very low, indicating low k.h and/or high skin (damage);
- Post-matrix injection shut-in results in a rapid pressure drop, back towards initial pressure, as expected;
- Fractures propagated during injection. During the high rate fracture injection period, the injection pressure fell by 73 psi, which was a strong indication of growing fractures. The fractures created did not connect into the albeit low, permeability reservoirs. Shut-in, post-fracture injection, did not result in rapid pressure drop. Pressure appeared to be ‘trapped’ in the fracture and surrounding matrix and did not leak-off rapidly towards initial aquifer pressure;
either the matrix in ZG–8 was significantly poorer than RCA indicates (as was found in ZG–11) and/or the formation was damaged—completely blocked. During the post–fracture shut–in periods, the entire open–hole section (not just the fracture–face) was also available for leak–off at a very elevated pressure. Based on the RCA data, which indicated a brine k.h of 42 mD.ft in the test interval, rapid leak–off should have taken place. Instead, bottom–hole pressures remained at high levels, even after ceasing injection. Possible reasons for this behaviour were either that the effective k.h was much lower than the values calculated from RCA or that the well–bore was extremely damaged preventing any leak–off. The damage required to prevent leak–off at such high pressure would have to been equivalent to complete blockage of the sand face; and

low matrix permeabilities rather than skin/damage seemed the most likely cause of low injection rates. Therefore, deep perforations were designed to penetrate likely drilling damage. The perforation of a 4 m interval, to reduce the effect of damage, did not result in any significant change of behaviour in the injection and falloff periods following perforation. Moreover, the final shut–in pressures in the post–perforation injection test also do not show a sharply downward trend towards initial pressures, as obtained in the first matrix injection/falloff. Thus no qualitative changes in fall–off behaviour could be observed from the attempt to remove damage at the well–bore.

Pressure falloff during initial matrix injection and later fracture injection stages is shown in Figure 3.11 and Figure 3.12 respectively.

**FIGURE 3.11: ZG–8, MATRIX FALLOFF 1 AND 2: LOG–LOG PLOT**

![Log-Log plot: dp and dp' normalised (Psi) vs dt](image)
Conclusions from the matrix injection periods were:

- In-situ, bulk property $k_h$ was less than $1/10^{th}$ brine $k_h$ from RCAs. During matrix injection conditions, in-situ $k_h$ was determined to be $\approx 3.48$ mD.ft from falloffs one and two vs RCA derived brine $k_h$ of 42 mD.ft;

- Drilling damage may have caused moderate skin. Skin of approximately eight was witnessed during the first two fall-offs. Deep perforations did not improve injectivity performance;

- Uncertainty remained on which net pay accepted the water. If the entire net pay of the test interval was considered to have accepted injected fluid, then the average brine perm from well test analysis would be of the order of 0.08 mD, based on a net thickness of injection interval of 13.44 m (44 ft); and

- No boundaries were detected in this ‘poorer’ Catherine at this location. The radius of investigation seen was 2600 ft for the entire test.

3.4.9 Water injection testing in ZG–10

ZG–10 is located in the northern part of the NDT about seven km South-East of the town of Emerald (Figure 2.1). This well encountered relatively good quality reservoirs with (ambient air core) permeability as high as 1189 mD found in distributary channel facies of the Catherine Sandstone. The earlier wells (ZG–7 to ZG–9), which lie between ZG5 and ZG10 also intersected the distributary channel facies in the Catherine Sandstone, but the reservoir quality was poor.
The water injection test in ZG–10 was undertaken in an 89 m (901–990 m bGL) thick open hole interval with a net sand thickness of approximately 51 m.

Average ambient air permeability of the test interval obtained from the RCA measurements was 30.2 mD and a brine average permeability of 15.4 mD. The brine k.h for the test interval was calculated to be 786 mD.m (2578 mD.ft).

ZG–10 is the only well, out of four core wells in which water injection tests were conducted, where the entire test was conducted under matrix conditions with reasonably high rates of injection. This Catherine Formation was drilled in an identical manner to the poorer quality ZG–7, ZG–8 and ZG–9 wells, which further discounts formation damage as the prime differentiator between ‘good’ and ‘poor’ Catherine Sandstones.

Three water injection tests, each followed by a falloff, were conducted in this well with rate of injection varying from 50 to 250 STB/d.

Pressure and rate history during the entire testing period is shown in Figure 3.13 and Figure 3.14.

**FIGURE 3.13: PRESSURE AND RATE HISTORY DURING INJECTION TESTING IN ZG–10**
The following conclusions were drawn from the interpretation of injection and fall–off data from the injection testing in ZG–10:

- In–situ, bulk–property, test derived \( k_h \) was of order \( 1/10^{th} \) that expected from RCAs. \( k_h \) of 70–80 mD.ft was interpreted from the well test vs an RCA–derived value of 786 mD.ft;
- Bulk, effective permeabilities were significantly lower expected from RCAs. If the entire sand sequence were considered to be contributing to injection, then the average brine perm from well test analysis would be of the order of 0.45–0.5 mD, compared to the 15.4 mD expected from RCA results;
- The average permeability of 0.5 mD derived from well test in ZG–10 was lower by a factor of 5 compared to the brine permeability calculated from RCA air permeability measurement;
- Fines migration in the open–hole conditions, or some form of time–dependent ‘scaling’ may have occurred. An increasing skin model (0–45) would be required to match the entire history of the test;
- The radius of investigation from the test in the longer fall–off–3 was 1400 ft; and
- Boundaries were detected at a relatively short distance in the ‘better’ Catherine Sandstones. Effects of potential boundaries can be seen from the pressure response (increasing derivative) at late–time in the fall–off 3. A parallel boundary (channel) model, with two boundaries 250 and 350 ft from well was consistent with the geology near this well.
3.4.10 Summary of results of CO₂ and water injection tests

Results from the CO₂ and water injection testing in ZG–11 and only water injection testing in four core wells ZG–7 to ZG–10 are summarised in Table 3.2 and Table 3.3 respectively.

3.5 Conclusions—Dynamic Testing

Dynamic tests (CO₂ and water injection tests) were essential to evaluate the influence of CO₂ and water injection in the various formations. The tests reduced uncertainty significantly. In so doing, estimates of in-situ, bulk-property, permeability and k.h as well as connectivity, were all significantly reduced.

The k.h values derived from the interpretation of the test results, indicate in-situ permeability conversion factors relative to RCA measured values are in the range of 5–50 and were likely caused by significant heterogeneity of the reservoirs—especially the Catherine Formation, where relatively good core, permeabilities were encountered in ZG–10 and ZG–5. In general, the better RCA results require most significant downward revision.

Among all the dynamic tests, the highest radius of investigation achieved was only around 2000 ft in the high permeability Catherine injection interval in ZG–11. Nevertheless, boundaries were detected in that well, though not completely closed, at relatively short distances (45–750 ft) even in these limited tests. Interpreted as channel-type effects, these results influence estimates of connectivity which drive well count (Subsections 4.6 and 8.3.1).

Supercritical injectivity of CO₂ was established under matrix injection conditions in the higher permeability Catherine Sandstone interval in ZG–11. Approximately 150 tpd of CO₂ was injected, however, this could only be sustained for 14 hours due to supply issues.

The matrix injection potential of the sands in most of the formations appears very low (~10 to 40 STB/d). Valid data was not obtained in all of the tests due to either formation damage and/or fracturing (when initiated) outside of the reservoir intervals.

Significant efforts are required to gather pressure data in CO₂ tests. Real time down-hole and surface data acquisition had helped to monitor the test closely to optimise the test durations, as well as to maximise the value of information. However, this adds greatly to cost as well as completions and operations complexity. In turn this increases operational risk and hence risk of not acquiring key data.

A large proportion of the appraisal value of information could have been obtained from production tests—but not the calibration of CO₂ injection rates to water injection rates.

In future projects, calibration from CO₂ to water dynamics (in-situ, rel-perm effects) early in a campaign could allow subsequent appraisal costs to be reduced by avoiding costly CO₂ injection schemes.
### TABLE 3.2: SUMMARY OF DP–2B, CO₂ AND WATER INJECTION TESTS IN ZG–11

<table>
<thead>
<tr>
<th>Test</th>
<th>Test period</th>
<th>Test interval (mRT)</th>
<th>Net injection zone thickness (ft)</th>
<th>$k_h$ (brine) (RCA) (mD.ft)</th>
<th>$k_h$ (brine) (well test) (mD.ft)</th>
<th>Ratio of $k_h$ (test) to $k_h$ (RCCA)</th>
<th>Radius of investigation (ft)</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Partial well CO₂ injection</td>
<td>11 Oct–12 Nov</td>
<td>942–1269</td>
<td>513.3</td>
<td>62.7</td>
<td>18</td>
<td>0.27</td>
<td>250</td>
<td>No boundary</td>
</tr>
<tr>
<td>Catherine CO₂ injection</td>
<td>28 Nov–13 Dec</td>
<td>888–941</td>
<td>96.7</td>
<td>3926.7</td>
<td>233</td>
<td>0.06</td>
<td>–</td>
<td>Channel boundary</td>
</tr>
<tr>
<td>Catherine water injection</td>
<td>28 Dec–17 Jan</td>
<td>878–941</td>
<td>96.7</td>
<td>3926.7</td>
<td>233</td>
<td>0.06</td>
<td>2000</td>
<td>Channel boundary</td>
</tr>
<tr>
<td>Aldebaran CO₂ injection</td>
<td>16 Feb–3 Mar</td>
<td>1231–1269</td>
<td>66.7</td>
<td>10.5</td>
<td>6</td>
<td>0.57</td>
<td>300</td>
<td>No boundary</td>
</tr>
</tbody>
</table>

### TABLE 3.3: SUMMARY OF DP–2B, WATER INJECTION TESTS IN ZG–7, ZG–8, ZG–9 AND ZG–10

<table>
<thead>
<tr>
<th>Test</th>
<th>Test period 2009–2010</th>
<th>Test interval (mMD)</th>
<th>Net injection zone thickness (ft)</th>
<th>$k_h$ (brine) (RCA) (mD.ft)</th>
<th>$k_h$ (brine) (well test) (mD.ft)</th>
<th>Ratio of $k_h$ (test) to $k_h$ (RCCA)</th>
<th>Radius of investigation (ft)</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>ZG–7</td>
<td>8 Nov–28 Jan</td>
<td>822–1006</td>
<td>212.3</td>
<td>106.17</td>
<td>15</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>ZG–8</td>
<td>24 Nov–18 Feb</td>
<td>1069–1087</td>
<td>44.8</td>
<td>40.0</td>
<td>4</td>
<td>0.09</td>
<td>2600</td>
<td>No boundary</td>
</tr>
<tr>
<td>ZG–9</td>
<td>8 Nov–28 Jan</td>
<td>893–948</td>
<td>174.0</td>
<td>62.5</td>
<td>22</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>ZG–10</td>
<td>18 Dec–16 Jan</td>
<td>901–990</td>
<td>154.0</td>
<td>785.0</td>
<td>80</td>
<td>0.10</td>
<td>1400</td>
<td>Channel boundary</td>
</tr>
</tbody>
</table>
4 Resource Assessment—Injectivity

4.1 Context

The potential injectivity of the target formations and its change over time was investigated using statistical combinations of, multiple scenarios of single well dynamic simulations of CO₂ injection. Shell Technology and Projects led the modelling work in this area.

The predictions from Single Well Models (SWMs) were matched to the injection test data gathered during the PFS work program. History–matched models were used to forecast CO₂ injection profiles for 30 years with sensitivities run on a number of key parameters. A total of 60 calibrated CO₂ injection profiles were generated. These were the bases for the estimates of the required well count.

4.2 Lessons Learnt

Well tests and laboratory rel–perms are essential to model calibration, especially where it can be expected that permeability data derived from core are not representative of bulk–scale transmissivity e.g. where there is significant depositional and/or diagenetic heterogeneity.

In a situation where full–field predictive models cannot confidently be built, a modelling strategy comprising multiple single well scenarios can be used to investigate and quantify key techno–economic uncertainties.

In addition to heterogeneity, reservoir connectivity has a significant impact injection rate decline over time. This would have a significant impact in well–count over time and on capex phasing because the aggregate injection rate of the well stock at any time would be decreasing.

In order to sustain aggregate rate, the drilling of new wells would be needed throughout the life of the project to keep up with decline. This is discussed in Section 8.

Pressure transmission through the NDT reservoirs is relatively poor. Therefore, to discount the presence of closed boundaries at 1 km to 2 km, injection or production tests might have to be run continuously for several months to gain confidence on decline rate predictions.

Due to depositional (and possibly structural) heterogeneity at field scale, more than one such test would likely be needed to de–risk an area–wide development.

The degree of compartmentalisation had the most significant impact on cumulative CO₂ injection per well but the relative impact depends on permeability. High permeability wells with 2 km bounded model were able to inject up to 150% additional cumulative CO₂ compared to a 1 km bounded model. Low permeability wells with 2 km boundary model were able to inject only 12% additional cumulative CO₂ compared to a 1 km bounded model.
4.3 Modelling Methodology and Input Parameters

Single well dynamic models were based on five wells, ZG–3, ZG–5, ZG–6, ZG–8 and ZG–10. Ranges and uncertainty in reservoir parameters was captured by building these models as they covered the range of reservoir properties intersected. Each of the five wells modelled had a full suite of logs and RCA data from which reservoir properties such as porosity, permeability, net thickness, saturation were interpreted. In addition, SCAL data from all the ZeroGen appraisal wells were incorporated into the dynamic models to evaluate uncertainties around relative permeabilities.

The single well models were constructed using the following methodology:

- radial geometry with the well in the centre;
  - grid blocks becoming coarser away from the well (Figure 4.1) with radially adjacent grid blocks increasing in size by a factor of 1.14;
- ‘closed’ outer boundary, allowing no fluid flow or pressure dissipation across it; and
- for each well, models with radius 500 m, 1000 m and 2000 m were constructed to reflect the uncertainty around reservoir continuity and connectivity.

Note that the maximum radius of investigation of any dynamic well test was around 750 m (ZG–8). Partial boundaries were seen in ZG–11 and ZG–10 (in the best Catherine Sandstones) at distances ranging from 45 m to 250 m (Section 3.4.10).

**FIGURE 4.1: EXAMPLE OF SINGLE WELL RADIAL MODEL (ZG–8)**

ZeroGen 8 water injection brine permeability (mD)
Injection of 100% pure CO₂ was modelled simultaneously into Catherine, Freitag and Aldebaran, across a single, open completion interval. No faults or fractures were modelled. CO₂ injection was simulated at constant bottom–hole pressure. An injection pressure constraint was imposed, equivalent to a 0.93 psi/ft fracture gradient—this was fixed at the shallowest (Catherine) injection interval. The single well models were initialised at hydrostatic pressure and 100% water saturation.

The average layer thickness modelled within the sandstone intervals was 5 m with a range from 1–6 m (finer layering for high permeability layers).

Up–scaled petrophysical properties were assigned to each layer and kept homogeneous within the layer with no lateral variability (i.e. layer–cake). Upscaling was by arithmetic average of over–burden corrected brine permeability, which multiplied by net thickness of each layer gave an up–scaled k.h. The Ingelara Formation (intermediate seal in Figure 2.2) was modelled as shale with zero permeability.

Measured vertical permeability (Kv) and horizontal permeability (Kh) were available from 24 core plugs from different ZeroGen wells (ZG–5, ZG–6, ZG–7, ZG–8 and ZG–9). Based on these data the Kv/Kh ratio was taken as 0.1 in the dynamic models. This was consistent with laboratory measurements for a wide core permeability range (0.1–300 mD).

The Mercury–Air capillary data gathered from SCAL experiments conducted on core plugs of the ZG–5 well were used to arrive at CO₂–brine capillary pressure. The measured Hg–Air data and the converted CO₂–brine capillary pressure data were used in the models. The measured Hg–Air data and the converted CO₂–brine capillary pressure data were used in the models.

An Equation of State (EOS) model, adopted from the UT Austin work on CO₂ properties, was used. A two–component CO₂–H₂O system was modelled using water as the pseudo hydrocarbon phase and had water properties assigned to it. Water viscosity and the volume shift property were tuned to achieve a reliable EOS. The main reason for modelling water as a pseudo hydrocarbon phase was to achieve mutual solubility effects and numerical stability. No reaction chemistry of CO₂ with brine and rock was modelled, hence the results were not affected by treating water as pseudo–hydrocarbon phase compared to aqueous phase.

For each well a sensitivity analysis was undertaken on well skin values of zero and four. In the ZG–11 injection test (air drilled well and thermal fracturing effect due low temperature CO₂ injection) the well skin was interpreted to be zero.

For each well, sensitivity to relative permeability was run. One case using CO₂ relative permeability curves from the UT Austin public access database and a second case based on unsteady state CO₂ relative permeability experiments on ZeroGen cores (Shell–ZeroGen, 2010c).

### 4.4 Calibration of Injection Model to Injection Tests

The ZG–5, ZG–8 and ZG–10 single well dynamic models were calibrated to water injection test data and ZG–11 was calibrated to CO₂ injection test data.

The calibrated single well models were simulated for 30 years of CO₂ injection to produce
forecasts for subsequent well count estimation using Monte Carlo simulation (Subsection 6.4).

The history matched model for ZG–8 is shown in Figure 4.2. Time is plotted against the x–axis and pressure and injection rates are plotted against the y–axis. Negative rates signify the injection phase. Also shown in the figure is the base model without a calibration or permeability modification (Perm mod = 1.0) factor.

In the history matched simulation model the brine permeability is reduced by a factor of 0.0875 to match pressure data. A skin of 7.5 was used throughout the history match period. The history match results were also supported by the similar interpreted results of permeability and skin using pressure transient analysis results tool, Saphir–ECRINTM.

**FIGURE 4.2: HISTORY MATCH OF ZG–8 DOWN-HOLE PRESSURE DATA**

For ZG–11 water injection test, a reasonable match of injection pressure data to simulated pressure history was achieved by reducing the brine permeability in the model by a factor of 0.07 with a skin of zero (Figure 4.3), which is lower than that seen in the cored wells.

For the ZG–11 CO₂ injection test, the injection pressure history and simulated pressure history are compared in Figure 4.4. The second injection and falloff data was used to history match as there was a packer leak during the initial injection period. Two cases are shown, one with permeability factor of 0.5 and one with permeability factor of 0.1. The later matches reasonably well with the falloff but does not match with the injection pressure data. The case with a permeability modifier of 0.5 matches the injection data well but not the falloff data.
FIGURE 4.3: HISTORY MATCH OF ZG–11 DOWN–HOLE PRESSURE DATA

ZeroGen 11 water injection history match

Bottom hole pressure (PSI)

Time (Days From Start of Injection)

Simulation

History

Water injection rate

FIGURE 4.4: HISTORY MATCH OF ZG–11 DOWN–HOLE PRESSURE DATA IN ALDEBARAN SANDSTONE

Aldebaran matrix injection test

BHP (PSI)

Time (days from start)

Packer Leak
Hence not considered for history match

History Match Period
Thin, high permeability layers seen in the wells are probably not laterally continuous across the area of investigation of the test and unless this is accounted for in the model, the actual injectivity could be much less than predicted.

A homogeneity factor, equal to the ratio of the well test k.h to log brine k.h was applied. The homogeneity factor was derived from the calibrated single well models of ZG–8, ZG–10 and ZG–11 and applied uniformly to all wells. A homogeneity factor was applied to match the log permeability with the in–situ permeabilities. A factor of 0.08 was applied to the (best ‘core perm’) Catherine Sandstone and 0.5 to the Freitag Formation and Aldebaran Sandstone, where there is less vertical permeability heterogeneity. The Aldebaran calibration point was estimated by history matching the Aldebaran CO₂ pilot injection rate in ZG–11 to a single well CO₂ injection model. The Freitag formation is similar to the Aldebaran Formation in terms of flow properties and hence the Aldebaran calibration factor has been applied to the Freitag.

4.5 Single Well Modelling Results (ZG–5 Example)

This subsection describes the modelling process using ZG–5 as an example. The injection rate and cumulative injection profiles for 30 years from the ZG–5 single well model are shown in Figure 4.5 and Figure 4.7. The initial injection rates vary from 130 to 190 tpd, which declines to 4 to 48 tpd at the end of 30 years. There is, of course, a higher decline rate for the cases with smaller boundary model. The cumulative CO₂ injected is in the range of 0.13 to 1.0 million tonnes.

**FIGURE 4.5: CO₂ INJECTION PROFILE WITH TIME, ZG–5**
ZG–5 was the ‘best’ i.e. on a typical well. For comparison, a similar model for ZG–3 is included below (Figure 4.6).

Note from comparison of these two figures the impact of uncertainties in connectivity and an order of magnitude effect on well initial rates due to significant heterogeneity.

**FIGURE 4.6: CO₂ INJECTION PROFILE WITH TIME, ZG–3**

*zG3 – Single well model*

Note: Vertical scale maximum is 10 tpd
The model with largest radius (2000 m) shows the highest initial injection rates and slower declines compared to models with smaller radius. This is because the pressure 'signal' takes longer to reach the model boundary which slows the rate of pressure increase of the whole system. The large radius model has more volume to be compressed and thus requires more volume of CO₂ to reach the same system average pressure compared to a small radius model.

**FIGURE 4.7: CUMULATIVE CO₂ INJECTION, ZG–5**

*Cumulative CO₂ injection ZeroGen 5*
The analytical, theoretical ‘ultimate’ CO₂ storage capacity based on system compressibility and CO₂ solubility is compared to the modelled injected CO₂ volume over 30 years in Table 4.1. The analytical ultimate capacity is calculated based on 100% sweep efficiency, 2% vol/vol CO₂ solubility in 5000 ppm KCl brine and the same final average pressure achieved in simulations. The ratio of cumulative injected to analytical ultimate capacity is higher for the smaller radius models indicating higher sweep efficiency.

### TABLE 4.1: COMPARISON OF ULTIMATE CAPACITY TO CUMULATIVE INJECTED, ZG–5

<table>
<thead>
<tr>
<th>Model radius (m)</th>
<th>Pore volume (million m³)</th>
<th>Cumulative injection (million T)</th>
<th>Analytical ultimate capacity (million T)</th>
<th>Cumulative injected/analytical ultimate capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>500</td>
<td>8.39</td>
<td>0.14</td>
<td>0.19</td>
<td>0.76</td>
</tr>
<tr>
<td>1000</td>
<td>32.57</td>
<td>0.37</td>
<td>0.69</td>
<td>0.53</td>
</tr>
<tr>
<td>2000</td>
<td>134.16</td>
<td>1.0</td>
<td>2.81</td>
<td>0.36</td>
</tr>
</tbody>
</table>

The plume migration at the end of 30 years of CO₂ injection, for the boundary sensitivity cases of 500 m, 1000 m and 2000 m is shown in Figure 4.8.

The CO₂ plume migrated furthest in the Catherine Sandstone layer 26 which had an air permeability of 468.72 mD:
- a maximum of 900 m for the 2000 m boundary case;
- 440 m for the 1000 m boundary case; and
- 280 m for the 500 m boundary case.
CHAPTER THREE  Storage Part A—Northern Denison Trough

FIGURE 4.8: PLUME MIGRATION AFTER 30 YEARS OF INJECTION (RESERVOIR BOUNDARY SENSITIVITY), ZG–5
The time taken to see an increase in pressure at the model boundary is three months in the 1000 m boundary case. Note that for a 2 km well spacing, this would be the time at which cross-well interference might start to have a negative impact on rates.

The increase in pressures at the end of 30 years injection period is shown in Figure 4.9 which illustrates that a maximum pressure increase of 9.65 MPa (1400 psi) is seen at a distance of 1000 m from the well in Catherine Sandstone.

**FIGURE 4.9: PRESSURE DIFFERENCE AROUND WELL AFTER 30 YEARS OF INJECTION, ZG–5**

The impact on CO₂ injection of varying the well skin from zero to four on CO₂ injection is shown in Figure 4.10. In the 500 m boundary model, the initial rate is 185 tpd for well skin zero and 105 tpd for the well skin four case. This is a reduction of 43% in initial injection rate with higher skin.
The impact of well skin is highest for the largest radius model, where injection rates are sustained for longer times. The cumulative injection volumes compared for the three boundary models with well skin zero and four shows that the difference in cumulative injection increases with model radius.

The effect on plume migration of well skin is only a 50 m reduction with a well skin of four compared to a well skin of zero (Figure 4.11).
FIGURE 4.11: PLUME MIGRATION AFTER 30 YEARS OF INJECTION (WELL SKIN SENSITIVITY), ZG–5

Skin = Zero

Skin = Four

CO₂ Saturation

1.0e+0

1.0e-1

1.0e-2

1.0e-3

1.0e-4

1.0e-5

Catherine

Freitag

Aldebran

(Well Skin Sensitivity, ZG–5)
The models with the ZeroGen experimental relative-permeability data (RlpH) indicated lower injection rates compared to the published relative-permeability data (RlpM). CO₂ injection rate for relative permeability cases for different boundary models for a well skin of zero are shown in Figure 4.12.

**FIGURE 4.12: IMPACT OF RELATIVE PERMEABILITY ON CO₂ INJECTION RATE, ZG–5**

The maximum plume migration would be higher for the ZeroGen experimental relative-permeability data (RlpH) but lower CO₂ saturations are observed throughout the reservoir, hence the cumulative injection is higher when using the published relative-permeability data (RlpM).

In summary, the average injection rates in the ‘best’ well ZG–5 varied from 11 to 90 tpd over the 30 year injection period. The injection rate decline is most rapid within the cases of more compartmentalised reservoirs (closer boundaries) and with higher well skin.

The impact of various sensitivity parameters (i.e. model boundary, well skin and relative permeability curves) on cumulative CO₂ injection is shown in Figure 4.13. The baseline of zero represents the reference case (1000 m boundary, zero skin and published relative-permeabilities).

Reservoir compartmentalisation (boundary) has a significantly larger impact on cumulative injection compared to well skin and relative-permeability. The 500 m boundary model is able to inject 60% less than the reference case, whereas the 2000 m boundary model is able to inject approximately 170% more.
4.6 Conclusions from all Single Well Models

The degree of compartmentalisation and reservoir boundary distance has a significant impact on cumulative CO₂ injection in wells with a high k.h (Figure 4.14). High permeability wells with 2000 m boundary model were able to inject up to 170% additional cumulative CO₂ compared to a 1000 m boundary model. Low permeability wells with 2000 m boundary model were able to inject only 12% additional cumulative CO₂ compared to a 1000 m boundary model.

Reservoir boundary distance has a significant impact injection rate decline over time. This would have a significant impact in well-count over time and on capex phasing because the aggregate injection rate of the well stock at any time would be decreasing, whereas the CO₂ rate from the plant remains constant. In order to sustain aggregate rate, the drilling of new wells would be needed throughout the life of the project to keep up with decline.

Pressure transmission through the NDT reservoirs is relatively poor. Therefore, to discount the presence of closed boundaries at 1 km to 2 km, injection tests might have to be run continuously for several months to gain confidence on decline rate predictions.

Due to depositional (and possibly structural) heterogeneity at field scale, more than one such test would likely be needed to de–risk an area–wide development.
Increasing well skin from zero to four could reduce the cumulative injection by up to 20%. Prediction of borehole or other fines and scaling could have a major impact on well-count expectations and on operating costs (work-over requirements). However, well skin would have minimal impact on plume migration distance after 30 years of CO₂ injection.

Models using the ZeroGen experimental relative-permeability curves injected lower cumulative CO₂ (2% less in high permeability wells and 9% less in low permeability wells) compared to published relative-permeability curves shown in Table 4.2. Understanding perms and any variation in rel-perms is essential.

**TABLE 4.2: RATE AND VOLUME PREDICTIONS BASED ON ZEROGEN EXPERIMENTAL RELATIVE–PERMEABILITY CURVES**

<table>
<thead>
<tr>
<th>Well</th>
<th>Net H (m)</th>
<th>KH (mD.m)</th>
<th>Avg. injection rate (tpd)</th>
<th>Cumulative CO₂ injection (million T)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Catherine</td>
<td>Freitag</td>
<td>Aldebaran</td>
<td></td>
</tr>
<tr>
<td>ZG–3</td>
<td>101.786</td>
<td>10.451</td>
<td>5.6</td>
<td>1.664</td>
</tr>
<tr>
<td>ZG–5</td>
<td>166.11</td>
<td>51.05</td>
<td>41.91</td>
<td>20.57</td>
</tr>
<tr>
<td>ZG–6</td>
<td>155.971</td>
<td>42.63</td>
<td>5.37</td>
<td>4.19</td>
</tr>
<tr>
<td>ZG–8</td>
<td>230.357</td>
<td>78.89</td>
<td>1.43</td>
<td>0.57</td>
</tr>
<tr>
<td>ZG–10</td>
<td>326.518</td>
<td>62.88</td>
<td>4.66</td>
<td>3.03</td>
</tr>
</tbody>
</table>
In lower permeability wells (ZG–1, ZG–4, ZG–3, ZG–6, ZG–7, ZG–8 and ZG–9) plume migration is insensitive to boundary distance. In the higher permeability wells (ZG–5 and ZG–10) the plume migration distance increases with boundary distance (Figure 4.15).

**FIGURE 4.15: PLUME MIGRATION AFTER 30 YEARS OF INJECTION FOR DIFFERENT MODEL BOUNDARY**

![Graph showing plume migration for different model boundary](image)

In low permeability wells (ZG–3, ZG–6 and ZG–8) the time–average CO$_2$ injection rate is 8 to 15 tpd and cumulative CO$_2$ injection is 0.09 to 0.17 million tonnes respectively.

In high permeability wells (ZG–5 and ZG–10) the weighted time–average injection CO$_2$ rate is 11 to 66 tpd and cumulative CO$_2$ injection is 0.13 to 0.74 million tonnes respectively. A summary is shown in Table 4.3.

**TABLE 4.3: SUMMARY OF WELL RATES AND CUMULATIVE CO$_2$ INJECTION FOR ZEROGEN TYPE WELLS**

<table>
<thead>
<tr>
<th>Well</th>
<th>Time average injection rate (tpd)</th>
<th>Cumulative CO$_2$ injection (million T)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ZG–3</td>
<td>5 to 7</td>
<td>0.05 to 0.08</td>
</tr>
<tr>
<td>ZG–5</td>
<td>11 to 90</td>
<td>0.13 to 1.00</td>
</tr>
<tr>
<td>ZG–6</td>
<td>9 to 21</td>
<td>0.10 to 0.23</td>
</tr>
<tr>
<td>ZG–8</td>
<td>11 to 18</td>
<td>0.12 to 0.19</td>
</tr>
<tr>
<td>ZG–10</td>
<td>11 to 43</td>
<td>0.12 to 0.47</td>
</tr>
</tbody>
</table>

Implications of these single well models on aggregate field injection and well–count estimates are evaluated further in Section 7.
5 Resource Assessment—Containment

5.1 Context
ZeroGen regarded secure long-term containment assurance of CO₂ to be of prime importance. For containment confidence in any CO₂ sequestration site, four main factors were considered to be critical:
- good seals which retain their integrity under injection pressure conditions;
- the integrity of legacy wells;
- suitable completions of new CO₂ injectors to avoid leakage; and
- lateral plume migration only within allowable limits of the container.

5.2 Lessons Learnt
Top seals proved to be relatively tight (very low permeabilities) and with CO₂ entry pressure considerably higher than fracture pressures or postulated injection pressures. MCIP and CO₂ permeability tests were essential for rapid de-risking.

Extended leak-off tests, supported by core-strength tests, were essential to put limits on injection pressures and acquiring these data in more than one well was critical to understanding the aerial variation in the stress fields. This can have a significant impact on development planning.

Seismic data quality in the area was poor due to surface basalts. At the end of the project it was not known whether a comprehensive fault map would be possible. It is possible that critically stressed faults might not be locatable, this would have added safety margins to injection pressure and hence increasing well counts.

Lateral migration in the NDT tight sand formations was likely to be less than 1 km. Modelling the likely scale and range of possible plume migration is critical to development planning and the definition of injection well exclusion margins from key features (legacy wells, significant faults and tenement boundaries).

A sequence stratigraphic revision and new framework was required to improve confidence in the lateral prediction of main and intermediate seals.

5.3 Ultimate and Primary Seals
A containment complex, may contain several reservoir horizons each with primary seals. In the terminology adopted here, an uppermost seal is defined as the ultimate seal, which defines the vertical extent of the container. CO₂ must be retained below this ultimate seal.
In general, NDT seals are formed by transgressive marine shales. Interaction of dry CO₂ with shale is known to cause desiccation at the contact surface, however, for massive units this is considered unlikely to cause seal–breach (Busch et al. 2008).

### 5.3.1 Ultimate seal—the Black Alley Shale

The regional top seal, Black Alley Shale (BAS), is present in the entire area with an average thickness of 30–55 m. Understanding the nature and properties of this seal was one of ZeroGen’s prime concerns.

Depositionally, the BAS accumulated in a stagnant standing water environment where evidently few forms of organic life could survive, at a time of voluminous volcanic input to the basin. Outcrops of the BAS are exposed in a creek near the entrance to the Carnarvon Gorge approximately 80 km south of Springsure, Figure 5.1. Lighter coloured tuff bands are very evident. The BAS has been mapped regionally despite poor seismic control. All of the ZeroGen wells that were drilled in the storage site intersected the BAS and it was cored in ZG–2, ZG–3, ZG–4, ZG–5 and ZG–6.

The BAS is a proven seal within the up–dip gas fields and there are no hydrocarbons above this seal in the NDT. Cap rock analysis on three core samples of BAS from ZeroGen wells concluded that measured permeability of these samples is in sub nano–Darcy range and hence these BAS cap rocks have excellent sealing capacity (ACS, 2008 and Aachen, 2010).

**FIGURE 5.1: BLACK ALLEY SHALE OUTCROP AT ENTRANCE TO CARNARVON GORGE**
Immediately overlying the BAS, is a widespread regressive coal measure sequence of the Bandanna Formation. The unit consists of feldspathic, lithic sandstone, sandy siltstone and coal (including oil shale). Some geologists believe the boundary between the marine BAS and the coal measure sequence of the Bandanna Formation is gradational. Brown et al. (1983) believe that the BAS forms the prodelta shales of the overlying deltaic and coal measure sequence of the Bandanna Formation. Unfortunately, the contact is very poorly exposed in outcrop and is generally covered by alluvium or scree. This comment is included to highlight the key importance of sequence stratigraphy in forming a view of seal geometries. ZeroGen undertook a significant review of these issues.

5.3.2 Other seals

The Peawaddy and Ingelara shale/shaly formations provide primary seals to the injection intervals. They occur above the Catherine and Freitag respectively. In the central portion of the license area, these formations may occur in more sandy sequences. The Peawaddy sequence is about 40–60 m thick, where as Ingelara is a massive formation with an average thickness of 85–140 m. The transgressive marine shales of the Ingelara, Peawaddy, and Lower Freitag formations are all proven regional seals for underlying reservoir sandstones within the updip gas fields. Regional stratigraphic correlations indicated that they are laterally extensive. Mercury injection seal capacity experiments were conducted on four samples from the Peawaddy in ZG–4 and results were comparable to the BAS.

For completeness, several thick and regionally extensive shales and siltstones within the Aldebaran sandstone may provide effective intra–formational seals. Presence of these thick shale/shaly layers significantly reduces the chance of upward leakage of CO₂ in to the geological formations above them and enhances the containment of injected CO₂ within the formations of injection.

5.4 Other Containment Factors

5.4.1 Geomechanical data integration

Based on the geomechanical analysis conducted by JRS Petroleum Research (Meyer, 2007 and Scott, 2009), a stress tensor was defined by the magnitudes of the three principal stresses (Sᵥ, SHmax, Shmin). The vertical stress magnitude was calculated using the density logs from four wells ZG–3 to ZG–6. Vertical stress magnitude calculations for the four wells indicate a vertical stress gradient of ~25 MPa/km. The horizontal maximum stress value estimated by the study of borehole breakout occurrences was estimated to be 47 MPa/km (2 psi/ft) in sand.

The minimum principal stress value determined from Extended Leak–off Tests (XLOTs) was indicated to be ~25 MPa/Km (Rao et al., 2010).

However, there are uncertainties on the magnitudes of principal stresses in the stress tensor. Given the compressional regime, the XLOT may have measured the vertical stress value as the minimum principal stress. Hence, this stress tensor needed to be accurately defined and constrained further (Shell–ZeroGen, 2010h). Results are summarised for NDT wells (from North to South) in Table 5.1.
The NDT area is subject to a stress regime on the boundary of strike–slip and thrust with a maximum horizontal stress direction of ~018N. These preliminary analyses (Campagna, 2010) indicate that the southern DP–2 wells on the flanks of Turkey Creek are in a largely compressional stress regime, whereas areas to the north and east may be in more of a strike–slip regime. This would have important implications for discussions on fracture stimulation because results from one area, e.g. the horizontal fracture evidenced on down–hole camera in ZG–11, may not be typical.

Vertical stress is usually the minimum principal stress confirmed that the NDT area. Any natural or induced fractures in the ZeroGen wells would then be expected to grow horizontally perpendicular to the vertical minimum principal stress, thereby localised in vertical plane and not affecting the regional seal integrity if properly designed and stimulated to aid injectivity in full field development.

Figure 5.2 shows possible different stress regimes (blue vs. red) based on curvature analysis of available data. The potential reverse state of stress was mapped out by determining the dip of the minimum stress and reveals large expanses of reverse stress states in the southern half of the project area. These were related to the fault complexities in that area. In the Northern half, the reverse areas emanate from the compressional quadrants of the faults in the Northeast. West of ZG–8 is a large expanse of reverse state in the foot wall section of the large North–South fault. This reverse region is enhanced in the south where interaction between two major fault systems occurs just west of ZG–7.

**TABLE 5.1: DISTRIBUTION OF FORMATION BREAKDOWN (FBP) AND FRACTURE CLOSURE PRESSURES (FCP) FROM XLOT (AND LOT) DATA**

<table>
<thead>
<tr>
<th>Well</th>
<th>Formation</th>
<th>Depth (m bGL)</th>
<th>FBP (psi/ft)</th>
<th>FCP (psi/ft)</th>
<th>Overburden (psi/ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ZG–10 Catherine</td>
<td>946</td>
<td>1.27</td>
<td>1.11</td>
<td>1.06</td>
<td></td>
</tr>
<tr>
<td>ZG–8 BAS</td>
<td>796</td>
<td>1.19</td>
<td>1.12</td>
<td>1.09</td>
<td></td>
</tr>
<tr>
<td>ZG–7 Ingelara</td>
<td>1031</td>
<td>0.94–1.17</td>
<td>1.08</td>
<td>1.09</td>
<td></td>
</tr>
<tr>
<td>ZG–7 Catherine</td>
<td>947</td>
<td>0.88–1.05</td>
<td>0.68–0.71</td>
<td>1.09</td>
<td></td>
</tr>
<tr>
<td>ZG–9 BAS</td>
<td>642</td>
<td>1.02</td>
<td>1.01</td>
<td>1.10</td>
<td></td>
</tr>
<tr>
<td>ZG–9 Catherine</td>
<td>918</td>
<td>1.39</td>
<td>1.08</td>
<td>1.10</td>
<td></td>
</tr>
<tr>
<td>ZG–5 BAS</td>
<td>612</td>
<td>1.26</td>
<td>1.13</td>
<td>1.09</td>
<td></td>
</tr>
<tr>
<td>ZG–6 BAS</td>
<td>874</td>
<td>1.33</td>
<td>1.10</td>
<td>1.10</td>
<td></td>
</tr>
<tr>
<td>ZG–2 BAS (LOT)</td>
<td>593</td>
<td>1.33</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>ZG–1 Bandanna (LOT)</td>
<td>522</td>
<td>0.82</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
5.4.2 Possible thermal effects on rock mechanics

The injection of cool fluids has a reducing effect on the tensile strength and hence fracture gradient of rocks. The magnitude of this effect may be important. If thermal fracturing must be avoided for reasons of cap–rock or well–bore integrity, then two major cost implications could ensue:

1. Injection BHPs would need to be reduced and hence well counts increase.
2. CO₂ might need to be heated, adding potential heating and power costs (Subsection 7.6.4).

The impact of long–term (cool) CO₂ injection on formation temperatures and hence in–situ stresses due to thermal cooling was investigated. Because of the relatively small injection rates and short injection periods during the ZG–11 pilot injection program, a minimal (negligible) effect of thermal cooling was observed in that test. However, long–term modelling results reveal that for a full–scale and long–term CO₂ injection, thermal stresses could play an important role and need to be considered for any facility or well design and in setting an upper bound on injection pressures (Singhal, 2010).

5.4.3 Fault framework

All available 2D seismic data were interpreted for the project, though no new data was acquired. No 3D seismic data existed.

2D seismic coverage of various vintages and qualities exists over the hydrocarbon accumulations showing major north–south trending faults and compartmentalisation of the up–dip gas–fields. Uncertainty of fault continuity and presence off the structure remained due to sparse low quality 2D. Presence of sub–seismic faults cannot be ruled out.

