The Costs of CO_2 Transport and Injection in Australia

Guy Allinson, Yildiray Cinar, Wanwan Hou & Peter R. Neal

Final Report

September 2009
CO2TECH Consultancy Report

CO2CRC Technologies Pty Ltd

PO Box 1130, Bentley, Western Australia 6102
Phone: +61 8 6436 8655
Fax: +61 8 6436 8555
Email: dhilditch@ictpl.com.au
Web: www.ictpl.com.au

Reference: Guy Allinson, Yildiray Cinar, Wanwan Hou & Peter R. Neal, 2009. The Costs of CO_2 Transport and Injection in Australia, School of Petroleum Engineering, The University of New South Wales, Sydney, Australia. CO2TECH Report Number RPT09-1536. Prepared for the Carbon Storage Taskforce, Department of Resources, Energy and Tourism, Canberra.

Disclaimer

This report has been prepared for the Carbon Storage Taskforce, Department of Resources, Energy and Tourism. CO2TECH conducted this analysis and prepared this report using reasonable care and skill consistent with normal industry practice. All results are based on information available at the time of review. Changes in factors upon which the review is based could affect the results. Forecasts are inherently uncertain because of events or combinations of events that cannot be foreseen including the actions of government, individuals, third parties and competitors. No implied warranty of merchantability or fitness for a particular purpose shall apply.

Some of the information on which this report is based has been provided by other organisations. CO2TECH has used such information without verification unless specifically noted. CO2TECH accepts no liability for errors or inaccuracies in information provided by others.

Summary

Our estimate of the cost of CO_2 transport and injection per tonne of CO_2 avoided for single source-sink matches in eastern Australia varies from A$10 per tonne (for the Latrobe Valley to the Gippsland Basin) to A$1,539 per tonne of CO_2 avoided (for North Queensland to the Denison Trough). For the combined source-sink cases, our best estimates of the costs range from A$14 per tonne (for All of Perth to the Bunbury Trough, South Perth) to A$6,200 per tonne of CO_2 avoided (for All of Perth to the Vlaming Basin).

For each single source-sink match, the up-front capital costs range from A$1.2 billion (for the Latrobe Valley to the Gippsland basin) to A$162 billion (for North Queensland to the Denison Trough). These capital costs do not include the cost of CO_2 capture or initial compression to supercritical conditions. The capital costs for the combined source-sink matches range from A$0.8 billion (for All of Perth to the Bunbury Trough, South Perth) to A$341 billion (for All of Perth to the Vlaming Basin).

The costs vary significantly depending on the rate of CO_2 injection, the characteristics of the storage reservoirs as well as their locations. The costs also subject to large uncertainties because they are based on uncertain estimates of reservoir characteristics as well as plant, equipment and services costs. Such uncertainties could be reduced by further exploration and appraisal, by detailed system design and by obtaining vendor quotes based on such designs.

Table of Contents

List of Figures

List of Tables

1 Introduction

This report contains our central estimates of the costs of carbon dioxide (CO_2) transport and injection for selected possible CO_2 storage projects in Australia. This is a first-pass scoping study. The projects are representative illustrations, chosen to help derive the approximate costs of CO_2 storage. We do not attempt to design the storage projects in detail as would be required for a full project feasibility study. The assessment has been prepared by the carbon capture and storage economics group at the University of New South Wales (UNSW), which is sponsored by the Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC). The CO2CRC has carried out this preliminary assessment under contract to the Commonwealth of Australia as represented by the Department of Resources, Energy and Tourism (“RET”). RET acts as the secretariat for the Carbon Storage Taskforce (“Taskforce”). The Taskforce works closely with the National Low Emissions Coal Council (NLECC).

The estimates are based on data concerning emissions, geological basin characteristics, pipeline routes and sizes and unit costs provided by RET, ACIL Tasman, Geoscience Australia, RISC and WorleyParsons. In addition, representatives of Chevron and Schlumberger provided advice. RET defined the CO_2 injection and sensitivity cases to be analysed.

This report includes estimates of the costs of compressing, transporting and injecting CO_2 emitted from selected existing large stationary sources. RET has combined the sources into emissions hubs where the CO_2 would be collected before transport. The estimates exclude the costs of capturing CO_2, and any preliminary compression and transport from the source to the hub. The estimates include the costs of compressing the CO_2 from a starting pressure of 8,000 kPa before transport.

The estimates are subject to very large uncertainties, are only indicative and could change substantially over time as technologies, storage capacities, equipment costs and other variables change. They are based on rule-of-thumb techniques for estimating equipment sizes and the costs of individual items of equipment and associated services. More detailed and extensive feasibility studies, based on more data, need to be undertaken before investment in any CO_2 transport and injection projects could be considered.

2 Assumptions and methods

For each of the cases we estimate the equipment sizes, the capital, operating and decommissioning costs, as well as the costs per tonne of CO_2 avoided for CO_2 transport and injection. The costs are presented in A$2009 terms. They are based on limited cost and reservoir data and have a large margin of error. We estimate the costs of the transport and injection projects excluding any tax effects and have not considered how any emissions trading regime will affect the economics. We have modelled only transport and injection economics and have not modelled the economics of capture or the sources emitting the CO_2.

The main assumptions and methods used for the analyses are listed below.

1. We assume that 90% of the CO_2 emitted from the sources is captured and injected into the subsurface. Therefore 10% of the CO_2 emissions are not captured. The assumed quantities emitted (90% of the total emissions) are given in detail in Appendix 1.

2. CO_2 avoided in transport and injection is the CO_2 injected less the CO_2 emitted in supplying energy to the compressors and auxiliary equipment required for the transport and injection process. In our calculations of CO_2 avoided, we take into account only that CO_2 emitted as part of the transport and injection process. We do not take into account those CO_2 emissions associated with capturing the CO_2 including the CO_2 not captured (referred to in 1 above). This approach means that it is not valid to add the costs per tonne of CO_2 avoided in transport and injection as calculated in this report to the costs of CO_2 avoided in capture.

3. We assume that energy from gas-fired power plants is used to provide the additional energy for all transport and injection operations (pumping, compression and auxiliary equipment). The power plants do not have capture facilities.

4. We assume an injection period of 25 years to calculate the costs of transport and injection.

5. Vertical wells are used for injecting CO_2 into onshore storage horizons; for offshore horizons we use deviated wells. The costs of individual wells are given in Appendix 2. For the basins where we were not given well costs we used our best estimate based on available costs. As directed by the Taskforce, we have added A$2 million to the cost of offshore wells to account for mobilisation.

6. In all cases, the CO_2 is compressed to a sufficiently high pressure (at least 8,000 kPa or 1,160 psia) to keep it in a supercritical state throughout the transport and injection stages. The maximum pipeline pressure is 15,000 kPa (2,176 psia). We do not include the costs of compressing the CO_2 from capture conditions to 8,000 kPa or the cost of collection pipelines within the emission hubs.

7. The pipelines used to transport CO_2 are made from X70 carbon-steel line pipe. The effects of terrain and land use on pipeline construction costs are not considered. Pipeline requirements estimated by WorleyParsons are given in Appendix 3. For the East Coast cases, we have followed pipeline routes identified by WorleyParsons. For the Perth Region cases, we have assumed transport along the corridor used by the Dampier-Bunbury Natural Gas Pipeline and its laterals.

8. We have not modelled the injection pipeline distribution system in detail. We calculate the total cost assuming a simple pipeline connection pattern and then apply a factor to allow for a more efficient connection design based on branches from a central point.

9. We have not included the cost of installing power transmission lines along the pipeline route to provide power for compression either along the route or at the point of injection.

10. We estimate the required number of injection wells using simple reservoir simulations. A simulation is set up for each location in a basin (shallow, middle and deep). Injection takes place in the centre of the basin and occupies 25% of the total basin area. We make this assumption because basin heterogeneity and structure, faulting, sweet spots for injection and so on means that the whole basin will not practically be available for injection. Increasing the injection area is expected to increase injectivity for a given total injection rate. Yet, increasing the injection area within the basin lowers the aquifer strength and so the overall injectivity is not expected to increase significantly. That part of the location surrounding the injection area is an aquifer. The simulation grid size varies depending on the area of the location.

    For each basin location and a given number of injection wells, by repeated simulations we establish iteratively the maximum rate of CO_2 that can be injected over 25 years without the pressure in the reservoir exceeding its fracture pressure. This maximum rate is then established for different numbers of wells. The maximum depends on the properties of the reservoir including its permeability, reservoir thickness and fracture pressure. These and the other reservoir properties assumed for each basin and each location in the basins are given in Appendix 4. An example of the results of simulations for different locations in the Surat Basin is shown in Figure 1.

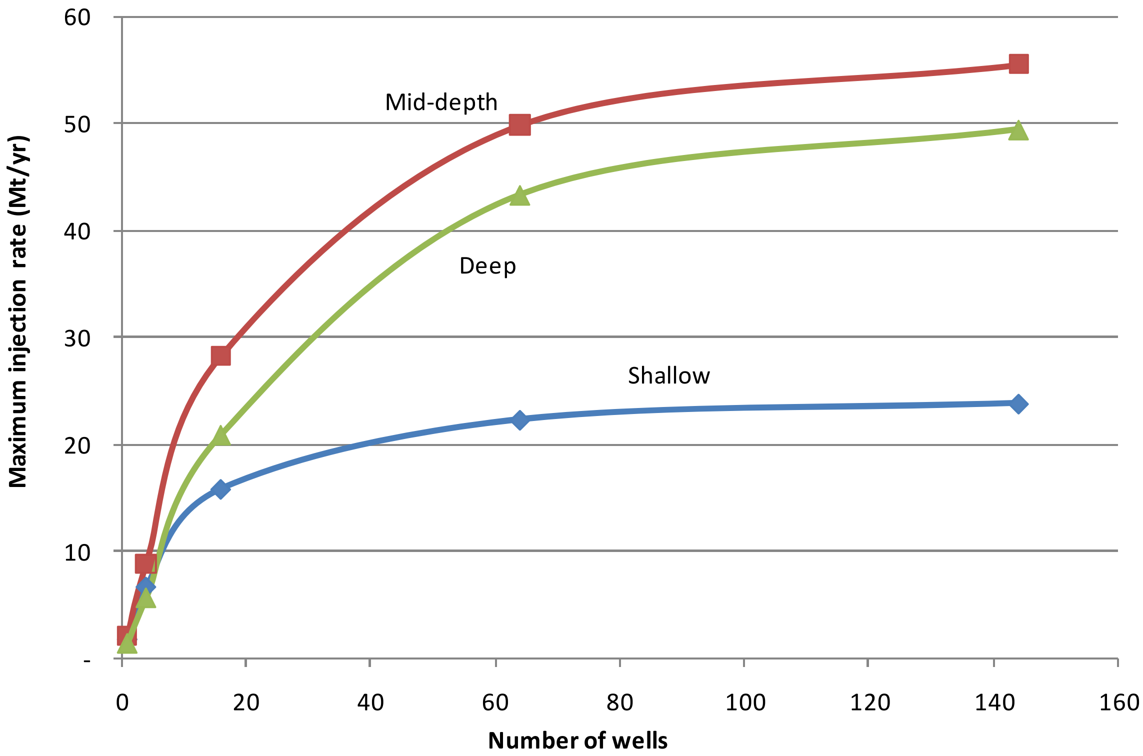


Figure 1 – Results of reservoir simulation – example for Surat Basin.

Figure 1 shows that as the number of wells increase, the maximum flow increases sharply. However, at large flow-rates interference between the injection wells dominates and reduces the increase in the maximum injection rate. At large flow-rates, it becomes difficult to inject more CO_2 because the wells interfere with one-another significantly. In some cases, the reservoir fracture pressure might be reached and this too can limit the rate at which CO_2 can be injected.

Based on the number of wells determined by reservoir simulation, we calculate the maximum injectivity of each well. This is the maximum injection rate divided by the number of wells.

The reservoir simulations are simple models and, although they take into account non-Darcy flow and well interference, they ignore many factors that would affect the injectivity of a well that would be achieved in practice (such as skin factor, tubing constraints, reservoir heterogeneity and so on). Therefore we adjust the simulated maximum well injectivity to give an estimate of its practical injectivity. This adjustment is based on an analysis and review of existing CO_2 injection projects worldwide as well as discussions and advice from Task Force representatives from Chevron and Schlumberger. Finally, we add a 10% contingency to the number of wells.

11. While we simulate them, we do not report results for any horizon in the Darling Basin, or the shallow horizon of the Denison Trough. We found that very large numbers of wells are required to achieve the necessary injection rates in these formations and so injection into these sinks is likely to be very expensive.

12. We estimate transport and injection costs in real A$2009 terms. Our calculations of the cost per tonne avoided incorporate a real discount rate of 12% as requested by the Taskforce. The calculations also assume a construction period of 3 years and an injection period of 25 years after which the project is decommissioned. Where possible, we have employed recommended IEA assumptions [1]. Our methodology for calculating the costs of CCS per tonne avoided is given in Allinson et al. 2006 [2]. We have also analysed the costs assuming a real discount rate of 7%.

13. We report the capital, operating and decommissioning costs for each case examined as well as the present value of these costs. We also present the specific cost of CO_2 injected and the specific cost of CO_2 avoided. The specific cost of CO_2 avoided is calculated by dividing the present value of all costs by the present value of CO_2 avoided. The specific cost of CO_2 injected is calculated in a similar way, but uses the present value of CO_2 injected.

3 Analysis

This analysis examines the costs of storing approximately 110 Mt/yr emitted by selected CO_2 sources in Queensland, New South Wales, the Latrobe Valley in Victoria and Western Australia. Figure 2 shows a schematic of the location of East Coast emissions hubs, storage basins and pipelines analysed in this study. Figure 3 shows the same features for the Perth Region.

Figure 2 – Approximate location of East Coast emission hubs, storage basins and pipelines considered

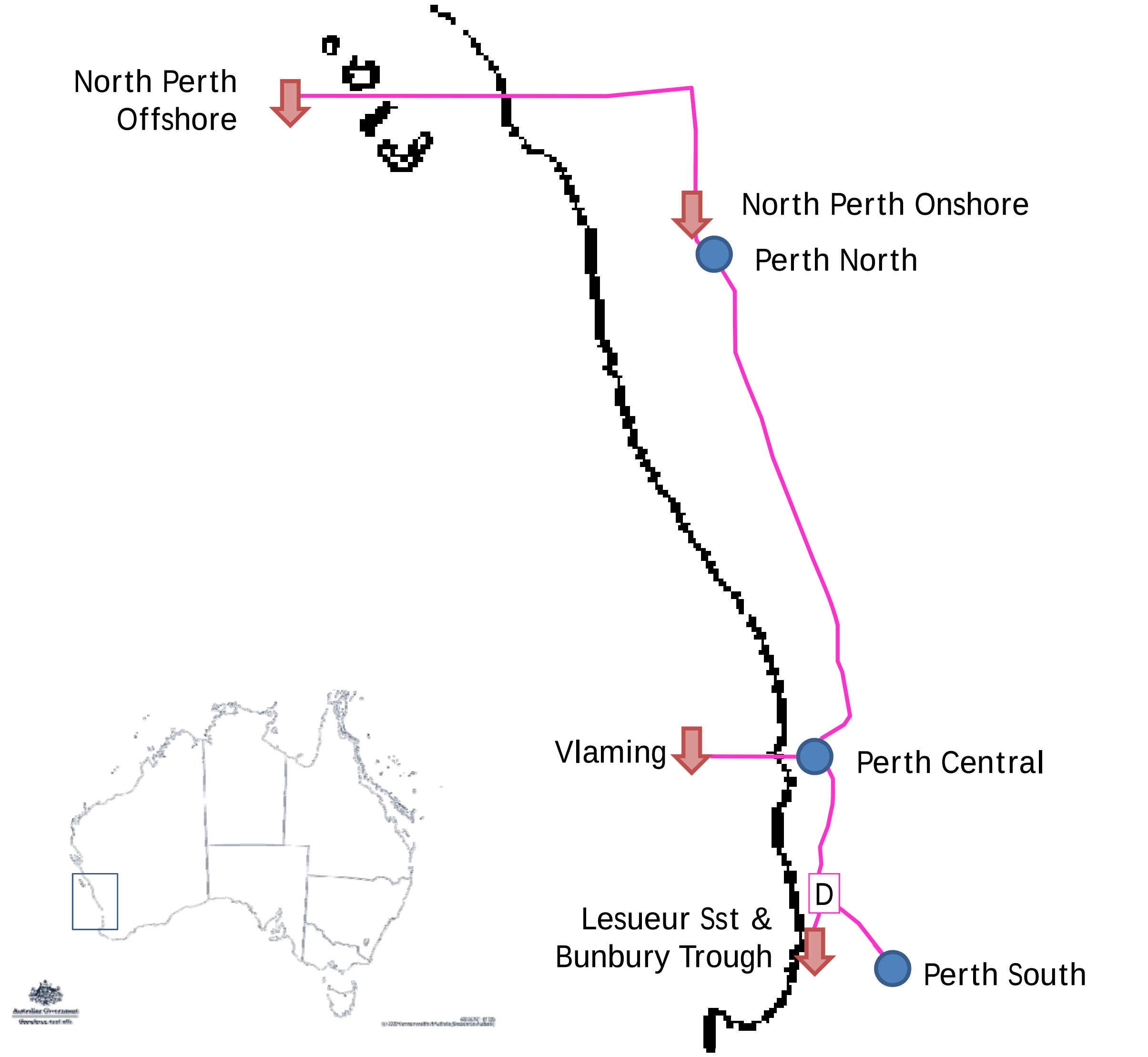


Figure 3 – Approximate location of Perth Region emission hubs, storage basins and pipelines considered

3.1 Range of cost estimates

Figure 4 and Table 1 show that our estimates of the costs of CO_2 compression, transport and injection for individual basins range from A$10 to A$1,539 per tonne avoided in A$2009 terms depending on the project. More detail is given in Appendix 6. Figure 5 and Table 2 show that our estimates of the costs for combined source cases range from A$14 to A$6,200 per tonne of CO_2 avoided. The results for component parts of the combined source cases are given in Appendix 5 and detailed results are given in Appendix 7. The results in Figure 4 and Table 1 are based on a real discount rate of 12%. Appendix 10 shows equivalent results using a discount rate of 7%.

The up-front capital costs range from A$0.8 billion (for All of Perth to the Bunbury Trough, South Perth) to A$341 billion (for All of Perth to the Vlaming Basin) in A$2009 terms. The present values of transport and injection capital, operating and decommissioning costs in range from approximately A$0.7 billion (for All of Perth to the Bunbury Trough, South Perth) to A$289 billion (for All of Perth to the Vlaming Basin).

None of our estimates include the cost of CO_2 capture.

The range of estimates reflects the different volumes of CO_2 injected, different transport distances and different characteristics of the storage reservoirs. Reservoir characteristics tend to account for most of the differences between the costs of the different cases.

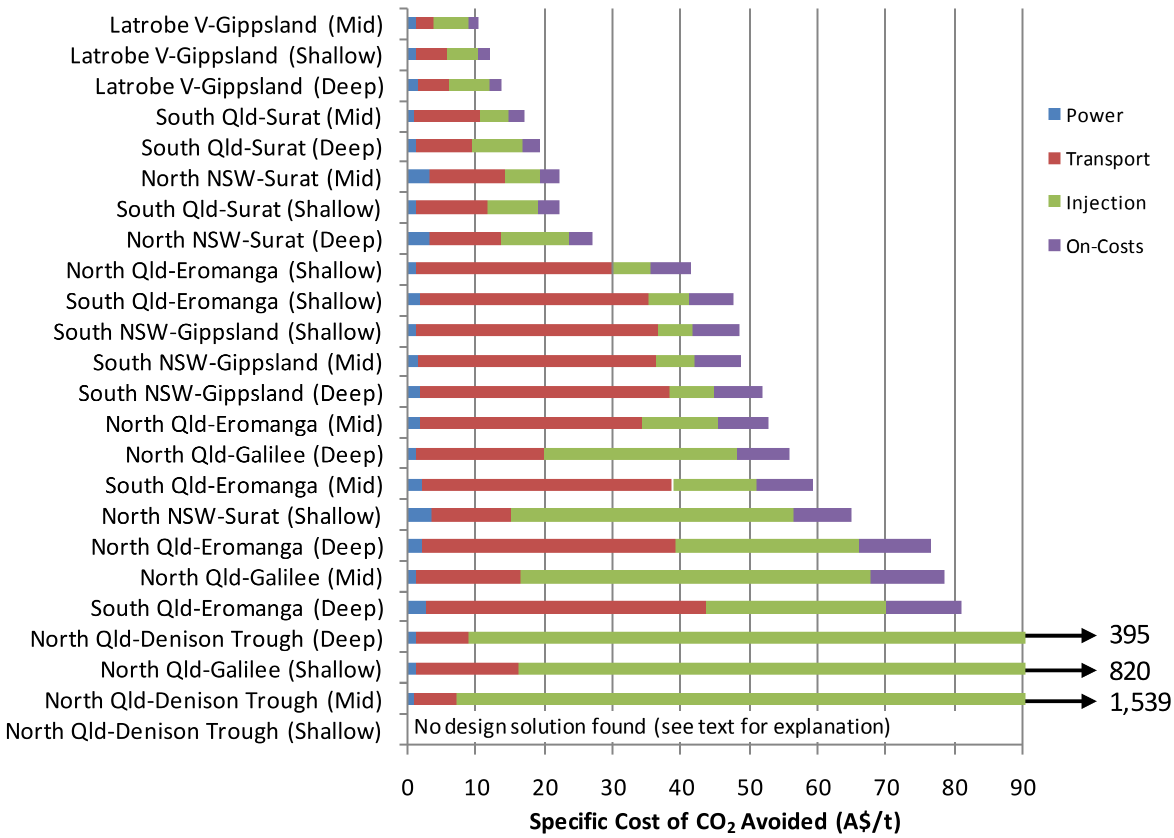


Figure 4 – Ranking of single source cases

The lowest-cost cases for the Perth Region of Western Australia involve injection into the mid-depth horizons of the Onshore Perth Basin (both in the North and the South, i.e. Bunbury Trough and Lesueur Sandstone). For the East Coast, the lowest-costs are associated with injection into the Gippsland Basin and the mid-depth and deep horizons of the Surat Basin. These sites give the lowest costs because they have favourable reservoir characteristics, particularly their high permeability-thicknesses and high pressure differentials. In addition, the sources and sinks are reasonably close.

The most expensive cases generally involve storage in formations with poor injectivities. Figure 4 includes three cases[1] where the costs exceed the limits of the graph. Similarly,

[1] Each of these cases required more than about 10,000 wells.

Figure 5 has six cases[2] that exceed the limits of the graph. In addition, each figure has some cases where the number of wells is so large[3] that finding a design solution is very difficult.