Three fault sets were present in the most mapped area:

1. Inverted normal faults. These are the primary half graben faults and have undergone at least one and possibly two reverse movements during compression. These trend north to northwest and are sub–vertical. Throws, appear to be in the range of decametres. The inverted faults approach 200 m of throw in the Springton–Turkey Creek area.
2. Rare small scale normal faults with throws in the decametre range. There is insufficient seismic spacing to obtain an accurate orientation on these faults.
3. Normal faults in the Bandanna (uppermost Permian). These decay down into the Mantuan, Catherine, and occasionally terminate below the Aldebaran reflector. Throws of up to 100 m are noted. The orientation in this area appears to be North–South.

In a compressional or strike slip stress setting, fault reactivation could be triggered by injection pressures. To evaluate this location, the orientation of faults would need to be imaged (on seismic surveys). Fault reactivation risk remained poorly assessed at the time the project was closed for other reasons.
5.4.4 Legacy wells

In the ZeroGen permit areas of NDT, legacy wells were virtually non-existent as the area underwent minimum exploration activity, mainly because of lack of hydrocarbon accumulations. For notional development planning, it was assumed that any such wells will be avoided.

FIGURE 5.2: ESTIMATED STRESS REGIMES OVER THE PROJECT AREA (REVERSE IN RED)
5.4.5 CO₂ injection wells

Another potential leak path for CO₂ to the shallow zones and to surface is via the CO₂ injection and monitoring wells drilled and completed during the execution of the sequestration project period.

If these wells (Subsection 7.6) were completed with CO₂ compliant cement and completion metallurgy, then the chances of these wells becoming potential leak path would reduce substantially. The only injection well in the ZeroGen Project so far ZG–11 was completed following this philosophy. In ZG–11, corrosion resistant (13 Cr) production casing was installed from top of BAS to Casing shoe and CO₂ resistant cement (Thermolock™) had been used to cement the production casing with cement rise to surface. Similarly, the tubulars used in injection and monitoring wells for full-field development would likely be a combination of carbon steel, GRE or chrome as appropriate.

5.4.6 Lateral migration

Under the Queensland GHG Storage Act (2009), any injected CO₂ must be retained within a licensed area. Therefore prior to Final Investment Decisions (FID) models must show little chance of migration outside of this area and developments plans must mitigate against it.

There were economic sub-surface resources surrounding ZeroGen’s tenements. In particular, several gas fields are on production to the west and south west. They are structurally up dip to the west of synclinal structures of ZeroGen permit area. From reservoir simulations carried out with the petrophysical properties measured in the ZeroGen appraisal wells, even though plume migration distance varied in different realisations, in no case was it predicted to reach the nearby gas fields. Chances of contamination of resources in the nearby gas fields were considered highly unlikely.

Moreover, the hydrodynamic connectivity or pressure communication between the up dip gas fields and down dip saline aquifers was not established and based on the reservoir pressure decline data of the nearby gas fields, it was believed that these fields are producing under depletion mode. Thus, the chances of contamination of the hydrocarbon resources in the nearby gas fields and CO₂ plume reaching the existing well stock in the gas fields was remote.

Finally, with reference to Subsection 7.3 ‘NDT Constraints to the Conceptual Development Area’, the risk would be further mitigated by including ‘no-drill’ margins around the edge of the tenements.

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6 Well ZG3 was drilled on the tenement boundary within 1–2 km of a heavily depleted gas field. Pressures in that well were normal hydrostatic despite several years of up-dip gas production. Calibrated models show <1 km plume movement in the tight, NDT reservoirs.
6 Resource Assessment—Capacity

6.1 Context

A wide body of literature exists describing various methodologies for calculation of GHG storage capacities. This section describes two such methods for capacity estimates for open and closed systems, based on adjustments made to estimates of accessible pore volume. The adjustments and estimates were constrained by storage ‘efficiency’ or ‘sweep’ factors derived from calibrated single well models, but estimates not based on full field dynamic models tied to a field development plan.

6.2 Lessons Learnt

Assumptions on far–field boundary conditions and on reservoir compartmentalisation have an order of magnitude impact on capacity estimates. Data is required to constrain these.

Early acquisition of connectivity data, through extended well (production) tests, is probably the most cost effective way to discount an area for commercial storage.

Estimates of capacity based on adjusted pore volumes and efficiency factors, do not inform in any useful way whether such capacity can be accessed at rates required by a tied CO₂ emitting plant.

6.3 Storage Capacity Estimation Methodology

6.3.1 Types of storage system

In many cases, saline aquifers have a large areal extent and for all practical purposes are considered open or ‘infinite acting’ system. However, in some cases, saline aquifers may be compartmentalised by lateral flow boundaries such as low–permeability zones created by change in pore structure (e.g. channels) or sealing faults. In these cases, formations would act as closed boundary units, as suggested by Zhou, 2008 (and others). **One of the foremost issues to be addressed for capacity estimation and rate forecasting is the type of far–field boundary conditions which exist in the assessment area.**

Both closed system and open system capacity estimation (ref. Figure 6.1 and Figure 6.2) were considered. In a fully closed system storage is only due to system compressibility and solubility of CO₂ in brine. In an open system, where formation brine is able to migrate away from the injection point in an infinite acting way, storage is contributed by system compressibility, solubility of CO₂ in brine and displacement of brine.
A maximum or ‘ultimate’ storage capacity was defined based on 100% sweep efficiency and final pressure of the formation equal to the injection pressure whereas ‘effective’ storage capacity takes into account sweep efficiency and final pressure which is average of initial pressure and injection pressure.

6.4 Capacity Estimation Inputs

Probability distributions functions based on 12 ZeroGen wells and regional data were constructed (Shell–ZeroGen, 2010g). Parameters modelled were: porosity, net thickness, pressure, compressibility, CO₂ solubility, sweep efficiency and irreducible water saturation.

Area

The net available area in the existing acreage (i.e. EPQ–1+EPQ–2) provided supercritical conditions of storing CO₂ is 409 km² out of 854 km² of total area. Figure 6.3 shows the available area (i.e. the area shown in green, yellow and blue within the acreage boundary).
This area included only high focus areas in the existing acreage (represented by B1, C1A and B2A, see Figure 6.3) and excluded environmentally sensitive areas, areas of restricted access, built-up areas, areas proximal to fault locations.

**FIGURE 6.3: AREA AVAILABLE FOR STORING CO₂, WITHIN EPQ–1+EPQ–2**
Table 6.1, shows the ranges of data used in probabilistic capacity calculations.

**TABLE 6.1: PARAMETERS USED IN CAPACITY ESTIMATION**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Type of distribution</th>
<th>Typical values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity</td>
<td>Triangular</td>
<td>8%–11%–14% (min – med – max)</td>
</tr>
<tr>
<td></td>
<td>(date from calibrated logs applied by facies–area)</td>
<td></td>
</tr>
<tr>
<td>Brine compressibility</td>
<td>Measured ranges</td>
<td>2.96 x 10^{-6} psi⁻¹ to 2.84 x 10^{-6} psi⁻¹</td>
</tr>
<tr>
<td>(50°C, 4500 ppm at injection</td>
<td></td>
<td></td>
</tr>
<tr>
<td>pressures)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pore compressibility</td>
<td>Triangular</td>
<td>10.1 x 10^{-6} psi⁻¹ (most likely)</td>
</tr>
<tr>
<td>(as above)</td>
<td>(from core data)</td>
<td>to 7.4 x 10^{-6} psi⁻¹ (min value)</td>
</tr>
<tr>
<td>Total compressibility</td>
<td>Triangular</td>
<td>2.96 x 10^{-6} psi⁻¹ (most likely)</td>
</tr>
<tr>
<td>(as above)</td>
<td>(calculated)</td>
<td>2.84 x 10^{-6} psi⁻¹</td>
</tr>
<tr>
<td>CO₂ solubility in mol fraction</td>
<td>Triangular</td>
<td>0.0235 (most likely) to 0.0248 (zero likelihood)</td>
</tr>
<tr>
<td>(as above)</td>
<td>(calculated using PVTSim™)</td>
<td></td>
</tr>
<tr>
<td>Irreducible water saturation</td>
<td>Range based on unsteady state SCAL</td>
<td>0.5–0.7</td>
</tr>
<tr>
<td>(Sw)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sweep efficiency</td>
<td>Table 72 re. single well models</td>
<td>0.03 to 0.59 (see Table)</td>
</tr>
</tbody>
</table>

**TABLE 6.2: SWEEP EFFICIENCIES SUED IN MONTE CARLO SIMULATION FOR CAPACITY ESTIMATION**

<table>
<thead>
<tr>
<th>Wells</th>
<th>Boundary of single well models</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>500 m</td>
</tr>
<tr>
<td>ZG–3</td>
<td>0.41</td>
</tr>
<tr>
<td>ZG–5</td>
<td>0.76</td>
</tr>
<tr>
<td>ZG–6</td>
<td>0.59</td>
</tr>
<tr>
<td>ZG–8</td>
<td>0.44</td>
</tr>
<tr>
<td>ZG–10</td>
<td>0.33</td>
</tr>
</tbody>
</table>

Monte Carlo simulation

The input parameter distributions were used to compute the CO₂ storage capacity using the equations described herein. Monte Carlo simulation was performed using the @RISK™ tool in Excel™ to arrive at a distribution for CO₂ storage capacity for the available area in the existing acreage. 1000 simulations were run to arrive at the distribution.
6.5 CO₂ Storage Potential for ZeroGen Acreage

The cumulative distribution curve of CO₂ storage capacity for open and closed systems is summarised in Table 6.3 and shown in Figure 6.5. The closed system CO₂ storage capacity is contributed by compressibility and solubility process whereas an open system CO₂ storage capacity is determined by solubility and displacement process.

**TABLE 6.3: SUMMARY OF EFFECTIVE AND ULTIMATE CO₂ STORAGE CAPACITY FOR OPEN AND CLOSED SYSTEMS FOR AVAILABLE AREA**

<table>
<thead>
<tr>
<th>Probability</th>
<th>Effective CO₂ storage capacity (million T)</th>
<th>Ultimate CO₂ storage capacity (million T)</th>
<th>Probability</th>
<th>Effective CO₂ storage capacity (million T)</th>
<th>Ultimate CO₂ storage capacity (million T)</th>
</tr>
</thead>
<tbody>
<tr>
<td>P90</td>
<td>385</td>
<td>1423</td>
<td>P90</td>
<td>50</td>
<td>131</td>
</tr>
<tr>
<td>P70</td>
<td>613</td>
<td>2007</td>
<td>P70</td>
<td>68</td>
<td>181</td>
</tr>
<tr>
<td>P50</td>
<td>865</td>
<td>2680</td>
<td>P50</td>
<td>87</td>
<td>230</td>
</tr>
<tr>
<td>P30</td>
<td>1195</td>
<td>3490</td>
<td>P30</td>
<td>113</td>
<td>288</td>
</tr>
<tr>
<td>P10</td>
<td>1969</td>
<td>4902</td>
<td>P10</td>
<td>163</td>
<td>386</td>
</tr>
</tbody>
</table>

**Estimate of probability of encountering an opened or closed system**

The cross–section of the regional geology (Figure 6.4) suggested that the ZeroGen storage site is bounded on either side by faults and outcrop of the reservoirs. Therefore, the ZeroGen storage site was considered more likely to resemble a closed system rather than an open system. An 80% probability of encountering a closed system was used to calculate the likely overall storage capacity of the container.
6.6 Conclusions for Capacity Estimation

Static capacity estimation was carried out only for the available areas (409 km²) out of the total available in EPQ–1 and EPQ–2 permit acreage of ZeroGen (Subsection 8.3).

These calculations were carried out for only those formations, which are sufficiently deep and provide conditions for super-critical injection of CO₂ and the formations suitable for only sub-critical injection (Mantuan Formation) was excluded at this time.

Data-driven probability distributions were used to model the range of all the input parameters.

Capacity estimation was carried out for open and closed boundary reservoirs. Based on the current geological understanding the available area is more representative of a closed system. CO₂ storage capacity with a high confidence of P90 probability is estimated to be 385 million tonnes for the open system and 50 million tonnes in the case of the closed system. At P50 storage capacity is 865 million tonnes for open and 87 million tonnes for a closed system.
An average sweep efficiency factor of 30%, derived from the calibrated single well dynamic simulations, was used for estimating capacities in the solubility and displacement processes. Single well models were calibrated based on a very short history of injection periods and thus may contain some uncertainty when applied for the full project lifecycle. The uncertainty in sweep efficiency can be reduced only when injection data is available to history match the models, for a number of years.

The capacities indicated above are the effective capacities. Ultimate capacity of the container is three to four times larger than the effective capacity.

Weighting the closed system at an arbitrary 80%, the EPQ–1 and EPQ–2 permit acreage have a P90 storage capacity of 117 million t of CO₂. This equates to approximately 290 kt per km². However, this did not inform confidence in whether or not this capacity could be accessed at desired rates, which was also contingent on dynamic well performance Field Development Plans (Subsection 8.3.2).

The calculation of a resource capacity using adjusted ‘static’ methods did not inform the economic, practical capacity in any useful way.
### 7 Notional Development Concept

#### 7.1 Context

The previous sections dealt a sub-surface technical evaluation of resource performance. This section deals with a simple engineering scenario which might be employed to exploit that resource.

In this section, first development constraints and then a simple pipeline and field, flow-line structure are discussed (and costed). These describe a pattern of simple, relatively low-cost vertical injection wells spaced at 2 x 2 km. The economic performance of this concept tied to the resource is discussed in Section 8.

#### 7.2 Lessons Learnt

It is essential that projects seeking to sequester CO₂ consider carefully whether matched rate or gross volume performance targets are most important and how to manage and allow for the risks of over-supply e.g. venting or sparing.

In contrast to oil and gas developments, which produce rates from a natural resource at rates determined by that resource, a GHG storage facility may have to attempt to sequester CO₂ at rates determined by the supply from an IGCC plant. The rate of this supply is not driven by the rate of change of field pressures. So, the natural resource must be able somehow to be ‘plumbed-in’ sustainably to match the supply. This is important. To match a constant rate of (for example) 2 Mtpa in an environment where maximum allowable sub-surface pressures are fixed and where initial reservoir pressures increase and hence flow-rates per well decrease with time (refer Subsection 4.5), additional wells will be needed over time to match the aggregate decline in the injection potential of the well stock.

Aggregate injection rates for any area have some physical limit, which is related to the separation required between wells to avoid interference (area per well) and the area of geological resource under license. Furthermore, for a given geological area or tenement area, it may not be physically possible to plumb-in a given resource in a way that can accept the required rate without breaching seal or fracture pressure constraints.

A conceptual development plan is essential. At the PFS phase, focus should be on investigating development concepts which are reasonably achievable and do not assume major developments in either technology or cost. Well and pipeline engineering studies should produce a realistic, useful and auditable basis for cost estimates and identify areas for improvement in subsequent stages.

Any notional development concept (engineered scenario) has to address both technical estimates of sub-surface performance as well as potential surface and environmental constraints to development which affect the efficiency with which a resource might safely be exploited. Realistically, risk avoidance exclusion zones should be included in any conceptual planning.
Early work is required to collect sub–surface, thermal conductivity data and to run thermal and flow models to investigate possible impacts of cooling in the injection reservoir. This could be positive (enhancing injection) or negative (increasing containment risk by reducing fracture gradient) has a major impact on development complexity and/or on well count (if injection pressures need to be reduced).

Monitoring (and verification) plans should be risk–based i.e. focused on areas with either the highest likelihood (albeit unlikely) of seepage, such as sub–critically stressed faults or legacy wells, or with the highest consequence of seepage (such as aquifers between injection zones and aquifers in use for potable agricultural water). Real monitoring scenarios need to be scoped out and costed. The timing required for collecting (e.g. seasonal) baseline data prior to injection may have a significant impact on development schedules.

7.3 NDT Constraints to the Conceptual Development Area

There were known constraints which would limit how an NDT storage resource could be developed (the concept). These were broadly grouped as follows:

- **Sub–surface risk mitigation related constraints**: Avoidance of areas with a higher containment risk either in terms of likelihood (e.g. legacy well bores) or consequence (e.g. proximity to other resource holder’s assets).
- **Surface constraints**: Land use, environmental and community issues.
- **Regulatory constraints**: Various Acts and Regulations such as the GHG Storage Act, Petroleum and Gas Act, Environmental Protection Act and the Water Act.

The field area would have to accommodate a very large number of wells (hundreds) with a spacing of 2 x 2 km, the surface flow–lines which would connect all of these to the CO₂ pipeline, well pads and access roads etc.

In order better to understand these issues, estimate which areas of the tenements could be drillable, and therefore how many wells might be accommodated, ZeroGen (with Resource and Land Management Services Pty Ltd, RLMS, Brisbane) created a series of ten constraints layers with which the notional, development concept was constrained.

The 10 constraints layers were as follows:

1. Sub–surface (risk avoidance) constraints.
2. Communities and neighbours constraints.
3. Regional ecosystems/regrowth and remnant vegetation.
4. Restriction areas (RST) (including catchments).
5. National parks, forests and reserves.
6. Watercourses and flood plains.
7. Land tenure (leasehold and freehold).
8. Native title and cultural heritage.
**CHAPTER THREE Storage Part A—Northern Denison Trough**

**LAYER 1: Sub-surface (risk avoidance) constraints**

The main sub-surface area for injection was defined by the limit of the 750 m depth contour of the Catherine Sandstone. Outside this is an area where the Catherine Reservoir is at sub-critical (virgin) pressures, however the Freitag and Aldebaran Formations are found at supercritical depths (Figure 7.1). This wider area was included in the area nominally available for development drilling. However, the prime area for development, i.e. the area which would have to contribute to the majority of the injection potential, was considered to be where the Catherine play was at 750 m or more.

Features were defined within 1 km of which injection wells might not be sited (Figure 7.1). These were:

- **Faults**
  - Note that seismic data are sparse in the core ‘CFA’ areas (Figure 7.1).
  - More faults were thought likely to be present.

- **Legacy wells**
  - Avoided with circular, sub-surface injection exclusion zone.

- **Tenement boundaries**
  - To avoid any injected CO₂ migrating beyond GHG tenements a 1 km zone was left undrilled around the boundaries.

The selection of 1 km is based on a maximum modelled plume dimension of around 900 m and would need to be studied further based any new peripheral data from the development drilling phase.

Figure 7.1 shows the Catherine, Freitag and Aldebaran Formations at supercritical depths along with the areas of exclusion (blue) for siting injector wells.

**LAYER 2: Community and neighbours**

Under the *GHG Storage Act 2009*, companies with GHG Exploration Permits have the rights to access and develop land in return for compensation and within constraints imposed by safety and environmental considerations.

For the purposes of concept development, ZeroGen assumed that no CO₂ injectors would be sited within Emerald, to allow a margin around this for future town planning and separation from peripheral dwellings, allowed for a 4 km ‘skirt’ around the outermost limits of the town (Figure 7.1). Road, and rail infrastructure, homesteads and high intensity (cotton) agriculture were also excluded from field development concepts.

Such exclusions were not based on a detailed risk assessment of the impact of a CO₂ storage development in these areas but were simply an approach to create an auditable development scenario.
LAYERS 3 to 6: Ecosystems, restricted areas (RST), reserves, watercourses and flood plains

Regional Ecosystems (REs) are communities of vegetation that are consistently associated with a particular combination of geology, land form and soil in a bioregion. All Endangered Regional Ecosystems (EREs) were mapped. Given the broad extent of EREs and ‘of concern’ regional ecosystems, CO₂ field development would need cross these areas. Some areas would be effectively ‘no go’ areas and so the area available for drilling was reduced. In many others, disturbances would need to be minimised, routing possibly lengthened and surface costs would likely increases.

RSTs included water catchment areas. Like the EREs, RSTs were mapped and avoided. There were no national parks or reserves in the conceptual development area.

Several watercourses including some major creek systems run W–E across the development area, feeding the S–N flowing Comet River located at the edge of the DAQ–1 and EPQ–1 tenements. In the wet season, these waterways swell considerably and provide barriers to N–S travel. Planning of flow–lines and roads had to consider the impact on the creek systems and additional costs, which would be incurred in any field lay–out.

AYER 7, 8 and 9: Land tenure, land use (agriculture), cultural heritage and native title

The majority land in the tenement areas was freehold with a large number (>50) of land–owners. Access and compensation negotiations would be required with virtually every land–holder for well sites, flow lines or access tracks.

The predominant land use was production from relatively natural environments. This is mainly beef cattle grazing and fattening presenting minimal impact from any field development. Some land particularly in the south is used for production from dry land agriculture and plantations. Irrigated cropping land, as well as intensive agricultural land exists at the North–West of Emerald. Any field development would ideally avoid these areas. However, irrigated and intensive agricultural land covers approximately one fifth of the main Catherine play area. For the conceptual level of the field development, ZeroGen considered they had access to these areas. However, this would result in an overestimate of available land for drilling.

The Aboriginal Cultural Heritage Act (ACHA) defines who an ‘Aboriginal party’ is for the purpose of developing a Cultural Heritage Management Plan. Primarily, the ACHA identifies the Aboriginal party by reference to who the registered native title claimants over the area in question are. Studies identified who the relevant Aboriginal parties for the area are. Searches indicated that there was no current registered native title claimant for the geosequestration area. However, the Yumba Burin was the registered cultural heritage body for this area. It would be their role to identify who the relevant Aboriginal parties for the area are. No well siting constraints were identified in this study, though it is feasible that the area could have been affected at later project stages.
LAYERS 10: Mining and petroleum tenures

Under the Storage GHG Act 2009, CO₂ injected in a storage lease is required to be monitorable within that lease to demonstrate containment. Therefore, to account for uncertainties in plume migration, a margin of 1 km around the lease boundaries was included as a ‘no—injection’ area. It is possible that negotiations with nearby tenement holders (of other resource rights) would require that margin to be increased. Commercial negotiations could be expected to be lengthy in particular any settlement on consequential loss or damages would be complex.

Prior to any full field development, the Act demands that coordination agreements be entered into to address any collocated rights. If such an agreement could not be entered into, the Act allows for ministerial discretion. Without such agreements, no final storage development could take place.

The ZeroGen tenements overlaid or were adjacent to:

- two active mining leases (MLs) involving several mining companies;
- two active mining development leases (MDLs) also involving several companies;
- four petroleum exploration permits (EPPs)—including areas of active coal seam gas exploration and an area nominated under an LNG—related EIS as part of a pipeline corridor; and
- three petroleum production leases (PLs) covering three active gas producing fields.

7.3.1 Summary—GHG storage development planning and constraints

It was necessary to create a scoping-level engineering field development plan. This entailed a significant amount of detailed survey and study work in order to consider sub—surface and surface technical and environmental constraints, as well as issues of land—use and land—ownership. Such studies were essential to inform cost, schedule and maximum well numbers (and hence injection rates) which might be accommodated.

7.4 Notional Field Lay—out and Architecture

7.4.1 The core area

The tenement area was divided in zones based on the limit of the 750 m depth contour of the Catherine Sandstone for each formation (Catherine, Freitag and Aldebaran). Table 7.1, Figure 7.1 and Figure 7.2 show the different zones with the presence of the sandstones below 750 m bGL.
The annotation of the different areas in this figure relate to the presence at super critical depths of Catherine (C) and/or Freitag (F) and/or Aldebaran (A) Formations. For example, CFA indicates the presence of all three at super critical depths.
### Table 7.1: Summary Table of Areas by Sub–Zones of NDT Storage Plays

<table>
<thead>
<tr>
<th>Zones</th>
<th>Location</th>
<th>Tenements</th>
<th>Formations</th>
<th>Area (km²)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A1</td>
<td>NW Emerald</td>
<td>DAQ–1</td>
<td>CFA</td>
<td>54.8</td>
</tr>
<tr>
<td>A2</td>
<td>NW Emerald</td>
<td>DAQ–1</td>
<td>FA</td>
<td>18.7</td>
</tr>
<tr>
<td>B1</td>
<td>SE Emerald</td>
<td>EPQ–2; DAQ–1; EPQ–1</td>
<td>CFA</td>
<td>281.4</td>
</tr>
<tr>
<td>B2a</td>
<td>SE Emerald</td>
<td>EPQ–2; DAQ–1; EPQ–2</td>
<td>FA</td>
<td>316.7</td>
</tr>
<tr>
<td>B2b</td>
<td>SE Emerald</td>
<td>EPQ–2; DAQ–1; EPQ–3</td>
<td>FA</td>
<td>28.1</td>
</tr>
<tr>
<td>C1a</td>
<td>E Turkey Creek</td>
<td>EPQ–1</td>
<td>CFA</td>
<td>114.6</td>
</tr>
<tr>
<td>C1b</td>
<td>W Turkey Creek</td>
<td>EPQ–2</td>
<td>CFA</td>
<td>29.7</td>
</tr>
<tr>
<td>C2</td>
<td>W Turkey Creek</td>
<td>EPQ–3</td>
<td>FA</td>
<td>42.3</td>
</tr>
</tbody>
</table>

Note 1: CFA: Catherine, Freitag, Aldebaran all below 750 mGL.
Note 2: FA: Freitag, Aldebaran below 750 mGL; Catherine above 750 mGL (subcritical depths).
Note 3: B2c zone not listed in the table as Freitag is only below 750 mGL.

Based on the above discussion, area B1 would need to be the main development area with an extension to the South (C1a) where the Catherine Reservoir is thought to become poorer (Section 2).

A further, large extension to the East (B2a) was discussed in well–count sections (Subsection 8.3.1) where the Catherine is less than 750 m bGL but Freitag and Aldebaran are at super–critical depths.

Other zones (A1, A2, B2a, B2b, C1b, C2) exist, but are either small and/or non–contiguous. And B2c zone has only the Freitag in supercritical depths. These are not discussed further at this stage.

### 7.4.2 In–field development

**Number of wells, length of flow–lines and roads**

The areas for a notional field development are shown in Figure 7.2, together with a nominal well and flow–line pattern based on a 2 km spacing—this spacing constrained by single well model results. Closer spacing increases cross–well pressure interference. Sequence optimisation, where initially wells are drilled on a wider spacing to prolong the time at which in–fill drilling is required, was not undertaken.

The number of wells which would fit within these constraints is shown in Table 7.2.
FIGURE 7.2: NOTIONAL 2x2 KM WELL SPACING, FIELD DEVELOPMENT LAY-OUT WITH REFERENCE TO CONSTRAINTS (CORE AREAS WERE B1 AND C1A)
Flow–lines are divided into two types (major and minor). For a core area, 130 well developments the required lengths are shown in Table 7.3 below.

**TABLE 7.3: SUMMARY OF MAJOR AND MINOR FLOW–LINE REQUIREMENTS**

<table>
<thead>
<tr>
<th>Reference case (B1 and C1a)</th>
<th>Zone</th>
<th>Major flow–lines (km)</th>
<th>Minor flow–lines (km)</th>
</tr>
</thead>
<tbody>
<tr>
<td>B1</td>
<td>67.8</td>
<td>116.2</td>
<td></td>
</tr>
<tr>
<td>B1 to C1a</td>
<td>4.8</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>C1a</td>
<td>31.5</td>
<td>45.7</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>104.1</strong></td>
<td><strong>161.9</strong></td>
<td></td>
</tr>
</tbody>
</table>

The 130 well–developments required designing, constructing and installing 104.1 km of major flow–lines and 161.9 km of minor flow–lines totalling 266 km.

Finally, a significant length of new access road (in–field only) was required. This road was estimated to be 100 km including 71 km within B1 and 29 km within C1a zones.

### 7.4.3 Summary parameters for in–field development

The summary parameters for a base case, in–field development included the core, licensed, supercritical area (B1 and C1a) of around 400 km². A further, new area of 316 km² (B2a) may have become available—but the Catherine would be at sub–critical depths (all formations shallow to the east). In the core area, approximately 130 wells could fit (CFA, Figure 7.1). A further 100–120 might fit into the area to the east. The upper, theoretical limit (i.e. developing almost all the area) would be of the order of 250 wells. Note that for a 130 well development, 265 km of flow–lines would be required; over 100 km of additional new access tracks would be required.
7.5 CO₂ Pipeline

**Functional requirement.** A 30 km high-pressure pipeline would have transported the CO₂ safely from the power station to the ZeroGen geosequestration point 30 km South East of Emerald. Two potential routes were studied in depth to ensure a feasible option (pink lines in Figure 7.2).

The MHI plant would have delivered CO₂ at 15 MPa at the plant terminal point. CO₂ would be delivered at the geosequestration well heads at a minimum of 17 MPa. Minimum whole-system pressure would be no less than 9 MPa.

**Pipeline materials.** The CO₂ pipeline material was high strength carbon steel complying with tested API 5L Grade X70 ERW—specified to have a temperature range of −45°C to 83°C. All materials in contact with the CO₂ mixture would be selected to achieve a low corrosion rate and compatibility with all contaminants. This included all minor materials, such as valve seals and major components, such as the main transport pipeline.

**Pipeline configuration.** From the main pipeline, CO₂ would flow into a distribution system consisting of multiple header pipes of reducing diameter, feeding the geosequestration reservoir via a large number of injection wells.

With an input of 15 MPa, boosting could be either at the geosequestration site into the main headers, or pumped from site higher pressure, nominally 20 MPag possibly avoiding the need for an in-field booster. Integrated systems modelling from compressor to reservoir was not undertaken for the PFS phase. However, this may have significant consequences on in-field booster, compression and controllability and costs.

**Pipeline coatings and cathodic protection systems.** Where required, external pipeline coating would be a recognised system such as:

- Fusion Bonded Epoxy (FBE);
- a tri-laminate using different grades of Polyethylene and/or FBE;
- thermal-bonded polymeric coatings to AS 4158;
- fusion bonded medium density polyethylene coatings to AS 4321;
- cold applied black bituminous paint to AS 2280; and
- polyethylene sleeve to AS 3680.

FBE coating was used for the basis of this study for all steel pipelines. In addition to this, pipelines may have required additional protection via rock jacket and/or concrete coating/s to suit the terrain and crossings. A cathodic protection system (impressed current or anode bed) would have been installed for all steel pipelines to provide additional corrosion protection to the pipeline. The CO₂ pipeline would be unlined internally.
Design capacity. The CO₂ delivery system would be designed for a carbon capture level of 90%, and would be capable of operating continuously at 90% capture. The capacity of the CO₂ transport and distribution system would be 389 tonnes/stream-hour. The annual design quantity of CO₂ transported and distributed to the well heads would be up to 2.9 million tonnes.
Design pressure. In cases where the pressure of the captured CO₂ at the inlet of pipeline is 15 MPag, the design pressure for the pipeline would have been $15 \times 1.05 = 15.75$ MPag and for the distribution system at the sequestration field would have been $20 \times 1.05 = 21$ MPag. In cases where the pressure of the captured CO₂ at the inlet of pipeline is 20 MPag, the design pressure for the pipeline and the distribution system at the sequestration field would have been $20 \times 1.05 = 21$ MPag. In addition, the CO₂ transport, pumping and delivery systems would have been designed to ensure that the pressure at all pipeline elevations is greater than the critical pressure for CO₂ (7.4 MPag) by a 20% margin for all steady state and transient operating conditions so that two–phase flow (liquid/gas or supercritical fluid/gas) does not occur. This was to be confirmed during the next stage of engineering.

Pipeline protection. Pipelines would have been designed with a combination of physical and administrative protection measures, in accordance with AS 2885.1, to prevent loss of integrity from external interference by identified threats.

The primary physical measure is burial depth, which would be increased in areas where likelihood of external interference is greater.

The nominal depth of cover appropriate for pipelines in a rural location is 750 mm. Cover would be increased locally for areas requiring greater protection, as determined by appropriate risk assessment for each pipeline. Minimum cover would be 1200 mm for major road crossings and 2000 mm for rail crossings. Minimum cover for pipelines would be increased to 1200mm in areas where cultivation is prevalent.

Route Selection and Studies (RLMS). RLMS was engaged to create a workable option for pipeline routing. Following this, the pipeline consultant, Hatch, carried out the preliminary CO₂ pipeline design for a main high pressure transmission pipeline from the power station to this point. They then branched the pipeline to a nominal well–field pattern. The well–field pattern was specified by ZeroGen.

Thus, planning (and costing) accounted for real on the ground conditions for a realistic route. Significant issues were flagged for crossing major highways, railways and creeks. The route sought to avoid farm dams and to minimise the impact on farm land.

Land use on the western side of the Comet River is dominated by cropping land (including irrigated land). As the project progresses and the corridor was further refined modifying the route to best minimise impacts on these higher intensity land uses would require careful planning and landowner negotiation.

Assessment criteria for pipeline routing were developed (Table 7.4).
### TABLE 7.4: ASSESSMENT OF ENSHAM SITE CORRIDOR OPTIONS AGAINST THE SELECTION CRITERIA

<table>
<thead>
<tr>
<th>Criteria</th>
<th>Risk/impact significance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Minimise corridor length</td>
<td></td>
</tr>
<tr>
<td>Minimise the terrain constraint on the route</td>
<td></td>
</tr>
<tr>
<td>Maximise ease of access for construction and operations</td>
<td>Located some distance from roads</td>
</tr>
<tr>
<td>Minimise construction constraints such as:</td>
<td></td>
</tr>
<tr>
<td>• Areas subject to inundation</td>
<td></td>
</tr>
<tr>
<td>• Soil stability and erodability</td>
<td></td>
</tr>
<tr>
<td>• Extent of rock</td>
<td></td>
</tr>
<tr>
<td>• Number of watercourse crossings</td>
<td></td>
</tr>
<tr>
<td>• Number of infrastructure crossings</td>
<td></td>
</tr>
<tr>
<td>• Working in third party easements</td>
<td></td>
</tr>
<tr>
<td>Minimise disturbance to existing landholders and land use</td>
<td></td>
</tr>
<tr>
<td>Minimise disturbance to areas of known ecological value</td>
<td></td>
</tr>
<tr>
<td>Minimise disturbance to known heritage values</td>
<td></td>
</tr>
<tr>
<td>Minimise disturbance to and potential interference from existing third party infrastructure</td>
<td>Rail and road infrastructure</td>
</tr>
</tbody>
</table>

*Legend: [Low significance](#) [Medium significance](#) [High significance](#)*

**Basic pipeline specifications.** In the reference case, the inlet pipeline pressure was 15 MPag assuming a well head pressure requirement of 17 MPag. This case indicates that a booster pump was required at the sequestration field and two booster pumps, with the capacity of 50% boost the CO₂ pressure to a discharge pressure of 19.04 MPag. Booster Pumps (multistage horizontal centrifugal) have a capacity of 238.6 m³/h each at 6231 kPa differential pressure.

The pipeline, main header, sub header and injection line preliminary sizes are listed in the Table 7.5 below.

### TABLE 7.5: 15 MPa OPTION PIPELINE AND BRANCH LINE SIZES

<table>
<thead>
<tr>
<th>Pipeline Length (km)</th>
<th>Pipeline diameter DN (mm)</th>
<th>Main header diameter DN (mm)</th>
<th>Sub header diameter DN (mm)</th>
<th>Injection line diameter DN (mm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>25.43</td>
<td>300</td>
<td>150</td>
<td>100</td>
<td>50</td>
</tr>
</tbody>
</table>

If the inlet pipeline pressure were 20 MPag the main pipeline diameter would be 400 mm, in–field distributions lines would be similar to the 15 MPa case.
7.5.1 Scoping cost estimates

The following table (Table 7.6) is a summary of the costs of the CO₂ pipelines for each installation scenario. Following an optimisation study, ZeroGen’s PFS base case was the 15 MPa option (which is compatible with the MHI plant terminal conditions).

**TABLE 7.6: CO₂ PIPELINE COST SUMMARIES FOR INSTALLATION SCENARIOS**

<table>
<thead>
<tr>
<th>Specification</th>
<th>Installation scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>15 MPag plus booster pump¹</td>
</tr>
<tr>
<td>Length (km)</td>
<td>25.43</td>
</tr>
<tr>
<td>Diameter (DN—mm)</td>
<td>300</td>
</tr>
<tr>
<td>Wall thickness (mm)</td>
<td>7.2</td>
</tr>
<tr>
<td>Material</td>
<td>API 5L Grade X70</td>
</tr>
<tr>
<td>Pump power (field booster)</td>
<td>2x800 kW</td>
</tr>
<tr>
<td>Capital cost</td>
<td>$55,689,000</td>
</tr>
<tr>
<td>Operating cost—annual</td>
<td>$2,355,000</td>
</tr>
</tbody>
</table>

*Note 1: Includes energy costs for pumps.*

7.5.2 Key issue not yet addressed

Delivery of steady rate CO₂ to the field was aspired, however, the reservoir system would be pressure constrained. Bottom hole and hence well-head pressures would be controlled not to rise above given levels described by the fracture gradient. Reservoir pressure in each well would increase over time (Subsections 4.5 and 8.3.4) and hence the flow rate at each well would (variably) decrease over time. The system would never be in a steady state, and dynamic flow and pressure control would be required to optimise the field. In addition, wells may for various reasons periodically come off line and therefore to manage the demand to sequester at steady rate, with minimal venting, a number of spare wells and operating, redundant margins would need to be determined. This may have a significant impact on:

- well and in–field capital costs and phasing (Subsection 8.3.4); and
- the need for in–field pressure management.

7.6 Conceptual Well Engineering

This subsection discusses considerations made when selecting well engineering and completion choices. The purpose was to arrive at meaningful and internally consistent performance and cost estimations for a given concept. AGR Asia Pacific in Brisbane were ZeroGen’s prime well engineering contractor.
In essence, the functional requirement of the set of wells to be installed is to inject sustainably and store safely 2 (to 3) MtMa for a period of 30 years while maintaining mechanical integrity to protect overlying aquifers from exposure to CO₂ and preventing loss to atmosphere or the well annulus.

As a notional basis for design, it was assumed that 98% CO₂ would be delivered at the wellhead at approximately 17 MPa (2500 psig) surface injection pressure. Thus, normal pressure operating environments for tubulars would be expected.

ZeroGen’s experience during its PFS study was in exploration wells and a single purpose built injection well with a design life of circa five years, rather than in injection wells with a long design life and minimum intervention philosophy.

Significant further work and field trials would be required to optimise well designs and establish the best possible completion and drilling techniques prior to finalising a BoD or design specification in any Field Development Plan.

### 7.6.1 Reference PFS conceptual well designs

The target design life was 50 years with 30 years of sustained injectivity. A large number of wells would be required for the NDT (100s). The preferred completions scenarios were also based on standard oilfield sizes including 7” cased and stimulated (8½” hole) and 6” or 6¼” open hole. Tubing size was nominally selected at 3½” with premium connections.

The boundary conditions for this study required that the CO₂ be delivered into the field and maintained in a dense state. The arrival pressures and temperatures were expected to be kept within the range of 12–17 MPa (1740–2500 psig) and 15–25°C (69–84°F). The downhole conditions at the sandface are expected to be kept within the range of 13–16 MPa (1894–2328 psi) and 64.5°C (148°F), however, reservoir pressure would be programmed as not to exceed the anticipated Catherine fracture.

The primary consideration in PFS concept design was to prevent failure of the formation at the casing shoe and along the open–hole section below it under all realistic load conditions and most basic, conservative, and streamlined set of principles for casing and tubing design.

The design was required to have a minimum of two barriers: injection tubing and casing/liner.

The final wells would have been designed around four factors:

- the needs of the completion to provide optimum injection over its lifetime;
- the need for reliable, safe pressure containment over the life of the well—and after abandonment;
- the cycle time required to put various design options into production; and
- minimal requirements for intervention.

A design catalogue of 10 different designs was generated. Only two are described hereunder. Vertical wells were considered as the reference case. These holes would be drilled to a TD of circa 1500 m bGL. The bottom hole depth would be chosen to intersect the mid Aldeberan Sandstone unit. Alternative cases have been discussed and costed (AGR(a), 2010) which would TD at the base of the Catherine however, the incremental cost of drilling to 1500 m were low (<$100,000). Hence a 1500 m TD well design reference case has been selected for PFS purposes.
Outstanding issues for further work would be:

- borehole stability and skin development through fines migration which will govern whether ‘open hole’ completions would be acceptable over the long term. Acquiring borehole stability data at an early stage has a high value; and
- possibility of injection enhancement (stimulation) which may require cased/lined holes (the more expensive option). It is likely a combination of these wells or other suitable well types will be required to meet the project objectives.

**Materials.** Casing strings potentially exposed to CO₂ were chosen to have appropriate (conservative) corrosion resistant metallurgy. Components of the ZeroGen reference case designs meet or exceed the API Materials of Construction specifications e.g. as reported in Meyer (2007).

The PFS reference case completion was composed of standard equipment that is CO₂ resistant materials as in a typical CO₂ flood well. The completion hardware would consist of high chrome (316ss clad or equivalent) metallurgy packer, a CRA tubing string, CRA tubing hanger, and a wellhead with 316ss or equivalent trim on valves all potentially wetted components.

Completion assumption were conservative and included a carbon steel surface casing, SuperCr13 as the immediate casing, SuperCr25 across the shoe and a high chrome metallurgy packer (set in the corrosion resistant production liner section).

The designs were predicated on low injection rates of supercritical CO₂ at approximately 1.5 MMscfpd at between 3000–3500 psi wellhead pressure. A small bore were utilised (i.e. 6’/₈” drill bit) creating a 5½ production liner made from GRE materials with 2’/₈” tubing made from GRE materials. Typically, four or five joints of 2’/₈” tubing were hung below an isolation packer. A relatively inexpensive lock–set packer is used with 9Cr mandrels for corrosion resistance, otherwise Internal Plastic Coating (IPC) on exposed metals is used. An on/off plug was set in the packers and serves as a flapper–type valve. The plug moves to the closed position when tubing were pulled and re–opened when tubing was re–set. This allowed for tubing strings to be pulled without risk of CO₂ blowback.

Research is required to confirm the very long–term use of GRE or other suitable CRA materials in CO₂ environments.

**Trajectories and clustering.** Clustering of surface locations was not considered in the PFS field development concept. Target Catherine sands are typically around 1000–750 m and required injection point separation is some 2 km. Studies showed a practical limit for deviation of around 60°. Consequently, clustered, deviated wells were not considered further for this stage.

Studies, conducted to investigate whether the injection performance of deviated or horizontal wells would have significant improved injectivity, showed little cost–effective enhancement in these NDT tight formations.

**Drilling fluids.** For PFS concept study no fluids optimisation studies were undertaken. However, air–drilling in ZG–11 had produced the best ‘skin’ results, therefore uncased PFS reference cases (Type 1 and 2) were assumed to be air–drilled.
Cementing considerations. Zonal isolation was considered a prime concern. The PFS reference case designs assumed “CO₂ resistant cement” in all potentially CO₂ wetted areas, this was assumed as a conservative high–cost case, not because such cements are proven to provide overall best isolation performance.

Reference Well Type 2—open hole completion

A ‘Type–2’, vertical, open–hole, well design has been defined as the reference case as shown in Figure 8.4. Importantly it is consistent with reservoir models, notwithstanding borehole stability and fines risks and was used to estimate costs.

The completion strategy follows practices developed in ZG–11 where zero–skin was achieved (albeit for a limited time). The intended injection targets are the Catherine, Freitag and Upper Aldebaran Sandstone Formations are treated as a single open–hole section.

Monitoring well injection with wellhead gauges was considered acceptable at this stage, however a number of dedicated monitoring wells had been included in the field development scenario.

Reference Well Type 3—cased hole completion with fracture stimulation

Significant choices need to be made with respect to an optimal completions strategy and key risks and uncertainties need to be reduced. Additional field trails and laboratory tests would be required to investigate stimulation techniques and borehole sensitivities.

In ‘Type 3’ a non–damaging drilling fluid would be used for drilling over the production zone and a corrosion resistant liner will be placed across the Black Alley Shale seal interface and along the entire production interval. Type 3 reference case well design includes fracture stimulation in the injection zone.

Fracture stimulation design requires subsequent modelling which needs to be calibrated in the main stress regimes under which the project operates (Campagna 2007 and 2010 and Figure 6.2). To characterise the reservoir and fracture dimensions, the production and pressure histories of selected wells were modelled using a finite–difference reservoir simulation along with analytical analysis methods. Importantly, fractures would need to be focused (i.e. instigated in the target matrix formation).

• In the ZG–11 well, it was established (via downhole camera) that fractures, which were propagated during the CO₂ injection tests, were horizontal. This is consistent with a minimum stress being the overburden stress. It was also established that fractures initiated in this and other well tests remained pressured–up and did not readily bleed–off into the matrix. This created some doubt that fracture simulation would yield significant benefits. For this reason, while injection rate sensitivities were modelled, the reference well design for PFS development concept was a simple, unstimulated well.

7.6.2 Injection well costs—Type 2

Detailed cost estimates were prepared for Type 2 (open hole) and Type 3 (stimulated) wells. Costs for single wells were constructed from historic costs and recent approaches to market. Single well costs were adjusted to allow for campaign savings in the project cost model.
The Level 1 cost estimates were performed by AGR Asia Pacific, based on their extensive experience with the ZeroGen Project and knowledge of drilling in the local area. Costs reported below are based on the Type 2 reference case well designs without operational contingency. Wells are drilled to a 1500 m TVD (the average depth to mid Aldeberan in the area).

A drilling time consistent with ZeroGen’s experience of approximately 14 days (campaign mode) was assumed to drill a Type 2 reference case well to 1500 m TVD.

Completion time using a service rig, estimated at six days, had been assumed. Total mobilisation to demobilisation time (in–field, between wells only) was assumed to be an average of two days. Well cost estimates included two days of standby with crew for unscheduled maintenance, weather delays and equipment deliveries.

A drilling rig rate of approximately $44k/day and a service rig rate of $18k/day was assumed based on 2010 market prices. However, it should be noted that a significant increase in demand may result from the emerging Coal Bed Methane industry and could significantly impact the estimated rates.

**FIGURE 7.4: SCHEMATIC DESIGN FOR A TYPE 2 OPEN HOLE COMPLETION**
Table 7.7, shows the cost estimates for the reference case Type 2 and the stimulated fracced option Type 3.

Total estimated well cost—without campaign adjustment for a Type 2 reference case well design is $2,873,000 (2010 market reference).
TABLE 7.7: SUMMARY WELL COST DATA FOR REFERENCE CASE, TYPE 3, FRACCED AND SIMPLE CATHERINE—ONLY WELL

<table>
<thead>
<tr>
<th>Summary data</th>
<th>Well type assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Type 2: Open hole (mid Aldebaran)</td>
</tr>
<tr>
<td></td>
<td>Type 2: Open hole (campaign mode)</td>
</tr>
<tr>
<td></td>
<td>Type 3: Cased hole (stimulated)</td>
</tr>
<tr>
<td></td>
<td>Type 3: Cased hole (campaign mode)</td>
</tr>
<tr>
<td>Total depth (TVD)</td>
<td>1500.00</td>
</tr>
<tr>
<td>Drilling total days</td>
<td>16.42</td>
</tr>
<tr>
<td></td>
<td>13.39</td>
</tr>
<tr>
<td></td>
<td>14.45</td>
</tr>
<tr>
<td></td>
<td>13.05</td>
</tr>
<tr>
<td>Cost summary—drilling (including camp)</td>
<td>$2,630,236</td>
</tr>
<tr>
<td></td>
<td>$2,342,639</td>
</tr>
<tr>
<td></td>
<td>$2,778,386</td>
</tr>
<tr>
<td></td>
<td>$2,599,697</td>
</tr>
<tr>
<td>Completion total days</td>
<td>5.84</td>
</tr>
<tr>
<td></td>
<td>5.84</td>
</tr>
<tr>
<td></td>
<td>13.67</td>
</tr>
<tr>
<td></td>
<td>13.67</td>
</tr>
<tr>
<td>Cost summary—completions (including camp)</td>
<td>$544,635</td>
</tr>
<tr>
<td></td>
<td>$530,222</td>
</tr>
<tr>
<td></td>
<td>$1,319,560</td>
</tr>
<tr>
<td></td>
<td>$1,147,834</td>
</tr>
<tr>
<td>Total cost estimate</td>
<td>$3,174,871</td>
</tr>
<tr>
<td></td>
<td>$2,872,861</td>
</tr>
<tr>
<td></td>
<td>$4,097,946</td>
</tr>
<tr>
<td></td>
<td>$3,747,532</td>
</tr>
</tbody>
</table>

Figure 7.6, shows an approximate breakdown of the cost estimates.

With reference to the main areas of optimisation (cost) they were:

- materials (assets);
- rig selection and market conditions; and
- drilling related services (service companies) which are essentially a well–engineering and contracting strategy challenge.

As seen by the pie chart in Figure 7.6, the cost disparity between a Type 2 and Type 3 reference well design is almost entirely in the completions cost (stimulation cost).

A higher well cost may be justified if the unit well development costs of injection ($/t/d) and storage ($/t) can be reduced and if greater volumes can be accessed through a stimulated well.
### 7.6.3 Well operations and operating costs

Due to assumptions on the operational downtime of the power plant, an average of 4400 tpd was anticipated. No information could be sourced on the failure rate of CO₂ injection wells. However the following assumptions were made from analogue developments. The probability of failure resulting in a major rig work–over was assumed to be 3%/well per year or a minor rig work–over was 4%/well per year. This gives a total well failure cost of approximately US$205,000 per well per year. This was applied to both injection and monitor wells.

The combination of well failure and stimulation costs gives a total operating costs of US$230,000 per well per year (2007 basis), equalling approximately 8% of the individual well capital costs. Other sources of information (shallow, onshore and minimal planned intervention) were consulted as there is little to no information available for determining well operating costs for CO₂ sequestration wells. These resources suggested using a 7% of capital costs per annum, per well, which compared well with that determined via well failure and stimulation requirements alone.

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#### FIGURE 7.6: BREAKDOWN OF COMPLETION COST ESTIMATES (OPEN VS FRACCED WELLS)

<table>
<thead>
<tr>
<th>Completion cost (by well type)</th>
<th>Type 1 Vertical Open Hole (1000m)</th>
<th>Type 2 Vertical Open Hole (1500m)</th>
<th>Type 3 Vertical Cased Hole</th>
</tr>
</thead>
<tbody>
<tr>
<td>Completions cost</td>
<td>$544,635</td>
<td>$544,635</td>
<td>$1,319,560</td>
</tr>
<tr>
<td>Evaluation</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
</tr>
<tr>
<td>General</td>
<td>5%</td>
<td>5%</td>
<td>2%</td>
</tr>
<tr>
<td>Camp total</td>
<td>11%</td>
<td>11%</td>
<td>7%</td>
</tr>
<tr>
<td>Manpower</td>
<td>12%</td>
<td>12%</td>
<td>9%</td>
</tr>
<tr>
<td>Location/project</td>
<td>3%</td>
<td>3%</td>
<td>1%</td>
</tr>
<tr>
<td>Assets</td>
<td>21%</td>
<td>21%</td>
<td>9%</td>
</tr>
<tr>
<td>Rigs</td>
<td>19%</td>
<td>19%</td>
<td>15%</td>
</tr>
<tr>
<td>Completion/stimulation</td>
<td>21%</td>
<td>21%</td>
<td>48%</td>
</tr>
<tr>
<td>Third party field</td>
<td>8%</td>
<td>8%</td>
<td>9%</td>
</tr>
</tbody>
</table>
7.6.4 Well–head skid—Control and costs

This subsection outlines some preliminary design considerations investigated by AGR Asia Pacific, for well–heads and associated control systems. Significant additional work would be required in the area including the development of an integrated injection system model.

From the pipeline a main distribution header would distribute flow from the main pipeline around the acreage through a nominal 50 mm (or 2”) above surface flow line from distribution headers to injection wells. Well spacing will be approximately 2 x 2 km.

The CO₂ process conditions delivered at each wellhead was assumed to be approximately 15–17 MPa, 20°C at 20–200 tonnes per day with an average of ~78 tpd for a 30 year life cycle. Electrical power would need to be available and be designed to meet demand equipment voltage and power requirements (i.e. no stand alone generation capacity).

A primary injection control philosophy was based on reservoir pressure control limited by fracture pressure. Data acquisition would be required to set surface injection parameters pressure, flow and temperature at each wellhead with flow meter accuracy in a range of ±2%. A vent system would be required as a safety release mechanism.

Operational venting issues and constraints were not addressed at this time.

**Equipment requirements per well.** To achieve the basic ZeroGen requirements, surface equipment required at each well would include the following main components (Figure 7.7):

- pressure control valve (assumed to be electrically actuated);
- wellhead pressure instrument (indicating transmitter);
- flow instrument (meter and indicating transmitter);
- temperature instrument (indicating transmitter);
- Pressure Safety Valve (PSV);
- isolation and drain manual valves (stainless steel); and
- control unit (remote terminal unit–RTU).

Key sensitivities are flow meter accuracy and the safety integrity level of system. An Emergency Shutdown (ESD) valve was not included at each wellhead at this stage and it was assumed the ESD system would be implemented within the plant, pipeline and distribution header systems. Length and material of two flow line from distribution header to wellhead was assumed 5 m Sch. 40 seamless Gr316L.

**Control methodology and system.** The control philosophy consists of a cascading effect along the distribution and injection network (AGR(b), 2010). Under normal operations CO₂ would be injected into each well, with the injection pressure controlled via the Pressure Control Value (PCV). As the pressure in each well rises to approach reservoir fracture pressure, the PCV shall actuate the pressure such that it remains within operational limits. Should a PCV be unable to control the pressure by remaining suitably ‘open’, the excess (balance of) CO₂ flow no longer being injected into that well, would be directed into another well by actuating an appropriate PCV accordingly.
This control philosophy could be implemented via a Distributed Control System (DCS), consisting of a small, local controller (RTU) situated at each well location, which would be wired to the local instruments at that well. This RTU will communicate with RTU’s at other wells and the overriding control system and Human–Machine Interface (HMI) in a wireless mesh network. This configuration could keep the control units at each well relatively simple and inexpensive, whilst maintaining the overriding control in a single central unit and location.

However, redundancy is required in the installed injection rate (well count) to allow for diversion of flow between wells to manage pressure.

**Vent system.** In the control methodology described above, the actuation of a PCV to control well pressure may result in excess CO₂ flow in other parts of the system. Should enough wells be operating in this mode, then it may become necessary to vent CO₂ product such that the maximum flow capability of the remaining PCV’s are not exceeded (AGR(b), 2010).

The preliminary design of this system consists of an on–off control valve which would be opened to release pressure from the system (main distribution header) by either venting CO₂ to the atmosphere (vent pit) or disposal in designated spare wells. For the purposes of the PFS development concept, a well sparing philosophy 1/7 has been assumed (Subsection 8.3.4). Venting provisions and operating philosophies require further detailed study including plant start–up and operation modelling (Figure 7.8).

**Heating contingency.** In response to the long–term injection of a cold fluid (CO₂), further study and risk assessment of this phenomenon is required. ZeroGen investigated a heating contingency which would on costs, infrastructure and land area required. Cooling could have significant impact. Subsection 5.4.2 describes the possibility of thermally induced fractures due to a possible decrease in reservoir temperature gradient, therefore the fracture gradient, over time. This was a very high level study. However, power estimates results are shown in Table 7.8.

### TABLE 7.8: SUMMARY OF ESTIMATED POWER REQUIREMENTS OF EACH WELL

<table>
<thead>
<tr>
<th>Item</th>
<th>Supply voltage</th>
<th>Power (kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pressure control valve</td>
<td>24VDC</td>
<td>0.4</td>
</tr>
<tr>
<td>Instrumentation</td>
<td>24VDC</td>
<td>Negligible</td>
</tr>
<tr>
<td>Control system</td>
<td>24VDC</td>
<td>0.5</td>
</tr>
<tr>
<td>Heater (if required)</td>
<td>415V</td>
<td>60</td>
</tr>
</tbody>
</table>
7.6.5 In-field control systems conclusion

Integrated control systems require significant further work. Provision for heating remains a major cost and infrastructure risk factor. Without heating, a wellhead control system would require minimal infrastructure at an estimated cost of ~AU$100,000 per well. However, significant exposure to upside cost remains after this simple scoping exercise due to integration control systems, redundancy, venting requirements and possibly heating.

7.7 Baselines, Monitoring, Measurement and Verification

Any field development would require baseline data, monitoring and verification. Initial concepts were discussed and mooted and early analyses undertaken, however, as the area became less attractive with ongoing analyses, no final plan was developed. This subsection presents some discussion points and a scoping estimate for a pragmatic baseline and monitoring plan.

In Central Queensland, groundwater resources are heavily used. A review of a total of 625 groundwater bores within a 5 km perimeter of EPQ–1 and EPQ–2 was undertaken. The vast majority of the bores were shallow (<100 m depth) within the tertiary basaltic and alluvial cover. Only 168 had chemical analyses and that was of varying date and quality. A collaboration commenced with Geoscience Australia and the Geological Survey of Queensland to develop a regional hydrogeochemical baseline for the area. The company provided its static geological model of the NDT and all water analysis data to this collaborative effort making all data open and transparent.

Notwithstanding this, monitoring deep groundwater would require ZeroGen to drill new, dedicated observation wells.

A conceptual, scoping monitoring plan for the NDT field development

Table 7.9 below discusses various NDT monitoring options based on a conceptual NDT development (Subsection 7.4), which includes 130 injectors within the B1 and C1a areas of injection (Figure 7.2).

Figure 7.9 gives a generic overview of the location of the various monitoring locations vis–a–vis the field of injectors.
### Table 7.9: Indicative Monitoring Plan

<table>
<thead>
<tr>
<th>M&amp;V Technology</th>
<th>Objectives</th>
<th>Reasons</th>
<th>Location</th>
<th>Frequency</th>
<th>Configuration</th>
<th>Number</th>
</tr>
</thead>
</table>
| Reservoir pressure | Risk management | • Monitor pressure build up around field margins.  
• Protection of claims from neighbouring assets.  
• Early warning of plume migration out of licensed area. | • Around the edges of the development.  
• Between the developed areas and other assets such as O&G fields or mines. | Continuous | • Simple wells completed only for pressure.  
• Expectation is that pressure is a long–lead indicator of presence of CO₂ plume. | • Existing wells ZG–4, ZG–5, ZG–7, ZG–8, ZG–9, ZG–10 and ZG–12 equipped.  
• 6 new wells strategically located. |
| Wellhead P (injection and annulus) | Risk management/assurance | • Monitor reservoir performance.  
• Measure potential casing/internal completion leaks. | • Pressure gauges at wellheads.  
• Possible regular MIT and USIT subject to further study. | Continuous | • Wellheads pressure (gauge).  
• Regular MIT surveys? | • All injectors  
• As indicated or per regular plan? |
| Reservoir sampling (peripheral) | Verification | • Only if pressure and models indicate possible plume presence.  
• Measure plume saturations and estimate remaining time to allow injection while avoiding plume leaving licensed areas. | • Around the edges of the development.  
• Between the developed areas and other assets such as O&G fields or mines. | As required (based on pressure data). | Wells drilled at a later time which can sample formation fluid. | Assuming a total of 6 over 30 years. |
| Deep aquifer pressure and sampling (saline, just above black alley shale) | Assurance | • Assess seal integrity and leakage pathways through faults by measuring pressure increase as indicator of leaks.  
• Sample fluids to confirm (or not) containment breach. | • Deepest part of syncline (where cap–rock pressures are modelled to be maximum).  
• Close to known faults through the cap–rock. | Continuous | Westbay multi–layered groundwater monitoring system installed in deep observation wells. | 12 multilevel deep groundwater monitoring wells. |
<table>
<thead>
<tr>
<th>M&amp;V Technology</th>
<th>Objectives</th>
<th>Reasons</th>
<th>Location</th>
<th>Frequency</th>
<th>Configuration</th>
<th>Number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shallow aquifer pressure and sampling</td>
<td>Verification</td>
<td>Measure water levels and chemistry in near-surface (above the Black Alley Shale) to confirm no contamination.</td>
<td>In the field areas where cap-rock pressures are modelled to be maximum and close to known faults through the cap-rock.</td>
<td>Continuous</td>
<td>Shallow groundwater monitoring using diver system.</td>
<td>6 dedicated shallow monitoring wells.</td>
</tr>
</tbody>
</table>
| Soil gas sampling                      | Verification| Measure natural background CO\textsubscript{2} and other gas (inc. CH\textsubscript{4}) to establish baseline conditions (Isotopic and concentration analysis). | • Baseline by soil type over 4 seasons.  
• During operation, sampling frequency increases (1 every 2 months) and is close to well-sites. | Continuous | • 1–2m soil gas chambers (automatic or manual) and lab analysis.  
• Flux measurements possible. | 14 soil gas chambers. |
| Atmospheric sampling                   | Verification| Measure atmospheric concentrations, isotopic compositions and fluxes of CO\textsubscript{2} and CH\textsubscript{4}. | • Close to background sources (Turkey Creek, Mine/s, Emerald etc.).  
• Close to potential leakage areas (wells, faults etc.).  
• Baseline/background reference points (away from any anthropogenic). | Continuous | • Lo–flo tower  
• Flux tower  
• Air sampling  
• Laboratory analysis | 8 Lo–flo/flux towers Air sampling (close to potential leakage points). |
| Weather monitoring station             | Verification| Measure atmospheric conditions required to interpret atmospheric sampling. | Situated with reference to prevailing wind directions. | Continuous | • Main monitoring station (weather tower).  
• Weather recording at atmospheric towers. | 1 main monitoring station. |
| Ecological surveys                     | Verification| • Baseline existing vegetation and ecosystems.  
• Monitor to prove no impact from injection operations. | In high risk (wells and faults) and high sensitive areas (EREs). | Seasonal | Site surveys, sampling and recording (seasonal).  
• Baseline: *4/yr  
• Injection: *6/yr  
• 4 zones selected around EREs/creeks. |
### TABLE 7.9: INDICATIVE MONITORING PLAN (CONT.)

<table>
<thead>
<tr>
<th>M&amp;V Technology</th>
<th>Objectives</th>
<th>Reasons</th>
<th>Location</th>
<th>Frequency</th>
<th>Configuration</th>
<th>Number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Watercourses quality survey</td>
<td>Verification</td>
<td>To confirm baseline (TDS, ions compositions) monitoring (i)</td>
<td>All main streams in tenement and also at major sources.</td>
<td>Regular (seasonal).</td>
<td>• Water sampling and field analysis.</td>
<td>Every 2 months combined with groundwater M&amp;V.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>through construction activities (roads, drilling etc) and (ii)</td>
<td></td>
<td></td>
<td>• Laboratory analysis.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>through operations.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mechanical integrity and CB surveys</td>
<td>Assurance</td>
<td>Confirm casing and cement integrity.</td>
<td>Every well (after 5 years).</td>
<td>Every 3 years.</td>
<td>Logging</td>
<td>Every well.</td>
</tr>
<tr>
<td>Through casing logging</td>
<td>Assurance</td>
<td>Confirm no CO₂ behind casing above injection zone.</td>
<td>Wells with other risk factors.</td>
<td>As indicated.</td>
<td>Logging</td>
<td>As indicated</td>
</tr>
<tr>
<td>Ground movement monitoring</td>
<td>Risk management</td>
<td>Measure ground movement due to injection for avoidance of claims and</td>
<td>Through the field.</td>
<td>As indicated.</td>
<td>Tiltmeters (continuous) InSAR (satellite or plane).</td>
<td>Tiltmeters: numerous InSAR (1–2 baseline; 8 during injection).</td>
</tr>
<tr>
<td></td>
<td></td>
<td>early detection of potential hazards.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pipeline leak detection</td>
<td>H&amp;S</td>
<td>Detection of emission sources due to loss of pipeline integrity.</td>
<td>Along the pipeline line.</td>
<td>Continuous</td>
<td>Leak detection system.</td>
<td>Not yet defined.</td>
</tr>
<tr>
<td>Pump (VSD) and compressor fugitive</td>
<td>H&amp;S</td>
<td>Detection of fugitive emission sources in most likely locations.</td>
<td>At site of plant.</td>
<td>Continuous</td>
<td>Detectors and alarms.</td>
<td>Not yet defined.</td>
</tr>
<tr>
<td>emissions</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
FIGURE 7.9: ILLUSTRATIVE MAP OF THE MONITORING TECHNOLOGIES DEPLOYED AS PART OF A CONCEPTUAL NDT FIELD DEVELOPMENT
7.8 Scoping CTS Development Costs—Coarse Estimates

A simple list of the major development and MMV cost items is given in Table 7.10:

**TABLE 7.10: SCOPEING COST ESTIMATES FOR A CONCEPTUAL MONITORING PLAN**

<table>
<thead>
<tr>
<th>Total cost $’000</th>
<th>Scalar cost/ well $’000</th>
<th>Quantity</th>
<th>Scoping: 129 active well development items</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Major development expenditure</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$470.800</td>
<td>$3.650</td>
<td>129</td>
<td>CO₂ NDT direct field capex (all)</td>
</tr>
<tr>
<td>$101.400</td>
<td>$0.786</td>
<td>129</td>
<td>Total pipeline and flow-lines and boosters</td>
</tr>
<tr>
<td>$26.400</td>
<td>$2.200</td>
<td>12</td>
<td>Well failures (no useful reservoir)</td>
</tr>
<tr>
<td>$78.475</td>
<td>$3.650</td>
<td>22</td>
<td>Spares and redundancy (extra wells)</td>
</tr>
<tr>
<td>$114.440</td>
<td></td>
<td></td>
<td>Allowance for indirect costs</td>
</tr>
<tr>
<td>$57.220</td>
<td></td>
<td></td>
<td>Allowance for enabling works</td>
</tr>
<tr>
<td>$10.000</td>
<td></td>
<td></td>
<td>Allowance for EIS costs</td>
</tr>
<tr>
<td><strong>$858.735</strong></td>
<td></td>
<td></td>
<td>Main CTS development capex</td>
</tr>
<tr>
<td><strong>Additional MMV development expenditure</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$12.000</td>
<td>$2.000</td>
<td>6</td>
<td>Deep pressure monitoring wells</td>
</tr>
<tr>
<td>$2.000</td>
<td>$0.100</td>
<td>20</td>
<td>Monitoring additions at injectors</td>
</tr>
<tr>
<td>$15.600</td>
<td>$1.300</td>
<td>12</td>
<td>Deep aquifer monitoring and sampling</td>
</tr>
<tr>
<td>$1.400</td>
<td>$0.100</td>
<td>14</td>
<td>Permanent soil gas sampling</td>
</tr>
<tr>
<td>$4.000</td>
<td>$0.500</td>
<td>8</td>
<td>Atmospheric sampling</td>
</tr>
<tr>
<td>$0.100</td>
<td>$0.100</td>
<td>1</td>
<td>Weather monitoring</td>
</tr>
<tr>
<td>$0.120</td>
<td>$0.002</td>
<td>60</td>
<td>CO₂ detectors (facilities etc)</td>
</tr>
<tr>
<td><strong>$35.220</strong></td>
<td></td>
<td></td>
<td>Additional MMV capex (circa 5% of total development capex)</td>
</tr>
<tr>
<td><strong>$893.955</strong></td>
<td></td>
<td></td>
<td><strong>Total of main development cost items</strong></td>
</tr>
<tr>
<td><strong>$31.181</strong></td>
<td></td>
<td></td>
<td>4.0% Overall annual operating costs factor assumption (Incl MMV opex)</td>
</tr>
</tbody>
</table>
8 Performance Analysis of Development Concept—Commercial Implications

8.1 Context
This subsection describes how the end-PFS decision tests were addressed based on geological characterisation and the notional development concept previously described using stochastic forecasting techniques. It discusses a method of assessing both performance predictions and confidence levels in those predictions using schema developed with Shell Technology and projects.

8.2 Lessons Learnt
It is essential to have stage-gate decisions defined in terms of required performance and required confidence in that performance. These decisions should include injection rate requirements over time and unit cost requirements.

Forecasts of aggregate field injection performance must be embedded in site-specific data calibrated by dynamic well test and a consistent conceptual development plan with detailed constraints considered.

It is important to simulate a field development drilling sequence (and resultant installed injection capability over time) the results of which account for all uncertainties in geological static and reservoir dynamic outcomes. This requires a multi-discipline approach to simulation and uncertainty analyses and some subjective judgements of likelihood. The impact of these judgements should also be investigated.

Based on current analyses and test data, it was considered highly unlikely that a rate of 2 Mtpa could be sustained for 30 years. Physical constraints on well spacing created a significant shortfall between the P50 (and P90) estimates of required well count and the extent of the geological play and areas of tenements available to ZeroGen.

No robust solution was found, which could deliver a sustained 2 Mtpa for 30 years. More complex development technologies would be required.

Based on a 130 well development, the P50 unit cost of transport and storage, would be of the order of $150/tonne but this would sequester only 22% the plant’s CO₂, though 65% would need to be captured, at least initially. There was no solution to the proscribed unit cost test which required storage and transport at less than $50/t.

Injection and dynamic capacity enhancement by approximately 300% per well (which would take a technology break-through and more complex wells), as well as significant cost reduction would be required and could not be foreseen within the project planning (and CCS Flagship) timeline.
8.3 Test 2—P50 Estimates of Rate

The ZeroGen Project would have required 60 million tonnes of CO₂ to be sequestered over 30 years at a rate of 2 Mtpa in the NDT. There would be an initial ramp–up period from 1.5 Mtpa in year one to 2 Mtpa from year three.

There was a finite core area in which 130 wells may be drilled and a possible (but unlicensed) area with space for up to another 120.

The key project decision in Q2 2010 was whether there was a >50% probability of ‘cost–effective’ storage. Cost–effective storage was defined as less than $50/tonne of CO₂ stored (transport and storage cost).

To address this, also required the following to be investigated:

- how many wells need to be batch drilled upfront before the start of injection? This is based on the confidence level required to match the CO₂ rate of 1.5 Mtpa at the end of the first year?; and
- what should the well spacing be for the initial batch?

8.3.1 Well count methodology

This subsection summarises the methodology to arrive at the total well count required, well phasing during the injection and number of wells required upfront (i.e. before injection starts) for commercial–scale carbon sequestration (Shell–ZeroGen, 2010i).

Assumptions

The following assumptions are stated for clarity and transparency in the overall well count methodology:

- the injection wells would be air drilled vertical wells with open–hole section from top Catherine to TD at the Mid–Aldebaran Unconformity (see long term hole issues with this in Subsection 7.6.1);
- the rate at which wells would be drilled was equal to the number of wells required to achieve the injection rate. In practice a drilling rate based on rig availability would determine the drilling campaign and number of wells required upfront;
- the target injection rate schedule was 2 Mtpa for 30 years with a ramp up over the first two years;
- the 12 appraisal wells drilled to date were assumed to have sufficient spatial distribution to provide high confidence that reservoir property ranges intersected within the area are representative of the range for the whole storage area;
- the input to the well count determination was a series of single well models of CO₂ injection based on the reservoir properties of five different appraisal wells (ZG–3; ZG–5; ZG–6; ZG–8; ZG–10). The TD of the wells vary from 1260–1750m MD, wells ZG–3, ZG–6, ZG–5 did not reach the Mid–Aldebaran Unconformity and hence single well models for these wells are slightly pessimistic in forecast;
• even though the 12 appraisal wells provided high confidence in capturing the range of reservoir properties in the acreage, there was no predictive model of reservoir properties other than regional trends based upon facies distribution and simple grid drilling is envisaged;
• well count was calculated based on an initial well spacing of 2 km. In practice, the decision on the well spacing for grid drilling would need to be taken in advance (a 4 km scenario was investigated but is not discussed herein);
• a failure rate of 10% was applied to the total number of wells—this represented well drilled in which no injection could be achieved;
• a sparing ratio of 1:7 was applied to the total number of successful wells i.e. one well out of seven would be used as a spare well, or alternatively all wells will be run at $6/7$th the maximum pressure in order to allow for buffering in the system if other wells trip out; and
• phasing: it was envisaged that batch drilling a number of wells would be required prior to the start of injection to meet the steep ramp up rate to 1.5 Mtpa (4109 tpd) at the end of one year. Batch wells would be based on a grid spacing of either 4 km or 2 km. Batch drilling in advance would:
  – allow acquisition of additional reservoir data upfront;
  – provide a schedule buffer; and
  – provide higher confidence levels of installed injection capacity for year end injection rate.

### 8.3.2 Dynamic simulation

As previously discussed, single well models were constructed for five type–wells designed to capture the range of outcomes and facies distributions in the full dataset (Figure 8.1 and Section 2).

To ensure that the single well dynamic models reflected a fuller range of remaining subsurface uncertainty, sensitivities were performed on the following input parameters.

**Reservoir continuity.** Model boundary radii (c.f. Subsection 3.4.10—boundaries seen on tests) of 500 m, 1000 m and 2000 m were modelled.

**Well skin.** Two different values of skin were applied to open hole injection from the top of Catherine to TD. A well skin of zero or four corresponds to air drilled and thermal fracturing effect due low temperature of injected CO$_2$.

**Relative permeability.** Two ‘curves’ were used:
- current case (based on CO$_2$ relative permeability curves literature database); and
- experimental case (measured curves based on unsteady state HYCAL experiments on ZeroGen cores).

### 60 injection scenarios for simulation

Each of the five single well model had 12 injection profiles (three boundary conditions x two skin values x two relative permeability cases). Each simulation forecast the injection profile and cumulative CO$_2$ injection over 30 years at monthly intervals to give sufficient granularity.
A total of 60 injection profiles were constructed. Each was assigned a probability of occurrence based on the probability of four parameters (well type in ZeroGen acreage, boundary of the model, well skin and relative permeability).

**FIGURE 8.1: LOCATIONS OF ZEROGEN WELLS (INDICATED BY RED POINTS)**
8.3.3 Assignment of probabilities to injection profiles

The probability of intersecting the geology represented by each well type should vary according to the areal position of the grid location and is (albeit to a weak extent) controlled by the local facies model (Section 2, ‘Geologic Framework’).

- The facies model for the Catherine, which is the formation where facies exerts most control on the reservoir properties, was considered. The area available for CO₂ storage was divided into three main Catherine facies types as shown in Figure 8.1. For each of the areas, the probability of the modelled well types was as shown in Table 8.1.

<table>
<thead>
<tr>
<th>Case</th>
<th>Region</th>
<th>Area km²</th>
<th>Well type proportions (fraction)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>ZG–10</td>
</tr>
<tr>
<td>Low Case</td>
<td>Delta Plain</td>
<td>293</td>
<td>0.10</td>
</tr>
<tr>
<td></td>
<td>Transitional Coastal</td>
<td>89</td>
<td>0.04</td>
</tr>
<tr>
<td></td>
<td>Delta Front</td>
<td>27</td>
<td>0.00</td>
</tr>
<tr>
<td></td>
<td>Total</td>
<td>409</td>
<td>0.08</td>
</tr>
<tr>
<td>Base Case</td>
<td>Delta Plain</td>
<td>293</td>
<td>0.20</td>
</tr>
<tr>
<td></td>
<td>Transitional Coastal</td>
<td>89</td>
<td>0.08</td>
</tr>
<tr>
<td></td>
<td>Delta Front</td>
<td>27</td>
<td>0.00</td>
</tr>
<tr>
<td></td>
<td>Total</td>
<td>409</td>
<td>0.16</td>
</tr>
<tr>
<td>High Case</td>
<td>Delta Plain</td>
<td>293</td>
<td>0.25</td>
</tr>
<tr>
<td></td>
<td>Transitional Coastal</td>
<td>89</td>
<td>0.10</td>
</tr>
<tr>
<td></td>
<td>Delta Front</td>
<td>27</td>
<td>0.00</td>
</tr>
<tr>
<td></td>
<td>Total</td>
<td>409</td>
<td>0.20</td>
</tr>
</tbody>
</table>

Constraints were applied as discussed in Subsection 7.3.

The areas (based on facies) were computed from the gross depositional static model. The proportion of each well type proportion was assigned by area (based on geological model supported by well test results, facies description and rock typing). For each well type a probability was also assigned to each of the sensitivities modelled i.e. model boundary, well skin and relative permeability. Other probabilities assigned for skin, boundary conditions and relative permeabilities are shown in Figure 8.2 (for ZG–8 as an example).

The results were dependent on the facies zonation in the static model and subjective choices about the relative weighting by well types, sensitivity to this subjective assessment was included in repeat simulations.
Probabilistic well count workflow

The probabilistic well count determination was calculated as follows.

1. Drilling commenced in year 0 (i.e. first time step). An injection profile was picked randomly from the 60 profiles based on their probability of occurrence. This injection profile over 30 years was the first to start building a cumulative injection profile.

2. Additional injection profiles were picked in a similar manner until their combined injection capacity in the first month met the required injection target rate at the end of the month.

3. The time step was then increased by one (month) and steps one and two are repeated to match the required injection rate target in month two. This was repeated for 360 months (i.e. 30 years from start) with additional wells added as required to make up for the injectivity decline in the wells and ensure the injection rate target was matched at all times.

4. Steps 1–3 constituted a single simulation run and gave a cumulative injection per month and number of wells required to meet the target rate at each month for a given input well probabilities. At first, 300 simulations were performed for each low, medium and high case (i.e. different well–type by area weightings).

5. All the 900 simulations (combining the low–mid–high cases with 300 simulation each) were used to generate multiple cumulative injection profiles and number of wells for a given time step. Hence, a distribution of number of wells was generated to provide P10, P50 (median) and P90 for each time step.

FIGURE 8.2: ILLUSTRATION OF PROBABILITY ASSIGNMENT TO EACH INJECTION PROFILE

![Diagram of probability assignment to each injection profile]

- ZeroGen 8
  - Boundary 500 m
    - Skin–0
      - RPM–1
        - 0.7
        - 0.8
        - 0.0
    - Skin–4
      - RPM–2
        - 0.3
        - 0.2
        - 0.0
  - Boundary 1000 m
    - Skin–0
      - RPM–1
        - 0.7
        - 0.8
        - 0.0
    - Skin–4
      - RPM–2
        - 0.3
        - 0.2
        - 0.0
  - Boundary 2000 m
    - Skin–0
      - RPM–1
        - 0.7
        - 0.8
        - 0.0
    - Skin–4
      - RPM–2
        - 0.3
        - 0.2
        - 0.0

- Modelled curves
  - RPM–1
    - 0.0
    - 0.0
    - 0.0

- Measured curves
  - RPM–2
    - 0.0
    - 0.0
    - 0.0

- RPM–1
  - 0.25
8.3.4 Well count required and phasing results

The robustness of a first pass analyses described above was examined by opening the uncertainty envelope—especially on allowed mixes of well–scenario.

To investigate the full range of P10 to P90, 50 additional cases were included using different well probabilities in the given acreage.

First, the base case well probability case (see Table 8.1) was used for multiple scenarios. Then, each individual well probability was varied from 0.1–1 with 0.1 incremental steps while maintaining the ratio of the remaining four wells same as in base case.

For example, if ZG–3 was assigned 0.1 then the remaining 0.9 probability to wells ZG–5, ZG–6, ZG–8, ZG–10 was distributed such that the four wells had same probability ratio as in base case.

In total 53 sets of input well probabilities were derived. For each set of input well probabilities, 300 simulation runs were performed to arrive at the well count. Hence 15,900 simulation results were generated.

At each time step 15,900 values of well count were generated which could then be compiled to give various probability values (e.g. P5, P10, P50, P90). The final cumulative well count probability was taken to be at the end of 30 year time period (i.e. at last time step, P10, P50 and P90).

The probability curve for the total number of vertical wells required at the end of 30 year time period is shown in Figure 8.3. The left side Y axis is qualitative and gives probability distribution for number of wells required to achieve the target. The probability or ‘P’ value is shown on right axis for the curve shown in black colour. For comparison, the coloured bars represent cases where all wells are of a single type. For example, only around 300 ZG5–type wells would be required compared to over 1000 ZG3–types.

A summary of this fuller uncertainty range is given in Table 8.2, below.

**TABLE 8.2: WELL COUNT UNCERTAINTY RANGES—FULL ANALYSIS**

<table>
<thead>
<tr>
<th></th>
<th>P10</th>
<th>P50</th>
<th>P90</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of wells</td>
<td>342</td>
<td>422</td>
<td>585</td>
</tr>
<tr>
<td>Number of wells (including failure rate + sparing ratio)</td>
<td>425</td>
<td>524</td>
<td>798</td>
</tr>
</tbody>
</table>

*Full uncertainty range—53 well probability sets.*
8.3.5 Well count conclusions

Total number of wells required, regardless of area available to support 65% capture and inject 2 Mtpa over approximately three years would be:

- 425 at P10 confidence level;
- 524 at P50 confidence level; and
- 798 at P90 confidence level.

8.3.6 Sequestration volumes for a limited well count

Rather than investigate how many wells (and what area) would be required to sequester 2 Mtpa, an alternative question was investigated.

The key question was:

> Given constraints of 130 and say 250 wells, what CO₂ could be stored given supply rates of 2 Mtpa (and 3 Mtpa)—and what is the resultant venting required when the rate can no longer be matched in the field?
To investigate this, a simplification of method was used, based on a weighted average well injection profile and ignoring, initially, sparing and well failures (which would inflate well counts by a factor 1.3 or decrease sequestration rates accordingly).

Figure 8.4 below, shows an initial ramp up of injection potential to match the required 2 Mtpa rate (65% capture). In the case of 130 wells, there is an immediate decline in cumulative injection rate from this well stock corresponding to an increasing gap between captured and sequestered CO$_2$ which would have to be vented.

In the case of 250 wells, the rates may be matched for a few years, however at around year 12, again a gap begins to appear.

The (optimistic) amount sequestered for the 130 and 250 wells case are 24.8 and 49.0 million tonnes respectively. If 65% capture and store, represents 60 million tonnes, then these figures represent IGCC capture and store of 27% and 53% respectively i.e. the former would vent more than half of all captured CO$_2$, the latter about 18% of all captured.