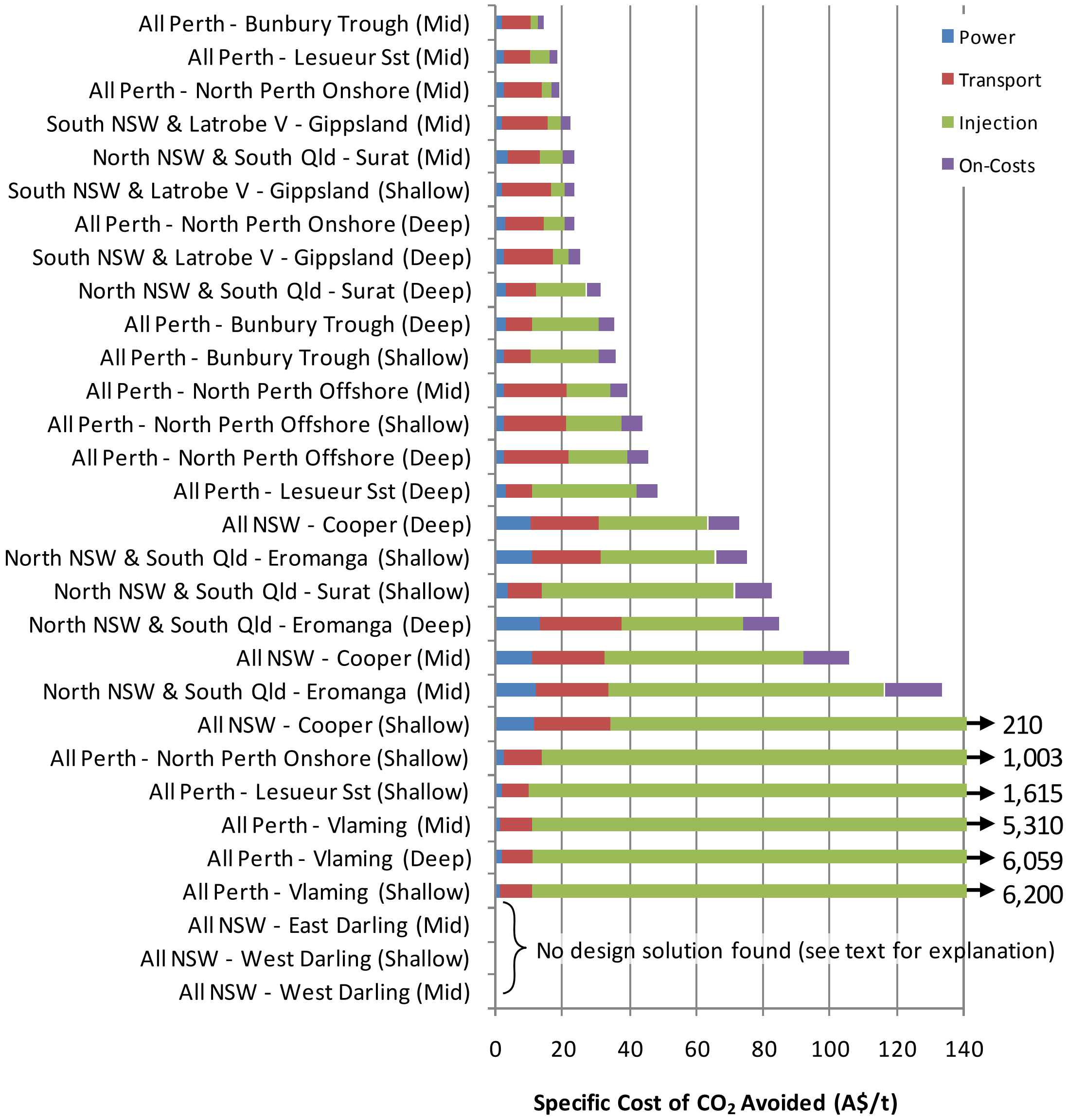


Figure 5 – Ranking of combined source cases

Each of the formations with very large numbers of wells has poor injectivities because of their geological characteristics. In particular —

- The shallow horizon of the Dennison Trough is only 10 m thick. In addition, because it is shallow (800 mSS) there is little difference between the maximum and minimum injection pressures (5 MPa). Therefore, in order to inject CO_2 at the given rates, large numbers of wells are required.

---

[2] Each of these cases required more than about 7,000 wells.

3 From approximately 180,000 wells for North Queensland into the shallow horizon of the Denison Trough to more than half a million wells for All of NSW into the shallow horizon of the West Darling Basin and into the mid-depth horizon of the East Darling Basin.

- The Darling Basin has reasonable thickness (about 100 m) but the porosity is relatively low. The porosity defines the volume of pore space, so storage capacity in this basin is not adequate for the given total injection rates.

Given the large uncertainties in making cost estimates and the fact that the costs for the case combinations are close together, the ranking might easily change with different assumptions. We have not carried out sensitivity or uncertainty analyses to determine how robust the rankings are to changes in assumptions.

3.2 Lowest costs

For North Queensland, the shallow Eromanga horizon gives the lowest cost of CO_2 avoided (A$41/t). This reflects that horizon's high permeability and its large injection pressure differential.

For the South Queensland and for North NSW, the mid-depth horizon in the Surat Basin offers the cheapest transport and injection option (A$17 and A$22 per tonne respectively). There is a relatively short transport distance and the formation properties are favourable. When these two emissions hubs are combined, the cheapest transport and injection option is again the mid-depth horizon of the Surat Basin (A$23 per tonne).

For South NSW and the Latrobe Valley, the mid-depth horizon in the Gippsland Basin gives the lowest cost of CO_2 avoided (A$49 and A$10 per tonne respectively) reflecting its attractive reservoir characteristics. The same is true when these sources are combined, where transport and injection in the mid-depth Gippsland Basin costs $22 per tonne.

When all the emissions from NSW are combined and injected into a single formation, the lowest cost of A$72 per tonne involves injecting CO_2 into the deep horizon of the Cooper Basin.

Finally, for the combined emissions from the Perth Region in Western Australia, the lowest cost transport and injection option in the South Perth Basin is for the mid-depth horizon of the Bunbury Trough (A$14 per tonne). For the North Perth Basin, the lowest cost case involves injection in the mid-depth horizon of the onshore portion of the basin (A$19 per tonne).

Table 1 – Results for single source cases[4]

Source	Location / Basin	Injection rate[5] Mt/yr	Capital costs A$ million	Annual operating costs A$ million/yr	PV of costs[6] A$ million	Specific cost of CO_2 avoided A$/t
North Queensland	Denison Trough (Shallow)	16.1	N/A[7]	N/A	N/A	N/A
North Queensland	Denison Trough (Mid)	16.1	162,415	2,703	137,764	1,539.1
North Queensland	Denison Trough (Deep)	16.1	41,740	684	35,345	395.1
North Queensland	Galilee (Shallow)	16.1	86,907	1,374	73,311	819.5
North Queensland	Galilee (Mid)	16.1	8,444	116	7,026	78.5
North Queensland	Galilee (Deep)	16.1	6,053	78	5,007	56.0
North Queensland	Eromanga (Shallow)	16.1	4,524	50	3,695	41.3
North Queensland	Eromanga (Mid)	16.1	5,717	68	4,700	52.7
North Queensland	Eromanga (Deep)	16.1	8,266	103	6,823	76.6
South Queensland	Surat (Shallow)	18.0	2,662	36	2,213	22.1
South Queensland	Surat (Mid)	18.0	2,037	29	1,700	17.0
South Queensland	Surat (Deep)	18.0	2,292	34	1,923	19.2
South Queensland	Eromanga (Shallow)	18.0	5,795	69	4,767	47.8
South Queensland	Eromanga (Mid)	18.0	7,163	88	5,905	59.3
South Queensland	Eromanga (Deep)	18.0	9,737	127	8,068	81.3
North NSW	Surat (Shallow)	33.5	14,042	243	11,972	65.1
North NSW	Surat (Mid)	33.5	4,589	106	4,068	22.1
North NSW	Surat (Deep)	33.5	5,647	123	4,962	27.0
South NSW	Gippsland (Shallow)	12.9	4,260	47	3,479	48.5
South NSW	Gippsland (Mid)	12.9	4,258	49	3,494	48.8
South NSW	Gippsland (Deep)	12.9	4,513	55	3,716	52.0
Latrobe Valley	Gippsland (Shallow)	18.3	1,406	26	1,207	11.9
Latrobe Valley	Gippsland (Mid)	18.3	1,179	25	1,029	10.1
Latrobe Valley	Gippsland (Deep)	18.3	1,584	32	1,379	13.6

[4] The numbers might not add or multiply exactly because of rounding.
[5] This is 90% of the CO_2 emitted from the source on the assumption that the capture process separates 90% of the CO_2 from the gas mixture emitted.
[6] PV stands for "present value"
[7] N/A means that no solution could be found with the economic model

Table 2 – Results for combined source cases[8]

Source	Location / Basin	Injection rate Mt/yr	Capital costs A$ million	Annual operating costs A$ million/yr	PV of costs A$ million	Specific cost of CO_2 avoided A$/t
South NSW & Latrobe V						
to	Gippsland (Shallow)	31.2	4,788	77	4,049	23.4
to	Gippsland (Mid)	31.2	4,542	74	3,849	22.3
to	Gippsland (Deep)	31.2	5,011	90	4,296	24.9
North NSW & South Qld						
to	Surat (Shallow)	51.5	27,357	469	23,293	82.3
to	Surat (Mid)	51.5	7,348	172	6,523	23.1
to	Surat (Deep)	51.5	10,066	211	8,794	31.0
North NSW & South Qld						
to	Eromanga (Shallow)	51.5	22,491	596	20,355	75.0
to	Eromanga (Mid)	51.5	40,725	923	35,954	133.4
to	Eromanga (Deep)	51.5	24,481	711	22,509	84.3
All NSW (South & North)						
to	East Darling (Mid)	46.4	N/A	N/A	N/A	N/A
to	West Darling (Shallow)	46.4	N/A	N/A	N/A	N/A
to	West Darling (Mid)	46.4	N/A	N/A	N/A	N/A
All NSW (South & North)						
to	Cooper (Shallow)	46.4	58,581	1,192	50,938	209.5
to	Cooper (Mid)	46.4	28,853	698	25,727	105.5
to	Cooper (Deep)	46.4	19,434	537	17,710	72.4
All Perth (South, Central & North)						
to	Vlaming (Shallow)	8.4	340,584	5,774	289,474	6,200.1
to	Vlaming (Mid)	8.4	291,494	4,943	247,756	5,310.0
to	Vlaming (Deep)	8.4	332,255	5,636	282,417	6,059.1
All Perth (South, Central & North)						
to	North Perth Onshore (Shallow)	8.4	54,819	926	46,576	1,003.4
to	North Perth Onshore (Mid)	8.4	995	20	866	18.6
to	North Perth Onshore (Deep)	8.4	1,256	25	1,090	23.5
All Perth (South, Central & North)						
to	North Perth Offshore (Shallow)	8.4	2,373	40	2,017	43.4
to	North Perth Offshore (Mid)	8.4	2,163	34	1,827	39.4
to	North Perth Offshore (Deep)	8.4	2,506	39	2,113	45.5
All Perth (South, Central & North)						
to	Lesueur Sandstone (Shallow)	8.4	88,521	1,501	75,238	1,615.1
to	Lesueur Sandstone (Mid)	8.4	964	21	844	18.2
to	Lesueur Sandstone (Deep)	8.4	2,575	51	2,234	48.2
All Perth (South, Central & North)						
to	Bunbury Trough (Shallow)	8.4	1,917	36	1,649	35.5
to	Bunbury Trough (Mid)	8.4	758	16	665	14.3
to	Bunbury Trough (Deep)	8.4	1,880	39	1,639	35.3

[8] Refer to the footnotes at the bottom of Table 1.

4 Sensitivity Analyses

In addition to the various single source and combined source case studies reported above in Section 3, at the request of the Taskforce, we have prepared a number of sensitivity analyses. The sensitivity analyses show the effect of changes in the assumptions for taking CO_2 from South Queensland, North NSW or both to the three storage horizons in the Surat Basin (see Appendix 4 for reservoir properties).

4.1 Seismic monitoring programme

The analyses reported above exclude the costs of a monitoring programme during the construction and injection periods. Our discussions with industry personnel and monitoring researchers indicate that, because CCS is a new technology, there is a wide range of (not necessarily consistent) views on how a seismic monitoring programme might be designed. The monitoring programme as a whole would also include observation wells. We discuss the effect of the latter in a separate section.

The analyses below show the how a seismic monitoring programme using conservative design assumptions affect the costs. Cheaper alternatives might be more appropriate, but we have not estimated costs for the range of design alternatives possible.

We assume that before injection, the operator shoots a 3D seismic survey over an area equal to 110% of our assumed injection area in the centre of the basin[9]. This initial survey is separate and in addition to the seismic surveys assumed in the exploration, appraisal and development programme referred to in section 4.6 below. After 2 years of injection and then every 5 years, the operator repeats this survey in a different, but overlapping location following the movement of the CO_2 plume. The operator repeats the survey once after injection has stopped. The size of each survey is the same — 110% of the injection area. The surveys might continue after injection has finished, but we have not modelled this. We assume that the 3D seismic survey acquisition and processing will cost A$12,750 per square kilometre. The results of this analysis are shown in Figure 6.

We estimate that the cost of a single seismic survey for the Surat Basin location is A$140 million and assume that a total of 7 surveys are conducted over the life of the project. The present value of these surveys is A$278 million.

The absolute cost of seismic surveys estimated, based on these assumptions, is only a function of the area of the basin surveyed. It is fixed regardless of numbers of wells or injection rate. The addition of seismic monitoring increases the specific cost of the different Surat Basin projects considered in this report by between 1% and 16%. The addition of seismic costs has least impact on the most expensive cases.

The costs discussed above and shown in Figure 6 are conservative. They could be lower after the initial seismic survey either (a) because the areas surveyed could be smaller or (b) the costs per square kilometre could be lower because 2D surveys are thought to be adequate and/or because there might be cost savings for a long-term programme.

[9] Our injection area is 25% of the basin area, therefore the seismic monitoring area is 27.5%

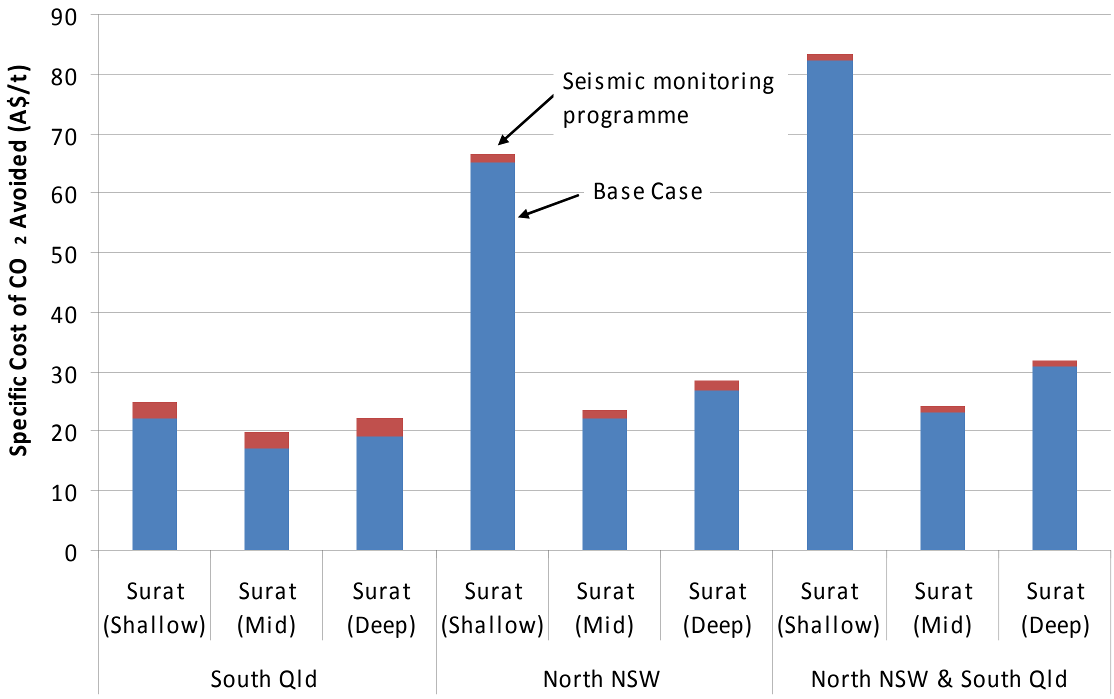


Figure 6 — Effect of adding a seismic monitoring programme on the specific cost of CO_2 avoided

4.2 Additional wells

Storage formations are heterogeneous and the distribution of formation properties is uncertain. This heterogeneity and uncertainty mean that some wells will be drilled into low injectivity sections of the formation. In addition, some wells may fail to reach the target formation for a range of reasons. This all means that a certain number of wells will be unsuccessful. In addition, part of the monitoring programme for the injection of CO_2 will involve the drilling of monitoring wells containing a range of sensors and sampling devices.

In order to assess the cost of impact of needing to drill additional wells we estimate the costs of the nine Surat Basin cases with 15% extra wells. The effect of this sensitivity is shown in Figure 7. It shows that adding an extra 15% wells increases the cost of CO_2 avoided by 3% to 11%, or by A$0.5 to A$8.7 per tonne of CO_2 avoided. The degree to which additional wells increases the cost of CO_2 avoided is proportional to original number of wells required.

4.3 Well workovers

It is possible that the performance of injection wells into saline aquifers will decrease over time because of salt precipitating in the pore space. To counteract this, we assume that wells will be worked over to recover injectivity. We assume that each well will be worked-over once every 5 years at a cost of A$0.5 million per well for the Surat Basin. That means that each well will be worked-over 5 times during the 25 year life of the project. The results of our analysis are shown in Figure 8.

Figure 8 shows that well workovers do not significantly increase the cost of CO_2 avoided. For most cases, workovers increase the cost of CO_2 avoided by 1% to 4%. For the two cases that had large numbers of wells (over 2,000 wells) the cost of CO_2 avoided increases by 8% or 10%.

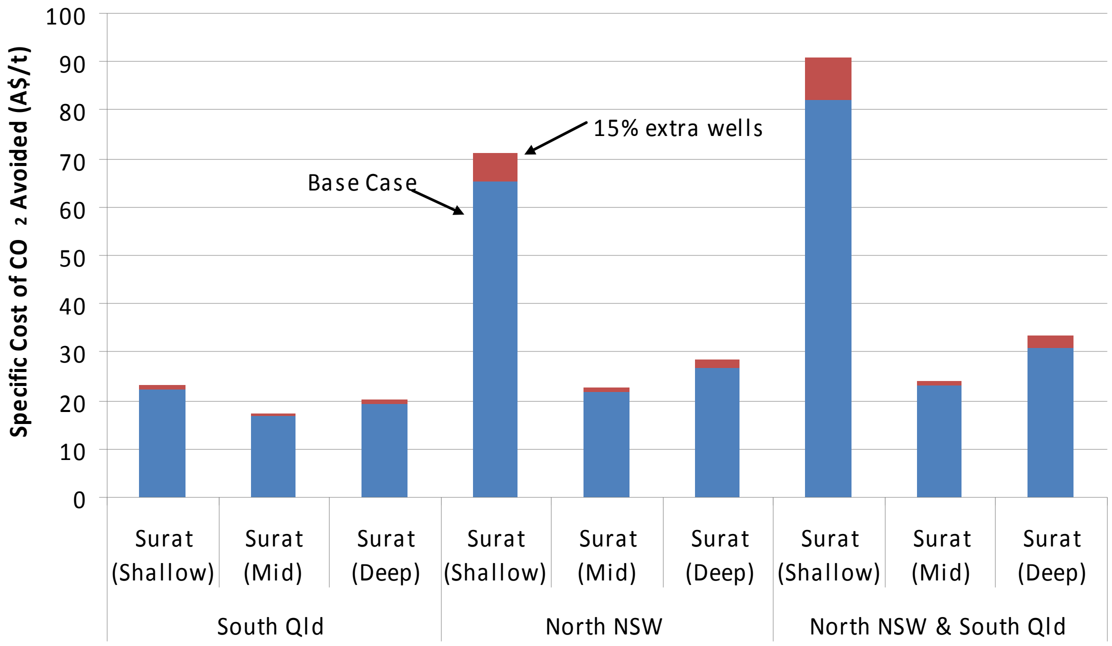


Figure 7 — Effect of 15% extra wells on the specific cost of CO_2 avoided

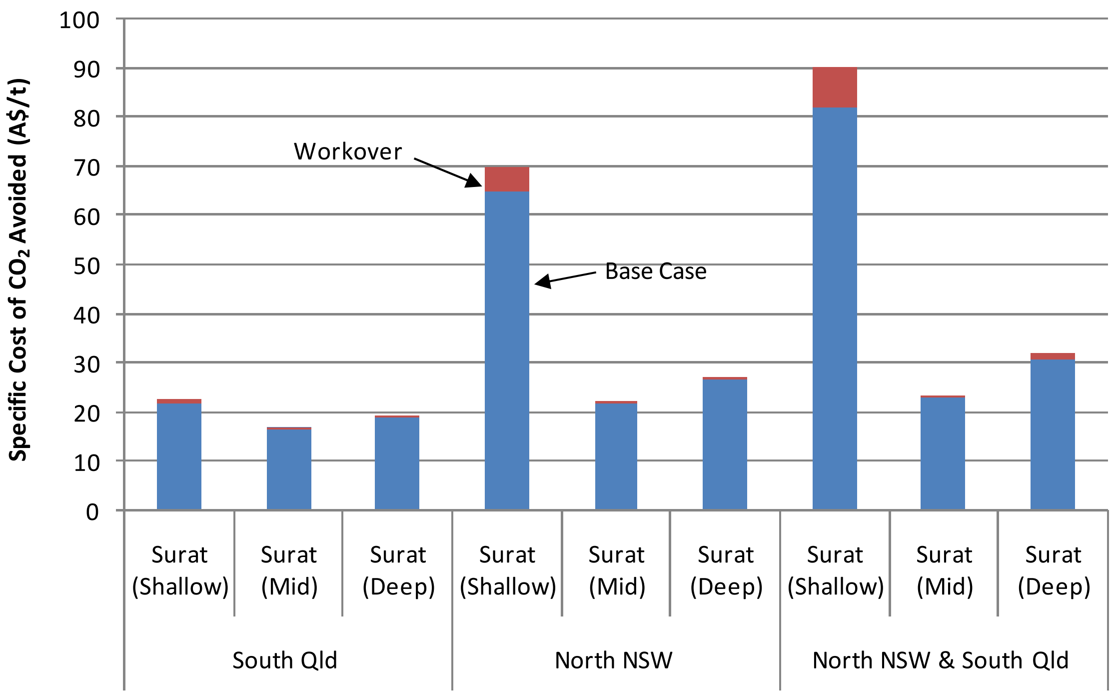


Figure 8 — Effect of well workovers on the specific cost of CO_2 avoided

4.4 Economies of scale

In general, the absolute cost of CCS increases with the volume of CO_2 captured and stored. However, for some items, costs increase more slowly than volume increases. In other words, there are often economies of scale. The specific costs of the whole CCS process often decrease with increasing flow-rate reflecting the economies of scale in the capture and transport components. In contrast, injection costs tend to increase with rate and so, when injection costs represent a large portion of the total cost, the specific cost of CCS may increase.

In order to illustrate the effects of economies of scale, we use a fixed system design (a fixed distance and number of boosters) and vary the flow-rate. The number of wells and the pipeline diameter are allowed to vary with flow-rate. We applied this approach to the cases involving CO2 transport and injection from South NSW to the mid-depth horizon of the Gippsland Basin and from North NSW to the deep horizon of the Surat Basin. These cases are chosen because they involve long transport distances, therefore transport costs will be large. They also represent one case where the injection cost is a significant component of the total cost and one case where it is not.

Figure 9 shows the results of an analysis of -

(a) CO_2 transport from North NSW with storage in the deep horizon of the Surat Basin, and

(b) CO_2 transport from South NSW with storage in the mid-depth horizon of the Gippsland Basin.

For the South NSW to Gippsland case, as the rate of CO_2 injected increases, the specific cost decreases and then increases. The initial fall in the specific cost is the result of economies of scale in transport. Transport dominates the costs at lower flow-rates.

In contrast, the North NSW to Surat case is flat up to 5 Mt/yr before it also increases with increasing numbers of wells. As the flow-rate increases, cost savings through economies of scale are more than offset by the cost of an increasing number of wells.

The variation in the transport and injection components of costs for the South NSW to Gippsland case is shown in Figure 10. We would expect that if the cost of capture and the cost of compression from near-atmospheric to supercritical pressures were included – the increased cost at high flow-rates for these cases would be moderated or eliminated.

Other analyses we have published [7–9] also show the effect of economies of scale in transport and injection for different situations.

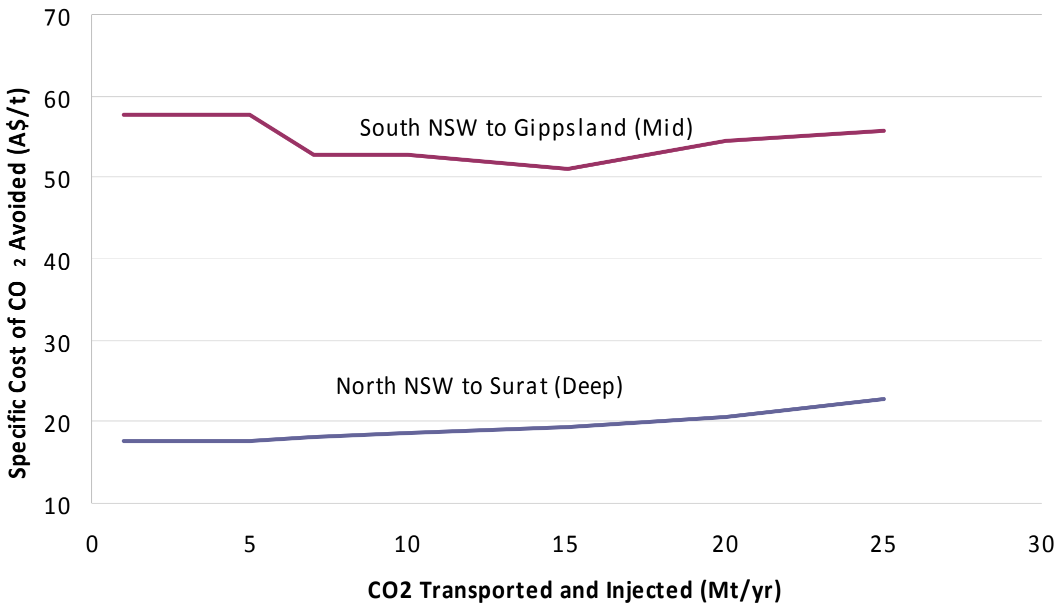


Figure 9 — Effect of changing capacity on the cost of CO_2 avoided

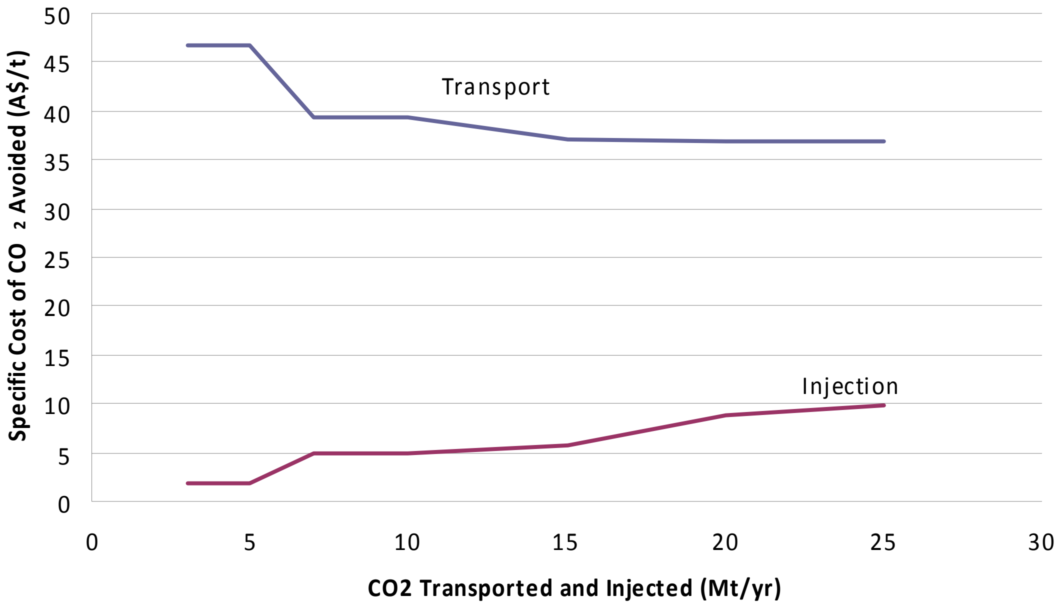


Figure 10 — Effect of changing capacity on the cost of transport and injection for the South NSW to Gippsland (Mid) case.

4.5 Discount rate

The sections above discuss the costs of CCS assuming a real discount rate of 12%. We also report the effect of a 7% real discount rate. Figure 11 gives a comparison of the effect using a discount rate of 7% compared to 12% on the cost of projects into the Surat basin[10]. The effect is to decrease the cost of CO_2 avoided by approximately 30%.

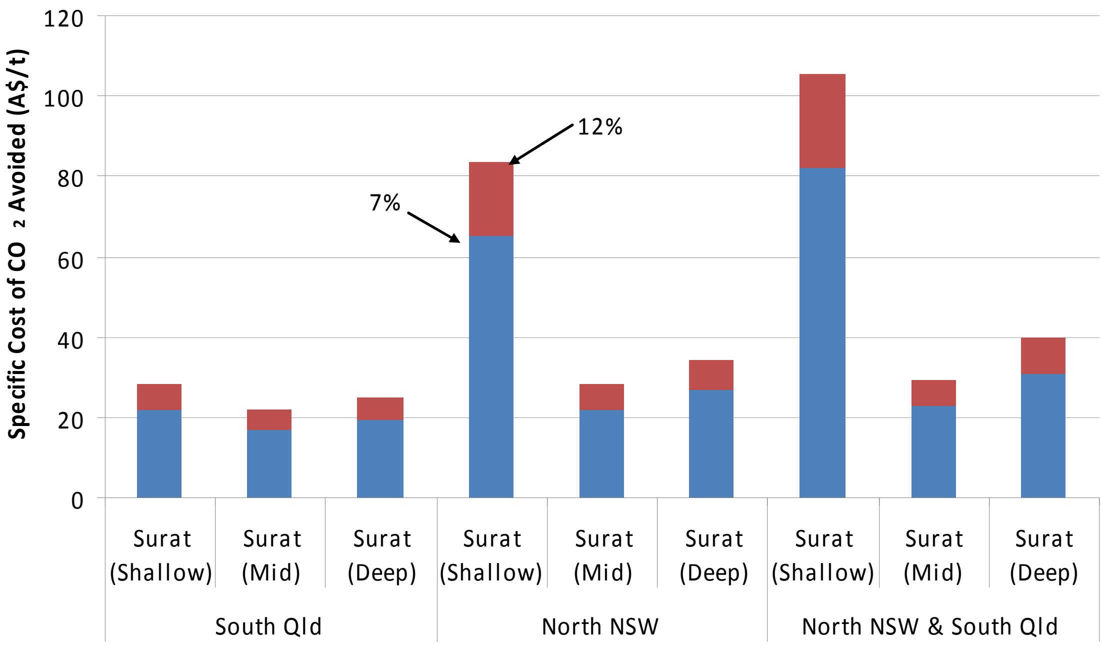


Figure 11 — Effect of discount rate on the specific cost of CO_2 avoided

4.6 Exploration, appraisal and development costs

Costs for the exploration, appraisal and development (EA&D) were estimated by the Taskforce for the basins analysed in the report [6]. This section shows the effect of adding these costs to the construction, operation and decommissioning costs (CO&D) of the combined source cases for the Surat Basin as shown in Table 2.

Table 3 shows —

(a) the present value of the EA&D costs as at 2010.

(b) the present value of the CO&D costs as at 2010. For this we assume that the CO&D costs are incurred starting in 2021 when the EA&D programme has finished. We discount these costs to 2010.

The specific cost of CO_2 avoided including EA&D costs are also given in Table 3 and are shown in Figure 12. Since EA&D costs are only available for injection rates of 51.5 Mt/yr, we show the combined source cases involving emissions from North NSW and South

10 The full set of results figures using a 7% real discount rate are provided in Appendix 10.

Queensland injected into the Surat Basin. The results of this analysis are shown in Table 3 and Figure 12 below. More detail is given in Appendix 8.

Table 3 – The effect of adding EA&D costs to cost of combined North NSW & South Qld to Surat Basin

Surat Basin horizon		Shallow	Mid-depth	Deep
Injection rate	Mt/yr	51.5	51.5	51.5
PV of exploration costs	A$ million	267	267	267
PV of appraisal and development costs	A$ million	144	144	144
PV of EA&D costs	A$ million	411	411	411
PV of CO&D costs	A$ million	6,696	1,875	1,875
PV of all costs	A$ million	7,107	2,286	2,286
Exploration costs per tonne of CO_2 avoided	A$/t	3.3	3.3	3.3
Appraisal and dev costs per tonne of CO_2 avoided	A$/t	1.8	1.8	1.8
Specific EA&D cost of CO_2 avoided	A$/t	5.1	5.1	5.0
Specific CO&D cost of CO_2 avoided	A$/t	82.3	23.1	31.0
Total specific cost of CO_2 avoided	A$/t	87.4	28.1	36.0

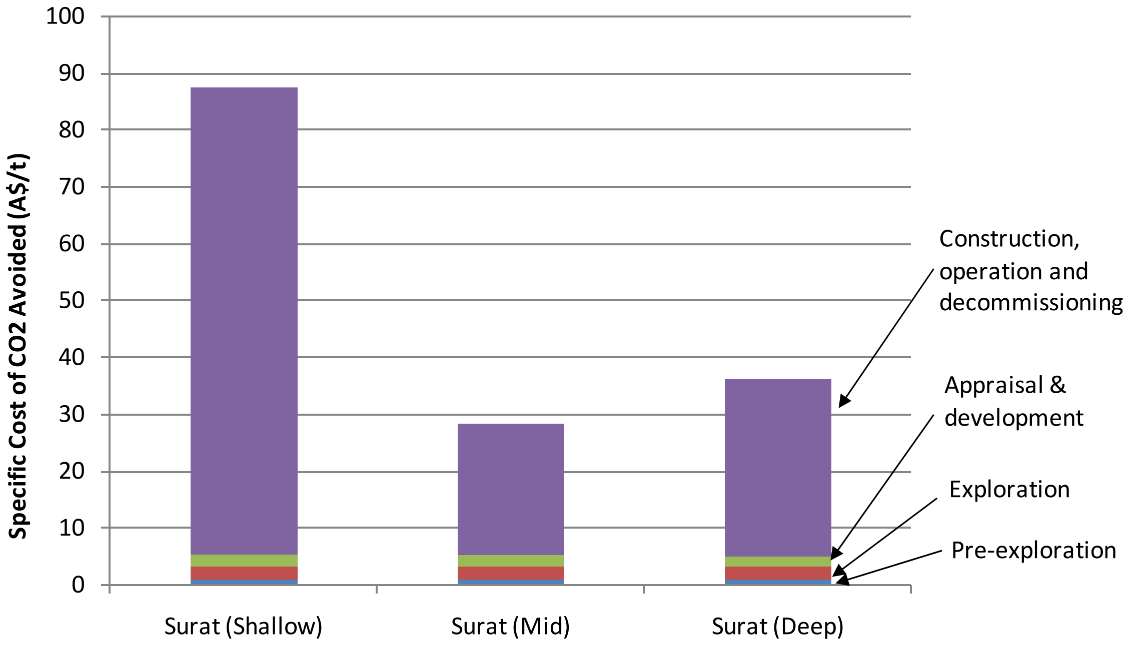


Figure 12 — Cost breakdown with the addition of exploration, appraisal and development costs

At a real discount rate of 12%, the present value of the total exploration, appraisal and development costs is A$0.41 billion. This is relatively small compared to the present value of the total construction, operating and decommissioning costs of the Surat Basin (A$1.9 billion for the best case and A$6.7 billion for the worst case).

Similarly, the specific cost of CO_2 avoided for the exploration, appraisal and development costs is A$5.1 per tonne is low compared to the construction, operating and decommissioning costs of the worst case of the Surat basin (A$82 per tonne). For the best case, the pre-construction costs contribute to approximately 18% of the total costs.

4.7 Expected Value analyses

In this analysis, we incorporate the EA&D risk by calculating the expected value (or the statistical mean value) of the decision to embark on the EA&D programme.

The expected value is —

> the NPV of the combined EA&D and CO&D programmes if exploration is successful multiplied by the probability of success
>
> less

the NPV of the exploration costs (excluding the appraisal and development costs) if exploration fails multiplied by the probability of failure.

We can calculate the NPV of the combined EA&D and CO&D programme as -

> the NPV of the receipts from that part of the CO_2 credit that is attributable to transport and injection for a range of CO_2 credits
>
> less
>
> the NPV of the costs of the EA&D and CO&D programme.

In this analysis, the NPV of the receipts from selling CO_2 credits related only to CO_2 transport and injection. The NPV of costs does not include the capture costs.

The Taskforce [6] has estimated that the probability of success for the exploration of the Surat Basin is 38%. Based on this, the expected value of the decision to embark on the EA&D programme can be calculated using the following equation.

$$EV = \text{NPV of success} * 38\% - \text{NPV of exploration costs} * (1\text{-}38\%) \qquad 1$$

Figure 13 shows a plot of the expected value as a function of that part of the price of carbon that is attributable to transport and injection. The figure shows that the minimum carbon price required to make the EA&D programme viable is the price at which the expected value equals zero. The minimum carbon price for the shallow, mid and deep cases of the Surat Basin are A$91 per tonne, A$33 per tonne and A$41 per tonne respectively. More detail is given in Appendix 9.

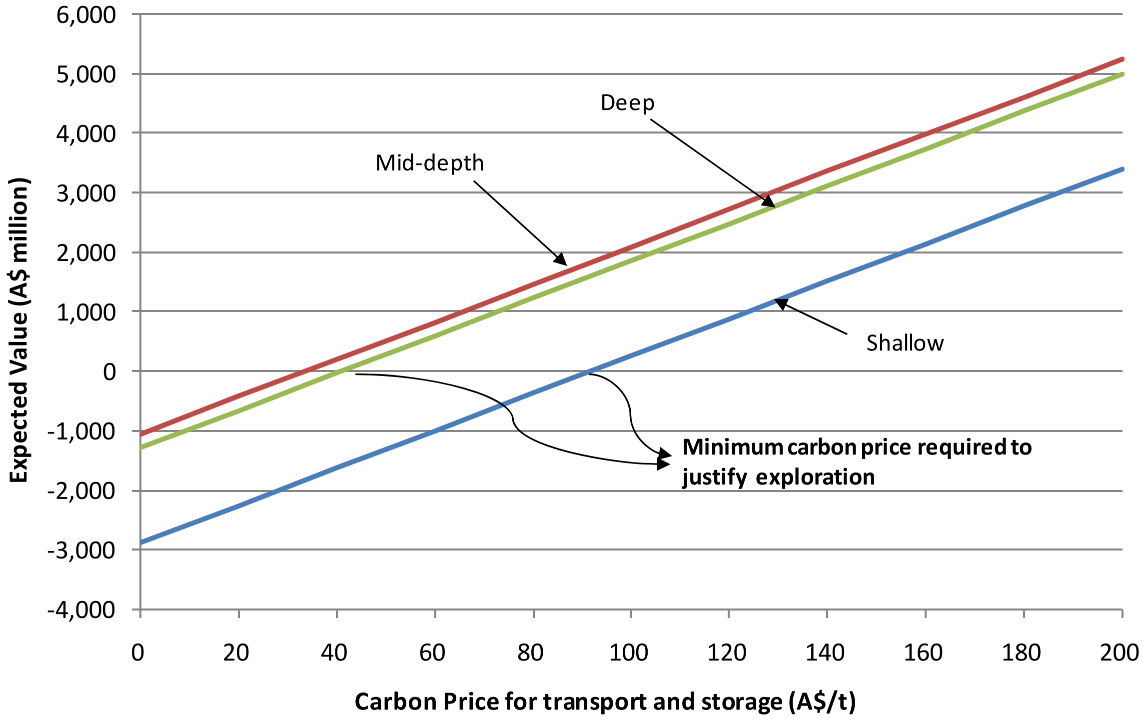


Figure 13 — Expected value analyses on that part of the carbon price available to cover the costs of transport and injection

4.8 Source location

At the request of the Taskforce, we also calculate the costs of transport and injection in the Surat Basin assuming that the South Queensland emissions hub is 100 km from the Surat rather than near Brisbane. For these cases, the emissions are collected into a hub at the point marked 'Alternate' on Figure 14 instead of the point marked 'Default'. We consider only the cost of CO_2 transport and injection in this analysis. We do not consider the cost of capture, building new infrastructure, new generating equipment, or establishing a new fuel supply network.

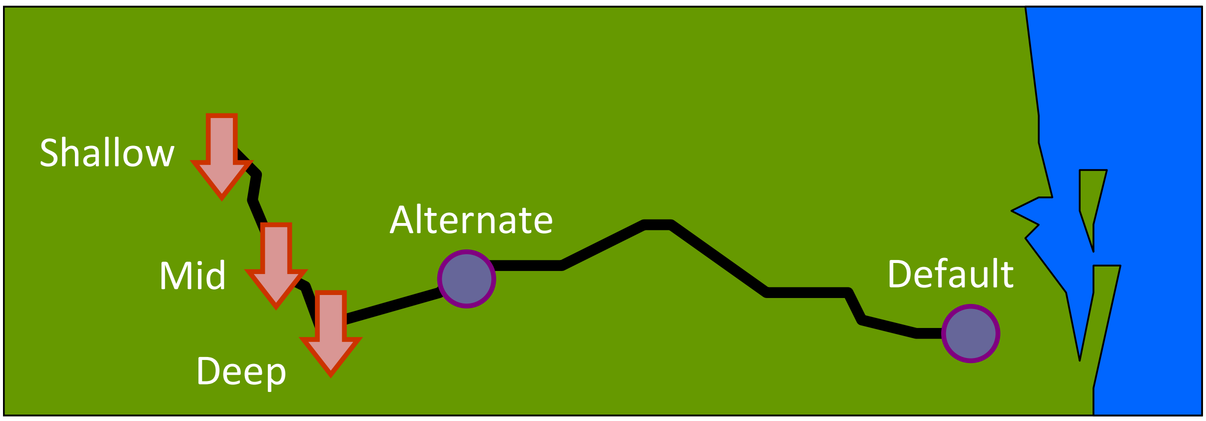


Figure 14 —Surat injection locations and the default and alternate South Queensland emission hub locations

Figure 15 shows the effect of re-locating the hub and so reducing the transport distance by 276 km. This change in location results in specific cost savings of around A$9/t and reduces the present value of all costs by about A$0.9 billion. The majority of the savings (in both capital and operating costs) are a result of the shorter transport distance.

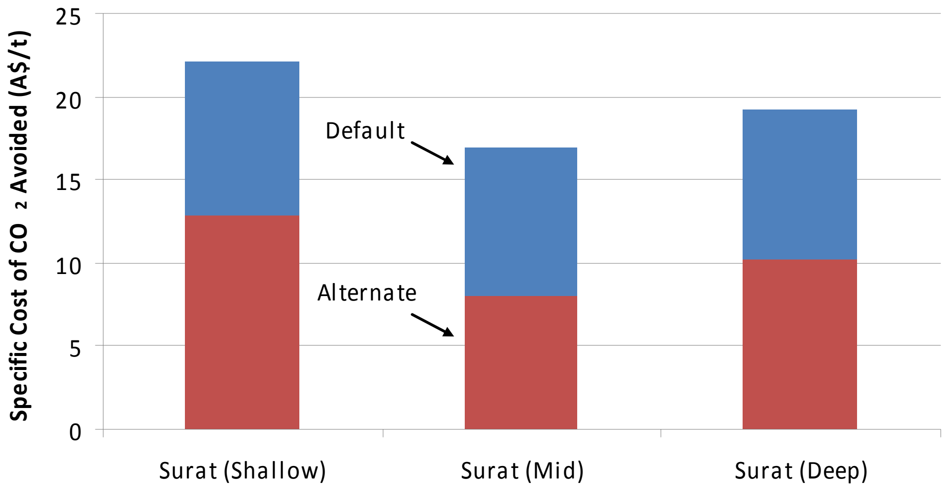


Figure 15 — Effect on cost of changing source location

5 Summary

Our best current estimates of the costs of CO_2 compression, transport and injection for individual source-sink matches in eastern Australia range from A$10 per tonne (for the Latrobe Valley to the Gippsland Basin) to A$1,539 (for North Queensland to the Denison Trough) per tonne of CO_2 avoided. Our best current estimates of the costs for combinations of sources range from A$22 to A$210 per tonne of CO_2 avoided on the East Coast, and A$14 to A$6,200 per tonne of CO_2 avoided in the Lesueur Sandstone in the Perth Region of Western Australia.

The up-front capital costs for each individual case range from A$1.2 billion (for the Latrobe Valley to the Gippsland basin) to approximately A$162 billion (for North Queensland to the Denison Trough). This does not include the cost of CO_2 capture or initial compression to supercritical conditions. For case combinations, the range of up-front capital costs is from A$0.8 billion to A$341 billion.

We examine the sensitivity of CO_2 transport and injection for the Surat Basin cases to selected changes in assumptions.