**FIGURE 8.4: SIMPLIFIED PREDICTION—INJECTION PERFORMANCE VS. 2 MILLION TPA TARGET OVER 30 YEARS FOR A FIXED SET OF 130 AND 250 WELLS**

Simplified illustration. 65% capture target 2 Min tpa for 30 years (using a simple average well profile)
8.4 Decision Test 3 Assessment of Unit Cost—$/tonne

A pseudo-commercial, hurdle rate for life-cycle, unit cost of transport and storage was defined at AU$50/tonne.

Initially, this unit cost ‘hurdle’ was scoped-out based on an annuity method. A capital availability and cost maximum of $800 million was assumed with annual operating cost of 2.5% p.a. Assuming that the capital was borrowed at 10%, annual repayment rates would be $76 million p.a. and annual operating costs would be $20 million p.a. Assuming a constant injection rate of 2 Mtpa over 30 years. This would to an annualised unit cost of around $48 per tonne—hence a $50/t target.

Later unit costs evaluations were based on real-terms, tax-free, break-even price (RTBEP, discounted full-life cycle costs/discounted injection rates) methodology to better account for capital phasing and injection rate decline in a way which is consistent with the resource performance and development concept.

8.4.1 Updated P50, $/t estimates

Based on the initial hurdle rate, a simplified unit costs was calculated using scoping estimates of capital costs in Subsection 7.5.1. for comparison with the unit cost tests. The results are shown below (Table 8.3):

<table>
<thead>
<tr>
<th>Target capture</th>
<th>Target injection rate (M tpa)</th>
<th>Target volume (M t)</th>
<th>No. of injector wells</th>
<th>Approx. stored vol (M t)</th>
<th>Capital cost (A$M)</th>
<th>P50 unit cost ($/t)</th>
<th>Approx. ‘regretted’ volume</th>
<th>Effective capture and store</th>
</tr>
</thead>
<tbody>
<tr>
<td>65%</td>
<td>2</td>
<td>60</td>
<td>130</td>
<td>20</td>
<td>$894</td>
<td>$160</td>
<td>40</td>
<td>22%</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>250</td>
<td>37</td>
<td>$1720</td>
<td>$167</td>
<td>23</td>
<td>40%</td>
</tr>
<tr>
<td>95%</td>
<td>3</td>
<td>84</td>
<td>250</td>
<td>56</td>
<td>$1720</td>
<td>$106</td>
<td>28</td>
<td>63%</td>
</tr>
<tr>
<td>65%</td>
<td>2</td>
<td>60</td>
<td>545</td>
<td>60</td>
<td>$3,750</td>
<td>$224</td>
<td>0</td>
<td>65%</td>
</tr>
</tbody>
</table>

Note: Capital costs are not true P50 costs. They include the main development costs only for injection wells, flow-lines and the main CO2 pipeline. For the 130 and 250 cases, spares and redundancy are not fully costed-in. Furthermore, these costs do not include monitoring wells or Feasibility Stage expenses nor indirect costs. True P50 costs (by the simple annuity method) are greater than shown here by over 20%.

Operating costs assumed at 2.5% pa may be considered optimistic based on experience in EOR operations (7% of well capital costs).

Finally, for comparison, a Discounted Cash-Flow (DCF) model was constructed for the reference case of 130 active wells, sequestering some 20 million tonnes over 30 years with an aggregate injection profile (Table 8.3).
In comparison with the first row, 65% capture case in Table 8.3, the unit cost using RTBEP method would be $140/t. This is equivalent to real terms, pre-tax, break-even carbon price, which would be required to cover transport and storage only.

The P50 unit cost of transport and storage, based on a 130 well development would be circa $160 ($140/t by the RTBEP method). This would sequester only 22% of the plant’s CO₂, though 65% would need to be captured, at least initially.

There was no solution to the required P50, $/t test. No physically-limited solution could sequester the required volumes and rates.

Using the benchmark ‘annuity’ method of calculation and assuming a limit of either 130 or 250 wells, P50 unit costs (or transport and storage only) would always be well in excess of $140/t. A unit cost of $50/t is not within the range of possibilities for the scenario mentioned.

8.5 Concept Variations and Improvements

Variations and improvements to the conceptual NDT, Field Development Plan (FDP) would be required to:

1. increase total pore volume accessible and thus volumes stored;
2. increase (especially end of life) injection rates to meet the project aspirations of a sustainable 2 (min) Mtpa; and
3. reduce the unit cost by a factor of three to four.

Furthermore, in the context of the post-PFS decision, for time and money to be invested in investigating these improvements, there would need to be sufficient confidence that they would be successful in the time available to the project. While a suite of investigations and field trials are possible, none were considered sufficiently promising compared to a refocus on newly gazetted GHG tenement areas in other basins.

For completeness, development concept improvements are described briefly hereafter. Improvements fall broadly into three categories (i) increasing the Gross Rock Volume (GRV) accessed, (ii) increasing injection rates per well; and/or (iii) decreasing costs.

8.5.1 Accessing more GRV

GRV measures included licensing additional areas to the East (where the Catherine is largely at sub-critical depths). This would increase the maximum well count to some 230 (still well short of the P50, 524 requirement). In addition, initially supercritical injection (flowing BHPs >74 bar) could be undertaken in the Mantuan Formation at sub-critical depths. The formation is similar in character to the Catherine with air permeabilities ranging from (3 to 68 mD) and similar issues with heterogeneity and connectivity. Coarse models suggest a wide range from 0.04 to 0.82 million tonnes per well. This is a similar, though uncalibrated, range to the one determined for the Catherine, Freitag Aldebaran (Table 4.2) though the two ranges are not additive as pressures may be limited by Mantuan fracture pressures. Another completion strategy would be required (see below).
8.5.2 Increasing rates per well

Measures to increase injection rates per well all increase unit well cost and complexity. Such measures could include dual or multiple completions which would optimise pressures per injection interval. Simple models showed that a 50% cumulative injection per well might be feasible, but at a relative cost increase of more than this compared to the simple well cost. Hence no net benefit in unit cost.

Injection stimulation might also be considered either in single completion schemes or with multiple completions. Such stimulations could include radial or abrasive jet drilling or hydraulic fracturing, both were considered but would have required several field trials to calibrate any improvement.

Initial hydraulic fracture modelling showed that fracture half lengths of around 50 m, might add 1% to 10% to cumulative injection per well, half–lengths of 500 m might increase cumulative injection by over 100% per well. However the latter would also require increased well spacing to avoid well interference. Such wells would also be significantly more expensive than the simple wells in the FDP concept. Furthermore, it was established by down–hole camera, that fractures initiated in the area are preferentially horizontal. While this is favourable for containment, given low kv/kh ratio and extreme heterogeneity, enhancement by hydraulic fracture stimulation would require significant trialling before becoming the core concept on which to base a decision to progress the project beyond PFS.

A deviated well might provided higher injectivity compared to a vertical well as it contacts more reservoir thickness. However, simple models calibrated in NDT formations, showed that for a 60° inclination, cumulative injection was increased by less than 10%, cost increases would be larger than this.

Pressure management by co–production of brine (e.g. from wells in the centre of a spot pattern) was also investigated. For this to be considered, reservoir connectivity would need further investigation (longer term dynamic testing at more locations) to optimise well spacing and avoid CO₂ break–through. Based on simple (favourable) models, water off–take might increase cumulative volumes at rates per well by up to five times. While the conversion of some wells to producers would decrease the available injection well count, the increase in rate per well might result in sufficient injection capacity. However, there would be significant additional infrastructure costs for brine flow–lines, brine storage and treatment and ultimate disposal.

Injection system and drilling sequence optimisation might also increase effective rate per well, but this was not studied at this time.

8.5.3 Cost optimisation

Typical, concept–selection studies would investigate materials optimisation (replacement of CRAs) and contracting strategies for key services and materials. While a project with >100 wells might lever some scale economies. In the context of the Australian market and a background of two to four very large coal seam gas, LNG projects, it was considered most likely that oil–field inflationary pressure would remain high.
9 Assessment of Storage ‘Reserves’

9.1 Context
The purpose of this subsection is to present a brief example of GHG storage resources with reference to a classification system proposed by Gorecki et al. (2008) in SPE publication 126421. That report summarises earlier CSLF, DOE and CO2CRC systems and considered them to be ‘inadequate to fully describe the various resource and capacity estimations that are made possible by the storage coefficient concept’ (ibid, p5). This subsection makes no judgement on the relative merits of one system vs another, but seeks only to examine a set of classifications to inform the debate. As in conventional oil and gas all require subjective judgement on technical maturity and there will be inconsistencies caused by differing economic requirements and assessments between parties undertaking the analyses.

9.2 Lessons Learnt
Estimates of practical (useful, rate–matched) storage resources need to be constrained by site–specific, dynamic well (test) data.

At least in areas characterised by relatively tight, heterogeneous formations, estimates based on static capacity calculations modified by storage ‘efficiency’ type corrections do not inform in any useful manner the area’s practical storage capacity.

Exercises which add such estimates together and assume that these usefully inform abatement potential are likely to be highly erroneous and hence misleading.

While static–based calculations are of no use as an indicator of economic GHG storage resource potential, they are probably of great use as a screening and relative ranking tool. They inform where additional exploration and appraisal should, on the balance of available evidence, be focused next.

9.3 Theoretical Storage Resource (Atlas) Estimates
ZeroGen’s permits overlie the NDT, which is a subset of the Bowen Basin of Central Queensland. Previously the storage potential of the area has been described in the Queensland, Carbon Dioxide Geological Storage Atlas (Bradshaw et al. 2009)—‘the Atlas’. In the Atlas, the area is referred to as the Bowen—Western, or BWW, and is ranked relatively as ‘high prospectivity’. The Atlas recognises three main reservoirs with storage potential i.e. in the Aldebaran, Freitag and Catherine Sandstone Formations. BWW is sub–divided into a Southern and NDT areas (ibid, p.70 and figure BWW12). The Northern area is larger than but overlies ZeroGen’s permit areas. The authors of the Atlas did not have access to final ZeroGen dynamic test information.
The capacity calculation methodology used in the Atlas is based on a static volumetrics taking into account estimates of gross rock volume, total pore volume, residual gas saturation and depth (temperature and pressure). Prospectivity factors such as reservoir quality cut-offs were also applied (<10% porosity and <5mD permeability) as suggested by the Queensland Geological Survey. A further reduction was applied by the authors based on an ‘invaded volume’ efficiency factor. In terms described in Gorecki et al., the maturity of this estimate is similar to a ‘Theoretical Storage Resource’ calculation which those authors describe as an ‘upper limit’. But important reductions from this have been applied in the Atlas as discussed in Spencer et al. 2010 and Bradshaw et al. 2010.

Thus, the Atlas methodology of Bradshaw et al. departs from this concept of a theoretical ‘upper limit’. However, they still consider that regional estimates are ‘always a gross overestimation’ of practical storage capacity (Bradshaw et al. 2009, p.33) and throughout the calculation conservative, estimates were taken for each parameters (J Bradshaw, pers. comm). The selection of conservative parameters as well as the application of poro–perm cut–offs thus represent an attempt to apply some technical constraints to an otherwise unconstrained count of pore–space. These constraints represent a form of preliminary characterisation.

The essence of the differentiation between Theoretical and Characterised Storage Resources, seems to be on the notion of whether a site has been ‘well characterised’ (Gorecki et al., 2009, p.8). A deeper meaning of this is not elucidated, nor is there likely to be a general scheme.

There is a spectrum of theoretical calculations possible, making increasingly sophisticated assumptions which correct from gross–pore volume to create a better approximation of useable pore volume. Likewise, characterisation activities lie on a spectrum from desk top studies and models, through site-specific seismic, stratigraphic wells, dynamic well tests, interference tests, 3D seismic and so on.

A useful cross–over from Theoretical to Characterised Resources might be when at least one dedicated well has been drilled specifically to investigate the storage potential of a site at or close to the injection point. With this consideration, the Atlas did indeed evaluate a type of Theoretical Resource Potential albeit not at any ‘upper limit’.

For the NDT, the Atlas records the following Theoretical Storage Resource.

**TABLE 9.1: THEORETICAL RESOURCE POTENTIAL AFTER THE ‘ATLAS’ (BRADSHAW ET AL., 2009)**

<table>
<thead>
<tr>
<th>Reservoir unit</th>
<th>Atlas Theoretical Resource Potential (million T)</th>
<th>Approximate ZeroGen licensed proportion (million T)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aldebaran</td>
<td>84</td>
<td>10—30</td>
</tr>
<tr>
<td>Freitag</td>
<td>56</td>
<td>40—50</td>
</tr>
<tr>
<td>Catherine</td>
<td>10</td>
<td>5—8</td>
</tr>
<tr>
<td>Summation</td>
<td>150</td>
<td>55—88</td>
</tr>
</tbody>
</table>
9.4 Characterised Storage Resource

ZeroGen’s ‘Characterised Storage’ calculation discussed hereunder remain essentially a static, adjusted pore–volume calculation, though one in which storage or ‘sweep’ efficiencies are constrained by simple calibrated injection models rather than published data or rules of thumb.

Calculation of adjusted static volumes is described in Section 6. For each system (i.e. closed and open system) an ‘ultimate’ storage capacity and ‘effective’ storage capacity was computed. The ultimate storage capacity assumed 100% sweep efficiency and final pressure of the formation equal to the injection pressure whereas effective storage capacity takes into account sweep efficiency and final pressure is average of initial pressure and injection pressure. It is the ‘effective’ storage capacity which is closest to a Characterised Storage Resource described by Gorecki et al 2009.

The CO₂ storage capacity for open and closed systems is summarised in Table 9.2 and Table 9.3.

The closed system CO₂ storage capacity is contributed by compressibility and solubility process whereas an open system CO₂ storage capacity is determined mainly by solubility and displacement process.

**TABLE 9.2: SUMMARY OF EFFECTIVE AND ULTIMATE CO₂ STORAGE CAPACITY FOR OPEN SYSTEMS FOR AVAILABLE AREA**

<table>
<thead>
<tr>
<th>Probability of exceeding capacity X</th>
<th>Effective CO₂ storage capacity (X million T)</th>
<th>Ultimate CO₂ storage capacity (X million T)</th>
<th>Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>P90</td>
<td>385</td>
<td>1423</td>
<td>27%</td>
</tr>
<tr>
<td>P50</td>
<td>865</td>
<td>2680</td>
<td>32%</td>
</tr>
<tr>
<td>P10</td>
<td>1969</td>
<td>4902</td>
<td>40%</td>
</tr>
</tbody>
</table>

**TABLE 9.3: SUMMARY OF EFFECTIVE AND ULTIMATE CO₂ STORAGE CAPACITY FOR CLOSED SYSTEMS FOR AVAILABLE AREA**

<table>
<thead>
<tr>
<th>Probability of exceeding capacity X</th>
<th>Effective CO₂ storage capacity (X million T)</th>
<th>Ultimate CO₂ storage capacity (X million T)</th>
<th>Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>P90</td>
<td>50</td>
<td>131</td>
<td>23%</td>
</tr>
<tr>
<td>P50</td>
<td>87</td>
<td>230</td>
<td>37%</td>
</tr>
<tr>
<td>P10</td>
<td>163</td>
<td>386</td>
<td>42%</td>
</tr>
</tbody>
</table>
Note that in this case, there is an order of magnitude difference between Characterised Resource calculations based on either open or closed system assumptions. This shows the importance of an assessment of reservoir dynamics.

Clearly either ‘perfect closed’ or ‘perfect open’ end-members are not geologically reasonable and it is essential to obtain appraisal data about the connectedness of the reservoir.

ZeroGen’s core and log data were consistent with fluvial systems throughout all reservoirs in the area. Channel type boundaries were evident in the well tests at less than 500 m from the test point. In addition, given low rate injection wells, the basic development concept was for numerous wells across the area with a 2 km well spacing such that wells would ‘see’ the injection pressure front from their neighbours. Therefore the ZeroGen storage site is considered to resemble most closely a closed system rather than an open system. The possibility that the outer wells may be in more of an ‘open’ situation relates to upside.

**Result—Characterised Storage Resource**

The Characterised Storage Resource (static method with model-based sweep efficiency adjustments) for the NDT Exploration Permits, assuming utilisation of Catherine, Freitag and Aldebaran reservoirs is thus of the order of **80–100 million tonnes** with a P50 level of technical confidence. Of this some 20–30 million tonnes is associated with the Catherine Formation.

But this does not inform the rate at which these resources can be ‘filled up’ or accessed

The notionally, ‘theoretical’ (but efficiency corrected) resources in the Atlas were slightly, but not significantly lower than those calculated by ZeroGen’s static methods after site characterisation.

Usually, static methods do apply some geological and engineering corrections. The application of model-based sweep efficiencies and the assumption of a near-closed system based on test data with a basic pattern development concept could be taken to mean that the resulting estimate is an Effective Storage Resource as it may be close to ‘the pore volume in known (well characterised) sites into which it is technically feasible to inject and store CO₂’ (Gorecki et al. 2008).

However, such a classification would be premature. There is no worked up development concept for injection into all three reservoirs which matches the static capacity calculation and hence a statement of technical feasibility could not be made. So, such a static estimate, based on real data but not a development concept, should remain a ‘characterised’ one.

**9.5 ZeroGen Effective Storage Resources**

As discussed earlier the focus on trying to establish Practical Resource estimates was the Catherine Formation thus the Theoretical Resource from which a Practical Resource was sought was the four to eight million tonnes of Catherine resources described in the Atlas.

Gorecki et al. (2009) link the definition of an ‘Effective’ resource to technical feasibility and also divide this into ‘Practical’ (economically feasible) and ‘Contingent’ (not yet economic) resources. In the context of a commercial-scale demonstration project within limited capital budgets it was possible to set an ‘Acceptable’ cost of $50/t, for the full life-cycle, PV costs of carbon transport and storage. Thus in the context of the economics of this project, any Characterised Resources which it were feasible to technically access (i) in the lifetime of the project, and (ii) at this unit cost or less, could be considered Practical Resources and those which would be more costly and/or accessed after 30 years would be Contingent Resources.
With reference to Figure 9.4, on a P50 level of technical confidence a 130 well, 2 km well pattern could inject a total of just 25 million tonnes over 30 years. It would take approximately 120 years for injection rates to decline close to zero by which time some 54 million tonnes would ultimately have been injected. This contrasts with a Characterised Resource estimate on which no project time-frame is imposed.

The pre-tax, real terms, break-even unit price of carbon required to cover transport and storage full life costs of such a 30 year development, on a PV basis at 10% discount rate, would be of the order of AUS$140/t (approximately 55% of this is storage). There is zero Effective Practical Capacity. There are Effective Contingent Resources of around 25 million tonnes in the Catherine Formation. Re-classification from Contingent Resources to Practical Capacity would require:

- a radically different development concept and/or technology break-through;
- a three-fold increase in the target unit cost or available capital for carbon transport and storage; and
- an alternative economic screening method involving a price for carbon. In this case an effective carbon price over the life of the project to cover CTS alone would be $140/t for break-even. To cover capture costs requires a higher price still.

9.6 Summary

The table below attempts to summarise the various resource estimates related to the ZeroGen area and exploration permits according to the proposed classification.

**TABLE 9.4: SUMMARY OF ZEROGEN RELATED RESOURCE ESTIMATES**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Catherine only &lt;10 million tonnes in NDT</td>
<td>Catherine only 20–30 million tonnes. Three formations in ZeroGen area 50–90 million tonnes. Three formations in whole of Western Bowen Basin 250 million tonnes</td>
<td>Catherine only 54 million tonnes³</td>
<td>Catherine Practical Capacity 0 million tonnes. Catherine Contingent Capacity 25 million tonnes</td>
</tr>
<tr>
<td>Unusable—due to current technical conditions circa 75 million tonnes (circa 50 in other formations + 29 Catherine after 30 years)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Uncharacterised—no dedicated GHG exploration wells. circa 150 million tonnes (mostly in Southern Denison Trough)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

1. At a P50 level of technical confidence.
2. At a P50 level of technical confidence but not at acceptable unit costs.
3. But unrealistic timeline of 120 years.
9.7 Conclusion

Reserves classifications need to address the maturity of the evaluation i.e. the amount and type of site specific data available and not just the capacity calculation methodology.

The ability to attain and maintain rate is the essential resource–defining determinant and not an arbitrary adjustment to gross pore volume.

The sum over various areas of Theoretical Storage Resources is unlikely to have any useful relationship to the ultimate Effective Storage Resource and hence Practical Storage Capacity.

The use of static model–based techniques as an indicator for useful preliminary accounting of storage potential is not recommended.

Static methodologies have a place in relative ranking and screening to aid the decision on where to first explore and appraise.

Only use of dynamic models (production or injection) constrained by site–specific test data should be used to evaluate resource potential in a way which is meaningful for abatement planning.

In the context of an aquifer storage site, ZeroGen suggest that the cross–over from Theoretical to Characterised Resources is when:
- there are exploration rights; and
- at least one dedicated well has been drilled specifically to investigate the storage potential of a site.

The cross–over from Characterised to Effective Resources then requires:
- storage and injection rights;
- dynamic well tests;
- a costed field development concept; and
- an economic ‘test’ of some nature.
10 Risk Assessment Using Evidence Support Logic

10.1 Context
This subsection describes technical risk and uncertainty assessment for prospective storage resources. Whole of project risk assessment and management are described elsewhere in this volume and in Greig, 2010 and Garnett et al. 2010.

10.2 Lessons Learnt
It is essential that the chosen ‘risk assessment’ methodology for storage resource assessment specifically differentiates uncertainties (lack of evidence) from positive or negative indications of risk which are based on available evidence. A structured and weighted logic linking assessment of key geotechnical parameters to ultimate storage suitability is required. Shell’s approach using Quintessa’s evidence support logic achieves these two requirements in an auditable manner (James et al. 2010).

Storage exploration and appraisal data acquisition and study programs should be focused on reducing large geotechnical uncertainties. Evidence (data and analyses) which can polarise storage risk assessment is of highest appraisal value and may allow for a rapid cessation of exploration spend.

The aim of storage exploration and appraisal is not to ‘prove-up’ a resource as quickly as possible but to ‘polarise’ its assessment (i.e. to ‘kill’ it or ‘prove’ it) as cost effectively as possible.

In the case of a ZeroGen–like project, with a significantly different history of aspired scale, initial extended well production tests, though more expensive on a per well basis, might have ‘killed’ the area more cost effectively than a larger number of relatively cheap cored and partially tested wells.

10.3 Introduction to Evidence Support Logic
Risk assessments of the ZeroGen storage site were undertaken using Shell’s approach to Evidence Support Logic (ESL) and Quintessa’s TELSA software. This was carried out at several points in the evolving project (Shell–ZeroGen, 2010a). The strengths of the ESL methodology are that it addresses both risk and uncertainty and so:

• it supports decisions regarding site selection and further data acquisition at early screening phases of a CCS project;
• it provides a common logical framework that can be applied to all CO₂ storage projects; and
• it achieves consistency in multi-disciplinary risk assessments across a portfolio of projects or repeat risk analyses with different teams and at different degrees of technical maturity.
Subject discussed in this subsection can also found in James et al. 2010.

ESL involves evaluating the support for an identified root hypothesis that is split into any number of sub–hypotheses, each of which can be associated with some fraction of the underlying basic evidence (Egan, 2010). A logical hypothesis hierarchy (or tree) links the root hypothesis to data or information at the lowest level (the leaves), via intermediate steps or sub–hypotheses. This information is known as evidence; evidence for, which supports a hypothesis; and evidence against, which refutes a hypothesis. ESL is an information propagation calculus developed from interval probability theory. It considers an open world view, in which information can be incomplete or even contradictory.

The evidence information about a node is displayed graphically as a horizontal bar with a green portion stemming from the left to show the proportion of evidence for, and a red portion stemming from the right to show the proportion of evidence against. The subsection between is coloured white to indicate the remaining uncertainty. Due to its appearance, this diagram is sometimes referred to as an ‘Italian flag’.

Before evidence can be assessed and entered into the hierarchical hypothesis model, it is necessary to describe and parameterise the logic by which that evidence is propagated upwards through the model in order to assess the extent of support for the top level hypothesis. A standard hypothesis hierarchy (tree) has been devised for CO2 storage site risk assessments.

**What is being assessed?**

The assessment exercise seeks to show where evidence supports or otherwise, a root hypothesis which states that:

**Stakeholders can be assured that the specified CO2 containment complex will accept and contain safely all required volumes in the subsurface for nominally 200+ years.**

The next level of sub–hypotheses breaks this down as shown in Table 10.1:

<table>
<thead>
<tr>
<th>Hypothesis branch</th>
<th>Main hypothesis to be tested</th>
</tr>
</thead>
<tbody>
<tr>
<td>Containment</td>
<td>Injected reactive fluids will not leak significantly from the complex.</td>
</tr>
<tr>
<td>Injectivity</td>
<td>Sufficient injectivity can be achieved and maintained.</td>
</tr>
<tr>
<td>Capacity</td>
<td>There is sufficient pore space to store all the CO2 volumes, (plus a large margin).</td>
</tr>
<tr>
<td>Baselines, monitoring and verification</td>
<td>The site can be baselined and potential escape to geosphere, hydrosphere, biosphere and atmosphere can be monitored.</td>
</tr>
</tbody>
</table>
Further subdivisions of the sub-hypotheses introduce the main risks associated with CO₂ Storage Site Risk Assessments, including: fault leakage, cap-rock strength, lateral migration of the CO₂ plume, reservoir heterogeneity, reactive chemistry, storage mechanisms, etc. All sub-hypotheses are then evaluated based on evidence and assessments rolled up to the top branch and main levels.

### 10.3.1 Risk and uncertainty assessment after PFS testing

A CO₂ storage site risk assessment was updated in March 2010 after the CO₂ and H₂O injection tests had been completed and the results interpreted. Additional geological core descriptions, well logs, RCA analyses from the five new appraisal wells were also available as was new data from the SCAL (rel perm) experiments and seal strength analyses.

The available evidence for and against each of the CO₂ storage risk areas (sub-hypothesis) and an ‘Italian Flag’ results for the reassessments are shown in Figure 10.1.

#### FIGURE 10.1: COMPARISON OF PRE AND POST DP–2B RISK AND UNCERTAINTY ASSESSMENT SHOWING MARKED REDUCTION IN UNCERTAINTY

**CO₂ storage site risk assessment**

<table>
<thead>
<tr>
<th>Demo scale project</th>
<th>Commercial scale project</th>
</tr>
</thead>
<tbody>
<tr>
<td>1MM tonnes CO₂ over 10 years</td>
<td>60MM tonnes CO₂ over 30 years</td>
</tr>
<tr>
<td>Storage site: EPQ 1</td>
<td>Storage site: EPQ 1 and EPQ 2</td>
</tr>
<tr>
<td>September 2008</td>
<td>March 2010</td>
</tr>
</tbody>
</table>

**Containment**

There is strong supporting evidence for containment, which reflects the positive results of the cap rock study, rock strength tests, XLOTs and regional stress analyses. Lack of evidence (white space) relates mainly to the lack of extensive seismic data which would be required to inform fault risk.
Capacity

Evidence supporting sufficient (high confidence in) capacity decreased sharply, due to the increase in amount of CO₂ to be stored. Storage capacity calculations (Subsections 6.4 and 8.3.2) show a risk of insufficient practical capacity, depending on assumptions used about storage efficiency and on the ability to fill the space available in the time frame of the project. This is reflected in negative evidence for capacity.

Injectivity

The relatively low CO₂ matrix injection rates achieved in the ZG–11 (Subsection 3.4.3) and water rates achieved in ZG–8 and ZG–10 tests (Subsections 3.4.8 and 3.4.9) are reflected in increase negative evidence for sustainable injectivity (30%). Uncertainty remains due to limited duration well tests, lack of well interference evidence and under-sampling of the area.

10.3.2 Summary—Impact of PFS campaign on project uncertainties

The PFS appraisal campaign from September 2008 to April 2010 achieved its objective by leading to a significant reduction in ‘white space’ (uncertainty). This can be seen on an ‘evidence ratio plot’ (Figure 10.2).

This plot illustrates the levels of evidence for each leaf hypothesis in the tree (or section of the tree, as chosen). The horizontal axis indicates the percentage uncertainty in evidence, with an increasing negative value representing increasing conflict or contradiction in the evidence. The vertical axis indicates the ratio of evidence for to evidence against. To avoid division by zero in this calculation, all evidence values are moved into the range [0.01, 1]. The background of the plot is shaded to indicate areas where evidence values are greater than or less than 0.5. Along with the two axes, this splits the plot up into eight distinct regions as indicated in Figure 10.2.

Each sub-hypothesis is plotted on the ratio plot according to its values of evidence for, uncertainty and evidence against. Thus the ratio plot provides a means to visualise the user-input data on a single graph, giving the opportunity to identify weak areas of knowledge and to single out pieces of evidence which may strongly affect the overall outcome of the model. The ratio plot provides a measure of the ‘value of information’ associated with the evidence. This is used to support decision making about future appraisal campaigns and data acquisition.

Thus Figure 10.2 shows that the root hypothesis has moved from having more supporting evidence than negative evidence in September 2008, to the final position where there are equal amounts of supporting and negative evidence. Note that the amount of negative evidence is of most significance, the aim is not for ‘balance’ but to have minimal uncertainty and minimal evidence against suitable storage.
FIGURE 10.2: UNCERTAINTY REDUCTION AS A RESULT OF DRILLING PHASE DP2B

Commercial scale project
60MM tonnes CO₂ over 30 years
Storage site: EPQ 1 and EPQ 2
March 2010

Risk Hypotheses with Significant Negative Evidence (Dotted line is Sept 2008 assessment)

1  Stakeholders can be assured that EPQ 1 and 2 will accept and safely contain 60MM tonnes CO₂ in the subsurface for 200+ years
17  Wells can be sited, drilled, completed and stimulated to achieve sufficient injectivity
18  Bottom hole pressures can be sufficiently quantified and managed to maintain injectivity
19  Heterogeneity of the reservoir is sufficiently understood to be confident of maintaining injectivity
22  There is sufficient pore space beneath the primary seal to contain 60MM tonnes of CO₂
23  The pore space outside the primary aquifer, but in the containment complex is sufficient to contain 60MM tonnes of CO₂

At the end of the PFS period there was significant evidence compiled against an acceptable development. The remaining technical white space related largely to:

- outstanding uncertainty in reservoir connectivity. Long-term (several months) injection tests were required with both water and CO₂ to detect boundaries at the 1–2 km intervals;
- the degree to which heterogeneity (mechanical, structural and reservoir) impacts the entire prospective development area, additional areas need to be drilled and tested;
- the ability to engineer wells with enhanced injectivity. Completion field trials need to be undertaken. Completion and borehole stability studies are required; and
- unassessed fault–related containment risk.

These technical challenges would require a focused trials and R&D exercise to address them and would not likely be solved in a timeframe demanded by the project.
11 Conclusions and Recommendations

11.1 Conclusions

Studies and field work demonstrated that the NDT storage resource did not meet (and would not be likely to meet) in the near future, the desired hurdle rates set by the three-level test.

While the NDT tenements might accommodate 60 (or 90) million tonnes in total, they are very unlikely to be able to accept and sustain a rate of 2 (or 3) Mtpa.

There was therefore no representative development which could confidently deliver 2 Mtpa and hence no chance that decision Test 2 could be met.

Unit costs had to be calculated either for a hypothetical case (545 wells) or for cases in which the area was maximally drilled-up but could not meet the sustained rate or volume requirements. These cases are summarised below for 130 and 250 well cases.

TABLE 11.1: UNIT DEVELOPMENT COSTS SUMMARY FOR VARIOUS CAPTURE AND WELL COUNT SCENARIOS

<table>
<thead>
<tr>
<th>Target capture (Mtpa)</th>
<th>Target volume (m T)</th>
<th>No. of injector wells</th>
<th>Approx. stored volume (m T)</th>
<th>Capital cost (AUS$M)</th>
<th>P50 unit cost ($/t for CTS)</th>
<th>Approx. ‘regretted’ volume (m T)</th>
<th>Effective capture and store (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>65% 2 60</td>
<td>130 20 $894 $160</td>
<td>40 22%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>95% 3 84</td>
<td>250 56 $1,720 $167</td>
<td>23 40%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>65% 2 60</td>
<td>545 60 $3,750 $224</td>
<td>0 65%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Note: Capital costs above are provisional and include direct costs only for injection wells, flow-lines and the main CO2 pipeline. They do not include spares or redundancy, monitoring wells, ‘feasibility stage’ expenses or indirect costs.

Operating costs assumed at 2.5% p.a. may be considered optimistic based on experience in EOR operations.

Possible improvements and variations to the basic FDP concept were identified, significant addition field trials and studies would be required taking two years or more to complete (notwithstanding tenement and funding delays) and costing upwards of $50 million. There was little confidence that such trials and studies would result in the required improvements in rate and unit cost.
11.2 Final Recommendation

It was essential that ZeroGen access a risk diverse portfolio in which to search for a GHG storage site. It was strongly recommended that the focus for storage be moved to the new tenements in the Surat Basin, with a further low-cost ‘hold’ option developed in parallel in the Galilee Basin.
Part B
Surat
1 Introduction to Surat Evaluation

1.1 Context

The following sections describing Surat Basin evaluations contrast with previous Northern Denison Trough (NDT) Chapter Three, Part A. The latter described a technically mature, data–rich, evaluation of a single prospective site which resulted from the investment of upwards of $130 million. The Surat sections, however, serve as an example of pre–tenement award, portfolio evaluation work resulting from an investment of less than $2 million.

Similar work (though on considerably less data) was conducted on areas of the Galilee Basin, however these are not discussed in any detail in this volume. Some key features of that work will be described in Bradshaw et al. (2011—*in prep*).

The *GHG Storage Act (Queensland)* was enacted early in 2010 and new GHG exploration permits were gazetted in April. Applications for these areas were based entirely on publicly available data and desk–top studies.

Exploration programs were constructed (but not undertaken) for the new tenements against a backdrop of the Commonwealth CCS Flagship program which required an integrated IGCC with CCS project to be operational by 2015.

1.2 Lessons Learnt

The Surat Basin has positive geological indications that carefully selected parts of it might be suitable for secure, commercial–scale GHG storage. However, the amount and quality of direct and modern data is limited. **Uncertainty rather than risk dominates current geotechnical assessments and more data is required to assess suitability or otherwise.**

From a combined geotechnical and risk minimisation perspective, the most promising areas for further analysis are Precipice Formation Sandstones, potentially sealed by Evergreen Formation in the deeper areas of the Mimosa syncline. The combination of Precipice and Evergreen is proven to have retained small gas columns at several locations in the Basin.

A secondary, deeper play comprising Triassic Showground Sandstones sealed by Snake Creek Mudstone (another proven hydrocarbon play) may also exist West of the basin axis.

Based on tenements gazetted in 2010, it would have been possible to construct a portfolio of exploration targets to diversify exploration risk. However, two common risks to potential future storage developments would apply across the whole basin. These are (i) coincidence with the Great Artesian Basin and (ii) potential conflict with other resources rights holders.

The Surat Basin and some formations in the underlying (Southern) Bowen Basin are defined as an integral part of the larger Great Artesian Basin (GAB). Data (pressure, flow and composition) pertaining to baseline conditions in deep lying aquifers of the GAB are sparse and largely...
unreliable. While some evidence exists supporting secure GHG containment, more data is required to enable scientific evaluation of whether any impacts would be significant.

The Surat Basin is overprinted by numerous existing resource tenement types. In particular, extensive Coal Seam Gas (CSG) and coal mining exploration and development are underway in the north and around the Eastern basin margin. Long standing conventional oil and gas developments are present, mainly in the West of the area. It is possible and desirable (to minimise development risks) to avoid mining and production lease areas (and applications for such). However it is not possible to avoid conventional oil and gas exploration permits.

The basin could be tested for suitability by an initial exploration program of up to five wells and a series of regional 2D seismic lines. Such work would serve not to progress a development but to fill in knowledge gaps. Contingent on the results, the initial program would need to be followed by later, site-specific appraisal program(s) of another two to four wells probably with a 3D seismic survey. This exploration and contingent appraisal would both be required prior to significant further investment in IGCC plant.

The cost of the initial program could require up to $90 million with an additional $90 million possibly required for appraisal. Such programs would apply ZeroGen lessons from the NDT, would be across a range of tenements and areas and would focus on collecting dynamic, extended well test data and vertical interference test data across potential sealing horizons. Additional data collection and modelling would be required in overlying GAB aquifer horizons and to establish baselines.

1.3 Available Tenements

The ZeroGen PFS period ended on 31 July 2010, with all substantial work completed for write up by May 2010. On 16 April 2010 in the Queensland Government Gazette (No. 104) the Queensland Government issued a call for tenders for up to 12 new GHG exploration permits for each of the 13 areas described as QLR2010–1–1 to QLR2010–1–13.

With reference to Figure 1.1 gazetted areas included:

1. six areas in the proven oil and gas Surat and (underlying) Bowen Basins (QLR2010–1–8 to 1–13);
2. five areas in the Galilee Basin (QLR2010 1–1 to 1–6). There is no proven hydrocarbon play in this basin; and
3. a single area in the Northern Denison Trough (QLR2010 1–7) which wrapped around existing ZeroGen tenements.

Prior to this gazettal, ZeroGen had commissioned high-level basin and play screening studies covering most basins in Queensland (CGSS¹, 2009 and MBA², 2009). These helped screen-out areas. However, significant additional data mining and study work was required once the precise new tenement locations were announced.

1 CGSS: CO₂ Geological Storage Solutions Pty Ltd.
2 MBA Petroleum Consultants Pty Ltd an AWT Group Company.
Note: In Figure 1.1 the six tenements to the South East are in the Surat Basin. The six North are in the Galilee Basin.

**TABLE 1.1: AREAS (km²) FOR KEY GHG TENEMENTS RELEASED IN APRIL 2010**

<table>
<thead>
<tr>
<th>Basin</th>
<th>Tenement reference</th>
<th>Area (km²)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NDT</td>
<td>Existing ZG tenements</td>
<td>&lt;1000</td>
</tr>
<tr>
<td>NDT</td>
<td>QLR2010 1–7</td>
<td>1576</td>
</tr>
<tr>
<td>Galilee</td>
<td>QLR2010 1–5</td>
<td>7774</td>
</tr>
<tr>
<td>Surat</td>
<td>QLR2010 1–8</td>
<td>7217</td>
</tr>
<tr>
<td>Surat</td>
<td>QLR2010 1–9</td>
<td>3155</td>
</tr>
<tr>
<td>Surat</td>
<td>QLR2010 1–10</td>
<td>1467</td>
</tr>
<tr>
<td>Surat</td>
<td>QLR2010 1–11</td>
<td>3653</td>
</tr>
<tr>
<td>Surat</td>
<td>QLR2010 1–12</td>
<td>4566</td>
</tr>
<tr>
<td>Surat</td>
<td>QLR2010 1–13</td>
<td>6941</td>
</tr>
</tbody>
</table>

Notes:
The new areas on offer were significantly larger than ZeroGen’s existing acreage holdings within the NDT. With the exception of an NDT tenement, all gazetted tenements were underlain by the GAB, a major source of relatively low salinity water for a large part of Australia. All tenements were collocated with extensive, overlapping resource tenements.
1.4 Structure of this Evaluation

To improve the chances of identifying and maturing secure storage, a program was required which would diversify and mitigate geotechnical and possible other development risks. Therefore, pre–tenement evaluations necessarily included several geographic areas and, where possible, more than one geological play. The evaluation in this volume follows the outline shown in Figure 1.2.

Background geology and key area–wide constraints are briefly described in Sections 3 and 4. Throughout these sections key risks and uncertainties are highlighted and feed into exploration strategy and work program (Sections 9 and 10).

Based on background geology, a regional model was constructed (Section 5) on which to base storage performance estimates. The building of this model and synthesis of data also highlighted additional uncertainties.

Storage performance estimations and major uncertainties therein are then described in Sections 6, 7 and 8. Opportunities and technologies for baseline monitoring and for plume and pressure monitoring were also evaluated, but are not reported in this Case History.

Uncertainties identified throughout the evaluation, together with constraints and strategic context, were then used to construct an exploration strategy (designed to maximise confidence) and hence a final exploration work program. As for the NDT evaluation, decisions tests were constructed and an initial, pre–award assessment of performance (and uncertainty in performance) was made.
2 Background Geology

2.1 Context

In 2009, the Queensland Department of Employment, Economic Development and Innovation (QDEEDI) compiled the Queensland Carbon Dioxide Geological Storage Atlas (Bradshaw et al. 2009). This ‘Atlas’ reviewed and assessed potential geological storage of CO₂ for 36 sedimentary basins and basin elements in Queensland. It comprised reviews of CO₂ emissions, Queensland seismicity, and a relative ranking with respect to prospectivity of each basin. The workflow resulted in three classifications: unsuitable, low prospectivity and high prospectivity.