- The effect of adding seismic monitoring is to increase the cost of CO_2 avoided by between A$1.0 and A$2.8 per tonne or between 1% and 16% of the base cost.

- Drilling extra wells to account for failed and monitoring wells increases the costs of CO_2 avoided by A$0.5 to A$1.4 per tonne for most cases and by over A$5.9 per tonne for cases with more than 2,000 wells. As a proportion of the base cost, extra wells lead to a cost increase of between 3% and 11%.

- Workover costs had little effect, increasing costs of CO_2 avoided by 1% to 4%. For the cases with more than 2,000 wells, the impact is between 8% and 10%.

- CO_2 transport and injection costs show economies of scale as the rate of CO_2 injection increases up to a point where injection costs dominate and then reverse the trend.

- The additional cost of exploration, appraisal and development is estimated to be A$5/t. This increases the cost of CO_2 avoided by 6% to 18%.

- Changing the real discount rate from 12% to 7% reduces the cost of CO_2 avoided by about 30%.

- An expected value analysis shows that the minimum carbon price required to cover the costs of exploration, appraisal and development for the Surat Basin sites is between A$33 per and A$91 per tonne injected.

- Relocating the South Queensland emissions hub to a site 100 km from the Surat Basin reduces the cost of CO_2 avoided by about A$9 per tonne or by between 42% and 52% of the base cost.

The costs are highly variable, being dependent on the rate of CO_2 injection as well as the characteristics and locations of the storage reservoirs. The costs are also uncertain because they are based on uncertain unit costs and storage reservoir characteristics. However, we have not quantified the cost uncertainties. Such uncertainties could be reduced by further exploration and appraisal, by detailed system design and by obtaining vendor quotes based on such designs. In addition, this is a scoping analysis based on rules of thumb and reservoir simulation to model the transport and injection of the CO_2. Therefore, our estimates might change based on more rigorous analysis.

6 References

1. IEA (2003), "IEA Technical and Financial Assessment Criteria: Criteria for Appraisal Studies", IEA/OECD, Paris.
2. Allinson, W.G., Ho, M.T., Neal, P.R., Wiley D.E., "The methodology used for estimating the costs of CCS", In *Proceedings of the 8th International Conference on Greenhouse Gas Control Technology (GHGT-8)*, Trondheim, Norway, 19–22 June 2006, Paper #0191.
3. ACIL Tasman (2009), "Australian stationary energy emissions (Final Draft)", ACIL Tasman
4. RISC (2009), "CO_2 Injection Well Cost Estimation for Federal Government Carbon Storage Taskforce", RISC
5. WorleyParsons (2009), "Summary of Pipeline Sizing Study", WorleyParsons, Brisbane 401001-00507-002-PR-REP-0001_B Summary of Pipeline Sizing Study.pdf.
6. Spence, K., (2009), "Exploration & Development of Carbon Storage Sites: An estimate of activity levels, resource requirements and costs", Carbon Storage Task Force, Department of Resources, Energy and Tourism
7. Cinar, Y., Neal, P.R., Allinson, W.G. and Sayers, J., "Geo-engineering and Economic Assessment of a Potential CO_2 Sequestration Site in Southeast Queensland, Australia", *SPE Reservoir Evaluation and Engineering*, in press, SPE 108924.
8. Cinar, Y., Bukhteeva, O., Neal, P.R., Allinson, W.G., and Paterson, L., "CO_2 Storage in Low Permeability Formations", *2008 SPE Improved Oil Recovery Symposium*, Tulsa OK., U.S.A., 19–23 April 2008, SPE 114028.
9. Neal, P.R., Ho, M.T., Dunsmore, R.E., Allinson, W.G., and McKee, G.A., "The economics of carbon capture and storage in the Latrobe Valley, Victoria, Australia" In *Proceedings of the 8th International Conference on Greenhouse Gas Control Technology (GHGT-8)*, Trondheim, Norway, 19–22 June 2006, Paper #0192.

Appendix 1 Emissions estimates from ACIL Tasman

Australian stationary energy emissions (3UHOLPLQDU\ Draft)

An assessment of stationary energy emissions by location suitable for capture and storage

Prepared for the Carbon Storage Taskforce

27 February 2009

ACIL Tasman

Economics Policy Strategy

Reliance and Disclaimer

ACIL Tasman Pty Ltd

ABN 68 102 652 148
Internet www.aciltasman.com.au

Melbourne (Head Office)

Level 6, 224-236 Queen Street
Melbourne VIC 3000

Telephone (+61 3) 9600 3144
Facsimile (+61 3) 9600 3155
Email melbourne@aciltasman.com.au

Brisbane

Level 15, 127 Creek Street
Brisbane QLD 4000
GPO Box 32
Brisbane QLD 4001

Telephone (+61 7) 3009 8700
Facsimile (+61 7) 3009 8799
Email brisbane@aciltasman.com.au

Canberra

Level 1, 33 Ainslie Place
Canberra City ACT 2600
GPO Box 1322
Canberra ACT 2601

Telephone (+61 2) 6103 8200
Facsimile (+61 2) 6103 8233
Email canberra@aciltasman.com.au

Darwin

Suite G1, Paspalis Centrepoint
48-50 Smith Street
Darwin NT 0800
GPO Box 908
Darwin NT 0801

Telephone (+61 8) 8943 0643
Facsimile (+61 8) 8941 0848
Email darwin@aciltasman.com.au

Perth

Centa Building C2, 118 Railway Street
West Perth WA 6005

Telephone (+61 8) 9449 9600
Facsimile (+61 8) 9322 3955
Email perth@aciltasman.com.au

Sydney

PO Box 1554
Double Bay NSW 1360

Telephone (+61 2) 9958 6644
Facsimile (+61 2) 8080 8142
Email sydney@aciltasman.com.au

For information on this report

Please contact:

Paul Hyslop
Telephone (07) 3009 8703
Mobile 0417 392 079
Email p.hyslop@aciltasman.com.au

1 Introduction and scope

The Carbon Storage Taskforce requested ACIL Tasman to assist it in developing an initial baseline of likely annual emissions from the stationary energy sector by geographical region that could be logically hubbed for transport to long term storage sites.

The purpose of the baseline was to establish quickly a reasonable initial estimate, by location of the annual emissions suitable for carbon capture and storage. It is understood that this initial estimate will then be used in consultation with industry and other stakeholders and will be further refined over time as better information becomes available.

The scope of the project included:

- Establishing annual emissions profiles for emitters or geographically collocated groups of emitters within the stationary energy sector
- Geographically grouping these emitters based on criteria set by the Carbon Storage Taskforce.

It was agreed that emissions projections for the years 2010, 2015 and 2020 would be used to set the baseline.

2 Methodology

ACIL Tasman has extensive experience in projections in both the electricity and gas markets in Australia including the development and production of LNG. Our projections are supported by our sophisticated models of the electricity and gas market, *PowerMark* and *GasMark Global*. Some details of these models are provided in Appendix A. We utilised recent gas and electricity market projections in developing the emissions baselines in this Report.

The stationary energy sector represents around 50% of total emissions in Australia with emissions from the sector being around 283 Mt CO2-e in 2005. This is projected to grow to around 304 Mt CO2-e over the initial Kyoto measurement period of 2008 – 2012 (prior to the introduction of the Carbon Pollution Reduction Scheme).

Electricity represents around two thirds of the 2008-2012 projected emissions at 204 Mt CO2-e with the remainder coming from direct combustion at 100 Mt CO2-e.

Direct combustion includes:

- non-electricity energy industries such as natural gas production and liquefaction, petroleum refining and the manufacture of solid fuels;
- manufacturing and construction industries including cement, metals processing, pulp, paper and print; non-metallic minerals; and food and beverages;
- small combustion such as home heating, on-site diesel generation, and on-farm machinery.

The methodology that we used in developing the initial baseline is set out in the following paragraphs.

Electricity sector emissions

We extracted projected emissions from a recent *PowerMark* model run. This model run was a case where emissions in 2020 fall to 10% below the emissions in year 2000. *PowerMark* explicitly models the efficiency and carbon intensity of all major power stations. Annual emissions by power station were extracted from the model run in the years 2010, 2015 and 2020.

The change in emissions over time for the electricity sector is important – particularly within the competitive wholesale electricity markets of the NEM and the SWIS. While electricity demand is expected to continue to grow, the effect of explicit carbon pricing through the proposed Carbon Pollution

Reduction Scheme (CPRS) is projected to result in a decrease in emission intensity over the period to 2020. Indeed, with carbon prices above $35/tonne CO_2, the modelling suggests that a number of large coal-fired power stations will no longer be commercially viable and will be forced into early retirement. These are projected to be replaced by gas-fired CCGT units which have an emissions intensity of around 0.4 to 0.5 tonnes per MWh, compared with brown coal at 1 to 1.2 tonnes per MWh.

This trend highlights an interesting paradox for carbon capture and storage efforts: the longer the lead-time for commercial deployment of CCS technology, the smaller the electricity sector emissions that are potentially able to be captured. However, once CCS technology is proven and is commercially competitive with alternative generation technologies (on a carbon inclusive basis), there is potentially a growing demand for CCS applications from the sector.

LNG and natural gas

Using a recent GasMark Global projection for Australia, we extracted gas projections for production at all gas basins in Australia and consumption across the country. We then calculated the associated emissions using estimated gas field content and emissions produced in gas and LNG production. Projections were extracted for the years 2010, 2015 and 2020.

According to AGO data the emission associated with gas production was around 8.6 Mt in 2000-01. This total has been pro-rated to 2007 based on APPEA production data for conventional gas. ACIL Tasman projections of gas production by Basin have been used to scale this total for 2010, 2015 and 2020. For offshore fields, 60% of the total estimated emissions are assumed to be associated with the field and 40% with onshore processing.

Emissions associated with the production of Coal Seam Gas (CSG) are assumed to comprise of combustion emissions associated with gas compression (assumed at 6% of gas produced).

Emissions associated with LNG production are handled separately from domestic gas supply. Emissions for LNG are split between the reservoir and liquefaction facility using assumed emission factors and reservoir compositions.

Other large stationary energy emissions

We reviewed other sources of concentrated emissions from the stationary energy sector. We concluded that the following industries could be reasonably considered for economic carbon capture and storage:

- Aluminium
- Alumina
- Cement
- Petroleum refining
- Steel and iron making.

We projected emissions for each of these sectors in 2010, 2015 and 2020 based on current production and projected growth or decline rates.

3 Assumptions

The data collated in this report is sourced from:

- *PowerMark* for electricity sector emissions
- *GasMark Global* for gas sector emissions
- General sectoral projections for other industries covered in the report.

The assumptions underlying the *PowerMark* and *GasMark Global* modelling are extensive as the models make projections for the gas and electricity sectors over extended study periods usually between 10 and 20 years in length.

The inputs to the models include disaggregated demand projections, existing suppliers and new entrant supply based on the competitive cost of technology and locations. New entry supply is committed on a commercial basis using the least cost solution at the time of the commitment.

In the case of electricity:

- demand is based on NEMMCO produced demand forecasts published in the annual Statement Of Opportunities
- Existing supply is modelled based on an extensive proprietary ACIL Tasman database of information about existing plant including fuel costs, heat rates, efficiencies and emissions intensities
- New entrant supply is based on commercial entry decisions using the least cost available technology at the time of commitment. These new entry costs are developed using a proprietary ACIL Tasman discounted cash flow model. We have assumed that plant fitted with CCS is not commercially available by 2020 and so only demonstration plant were included in the supply side modelling.

In the case of gas:

- Demand is based on ACIL Tasman projected growth rates using a consensus forecast from a variety of sources
- Existing supply is modelled based on an extensive proprietary ACIL Tasman database of information about existing fields
- New entrant supply is based on commercial least cost entry using established and projected reserves.

In the case of the other industries growth was projected through ACIL Tasman analysis of the likely additions and retirements in each case.

3.1 White paper assumptions – key differences

ACIL Tasman does not have complete knowledge of the White Paper assumptions as it was not involved in the detailed Treasury modelling and is not privy to all assumptions underlying that modelling.

However ACIL Tasman undertook some electricity sector modelling for the Department of Climate Change(DCC). In particular we modelled the CPRS5 as Policy Case #3 case using the following assumptions provided by DCC:

- Electricity demand growth and system load factors
- Gas prices
- Carbon price
- New entry costs
- Renewables.

Electricity demand projections provided by DCC in the CPRS case had a compound growth rate of 1.53% compared with the most recent NEMMCO forecast of 2.15% which has accounted for a modest emissions permit price of around $20 in 2010. ACIL Tasman estimated a modest affect on energy and demand from the introduction of the CPRS. Hence the White Paper modelling would appear to have demand projections that are lower than those used in the 10% case. This would primarily affect the new entry schedule with new entry being later in the lower demand case.

Gas prices provided by DCC were generally between 10 and 20% lower than ACIL Tasman's own projection used in the 10% reduction case. ACIL Tasman was instructed to use its own coal price projections. Hence gas fired plant were inherently more competitive in the DCC modelling. This is significant because much of the replacement for coal will be open and combined cycle gas fired plant.

Where seeking a carbon reduction target ACIL Tasman would typically iterate the modelling to find the carbon price that meets the target. This was not possible because the prices were set by DCC. It should be noted that our modelling of the CPRS5 case using the carbon prices provided to us by DCC did not result in a 5% reduction in emissions over 2000 levels by 2020. We found that the emissions reduced by around 3.2% over 2010/11 levels and stabilised rather than fell further.

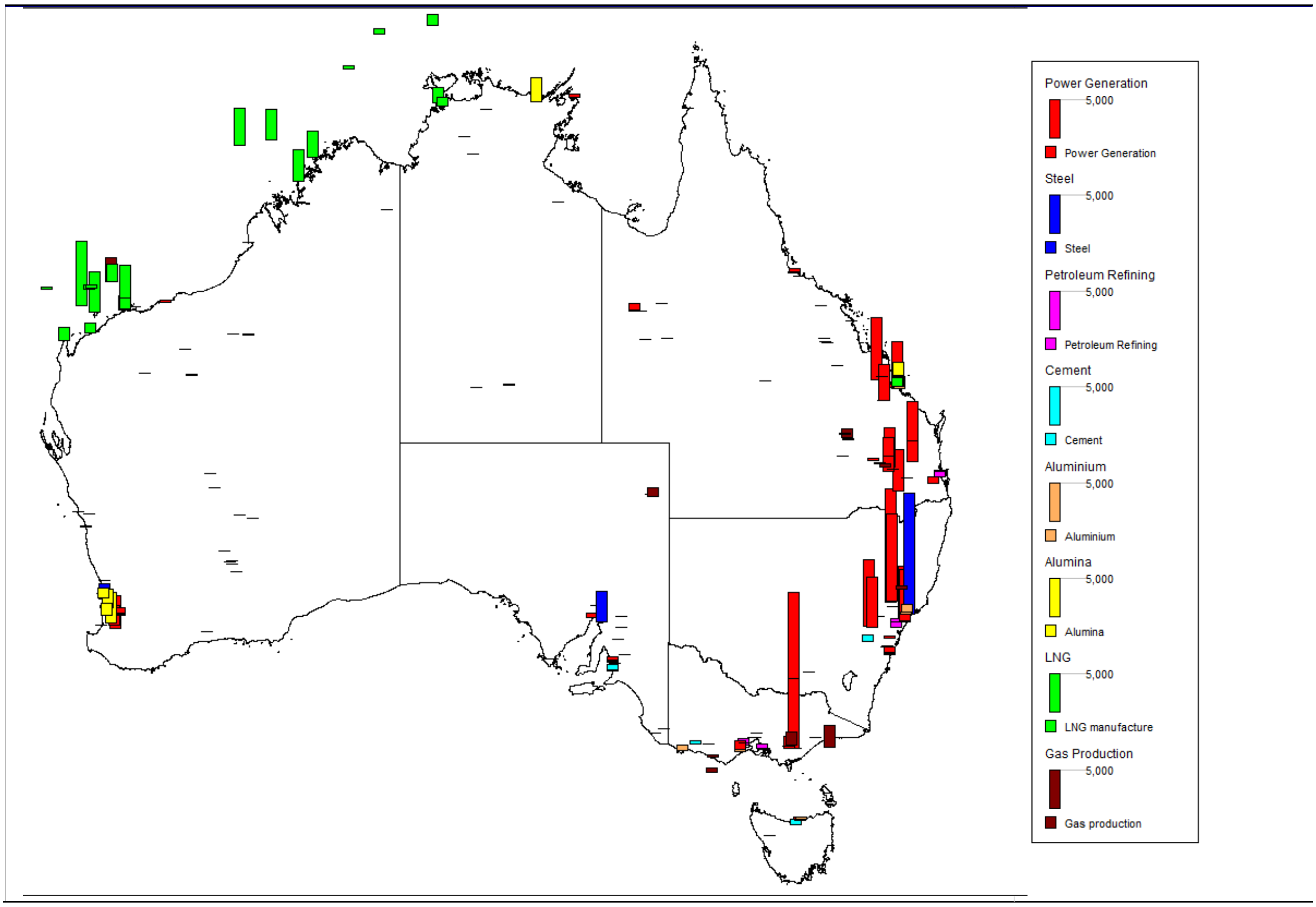
New entrant costs were provided based on the White Paper modelling effort. The new entrant costs provided to ACIL Tasman were generally lower than those used by ACIL Tasman in its own projections including in the 10% reduction case. In addition the availability of new entrant CCS technologies by 2017 was much earlier than what ACIL Tasman considers realistic based on discussions with experts and suppliers. From a modelling perspective, new entrants would enter the market at lower average prices in the White Paper modelling and the new CCS technologies would be competitive at lower prices at an earlier point in time.

DCC provided ACIL Tasman with the renewable energy schedule which was incorporated into the modelling exogenously. This led to around 28,000 GWh of additional generation between 2010 and 2020. In ACIL Tasman's 10% reduction case, we assumed around 32,500 GWh of additional renewable generation over the same period (based on our analysis of technologies and likely entrants).

4 Results

The emission estimates for each sector examined in 2020 are shown graphically in Figure 1.

Figure 1 **Summary of geographical emissions estimated for 2020**



Data source: Various sources

Noticeably there are up to nine key areas of emissions concentrations around Australia being

- Gladstone, Rockhampton and Biloela
- The East Surat basin
- The Hunter Valley and Newcastle
- NSW West/Lithgow
- The Latrobe Valley
- Port Augusta and Port Kembla
- Perth and Kwinana
- The North West shelf

- Darwin

The emissions projections for each of these locations for each of 2010, 2015 and 2020 are set out in Table 1.

Table 1 **Total emissions projections by key location ('000 tonnes)**

Location	2010	2015	2020
Gladstone, Rockhampton and Biloela	32,107	32,372	29,332
East Surat basin	23,287	24,649	27,540
Hunter Valley and Newcastle	44,763	40,616	38,721
NSW west and Lithgow	13,688	14,093	14,342
Latrobe Valley	60,631	44,391	30,603
Port Augusta and Port Kembla	8,963	7,772	3,842
Perth and Kwinana	27,878	25,420	25,139
North West Shelf	6,938	10,169	16,618
Darwin	1,221	4,521	7,722
Total Key Sites	**219,476**	**204,003**	**193,859**

Data source: Various

5 Comparison with CPRS5

An additional request was made to comment on the impact of a 5% emissions reductions target by 2020 that has been the focus of recent government policy versus a 10% emissions reduction target assumed in this report. The impact is material particularly in Victoria and in the Hunter region in NSW in both 2015 and 2020 where the bulk of the difference in savings are made through the closure of coal fired power stations.

The comparison cannot be made precisely because of some differences in near term new entrant planting assumptions in the two cases as the 10% case was run early in 2008 and the 5% case late in 2008.

Table 2 shows the emissions estimate comparisons for the two cases for the years 2015 and 2020.

Table 2 **Emissions Comparisons 10% and CPRS5 5% cases**

Location	2015		2020	
	Carbon Storage	CPRS5 Equivalent	Carbon Storage	CPRS5 Equivalent
Gladstone, Rockhampton and Biloela	32,372	39,572	29,332	39,956
East Surat basin	24,649	24,725	27,540	29,115
Hunter Valley and Newcastle	40,616	51,252	38,721	51,312
NSW west and Lithgow	14,093	11,810	14,342	11,077
Latrobe Valley	44,391	57,160	30,603	57,023
Port Augusta and Port Kembla	7,772	8,853	3,842	4,402
Perth and Kwinana	25,420	25,420	25,139	25,139
North West Shelf	10,169	10,169	16,618	16,618
Darwin	4,521	4,521	7,722	7,722
Total Key Sites	204,003	233,481	193,859	242,364

Data source: Various

A comparison of the two cases shows that shifting to a 5% emissions reduction target from a 10% emissions reduction target leads to a material change in emissions projections for 2015 and 2020. The shift from 10% to 5% leads to an increase in projected emissions available for capture of around 29 million tonnes or 14.4% in 2015 and around 49 million tonnes or 25% in 2020.

6 Conclusions

The initial projections indicate that there are up to nine key sites around Australia that are worth considering for carbon capture and storage, based on emissions concentration, representing around 74% of projected stationary energy emissions in 2010.

Based on our projections the proportion of total stationary energy emissions encompassed by these key locations grows to 82% by 2020 while total emissions falls from 227 Mt in 2010 to 210 Mt in 2020.

While we have identified the potential regions using geographical concentrations, further work is required to determine whether carbon capture and storage is viable including:

- An economic and technical assessment of the carbon capture processes required in each region including the ability to economically retrofit carbon capture technology
- A geological, technical and economic assessment of possible storage sites and storage technologies for each key site identified
- An technical and economic assessment of the transportation of emissions from the key sites to storage locations where identified
- An economic assessment of the need for economic regulation of carbon capture and storage including the need for government funding and regulated access in order to avoid market failure.

Further a comparison of our projections based on a 10% emissions reduction target by 2020 over 2000 levels with projections from the CPRS5 5% reduction target leads to a material difference in emissions projections in both 2015 and 2020.

A PowerMark and GasMark Global

A.1 PowerMark

PowerMark has been developed over the past 10 years in parallel with the development of the NEM. The model is used extensively by ACIL Tasman in simulations and sensitivity analyses conducted on behalf of industry clients. PowerMark is a complex model with many unique and valuable features. It provides insights into:

- wholesale pool price trends and volatility;
- variability attributable to weather/outages and other stochastic events;
- market power and implications for generator bidding behaviour;
- network utilisation and generation capacity constraints;
- viability of merchant plant and regional interconnections;
- contract and price cap values;
- timing, size and configuration of new entrant generators;
- demands for coal, gas and other fuels; and
- the cost outlook for buyers of wholesale electricity.

PowerMark effectively replicates the NEMMCO settlement engine — SPD engine (scheduling, pricing and dispatch). This is achieved through the use of a large-scale LP-based solution incorporating features such as quadratic interconnector loss functions, unit ramp rates, network constraints and dispatchable loads. The veracity of modelled outcomes relative to the NEMMCO SPD has been extensively tested and exhibits an extremely close fit.

In accordance with the NEM's market design, the price at any one period is the cost of the next increment of generation in each region (the shadow or dual price within the LP). The LP seeks to minimise the aggregate cost of generation for the market as a whole, whilst meeting regional demand and other network constraints.

A distinctive feature of PowerMark is the inclusion of a portfolio optimisation module. This optional setting allows selected portfolios to seek to maximise net revenue positions (taking into consideration contracts for differences) for each period. These modified generator offers are then resubmitted to the settlement engine to determine prices and dispatch levels. Each period is iterated until a convergence point (based on Nash-Cournot equilibria theory) is found.

A.2 GasMark Global

GasMark Global (GMG) is a generic gas modelling platform developed by ACIL Tasman. GMG has the flexibility to represent the unique characteristics of gas markets across the globe, including both pipeline gas and LNG. Its potential applications cover a broad scope— from global LNG trade, through to intra-country and regional market analysis. GasMark Global Australia (GMG Australia) is an Australian version of the model which focuses specifically on the Australian market (including both Eastern Australian and Western Australian modules), but which has the capacity to interface with international LNG markets.

Settlement

At its core, GMG Australia is a partial spatial equilibrium model. The market is represented by a collection of spatially related nodal objects (supply sources, demand points, LNG liquefaction and receiving facilities), connected via a network of pipeline or LNG shipping elements (in a similar fashion to 'arks' within a network model).

The equilibrium solution of the model is found through application of linear programming techniques which seek to maximise the sum of producer and consumer surplus across the entire market simultaneously. The objective function of this solution, which is well established in economic theory[1], consists of three terms:

- the integral of the demand price function over demand; minus
- the integral of the supply price function over supply; minus
- the sum of the transportation, conversion and storage costs.

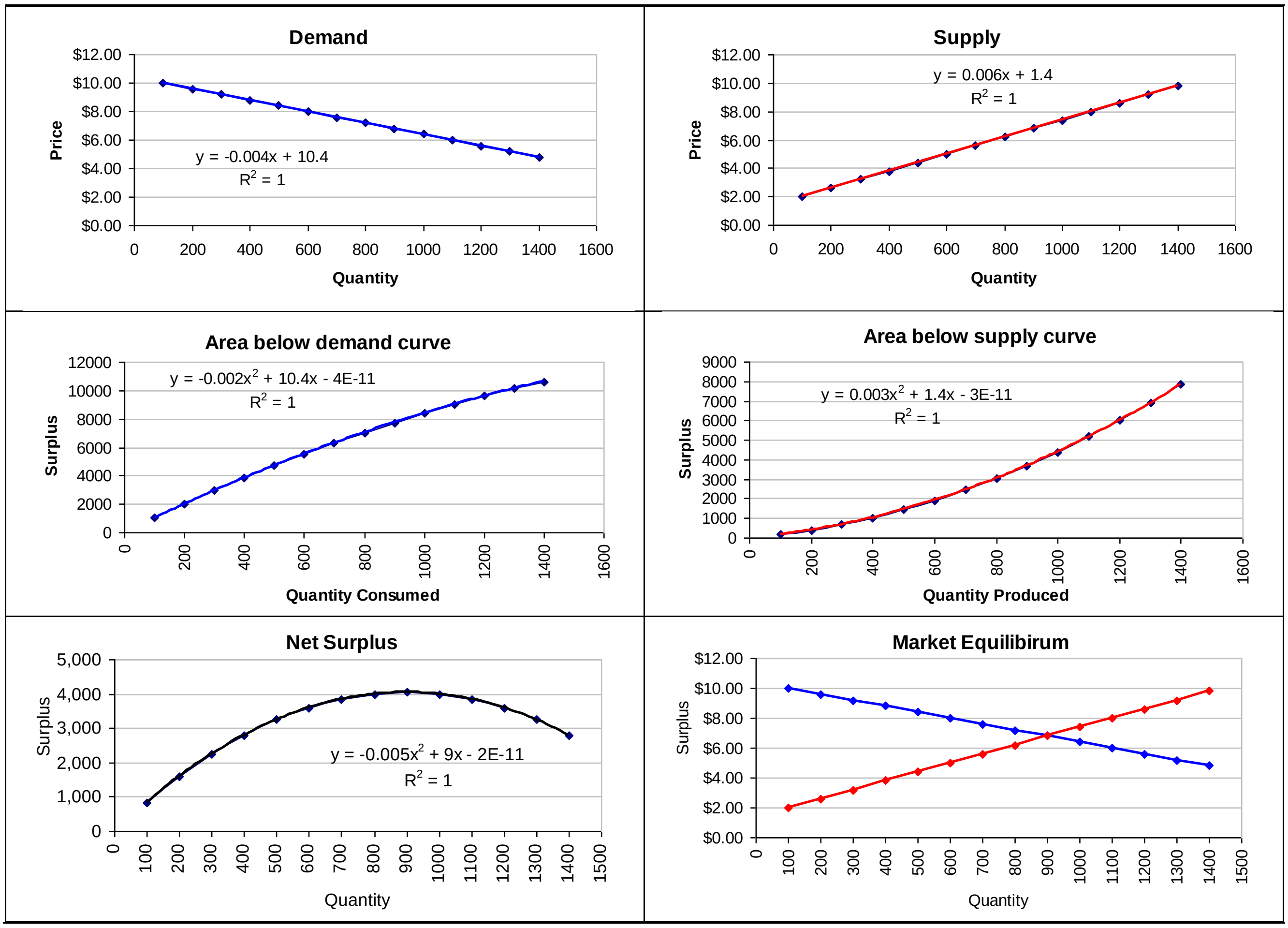
The solution results in an economically efficient system where lower cost sources of supply are utilised before more expensive sources and end-users who have higher willingness to pay are served before those who are less willing to pay. Through the process of maximising producer and consumer surplus, transportation costs are minimised and spatial arbitrage opportunities are eliminated. Each market is cleared with a single competitive price.

Figure 2 seeks to explain diagrammatically a simplified example of the optimisation process. The two charts at the top of Figure 2 show simple linear demand and supply functions for a particular market. The figures in the middle of Figure 2 show the integrals of these demand and supply functions, which represent the areas under the demand and supply curves. These are equivalent

[1] The theoretical framework for the market solution used in GMG is attributed to Nobel Prize winning economist Paul Samuelson.

to the consumer and producer surpluses at each price point along the curve. The figure on the bottom left shows the summation of the consumer and producer surplus, with a maximum clearly evident at a quantity of 900 units. This is equivalent to the equilibrium quantity when demand and supply curves are overlayed as shown in the bottom right figure.

Figure 2 **Simplified example of market equilibrium and settlement process**



Data source: ACIL Tasman

The distinguishing characteristic of spatial price equilibrium models lies in their recognition of the importance of space and transportation costs associated with transporting a commodity from a supply source to a demand centre. Since gas markets are interlinked by a complex series of transportation paths (pipelines, shipping paths) with distinct pricing structures (fixed, zonal or distance based), GMG Australia also includes a detailed network model with these features.

Spatial price equilibrium models have been used to study problems in a number of fields including agriculture, energy markets, mineral economics, as well as in finance. These perfectly competitive partial equilibrium models assume that there are many producers and consumers involved in the production and consumption, respectively, of one or more commodities and that as a result the market settles in an economically efficient fashion. Similar approaches are used within gas market models across the world. Examples include:

- Gas Pipeline Competition Model (GPCM®) developed by RBAC Inc energy industry forecasting systems in the USA.
- Market Builder from Altos Partners, another US-based energy market analysis company.

Data inputs

The user can establish the level of detail by defining a set of supply regions, customers, demand regions, pipelines and LNG facilities. These sets of basic entities in the model can be very detailed or aggregated as best suits the objectives of the user. A 'pipeline' could represent an actual pipeline or a pipeline corridor between a supply and a demand region. A supplier could be a whole gas production basin aggregating the output of many individual fields, or could be a specific producer in a smaller region. Similarly a demand point could be a single industrial user or an aggregation of small consumers such as the residential and commercial users typically serviced by energy utility companies.

The inputs to GMG Australia can be categorised as follows:

- **Existing and potential new sources of gas supply**: these are characterised by assumptions about available reserves, production rates, production decline characteristics, and minimum price expectations of the producer. These price expectations may be based on long-run marginal costs of production or on market expectations, including producer's understandings of substitute prices.
- **Existing and potential new gas demand**: demand may relate to a specific load such as a power station, or fertiliser plant. Alternatively it may relate to a group or aggregation of customers, such as the residential or commercial utility load in a particular region or location. Loads are defined in terms of their location, annual gas demand, price tolerance and price elasticity of demand (that is, the amount by which demand will increase or decrease depending on the price at which gas can be delivered), and load factor (defined as the ratio between average and maximum daily quantity requirements).
- **Existing, new and expanded transmission pipeline capacity**: pipelines are represented in terms of their geographic location, physical capacity, system average load factor (which is relevant to determination of the effective annual throughput capability given assumptions regarding short-term [daily] capacity limits) and tariffs.

- **Existing and potential new LNG facilities**: LNG facilities include liquefaction plants, regasification (receiving) terminals and assumptions regarding shipping costs and routes. LNG facilities play a similar role to pipelines in that they link supply sources with demand. LNG plants and terminals are defined at the plant level and require assumptions with regard to annual throughput capacity and tariffs for conversion.

Appendix 2 Detailed well cost estimates from RISC

Integrity Experience Advice

CO_2 Injection Well Cost Estimation

For

Federal Government Carbon Storage Taskforce

' UDIW

March 2009

Declaration

The Federal Government Carbon Storage Taskforce has commissioned Resource Investment Strategy Consultants ("RISC") to provide an independent estimate of well costs for CO2 disposal wells.

The assessment of petroleum assets is subject to uncertainty because it involves judgments on many variables that cannot be precisely assessed, including reserves, future oil and gas production rates, the costs associated with producing these volumes, access to product markets, product prices and the potential impact of fiscal/regulatory changes.

The statements and opinions attributable to RISC are given in good faith and in the belief that such statements are neither false nor misleading. In carrying out its tasks, RISC has considered and relied upon information obtained from the Department of Energy, Resources and Tourism as well as information in the public domain. The information provided to RISC has included both hard copy and electronic information.

Whilst every effort has been made to verify data and resolve apparent inconsistencies, neither RISC nor its servants accept any liability for its accuracy, nor do we warrant that our enquiries have revealed all of the matters, which an extensive examination may disclose. In particular, we have not independently verified, encumbrances, regulations or fiscal terms which apply to this field.

We believe our review and conclusions are sound but no warranty of accuracy or reliability is given to our conclusions.

RISC has no pecuniary interest, other than to the extent of the professional fees receivable for the preparation of this report, or other interest in the assets evaluated, that could reasonably be regarded as affecting our ability to give an unbiased view of these assets.

Our review was carried out only for the purpose referred to above and may not have relevance in other contexts.

DOCUMENT CONTROL

CO_2 Injection Well Cost Estimation

Client Name	DRET, Clean Coal and CO2 Section	**Client Representative**		Peter Wilson	
RISC Coordinator	Graham Jeffery	**RISC Job No**	8.0131	**Client Order No**	2788

Approvals

	Name/	**Signature**	**Date**
Prepared by	Dogan Seyyar		
Prepared by			
Prepared by			
Prepared by			
Prepared by			
Peer Review by	Simon Whitaker		
Editorial Review by	Graham Jeffery		
Authorised for Release by	Graham Jeffery		

Revision History

Revision	**Date**	**Description**	**Checked by**	**Approved by**

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1 INTRODUCTION

The Federal Government Carbon Storage Taskforce is currently developing a strategy for CO2 reinjection. As part of this work suitable geological basins have been identified as potentially suitable for CO2 injection. RISC has been requested to estimate costs for injection wells in each basin, based on information provided by the Department of Resources, Energy and Tourism (DRET, the Client). This report summarises RISC's findings using two future oil price scenarios.

2 CO_2 INJECTION WELL COST ESTIMATION

2.1 Client Provided Data

The client has provided characteristics for each basin using p90, p50 and p10 nomenclature to describe the range of cases. Water depth data for offshore injection basins and injection depth are shown in the Table below. RISC has not attempted to verify this data.

	QLD			QLD			QLD			QLD		
	Bowen			Denison			Galilee			Surat		
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
Water Depth, m	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Injection Depth, m	1,500	1,800	2,600	-	-	-	800	1,080	1,360	1,200	1,700	2,200

	SA/QLD			SA/QLD			NSW/QLD			VIC		
	Cooper			Eromanga			Clarence- Moreton			Gippsland		
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
Water Depth, m	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	64	52	70
Injection Depth, m	1,950	2,400	2,850	1,200	1,700	2,100	1,000	1,500	2,000	2,100	2,700	3,300

	VIC			VIC			VIC			VIC		
	Bass			Torquay			Otway - East			Otway -West		
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
Water Depth, m	-	77	82	78	73	79	N/A	64	85	-	-	85
Injection Depth, m	-	2,650	3,000	1,100	1,500	1,800	1,100	1,800	2,500	-	-	1,700

	WA			WA			WA			WA		
	Darling			Perth -Onshore South			Perth - Onshore North			Perth - Vlaming		
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
Water Depth, m	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	42	109	147
Injection Depth, m	900	1,300	-	-	-	-	-	-	-	1,800	2,130	2,630

Table 1 Data Provided by the Client

2.2 Assumptions

RISC has used its proprietry cost estimating tool to assess the cost of CO_2 injection wells of for the different depth in the various basins. Well time/depth data for the wells drilled between 1990 and 2007 has been gathered from the APPEA[1] Quarterly Drilling Statistics database and used for benchmarking. The figures below show the depth vs time distributions for onshore/and offshore wells drilled in the basins under consideration.

[1] Australian Petroleum Producers and Exploration Association

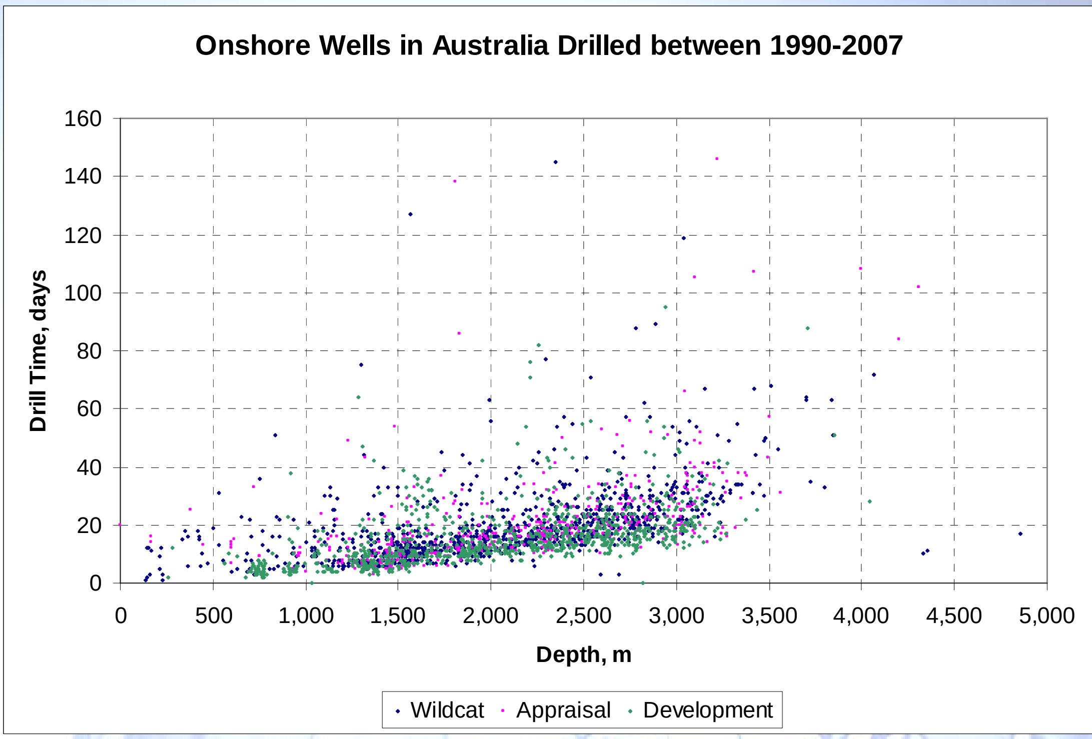


Figure 1 Depth vs Time Curves for Onshore Wells

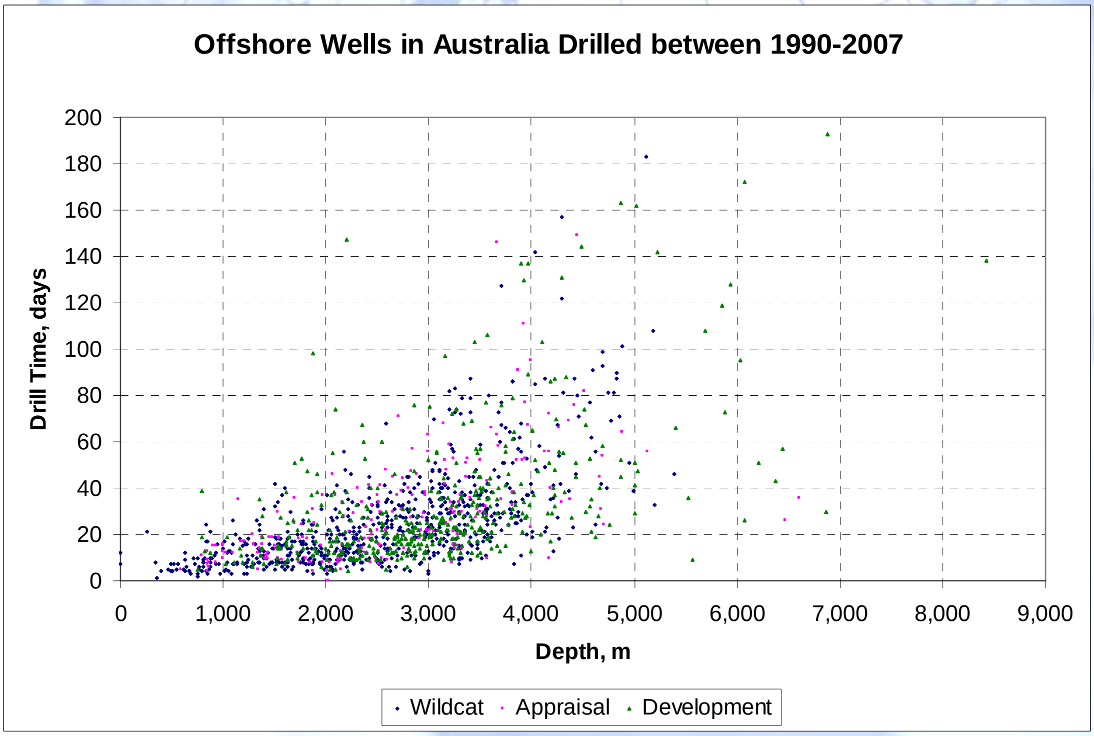


Figure 2 Depth vs Time Curves for Offshore Wells

Given the uncertainties in the oil and gas services market and drilling activities in particular, RISC has elected to create two estimates, for oil price environments of US$50/bbl and US$100/bbl. Increased market activity based on historically high oil prices has caused recent widespread cost increases and drilling rig rates in particulalr have been subject to extraordinary increases.

The figure below shows Upstream Cost Index (an index developed by IHS Energy to monitor upstream oil and gas cost developments) and ODS Petrodata Rig Rate Index movements since end-2004, with WTI oil price.

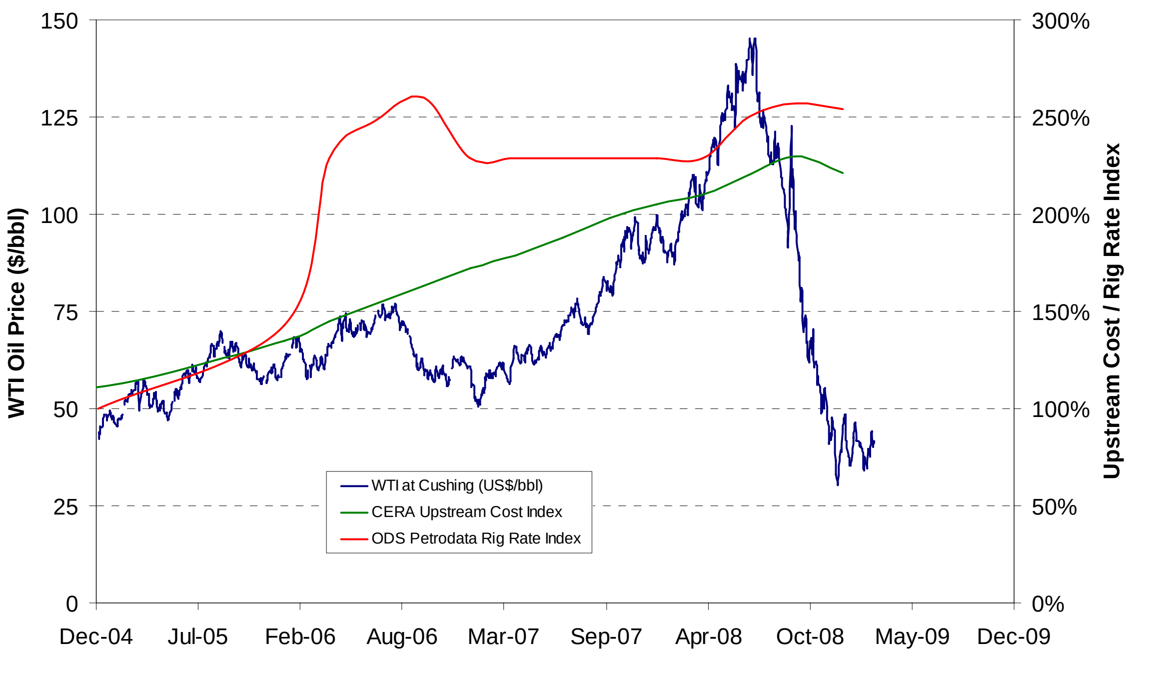


Figure 3 Oil Price vs CERA Upstream Cost Index and Rig Rate Index

RISC has also used the CRU[2]spi Steel Index for the two oil price environments to account for the effects of steel prices on the drilling and completion materials.