Five basins were determined to have ‘high prospectivity’ i.e. the Bowen Basin (Southern and Western areas, which included the Northern Denison Trough), Surat Basin, Galilee Basin, Eromanga Basin and Cooper Basin (Figure 2.1). This was based on the presence and integrity of seals, reservoir depth > 800 m below ground level, minimal deformation, regional reservoir porosity and permeability greater than 10% and 5 mD, respectively.

FIGURE 2.1: MAP SHOWING GREENHOUSE GAS STORAGE EXPLORATION TENEMENTS IN QUEENSLAND, AND THE FIVE HIGH–PROSPECTIVITY BASINS

As assessed by Bradshaw et al. (2009). The gazetted areas of interest are shown in green for Surat, and grey for Galilee.
2.2 Lessons Learnt

The Surat and Bowen Basins have much in common with onshore basins globally. Complex geology should be expected to require more exploration and appraisal efforts than for offshore geographic and depositional settings.

- Both basins have complex, mainly continental preserved depositional histories and the Bowen Basin in particular has a very complex structural history.
- The main reservoirs of interest are predominantly fluvial. Jurassic, Precipice reservoirs are extensive and low dip, however their connectivity is largely unknown.
- The Evergreen ‘seal’ is only proven locally.

Despite a long history of water, coal and oil and gas exploitation, the basic identification of key formations, especially the Evergreen Formation is inconsistent on available public data. An improved sequence stratigraphic view would benefit reservoir and seal prediction and risk assessment.

2.3 Basic Stratigraphy and Depositional Environments

Figure 2.1 and Figure 2.4 show the locations and main tectonic elements of the Bowen and Surat Basins. The main stratigraphic units are shown in Figure 2.2 and Figure 2.3. For cross reference purposes, the formations appraised in the NDT were Permian sandstones beneath the Black Alley Shale, age equivalent to the Tinowan Formation.

Of principle interest for GHG storage are (i) the Lower Jurassic, Surat Basin, Precipice Sandstone reservoir sealed by silts and shales of the upper Evergreen Formation; and, (ii) the Triassic, Bowen Basin, Showgrounds Sandstone, sealed by the Snake Creek Member (lower Moolayember Formation). Both are proven hydrocarbon plays, the latter being restricted to the western flank of the Bowen Basin.

An in–depth literature review was conducted to create a consistent framework, on which to build all future evaluations and performance assessments. Only a brief overview of the salient regional geology is included here, highlighting a series of continental–dominated depositional events. The reservoir and seal quality and continuity were likely to be highly variable.

The Bowen Basin is a Permo–Triassic sedimentary basin and is the northern continuation of the Sydney–Gunnedah Basin (Kassan and Fielding 1996). Figure 2.2, shows a summary with stratigraphic and depositional descriptions modified after Bradshaw et al. (2009). Other references recommended include Geoscience Australia (2008a) and Green et al. (1997a).

The Surat Basin is a North–West trending sedimentary basin that unconformably overlies the southern half of the Bowen Basin (Figure 2.4 and Figure 2.5). Deposition commenced during a period of passive thermal subsidence, and Early Jurassic sediments were fluvio–lacustrine. Figure 2.3, shows a summary of the main stratigraphy and depositional environments modified after Bradshaw et al. (2009). Other key references include Geosciences Australia (2008b) and Mollan et al. (1972).
The base of the basin comprises the Precipice Sandstone which is sealed, at least locally for small oil and gas columns, by upper-Precipice shaley units and/or shaley-silty units of the Evergreen Formation.

The upper Evergreen Formation is a proven conventional possibly ‘regional’ seal for the Precipice Sandstone. However, lower units of the Evergreen Formation, such as the Boxvale Sandstone Member and lower Evergreen Formation, could also be secondary reservoir targets. Identification of the Evergreen in historic records tend be lithostratigraphic. The sequence stratigraphic structure of the Evergreen is complex and an improved view would benefit seal prediction and risk assessment.

**FIGURE 2.2: BOWEN BASIN STRATIGRAPHY**

Showing the reservoir and seal with a brief description of the lithology and depositional environment (after Bradshaw et al. 2009).

On the right, a gamma-ray log of Churchie-1 well displays the well-log signature typical of each stratigraphic unit.
The Walloon subgroup is currently a very active target for intensive CSG exploration and developments—an activity which entails significant water extraction. Above the Walloon subgroup lie several other aquifers and aquitards. Many of these contain low salinity water (<5000 ppm) and are heavily used towards the edges of the basin as depths become shallower. The Gubberamunda Sandstone sustains large artesian bores over much of the Surat Basin.

FIGURE 2.3: SURAT BASIN STRATIGRAPHY

Showing the reservoir and seal with a brief description of the lithology and depositional environment (after Bradshaw et al. 2009).

On the right, a gamma ray log of Bell Bird South–1 well displays the well–log signature typical of each stratigraphic unit.
2.4 Tectonic Aspects of the Bowen and Surat Basins

There is a significant body of literature on the structural evolution of these basins (included in references). Figure 2.4 and Figure 2.5 show a summary of the main features.

The structure of the Bowen Basin was a result of the convergence of an oceanic and a continental tectonic plate during the Permian. A long North–South trending back–arc environment (Othman and Ward 2002), as well as a series of grabens and half–grabens such as the Denison Trough were generated (Fielding et al. 1992; Green et al. 1997b).

Following a Permian period of uniform regional thermal subsidence, a marine transgression spread over most of the basin (Cadman et al. 1998). The late Permian saw changes in tectonic style and a new sediment source, a western craton and the transition to a foreland basin (Baker et al. 1993; Green et al. 1997b). The end of the Permian saw a marine regression, as well as granite intrusions and activation of the Goondiwindi–Moonie Fault and the Leichhardt Fault (Figure 2.4). The Late Permian coal swamp environment changed to drier continental conditions. Significant subsidence in the Taroom Trough caused it to become the major depocentre (Cadman et al. 1998). Regional uplift, folding, and erosion of Bowen Basin sediments took place in middle to Late Triassic times (see, Green et al. 1997b and Cadman et al. 1998).

Sedimentation set in the Surat Basin in the early Jurassic (Precipice). Deposition was initially focused in the Mimosa Syncline which is a broad sag–like syncline overlying the older Taroom Trough (Figure 2.4 and Green et al. 1997b). The driving force that initiated the Surat Basin is still controversial (see, Korsch et al. 1989 and Veevers et al. 1982).

The seismic line shown in Figure 2.5 displays the main tectonic features, including the major faults in both flanks of the basin. Such faults could compromise the quality of potential seals (Subsection 6.5). However, the Bowen Basin is fairly aseismic.

There is a consistent North–Northeast maximum horizontal stress orientation for more than 500 km in the Bowen Basin (Bradshaw et al. 2009; Hillis et al. 1999). The steeply dipping faults in the North–Northwest direction are oblique to the maximum horizontal stress orientation (Hillis et al. 1999), and this may encourage faults to seal (Bradshaw et al. 2009).
FIGURE 2.4: TECTONIC ELEMENTS OF THE BOWEN AND SURAT BASINS (AFTER CADMAN ET AL., 1998)
From Bradshaw et al. 2009. This cross section runs west–east across the Bowen and Surat Basins, and shows the Roma Shelf and Taroom Trough, as well as the Leichhardt Fault and Moonie Fault. The unconformity at the contact between the basins can also be seen.
3 The Great Artesian Basin

3.1 Context

The Great Artesian Basin (GAB) covers much of Queensland, New South Wales, South Australia, and the Northern Territory and is the world’s largest artesian basin (Figure 3.1). It comprises numerous sectors or sub–basins that constitute one of Australia’s most important groundwater resources. The GAB has been described as a confined groundwater resource comprising a multi–layered system of aquifers that can extend in places to depths of 3 km deposited within the Carpentaria, Eromanga and Surat Basins (www.nrwl.qld.gov.au). It covers an area of circa 1.7 million square kilometres and sustains most of the pastoral and community needs of about 23% of Australia’s surface (GAB Consultative Council, 2000).

FIGURE 3.1: LOCATION MAP SHOWING THE GAB (AFTER HABERMEHL, 2002)

Blue spots indicate spring concentrations.
Use of GAB groundwater resources is intensive and widespread (and ineffectively measured). Interconnectivity and the aerial variation of interconnectivity between Bowen and Surat Basins and between intra–Surat formations are poorly understood.

Several additional studies had to be commissioned to investigate the state of knowledge of the GAB, investigate possible pressure regimes and compile evidence about hydrodynamic and geochemical characteristics (ZeroGen–CSA3 2010a, ZeroGen–CSA 2010b, ZeroGen–CSA 2010c, Berly 2010, SWS 2010 and CSIRO, Hortle 2010). The Geological Survey of Queensland (GSQ) papers (Hodgkinson et al. 2009 and 2010) are also key references, which discuss issues related to GHG sequestration in the GAB.

### 3.2 Lessons Learnt

The GAB is not a single or simple ‘a basin’ or ‘a resource’, it is geologically complex, multi–component and poorly measured.

Key areas and plays within the GAB have retained oil and gas accumulations for millions of years. The deep reservoirs in the areas identified as ‘of possible interest’ are not currently used for abstraction.

Interference with GAB waters comes under several regulations. There is little experience with injection of any fluids within the GAB except re–injection of waters associated with oil and gas production.

It is essential to understand the greater context in which prospective GHG tenements lie, this context includes groundwater resources and their uses and future users. It was considered critical that the state of GAB groundwater resources would be evaluated as an integral part of any work program prior to any decision to inject CO2. Specific baselines for pressure distribution (hydraulic head), hydraulic and chemical properties would need to be understood in the GHG tenement areas and in several formations.

There is unlikely to be a static baseline of GAB pressure and flow conditions. It is thought that abstraction significantly out–strips recharge. Concurrent operations in neighbouring areas relating to produced water from CSG operations would also require local site evaluation of ‘overburden’ formations. Establishing hydrodynamic conditions and monitoring near these areas would be essential to assuring future ‘non interference’ of neighbouring resource extraction or operations.

Potential lateral and vertical connectivity between groundwater aquifers and potential storage reservoirs also needed to be assessed. Indications that the Evergreen Formation is an effective seal need to be extended from where it is established (in conventional oil and gas fields) into the areas of most interest for storage. Seal retention capacity also needed to be quantified as those fields hold only small columns.

There are virtually no data on the deeper reaches of the Surat (GAB) in the areas of most interest for GHG storage. New, high fidelity and bespoke data, focused on (deep) groundwater dynamics

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3 CSA: Carbon Store Australia Pty Ltd—a Schlumberger Company.
and monitoring baseline conditions would be essential to evaluate whether or not GHG could be stored securely at industrial scale in the tenement areas.

3.3 Abstraction

It is a condition of any GHG permit that the holder cannot take or interfere with water as defined under the Water Act 2000 (Qld), unless the taking or interference is authorised under that Act. This includes ground waters of the GAB. Injection of CO₂ into the GAB formations has not been tested under the Act.

The Water Resources (GAB) Plan 2006 is the primary legislation for groundwater management of the GAB in Queensland. The Great Artesian Basin Resource Operations Plan 2007 implements the Water Resource Plan. The Surat Basin is divided into seven groundwater management areas and 26 groundwater management (vertical) units. The plan also stipulates that a minimum separation distance from existing licensed bores be maintained to ensure a drawdown of no more than 5 m.

Water is currently being extracted from the basin margins from the Clematis and Moolayember in the Bowen Basin and in the Surat Basin, from the Precipice Sandstone, the Hutton Sandstone, Walloon Subgroup, Springbok Sandstone and Gubberamunda Sandstones (ref. Figure 2.3).

The distribution of water wells in and around the proposed tenement areas was extracted from the Department of Environment and Resource Management (DERM) Groundwater Database and is displayed in Figure 3.2. Where possible these were sub-divided by aquifer. However, there are a large number of water bores where no correlation to aquifer was available (Hortle, 2010).

Most groundwater bores screened were in the shallow Gubberamunda Sandstone and the Mooga Sandstone in the Surat Basin (Figure 1.1), though the Jurassic Hutton Sandstone which overlies the main storage play is also a prolific source of groundwater in the North and North-East of the basin.

With reference to Figure 3.2, the majority of water wells in tenements 1–8 and 1–9 extract from the main Lower Cretaceous–Jurassic Cadna–owie–Hooray aquifer group. In tenements 1–12 and 1–13 the distribution of water wells is concentrated in the North–East and water is predominantly abstracted from the Cretaceous Rolling Downs Group and Alluvial Formations. Areas targeted for further investigation at Precipice level did not contain water bores extracting from below the Walloon Formations.

3.4 Natural and Anthropogenic Flow

Regional groundwater flow is thought to be directed to the West–Southwest of the areas of interest (Hodgkinson et al. 2009). Residence times are thought to be up to 2 million years in certain areas (Radke et al. 2000), though 100 to 500 thousand years may be more likely in the areas of interest. Long residence times suggest very low flow velocities of between 1 to 5 m/yr (Henning, 2005). Long-term fluid flow modelling associated with a monitoring program would be needed to evaluate the impact of groundwater flow on the GHG storage system. However, with available data, it is difficult to build a baseline pressure field.
In addition to bores, natural discharge takes place via spring flow in the southern part of GAB. Presently the estimated total discharge of approximately 1 billion cubic metres is equally divided between natural discharges and bore discharge (Kellett et al. 2003). Models suggest that discharge is 70% greater than recharge (Welsh, 2006; Love et al. 2000) and underlines the necessity for careful resource management.

### 3.4.1 Surat Basin

In the Surat, most pressure or ‘head’ measurements are concentrated along the Northern margins. A long period of groundwater exploitation has seen a large decline in groundwater heads within sandstone aquifers such that many once artesian bores have ceased to flow naturally. Four wells with time–series data (large red dots in Figure 3.2) exhibit declines of up to 20 m head between 1960's and 1990's (Hortle, 2010). These are in aquifers shallower than the Evergreen Formation. The asynchronous nature of these measurements complicates the construction of a current potentiometric surface for specific strata of interest. However, a recently constructed hydrodynamic flow net is shown for Precipice Sandstone in Figure 3.3.

Produced water and produced water re–injection from aerially CSG operations (Figure 4.1) could significantly affect the regional groundwater flow pattern in the shallow zones of the Surat Basin and local stress fields. The impact of such operations on deeper and more distal regions is unknown.

### 3.4.2 Bowen Basin

In the Bowen Basin, aquifers lack direct measurements of head, pressure and chemical compositions. The current understanding of hydraulic communication between Triassic and Jurassic aquifers is based on hydrocarbon migration and source rock correlation models. Flow is broadly towards the South and South–West. However, discharge may occur vertically in places e.g. through the Moonie Fault (Figure 2.4) and there is currently no data to confirm a hypothesis that Bowen and Surat Basins are in present–day hydrodynamic communication (Hortle, 2010).

To the West of the basin, conventional hydrocarbon production has caused considerable decline in pressure in the Showgrounds Formation in the Wunger Ridge area (Figure 2.4).
3.5 Vertical Connectivity

A regional model proposed by Hitchon and Hays (1971) and Herczeg and Love (2007), suggested vertical connectivity between the Surat Basin and underlying Bowen Basin. Vertical connectivity would be an important issue for the containment of injected CO$_2$ with the purpose of long-term storage. Henning et al. (2006) suggested that vertical hydraulic communication between Bowen and Surat Basins is readily apparent in some areas but not in others.

In this context, the sealing capacity of the (upper) Evergreen Formation is of special interest. The comprehensive integrative studies by Hodgkinson et al. (2009, 2010) and an extension by CSIRO$^4$ (Hortle, 2010), commissioned by ZeroGen, produced a hydrodynamic evaluation which focused especially on the Precipice Sandstone and the Hutton Sandstone. These studies supported the hypothesis that the Evergreen Formation could be a regional seal to the Precipice Sandstone. Pressure data were used to examine the degree of vertical connectivity between these aquifer units in the basin. Generally these aquifers are hydraulically separated, with a reported 100 m head (10 bar) difference shown at least in two wells. All aquifers above the Hutton Sandstone share a common, virgin pressure gradient (at least in a geological time-frame).

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$^4$CSIRO—Commonwealth Scientific and Industrial Research Organisation
Geochemical evidence also provides some (albeit minor) support that the Evergreen Formation acts more regionally as a seal. Precipice Sandstone groundwater tends to be ‘fresher’ while the Hutton Sandstone groundwater displays much higher concentrations on average 1430 mg/L. It must be noted however, that most samples from the Precipice Sandstone have been taken in or close to recharge zones where groundwater is fresher than in the GHG tenement areas for potential GHG storage (deeper) where data is non–existent.

**FIGURE 3.3: REGIONAL HYDRODYNAMIC FLOWNET FOR THE PRECIPICE SANDSTONE**

*From Hodgkinson, et al. 2010. GHG tenement boundaries are also shown.*
4 Other Economic Resources

4.1 Context
The purpose of this chapter is to highlight the degree of complexity which arises from the presence of rights holders for other economic resources and their activities and plans.

4.2 Lessons Learnt
Virtually all the GHG tenement areas are covered at least by exploration permits for other natural resources. A significant area is covered by development leases for either coal mining, coal seam gas or conventional oil and gas production.

At least in theory GHG storage is potentially in conflict or could interfere with the holders these other resource rights due to possible pressure impacts, fluid contamination, limitations on simultaneous operations or perceptions of or possible impacts on local communities.

Genuine technical complexity would lead to commercial complexity as parties sought to cover commercial risk through coordination agreements. That process would be necessarily slow.

The primary strategy to reduce GHG storage exploration, appraisal and development risk is probably to keep a large distance from other resource developments.

4.3 Oil and Gas and CSG Fields
There is significant technical data directly relevant to GHG storage evaluations in most producing hydrocarbon provinces. However, considerable time and effort is required for field reviews so that both regional connectivity and ‘basin plumbing’ are understood, as well as short time–scale reservoir dynamics. In addition, such field reviews (e.g. CGSS® 2010a and 2010b) are also required to evaluate the potential for commercial interference and risk and to inform separation margins.

In the Surat GHG tenement areas, there are 159 producing hydrocarbon fields. The location of Petroleum Leases (PLs, in Figure 4.1) shows, on the one hand, where data is concentrated and, on the other hand, also displays where the GHG storage exploration areas overlie PLs.

In five of the six GHG Permits, there are 35 producing and 15 non–commercial discoveries. The largest number of producing gas fields occurs in the west of QLR2010–1–8, which includes part of the major oil and gas producing regions of the Wunger Ridge and Roma Shelf.

In the mid 1990s Coal Seam Gas (CSG) became a major focus in Queensland, and now supplies approximately 80% of the State gas market. Major CSG activities linked to LNG production have since been sanctioned by several companies with forecasts of additional wells in existing and
proposed production leases in excess of 10,000. These projects cover a large swathe of the GHG tenements. Furthermore, CSG operations at the scales proposed raise significant challenges with water management. Many treatments and disposal methods are being investigated. This includes treatment and reinjection with one of the main potential reinjection horizons being the Precipice Sandstone.

Potential for resource conflict with CSG operations is summarised in Table 4.1:

**TABLE 4.1: POTENTIAL (THEORETICAL) AREAS FOR CONFLICT BETWEEN GHG AND OTHER RESOURCE OPERATIONS.**

<table>
<thead>
<tr>
<th>Potential conflict</th>
<th>Description of techno–commercial issues</th>
</tr>
</thead>
<tbody>
<tr>
<td>Injection pressures and injectates</td>
<td>Competing pressures in Precipice Reservoirs for GHG vs CSG–related water injection could lead to loss of injection performance on both sides—depending on reservoir connectivity. Furthermore, baselines and separation of environmental risk and liability between parties could be impacted depending on the nature and composition of the injectate.</td>
</tr>
<tr>
<td>Pressure depletion mechanics</td>
<td>Depletion of overlying aquifers and/or inflation of Precipice Reservoirs either co–located or laterally offset, could give rise to currently un–evaluated geomechanical (fault reactivation) and GHG containment risks. Loss of containment could lead to a currently unassessed risk of contamination of sales gas by CO₂ incursion and resultant compensation requirements.</td>
</tr>
<tr>
<td>Simultaneous operations</td>
<td>Simultaneous surface and drilling GHG and CSG operations would require significant coordination at an operational level. Each operation could increase drilling issues and costs for the other.</td>
</tr>
<tr>
<td>Operations standards and communities</td>
<td>Behaviours of existing operators and their impact on communities and the wider public could have an impact on acceptance of others’ operations.</td>
</tr>
</tbody>
</table>

Genuine technical complexity would lead to commercial complexity as parties sought to cover commercial risk through coordination agreements. The *GHG Storage Act* allows ultimately for ministerial discretion in the case of resource conflict. In the case of a co–located or neighbouring proposals, a State Government minister may have to choose between CSG exploitation (and royalties) and GHG storage (and costs).

However, while assessment would still be required, all of these risk factors decrease with increasing separation distance. The principal risk management response was ‘avoidance’. ZeroGen’s exploration strategy was to avoid active production and mining leases and CSG areas as much as possible.
FIGURE 4.1: OPERATORS FOR OIL, GAS AND CSG RESOURCES IN THE AREA OF INTEREST (AFTER CGSS, 2010B)
4.4 Coal Resources

A total of 66 Coal Exploration Tenements (EPCs) extend over the GHG acreage release areas (Figure 4.2). In addition, the GHG acreage release areas included two operating open-cut coal mines, 15 mining leases, 12 mineral development licences, 11 mineral licences under application, and 14 mineral development licences also under application.

There are also 27 exploration permits which appear to be focusing on UCG, with six areas under application for either mining or mineral development licences.

Most coal exploration activity was centred on a 50 km swath trending Northwest from the Kogan Creek and Wilkie Creek open-cut mines focusing on the Northern sectors of tenements 1–13, 1–9, and 1–8. Exploration was concentrated around several major coal projects and significant coal resources.
5 Framework for Performance Modelling

5.1 Context

The purposes of this section are to highlight the amount of work which was required to produce even a basic evaluation of storage potential, how such work is essential to uncover key uncertainties and data needs and to show preliminary findings specific to the two focus basins.

Existing data were re–interpreted and integrated to build a coherent regional geological model. In essence this type of data–mining exercise is an (often unsuccessful) attempt to extract meaningful interpretations and trends out of poor quality and incomplete legacy data.

Based on the (gross) subsurface configuration of potential reservoirs revealed by the model, three ‘type’ areas were identified for more detailed study including preliminary probabilistic and illustrative dynamic modelling.

Additional constraints analysis studies (e.g. RLMS, 2010) also had to be conducted. These investigated high level information related to local government areas, topography, infrastructure, land use and tenure, environment (including matters of National Environmental Significance, environmentally sensitive areas and regional ecosystems), Native Title, water resources and landholders for each tenement.

5.2 Lessons Learnt

The geological synthesis of existing data required significant efforts (>1 million).

Current knowledge in the technical and scientific literature needed to be critically reviewed. Significant amounts of data required reinterpretation (formation tops, DSTs, sequence correlations, seismic–well ties etc). Significant data reprocessing (seismic and well logs) is still required and a regional review of sequence stratigraphy is essential.

While a regional framework model, in agreement with existing data and literature, can be and was constructed, it was more illustrative than predictive. Significant efforts are required to create regional static models consistent with all data.

The GAB requires that exploration and appraisal activities be designed explicitly to address groundwater issues. Groundwater data are currently concentrated in shallow formations and along the edges of the basin, extrapolation into the deeper zones of interest needs to be guided by new data from those zones.

While groundwater head data indicated that units in the Evergreen Formation seal and thus there may be a regionally sealed lower Jurassic play, its characteristics and quality in the tenement areas still need to be confirmed by new data.

There is space in the basin for GHG exploration to be undertaken away from current production and mining leases; these more basin–ward areas carry less development risk in the case of success.
Distribution of well core data is not uniform and tends to be clustered. There is little basin–centre data and no MCIP data for possible Jurassic sealing horizons.

Available reservoir data indicate that permeabilities well in excess of 150 mD are common. Thick, clean sands are present in the Precipice Sandstones. However, uncertainties remained large due to both sparse data coverage and poor data quality.

Dynamic well test data are sparse and peripheral to the more attractive areas. Precipice Sandstone transmissibility (k.h) values in the order of 100s to 1000s of mD.ft. Showgrounds Sandstone transmissibility (k.h) values could be in the order of 1000s mD.ft. Well tests indicate favourable flow properties but, calibration of publically available tests and confident extrapolation into the basin centre is not possible.

The Precipice Sandstone probably has fairly stable mineral assemblages in the presence of injected CO₂. However, collection of high quality rock and brine samples would need to be a key aim of any work program.

The work done needs to be preserved for subsequent studies. All ZeroGen data and evaluations have been passed to the Geological Survey of Queensland.

### 5.3 Seismic Data

Approximately 51,000 line km of seismic were acquired in the Bowen and Surat Basins between 1959 and 2010. Some scanned and a limited number of digital SEG–Y files were available. Reprocessing of existing data would be a part of the post–award work program in GHG tenement areas in order to improve the resolution of local underground structures.

Available seismic survey lines were also concentrated on the Western side though a few seismic lines extended into and across the Taroom Trough, in particular in the South (Figure 2.4 and Figure 2.5). Seismic interpretation had been carried out by the Geological Survey of Queensland in the past, and structural grids for the main units were mapped regionally and were publically available. These were revised, re–tied to wells and used as the basis for regional models (using Schlumberger’s Petrel™ software).

The vintage and spatial distribution of seismic lines in the GHG tenement areas was highly variable. The degree of seismic coverage is different for each tenement (Table 5.1). Even though line density seems quite high in some areas (e.g. QLR2010–1–8 with 418 lines), not all of these lines have available data or transect the area completely.

In addition, significant data gaps exist in the GHG tenement areas, and new 2D seismic surveys, designed to link existing wells and seismic lines, ultimately closing these gaps, would have to be included in the proposed work program.

### 5.4 Well Data

Well reports, scanned well logs, and digital geophysical wireline logs of existing wells in the area were available in the public domain. Selected available data was loaded for basin modelling. Only well tops as defined by the GSQ were considered for modelling purposes as they followed the current stratigraphic nomenclature of the basins.
Data coverage for the Surat and Bowen Basins is highly concentrated in the flanks of the basins. Large numbers of well data are located in the Western side along the Roma Shelf and the Wunger Ridge where almost 90% of the hydrocarbon fields are located. These wells primarily target Jurassic and Triassic sediments with a small number penetrating the Permian strata. Limited well data is available within the Taroom Trough and central Mimosa Syncline.

The vast majority of existing deep data is outside the GHG tenement areas and is predominantly in the Roma Shelf and Wunger Ridge areas (Figure 2.4) where there is the greatest concentration of oil fields (Figure 4.1). Therefore, it was necessary to extrapolate these offset data into the applications areas to this assessment.

It is important to note that well formation tops and inter-well correlations tend to be lithostratigraphic in nature and a sequence stratigraphic review of the lower Jurassic of the Surat Basin was proposed as a part of any exploration program. This is because lateral prediction of the Evergreen sealing formations would have a major impact on containment risk assessment.

With respect to individual tenements, the distribution of well and seismic data varies greatly (see Table 5.1). This table represents the lateral geographic distribution of data, but it is important to note vertical coverage is variable as well.

**TABLE 5.1: BREAKDOWN OF EXISTING DATA FOR EACH OF THE TENEMENTS OF INTEREST**

<table>
<thead>
<tr>
<th>Tenement</th>
<th>No. wells</th>
<th>Wells with core</th>
<th>Wells with log evaluation in petrel</th>
<th>No. of seismic lines</th>
</tr>
</thead>
<tbody>
<tr>
<td>QLR2010–1–8</td>
<td>158</td>
<td>9</td>
<td>24</td>
<td>418</td>
</tr>
<tr>
<td>QLR2010–1–9</td>
<td>43</td>
<td>4</td>
<td>11</td>
<td>123</td>
</tr>
<tr>
<td>QLR2010–1–11</td>
<td>7</td>
<td>0</td>
<td>4</td>
<td>135</td>
</tr>
<tr>
<td>QLR2010–1–12</td>
<td>123</td>
<td>4</td>
<td>20</td>
<td>347</td>
</tr>
<tr>
<td>QLR2010–1–13</td>
<td>363</td>
<td>2</td>
<td>5</td>
<td>376</td>
</tr>
</tbody>
</table>

*Wells are Precipice penetrations.*

### 5.4.1 Logging data

183 offset wells with logs were used to build the regional geological static model. However, available logging suites were often quite limited. Density and neutron porosity logs were not always acquired in the older wells and many did not have the full suite of logs necessary for a detailed petrophysical analysis.

Additional data purchases and interpretation would need to be part of the post-award evaluation plan and costs.

Key wells were selected for petrophysical analysis using Schlumberger’s ELAN™ program (Geoframe 4.3). This is a multi-mineral log analysis program which computes the most probable formation mineralogy and pore fluid volumes using a multi-log, least-squares inversion technique. The analyses provided important parameters used for property modelling, such as porosity, permeability and net-to-gross as input for static and dynamic reservoir models.
The choice of wells was based on their locations and availability and quality of digital data. Digital logs were sourced from QPED and loaded into Petrel. Data from these logs, in particular gamma ray, were used to populate the 3D spatial domain in the model.

### 5.4.2 Core data

Sidewall core measurements and petrophysical core data such as horizontal permeability and porosity were compiled and then interpreted. Calibration between core and in-situ, bulk-scale (test) properties were not available and a key part of any future work program would be to address this.

Where available, core data was used to calibrate ELAN™ results and these results used to inform property estimates (e.g. Figure 5.1).

**FIGURE 5.1: EXAMPLE: WELL SECTION FOR THE ELAN WELL (TRELINGA–1)**

Showing from left to right: measured depth, gamma ray, lithology, stratigraphic units, core data (red spots) superimposed on permeability and porosity logs and well tops. Notice that permeability and porosity data match with the derived effective porosity and absolute permeability well logs.
Distribution of well core data was not uniform and tended to be clustered. However, such data had to be used to obtain the trend of reservoir porosity (and permeability) degradation with depth and also to reveal lateral trends. No strong, clear depth trend was evident based on the raw data gathered from the QPED database and Atlas (Figure 5.2).

5.5 Porosity and Permeability Evaluation

ELAN™ petrophysical evaluation was based on a compositional model consisting of sand, shale, silt, and gas. Formation fluid (water) salinity was assumed to vary for different zones as reported in the Well Completion Reports (WCRs). An analogue water saturation equation was used to compute water saturation \( S_w \).

Available mineralogical analyses showed that illite and kaolinite were the most likely clay minerals present through the main play and study area. Therefore, permeability values were computed assuming 80% illite and 20% kaolinite.

**FIGURE 5.2: DEPTH TREND OF POROSITY AND PERMEABILITY CROSS PLOTS OF RESERVOIR UNITS IN THE SURAT BASIN**

![Graph showing depth trend of porosity and permeability](image)

After Bradshaw et al. 2009. Notice that no clear permeability depth trend is observed, though degradation of reservoir properties is expected with increasing depth.
This yielded slightly higher permeability than with a 100% illite assumption. Two different sets of cut–offs were applied:

a. Maximum: PHIE > 12%; Vcl < 30%; Perm > 10 mD; and
b. Optimum: PHIE > 0.1%; Vcl < 30%; Perm > 5 mD; and
c. where PHIE is effective porosity and Vcl is clay volume.

Continuous porosity, permeability and net–to–gross 'logs' were produced with detailed log interpretation reports (ZeroGen–CSA, 2010a).

The interpretation of these wells was a primary input for the 3D regional geological model and to prepare scoping, dynamic simulations. A geostatistical process guided by geological reasoning was used in the construction of the regional static models to ensure that the information from the relatively sparse input dataset is applied in a manner that is consistent with the geological knowledge of the area.

However, uncertainties remained large due to both sparse data coverage and poor data quality.

### 5.5.1 Flow test data transmisivity and permeability evaluation

Drill–Stem Test (DST) data were often the only direct evidence of the capacity of flow for the tested formations and therefore, provided direct estimates of transmissibility (permeability–thickness product, or k.h).

A data mining exercise was performed by Carbon Store Australia Pty Ltd (CSA—a Schlumberger company) to identify, review, and select publically–available high–quality shut–in pressure data of DST across the Precipice Sandstone and Showgrounds Sandstone for subsequent Pressure Transient Analysis (PTA). The strategy was to select test data with stabilised rate and shut–in pressure data, recorded in a small time interval and supported by corresponding field plots.

Well completion and formation test reports of some 142 wells within 59 petroleum fields and exploration areas were scrutinised and assessed for suitability for subsequent PTA (ZeroGen–CSA, 2010b). However:

- there was no digital data available in public domain;
- accurate rate estimation was not possible and key supporting data was often lacking;
- shut–in pressure data, if provided in hardcopies, were generally in an excessively large time–interval format, preventing meaningful Horner plot analysis; and
- data quality was generally poor, in many cases, pressure plots were no longer visible.

The minimum data requirement for pressure transient analysis was met by just 24 DST datasets. Thirteen datasets were of Precipice DSTs, the remaining eleven were Showground DSTs.

The primary objective of analyses was to estimate, the in–situ flow properties of the tested reservoirs. Ideally this would require conventional Horner plot analysis of pressure build–up or drawdown data. Then, the wellbore storage effect and reservoir transient flow response could be properly identified and analysed for reservoir flow properties, such as transmissibility and wellbore skin.
However, such an approach was not possible due to the low data resolution and absence of data in digital form. Therefore, an analytical flow equation for a constant–rate line–source well during the infinite acting period (Economides et al. 2000) was utilised to relate pressure drop and production rate to formation transmissibility (k.h).

To produce scoping level estimates, two scenarios for total skin were analysed: low damage with a skin value of 5 and high damage with a skin value of 20. Production rates, pressures, and petrophysical data were derived from the well completion reports.

The following tables (Table 5.2, Table 5.3 and Table 5.4) show the results of the DST evaluation for Precipice Sandstone and Showgrounds Sandstone in the basins.

The location of these data points can be seen in Figure 5.3. No spatial trend can be recognised.

The results of the analytical assessment indicate Precipice Sandstone transmissibility (k.h) values in the order of 100s to 1000s of mD.ft. The results indicate that the Showgrounds Sandstone transmissibility (k.h) values could be in the order of 1000s mD.ft for tenement QLR2010–1–8.
## Table 5.2: Results of DST Evaluations for Wells in Tenement QLR.2010–1–8

<table>
<thead>
<tr>
<th>No.</th>
<th>Well</th>
<th>Formation</th>
<th>Net thickness (ft)</th>
<th>Transmissibility (mD.ft) for skin = 5</th>
<th>Transmissibility (mD.ft) for skin = 20</th>
<th>Permeability (mD) for skin = 5</th>
<th>Permeability (mD) for skin = 20</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Caneon–1</td>
<td>Precipice</td>
<td>21</td>
<td>699</td>
<td>1684</td>
<td>33</td>
<td>80</td>
</tr>
<tr>
<td>2</td>
<td>Mascotte–1</td>
<td>Precipice</td>
<td>31</td>
<td>611</td>
<td>1216</td>
<td>20</td>
<td>39</td>
</tr>
<tr>
<td>3</td>
<td>Pickanjinnie–10</td>
<td>Precipice</td>
<td>23</td>
<td>264</td>
<td>997</td>
<td>12</td>
<td>44</td>
</tr>
<tr>
<td>4</td>
<td>Pickanjinnie–4</td>
<td>Precipice</td>
<td>13</td>
<td>696</td>
<td>1666</td>
<td>54</td>
<td>129</td>
</tr>
<tr>
<td>5</td>
<td>Stakeyard–2</td>
<td>Precipice</td>
<td>23</td>
<td>5</td>
<td>13</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>6</td>
<td>Wallumbilla South–2</td>
<td>Precipice</td>
<td>11</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>7</td>
<td>Wingnut–1</td>
<td>Precipice</td>
<td>3</td>
<td>132</td>
<td>314</td>
<td>45</td>
<td>106</td>
</tr>
<tr>
<td>8</td>
<td>Pickanjinnie–3</td>
<td>Showground</td>
<td>10</td>
<td>84</td>
<td>257</td>
<td>9</td>
<td>27</td>
</tr>
<tr>
<td>9</td>
<td>Pine Ridge–15</td>
<td>Showground</td>
<td>29</td>
<td>1290</td>
<td>3083</td>
<td>44</td>
<td>105</td>
</tr>
<tr>
<td>10</td>
<td>Raslie–6</td>
<td>Showground</td>
<td>13</td>
<td>3529</td>
<td>8053</td>
<td>270</td>
<td>615</td>
</tr>
<tr>
<td>11</td>
<td>Wingnut–1</td>
<td>Showground</td>
<td>13</td>
<td>2243</td>
<td>5164</td>
<td>171</td>
<td>394</td>
</tr>
<tr>
<td>12</td>
<td>Wingnut–2</td>
<td>Showground</td>
<td>4</td>
<td>1300</td>
<td>3802</td>
<td>367</td>
<td>1073</td>
</tr>
</tbody>
</table>
### TABLE 5.3: RESULTS OF DST EVALUATIONS FOR WELLS IN THE WUNGER RIDGE AREA

<table>
<thead>
<tr>
<th>No.</th>
<th>Well</th>
<th>Formation</th>
<th>Net thickness (ft)</th>
<th>Transmissibility (mD.ft) for skin = 5</th>
<th>Transmissibility (mD.ft) for skin = 20</th>
<th>Permeability (mD) for skin = 5</th>
<th>Permeability (mD) for skin = 20</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Alton–2</td>
<td>Precipice</td>
<td>7</td>
<td>1668</td>
<td>3712</td>
<td>257</td>
<td>571</td>
</tr>
<tr>
<td>2</td>
<td>Alton–3</td>
<td>Precipice</td>
<td>12</td>
<td>693</td>
<td>1403</td>
<td>58</td>
<td>118</td>
</tr>
<tr>
<td>3</td>
<td>Alton–5</td>
<td>Precipice</td>
<td>6</td>
<td>1035</td>
<td>2316</td>
<td>185</td>
<td>414</td>
</tr>
<tr>
<td>4</td>
<td>Namarah–4</td>
<td>Showground</td>
<td>16</td>
<td>96</td>
<td>244</td>
<td>6</td>
<td>16</td>
</tr>
<tr>
<td>5</td>
<td>Parknook–3</td>
<td>Showground</td>
<td>6</td>
<td>66</td>
<td>164</td>
<td>11</td>
<td>26</td>
</tr>
<tr>
<td>6</td>
<td>Rednook–1</td>
<td>Showground</td>
<td>10</td>
<td>19</td>
<td>49</td>
<td>2</td>
<td>5</td>
</tr>
<tr>
<td>7</td>
<td>Waggamba–1</td>
<td>Showground</td>
<td>19</td>
<td>1</td>
<td>2</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>8</td>
<td>Warroon–1</td>
<td>Showground</td>
<td>8</td>
<td>250</td>
<td>605</td>
<td>32</td>
<td>77</td>
</tr>
<tr>
<td>9</td>
<td>Taylor–1</td>
<td>Showground</td>
<td>10</td>
<td>5450</td>
<td>4429</td>
<td>554</td>
<td>450</td>
</tr>
</tbody>
</table>

### TABLE 5.4: RESULTS OF DST EVALUATIONS FOR WELLS RELEVANT TO TENEMENTS QLR2010–1–1, QLR2010–1–12 AND QLR2010–1–13

<table>
<thead>
<tr>
<th>No.</th>
<th>Well</th>
<th>Formation</th>
<th>Net thickness (ft)</th>
<th>Transmissibility (mD.ft) for skin = 5</th>
<th>Transmissibility (mD.ft) for skin = 20</th>
<th>Permeability (mD) for skin = 5</th>
<th>Permeability (mD) for skin = 20</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Moonie–1</td>
<td>Precipice</td>
<td>10</td>
<td>4365</td>
<td>9576</td>
<td>437</td>
<td>958</td>
</tr>
<tr>
<td>2</td>
<td>Moonie–1</td>
<td>Precipice</td>
<td>42</td>
<td>2929</td>
<td>6698</td>
<td>70</td>
<td>159</td>
</tr>
<tr>
<td>3</td>
<td>Moonie–10</td>
<td>Precipice</td>
<td>20</td>
<td>772</td>
<td>1793</td>
<td>39</td>
<td>90</td>
</tr>
</tbody>
</table>
FIGURE 5.3: WELL DATA AND THE SCANNED SEISMIC DATA LOADED AND INTERPRETED IN PETREL FOR THE REGIONAL STATIC MODELLING

ELAN wells, wells with DST interpreted data and wells with Gamma Ray logs used for facies modelling. Covering all GHG tenement areas.
5.6 Geochemical Evaluation

5.6.1 Introduction

Injection of CO₂ into sub-surface aquifers has the potential to create chemical reactions which may either be benign or may cause deterioration in performance. As CO₂ reacts with water to form carbonic acid, this could be a possible cause of chemical interactions between minerals of the rock chemical species and injected CO₂ (Kaszuba, et al. 2003, 2005; Kharaka, et al. 2006). However, the impact and time frame of chemical reactions in siliciclastic reservoir and seal lithologies is not clear and would likely be location and case specific.