A summary of unit costs used by RISC for the well cost estimations is presented below:

[2] Commodity Resource Unit

			Onshore <1000 m	Onshore >1000 m	Shallow Water	Deep Water
50$/bbl Oil Price Economic Environment	CRUSPI Index		150	150	150	150
	Rig Rate	US$k/d	12.5	17.5	140	275
	Service/Support Rate	US$k/d	10	12.5	125	150
100$/bbl Oil Price Economic Environment	CRUSPI Index		250	250	250	250
	Rig Rate	US$k/d	17.5	25	200	400
	Service/Support Rate	US$k/d	12.5	15	150	175

Table 2 Summary of Assumptions

- onshore wells up to 1,000-1,200 m drilled depth can be achieved by using a small capacity cheaper rig as used for CSG operations in Queensland.
- offshore, a water depth of 100 m is assumed as the limit for jack-up drilling rigs; at greater water depths a semi-submergible rig is assumed to be required.
- all wells are assumed to be vertical (although in practice projects may utilise horizontal wells).
- all well cost estimates have a 20% contingency related to the time component.
- an exchange rate of 0.7 has been used for conversion from US$ to A$
- costs are estimated in 2009 dollars

2.3 RISC Time vs Depth and Cost vs Depth Curves

RISC's time vs depth and cost vs depth curves for the estimates for onshore and offshore CO_2 injection wells are shown below:

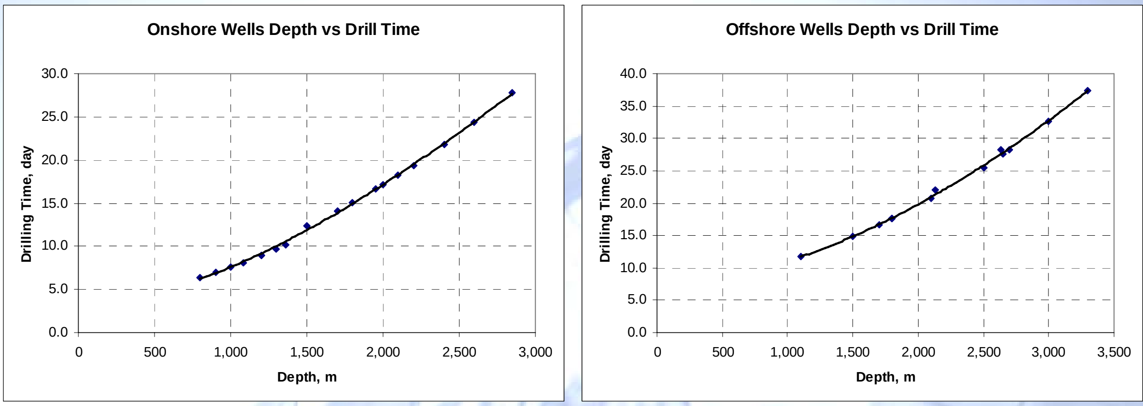


Figure 4 Time vs Depth Curves

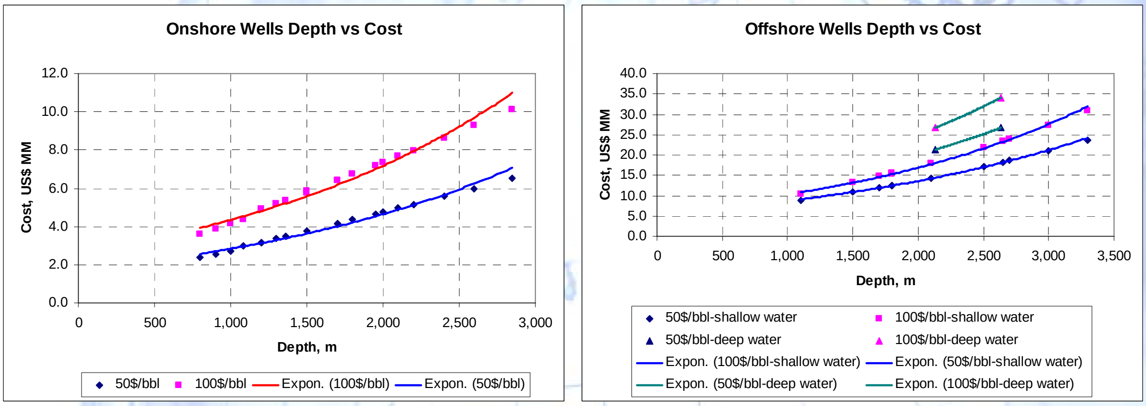


Figure 5 Cost vs Depth Curves

Cost estimates have been compared to the spread of historic data in the charts below, which includes all types of wells - wildcats, appraisal and development. RISC estimates include time for rig mobilisation, establishment and well completions, while some past actual well costs do not and RISC estimates include 20% time-related contingency.

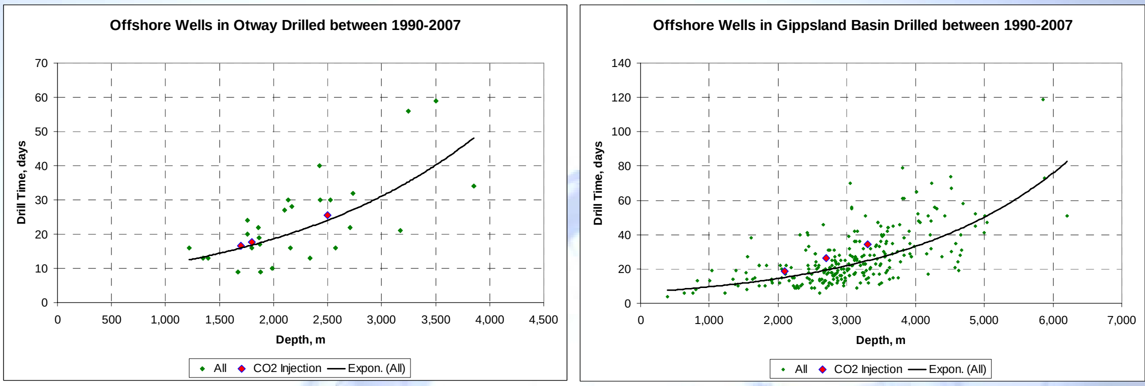


Figure 6 Comparison of Offshore Well Time Estimates against Historic Data

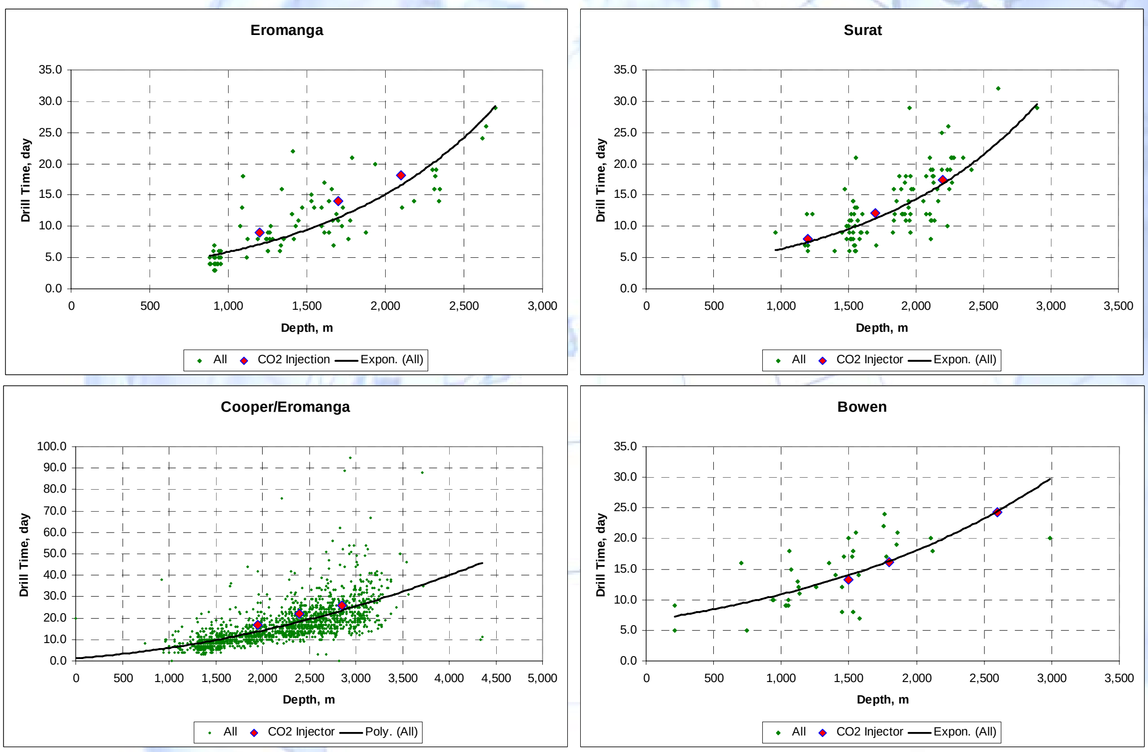


Figure 7 Comparison of Onshore Well Time Estimates against Historic Data

2.4 Well Costs

RISC's well cost estimates for all basins and depths under consideration are tabulated below:

			QLD			QLD			QLD			QLD		
			Bowen			Denison			Galilee			Surat		
			P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
	Water Depth	m	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Depth	m	1,500	1,800	2,600	-	-	-	800	1,080	1,360	1,200	1,700	2,200
	Drilling Time	day	11.3	15.1	24.3	-	-	-	6.4	8.1	10.2	9.0	14.1	19.4
50$/bbl	Unit Well Cost	US$ MM	2.6	3.1	4.2	-	-	-	1.7	2.1	2.4	2.2	2.9	3.6
		A$ MM	3.7	4.4	6.0	-	-	-	2.4	3.0	3.5	3.2	4.2	5.2
100$/bbl		US$ MM	4.0	4.7	6.5	-	-	-	2.5	3.1	3.8	3.4	4.5	5.6
		A$ MM	5.8	6.7	9.3	-	-	-	3.6	4.4	5.4	4.9	6.4	8.0

			SA/QLD			SA/QLD			NSW/QLD			VIC		
			Cooper			Eromanga			Clarence- Moreton			Gippsland		
			P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
	Water Depth	m	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	64	52	70
	Depth	m	1,950	2,400	2,850	1,200	1,700	2,100	1,000	1,500	2,000	2,100	2,700	3,300
	Drilling Time	day	16.6	21.8	27.9	9.0	14.1	18.2	7.6	12.3	17.1	20.7	28.2	37.5
50$/bbl	Unit Well Cost	US$ MM	3.3	3.9	4.6	2.2	2.9	3.5	1.9	2.7	3.3	10.1	13.0	16.6
		A$ MM	4.7	5.6	6.5	3.2	4.2	5.0	2.7	3.8	4.8	14.4	18.6	23.7
100$/bbl		US$ MM	5.0	6.0	7.1	3.4	4.5	5.4	2.9	4.1	5.1	12.6	16.8	21.7
		A$ MM	7.2	8.6	10.1	4.9	6.4	7.7	4.1	5.8	7.4	18.0	23.9	30.9

			VIC			VIC			VIC			VIC		
			Bass			Torquay			Otway - East			Otway -West		
			P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
	Water Depth	m	-	77	82	78	73	79	N/A	64	85	-	-	85
	Depth	m	-	2,650	3,000	1,100	1,500	1,800	1,100	1,800	2,500	-	-	1,700
	Drilling Time	day	-	27.5	32.6	11.8	14.8	17.6	14.3	17.6	25.5	-	-	16.6
50$/bbl	Unit Well Cost	US$ MM	-	12.8	14.8	6.2	7.6	8.8	2.4	8.8	12.0	-	-	8.4
		A$ MM	-	18.3	21.1	8.9	10.9	12.5	3.5	12.5	17.2	-	-	12.0
100$/bbl		US$ MM	-	16.4	19.1	7.2	9.2	10.8	3.4	10.8	15.3	-	-	10.3
		A$ MM	-	23.5	27.3	10.3	13.1	15.5	4.9	15.5	21.9	-	-	14.7

			WA			WA			WA			WA		
			Darling			Perth -Onshore South			Perth - Onshore North			Perth - Vlaming		
			P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
	Water Depth	m	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	42	109	147
	Depth	m	900	1,300	-	-	-	-	-	-	-	1,800	2,130	2,630
	Drilling Time	day	7.0	9.7	-	-	-	-	-	-	-	17.6	22.1	28.3
50$/bbl	Unit Well Cost	US$ MM	1.8	2.4	-	-	-	-	-	-	-	8.7	14.9	18.6
		A$ MM	2.5	3.4	-	-	-	-	-	-	-	12.5	21.3	26.6
100$/bbl		US$ MM	2.7	3.6	-	-	-	-	-	-	-	10.8	18.7	23.8
		A$ MM	3.9	5.2	-	-	-	-	-	-	-	15.4	26.7	34.0

Table 3 Summary of Cost Estimates

3 APPENDIX – WELL DESIGN CONSIDERATIONS[3]

Drilling and completion technology for injection wells in the oil and gas industry has evolved to a highly sophisticated state, such that it is now possible to drill and complete vertical and extended reach wells (including horizontal wells) in deep formations, using multiple completions and with corrosive fluids. On the basis of extensive oil industry experience, the technologies for drilling, injection, stimulation and completion for CO_2 injection wells exist and are being practised with some adaptations in CO_2 storage projects. In a CO_2 injection well, the principal well design considerations include pressure, corrosion-resistant materials and production and injection rates.

The design of a CO_2 injection well is very similar to that of a gas injection well in an oil field or natural gas storage project. Most downhole components need to be upgraded for higher pressure ratings and corrosion resistance. The technology for handling CO_2 has already been developed for Enhanced Oil Recovery operations and for the disposal of acid gas. Horizontal and extended reach wells can be good options for improving the rate of CO_2 injection from individual wells. The Weyburn field in Canada is an example in which the use of horizontal injection wells is improving oil recovery and increasing CO_2 storage. The horizontal injectors reduce the number of injection wells required for field development and has the added advantage that it can create injection profiles that reduce the adverse effects of injected-gas preferentially flowing through high-permeability zones.

An injection well and a wellhead are depicted in Figure 8.

Injection wells are commonly equipped with two valves for well control, one for regular use and one reserved for safety shutoff. In acid gas injection wells, a downhole safety valve is incorporated in the tubing, so that if equipment fails at the surface, the well is automatically shut down to prevent back flow. It is recommended that an automatic shutoff valve is installed on all CO_2 wells to ensure that no release occurs and to prevent CO_2 from inadvertently flowing back into the injection system. A typical downhole configuration for an injection well includes a double-grip packer, an on-off tool and a downhole shutoff valve. Annular pressure monitors help detect leaks in packers and tubing which is important in taking rapid corrective action. To prevent dangerous high-pressure buildup on surface equipment and to avoid CO_2 releases into the atmosphere, CO_2 injection must cease as soon as leaks occur. Rupture disks and safety valves can be used to relieve built-up pressure. Adequate plans need to be in place for dealing with excess CO_2 if the injection well needs to be shut in. Options include having a backup injection well or methods to safely vent CO_2 to the atmosphere.

The biggest difference between a typical gas injection well and CO2 injection well is cement and casing to cater for the CO2 corrosion factor. To cement a CO2 Sequestration well, a special (and very expensive) type of cement called “thermalock” needs to be used. Anything equipment that is going to come into contact with the CO2 i.e parts of the wellhead, casing shoes etc. should be chrome steel.

---

[3] IPCC Special Report on Carbon Dioxide Capture and Storage - 2005

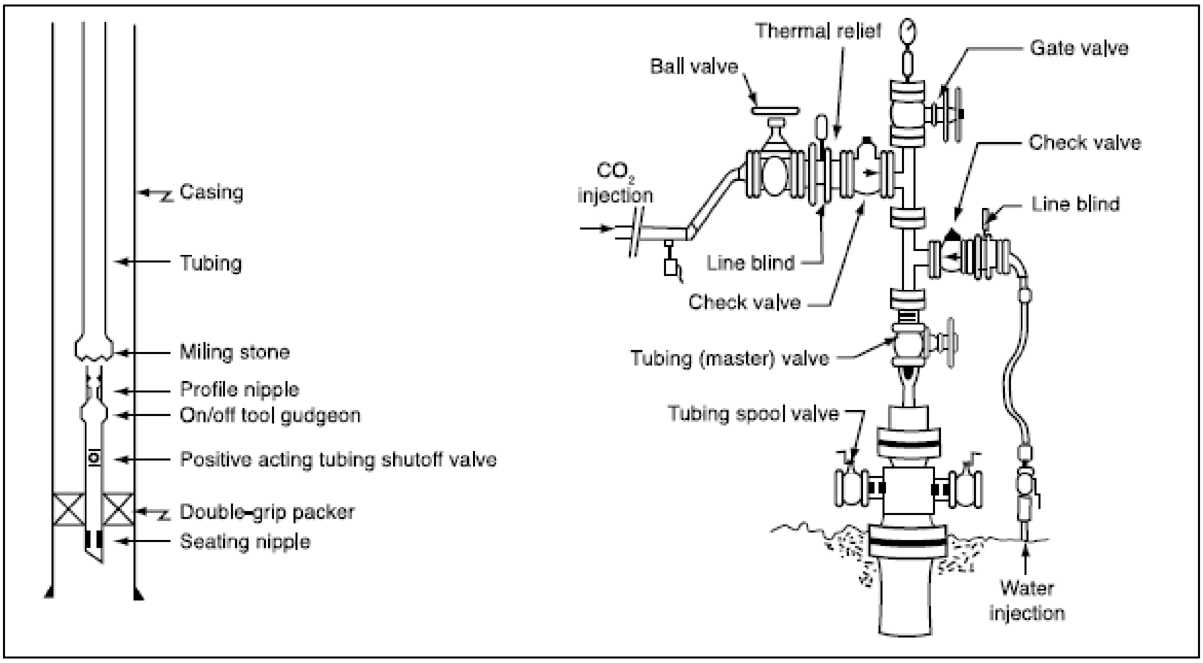


Figure 8 Typical CO_2 Injection Well and Wellhead Configuration

Proper maintenance of CO_2 injection wells is necessary to avoid leakage and well failures. Several practical procedures can be used to reduce the chance of CO_2 blow-out (uncontrolled flow) and mitigate the adverse effects if one should occur. These include periodic wellbore integrity surveys on drilled injection wells, improved blow-out prevention (BOP) maintenance, and installation of additional BOP on suspect wells, improved crew awareness, contingency planning and emergency response training.

For CO_2 injection through existing and old wells, key factors include the mechanical condition of the well and quality of the cement and well maintenance. A leaking wellbore annulus can be a pathway for CO_2 migration. Detailed logging programmes for checking wellbore integrity can be conducted by the operator to protect formations and prevent reservoir cross-flow. A well used for injection must be equipped with a packer to isolate pressure to the injection interval. All materials used in injection wells should be designed to anticipate peak volume, pressure and temperature. In the case of wet gas (containing free water), use of corrosion-resistant material is essential.

AUSTRALIAN HERITAGE

INTERNATIONAL EXPERIENCE

GLOBAL VISION

RISC Pty Ltd

Resource Investment Strategy Consultants

HEAD OFFICE – AUSTRALIA

Level 3
1138 Hay Street
WEST PERTH WA 6005

Telephone:	+61 8 9420 6660
Fax:	+61 8 9420 6690
E-mail:	risc@riscpl.com
Website:	www.riscpl.com

UNITED KINGDOM

Golden Cross House
8 Duncannon Street
The Strand
LONDON WC2N 4JF

Telephone:	+44 (0) 207 484 8740
Fax:	+44 (0) 207 484 5100
E-mail:	riscuk@riscpl.com
Website:	www.riscpl.com

Appendix 3 Pipeline size estimates from WorleyParsons

WorleyParsons
resources & energy

EcoNomics

DEPT. OF RESOURCES, ENERGY AND TOURISM

DRET CCS Task Force Support

Summary of Pipeline Sizing Study

Draft

401001-00507 – 401001-00507-00-PR-REP-0001

16-Apr-09

Hydrocarbons
Level 3, 80 Albert Street
Brisbane QLD 4000
Australia
Telephone: +61 7 3221 7444
Facsimile: +61 7 3221 7791
www.worleyparsons.com
ABN 61 001 279 812

WorleyParsons

resources & energy

EcoNomics

DEPT. OF RESOURCES, ENERGY AND TOURISM
DRET CCS TASK FORCE SUPPORT
SUMMARY OF PIPELINE SIZING STUDY

SYNOPSIS

The Australian Government Department of Resources, Energy and Tourism (DRET) have requested WorleyParsons to conduct a preliminary flow modelling analysis for a proposed pipeline system transporting near pure supercritical carbon dioxide (CO_2) based on various flow rates and pipeline lengths.

This document summarises 56 flow modelling cases based on eight (8) different flow rates (from 5.0 Mtpa to 40.0 Mtpa in 5.0 Mtpa increments) and seven (7) different pipeline lengths (from 200 km to 1,400 km in 200 km increments).

PROJECT 401001-00507 - DRET CCS TASK FORCE SUPPORT

REV	DESCRIPTION	ORIG	REVIEW	WORLEY-PARSONS APPROVAL	DATE	CLIENT APPROVAL	DATE
A	Issued for Internal Review	H Kikkawa	A Datta	N/A	16-Apr-09	N/A	
B	Issued for Client Review	H Kikkawa	A Datta	N/A	16-Apr-09		

CONTENTS

DEPT. OF RESOURCES, ENERGY AND TOURISM
DRET CCS TASK FORCE SUPPORT
SUMMARY OF PIPELINE SIZING STUDY

1. INTRODUCTION

The Australian Government Department of Resources, Energy and Tourism (DRET) have requested WorleyParsons to conduct a preliminary flow modelling analysis for a proposed pipeline system transporting near pure supercritical carbon dioxide (CO_2) based on various flow rates and pipeline lengths. This scope of work is part of the Low Emissions Coal and Carbon Dioxide Storage.

This document summarises 56 flow modelling cases based on eight (8) different flow rates (from 5.0 Mtpa to 40.0 Mtpa in 5.0 Mtpa increments) and seven (7) different pipeline lengths (from 200 km to 1,400 km in 200 km increments).

2. DESIGN BASIS

The principle requirement for the hydraulic model of this pipeline system is to establish the required pipeline size to transport near pure supercritical carbon dioxide (CO_2) based on different combinations of flow rates and pipeline lengths.

2.1 Process Assumptions

The following list identifies the main assumptions used in the hydraulic model.

1. Pipeline class to be CL900, with a design pressure of 15,300 kPag.
2. Changes in pipeline elevation not considered in the model due to lack of available information. The impact of static pressure associated with changes in pipeline elevation should be further analysed since the density of supercritical CO_2 is approximately 850 kg/m^3.
3. The pipe material class of the pipeline has been assumed to be API 5L X70 steel using a design factor of 0.72 (as per AS 2885.1-2007) and no internal corrosion allowance.
4. The pipeline has been assumed to have an absolute roughness value of 0.0254 mm.
5. CO_2 fluid assumed to be free of water.
6. No mid-line pumping/compression facilities considered along the length of the given pipelines.

Further specific assumptions and modelling parameters are discussed in relevant sections below.

2.2 Process Modelling Software

The flow model was constructed using Aspen HYSYS version 6.5 with PIPESYS extension and Peng Robinson equations of state. Aspen HYSYS has been used in various CO_2 related pipeline projects, and as such, has been incorporated for this scope of work.

2.3 Gas Compositions

The following composition shown in Table 1 has been assumed in the hydraulic model to represent the carbon dioxide being transported through the system.

Table 1 CO_2 Composition

Component	Mole Percent
Carbon Dioxide	99.97
Nitrogen	0.02
Hydrogen	0.01
Total	**100.00**

2.4 Operating Parameters

The following process operating parameters have been used in the steady state model.

2.4.1 Flow Rate

The following eight (8) flow rates have been used in the hydraulic model based on information supplied by DRET, as shown in Table 2.

Table 2 Design Flow Rates

Flow Case	Million Tonnes per Annum (Mtpa)	Kilograms per Hour (kg/hr)
1	5.0	570,800
2	10.0	1,142,000
3	15.0	1,712,000
4	20.0	2,283,000
5	25.0	2,854,000
6	30.0	3,425,000
7	35.0	3,995,000
8	40.0	4,566,000

2.4.2 Pressure

The following pressure specifications have been used in the hydraulic model.

- Pipeline Inlet Pressure 15,000 kPag
- Minimum Pipeline Outlet Pressure 8,000 kPag

By achieving a pipeline outlet pressure above the minimum set value of 8,000 kPag ensures that the CO_2 fluid remains in the dense phase.

2.4.3 Temperature

The following temperature specifications have been assumed in the hydraulic model.

- Pipeline Inlet Temperature 25°C
- Sub Soil Temperature 25°C

2.5 Pipeline Parameters

The following pipeline parameters and specifications have been used in the steady state model.

2.5.1 Pipeline Lengths

The following seven (7) pipeline lengths have been used in the hydraulic model based on information supplied by DRET, as shown in Table 3.

Table 3 Design Pipeline Lengths

Length Case	Pipeline Length (km)
1	200
2	400
3	600
4	800
5	1,000
6	1,200
7	1,400

2.5.2 Pipeline Dimensions

As stated previously in Section 2.1, the pipe material grade has been assumed to be API 5L X70 (which has a specified minimum yield strength of 483 MPa) with a design factor of 0.72 (as per AS 2885.1-2007) and no internal corrosion allowance. Based on these assumptions and in accordance with Australian Standard (AS) 2885.1-2007 Clause 5.4.3, Table 4 has summarised the required pipeline wall thicknesses for various pipeline diameters.

Table 4 Wall Thickness for Class 900 API 5L X70 Pipeline, per AS 2885.1-2007

Nominal Diameter		Outer Diameter	Wall Thickness with
(DN)	(inch)	(mm)	DF = 0.72 (mm)
400	16	406.4	9.0
450	18	457.2	10.1
500	20	508.0	11.2
550	22	558.8	12.3
600	24	609.6	13.5
650	26	660.4	14.6
700	28	711.2	15.7
750	30	762.0	16.8
800	32	812.8	17.9
850	34	863.6	19.0
900	36	914.4	20.2

Nominal Diameter (DN)	(inch)	Outer Diameter (mm)	Wall Thickness with DF = 0.72 (mm)
950	38	965.2	21.3
1000	40	1016.0	22.4
1050	42	1066.8	23.5
1100	44	1117.6	24.6
1150	46	1168.4	25.8
1200	48	1219.2	26.9
1300	52	1320.8	29.1
1350	54	1371.6	30.2

Note that line size DN 1250 (50") is not listed in the API 5L specification and therefore not considered in this study.

These wall thicknesses have been used in the hydraulic model for the applicable pipeline diameters.

2.5.3 Modelling Parameters

The pipeline segments have been modelled using the PIPESYS extension in HYSYS.

The heat loss has been modelled using a buried heat transfer environment (as the pipeline is assumed to be underground). The following parameters have been specified for the PIPESYS model.

- A centre line depth of 1,500 mm.
- A soil type defined as "dry sandy soil", which has a soil conductivity of 0.562 W/m-K.
- A default steel conductivity of 48.461 W/m-K for the pipeline.
- A pipe coating defined as "high density polyethylene" (equivalent to a 3LPE coating) with a conductivity of 0.363 W/m-K and thickness of 2.0 mm.

3. SUMMARY OF RESULTS

Table 5 has summarised the 56 flow modelling cases based on different flow rates and pipeline lengths.

Table 5 Summary of Flow Modelling Results

Flow Rate \ Length	200 km	400 km	600 km	800 km	1,000 km	1,200 km	1,400 km
5.0 Mtpa	DN 400 (16")	DN 450 (18")	DN 500 (20")	DN 550 (22")	DN 550 (22")	DN 600 (24")	DN 600 (24")
10.0 Mtpa	DN 550 (22")	DN 600 (24")	DN 650 (26")	DN 700 (28")	DN 750 (30")	DN 750 (30")	DN 800 (32")
15.0 Mtpa	DN 600 (24")	DN 700 (28")	DN 750 (30")	DN 800 (32")	DN 850 (34")	DN 850 (34")	DN 900 (36")
20.0 Mtpa	DN 700 (28")	DN 800 (32")	DN 850 (34")	DN 900 (36")	DN 950 (38")	DN 950 (38")	DN 1000 (40")
25.0 Mtpa	DN 750 (30")	DN 850 (34")	DN 950 (38")	DN 1000 (40")	DN 1000 (40")	DN 1050 (42")	DN 1100 (44")
30.0 Mtpa	DN 800 (32")	DN 900 (36")	DN 1000 (40")	DN 1050 (42")	DN 1100 (44")	DN 1150 (46")	DN 1150 (46")
35.0 Mtpa	DN 850 (34")	DN 950 (38")	DN 1050 (42")	DN 1100 (44")	DN 1150 (46")	DN 1200 (48")	DN 1300 (52")
40.0 Mtpa	DN 900 (36")	DN 1000 (40")	DN 1100 (44")	DN 1150 (46")	DN 1200 (48")	DN 1300 (52")	DN 1300 (52")

Important Notes:

1. For all cases, pipeline sizing has been based on achieving a pipeline outlet pressure above 8,000 kPag to ensure the CO_2 fluid remains in the dense phase.
2. Refer to Table 4 for the appropriate pipeline wall thickness for each pipeline diameter, which has been prepared on the basis of a Class 900, API 5L X70 pipeline with a design factor of 0.72, as per AS 2885.1-2007.
3. Changes in pipeline elevation were not considered in the above analysis.
4. Certain nominal pipeline sizes or wall thickness specifications may not be available in Australia.

4. REFERENCES

1. CO_2 Pipeline Sizing Calculation [401001-00507-PR-CAL-0001]
2. Australian Standard (AS) 2885.1-2007 Pipelines – Gas and Liquid Petroleum: Design and Construction
3. American Petroleum Institute (API) 5L – Specification for Line Pipe

Appendix 4 Reservoir property estimates from Geoscience Australia

Table 4 – Reservoir property estimates from Geoscience Australia – Eastern Region

State	Name	Injectivity Data for Conceptual Injection Sites	Areal extent of basin	Depth base seal	Formation thickness	Injection depth	Porosity	Permeability	Formation temperature	Formation pressure at injection depth	Fracture pressure at injection depth
			km²	m	m	m RKB	%	mD	°C	MPa	Mpa
QLD	Denison Trough	Shallow	10,500	790	10	800	19.0	350	52	8.10	13.30
		Mid	10,500	1,200	50	1,250	16.0	90	60	12.65	20.78
		Deep	10,500	1,350	100	1,450	13.0	20	65	14.65	24.10
QLD	Galilee	Shallow	30,000	780	20	800	22.0	2,000	60	8.20	13.30
		Mid	30,000	980	100	1,080	19.0	190	70	11.06	17.96
		Deep	30,000	1,160	200	1,360	16.0	15	79	13.93	22.62
QLD	Surat	Shallow	40,000	1,170	30	1,200	25.0	6,000	58	12.13	19.93
		Mid	40,000	1,625	75	1,700	22.0	750	68	17.24	28.24
		Deep	40,000	2,070	130	2,200	19.0	100	80	22.27	36.54
SA & QLD	Eromanga	Shallow	40,000	1,150	50	1,200	22.2	3,520	88	11.93	19.81
		Mid	40,000	1,600	100	1,700	18.0	120	100	16.89	28.07
		Deep	40,000	1,850	150	2,000	15.5	18	108	19.89	33.02
SA & QLD	Cooper	Shallow	35,000	1,900	50	1,950	16.7	446	106	19.41	32.19
		Mid	35,000	2,125	125	2,250	15.0	108	120	22.41	37.15
		Deep	35,000	2,300	200	2,500	13.0	29	132	24.89	41.28
VIC	Offshore Gippsland	Shallow	16,000	1,600	500	2,100	24.0	1,400	90	20.89	37.61
		Mid	16,000	2,000	700	2,700	22.0	400	110	26.89	48.36
		Deep	16,000	2,400	900	3,300	20.5	125	130	32.82	59.10
NSW	Darling West	Shallow	5,350	800	100	900	13.9	150	67	9.00	14.86
		Mid	5,350	1,200	100	1,300	11.5	100	80	13.00	21.46
NSW	Darling East	Mid	2,900	1,200	150	1,350	11.5	70	80	13.00	22.29

Table 5 – Reservoir property estimates from Geoscience Australia – Perth Region

State	Name	Injectivity Data for Conceptual Injection Sites	Areal extent of basin	Depth base seal	Formation thickness	Injection depth	Porosity	Permeability	Formation temperature	Formation pressure at injection depth	Fracture pressure at injection depth
			km²	m	m	m RKB	%	mD	°C	MPa	Mpa
WA	Perth - Offshore North	Shallow	15,500	800	200	1000	26.2	2,857	43	10.10	14.92
		Mid	15,500	1,300	400	1,700	22.0	294	63	17.17	25.36
		Deep	15,500	1,800	600	2,400	18.0	31	82	24.20	35.81
WA	Perth - Onshore North	Shallow	4,400	1450	50	1500	26.6	1,825	57	15.13	22.38
		Mid	4,400	2125	125	2,250	22.0	336	78	22.68	33.57
		Deep	4,400	2,800	200	3,000	17.5	52	99	30.26	44.76
WA	Perth - Vlaming	Shallow	1,100	1,650	150	1,800	24.8	1,108	65	18.17	26.86
		Mid	1,100	1,930	200	2,130	22.0	194	75	21.47	31.78
		Deep	1,100	2,330	300	2,630	17.5	14	88	26.54	39.24
WA	Perth - Onshore South (Lesueur Sandstone)	Shallow	1,500	1,200	180	1,380	17.3	300	54	13.92	20.59
		Mid	1,500	1,750	1215	2,965	12.5	36	98	29.92	44.24
		Deep	1,500	2,300	2250	4,550	7.8	7	142	45.91	67.89
WA	Perth - Onshore South (Bunbury Trough)	Shallow	2,475	800	300	1,100	30.0	1,535	46	11.10	16.41
		Mid	2,475	1,350	1200	2,550	23.0	100	86	25.73	38.05
		Deep	2,475	1,900	2100	4,000	16.0	7	127	40.36	59.68

Appendix 5 Breakdown of cost estimates for combined source cases

Table 6 – Breakdown of results for combined source cases from South NSW & Latrobe Valley to the offshore Gippsland Basin[11]

Source	Basin	Injection rate Mt/yr	Capital costs A$ million	Annual operating costs A$ million/yr	Present value of all costs A$ million	Specific cost of CO_2 avoided A$/t
South NSW & Latrobe V – Gippsland (Shallow)						
South NSW	Junction A	12.9	2,952	32	2,412	33.6
Latrobe V	Junction A	18.3	213.0	7	201.5	2.0
Junction A	Gippsland (Shallow)	31.2	1,623	37	1,436	8.3
Total		31.2	4,788	77	4,049	23.4
South NSW & Latrobe V – Gippsland (Mid)						
South NSW	Junction A	12.9	2,952	32	2,412	33.6
Latrobe V	Junction A	18.3	213.0	7	201.5	2.0
Junction A	Gippsland (Mid)	31.2	1,377	34	1,235	7.1
Total		31.2	4,542	74	3,849	22.3
South NSW & Latrobe V – Gippsland (Deep)						
South NSW	Junction A	12.9	2,952	32	2,412	33.6
Latrobe V	Junction A	18.3	213.0	7	201.5	2.0
Junction A	Gippsland (Deep)	31.2	1,847	51	1,683	9.7
Total		31.2	5,011	90	4,296	24.9

[11] Refer to the footnotes at the bottom of Table 1

Table 7 – Breakdown of results for combined source cases from North NSW & South Queensland to the Surat Basin[12]

Source	Basin	Injection rate Mt/yr	Capital costs A$ million	Annual operating costs A$ million/yr	Present value of all costs A$ million	Specific cost of CO_2 avoided A$/t
North NSW & South Qld – Surat (Shallow)						
North NSW	Junction B	33.5	3,011	81	2,734	14.8
South Qld	Junction B	18.0	1,197.1	21	1,021.1	10.2
Junction B	Surat (Shallow)	51.5	23,148	367	19,537	68.3
Total		51.5	27,357	469	23,293	82.3
North NSW & South Qld – Surat (Mid)						
North NSW	Junction B	33.5	3,011	81	2,734	14.8
South Qld	Junction B	18.0	1,197.1	21	1,021.1	10.2
Junction B	Surat (Mid)	51.5	3,140	70	2,768	9.7
Total		51.5	7,348	172	6,523	23.1
North NSW & South Qld – Surat (Deep)						
North NSW	Junction B	33.5	3,011	81	2,734	14.8
South Qld	Junction B	18.0	1,197.1	21	1,021.1	10.2
Junction B	Surat (Deep)	51.5	5,857	110	5,039	17.6
Total		51.5	10,066	211	8,794	31.0

[12] Refer to the footnotes at the bottom of Table 1

Table 8 – Breakdown of results for combined source cases from North NSW & South Queensland to the Eromanga Basin[13]

Source	Basin	Injection rate Mt/yr	Capital costs A$ million	Annual operating costs A$ million/yr	Present value of all costs A$ million	Specific cost of CO_2 avoided A$/t
North NSW & South Qld – Eromanga (Shallow)						
North NSW	Junction B	33.5	3,011	81	2,734	14.8
South Qld	Junction B	18.0	1,197.1	21	1,021.1	10.2
Junction B	Eromanga (Shallow)	51.5	18,282	495	16,600	60.5
Total		51.5	22,491	596	20,355	75.0
North NSW & South Qld – Eromanga (Mid)						
North NSW	Junction B	33.5	3,011	81	2,734	14.8
South Qld	Junction B	18.0	1,197.1	21	1,021.1	10.2
Junction B	Eromanga (Mid)	51.5	36,517	821	32,199	118.1
Total		51.5	40,725	923	35,954	133.4
North NSW & South Qld – Eromanga (Deep)						
North NSW	Junction B	33.5	3,011	81	2,734	14.8
South Qld	Junction B	18.0	1,197	21	1,021	10.2
Junction B	Eromanga (Deep)	51.5	20,273	610	18,754	69.4
Total		51.5	24,481	711	22,509	84.3

[13] Refer to the footnotes at the bottom of Table 1

Table 9 – Breakdown of results for combined source cases from All NSW to the Darling Basin[14]

Source	Basin	Injection rate Mt/yr	Capital costs A$ million	Annual operating costs A$million/yr	Present value of all costs A$ million	Specific cost of CO_2 avoided A$/t
All NSW – East Darling (Mid)						
North NSW	Junction C	33.5	2,365	66	2,160	11.7
South NSW	Junction C	12.9	497	12	443	6.2
Junction C	East Darling (Mid)	46.4	N/A	N/A	N/A	N/A
Total		46.4	N/A	N/A	N/A	N/A
All NSW – West Darling (Shallow)						
North NSW	Junction C	33.5	2,365	66	2,160	11.7
South NSW	Junction C	12.9	497	12	443	6.2
Junction C	West Darling (Shallow)	46.4	N/A	N/A	N/A	N/A
Total		46.4	N/A	N/A	N/A	N/A
All NSW – West Darling (Mid)						
North NSW	Junction C	33.5	2,365	66	2,160	11.7
South NSW	Junction C	12.9	497	12	443	6.2
Junction C	West Darling (Mid)	46.4	N/A	N/A	N/A	N/A
Total		46.4	N/A	N/A	N/A	N/A

[14] Refer to the footnotes at the bottom of Table 1

Table 10 – Breakdown of results for combined source cases from All NSW to the Cooper Basin[15]

Source	Basin	Injection rate Mt/yr	Capital costs A$ million	Annual operating costs A$million/yr	Present value of all costs A$ million	Specific cost of CO_2 avoided A$/t
All NSW – Cooper (Shallow)						
North NSW	Junction C	33.5	2,365	66	2,160	11.7
South NSW	Junction C	12.9	497.4	12	442.8	6.2
Junction C	Cooper (Shallow)	46.4	55,718	1,114	48,335	196.8
Total		46.4	58,581	1,192	50,938	209.5
All NSW – Cooper (Mid)						
North NSW	Junction C	33.5	2,365	66	2,160	11.7
South NSW	Junction C	12.9	497.4	12	442.8	6.2
Junction C	Cooper (Mid)	46.4	25,990	621	23,124	93.8
Total		46.4	28,853	698	25,727	105.5
All NSW – Cooper (Deep)						
North NSW	Junction C	33.5	2,365	66	2,160	11.7
South NSW	Junction C	12.9	497.4	12	442.8	6.2
Junction C	Cooper (Deep)	46.4	16,571	459	15,107	61.1
Total		46.4	19,434	537	17,710	72.4

[15] Refer to the footnotes at the bottom of Table 1

Table 11 – Breakdown of results for combined source cases from All Perth to the Onshore North Perth Basin[16]

Source	Basin	Injection rate Mt/yr	Capital costs A$ million	Annual operating costs A$million/yr	Present value of all costs A$ million	Specific cost of CO_2 avoided A$/t
All Perth – North Perth Onshore (Shallow)						
Perth South	Junction D	5.0	252	5	217	7.8
Perth Central	Perth North	6.2	402	7	343	10.0
Perth North	North Perth Onshore (Shallow)	8.4	54,165	914	46,016	985.9
Total		8.4	54,819	926	46,576	1,003.4
All Perth – North Perth Onshore (Mid)						
Perth South	Junction D	5.0	252	5	217	7.8
Perth Central	Perth North	6.2	402	7	343	10.0
Perth North	North Perth Onshore (Mid)	8.4	341	9	306	6.6
Total		8.4	995	20	866	18.6
All Perth – North Perth Onshore (Deep)						
Perth South	Junction D	5.0	252	5	217	7.8
Perth Central	Perth North	6.2	402	7	343	10.0
Perth North	North Perth Onshore (Deep)	8.4	602	13	530	11.4
Total		8.4	1,256	25	1,090	23.5

[16] Refer to the footnotes at the bottom of Table 1

Table 12 – Breakdown of results for combined source cases from All Perth to the Offshore North Perth Basin[17]

Source	Basin	Injection rate Mt/yr	Capital costs A$ million	Annual operating costs A$million/yr	Present value of all costs A$ million	Specific cost of CO_2 avoided A$/t
All Perth – North Perth Offshore (Shallow)						
Perth South	Perth Central	5.0	252	5	217	7.8
Perth Central	Perth North	6.2	402	7	343	10.0
Perth North	North Perth Offshore (Shallow)	8.4	1,718	28	1,457	31.2
Total		8.4	2,373	40	2,017	43.4
All Perth – North Perth Offshore (Mid)						
Perth South	Perth Central	5.0	252	5	217	7.8
Perth Central	Perth North	6.2	402	7	343	10.0
Perth North	North Perth Offshore (Mid)	8.4	1,509	23	1,268	27.2
Total		8.4	2,163	34	1,827	39.4
All Perth – North Perth Offshore (Deep)						
Perth South	Perth Central	5.0	252	5	217	7.8
Perth Central	Perth North	6.2	402	7	343	10.0
Perth North	North Perth Offshore (Deep)	8.4	1,852	28	1,553	33.3
Total		8.4	2,506	39	2,113	45.5

[17] Refer to the footnotes at the bottom of Table 1

Table 13 – Breakdown of results for combined source cases from All Perth to the Vlaming Basin[18]

Source	Basin	Injection rate Mt/yr	Capital costs A$ million	Annual operating costs A$million/yr	Present value of all costs A$ million	Specific cost of CO_2 avoided A$/t
All Perth – Vlaming (Shallow)						
Perth South	Perth Central	5.0	252	5	217	7.8
Perth Central	Perth Central	1.2	0	0	0	0.0
Perth North	Perth Central	2.2	257	3	212	17.4
Junction 4	Vlaming (Shallow)	8.4	340,075	5,766	289,045	6,172.4
Total		8.4	340,584	5,774	289,474	6,200.1
All Perth – Vlaming (Mid)						
Perth South	Perth Central	5.0	252	5	217	7.8
Perth Central	Perth Central	1.2	0	0	0	0.0
Perth North	Perth Central	2.2	257	3	212	17.4
Junction D	Vlaming (Mid)	8.4	290,985	4,935	247,327	5,284.9
Total		8.4	291,494	4,943	247,756	5,310.0
All Perth – Vlaming (Deep)						
Perth South	Perth Central	5.0	252	5	217	7.8
Perth Central	Perth Central	1.2	0	0	0	0.0
Perth North	Perth Central	2.2	257	3	212	17.4
Junction D	Vlaming (Deep)	8.4	331,746	5,629	281,988	6,031.7
Total		8.4	332,255	5,636	282,417	6,059.1

[18] Refer to the footnotes at the bottom of Table 1

Table 14 – Breakdown of results for combined source cases from All Perth to the Lesueur Sandstone[19]

Source	Basin	Injection rate Mt/yr	Capital costs A$ million	Annual operating costs A$million/yr	Present value of all costs A$ million	Specific cost of CO_2 avoided A$/t
All Perth – Lesueur Sandstone (Shallow)						
Perth South	Junction D	5.0	93	3	86	3.1
Perth North	Perth Central	2.2	257	3	212	17.4
Perth Central	Junction D	3.4	183	4	159	8.4
Junction D	Lesueur Sst (Shallow)	8.4	87,988	1,491	74,781	1,598.6
Total		8.4	88,521	1,501	75,238	1,615.1
All Perth – Lesueur Sandstone (Mid)						
Perth South	Junction D	5.0	93	3	86	3.1
Perth North	Perth Central	2.2	257	3	212	17.4
Perth Central	Junction D	3.4	183	4	159	8.4
Junction D	Lesueur Sst (Mid)	8.4	431	11	387	8.3
Total		8.4	964	21	844	18.2
All Perth – Lesueur Sandstone (Deep)						
Perth South	Junction D	5.0	93	3	86	3.1
Perth North	Perth Central	2.2	257	3	212	17.4
Perth Central	Junction D	3.4	183	4	159	8.4
Junction D	Lesueur Sst(Deep)	8.4	2,042	42	1,777	38.2
Total		8.4	2,575	51	2,234	48.2

[19] Refer to the footnotes at the bottom of Table 1

Table 15 – Breakdown of results for combined source cases from All Perth to the Bunbury Trough[20]