5.6.2 Local analyses

To evaluate the chemical changes that may be caused by the injection of CO₂ in the target reservoirs in Queensland, the compositions of the rocks of interest (reservoir and seal and potentially any lithologies along potential leakage paths) and the composition of the water residing in the pores are needed. Collection of high quality rock and brine samples would need to be a key aim of any work program.

Analyses by Hodgkinson et al. (2009) evaluated potential water–rock interactions with injected CO₂ in a Queensland setting this was the key reference for this subsection. Analysis and extrapolation of mineralogical data from the Precipice Sandstone across the basin suggested that it has fairly stable mineral assemblages in the presence of injected CO₂ (ibid).

Hydrochemical analyses are abundantly available in public data bases with major ion compositions and at times also minor ion chemistry, as well as pH and alkalinity. However, comprehensive analyses are rare. No analysis of water from the Showgrounds Sandstone in the Bowen Basin was found (Berly, 2010 and SWS, 2010).

The major ion hydrochemical groundwater trend dominating all Jurassic and Cretaceous aquifers (except the Walloon Subgroup) is Na–Cl compositions at shallow depths around recharge zones, evolving to Na–HCO₃ with increasing depth. Salinity is mainly 300–1500 mg/L Total Dissolved Solids (TDS). It increases with depth, but might not exceed 3500 mg/L. The pH generally ranges between 8 and 8.6.

Acid buffering capability is large indicated by equilibrium speciation and reaction path simulations (Hodgkinson et al. 2009) also suggesting the groundwater systems may have capacity to naturally remediate acidic pH induced by dissolution of injected CO₂.

In general the implications of existing data and models for GHG storage are difficult to evaluate. The timeframe of relevant reactions is not clear. Reaction rates from laboratory experiments and field data can vary enormously, and model results may reflect more the underlying thermodynamic data base than provide insights for the field (White and Brantley, 2003).

However, overall, the likely impact on porosity and permeability may be small because the reactive phases of the mineral assemblies represent a small fraction of the rock and quartz is the dominant component of the matrix framework.
5.7 Static Modelling

5.7.1 Structural modelling

Structural grids were adjusted and corrected to tie all the well tops obtained from the Queensland exploration database (Figure 5.4). Scanned images of seismic sections and regional cross sections were employed for structural validation (ZeroGen–CSA, 2010a, 2010b, 2010c).

Additional structural grids for the Boxvale Sandstone Member, lower Evergreen Formation and Snake Creek Mudstone Member (Figure 2.3 and Figure 2.3) were generated from well tops and shaped according to the nearest vertical seismic horizon provided.

Isopach maps for each unit were generated and adjusted using stratigraphic thicknesses from well tops. This exercise was error prone due to data quality and the consistency of formation top identification. For example, it resulted in an anomalous thickness of the Evergreen Formation in the Northern part of the tenements 1–8 and 1–9 (Figure 6.5). It probably also resulted in errors in apparent dip. Sequence stratigraphic review and re–correlation was to be addressed in the proposed work program.

The regional static model constructed using a 500 x 500 m grid size. In the vertical direction, the geological formations were divided into layers. Considerations related to dynamic modelling guided in part the layering scheme. Greater resolution was imposed on the potential reservoir targets, with layers a few metres thick. Therefore, the number of layers was fixed, but the thickness was allowed to vary along an individual layer being larger where the geological formation of interest is thicker. Thinner portions of the formation were represented at higher resolution than thicker portions. Finally, a 3D structure of layers was obtained, honouring the overall (gross) geometry.

No faults were incorporated or modelled in this stage of the project, but fault mapping was considered to be a key part of the exploration work program.

5.7.2 Facies modelling

Facies modelling was employed to help incorporate important gross, depositional features and known larger scale (regional) trends. The distribution reflects a subjective judgement on the geology. Therefore, models can be considered as illustrative or scoping models and not sensu–stricto predictive models.

The coarse regional model comprises three litho–facies (sand, silt and shale).

Facies were defined according to the amount of clay present interpreted from well logs (V–shale or ‘shale volume’). A cut–off was applied to the ELAN™ wells to define the individual facies at each well: Sand less than 12% V–shale; Silt between 12% and 65% V–shale, and; Shale greater than 65% V–shale. Additional wells with gamma–ray logs were also used to extend the facies definition spatially. The facies were defined in an analogous fashion as for the ELAN™ wells, in Figure 5.3, the right–most track displays the ‘facies log’ obtained from this procedure for ELAN wells. Similar profiles were generated for gamma–ray wells.
### TABLE 5.5: SELECTED AND INTERPRETED WELL AND SEISMIC DATA USED TO CONSTRUCT THE REGIONAL STATIC MODEL

<table>
<thead>
<tr>
<th>Data</th>
<th>Number/formation</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Well data</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wells intersecting Precipice Sandstone</td>
<td>624</td>
<td>Well penetrations for the Precipice shows high density in both flanks of the basin. Note however that all formation picks are lithostratigraphic.</td>
</tr>
<tr>
<td>Wells intersecting Showgrounds Sandstone</td>
<td>381</td>
<td>High well density is observed in the Western side of the basin along Roma Shelf and Wunger Ridge.</td>
</tr>
<tr>
<td>ELAN wells</td>
<td>5 (in area)</td>
<td>Wells with full datasets are limited. Wells have been selected spread across the basin for extrapolation and as ‘low, med and high’ type wells.</td>
</tr>
<tr>
<td>DST wells</td>
<td>22 (in area)</td>
<td>Only 22 representative wells of 120 were selected for DST analysis and 90% of them lie along the Wunger Ridge and Roma Shelf, where oil and gas fields are present.</td>
</tr>
<tr>
<td>Well logs (gamma ray)</td>
<td>183</td>
<td>Selected public available well log data from QPED database were loaded into Petrel. Wells with Gamma Ray were useful for regional facies analysis and modelling.</td>
</tr>
<tr>
<td><strong>Seismic data</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Seismic lines</td>
<td>68 to date</td>
<td>A total of 68 regional scanned images from QPED database covering the basins were loaded into Petrel for structural grid validation—all seismic data continue to be sourced and will be incorporated into the model after reprocessing (see Work Plan in Volume 5).</td>
</tr>
<tr>
<td><strong>Seismic horizons (depth)</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>S–30</td>
<td>Top Evergreen Formation</td>
<td>Structural grids were also generated from well tops (QPED database) for the intraformational units in Evergreen Formation such as Boxvale Sandstone member and lower Evergreen Formation.</td>
</tr>
<tr>
<td>S–20</td>
<td>Top Precipice Sandstone</td>
<td></td>
</tr>
<tr>
<td>S–10</td>
<td>Top Moolayember Formation</td>
<td>Snake Creek Mudstone Member (lower Moolayember formation) was generated and included using well tops information for QPED database.</td>
</tr>
<tr>
<td>B–90</td>
<td>Top Showgrounds Sandstone</td>
<td></td>
</tr>
<tr>
<td>B–80</td>
<td>Top Rewan group</td>
<td></td>
</tr>
</tbody>
</table>

Well data and seismic data were gathered from QPED database available at Geological Survey of Queensland. Well tops were compiled from the Geological Survey of Queensland stratigraphy tables provided. QDEEDI provided the listed seismic horizons.
Illustrating data integration: seismic images (light blue lines), well tops (red dots) and seismic horizons (vertical slice). This helped to define and validate the lateral extent of the lithological units and vertically tied the seismic horizons using well tops.

Finally, the facies were extrapolated from the wells into the model with the Sequential Indicator Simulation Algorithm in Petrel™ for each unit. Subsequently, known characteristics of the depositional environments along the direction of sedimentation were applied for the target reservoirs (Precipice Sandstone and Showgrounds Sandstone). Previous interpretations of the palaeographic environment of deposition of Showgrounds Sandstone in the Wunger Ridge (Sayers et al. 2006) were used as a guide to propagate facies through the 3D model domain. Other studies (Bradshaw et al. 2009) indicate that the Showgrounds Sandstone changes laterally to more silty and shaly facies towards the eastern flank of the syncline.

No direct sedimentation modelling was possible, the Showgrounds fluvial environment was arbitrarily truncated in the western side towards the syncline axis where reservoir properties tend to deteriorate according to the palaeographic environment. For the Precipice Sandstone no individual fluvial trends were incorporated.

A view of the result of illustrative facies modelling is given in Figure 5.5.
5.7.3 Property modelling

Each grid cell was populated by a single value porosity, net-to-gross and permeability to allow later extraction of scenario models for dynamic simulations. These properties were distributed and assigned to the facies distribution for each formation. Effective porosity and permeability were derived from ELAN™ Wells and then up-scaled.

An arithmetic mean averaging method was used for porosity. For permeability, a geometric averaging method was used.

A porosity and permeability cross plot from up-scaled data was used with the aim to validate the relationship for data points associated to each facies. The cross plot in Figure 5.6 shows the effective porosity and permeability of the up-scaled ELAN™ wells coloured by facies.

Despite the sophisticated algorithms this remains a coarse regional model, only intended to be illustrative of gross trends and gross heterogeneity.
The up-scaling process for net-to-gross ratio (N/G) is based on the volume of clay from the ELAN and gamma-ray wells for each facies and formation. N/G=0 was imposed on shale facies. Following the (vertical) up-scaling process along the wells, the Sequential Gaussian Simulation (SGS) algorithm was used to distribute the property within the 3D grid. The variation within the data results from the up-scaled statistical analysis and a simple default variogram.

Well data show areas where the Precipice Sandstone is a thick ‘blocky’ sand (in the North East, within the paleo basin axis) and in the more distal South, to the West of the paleo basin axis it comprises thinner ‘channels’ but often with good reservoir quality. Up-scaled porosity and permeability are higher for the Precipice Sandstone in the Northern part of the basin. Historic differentiation between the Precipice and Boxvale (lower Evergreen) Sandstones may not be consistent and is problematic for mapping quality regionally and depositional patterns.

Similarly, the Showgrounds Sandstone yields low values East and down flank of the Wunger Ridge (e.g. Overston–1). However, further North, where the Showgrounds Sandstone is undifferentiated from the Clematis Group in old interpretations, there are down-flank layers possibly with good reservoir properties (e.g. Tiggrigie Creek–1).

A 3D permeability–porosity–N/G model was guided by a geological facies model. Porosity and permeability depth trends were also applied to the sandy facies for the target reservoirs (Precipice Sandstone and Showgrounds Sandstone), see Figure 5.8. Additional trend control from existing core data was applied to the permeability 3D model for the target reservoirs.

Figure 5.9 illustrates the result of the static model building process: a map view of the (up-scaled) variation in permeability at the top of Precipice Sandstone. High permeability (red) is encountered to the North and North–East. The gross-pattern also agrees with that observed from groundwater data (SWS, 2010 and Berly, 2010).

Given this regional approach, a sense-check was attempted, which compared DST analyses with model predictions. For this exercise, transmissibility values for the Precipice and Showgrounds Sandstones were computed from the models at the approximate position of each DST well. Vertically, both formations of interest are described by 12 layers. A mean transmissibility was computed as the product of the vertical geometric mean model permeability, the vertical arithmetic mean N/G and the formation thickness (sum of 12 cell heights). A cross-plot allows both kinds of estimates to be compared (Figure 5.7).

DST results are widely scattered over more than an order of magnitude and no spatial pattern has been detected. There are more model values which are lower than actual DST results than higher. Model transmissibility for the Showgrounds Sandstone was consistently below DST values.
While an important attempt to find an independent data-set with which to check geological models, no clear match could be made between DST and regional model predictions. This could be due to inconsistencies and uncertainties in raw data and/or very coarse modelling parameters and/or the model being entirely unrepresentative.

Figure 5.10 shows a section of the 3D static model sliced vertically from South–West to North–East. Here the contrasting geometry between the Precipice Sandstone and the Showgrounds Sandstone can be seen. The view is distorted because of the compromise that needs to be accepted to display 3D features as a 2D projection.

For the GHG tenements 1–8 and 1–9 the Precipice Sandstone section may have (up–scaled) permeability in the range 10 to 1000 mD (green to red colours) with the high values concentrated in tenement 1–9 (Figure 5.10 b). Porosity and net-to-gross shows similar trends.

The Showgrounds Sandstone is more heterogeneous with some zones up to 300 mD (yellow colours) along the fluvial channel cells in the Western side of the syncline (tenement QLR2010–1–8) and low (practically zero) permeability in the eastern side (QLR2010–1–9) where the silt and shale are the predominant log facies.
5.7.4 Coarse property model conclusions

The paucity of knowledge specific to the areas gazetted as GHG exploration tenements made it necessary to extrapolate regional offset data into the application areas. A regional static geological model was built using and integrating a selection of existing data. Geophysical logs were re-interpreted with the specific objective of GHG storage. These were integrated with seismic data and interpreted seismic sections and geological cross-sections. Geostatistical methods were applied to interpolate and populate the digital model guided by a significant degree of professional judgement and published technical literature. Stochastic Algorithms (SGS) were used to populate a grid with properties (net-to-gross, porosity, permeability) and reflect some of the heterogeneity in the data for a single realisation.

The model was illustrative and not predictive. It had major shortcomings and does not match well available (‘noisy’) DST data at the margins of the model. However, it appears to capture many characteristics and current geological thinking discussed in the literature, gross scale aerial heterogeneity and depth trends.

This type of regional static modelling allows for several sector models to be extracted for dynamic scenario modelling which are consistent with available data and regional geology and which differ in depth, dip and poro–perm properties and poro–perm variation.
Depth is in metres subsea (datum of 400 m above sea level). Note that high concentration areas of points are related and clustered to individual ELAN wells used for analysis e.g. permeability data at ~500 m subsea (900 mGL) shows high permeability values associated to the Trelinga–1 well.
Note high values (around 1000 mD in red) are concentrated in tenements QLR2010–1–8– and QLR2010–1–9 towards the sub-crop area. Black dots are all wells that intersect the Precipice Sandstone, red lines represent major faults. Blue to green colours represent low permeability (0.1 to 10 mD). Permeabilities in the range 100 mD to 1000 mD are yellow–orange–red. This distribution is also observed in groundwater data.
FIGURE 5.10: TRANSECT INTERSECTION SLICING TENEMENTS QLR2010–1–8 AND QLR2010–1–9 FROM SOUTH–WEST TO NORTH–EAST (MUGGLETON–1 TO TRELINGA–1 WELLS)

Showing a) porosity, b) permeability, and c) net–to–gross distribution for Precipice Sandstone and Showgrounds Sandstone. Vertical profile shows that high values are located in tenement QLR2010–1–9 for Precipice Sandstone (Trelinga Anticline) reaching up to 1000 mD (red colour) diminishing toward tenement QLR2010–1–8 in the range of 1–500 mD (green to orange colours). Tenement QLR2010–1–8 shows permeability for Showgrounds Sandstone in the range 0.1–300 mD (purple to yellow colours) where fluvial channels are present. Porosity and net–to–gross also reflect the permeability trend.
5.8 Storage Concept and Initial Target Location Considerations

The basin-wide illustrative model encompassed an area of several thousand square kilometres. This large-scale approach was necessary because of the large tracts of unmapped areas within the gazetted areas for exploration. From this regional framework, further tenement specific investigations were required to investigate the likelihood of sustaining industrial scale long-term CO₂ injection and storage securely (Section 7).

Targeting

Figure 5.11 shows, in a typical Surat Precipice model, the relative proportion of injected CO₂ from commencement of injection to 200 years. Note the rapid increase in immobile (residual) CO₂ immediately after cessation of injection in year 30.

**FIGURE 5.11: PHASE PARTITION OF CO₂ (QLR2010–1–12)**

![Graph showing phase partition of CO₂](image)

CO₂ flow in the subsurface would be driven by the injection pressure and to a lesser extent by buoyancy due to the low density of CO₂ compared to the ambient reservoir fluid.

Supercritical CO₂ would be injected at depths generally greater than 1500 m (not least because shallower areas tended to be close to CSG Production Leases).

Areas with very low dips were targeted preferentially minimising lateral migration. Figure 6.11 shows a range of plume migration distances from several Surat model scenarios (different areas of the regional model). Flow-path tortuosities would increase dissolution, but too much heterogeneity could prevent pressure dissipation in the reservoir and hence reduce injection rate over time.
CO₂ would be delivered at the well head at a pressure and temperature engineered to manage problems in the well (hydrate formation, unwanted multi-phase flow etc.) and the reservoir (e.g. thermal fracturing). Field management practices would ensure that seal retention, fracture and fault reactivation pressures would not be exceeded even when large rates of CO₂ were injected. At any given time, maximum pressure in the system would be at the injection point i.e. this pressure would be an engineered and managed and regulated parameter. Maximum overpressure would be reached at the end of injection.

A final uncertainty which might impact on pressures and flow directions, would be the geomechanical and hydrodynamic impact of neighbouring water extraction or re-injection activities—especially those related to CSG operations.

**Selection of subsurface geological targets for exploration and modelling**

The selection of potential subsurface geological exploration targets was derived from considerations of surface constraints and from regional models. Thus a sub-set of each tenement was selected to evaluate storage performance potential. A static model for three different tenement ‘type areas’ was extracted from the regional static model for probabilistic and dynamic modelling of selected injection scenarios. By extracting areas from the regional model, which had different degrees of dip and heterogeneity, a range of outcomes were generated, that were indicative of model uncertainties.

Figure 5.10 illustrates the subsurface geometry for tenement 1–8, the relationship between the target formations, and their distribution in the target sites. The areas shown as purple ellipses were selected for modelling and placement of model injection wells.

The Showgrounds Sandstone thickens towards the syncline axis and the northern part of the basin. This unit is truncated in the western flank of the tenement by the basal Jurassic unconformity (Base Precipice Sandstone), which forms also the erosional limit of the Moolayember Formation. The Precipice Sandstone covers the entire GHG tenement and is thinning into the west direction.

For the purposes of injection modelling:

- CO₂ would be injected in sand bodies deep in the Precipice Sandstone and/or Showgrounds Sandstone;
- the Showgrounds has immediate top seal (Snake Creek Mudstone Member). Also the Moolayember Formation contains other impermeable zones;
- injection would be deep within the Precipice Sandstone. Injected CO₂ would be able to migrate vertically until it reaches seals within the Evergreen Formation. Low dip (<1.5 deg) suggests the lateral spread after cessation of injection may be limited; and
- the Southern area of tenement 1–8 may be a significant extension to the modelled area.

Exploration areas and subsequent notional injection developments were selected similarly in the other tenements.
6 Resource Assessment—Containment

6.1 Context
Possible performance of the storage resource in terms of injectivity, capacity and containment was evaluated using a set of dynamic models which were extracted and refined from the gross, illustrative regional model. These extracts were used to drive discrete injection simulations and area-wide, well based property statistics were used to drive complementary probabilistic modelling. Uncertainties in the performance predictions were also evaluated; reduction of these became a key aim of the exploration work program.

6.2 Lessons Learnt
Natural seismicity is likely not a major issue.

Understanding lateral seal continuity and sequence stratigraphy is currently inadequate.

Some evidence exists which supports the Evergreen as regionally extensive seals, but at present only minimum quantitative values of retention pressure can be made. At present, retention pressure evidence is for values lower than estimates of pressure required, based on coarse models.

Fault reactivation is most likely in faults with an orientation similar to the Moonie Fault (NE–SW). Very conservative reactivation pressures compared with possible pressure evolution indicates that maintaining a distance of a few kilometres from such features would significantly mitigate reactivation risk. Fault locations need to be established.

Lateral plume migration of less than 10 km in 200 years (for 60 million tonnes) seem likely. Areas can be selected for investigation with low dip and in which few legacy wells occur.

It is critical to obtain site-specific data to allow quantification of retention pressures (MCIP, fracture propagation and fault reactivation).

It is critical to obtain site-specific reservoir data which will allow models to be built and predict pressure evolution under injection conditions (transmissitivity, connectivity, kv/kh ratios etc.).

6.3 Evaluation of Containment
The following evidence informing containment security was evaluated:

a. geology, lithology, deposition and seal thickness;
b. chemical compositional variations across the main seal;
c. hydrocarbon column heights;
d. differential hydrostatic heads;
e. fracture gradients and pressures; and
f. estimates of fault reactivation pressures.
In addition, lateral plume migration distances were informed by scenario injection models. The possible scale of migration and the location of legacy wells and tenement boundaries served to restrict areas (low dip, basin centred) considered most favourable for exploration.

Estimates of pressure constraints (from c to f above) were compared with overpressures derived from injection models to investigate the extent to which sealing pressures are sufficiently ‘known’ within possible operating envelopes. Containment performance would be a function of inherent site characteristics and how it is operated and managed. In general, injection points would be chosen and Bottom Hole Pressures (BHPs) managed (and regulated) such that pressures at the cap–rock or critically stressed faults would not exceed key limits quantified by models and lab–samples based on new data (less some safety margin).

Wells would also be located so worse–case, plume migration models would not intersect legacy wells or known faults and plumes would not migrate outside tenement boundaries (as required under relevant regulations in Queensland).

6.4 Top and Intra–Formational Seals: Geological, Petroleum and Hydrodynamic Evidence

The upper Evergreen Formation may effectively be a continuous sequence of shale and siltstone but is not consistently developed across the basin. Lateral prediction of seal potential is an issue. Vertical heterogeneity would cause any CO₂ migration path to be tortuous, enhancing trapping mechanisms (solubility and residual saturation), minimising the amount of CO₂ reaching the top seal and reducing injection–related pressures at the seal.

6.4.1 Hydrocarbon columns

As calibration, Evergreen lithology was determined from well logs by V–shale calculations in areas where it is a localised proven seal for gas sands in the Precipice e.g. Figure 6.3.

From these examples, it can be seen that these Evergreen lacustrine facies together (wide extent in the upper Evergreen Formation and locally in the lower Evergreen Formation) hold hydrocarbon columns. From field data, column heights may be in excess of 50 m. However, values are extracted from partial data publicly available in only five oil and gas fields.

Figure 6.4 shows the regional extent of the silt and shale facies for the upper Evergreen Formation, based on wireline log characteristics correlating lithological responses from current hydrocarbons fields and central parts of the basin. The assumption is that log response of a good seal seen in other parts of the basin indicates similar seal quality (analogue evidence).

Table 6.1 shows column heights which range between 14–55 m. These low values can be attributed to the scale of the structure (e.g. small anticlines) and not the retention limit of the seals. In the northern tenement area, the seal tends to be thicker and therefore probably have a higher retention potential. In the central, deeper, synclinal features, it can be reasonably expected that both capillary entry pressures and fracture propagation pressures would be higher than on the shallower anticlines.
FIGURE 6.1: OVERVIEW OF MODELLING DOMAINS

Depth to top upper Evergreen Formation (regional seal, depths < 800 mGL are in red) extracted from the digital model shows outline of the sector models (pink squares) with respective notional injection well (red dots). Radial models are in grey dots. Potential areas suitable for CO₂ injection (solid white line for the Precipice Sandstone and Showgrounds Sandstone in dashed grey line in QLR–2010–1–8 only) used in probabilistic modelling are defined inside each tenement constrained by PLs (dark grey areas). Note the Clematis Sandstone zero−edge in blue and Precipice Sandstone in purple.
6.4.2 Lithology/thickness

There were no public domain studies on the sealing capacity of the upper Evergreen Formation, and no available MICP analyses.

MICP analysis has been performed previously on Snake Creek mudstone in the Wunger Ridge for two wells (Harbour–1 and Hollow Tree–1). This has revealed CO₂ retention heights in the order of 490 to 910 m (Daniel 2005) (Figure 6.6). This could indicate retention pressures up to 40 bar. Furthermore, pressure depth analysis based on CSIRO data also shows low pressure points in some places within the Moolayember Formation (Hortle, 2010). This indicates potential baffles or localised seals at different levels within the formation (e.g. Tiggrigie Creek–1).
Maximum thickness of pay sandstone is around 3.5 m and 7 m, respectively. The Evergreen Formation in Bony Creek–17 is approximately 60 m thick and mainly comprised of silt and shale, and is a 24 m silty–shaly section in Pickanjinnie–10. The correlation shows that the upper Evergreen Formation is mainly silt and shale facies with a very small amount of sand. Note that the directly overlying seal for the Precipice Sandstone is the shale unit for the lower Evergreen Formation.

Figure 6.4 shows the regional extent of the silt and shale facies for the upper Evergreen Formation, based on wireline log characteristics correlating lithological responses from current hydrocarbons fields and central parts of the basin. The assumption is that log response of a good seal seen in other parts of the basin indicates similar seal quality (analogue evidence).
TABLE 6.1: COLUMN HEIGHTS AND RESERVOIRS FOR FIVE HYDROCARBON FIELDS IN THE BOWEN AND SURAT BASINS

<table>
<thead>
<tr>
<th>Hydrocarbon field</th>
<th>Reservoir unit</th>
<th>Minimum column height (m)</th>
<th>Seal</th>
<th>Hydrocarbon type</th>
<th>Min ΔP estimated from column heights (bar)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Moonie</td>
<td>Precipice Sandstone</td>
<td>23</td>
<td>Evergreen Formation</td>
<td>Oil</td>
<td>2.0</td>
</tr>
<tr>
<td>Waratah</td>
<td>Showgrounds Sandstone</td>
<td>14</td>
<td>Moolayember Formation</td>
<td>Oil and Gas</td>
<td>1.2</td>
</tr>
<tr>
<td>Bony Creek</td>
<td>Precipice Sandstone</td>
<td>55</td>
<td>Evergreen Formation</td>
<td>Gas</td>
<td>7.5</td>
</tr>
<tr>
<td>Lamen</td>
<td>Precipice Sandstone</td>
<td>14</td>
<td>Evergreen Formation</td>
<td>Gas</td>
<td>1.2</td>
</tr>
<tr>
<td>Beaufort</td>
<td>Showgrounds Sandstone</td>
<td>17</td>
<td>Evergreen Formation</td>
<td>Gas</td>
<td>2.3</td>
</tr>
</tbody>
</table>

The immediately overlying seal is also listed. Only the Moonie Field is within one of the gazetted tenements, QLR2010112.

FIGURE 6.4: 3D PERSPECTIVE ON THE TOP PRECIPICE SANDSTONE

Note: 250 m contour intervals. Showing well logs of the sealing unit, the upper Evergreen Formation (red boxes), for nine wells across the basin. Green and red circles represent gas and oil units, respectively. This 3D figure denotes the shaly and silty facies of the seal interpreted from gamma ray responses.
Colour scheme in 40 m intervals, grey areas represent thickness less than 40 m. Superimposed is the structural map of base upper Evergreen (top Boxvale Sandstone Member isoline interval 200 mSS). White filled polygons refer to the oil and gas fields reservoirs directly below the top regional seal. Blue line is the Showgrounds Sandstone zero–edge. Note anomalous thick isopach values in the northern part of the basin as result of insufficient control data points.

The thickness of this regional top seal (upper Evergreen Formation) generally increases from the flanks to the central portion of the syncline. It covers all the GHG tenements with thicknesses greater than 40 m, and depths greater than 800 m (400 m subsea) suitable for supercritical CO₂ storage (Figure 6.5). The seal is proven for hydrocarbon fields in the Roma and Moonie areas. Sealing quality is expected to improve towards the syncline axis. However, its quality to the South and East of the tenement areas require further testing.
6.4.3 Hydrodynamic evidence

Hydrodynamic analysis from previous studies (Hodgkinson et al. 2009, 2010) suggested a typical hydraulic pressure separation between Precipice and Hutton Reservoirs of the order of 10 bar.

Distribution of the pressure/depth relationship was examined in the same study for two clusters of wells in the South East part of Surat Basin (Figure 6.6). As part of this evaluation, difference pressure gradient trend for the Precipice Sandstone and the Hutton Sandstone was observed in the well Yarrala-1 and the estimated pressure difference ($\Delta P$) was around 200 psi (14 bar) at bottom of the Evergreen Formation (700 m depth). This well, located in the eastern side of tenements QLR20101–12/13, is one of the few wells with Reservoir Formation Test (RFT) data in the Jurassic and Triassic Reservoirs.

Assessment of maximum seal retention pressures in site specific locations is critical.

**FIGURE 6.6: LOCATIONS OF FORMATION PRESSURE DATA POINTS FROM PETROLEUM WELLS THAT HAVE BEEN ASSESSED USING THE CSIRO PRESSURE QC METHODOLOGY**

Modified after Figure 3.3 and 36A in Hodgkinson et al. (2009). Red and blue circles denote the clusters of wells where the pressure/depth relationship was evaluated. Also depicted are $\Delta P$ values from RFT analysis in Yarrala–1 and the minimum $\Delta P$ estimated from Precipice Sandstone column heights shown in Table 6.1 are highlighted in red.
6.4.4 Geochemical evidence

There is also geochemical evidence which adds minor support to the sealing nature of the Evergreen i.e. the difference in water composition across it. Salinity and hence fluid density in the Hutton Sandstone is consistently higher than in the Precipice Sandstone (Hodgkinson, et al., 2009) indicating lack of mixing and flow over geological time-scales.

**Bowen Basin.** Intra-formational seals present in Bowen Basin are mainly located in the Upper Triassic section in the Moolayember Formation. The Snake Creek Mudstone Member is one of these proven seal units for reservoirs present in the Showgrounds Sandstone and the Rewan Group in the Wunger Ridge. This shale unit has also been intercepted in the Eastern part of the basin exhibiting similar sealing quality properties.

6.4.5 Evidence of seal quality—Summary

The analysis of the current state of knowledge indicates that the Evergreen Formation may form a valid top seal based on hydrocarbon, hydrodynamic and geochemical evidence. However, at present only minimum seal retention pressures of the order of 10 bar are proven and not in the area of interest.

Dynamic sector models (Subsection 7.4) investigated possible pressure development for an injection scenario and found that retention of 80 bar or greater may be required if maximum rates are to be exploited.

In the proposed Exploration Work Program, new data on new cores of the top seal as well as other potential intermediate seals and baffles was to have been collected and submitted to the type of evaluation presented here. Bulk-scale, vertical interference tests would be proposed to measure vertical communication directly.

Analogue evidence comparing log characteristics from proven hydrocarbon accumulations to deepen basin-centre wells is broadly supportive of the continued presence of seals.

6.5 Geomechanics, Seismicity, Faults and Fractures

Faults and fractures while not necessarily inherently ‘leaky’ had to be assessed with respect to the possibility for leakage caused by injection induced reactivation. Simple sand-juxtaposition related leakage would also require assessment in the area based on new seismic data.

Natural and induced seismicity could in theory impact the security of containment of the injected CO₂ by reactivating faults or stressing reservoir seals to failure. However, the presence of emplaced hydrocarbons in the existing fields, which have been contained for millions of years may be taken in support of a judgement that natural seismicity might not be consequential to containment performance.

Moreover, the risk of significant natural seismicity (earthquakes) in the Bowen Basin is considered low (Bradshaw et al. 2009). Figure 6.7 shows the magnitude and distribution of earthquakes reported in the Bowen Basin since 1875. As the figure shows, only one earthquake has been
reported in the areas of interest. Furthermore, all of the earthquakes have had a magnitude of less than 5.3 on Richter Scale and the majority of onshore earthquakes were non-damaging, and low in magnitude (Bradshaw et al. 2009).

Minimal data were available for the Mesozoic strata in the Surat Basin region for this. The geomechanical properties and the present-day state of stress of the Permo-Triassic sediments of the Bowen Basin are better understood based on hydraulic fracturing treatments and analysis of image logs (Hillis et al. 1999; 2008). The regional stress field of Queensland is consistently orientated North-Northeast in the Bowen Basin (Hillis et al. 1999) (Figure 6.7). Data interpreted from ZeroGen’s 2006-2010 NDT exploration drilling through Permian strata in Denison Trough encountered fracture gradients of greater than 1.1 psia/ft. This value is associated to a compressional stress environment as is shown for the Bowen Basin on the current World Stress map. Subsequently for Surat Basin, a fracture gradient of 1.0 psia/ft was assumed for simple modelling purposes—it was considered essential to measured fracture propagation pressures in any exploration work program.

**FIGURE 6.7: EARTHQUAKE HAZARD MAP FOR QUEENSLAND (AFTER HILLIS ET AL. 1999)**

![Earthquake Hazard Map for Queensland](image)

Depicted is the risk of earthquake, where higher numbers represent an increased risk. In general, risk increases towards the East. Also shown are the locations and magnitudes of all earthquakes recorded in Queensland. Green lines represent direction of the maximum horizontal stress field, indicating that there is a strong North North-East stress field trend. The majority of onshore earthquakes were non-damaging, and the Bowen Basin and Surat Basin appear to be fairly aseismic (after Hillis et al. 1999).
Late Cretaceous deformation led to limited propagation of reactivated thrust faults of the underlying Bowen Basin into the Mesozoic succession of the Surat Basin (Cadman et al. 1998). Although these older regional faults were reactivated during the Late Cretaceous at depth, they seem not to propagate upwards or only a short distance into the Surat Basin sediments (Korsch and Totterdell, 2009) (see Figure 2.5, seismic line BMR–84–14).

However, most of the oil and gas reservoirs, reported in the Hutton Sandstone could be interpreted to be aligned with the regional fault systems in the basin and these shows might be associated with fault leakage (see Figure 6.8), in particular for the systems located in the eastern margin of the Bowen Basin as described by Cadman et al. (1998). If they cannot be avoided, fault seal studies are required to determine the current sealing capacity of the faults. Geochemistry for oil and gas shows in the Hutton Sandstone may prove useful if quality data are available.

Faults of the Bowen Basin are striking north–northwest and are oblique to the maximum horizontal stress orientation and this encourages faults to seal (Hillis et al. 1999).

Even if the mapped reactivated faults seem not to reach the regional seal, the main strategy for containment risk management should be

• mapping them in the exploration program; and
• avoidance of injection well placement close to faults in the reservoir seal successions of the Surat Basin.

6.5.1 Geomechanical Modelling of Faults

In 2010 there were no data available for the specific areas and depth intervals of interest to allow any sophisticated geomechanical investigation except for a rough screening of the types and orientations of faults in a regional context of the present tectonic setting. In certain subsurface environments, the storage of large amounts of CO₂ implies subjecting the subsurface to pressures greater than the pre–injection pressure over long periods. Data collected during exploration/appraisal phases will allow a pressure management strategy and pressure limits to be established. In addition to laboratory tests and dynamic models, geomechanical modelling can assist in evaluating the impact and effectiveness of selected injection and pressure management strategies.

Preliminary fault reactivation evaluation using geomechanical simulation in the Bowen Basin was carried out for three different plane orientations (Figure 6.8). The first is the mean fault orientation in the Bowen Basin, published by Hillis et al. (1999), which represents the Hutton–Wallumbilla Fault (tenement 1–8) in the Roma Shelf area. Both other directions, namely the strike of the Goondiwindi–Moonie (tenements 1–11, 1–12 and 1–13) and the Burunga fault systems (tenement 1–9) are described in Bradshaw et al. (2009) and are situated at the eastern site of the basin.

The following data would be necessary to start a fault/fracture analysis: vertical stress magnitude, minimum and maximum horizontal stress magnitude, minimum horizontal stress azimuth, pore pressure, friction angle and cohesion, fault depth, dip and dip azimuth. These data would have been acquired in the initial work program. For the pre–tenement analyses, several assumptions had to be made.
The vertical stress gradient was assumed to be of the order of 0.255 bar/m (1psi/ft) at a depth of 1200 m (3937 ft). Minimum and maximum horizontal stress magnitudes were estimated (from unpublished, internal Schlumberger source). The stress regime in 1200 m depth was assumed as strike–slip regime ($S_{h}>S_{v}>S_{v}$).

Pore pressure was defined to be hydrostatic (0.435 psi/ft). To use a worst case for fault slippage, rocks were considered unconsolidated (zero cohesion). The friction angle is expected to be about 25 degrees. After running the simulation none of the three fault directions, under normal conditions was close to being critically stressed (Figure 6.9) i.e. under the assumption of hydrostatic pressure.

**FIGURE 6.8: MAP ILLUSTRATING PRESENCE OF HYDROCARBON SHOWS RECORDED IN THE HUTTON SANDSTONE IN THE GHG ACREAGE RELEASED AREAS (CGSSB, 2010)**

Superimposed is the base of upper Evergreen Formation (black contour lines 200 m (mSS)). Grey areas denote upper Evergreen Formation thickness less than 40 m. Note that hydrocarbon shows in the Hutton Sandstone are aligned to the existing faults and areas where thickness of the upper Evergreen Formation is less than 40 m.
In addition to a friction angle of 25°, four simulations were performed varying friction angles in the range of 20° to 40°, to explore the sensitivity to this parameter (see Table 6.2). The choice of this range is based on experimental test published by Byerlee (1978). In these simulations, the pore pressure was increased until the reactivation threshold was attained. This provides an estimate of the maximum $\Delta P$ that faults can hold before being reactivated (fuller descriptions are contained in the supplementary reports).

The result shows $\Delta P$ values in the range of 44 to 88 bar. A Moonie–type fault would be first to be reactivated. The reservoir pore pressure would have to experience an increase from 120 bar (hydrostatic conditions at depths around 1200 m) to 164 bar under strike slip regime to affect fault stability. The lowest calculated differential pressure defines the most conservative estimate of fault reactivation pressure in the absence of stress and friction angle data.

To date, ZeroGen’s simple (open) dynamic models under a fracturing pressure constraint resulted in overpressures are less than 40 bar some 4 km away from an injection site. Modelled overpressures were well below the estimated tolerance range of the known faults as indicated by geomechanical modelling—if the system is open.

**FIGURE 6.9: RESULTS OF FAULT STABILITY ANALYSIS (ZEROGEN–CSA, 2010C)**

![Graph showing fault stability analysis results.](image)

*First trial, showing no critically stressed faults (green points: stable faults/red points: critically stressed faults). The three different fault/fracture orientations used in this study are shown below the screen shot.*
Studies and new seismic data would be needed to map potentially unknown faults and re-examine the likelihood of fault reactivation near to the injection point. To setup a reasonable geomechanical model of the prospective area additional information is needed. Image logs in future wells are crucial to measure breakout and tensile fracture orientations and define stress orientations. Leak-off tests are also required to obtain horizontal stress magnitudes. Cohesion and friction angles need to be measured. These requirements will be addressed in the initial logging and hydraulic test program for the proposed wells.

### Pressure Constraints and Management

The injection of CO₂ would cause subsurface pressures to change through time. Maximum overpressure, the difference between pressure at the end of injection and the initial (hydrostatic) pressure, would be reached at the end of injection. Dynamic simulations were run (by CSA) to investigate ranges of pressure build up. In these simulations, the Bottom–Hole Pressure (BHP) was free to increase to within 90% of the fracturing pressure. Injection rates were held constant (e.g. at 2 Mtpa) unless it had to be reduced because the pressure had attained the 90% limit.

A simple one vertical injection well scenario was constructed. Generally, the highest pressure in the storage system would be at the injection well during the injection process. In practice, this pressure could be controlled.

All sector models simulated had ‘open’ boundaries. The basin is reported as being essentially ‘artesian’ with pressure connection to recharge zones. However, this choice of closed model boundaries was not a prediction, but a scoping scenario. Pressures modelled would be lower and plume migration further than for closed or partially bounded systems.

Figure 6.10 shows a Showgrounds injection scenario. Similar models were used to scope out the size and magnitude of pressure signatures to inform discussions on (i) separation margins from other operations and field and (ii) what pressures might be seen by the ultimate cap–rocks (and how might this compare with the extent to which they are currently known).

For the Showground, maximum overpressure is around the well. In these scenarios, overpressure of more than 100 bar extends laterally over approximately 3 km, it decreases with distance from the well but is still significant (circa 50 bar) at a distance of 5 km. Therefore, the simple measure...
of placing injection wells away from known faults and legacy wells avoids or at least limits exposure to potential fault reactivation pressures. For example, if fault reactivation pressures were of the order of 50 bar, then injection wells would need to be planned at distances greater than this. In this model, directly above the well, the seal experiences about 100 bar maximum overpressure.

Finally, it was not possible to maintain an injection rate of 2 Mtpa for 30 years, the pressure limit forced it to be reduced to a sustainable level of 1.2 Mtpa per well. At the start of injection some 2 to 3 wells would be required to meet the target sequestration rates. The rate of change of pressure increase with time would be a key techno–economic parameter to measure. Extended well tests would need to be planned in the exploration work program.


\[ \Delta \text{ Values from 1 Jan 2010 to 26 Dec 2039 } \ J=45 \]

Note that overpressures greater than 100 bar extend 1.5 km each side of the well. White cells are inactive.

Similar models were run for tenements 1–8, 1–9 and 1–12 and 13 for Precipice injection scenarios. Modelled (open system) pressures at the end of a 30 year injection period for injection are summarised in Table 6.3.

These modelled pressure build–ups are on the whole higher than the scoped range of fault reactivation pressures (Table 6.2) indicating that fault–well separations of the order of 6 km might be reasonable but also showing the criticality of obtaining data on fault geometry, cohesion and friction angle.
In contrast, the modelled required retention pressures (at base seal after 30 years) are significantly higher than any which are evidenced by oil column data (Table 6.3).

Figure 6.4 shows the regional extent of the silt and shale facies for the upper Evergreen Formation, based on wireline log characteristics correlating lithological responses from current hydrocarbons fields and central parts of the basin. The assumption is that log response of a good seal seen in other parts of the basin indicates similar seal quality (analogue evidence).

This shows the key need for the evergreen seal to be heavily appraised though core MCIP and CO₂ CIP tests and through vertical interference tests. Both were a core part of the proposed work program.

**TABLE 6.3: SUMMARY OF MODELLED PRESSURE EVOLUTION FROM OPEN SECTOR MODELS**

<table>
<thead>
<tr>
<th>Tenement QLR2010</th>
<th>Formation</th>
<th>Model injection rate per well (Mtpa)</th>
<th>Over–pressure at 6 km from well at end injection</th>
<th>Pressure at base seal at end injection</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>1–8</td>
<td>Showground</td>
<td>1.2</td>
<td>70–80 bar</td>
<td>100 bar</td>
<td>Heterogenous, and lower permeability than Precipice</td>
</tr>
<tr>
<td>1–8</td>
<td>Precipice</td>
<td>2 (3)</td>
<td>20–30 bar</td>
<td>34 (50) bar</td>
<td>Medium quality Precipice</td>
</tr>
<tr>
<td>1–9</td>
<td>Precipice</td>
<td>2 (3)</td>
<td>15–25 bar</td>
<td>25 (34) bar</td>
<td>Highest quality Precipice</td>
</tr>
<tr>
<td>1–12 and 13</td>
<td>Precipice</td>
<td>2 (3)</td>
<td>40–50 bar</td>
<td>70 (104) bar</td>
<td>Lowest quality Precipice</td>
</tr>
</tbody>
</table>

Furthermore, modelled pressure build–up in these illustrations also show importance of establishing with new data to evaluate (i) vertical permeability over the whole Precipice–Evergreen column; (ii) bulk–scale heterogeneity and effective in–situ k.h; and (iii) large-scale, reservoir continuity and hence pressure build–up over time.

### 6.6.1 Summary comments on pressure build–up and management

While all models did include regional scale vertical and lateral heterogeneity, they did not include compartmentalisation caused by either channels and/or faults. These significantly impact the pressure behaviour. If BHPs were to be managed below the lower of fracture or capillary entry pressures, this need not affect containment assurance. However, injection rates per well could be significantly affected over time.

At this stage, it was not relevant that model pressures at the seal range from 30 to 100 bar and are higher than retention pressures estimated from hydrocarbon column heights and other data (circa 10 bar). The latter represents minimum retention pressure: the maxima are not known.
Although there are no measurements to compare the simulations results, model overpressures exceeding retention pressures are not necessarily an evidence of lack of suitability, but rather suggest the need to engineer pressures carefully and possibly use horizontal well technology or a higher well count to ensure lower overall system pressure. All sector models are considered open systems (open basin–ward), as soon as injection stops, the pressure relaxes.

Finally, these low resolution models suggest that choosing the appropriate injection strategy and placing wells carefully allows pressure to be managed without exceeding capillary entry, fault reactivation or fracturing pressures and exposure of legacy wells to be minimised or even avoided. They also serve as examples of the modelling studies to be included in the post–drill work plan. To properly define a pressure management system and associated pressure boundaries, it is essential that relevant rock properties (capillary entry pressures, fracturing pressures) are measured in the GHG tenement areas for the reservoir as well as top and intra–formational seals.

6.7 Lateral Plume Migration and Separation Margins

By careful selection of areas, there were few abandoned legacy wells in the proposed focus exploration areas. Completion reports of these wells were available, however a significant number of wells were old, with reduced information and poor quality data. Cement Bond Logs were generally not available. No reports were found which indicated any zonal isolation issues with legacy wells in the area.

Generally, the principle of avoidance guided exploration choices. Numerical modelling of CO₂ injection was used to estimate plume and pressure (Table 6.3) spread.

Numerous (open) sector model results were compiled to show the extent of the CO₂ footprint (maximum lateral extent) 200 years after 30 years of continuous injection ceases and offers insight as to the potential separation distance required from legacy wells. Note that open systems models tend to predict longer plume migration distances but smaller pressure build ups.

Figure 6.11 summarises the range of plume spread scenarios for Precipice injection.

6.7.1 Summary comments on lateral migration

Coarse simulations suggested that careful well and injection point placement may be able to avoid any injected CO₂ plume coming into contact with legacy well bores.

Areas exist and have been coarsely modelled where Precipice injection of 60 million tonnes (40 million tonnes in Showgrounds) of CO₂ would not contact legacy wells 200 years after injection has stopped. Plume migration in the low–dip areas of choice was typically less than 10 km radius.

The pressure influence of injection extends significantly further than that of the CO₂ plume, and legacy wells could potentially be exposed to higher pressure during a certain time but CO₂ cross–flow would not necessarily ensue. At the end of injection, in these models, potentially a few wells may experience overpressure of the order of a few 10s of bar—this would need to be revised if the injection system was found to be closed or partially bounded.
6.8 Impact of Containment Uncertainty on Work Program

Figure 6.12 illustrates available evidence and uncertainty in current containment evaluations. This is an example of qualitative, triple valued logic. Green and the amount of green represent data which is supportive of requirements for storage. Likewise red is for non-supporting evidence. White space is then uncertainty caused by lack of adequate data.

Containment consists of the elements: integrity of cap rock (top seal), closed faults and fractures, integrity of new and old wellbores and laterally contained CO₂ plume in the subsurface.

Uncertainty (white space) is large because the necessary data for fuller containment assessment do not yet exist for the tenement area.

Exploration and appraisal work programs would need to be designed to provide data to in-fill white space (uncertainty), as follows:

- long-term continuous monitoring would be established in overlying and injection aquifers;
- cores would be recovered to measure MCIP, rock strength, mineralogical and petrographic data. Vertical and horizontal permeability profiles will also be derived;
- extended leak-off tests would measure in-situ fracture gradients;
- geophysical logging and break-out analyses would allow quantification of stress regimes. Image logs would detect fracture density and orientations;
- extended production tests in the deeper horizons could be accompanied by a monitoring well in the Hutton creating a Vertical Integrity Test;
- seismic reprocessing and new seismic surveys would provide better mapping of faults; and a 3D survey would likely be required once other indicator data was positive e.g. for a site-specific appraisal phase.
Red shading signifies existing data does not support integrity, green that integrity is supported by existing data. White denotes lack of data to enable assessment of integrity. See text for more detailed explanation.
7 Resource Assessment—Injectivity

7.1 Context

Possible injectivity performance was examined by ZeroGen with Carbon Store Australia Pty Ltd (CSA) with both probabilistic and scenario based deterministic models.

Conceptually any injection profile over time can be represented by an instantaneous, initial injection rate and a rate which was a function of time. Uncertainty analyses on both initial rates and on ‘decline factors’ were therefore carried out. The latter were informed by open, sector models, taken from the heterogeneous regional model as well as by closed single well models using different ranges of closed radii. Together these two analyses were used to inform the value of different information types which were to be collected in an exploration campaign (in terms of the impact on rate forecasting and well count).

7.2 Lessons Learnt

Potential injectivity of the formations evaluated in the Surat and Bowen Basins are generally one to two orders of magnitude greater than those in the NDT.

There is a wide range of median single well, initial injection rates in the Precipice from 0.1 to 2.4 Mtpa depending mostly on facies, with some very high transmissivity (k.h) units encountered historically.

Showgrounds single well, initial injection rates between 0.01 and 0.1 Mtpa are expected (if the formation is encountered).

Given large uncertainties, none of the tenements could be disqualified on the basis of this modelling.

The greatest predictive uncertainties are (i) reservoir connectivity and hence the build up of pressure over time and (ii) the facies intersected by the wells, as there is no deterministic predictive model.

An exploration/appraisal program would need to include significant core measurements and experiments and a series of fit–for–purpose extended well production tests to reduce uncertainty.

Estimates of the number of wells required (based on simple vertical injection wells) for a Precipice development for 60 million tonnes at 2 Mtpa is between 6 and 42. This compares with a P50 case of over 500 for the NDT.
7.3 Probabilistic Assessment of Initial Well Injectivity ($I_0$)

Single well injection rate was evaluated by considering the impact of pressure difference as well as reservoir and fluid properties on CO2 flow within the reservoir. An analytical expression was used to obtain CO2 injection rate assuming pseudo–steady state behaviour. Should this condition be compromised, the model would likely underestimate the injection rate prediction.

The following Darcy’s Law approximation for pseudo–steady state compressible fluid flow in a porous medium is used:

$$q_{CO_2} = \frac{k_{absolute} k_{rCO_2} h_{gross} NTG (p_{inj} - p_{res})}{25.15 \mu_{CO_2} B_{CO_2} \ln \left( \frac{r_e}{r_w} \right) - 0.75 + S}$$

<table>
<thead>
<tr>
<th>$q_{CO_2}$</th>
<th>CO2 injection rate ($10^3$ scf/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$k_{absolute}$</td>
<td>Absolute reservoir permeability (mD)</td>
</tr>
<tr>
<td>$k_{rCO_2}$</td>
<td>CO2 relative permeability (dimensionless)</td>
</tr>
<tr>
<td>$h_{gross}$</td>
<td>Gross thickness (m)</td>
</tr>
<tr>
<td>$NTG$</td>
<td>Net to gross thickness ratio (dimensionless)</td>
</tr>
<tr>
<td>$p_{inj}$</td>
<td>Bottomhole injection pressure (psi)—limited by the fracture gradient</td>
</tr>
<tr>
<td>$p_{res}$</td>
<td>Reservoir pore pressure (psi)</td>
</tr>
<tr>
<td>$\mu_{CO_2}$</td>
<td>Average CO2 viscosity (cP), at reservoir conditions</td>
</tr>
<tr>
<td>$B_{CO_2}$</td>
<td>Average CO2 formation volume factor (ft³/103scf), at reservoir conditions</td>
</tr>
<tr>
<td>$r_e$</td>
<td>Reservoir drainage radius (ft)</td>
</tr>
<tr>
<td>$r_w$</td>
<td>Wellbore radius (ft)</td>
</tr>
<tr>
<td>$S$</td>
<td>Well skin (dimensionless)</td>
</tr>
</tbody>
</table>

The relevant fluid properties are CO2 viscosity and density (depending on pressure and represented by the formation volume factor). Significant uncertainty ranges existed for reservoir parameters such as NTG, $h_{gross}$ and permeability. Lesser uncertainties were also present such as fracture gradients in the basin centre areas (which were used to constrain injection pressure limits). Probability Density Functions (PDFs) of these parameters were constructed from available data and literature, applied to the areas selected for modelling and possible exploration and ranges of steady state, initial injection were constructed.

In the simulations, reservoir drainage and wellbore radii were assumed at 2500 m and 0.1 m, respectively. Bottomhole injection pressure was set at 90% of the assumed reservoir fracture gradient (1 psi/ft).

The results of the analytical assessment of CO2 storage single–well injection rate are summarised in Table 7.1.

Note that the main sensitivity for prediction of well initial (steady state) injectivity is absolute permeability. This is not the permeability derived from core–scale or Wireline formation tester scale measurements. Either, these would have to be integrated using some core–log calibration.
method such as ELAN™ (this leaves residual uncertainty but is generally cheaper). Permeabilities in this formula relate more closely to those derived from production tests across the net reservoir interval.

**TABLE 7.1: SUMMARY OF STORAGE INJECTIVITY ASSESSMENT RESULTS FOR ALL AREAS (MTPA)**

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mean</td>
<td>0.9</td>
<td>0.1</td>
<td>3.5</td>
<td>0.5</td>
<td>0.3</td>
<td></td>
</tr>
<tr>
<td>Mode</td>
<td>0.1</td>
<td>0.01</td>
<td>1.1</td>
<td>0.1</td>
<td>0.02</td>
<td></td>
</tr>
<tr>
<td>Median (P50)</td>
<td>0.5</td>
<td>0.1</td>
<td>2.4</td>
<td>0.4</td>
<td>0.2</td>
<td></td>
</tr>
<tr>
<td>P90</td>
<td>0.1</td>
<td>0.01</td>
<td>0.8</td>
<td>0.1</td>
<td>0.04</td>
<td></td>
</tr>
</tbody>
</table>

**(Tornado) Impact of top two parameter uncertainties on range of injection**

<table>
<thead>
<tr>
<th></th>
<th>Absolute (bulk) permeability</th>
<th>Thickness</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>72%</td>
<td>42%</td>
</tr>
<tr>
<td></td>
<td>76%</td>
<td>50%</td>
</tr>
<tr>
<td></td>
<td>73%</td>
<td>10%</td>
</tr>
<tr>
<td></td>
<td>64%</td>
<td>17%</td>
</tr>
<tr>
<td></td>
<td>28%</td>
<td>28%</td>
</tr>
</tbody>
</table>

There may be considerable upside in considering deviated or horizontal injection wells in these formations.

It is worth remembering that the critical parameters contributing most to uncertainty in initial injection rate (and well count) estimates are absolute permeability and gross thickness. At present, there are no specific measurements of permeability in the GHG tenements and resolution of formation thickness (area specific seismic and well data and especially well testing) is low. Relative permeabilities may be also an issue. Therefore, the exploration/appraisal program would need to include significant core measurements and experiments and a series of fit-for-purpose well tests to reduce uncertainty.

Parameters contributing most to uncertainty in injection rate decline over time are not assessed in this method, but relate to reservoir heterogeneity and connectivity (far-field barriers). ZeroGen’s experience in the NDT has led it to propose extensive dynamic testing in the initial phases. These will be assessed first by extended well tests and later possibly by 3D seismic or high resolution 2D.

However, taking the large uncertainties into account, none of the tenements can be disqualified on the basis of these results alone.

### 7.4 Deterministic Models for Injectivity

Two types of models were created: radial and sector models. The radial models explore the impact of unknown or undetected flow barriers leading to compartmentalisation and hence rate decline overtime. Essentially, the model can be thought of as a cylindrical container or tank filled
with reservoir rock in which CO₂ is injected in its axis. By varying the size of the container, the influence of compartment size on the injection and storage performance was investigated.

Sector models were also made by extracting from the regional geological model and refined (Figure 6.1). The combined interpretation of these two kinds of models were used to inform the importance of reservoir architecture and of extended well testing in the exploration work program.

In all models, injection of pure CO₂ was simulated with Schlumberger’s ECLIPSE 300™, a compositional code with its CO₂ specific features (CO₂STORE). In all scenarios, CO₂ was injected for 30 years. Injection rate was kept constant at 2 Mtpa unless the pressure built up to the maximum BHP imposed as 90% of the fracture gradient. In that case injection rate diminished to maintain BHP below frac.

### 7.4.1 Radial models

The radial models consisted of a 2D radially symmetric geometry, forming a cylindrical modelling domain (Figure 7.1). The central axis represents the injection well. The properties of this domain (porosity, permeability) were laterally uniform and homogeneous. In the vertical direction, the model was layered, according to an up-scaled well profile. Three ‘type’ well profiles were selected based on selected wells. These Trelinga 1 (an exceptionally good reservoir quality), Moonie–39 (an average reservoir quality) and Overston (a poor reservoir quality). These wells were deemed to represent a range of possible properties that may be encountered when drilling in different places in the basin and not necessarily only specific to those well sites (Figure 7.1).

**FIGURE 7.1: RADIAL MODEL GEOMETRY (ZEROGEN–CSA, 2010C)**

![Lateral Permeability [mD]](image)

The boundary is placed at 5 km or 10 km to mimic a flow barrier. No-flow condition is imposed across all boundaries (top, bottom, lateral).
The models were used to understand the effect of ‘no flow’ barriers placed at 5 km and 10 km from the injection well. This is equivalent to a compartment area of 78.5 km² and 314 km², respectively. This no–flow boundary created a fully contained system as top and bottom were also no–flow boundaries. Once injection began, the pressure increased and the rate of increase depended on permeability, the distance to the barrier and the system compressibility. Results are shown in Figure 7.2 (rate) and Figure 7.3 (pressure).

It is immediately evident that sustained industrial-scale injection rates would not be possible within some scales of bounded compartments, the flow and pressure response to the boundary would be evident in some cases at the early stages of injection—indicating that extended well tests may detect them. In some cases, and highly dependent on distance to boundaries, considerable rates and stored amounts might be achieved, though with a sudden pressure increase and shut–down in injectivity.

In the Overston (LOW) scenario, permeability is relatively poor especially in the Showgrounds Sandstone section (rates less than 20,000 tpa). Injection into the Precipice Sandstone drops from initial rate of 2 Mtpa to less than 0.2 Mtpa, decreasing continuously until injection is stopped at 30 years.

Initial injectivity in the Moonie (MEDIUM) scenario was also less than the target rate at less than 0.9 Mtpa and decreased continuously.

The Trelinga model (HIGH) represents the highest permeability scenario so that initially it is possible to inject 2 Mtpa. In the 5 km closed boundary case, after 5 years, the BHP limit is reached and the well shuts down after about seven years of sustained injection. For a barrier at 10 km injection might be sustainable for circa 28 years.

Figure 7.3 displays the pressure development in the well and at a distance of 5 km from the injection well for the three type models. The rate of increase depends on the distance to the barrier, being significantly higher for the 5 km boundary. In Trelinga, a scenario with greatest mean permeability, the pressure at the well and the pressure at 5 km distance track each other from the start.

It is thought unlikely in an artesian system that a fully closed compartment would be encountered. In the case of compartmentalisation, the field development strategy may be quite complex with timing of additional wells and storage concepts for individual compartments, if they are known. The presence of compartment would lead to a staged drilling, development. The scale and degree of compartmentalisation would determine the well count and phasing required.

Seismic data would be one approach to reducing uncertainty. Well tests would be of great value to assess barriers that may be below seismic resolution or that may have escaped detection for other reasons. The presence of flow barriers potentially has a large impact on development options for CO₂ storage.
FIGURE 7.2: INJECTION RATE THROUGH TIME FOR OVERSTON (A), MOONIE (B) AND TRELINGA (C) FOR ATTEMPTED 2 MTPA AND 3 MTPA
FIGURE 7.3: PRESSURE DEVELOPMENT AT A MONITORING POINT 5KM DISTANT FROM THE WELL FOR OVERSTONE (A), MOONIE (B) AND TRELINGA (C)
7.4.2 Sector models for rate and plume dynamics

No internal fault modelling was included in sector model extracted from the regional model. The lateral boundaries were kept at hydrostatic pressure. This implies that if pressure increases closer to the boundaries, fluids could move through it out of the modelling domain. The heterogeneity of the permeability field would influence CO₂ migration and plume development, as would the geometry or topography of the base of the sealing unit (assumed a no-flow boundary).

In general, several unbounded sector models injecting in the Precipice were able to sustain injection rates of almost 2 Mtpa over 30 years. A model with injection section in Showgrounds Sandstone was only able to maintain an injection rate of 1.2 Mtpa.

Bulk-scale initial injectivity and compartmentalisation or pressure evolution over time were deemed to be the critical injectivity uncertainties to be addressed.

Plume spread and distribution for unbounded sector models were investigated and are shown below for several well scenarios.

QLR2010–1–8

FIGURE 7.4: WE VERTICAL SECTION THROUGH THE PLANE CONTAINING THE INJECTION WELL DISPLAYS CO₂ SATURATION AT 200 YEARS AFTER INJECTION HAS CEASED IN SHOWGROUNDS SANDSTONE IN QLR2010–1–8

6 Nov 2239  J=45

A total amount of 60 Mt was injected in 30 years. Grid size is 500 m x 500 m (except where refined around the well). White cells are inactive (N/G = 0) and represent baffles.
In contrast to the precipice modelling, in this Showgrounds scenario, 41 million tonnes of CO₂ were injected. The permeability in general is less than that in the Precipice Sandstone. This results in a more cylindrical shape of the injection front around the well. Upward migration is less and a large amount of CO₂ remains vertically distributed, limiting the lateral footprint of the plume (Figure 7.4).

**Figure 7.5:** WE VERICAL SECTION THROUGH THE PLANE CONTAINING THE INJECTION WELL DISPLAYS CO₂ SATURATION AT 200 YEARS AFTER INJECTION HAS CEASED IN PRECIPICE SANDSTONE IN QLR2010–1–8

A total amount of 60 Mt was injected in 30 years. Grid size is 500 m x 500 m (except where refined around the well). White cells are inactive (N/G=0) and represent baffles.

In this precipice scenario, the lateral spread of CO₂ injected reflects a higher permeability when compared to the Showgrounds scenario. During injection the CO₂ spreads laterally. After injection stops, the plume practically only migrates upwards through buoyancy, leaving behind a green ‘trail’ of residually (immobile) trapped CO₂ (Figure 7.5).
A total amount of 60 Mt was injected in 30 years. Grid size is 500 m x 500 m (except where refined around the well). White cells are inactive (N/G=0) and represent baffles.

In common with other tenement locations and Precipice scenarios, the CO2 spreads radially (in this case just 4km from the injection site after 200 years - note the vertical exaggeration on Figure 7.6). After injection stops buoyancy drives the plume and residual trapping progressively reduces the migrating volume.
A total amount of 60 Mt was injected in 30 years. Grid size is 500 m x 500 m (except where refined around the well). White cells are inactive (N/G=0) and represent baffles.

Heterogeneity impacts rate, rate decline (pressure dissipation) and plume dynamics.

It is apparent that the distribution and extent of baffles (intra-formational sealing bodies defined by N/G=0 in the static model) strongly affects the plume geometry. In the models, CO2 spreads laterally during injection. After injection stops, in a low dip environment, CO2 only migrates upwards through buoyancy or not at all, leaving behind a green ‘trail’ of residually (immobile) trapped CO2 (Figure 7.7). Instead of ponding directly underneath the seal, CO2 may also accumulate into smaller-scale zones underneath each baffle. At 200 years after cessation of injection, the model showed these zones as red high saturation zones. The green represents CO2 at residual saturation (30%). The result of these heterogeneities was that little CO2 actually reached the seal compared to the total injected amount. Baffles are important impediments to vertical migration. These baffles also delayed the arrival of larger amounts of CO2 at the seal and a reduction in maximum pressure was also seen. The impact of vertical and lateral heterogeneity can have a major impact on pressures experienced by the main seal. While they may not be mappable. Vertical pressure transmission might be measured by interference tests.
Good seismic resolution, core analysis and studies to illuminate the depositional environments would contribute to reveal heterogeneity patterns. But it is important to note that many of these features might be below seismic resolution and that baffles may go undetected without well designed well tests.

7.5 Implications for Well Counts During Development

The injectivity rates described above account for single well estimates of either initial well injection rates (probabilistic, analytical method) or initial rates plus long–term rate decline (single well models). Based on these assessments, ‘typical’ well injection performance can be constructed using an (over) simple injection performance ‘type curve’ of the form:

\[ I(t) = I_0 e^{-at} \]

where injection in a type–well at time \( t \) can be simulated from a probability distribution function for well initials ‘\( I_0 \)’ and decline parameter ‘\( a \)’.

Ranges of ‘\( I_0 \)’ can be determined from models and probabilistic assessments (Subsection 7.4 ‘Radial Models’) and ‘\( a \)’ from simple single well models with different boundary conditions. This in turn can be used as a rough estimate for the ranges of well numbers needed in a potential development.

Using this methodology, a simplified Monte Carlo simulation of well initial and decline parameters was performed for the Precipice Sandstone Reservoir.

A drilling sequence related to simulated well performance was then generated. This was designed to ensure that injection rates were maintained through the project life. The simulation compensates for high decline in injection rates with an increased well count. The resultant well count distribution is shown in Figure 7.8 below.

Given the paucity of dynamic data in the core tenement areas, the range of outcomes estimated in this simulation is probably too limited.

However, for the purposes of selecting a simple, mid–case scenario an assumption of 13 injection wells was used to create a notional development. This would comprise three wells possibly drilled as keepers in the E&A phase and a further 10 during subsequent drilling phases. For this scenario, the drilling of one to two wells every four or so years would be required to manage decline rates due to reservoir pressure increases.

Note that these results reflect a single vertical well injection scenario, with no well engineering optimisation—this could be significant. Generally, though single, vertical well injectivity was lower than total required rates of 2–3 Mtpa.

Multiple wells would likely be required; the number depends heavily on the connectivity and heterogeneity of the reservoir. It is essential to discover this information as soon as possible in the program—hence, the early program included extensive dynamic testing at more than one site.
Figure 7.8: Monte Carlo Simulation of Well Count for a Possible Precipice Storage Development Considering a Simple Average Type–Well Decline Curve

Cumulative probability

Well count

Number of Precipice wells to Sustain 2 min TPA for 30 years

> 0

Certainty: 98.74%

< 100

P10 = 42

P50 = 13

P90 = 6
8 Resource Assessment—Capacity

8.1 Context

Absent significant dynamic test data, static derivation of capacity was undertaken. The evaluations discussed herein refer mainly to static estimates of ‘corrected pore space’.

8.2 Lessons Learnt

Only 40% of the gazetted areas represent less complex areas for development i.e. without major overlapping resource issues and allowing for separation margins from environmentally sensitive areas and tenement boundaries.

Static–based capacity calculations may have limited benefit in informing dynamic ‘practical capacity’ but the causes of discrepancies between the two may be less severe in the Precipice Reservoirs.

Individual tenements have un–risked, P50 static capacities of the order of that required by the ZeroGen Project.

Across the available Surat tenements and plays there is an un–risked, P50 static capacity of the order of 400 million tonnes. Significant upside exists in each area evaluated and contiguous areas were not fully accounted for.

While individual sectors in single tenements are of the right order of magnitude, but holding just one of these would provide insufficient ‘risk coverage’.

Access to multiple, adjacent tenements would be required to increase the chances of licensing adequate storage.

The main uncertainty is the rate at which the pore space can be accessed and the well count and spacing required to manage injection below critical restraining pressures. A further uncertainty remains about the precise direction of plume spread, which in the very low dip areas selected would be dominated by depositional facies. Reservoir heterogeneity and compartmentalisation are thus key uncertainties which any exploration program would need to assess.

While based only on desktop analyses, even given the exclusion from that analysis of large areas of the basin, the chances of developing storage for a ZeroGen Project which would satisfy the three level decision test (Chapter 3, Part A, Subsection 2.3.1 and Part B, Table 9.5), were considered to be significantly better than in the Northern Denison Trough Tenements.
8.3 Probabilistic Evaluation of Capacity

Storage capacity in this method was evaluated by accounting for the changes in fluid distribution in the pores of the reservoir rock as a result of formation fluid displacement by CO₂ injection. The aim of such a calculation was primarily to quantify which parameters have the most impact on capacity uncertainty and hence develop a data acquisition plan accordingly.

Capacity estimates derived volumetrically from the estimation of pore space available for CO₂ storage. In contrast to injectivity assessments, these capacities relate to regions or areas and not to single wells (ZeroGen–CSAb, 2010).

Pore volume was then translated into CO₂ mass using CO₂ density evaluated at reservoir conditions. The mathematical expression used to compute the CO₂ storage capacity is given as follows:

\[
m_{\text{CO}_2} = \phi A h_{\text{gross}} (NTG) \phi_{\text{total}} \frac{\phi_{\text{effective}}}{\phi_{\text{total}}} (1-S_{wr}) \rho_{\text{CO}_2} E_{\text{storage}}
\]

- \( m_{\text{CO}_2} \): CO₂ mass (kg)
- \( A \): Area Suitable for CO₂ injection (m²)
- \( h_{\text{gross}} \): Gross thickness (m)
- \( NTG \): Net to gross thickness ratio (dimensionless)
- \( \phi_{\text{total}} \): Total porosity (dimensionless)
- \( \phi_{\text{effective}} \): Effective porosity (dimensionless)
- \( S_{wr} \): Irreducible water saturation (dimensionless)
- \( \rho_{\text{CO}_2} \): In–situ CO₂ density (kg/m³)
- \( E_{\text{storage}} \): Storage efficiency (dimensionless)

The gross thickness multiplied by the net–to–gross ratio is the portion of reservoir thickness that is potentially available to fluid flow. Total porosity is the ratio of pore volume to rock bulk volume. Effective porosity was estimated as the volume of interconnected pores. Irreducible water saturation was an estimate of the volume of water trapped in the pores by capillary action that would not be available for CO₂ storage. Storage efficiency was a correction factor introduced to the equation to account for the fact that a fraction of the pore volume may not be accessible to CO₂ flow due to various reasons. It combines the effects of reservoir heterogeneity, sweep efficiency, fluid flow hysteresis, and gravity segregation.

Area specific (driven by regional models and available data) Probability Density Functions (PDFs) were defined for the parameters of the equation. The ranges were selected to reflect the uncertainty of individual parameters or the natural variation of reservoir properties. Significant effort was required to derive these data distributions (ibid).

The calculation is in general most sensitive to the range of area (A) over which capacity was calculated. In this case, the area defined for CO₂ storage was based on a reduction from the gazetted tenement area as follows:

1. Active Petroleum Lease areas were removed from consideration to be consistent with the strategy of avoiding resource conflicts.
2. Proximity to legacy wells or potential leakage features such as faults were used to further reduce the area i.e. assuming any future development would seek to avoid emplacing a plume in these areas. A ‘no plume’ skirt of around 4 km was included.
3. A ‘no plume’ margin of around 6 km around the tenement boundaries was also subtracted.

This methodology typically allowed between 30% and 60% of the tenement areas to be counted in any capacity calculation, depending on the amount over overlapping resource activity.

A review of literature on Storage efficiency (Cavanagh et al. 2010) indicated that

‘the USDOE (2008) determined via Monte Carlo analysis that the realistic range for likely geological settings is between 1% and 4% for a 15–to–85% confidence interval, giving average efficiency of 2.4% for 50% confidence. The range used in regional assessments of storage capacity is typically 0.2% to 4%, while many recent evaluations use 1% or 2% of the pore volume (SCCS, 2009; IEAGHG, 2009)’.

It should be noted that these storage efficiency ranges were derived from application to gross pore volume on a basin–wide scale. This Surat, pre–tenement capacity analysis, however, is based on net pore volume where gross pore volume reductions are applied a priori through net–to–gross thickness ratio, irreducible water saturation, and effective porosity. Generally, the storage efficiency is related to the reference efficiency by the following equation (ZeroGen–CSA, 2010b):

\[
E_s = \frac{E_{s,\text{reference}}}{(NTG)\phi_{\text{effective}}(1 - S_{\text{irr}})} \phi_{\text{total}}
\]

The typical ‘storage efficiency’ value for these assessment was conservatively set at 2.5% and applied only to the reduced total tenement areas (above). Monte Carlo simulation was performed. The outcome of these analyses are given in Table 8.1.

**TABLE 8.1: SUMMARY OF STORAGE CAPACITY ASSESSMENT RESULTS FOR ALL AREAS (MT)**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Formation</strong></td>
<td></td>
<td>Precipice</td>
<td>Showgrounds</td>
<td>Precipice</td>
<td>Precipice</td>
<td>Precipice</td>
</tr>
<tr>
<td>Mean</td>
<td></td>
<td>103</td>
<td>119</td>
<td>55</td>
<td>109</td>
<td>49</td>
</tr>
<tr>
<td>Mode</td>
<td></td>
<td>61</td>
<td>30</td>
<td>43</td>
<td>82</td>
<td>33</td>
</tr>
<tr>
<td><strong>Median (P50)</strong></td>
<td></td>
<td>87</td>
<td>80</td>
<td>50</td>
<td>100</td>
<td>44</td>
</tr>
<tr>
<td>P90</td>
<td></td>
<td>34</td>
<td>22</td>
<td>25</td>
<td>43</td>
<td>15</td>
</tr>
<tr>
<td>(Tornado) Impact of top three parameter uncertainties on range of injection</td>
<td>Gross thickness</td>
<td>65%</td>
<td>83%</td>
<td>28%</td>
<td>51%</td>
<td>67%</td>
</tr>
<tr>
<td></td>
<td>Net to gross</td>
<td>12%</td>
<td>8%</td>
<td>32%</td>
<td>15%</td>
<td>11%</td>
</tr>
<tr>
<td></td>
<td>Storage efficiency</td>
<td>10%</td>
<td>5%</td>
<td>18%</td>
<td>14%</td>
<td>10%</td>
</tr>
</tbody>
</table>
Generally, these probabilistic estimates of capacity indicate that assuming enough tenements can be accessed for exploration (to allow for failures), there may be little capacity constraint on ZeroGen’s requirements (60 to 90 million tonnes). Furthermore, there is significant upside and a Hub development could have been possible. Figure 8.1 shows the statistical addition of the above tenement capacity ranges.

The total un–risked, storage volume from the main areas of the portfolio was around 400 mln t (396 million tonnes in Figure 8.1). This was the capacity which the full work program would be exposed to. Note that it is the sum over prioritised contiguous areas, allowing for Precipice (and Showgrounds in Tenement 1–8) volumes only.

- There may also be a considerable upside to these estimates. For example, the estimates above do not include additional potential storage formations such as Moolayember, Clematis, and Boxvale units.

**FIGURE 8.1: PROBABILISTIC, COMBINED CAPACITY ESTIMATE FOR ZEROGEN’S PROPOSED TENEMENTS**

A comparison of storage resources (or ‘reserves’) from static calculations was included in the NDT sections of this volume (Chapter 3, Part A, Subsection 10). Practical capacities, which need to match CO₂ supply rates, may have little relation to static calculations.

Static calculations are of most use in ranking areas rather than storage accounting—dynamic data are required to increase confidence.
However, evidence suggests that Precipice Reservoir (core–log derived k.h) is an order or magnitude (or more) better than NDT geology. The very small–scale, extreme heterogeneity and short radius boundaries present in the NDT are less likely to be present in the Precipice. Therefore causes of difference between static capacity calculations and dynamic, practical capacity may be less severe.

Notwithstanding this, the main uncertainty remaining (other than extrapolation away from well control) was on the time dependency of pressure evolution in the injection formations. Underlying uncertainties in predicting this relate to reservoir deposition and flow architecture and hence the associated sweep efficiency.
9 Exploration and Appraisal Strategy

9.1 Context

An exploration strategy was required which would give, a–priori, based on desk–top evaluations—a high level of confidence that at least one potential storage site could be matured to development.

The aim of this chapter is to highlight some key discussions towards the formation of such a strategy which would drive an exploration work program.

9.2 Lessons Learnt

The funding environment and competitive bid process (for an integrated storage and power project) which was demanded by the Commonwealth CCS Flagship Program did not allow a coherent exploration strategy to be formed. It was not possible to establish capital limits, trade–offs between cost, schedule and risk nor funders’ risk tolerance.

The parameters set as part of the Flagships process caused deployment risk through the imposition of a 2015 time–frame which would have demanded significant investment in plant while basic exploration was in progress. It is the equivalent of starting to develop a gas-fired power station before any gas is discovered.

Interaction between a State–level competitive process for GHG Tenements and the Federal–level competition for funding, meant that the submission for one were contingent on the success of the other.

While such projects are publically funded, absent any commercial drivers for storage exploration, it might be more appropriate for governments to obtain key data prior to establishing whether integrated developments programs are feasible. It should be noted however that the nature of exploration and appraisal works required are considerably more than those traditionally undertaken in a ‘pre–competitive’ exploration setting e.g. by State geological surveys.

Access to a risk–diverse portfolio of possible storage sites and commitment to a potentially large exploration program is essential if high confidence limits are required—there are many reasons that individual areas may prove unsuitable.

In a Queensland context, there are significant common risks across the entire set of GHG Tenements. The most significant of these is probably the presence of the Great Artesian Basin. This risk is both technical (containment and isolation) and socio–political. However, it is uncertainty as to its physical properties which need to be reduced before risks can even properly be evaluated.

Significant reductions in project risk can be obtained by careful focus of exploration locations away from natural, environmental and developmental (leases) risk features.
It is critical to map which geotechnical uncertainties are critical to resource maturation and to define a program which obtains ‘killer’ data—rather than to incrementally ‘prove up’ a resource.

9.2.1 NDT lessons transferred

**Portfolio Risk Management:** More than one geologic and geographic option would be needed in the exploration program. The portfolio of options should not be exposed to common over-riding risks.

**Containment assurance data would be the first and highest priority**: 
- core data are essential, MCIP and CO₂ ‘CIP’ data are key;
- Extended Leak Off Tests (XLOT) data are essential (but operationally difficult to acquire);
- image logs are required for fracture characterisation and require integration with diverse data sets;
- geomechanical modelling is critical—significant extra seismic might be needed;
- Vertical Interference Tests might be needed over the whole (bulk) seal interval; and
- monitoring overlying aquifers would need to remain an ongoing focus throughout the campaign.

**Achieving sustained injectivity drives unit development costs:**
- long–term, dynamic (e.g. production) tests would be required to predict confidently injection rates overtime and detect reservoir boundaries;
- CO₂ relative permeability data is critical and difficult to acquire and measure. In–situ measurements were to be attempted as well as lab results; and
- additional borehole stability related data are required to assure long–term well integrity and for sustained flow assurance. These should be acquired as soon as possible and require special CO₂ exposure tests.

9.3 Strategic Framing

Ordinarily strategic analysis for an exploration and appraisal campaign would start by looking at key constraints which would govern a strategy, such as:
- what is the capital availability (cap) and possible phasing;
  - what are the available ‘funds at risk’?
  - how much can be invested and ‘lost’—what is risk tolerance of investors?
- what is the relative strength of strategic drivers (Figure 9.1);
  - can trade–offs be made between storage confidence, cost and schedule?
  - what is the relative merit of say a one to two year acceleration, against which to judge more costly parallel, contingent or possibly redundant activities?

---

6 Note that this was reasonably well assured early in the process for the NDT and focus transferred to injectivity risks, however, that early risk assessment work was critical.
However, in the context of a competitive tender for GHG Tenements, the exploration funds for which would be contingent on a separate competitive tender for CCS Flagships Program funding, such simple constraints could not be defined.

The Flagships process required high confidence and hence a large number of plays and tenements, however, access to these was via a separate competitive process and hence could not be guaranteed.

Consequently, work programs were constructed without clarity on ultimate financial constraints, nor on the number of tenements which would be accessed. Such ‘bottoms up’ programs would likely require modification once funders and other stakeholders would make their capital limits, risk tolerance and constraints better known.

**FIGURE 9.1: ILLUSTRATION TRADE–OFFS IN EXPLORATION STRATEGY**

While constraints were not clear, several guiding principles had to be articulated to guide the strategic process and limit the range of possible work programs. A summary of discussions is shown in Table 9.2.
9.4 Strategy Formation

With a ‘blank sheet’ and no clear financial constraints and no tenements, the following questions in Table 9.1 were framed and investigated.

**TABLE 9.1: KEY QUESTIONS DRIVING ZEROGEN’S E&A STRATEGY**

<table>
<thead>
<tr>
<th>No.</th>
<th>Questions shaping ZeroGen’s forward storage program</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>How many and which tenements are required for confidence in delivering at least one site with adequate size and rate potential?</td>
</tr>
<tr>
<td>2</td>
<td>Within these tenements, where are the main and initial focus areas which could:</td>
</tr>
<tr>
<td>2a</td>
<td>Be matured soonest—to fit flagship timelines?</td>
</tr>
<tr>
<td>2b</td>
<td>Be an expandable solution for a hub in a longer timeframe?</td>
</tr>
<tr>
<td>3</td>
<td>What exploration activities and data are required to best mature (or quickly kill) these potential areas’ sites?</td>
</tr>
</tbody>
</table>

To address these required an analysis of risk, geotechnical and other preliminary assessments of storage resource performance were conducted. A discussion on tenement selection and work program design (Questions 1 and 3, Table 9.1) follows.

**TABLE 9.2: EXPLORATION AND APPRAISAL STRATEGY GUIDING PRINCIPLES**

<table>
<thead>
<tr>
<th>Principle</th>
<th>Assumptions</th>
<th>Implications</th>
</tr>
</thead>
</table>
| Storage confidence| It is important to funders and stakeholders at the start of the exploration program to have a very high degree of confidence in finding, appraising and developing at least one or more site. This is required before committing to a storage ‘finding and proving’ program. More importantly, it is required before further investment in IGCC plant which is demanded by the Flagships Program. | • An exploration program was required across more than one Surat option—conventional portfolio statistics—the more options, the more confidence that at least one would work.  
• Tenements were high–graded in areas in which there was more than one independently risked, geologic play.  
• A very comprehensive immediate data gathering program (well and test)—focused on finding out any ‘killer’ negative evidence as soon as possible—was designed.  
• A low cost, contingent option outside the Surat Basin was applied for. This could have been converted to a drilling option if the Surat options proved not to be ‘working’ either from a schedule of containment perspective. |
## Principle Assumptions Implications

<table>
<thead>
<tr>
<th>Principle</th>
<th>Assumptions</th>
<th>Implications</th>
</tr>
</thead>
</table>
| Schedule  | Schedule is the key driver—significant storage ‘proving’ activities are required to enable IGCC final investment decisions in the general Flagships timeline. The proposed program is heavily influenced by Flagships schedule and Exploration Permit four year terms. | • New, initial wells were placed on existing seismic lines (potentially sub-optimally with respect to geological risk or performance) and it was intended to drill as soon as possible, was preferred.  
• All new wells were placed well outside the main Coal Seam Gas plays and other Production Leases.  
• Post-exploration, appraisal planning looked at acquiring seismic with two crews to site appraisal wells.  
• In areas with the highest probability of success exploration wells were drilled such that they could be converted to a ‘keeper’ for monitoring or for CO₂ injection. |
| Cost      | Cost remains an important driver. Funds are limited. However, neither a cap nor a risk tolerance is communicated at this time.                                                                              | • Rigs were not to be mobilised in parallel—a sequential drilling sequence was planned.  
• In some areas with highest seal risk, ‘cheap’ stratigraphic test wells were to be drilled initially to collect seal core samples rather than a more expensive fully tested well (which might be sub-optimally placed).  
• A campaign of drilling was planned (more lessons, less mob costs, better commercial rates).  
• An Early Development Scheme (EDS) was aimed for—appraising a sub-area which might be developed quickest and applying high resolution, appraisal 2D or 3D in a relatively small ‘patch’.  
• Committing only an initial desktop study in the Galilee Basin option in anticipation of a possible later drilling and seismic option.  
• Seeking cost, data and operational synergies with the other operators and programs. |
9.5 Area Risk Discussions for Surat Tenements

The following areas were discounted:

1. areas with reservoir depths <800 m bGL; and
2. areas with overlapping resources in or almost in production (Mining or Production Leases or Lease Applications).

Remaining areas were then further segmented into areas with other common risk factors. Factors discussed in Table 9.3 were applied to allow a differentiation and ranking between segments. As an illustration, an initial area segmentation is shown in Figure 9.3. This was subsequently ranked due to ongoing industry developments.

### TABLE 9.3: TENEMENT AND PLAY SEGMENT SCREENING DISCUSSIONS FOR SEGMENT DIFFERENTIATION

<table>
<thead>
<tr>
<th>Main filter by tenement/segment</th>
<th>Screening and ranking discussions</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Project risk—Diversity</strong></td>
<td>Number of independent geological plays. The Triassic Showgrounds play is present in the West only.</td>
</tr>
<tr>
<td></td>
<td>Complexity of overlapping rights activity (production, applications for production, exploration and an assessment of the chances that exploration permits would be converted).</td>
</tr>
<tr>
<td><strong>Containment risk factors (incl GAB)</strong></td>
<td>The number and depths of legacy wells.</td>
</tr>
<tr>
<td></td>
<td>Seal thickness and quality (estimated net shale/silt).</td>
</tr>
<tr>
<td></td>
<td>Regional seal (presence of ‘nearby’ hydrocarbon columns).</td>
</tr>
<tr>
<td></td>
<td>Relative degree of structuration (e.g. large faults cutting up through the lower Jurassic). Evergreen, faults which might be critically stressed, relative curvature of formations data etc).</td>
</tr>
<tr>
<td></td>
<td>Isolation from other GAB users (distance from extraction bores, distance from Moonie–type faults).</td>
</tr>
<tr>
<td></td>
<td>Structural dip (low dips preferred).</td>
</tr>
<tr>
<td><strong>Injectivity</strong></td>
<td>Reservoir depths (800–1500 m and deeper than 1500 m).</td>
</tr>
<tr>
<td></td>
<td>Indications of ‘initial’ injectivity from existing data (k.h). e.g. whether Precipice was large and ‘blocky’ or thinner channels.</td>
</tr>
<tr>
<td></td>
<td>Relative degree of heterogeneity and/or compartmentalisation (from stratigraphy or structural arguments or production data).</td>
</tr>
</tbody>
</table>
Main filter by tenement/segment | Screening and ranking discussions
--- | ---
Capacity | Areal extent at least sufficient for project needs (see sections on ‘capacity’).
 | Large contiguous area possible (incl. adjacent to unlicensed).
 | Expandable for a future ‘hub’.
Schedule drive (Flagships) | Amount and quality of existing data sufficient to allow initial exploration drilling and testing without the need for new seismic.
 | Degree of local landholder activism and opposition to other developments.

The segmentation and ranking discussion is shown illustratively in Figure 9.2.

**FIGURE 9.2: PROCESS OF PLAY AND AREA EXCLUSION AND SEGMENTATION**
9.6 IGCC and Hub Development Issues and Synergies

At the time of applying for Surat Basin Tenements the location of ZeroGen’s proposed IGCC plant was fixed only due to the CCS Flagships qualifying schedule criteria. However, ZeroGen recommended a relaxation to the schedule criteria to allow for additional site assessments in the Surat area.

While, the approach to storage site exploration, was primarily driven by geotechnical issues (risk and performance) and then by development risk, specifically in the form of avoidance of overlapping resource issues (schedule and ‘doability’), possible IGCC locations were also considered. Figure 9.3, shows the location of the Surat GHG Tenements and initial focus (NW, NE and SE) and the locations of significant infrastructure which could impact project, plant site choice and considerations about a future hub.

All else being equal, the best initial storage hub site with least infrastructure and synergy risk would be in the SE tenements. Existing coal and power infrastructure is in place and CSG developments might even alleviate water supply problems. Further site study work was required. However, the lowest geological risk, in the remaining areas, may be in the NW Surat (Tenement 1–8) where two independent plays may exist, including one underneath the Jurassic sediments of the Great Artesian Basin.

The initial exploration work program was to take place across three main areas:

- the NW, Tenement 1–8, where there may be two co-located plays and geological risk may be lowest (and in areas away from CSG Leases);
- the NE, the Southern-most part of tenement 1–9, again in areas well south of Mining or CSG Leases, where there may be only one play, but the Precipice is likely to be of highest quality; and
- the SE where an IGCC might be well situated and with a very large contiguous area which might become an initial hub development with respect to other infrastructure and other large emitters; but, seal prediction and local CSG and other developmental issues may be problematic.

No one storage site could be selected with confidence at this time. The initial activity set was chosen to balance the demands of portfolio risk management, expediency and to a lesser extent development synergies.
Note: Shown with current major CO₂ emitters (source: National Carbon Mapping and Infrastructure Plan—Australia, 2010).
### 9.7 Surat High Level Risks and Critical Issues

Table 9.4 below summarises high level risks and critical issues relating to storage.

<table>
<thead>
<tr>
<th>Risk/issue</th>
<th>Narrative</th>
<th>Preliminary rating</th>
<th>Mitigation</th>
</tr>
</thead>
</table>
| Containment uncertainty and risk  | Containment assurance, either vertical or lateral, not possible to demonstrate to required confidence levels at this stage due to scarcity of data.                                                            | Critical           | • Initial work program data and comprehensive tests.  
• Heavy focus on overlying GAB aquifers (below).                                                                                                                                                           |
| Great Artesian Basin              | Multiple usage of resources to be sustainably managed under Water Resource (GAB) Act. Possible socio-political sensitivities. Delays and complex EIS process.  
However, 92% of available storage in QLD is thought to be in the GAB. More data and investigations are needed to establish whether (or not) this storage (i) exists and (ii) can be securely developed. | Critical           | • Baseline data (pressures and compositions in deep basin).  
• Zonal isolation.  
• Technical study of seal qualities and zonal isolation.  
• Engagement with regulator and stakeholders.  
• Early engagement on EIS requirements.  
• Open, transparent analysis and independent verification.                                                                                                                                                 |
| Overlapping and nearby resource   | The GHG Act allows for coordination agreements—other parties can delay award of permits and leases and schedule of operations program.                                                                      | Very serious        | • Focus if possible away from other resource users.                                                                                                                                                       |
| scale                             |                                                                                                                                                                                                           |                    |                                                                                                                                                                                                          |
| Portfolio scale                   | The proposed portfolio scale is critical to confidence in ultimate storage developments at this stage. This requires commitment to a significant initial work program. Failure to access or fund the whole initial program is equivalent to accepting more risk, lower confidence. | Significant        | • Clarify the overall portfolio strategy.  
• Apply a ‘rapid kill’ test approach.  
• Apply for tenements and funding through Flagships PFS.                                                                                                                                                 |
### TABLE 9.4: SUMMARY OF RISKS AND CRITICAL ISSUES FOR DEVELOPING FLAGSHIP STORAGE (CONT.)

<table>
<thead>
<tr>
<th>Risk/issue</th>
<th>Narrative</th>
<th>Preliminary rating</th>
<th>Mitigation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Integration of schedule</td>
<td>IGCC plant site decision, storage land access, pipeline routing and EIS (especially on storage) all give rise to schedule risk.</td>
<td>Significant</td>
<td>• Rapid new site appraisals. • Immediate environmental baseline surveys. • Multiple corridor studies.</td>
</tr>
<tr>
<td>CCS complex project landscape</td>
<td>Multiple immature projects seeking same funding under Flagship program. Possible division of funds and/or loss of portfolio scale and cost effectiveness.</td>
<td>Significant</td>
<td>• Propose a single, multi-user Hub project. Seek collaboration. Engage with State Geological Survey.</td>
</tr>
</tbody>
</table>

### 9.7.1 A reality check on expected ultimate success rates

In contrast with petroleum exploration projects, there is no calibrated history regarding success rates or project experience (providing cost/schedule risk profiles) on which to base expectations of ultimate success from a carbon storage exploration program. However, some view of success probability would be critical to informing the required portfolio size (question 1, Table 9.1).

In May 2010, MIT’s Carbon Capture and Storage Technologies, CCS Database7, listed 39 ‘active’ projects of a similar scale to ZeroGen. Excluding EOR and EGR projects, of these 12 reasonably scaled, CCS projects in that list, had some form of plan or proposal to sequester significant quantities of CO₂. All were at very early stages of development; mostly less mature than ZeroGen’s NDT option.

More mature projects were also listed. Four ‘dormant’ or restructuring projects (FutureGen, Carson–DF2, Mongstad and Killingholme) and six formally cancelled projects (Kwinana–DF3, Peterhead–DF16, Tilbury, Wallula, SaskPower and Halten/Draugen9). In addition, Monash, Barendrecht10 and ZeroGen’s NDT option might have been added as ‘cancelled’.

There were three, very well known large-scale ‘storage’ projects in operation globally, all related to conventional oil and gas operations:

- Sleipner 1 Mtpa since 1996
- Snøhvit 0.7 Mtpa since 2008
- InSalah 0.8 Mtpa since 2004

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10 Barendrecht: [http://online.wsj.com/article/SB124024483430835389.html](http://online.wsj.com/article/SB124024483430835389.html)
The latter two are relatively recent and had reported unpredicted events with CO₂, ‘early’ breakthrough in monitoring wells and ground heave in InSalah¹¹ and with loss of sustained injection rates, in Snøhvit¹². Even when projects have been developed, there can be considerable residual risk and uncertainty.

ZeroGen was seeking to develop more storage volume and rate than any of the three currently operating projects.

What chance of ultimate success can be assigned at the pre–drill exploration stage? Current global experience indicates a chance factor considerably less than 50%.

9.8 The Three Level Decision Test (for a Surat Portfolio)

The original storage project decision test (Table 9.5) was designed to guide decisions on a single, named, technically mature and specific site in the NDT.

<table>
<thead>
<tr>
<th>Test</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Can 60 M¹ (to 90 M) tonnes be securely stored in the site or sites?</td>
</tr>
<tr>
<td>2</td>
<td>Can 2 M (to 3 M) tpa be sustained for 30 years in the site or sites?</td>
</tr>
<tr>
<td>3</td>
<td>Is the P50, full life–cycle, unit cost of transport and storage less than $50/t (P75 for FID)?</td>
</tr>
</tbody>
</table>

¹ Note that for 3 mln tpa this is over 80 mln tpa. The tests are usually referenced at 2 mln tpa for simplicity.

While less evident in the evaluation of a mature area such as the NDT, it is important to recognise that the decision tests are impacted by both risk and uncertainty. For example:

- **Risk** The chance that a site simply cannot (or cannot be proven to a very high degree of confidence to) store securely—or, that sustained, rate matched injection simply cannot be achieved.

- **Uncertainty** Once storage security is assured (de–risked), the range of storage capacities possible can be expressed as ranges P10, P50, P90, etc. and the underlying causes of the uncertainty defined and mitigated—and likewise for injectivity uncertainty.

In the case of the NDT, it was established early on that containment risk was relatively low risk and therefore there was *some* secure storage to be further assessed. Hence the early focus was on understanding confidence levels (uncertainty ranges) in capacity and injectivity.

¹¹ Technical surprises at InSalah [www.co2captureandstorage.info/EA%20June%202013%20In%20Salah%20Kevin%20Dodds.pdf](http://www.co2captureandstorage.info/EA%20June%202013%20In%20Salah%20Kevin%20Dodds.pdf)

However, the test required modification to be applied across a portfolio and appraisal and development scenarios where those evaluations were based on desktop studies, pre-award. In particular the framing of these tests became:

‘Is there a high level of a-priori, confidence that given the high-graded set of areas/tenements and the proposed initial exploration spend that secure, contained, developable storage of at least 60–90 mln t, at 2–3 mln tpa, may be matured to a P50 level of confidence at $50/t — in at least one site?’

9.8.1 Test 1—Capacity

With respect to the first test (secure capacity); ‘security’ required that seal retention pressures (fracture propagation, capillary entry and fault reactivation) would all need to be measured and their uncertainty bounds established. In addition, improved geological lateral prediction confidence would be required. If injection pressures could be managed to within 90% of the lowest of these values while maintaining acceptable rates (and if worse case lateral migration could be shown to be contained within tenement bounds) then containment would be deemed to be secure.

Capacity was re-framed in terms of risked or expectation capacities and the number of potential sites in a portfolio set.

For each contiguous initial focus area, un-risked probabilistic volumetrics (capacities) were evaluated. These were compared with required storage volumes to determine sufficiency. Then, sensitivity to subjective, a-priori, perceived risks to ultimate development were investigated.

In essence, if the sum of risked (expectation) capacities from the portfolio were greater than the required project capacity, there was greater confidence that the portfolio might deliver the required storage (Test 1, Table 9.5).

After evaluation, the total risked capacity (chance of success x P50 success capacity) of the set of sites and tenements was greater than the 60–90 million tonne requirement—and the P50, unrisked capacities of individual prospect sites were similar to that requirement with significant upside.

However, because, there was a discrete risk of ‘failure’ for individual sites, confidence also needed to be gained that there is a sufficient number of sites which would be available. This was investigated simplistically using binomial statistics.

Notwithstanding common or systemic risks, assuming an individual chance of success for any pre-award site of say 50% to 30%, then access to between, three and seven potential sites would be required for a 90% level of confidence that at least one might be matured from the set.

9.8.2 Test 2—Sustained injectivity

Ranges of instantaneous injection rates were derived from available well logs, DST and gross-regional models. Pressure increase or decline ranges were also derived from available data, heterogeneity scenarios from regional modelling and boundary condition scenarios. Based on this scoping it was considered likely that sustained injection rates of two Mtpa could be achieved (to a P50 level of confidence) with between six and 42 wells.
In general, single well initial injectivities were modelled to be lower than total required rates of two to three Mtpa. The range per well was large from 100,000 tpa (280 tpd) to over 2 Mtpa (5400 tpd—unconstrained model). Reservoir connectivity (Precipice) was thought to be better than in the Bowen Basin Formations (largely anecdotal evidence of aquifer support in producing fields), however additional data would be required to confirm this as the main economic parameter.

9.8.3 Test 3—Unit costs

Unit cost estimations required multiple and sequential assumptions (Figure 9.4) and were thus not robust. Investigations simply addressed whether within the range of scenarios, there were reasonable possibilities which could be developed for less than $50/t.

To evaluate this, the following compound assumptions had to be made:

- the results of the Initial exploration campaign;
- the subsequent required scope of a later appraisal program;
- the results of the later campaign and subsequent required scope of the development; and
- the locations of the final development and of the IGCC plant.

The very large uncertainties in ultimate project configuration (well count and pipeline length) dominated uncertainties in specific engineering (unit development) costs. The main approach to managing this uncertainty would have been to stage gate the investment, reassessing these costs after the initial and later exploration and appraisal programs.

Notwithstanding this, for reasonable intra–Surat success scenarios, unit costs of carbon transport and storage were $33/t, with $53/t for an Ensham (NDT) plant to north Surat storage scenario.

Within the Surat there is a wide range of location options and hence pipeline lengths. For example, given a development well count of 13 and a 65 km pipeline, unit costs could be of the order of $24/t.

9.9 Summary

There were geotechnical as well as developmental and environmental risks some or all of which could negate the chances of a successful development. If individual areas are considered to have an independent chance factor of say, 30–50%, then a portfolio of three to seven might be adequate (to generate confidence). However, the GHG tenement areas are not independent and contain common risks i.e. significant potential constraints to timely exploitation of storage resources due to (i) overlapping rights of other resource holders and (ii) the GAB.

The former can be avoided, albeit by moving to deeper parts of the basin. Such ‘avoidance’ would mean accepting probably decreased reservoir performance and likely a relative improvement in basic seal retention properties. However, the latter issue cannot be avoided and only by careful site selection and intensive characterisation of the lower parts of the GAB, can the risks be evaluated.

13 These unit costs are present value, full life–cycle, post exploration costs equivalent to a pre–tax, break–even carbon price for carbon transported and stored (not avoided).
There was good evidence that the main Precipice play is sealed locally and some evidence that it is sealed regionally, though this is weak. Therefore initial efforts would have to focus on establishing seal retention pressures and predicting vertical transmission of pressure.

There were reasonable scenarios in which 2–3 Mtpa could be sustained and unit costs could be below $50/t.

**FIGURE 9.4: EXPLORATION, APPRAISAL AND DEVELOPMENT SCENARIOS**

*Project scenarios (not all 216 branches expanded)*

<table>
<thead>
<tr>
<th>Proposed portfolio</th>
<th>Possible area outcomes</th>
<th>Possible successful play outcomes in that area</th>
<th>Assumed scale of Later Appraisal required to get to development decision</th>
<th>Assumed total number of Development Wells (includes 3 from E&amp;A phase)</th>
<th>Assumed Length of Pipe (location of plant)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Initial Exploration and Appraisal Program</strong></td>
<td><strong>Showgrounds</strong></td>
<td><strong>1x Appraisal Well with Extended Water Production Test and 3D Seismic</strong></td>
<td><strong>HIGH 27 Wells</strong></td>
<td><strong>LONG NDT – Surat 350 – 400km</strong></td>
<td></td>
</tr>
<tr>
<td>3–6 Initial Areas/Plays</td>
<td><strong>Precipice</strong></td>
<td><strong>2x Appraisal Wells + Extended Production Test + LT CO2 Test + 3D Seismic</strong></td>
<td><strong>MEDIUM 13 Wells</strong></td>
<td><strong>MEDIUM Cross – Surat (W–E) 90km</strong></td>
<td></td>
</tr>
<tr>
<td>4–6 Tenements</td>
<td><strong>Showground and Precipice</strong></td>
<td><strong>Larger Appraisal Program? More Wells and Testing</strong></td>
<td><strong>LOW 8 Wells</strong></td>
<td><strong>SHORT Near Plant 30km</strong></td>
<td></td>
</tr>
<tr>
<td>3x Fully Tested Wells</td>
<td><strong>More Than One Selected For Appraisal</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2x Aquifer Wells</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4x Stratigraphic Core Wells</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Seismic Data</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>All Plays Fail</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Go To Galilee</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>One Area Selected For Further Appraisal</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Go To Galilee</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Storage Return To Other Surat Area Or Go To Galilee</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**P50**

**P75**

**Exploration Permit**

- EIS proper: From mid 2011 and Jan 2012
- 3 wells ready, all wells possibly by 2015

**Storage Lease**

- EIS prep from Oct 2010
- EIS proper (CTS): Start between Q3/11 and Q1/12 (+2Years)
- Pipeline construct starts at EIS approvals

*Note: Highlighting (i) a mid–case, Precipice, single area, two well plus 3D follow up appraisal, and (ii) three possible well count outcomes and three possible pipeline length outcomes.*
10 Exploration Work Program

The purpose of this section is simply to present an example of a multi-tenement, GHG exploration and appraisal program. Since the program was not undertaken, there are no ‘lessons learnt’ as for the other chapters. Costs (2010 basis) are included and a list of the various geotechnical work-program elements.

10.1 Program Build Principles

The program was constructed with the following principles:

a. obtain rights for enough tenements for portfolio confidence;

b. acquire killer and common-risk data first, focusing on the most prospective tenements, as currently viewed. This required the following:
   1. data to establish baseline pressure and composition of the lower Jurassic GAB Formations;
   2. data to investigate the integrity of the Evergreen seal and the pressures it would experience during injection; and, analyses to improve confidence in the lateral prediction of seal quality; and
   3. data required to evaluate time-dependent pressure evolution in the reservoir and data required to improve lateral prediction of this parameter.

c. program flexibility such that funds could be diverted from exploration in other tenements to appraisal of success in the earliest exploration programs.

10.2 Outline Work Program

A work program for tenement applications was constructed in two parts an ‘initial’ or exploration work program in line with principles a. to c., above. This would be followed, contingent on ‘success’ at any one site, by a ‘later’, follow-up appraisal program which would be site focused.

An initial exploration work program could require up to $71.6 million (Table 10.1) over 12–24 months (assuming all tenements applied for were awarded) and would include:

- up to 5420 km of reprocessing and re-interpretation of existing seismic lines;
- up to 1800 km of modern 2D seismic acquisition and interpretation;
- up to three conventional oil and gas exploration wells (in different tenements); one of these to a maximum depth of 2700 m (to also test the Showgrounds play), the others to around 2100 m;
- multi-level, dynamic flow tests would be carried out for the three exploration wells including production testing (water) and very short-term CO2 injection testing;
- up to three aquifer monitoring wells drilled to a depth of approximately 1500 m (to above the main cap-rock) and co-located with the conventional exploration wells;
vertical interference tests across the potential Evergreen cap–rock using the conventional and aquifer well pair;

up to three stratigraphic wells to be drilled, cored, logged, and sampled to determine reservoir and seal properties and characteristics in areas of least data coverage;

a large number of geological and geophysical studies undertaken over two years to define the storage potential and prospectivity of the targeted areas of interest;

environmental and ecosystem studies including atmospheric baseline studies; and

engineering scoping studies (wells, facilities and pipelines).

### TABLE 10.1: COST ESTIMATES FOR THE INITIAL EXPLORATION WORK PROGRAM (PER YEAR)

<table>
<thead>
<tr>
<th>Exploration (initial work program)</th>
<th>Total across all tenements</th>
<th>Year 1</th>
<th>Year 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>3 E&amp;A wells drill and tested</td>
<td>$24,000,000</td>
<td>$7,200,000</td>
<td>$16,800,000</td>
</tr>
<tr>
<td>3 x Aquifer monitoring wells and VIT</td>
<td>$6,900,000</td>
<td>$700,000</td>
<td>$6,200,000</td>
</tr>
<tr>
<td>3 x Stratigraphic Delineation wells</td>
<td>$11,400,000</td>
<td>$1,100,000</td>
<td>$10,300,000</td>
</tr>
<tr>
<td>Seismic—reprocessing</td>
<td>$1,200,000</td>
<td>$900,000</td>
<td>$300,000</td>
</tr>
<tr>
<td>Seismic—acquisition (2D)</td>
<td>$15,500,000</td>
<td>$1,500,000</td>
<td>$14,000,000</td>
</tr>
<tr>
<td>M&amp;V tests (VSP)</td>
<td>$600,000</td>
<td>$–</td>
<td>$600,000</td>
</tr>
<tr>
<td>Very short term injection equipment</td>
<td>$2,300,000</td>
<td>$200,000</td>
<td>$2,100,000</td>
</tr>
<tr>
<td>G&amp;G&amp;Env. studies</td>
<td>$6,300,000</td>
<td>$4,300,000</td>
<td>$2,000,000</td>
</tr>
<tr>
<td>Project management and support</td>
<td>$3,400,000</td>
<td>$2,200,000</td>
<td>$1,200,000</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$71,600,000</strong></td>
<td><strong>$18,100,000</strong></td>
<td><strong>$53,500,000</strong></td>
</tr>
</tbody>
</table>

The details of a ‘later’ appraisal work program would depend on the results from the above exploration program. A nominal, contingent program was created which would require approximately $70 million (Table 10.2), again over approximately 24 months. This would include:

- drilling up to two offset appraisal wells but designed as ‘keeper’ wells for later CO₂ injection (in areas of highest PoS). The decision to drill, potentially more expensive keeper wells was also influenced by the demands of the Flagships 2015 operational date;

- further dynamic flow tests commencing with water production (interference) test and again very short–term, low rate CO₂ injection tests;
  - a possible longer–term CO₂ test was included in notional plans and budgets though most if not all reducible uncertainties might be addressed without it.

- up to two further aquifer monitoring wells;

- further vertical interference tests to assess seal containment of the Upper Evergreen;
baseline monitoring to establish the conditions at the selected appraisal site;
• allowance for up to 570 km$^2$ of 3D seismic to locate future development injection wells and fully characterise faults; and
• full field development engineering studies including sub–surface, well engineering optimisation and pipeline and facilities feasibility studies.

Community consultation was planned early from the first year and would be performed throughout the duration of the exploration permit (to year four), although with varying intensity. Costs are included in project management and EIS costs.

### TABLE 10.2: COST ESTIMATES FOR NOTIONAL LATER APPRAISAL WORK PROGRAM

<table>
<thead>
<tr>
<th>Appraisal (later work program)</th>
<th>Successful tenement</th>
</tr>
</thead>
<tbody>
<tr>
<td>2 x Appraisal offset wells drill and tests</td>
<td>$14,800,000</td>
</tr>
<tr>
<td>2 x Aquifer monitoring wells and VIT</td>
<td>$7,200,000</td>
</tr>
<tr>
<td>Allowance for 2 x large scale CO$_2$ tests (and facilities)</td>
<td>$20,000,000</td>
</tr>
<tr>
<td>Permanent completion with CRA as possible injectors</td>
<td>$1,600,000</td>
</tr>
<tr>
<td>Site specific 3D Seismic acquisition</td>
<td>$8,700,000</td>
</tr>
<tr>
<td>M&amp;V installations and studies</td>
<td>$2,100,000</td>
</tr>
<tr>
<td>Initial Environmental Impact Statement prep and studies</td>
<td>$4,780,000</td>
</tr>
<tr>
<td>G&amp;G&amp;Env. Field Development studies</td>
<td>$7,700,000</td>
</tr>
<tr>
<td>Project management and support</td>
<td>$3,120,000</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$70,000,000</strong></td>
</tr>
</tbody>
</table>

Below is the estimated cost for drilling, coring, logging and well and extended production testing for a 2700 m conventional exploration type (Table 10.3).
### TABLE 10.3: SUMMARY OF COST ESTIMATES FOR SURAT TYPE WELLS (DRILLING, TESTING AND COMPLETION COSTS)

<table>
<thead>
<tr>
<th>Summary item</th>
<th>Cost estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Drilling cost summary</strong></td>
<td></td>
</tr>
<tr>
<td>Total depth (if, two plays)</td>
<td>2700 m</td>
</tr>
<tr>
<td>Drilling total days</td>
<td>36 days</td>
</tr>
<tr>
<td>Total cost drilling</td>
<td>$4,900,000</td>
</tr>
<tr>
<td><strong>Extended multi–level testing cost summary</strong></td>
<td></td>
</tr>
<tr>
<td>Total depth</td>
<td>2700 m</td>
</tr>
<tr>
<td>Testing total days</td>
<td>115 days</td>
</tr>
<tr>
<td>Total cost testing</td>
<td>$1,900,000</td>
</tr>
<tr>
<td><strong>Completion cost summary</strong></td>
<td></td>
</tr>
<tr>
<td>Total depth</td>
<td>2700 m</td>
</tr>
<tr>
<td>Completion total days</td>
<td>8.25 days</td>
</tr>
<tr>
<td>Total cost completion</td>
<td>$600,000</td>
</tr>
<tr>
<td><strong>Total well cost estimate</strong></td>
<td><strong>$7,400,000</strong></td>
</tr>
</tbody>
</table>

Stratigraphic well costs were based on use of mineral rig using previous HQ core drilling costs from ZeroGen NDT drilling campaign as a guide but adjusted to include extra well tests. The same principle applies to the cost for the aquifer wells (without coring/logging costs).

Pending results and within a later field development concept, more wells may be drilled, but not as part of this tenement work.

### 10.3 Key Work Program Elements

The following section seek only to highlight and list elements of the required work program and to demonstrate the range of issues which need to be budgeted for.

#### 10.3.1 Logging program

This program would have been more extensive to include part of the overburden.

The suite would include a PEX suite (GR–CAL–Density–Neutron–DLL); FWF sonic; image log (acoustic and/or resistivity image log) and NMR. A PEX suite with FWF sonic would also be run over the surface hole prior to running intermediate casing as density and sonic logs would be required over this interval to calibrate the geomechanical model.
The PEX suite would provide V–shale, porosity, permeability and saturation profiles for the open hole sections and these would be calibrated to the core measurements.

The full wave form sonic log would be processed for shear and used to generate mechanical property logs (Poissons ratio, Youngs Modulus, rock strength).

The image logs would be interpreted for breakouts; fracture analysis (inputs to the geomechanical model) and for palaeo–current indicators (input to the depositional models).

An NMR tool measures the petrophysical properties of rocks and formation fluids using Nuclear–Magnetic Resonance (NMR) imaging technology. Neutron, density and sonic porosities are more sensitive to lithology than to reservoir fluids. Porosity measurements with neutron–density combinations provide an estimate of total porosity, which is all the pore space in the reservoir irrespective of the pores being interconnected or isolated. Furthermore, porosity and resistivity logs provide few clues about other petrophysical information like pore–size, grain–size distribution and permeability.

10.3.2 Rig–based testing programs

Well testing data were practically non–existent in the area and formations of interest of the ZeroGen Project. A new testing program was required to provide transmissivity data and pressure transients as a response. Permeability measurements (horizontal and vertical) throughout the sub–seal stratigraphic column will be conducted.

Open hole DSTs

DST would be used to determine permeability thickness and flow potential at bulk scale and used with core to calibrate for response for future well. Fluid samples would be required, as a minimum from the Hutton and Precipice Sandstones and from Hutton, Precipice and Showgrounds Formations for the deeper wells.

Extended Leak Off Tests (XLOTs)

XLOTs would be performed, using inflatable tools, at depth intervals of potential seals selected from logging data. The objective of XLOTs would be to obtain information on the seal properties and the stress regime.

10.3.3 Off–rig, production/injection dynamic tests

In addition to DSTs, ZeroGen planned to undertake two main types of dynamic tests:

• long–term water production tests; and
• very small–scale, short–term CO₂ injection tests to calibrate in–situ relative permeabilities.

In addition, provision was made in ‘later’ plans to conduct ‘possible’, long–term CO₂ injection tests, principally in the Precipice Formation. These may be required for the calibration of dynamic reservoir models of CO₂ injection and associated pressure increase.
The main dynamic flow tests aimed to:

1. Evaluate dynamic ‘kh’ i.e. the behaviour of in-situ, bulk-scale reservoirs from these tests.
2. Evaluate potential reservoir boundaries within a desired radius of investigation to assess possible rapid decline of injection rate with time which would massively increase required well count.
3. Establish CO₂ initial injection into reservoir sequences (principally the Precipice but also the Showgrounds, Rewan Group and perhaps the Moolayember Formations).

**Long-term production (water) test**

Production (water) tests could be used to investigate reservoir connectivity with lower risk and less ambiguity than water or CO₂ injection tests. The latter are always associated with issues of maintaining supply of injectate, conditioning it to avoid scaling, concerns about fines migration and plugging, concerns about foreign matter from the injection facilities and filtering and so on.

With the addition of an aquifer monitoring well above the Evergreen Formation, the production test was also planned to investigate vertical interference i.e. measure the vertical transmission of pressure across the seal during extended flow tests.

The length of the production test required to test a certain Radius of Investigation (RoI) would be dependent on the permeability. The radius which requires testing is of the order of a few kilometres. Simple models indicated that if boundaries were closed and at less than 5 km radius, then this could have a major impact on rate and well count (Subsection 7.4.1).

To determine the distance seen up to a given test time, a derivative pressure response can then be matched to the minimum circular boundary model that still matches the test response up to any given test time. While the test duration was dependent on permeability it is not in theory dependent on rate. However, there is a minimum rate required to ensure that ‘gauge noise’ is not an issue. Producing at low rates would be preferred to minimise issues with water handling at surface.

Initial, model-derived, produced water quantities were typically estimated to be less than 20,000 bbl which would require production test durations of the order of 20 days for high permeability cases and up to 90 days for lower permeabilities. Each production period would be followed by a number of days of pressure build-up. Wells would be completed so that following build up they continue to measure pressure to add to baseline information and complement the aquifer wells.

**Very short-term testing—a mobile CO₂ injection facility**

The most critical information gained from CO₂ testing would be initial relative permeability effects and calibration of water rates. Virtually all other CO₂-specific issues can first be measured in the lab or are too long a time scale to be field tested.

Therefore, a new mobile permeability testing rig was planned which would allow a direct CO₂ injection assessment of the permeability using a mobile, truck mounted suite of equipment. The concept was to use high pressure CO₂ rated cylinders to be incorporated into part of a downhole tool, consisting of a tandem inflatable packer and downhole controller.
This system would be run into a well and the packers inflated to isolate a specific section of the formation to be tested. Using surface controls, the supercritical CO$_2$ in the cylinders would then be injected using a surface water pump to displace the CO$_2$ into the formation at a constant rate, while pressure was monitored. Using this method a number of zones could be tested during a single trip in the well, providing a vertical distribution of formation CO$_2$ permeability without the need for a rig or permanent completion.

**Fluid sampling and analysis**

Significant efforts would be required to collect representative PVT samples. Some fluid sampling would be performed during DST, though alternative methods may be required. All well designs allowed for sampling using slick–line operations. Extended element analyses were planned on samples of all clean formation water recovered from the well tests.

**10.3.4 Coring and core analysis program**

Extensive coring was planned focusing on both main cap–rock and reservoir in the conventional wells and also the over–burden in the aquifer monitoring and stratigraphic test wells (much of the drilling would be with continuous coring methods).

**Core description.** Full core descriptions would be used to determine predictive factors such as lithology and facies and have been used to influence sub–surface models.

Detailed core logging would be made of all cores. Depositional facies and facies interpretations would be made on the basis of the logged sedimentary structures and grain–size measurements. This information would be combined with the palaeocurrent data derived from the image logs to construct palaeo–environment models. The objective of these models would be to produce laterally predictive models.

**Routine Core Analysis (RCA) program.** Measurements would be taken to calibrate and correlate well logs e.g. core gamma logging and grain density determination. The composition and pore architecture of encountered lithologies would also be obtained by a variety of analyses: thin sections, X–ray diffraction (XRD), Scanning Electron Microscopy (SEM) and specific analysis of clay mineralogy and diagenesis/cements.

A selection of horizontal and vertical core plugs would be taken for measurements of base parameters (grain density; ambient air porosity and permeability). A selection of these plugs would be remeasured under stressed conditions (overburden pressure) to provide in–situ porosity and in–situ air, Klinkenburg and brine permeabilities.

A probe–permeameter would be run over all cored test intervals as an independent measure of k.h to be compared with the well test k.h estimate.

**Special Core Analysis Laboratory (SCAL)** would be required to obtain additional critical parameters for establishing containment quality and pressure constraints for safe injection and better potential storage performance evaluation: relative permeability (brine–CO$_2$) in the reservoir, capillary entry pressures and capillary pressures (mercury injection method) as a function of CO$_2$ saturation, geomechanical measurements (elastic moduli, rock strength, poro–elastic constants) in both reservoir and sealing units. Relative permeability is critical to evaluate subsurface
migration of CO₂ including pressures developed during injection and the degree of residual saturation trapping. Capillary pressure measurements would constrain the capillary sealing quality of the top seal and intra–formational baffles.

Therefore, a SCAL program would include measurement of petrophysical properties; NMR T2 relaxation times and CO₂–brine relative permeability experiments. Mercury Injection Capillary Pressure (MICP) measurements would be made on samples taken from the seal horizons such as the Snake Creek Mudstone and Evergreen.

Petrophysical parameters, Formation Resistivity Factor, multi salinity formation factor and cementation exponent ‘m’ would be measured on core plug samples for the purpose of calibration of petrophysical models.

Nuclear magnetic resonance spectroscopy CPMG–T2 methods would be used to analyse core plugs to determine porosity characteristics and to define moveable fluid cut–offs. Fluid T1/T2 will be determined on synthetic brine or produced water samples. T2 input parameters derived from these measurements would be used to calibrate the NMR tool.

The relative permeability experiments will include:
- measurement of single phase permeability with brine and CO₂ at reservoir conditions;
- measurement of relative permeability curves (both drainage and imbibition); and
- measurement of capillary pressure curves (both drainage and imbibition).

**Petrology**

Petrological analyses would include fine–fraction X–ray Diffraction (XRD) analysis to determine clay mineralogies; SEM in order to determine porosity characteristics; Energy Dispersive Spectrometry (EDS) to confirm authigenic clay and carbonate composition and thin section analysis to determine composition, diagenetic effects and porosity characteristics.

**10.3.5 Additional technical studies list**

The above program outlines the proposed work program. However, a significant number of additional geotechnical studies would also be required—a sample of these is shown below.

1. Petrophysical analyses.
2. Conventional integrated static modelling (several scenarios).
3. Conventional dynamic modelling (several scenarios).
4. Seal characterisation and comparison with predicted pressure evolution.
5. Geomechanical experiments and modelling—quantification of all confining pressures and uncertainties.
6. Geochemical experiments and modelling—calibration of reaction sets and prediction of reactive issues.
7. Geophysical studies—seismic acquisition and processing optimisation.
9. Containment potential study—integrated view of all confining pressures and seal geometry coupled with pressure predictions from flow models.

10. Potential migration paths study/petrogeology/groundwater resources—worst credible case scenario modelling for comparison with environmental (receptor) sensitivity analyses.

11. Hydrogeological baseline study—new integrated mode complete with full new dataset and pressures.

12. Induced water displacement study—far-field modelling study on impact of brine displacement.

13. On-going environment/atmospheric monitoring for GHGs—implementation of monitoring stations and periodic reporting.

14. Ecosystem characterisation and sensitivity analyses—sampling and multi-seasonal monitoring of the ecosystem types in the tenement areas. To include soil gas by eco-type and season.

15. Environmental sensitivity analysis. Investigations into possible consequences of elevated CO₂ levels in various locations to address ‘what is impact of CO₂ in potential receptor areas?’.


17. On-going reservoir monitoring—post injection test monitoring of conventional wells.

18. Full suite of well engineering (including fluids and cementing) studies.

19. Prefeasibility level studies for transport and injection facilities engineering and flow assurance.
References and Contributors
References

Chapter One


Chapter Three—Part A


Chapter Three—Part B

ZeroGen and ZeroGen commissioned reports

AGR, 2010: Surat project—preliminary well design document. A ZeroGen proprietary report by AGR Asia Pacific Pty Ltd.


RLMS, 2010. Inter Basin Carbon Dioxide Pipeline Corridor Study. A proprietary ZeroGen report by Resource and Land Management Services Pty Ltd.


ZeroGen, 2009 IGCC and CCS Scoping Study (June 2009).


**Other references**


ZeroGen Contributors

The following list is provided in part to acknowledge the people, companies and organisations involved in producing ZeroGen’s Prefeasibility Study and in part to highlight the range and depth of contributors and scale of organisation required to produce such a study.

Given the project’s long and complex history, the list is not complete and the editors apologise for any omissions. This is not intentional and does not in any way reflect on the contributions made by individuals or companies involved.

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The Australian Government
The Australian Coal Association

Co–developers

Mitsubishi Corporation
Mitsubishi Heavy Industries Ltd

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**Major contributing companies**

**IGCC plant and CO₂ studies**

- 4T Consultants (Australia)
- AECOM (Brisbane, Australia)
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- WorleyParsons (Brisbane, Australia)
**Storage operations and studies**

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Det Norske Veritas (Norway)
Hycal Energy Research Laboratories (Canada)
JRS Petroleum Research (Australia)
Julian Baker Associates (Brisbane, Australia)
MBA Petroleum Consultants (Brisbane, Australia)
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Resource and Land Management Services (Brisbane, Australia)
Saros (Australia)
Schlumberger Group (Oilfield, Carbon and Water Services – Australia)
Shell (Shell Global Solutions and Shell Technology India)
Vause Wireline Australia Pty Ltd (Roma, Australia)
Viking Cementing Services (Brisbane, Australia)
Weatherford Laboratories (Brisbane, Australia)
Wood Group Wagner (Brisbane, Australia)

**Supporters, Collaborators and Memberships**

- Global CCS Institute (member);
- Carbon Capture and Storage Association (member);
- Gasification Users Association (member);
- Electric Power Research Institute (member);
- Carbon Sequestration Leadership Forum (Associate member);
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