Source	Basin	Injection rate Mt/yr	Capital costs A$ million	Annual operating costs A$million/yr	Present value of all costs A$ million	Specific cost of CO_2 avoided A$/t
All Perth – Bunbury Trough (Shallow)						
Perth South	Junction D	5.0	93	3	86	3.1
Perth North	Perth Central	2.2	257	3	212	17.4
Perth Central	Junction D	3.4	183	4	159	8.4
Junction D	Bunbury Trough (Shallow)	8.4	1,384	26	1,192	25.5
Total		8.4	1,917	36	1,649	35.5
All Perth – Bunbury Trough (Mid)						
Perth South	Junction D	5.0	93	3	86	3.1
Perth North	Perth Central	2.2	257	3	212	17.4
Perth Central	Junction D	3.4	183	4	159	8.4
Junction D	Bunbury Trough (Mid)	8.4	224	7	208	4.4
Total		8.4	758	16	665	14.3
All Perth – Bunbury Trough (Deep)						
Perth South	Junction D	5.0	93	3	86	3.1
Perth North	Perth Central	2.2	257	3	212	17.4
Perth Central	Junction D	3.4	183	4	159	8.4
Junction D	Bunbury Trough (Deep)	8.4	1,347	29	1,182	25.4
Total		8.4	1,880	39	1,639	35.3

[20] Refer to the footnotes at the bottom of Table 1

Appendix 6 Detailed cost estimates for single source cases

Draft: Detailed storage cost estimates for Single Source cases

Results from run 2009-0722-1607

RESULTS FOR CASE		NQld-DeniS	NQld-DeniM	NQld-DeniD	NQld-GaliS	NQld-GaliM	NQld-GaliD	NQld-EromS	NQld-EromM	NQld-EromD	SQld-SuraS	SQld-SuraM	SQld-SuraD	SQld-EromS	SQld-EromM	SQld-EromD
Case Details		No solution														
Source	–	North Qld	North Qld	North Qld	North Qld	North Qld	North Qld	North Qld	North Qld	North Qld	South Qld	South Qld	South Qld	South Qld	South Qld	South Qld
Sink	–	Denison Trough (Shallow)	Denison Trough (Mid)	Denison Trough (Deep)	Galilee (Shallow)	Galilee (Mid)	Galilee (Deep)	Eromanga (Shallow)	Eromanga (Mid)	Eromanga (Deep)	Surat (Shallow)	Surat (Mid)	Surat (Deep)	Eromanga (Shallow)	Eromanga (Mid)	Eromanga (Deep)
Transport Distance	km	399	288	356	615	618	711	1,020	1,148	1,313	479	425	376	1,312	1,440	1,605
Annual CO_2 flows		0														
Injected	Mt/yr	16	16	16	16	16	16	16	16	16	18	18	18	18	18	18
Avoided	Mt/yr	N/A	16	16	16	16	16	16	16	16	18	18	18	18	18	18
Total CO_2 flows		0														
Injected	Mt	403	403	403	403	403	403	403	403	403	450	450	450	450	450	450
Avoided	Mt	N/A	401	401	401	401	401	401	400	399	448	448	448	446	446	445
Present Value of CO_2 flows		0														
Injected	Mt	N/A	90	90	90	90	90	90	90	90	100	100	100	100	100	100
Avoided	Mt	N/A	90	89	89	89	89	89	89	89	100	100	100	100	100	99
Transport Design		0														
Nominal Pipeline Outer Diameter	mm	N/A	850	850	950	950	1,000	1,050	1,050	1,050	950	950	950	1,050	1,050	1,050
Total Length of Pipelines	km	399	288	356	615	618	711	1,020	1,148	1,313	479	425	376	1,312	1,440	1,605
Number of Compressor Stations	–	N/A	1	1	1	1	1	1	2	2	1	1	1	2	2	3
Total Compressor Power	MW	N/A	24	28	28	28	27	29	43	50	31	29	32	54	63	78
Formation Properties		0														
Injection Depth	m	800	1,250	1,450	800	1,080	1,360	1,200	1,700	2,000	1,200	1,700	2,200	1,200	1,700	2,000
Effective Permeability	mD	350	90	20	2,000	190	15	3,520	120	18	6,000	750	100	3,520	120	18
Formation Thickness	m	10	50	100	20	100	200	50	100	150	30	75	130	50	100	150
Formation Temperature	°C	52	60	65	60	70	79	88	100	108	58	68	80	88	100	108
Formation Pressure	kPa	8,100	12,650	14,650	8,200	11,060	13,930	11,930	16,890	19,890	12,130	17,240	22,270	11,930	16,890	19,890
Injection Pressure	kPa	13,268	20,636	23,822	13,249	17,683	22,062	19,674	27,792	32,607	19,849	28,029	36,182	19,674	27,792	32,607
Injection Design		0														
Number of Wells	–	179,480	45,224	9,292	31,734	1,376	532	48	108	297	101	36	60	63	148	335
Well Spacing Distance	km	0	0	1	0	2	4	14	10	6	10	17	13	13	8	5
Number of Platforms	–	N/A	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Distribution Length	km	N/A	2,506	1,136	3,548	738	459	156	237	395	229	134	175	180	278	420
Total Extra Power Required	MW	N/A	24	28	28	28	27	29	43	50	31	29	32	54	63	78
Total Capital Costs		0														
Total Extra Power	A\$MM	N/A	49	56	55	55	54	58	80	92	61	57	63	99	111	134
Total Transport	A\$MM	N/A	683	839	1,670	1,678	2,070	3,171	3,589	4,098	1,306	1,161	1,030	4,095	4,490	5,022
Total Injection	A\$MM	N/A	137,258	34,569	72,112	5,440	3,018	615	1,188	2,833	894	512	854	730	1,485	3,116
Total On-Costs	A\$MM	N/A	24,424	6,277	13,069	1,270	910	680	860	1,243	400	306	345	871	1,077	1,464
Total Cost	A\$MM	N/A	162,415	41,740	86,907	8,444	6,053	4,524	5,717	8,266	2,662	2,037	2,292	5,795	7,163	9,737
Annual Operating Costs		0														
Total Cost	A\$MM/yr	N/A	2,703	684	1,374	116	78	50	68	103	36	29	34	69	88	127
Total Decommissioning Costs		0														
Total Cost	A\$MM	N/A	40,589	10,419	21,710	2,095	1,497	1,114	1,406	2,040	647	492	554	1,420	1,758	2,395
Present Value of All Costs		0														
Total Extra Power	A\$MM	N/A	84	96	95	96	94	100	142	165	106	99	109	178	203	248
Total Transport	A\$MM	N/A	558	684	1,359	1,365	1,683	2,576	2,919	3,332	1,063	946	839	3,329	3,650	4,085
Total Injection	A\$MM	N/A	118,675	29,824	61,987	4,606	2,542	507	989	2,388	741	424	714	602	1,239	2,629
Total On-Costs	A\$MM	N/A	18,447	4,741	9,871	959	687	514	649	939	302	231	260	658	813	1,106
Total Cost	A\$MM	N/A	137,764	35,345	73,311	7,026	5,007	3,695	4,700	6,823	2,213	1,700	1,923	4,767	5,905	8,068
Specific Cost of CO_2 Injected		0														
Total Extra Power	A\$/t	N/A	0.9	1.1	1.1	1.1	1.0	1.1	1.6	1.8	1.1	1.0	1.1	1.8	2.0	2.5
Total Transport	A\$/t	N/A	6.2	7.6	15.1	15.2	18.7	28.7	32.5	37.1	10.6	9.4	8.4	33.1	36.3	40.7
Total Injection	A\$/t	N/A	1,320.4	331.8	689.7	51.2	28.3	5.6	11.0	26.6	7.4	4.2	7.1	6.0	12.3	26.2
Total On-Costs	A\$/t	N/A	205.2	52.7	109.8	10.7	7.6	5.7	7.2	10.4	3.0	2.3	2.6	6.5	8.1	11.0
Total Cost	A\$/t	N/A	1,532.8	393.2	815.7	78.2	55.7	41.1	52.3	75.9	22.0	16.9	19.1	47.4	58.8	80.3
Specific Cost of CO_2 Avoided		0.0														
Total Extra Power	A\$/t	N/A	0.9	1.1	1.1	1.1	1.0	1.1	1.6	1.8	1.1	1.0	1.1	1.8	2.0	2.5
Total Transport	A\$/t	N/A	6.2	7.6	15.2	15.3	18.8	28.8	32.7	37.4	10.6	9.5	8.4	33.4	36.7	41.1
Total Injection	A\$/t	N/A	1,325.8	333.4	692.9	51.5	28.4	5.7	11.1	26.8	7.4	4.2	7.1	6.0	12.5	26.5
Total On-Costs	A\$/t	N/A	206.1	53.0	110.3	10.7	7.7	5.7	7.3	10.5	3.0	2.3	2.6	6.6	8.2	11.1
Total Cost	A\$/t	N/A	1,539.1	395.1	819.5	78.5	56.0	41.3	52.7	76.6	22.1	17.0	19.2	47.8	59.3	81.3

Draft: Detailed storage cost estimates for Single Source cases

Results from run 2009-0722-1607

RESULTS FOR CASE		NNew-SuraS	NNew-SuraM	NNew-SuraD	SNew-GippS	SNew-GippM	SNew-GippD	LatV-GippS	LatV-GippM	LatV-GippD
Case Details										
Source	–	North NSW	North NSW	North NSW	South NSW	South NSW	South NSW	Latrobe V	Latrobe V	Latrobe V
Sink	–	Surat (Shallow)	Surat (Mid)	Surat (Deep)	Gippsland (Shallow)	Gippsland (Mid)	Gippsland (Deep)	Gippsland (Shallow)	Gippsland (Mid)	Gippsland (Deep)
Transport Distance	km	813	759	710	1,057	978	1,012	204	125	159
Annual CO_2 flows										
Injected	Mt/yr	33	33	33	13	13	13	18	18	18
Avoided	Mt/yr	33	33	33	13	13	13	18	18	18
Total CO_2 flows										
Injected	Mt	837	837	837	322	322	322	458	458	458
Avoided	Mt	823	824	824	321	320	320	455	455	455
Present Value of CO_2 flows										
Injected	Mt	187	187	187	72	72	72	102	102	102
Avoided	Mt	184	184	184	72	72	71	102	102	102
Transport Design										
Nominal Pipeline Outer Diameter	mm	1,050	1,050	1,050	1,000	1,050	1,050	850	850	1,000
Total Length of Pipelines	km	813	759	710	1,057	978	1,012	204	125	159
Number of Compressor Stations	–	4	4	4	1	2	2	1	1	2
Total Compressor Power	MW	206	195	196	23	30	37	31	32	42
Formation Properties										
Injection Depth	m	1,200	1,700	2,200	2,100	2,700	3,300	2,100	2,700	3,300
Effective Permeability	mD	6,000	750	100	1,400	400	125	1,400	400	125
Formation Thickness	m	30	75	130	500	700	900	500	700	900
Formation Temperature	°C	58	68	80	90	110	130	90	110	130
Formation Pressure	kPa	12,130	17,240	22,270	20,890	26,890	32,820	20,890	26,890	32,820
Fracture Pressure	kPa	19,849	28,029	36,182	36,118	46,267	56,416	36,118	46,267	56,416
Injection Design										
Number of Wells	–	2,064	100	188	8	8	9	12	12	12
Well Spacing Distance	km	2	10	7	22	22	21	18	18	18
Number of Platforms	–	0	0	0	2	2	2	3	3	3
Distribution Length	km	1,044	228	314	67	67	63	110	110	110
Total Extra Power Required	MW	206	195	196	23	30	37	31	32	42
Total Capital Costs										
Total Extra Power	A$MM	306	292	293	48	59	72	61	63	79
Total Transport	A$MM	2,648	2,481	2,330	3,136	3,078	3,210	579	339	557
Total Injection	A$MM	8,976	1,126	2,175	435	482	552	555	600	709
Total On-Costs	A$MM	2,112	690	849	641	640	679	211	177	238
Total Cost	A$MM	14,042	4,589	5,647	4,260	4,258	4,513	1,406	1,179	1,584
Annual Operating Costs										
Total Cost	A$MM/yr	243	106	123	47	49	55	26	25	32
Total Decommissioning Costs										
Total Cost	A$MM	3,421	1,062	1,326	1,051	1,047	1,107	334	276	373
Present Value of All Costs										
Total Extra Power	A$MM	604	574	577	82	102	126	105	110	140
Total Transport	A$MM	2,171	2,036	1,913	2,547	2,502	2,610	473	279	460
Total Injection	A$MM	7,602	937	1,831	366	406	468	468	507	599
Total On-Costs	A$MM	1,594	521	641	484	484	512	160	134	180
Total Cost	A$MM	11,972	4,068	4,962	3,479	3,494	3,716	1,207	1,029	1,379
Specific Cost of CO_2 Injected										
Total Extra Power	A$/t	3.2	3.1	3.1	1.1	1.4	1.8	1.0	1.1	1.4
Total Transport	A$/t	11.6	10.9	10.2	35.4	34.7	36.2	4.6	2.7	4.5
Total Injection	A$/t	40.6	5.0	9.8	5.1	5.6	6.5	4.6	5.0	5.9
Total On-Costs	A$/t	8.5	2.8	3.4	6.7	6.7	7.1	1.6	1.3	1.8
Total Cost	A$/t	64.0	21.8	26.5	48.3	48.5	51.6	11.8	10.1	13.5
Specific Cost of CO_2 Avoided										
Total Extra Power	A$/t	3.3	3.1	3.1	1.1	1.4	1.8	1.0	1.1	1.4
Total Transport	A$/t	11.8	11.1	10.4	35.5	35.0	36.5	4.7	2.7	4.5
Total Injection	A$/t	41.4	5.1	10.0	5.1	5.7	6.5	4.6	5.0	5.9
Total On-Costs	A$/t	8.7	2.8	3.5	6.8	6.8	7.2	1.6	1.3	1.8
Total Cost	A$/t	65.1	22.1	27.0	48.5	48.8	52.0	11.9	10.1	13.6

Appendix 7 Detailed cost estimates for combined source cases

Draft: Detailed storage cost estimates for Combined Source cases

Results from run 2009-0722-1607

RESULTS FOR CASE		South NSW & Latrobe V to Gippsland (Shallow)				South NSW & Latrobe V to Gippsland (Mid)				South NSW & Latrobe V to Gippsland (Deep)			
Case Details					TOTAL				TOTAL				TOTAL
Source	–	South NSW	Latrobe V	Junction A	South NSW & Latrobe V	South NSW	Latrobe V	Junction A	South NSW & Latrobe V	South NSW	Latrobe V	Junction A	South NSW & Latrobe V
Sink	–	Junction A	Junction A	Gippsland (Shallow)	Gippsland (Shallow)	Junction A	Junction A	Gippsland (Mid)	Gippsland (Mid)	Junction A	Junction A	Gippsland (Deep)	Gippsland (Deep)
Transport Distance	km	913	60	144	1,117	913	60	65	1,038	913	60	99	1,072
Annual CO_2 flows													
Injected	Mt/yr	13	18	31	31	13	18	31	31	13	18	31	31
Avoided	Mt/yr	13	18	31	31	13	18	31	31	13	18	31	31
Total CO_2 flows													
Injected	Mt	322	458	780	780	322	458	780	780	322	458	780	780
Avoided	Mt	321	457	776	774	321	457	776	774	321	457	775	772
Present Value of CO_2 flows													
Injected	Mt	72	102	174	174	72	102	174	174	72	102	174	174
Avoided	Mt	72	102	173	173	72	102	173	173	72	102	173	172
Transport Design													
Nominal Pipeline Outer Diam	mm	950	800	950	950;800;950	950	800	950	950;800;950	950	800	1,050	950;800;1050
Total Length of Pipelines	km	913	60	144	1,117	913	60	65	1,038	913	60	99	1,072
Number of Compressor Stati	–	1	1	1	3	1	1	1	3	1	1	2	4
Total Compressor Power	MW	21	14	56	92	21	14	53	88	21	14	76	112
Formation Properties													
Injection Depth	m	N/A	N/A	2,100	2,100	N/A	N/A	2,700	2,700	N/A	N/A	3,300	3,300
Effective Permeability	mD	N/A	N/A	1,400	1,400	N/A	N/A	400	400	N/A	N/A	125	125
Formation Thickness	m	N/A	N/A	500	500	N/A	N/A	700	700	N/A	N/A	900	900
Formation Temperature	°C	N/A	N/A	90	90	N/A	N/A	110	110	N/A	N/A	130	130
Formation Pressure	kPa	N/A	N/A	20,890	20,890	N/A	N/A	26,890	26,890	N/A	N/A	32,820	32,820
Fracture Pressure	kPa	N/A	N/A	36,118	36,118	N/A	N/A	46,267	46,267	N/A	N/A	56,416	56,416
Injection Design													
Number of Wells	–	N/A	N/A	20	20	N/A	N/A	20	20	N/A	N/A	20	20
Well Spacing Distance	km	N/A	N/A	14	14	N/A	N/A	14	14	N/A	N/A	14	14
Number of Platforms	–	N/A	N/A	4	4	N/A	N/A	4	4	N/A	N/A	4	4
Distribution Network Length	km	N/A	N/A	127	127	N/A	N/A	127	127	N/A	N/A	127	127
Total Extra Power Required	MW	21	14	56	92	21	14	53	88	21	14	76	112
Total Capital Costs													
Total Extra Power	A$MM	45	31	102	178	45	31	96	172	45	31	131	207
Total Transport	A$MM	2,463	149	499	3,112	2,463	149	235	2,848	2,463	149	475	3,088
Total Injection	A$MM	0	0	778	778	0	0	839	839	0	0	963	963
Total On-Costs	A$MM	444	32	244	720	444	32	207	683	444	32	278	754
Total Cost	A$MM	2,952	213	1,623	4,788	2,952	213	1,377	4,542	2,952	213	1,847	5,011
Annual Operating Costs													
Total Cost	A$MM/yr	32	7	37	77	32	7	34	74	32	7	51	90
Total Decommissioning Costs													
Total Cost	A$MM	725	44	376	1,145	725	44	316	1,085	725	44	423	1,192
Present Value of All Costs													
Total Extra Power	A$MM	76	52	184	312	76	52	172	300	76	52	242	369
Total Transport	A$MM	2,001	125	411	2,537	2,001	125	196	2,323	2,001	125	416	2,543
Total Injection	A$MM	0	0	657	657	0	0	710	710	0	0	815	815
Total On-Costs	A$MM	335	24	184	543	335	24	156	516	335	24	210	569
Total Cost	A$MM	2,412	201	1,436	4,049	2,412	201	1,235	3,849	2,412	201	1,683	4,296
Specific Cost of CO_2 Injected													
Total Extra Power	A$/t	1.1	0.5	1.1	1.8	1.1	0.5	1.0	1.7	1.1	0.5	1.4	2.1
Total Transport	A$/t	27.8	1.2	2.4	14.6	27.8	1.2	1.1	13.3	27.8	1.2	2.4	14.6
Total Injection	A$/t	0.0	0.0	3.8	3.8	0.0	0.0	4.1	4.1	0.0	0.0	4.7	4.7
Total On-Costs	A$/t	4.7	0.2	1.1	3.1	4.7	0.2	0.9	3.0	4.7	0.2	1.2	3.3
Total Cost	A$/t	33.5	2.0	8.2	23.2	33.5	2.0	7.1	22.1	33.5	2.0	9.7	24.7
Specific Cost of CO_2 Avoided													
Total Extra Power	A$/t	1.1	0.5	1.1	1.8	1.1	0.5	1.0	1.7	1.1	0.5	1.4	2.1
Total Transport	A$/t	27.9	1.2	2.4	14.7	27.9	1.2	1.1	13.4	27.9	1.2	2.4	14.7
Total Injection	A$/t	0.0	0.0	3.8	3.8	0.0	0.0	4.1	4.1	0.0	0.0	4.7	4.7
Total On-Costs	A$/t	4.7	0.2	1.1	3.1	4.7	0.2	0.9	3.0	4.7	0.2	1.2	3.3
Total Cost	A$/t	33.6	2.0	8.3	23.4	33.6	2.0	7.1	22.3	33.6	2.0	9.7	24.9

Draft: Detailed storage cost estimates for Combined Source cases

Results from run 2009-0722-1607

RESULTS FOR CASE		North NSW & South Qld to Surat (Shallow)				North NSW & South Qld to Surat (Mid)				North NSW & South Qld to Surat (Deep)			
Case Details					TOTAL				TOTAL				TOTAL
Source	–	North NSW	South Qld	Junction B	North NSW & South Qld	North NSW	South Qld	Junction B	North NSW & South Qld	North NSW	South Qld	Junction B	North NSW & South Qld
Sink	–	Junction B	Junction B	Surat (Shallow)	Surat (Shallow)	Junction B	Junction B	Surat (Mid)	Surat (Mid)	Junction B	Junction B	Surat (Deep)	Surat (Deep)
Transport Distance	km	710	376	103	1,189	710	376	49	1,135	710	376	0	1,086
Annual CO_2 flows													
Injected	Mt/yr	33	18	52	52	33	18	52	52	33	18	52	52
Avoided	Mt/yr	33	18	51	51	33	18	51	51	33	18	51	51
Total CO_2 flows													
Injected	Mt	837	450	1,288	1,288	837	450	1,288	1,288	837	450	1,288	1,288
Avoided	Mt	826	448	1,281	1,267	826	448	1,281	1,267	826	448	1,285	1,271
Present Value of CO_2 flows													
Injected	Mt	187	100	288	288	187	100	288	288	187	100	288	288
Avoided	Mt	184	100	286	283	184	100	286	283	184	100	287	284
Transport Design													
Nominal Pipeline Outer Diam	mm	1,050	900	1,050	1050;900;1050	1,050	900	900	1050;900;900	1,050	900	100	1050;900;100
Total Length of Pipelines	km	710	376	103	1,189	710	376	49	1,135	710	376	0	1,086
Number of Compressor Stations	–	3	1	1	5	3	1	1	5	3	1	1	5
Total Compressor Power	MW	173	31	90	294	173	31	93	296	173	31	35	239
Formation Properties													
Injection Depth	m	N/A	N/A	1,200	1,200	N/A	N/A	1,700	1,700	N/A	N/A	2,200	2,200
Effective Permeability	mD	N/A	N/A	6,000	6,000	N/A	N/A	750	750	N/A	N/A	100	100
Formation Thickness	m	N/A	N/A	30	30	N/A	N/A	75	75	N/A	N/A	130	130
Formation Temperature	°C	N/A	N/A	58	58	N/A	N/A	68	68	N/A	N/A	80	80
Formation Pressure	kPa	N/A	N/A	12,130	12,130	N/A	N/A	17,240	17,240	N/A	N/A	22,270	22,270
Fracture Pressure	kPa	N/A	N/A	19,849	19,849	N/A	N/A	28,029	28,029	N/A	N/A	36,182	36,182
Injection Design													
Number of Wells	–	N/A	N/A	5,056	5,056	N/A	N/A	313	313	N/A	N/A	735	735
Well Spacing Distance	km	N/A	N/A	1	1	N/A	N/A	6	6	N/A	N/A	4	4
Number of Platforms	–	N/A	N/A	0	0	N/A	N/A	0	0	N/A	N/A	0	0
Distribution Pipeline Length	km	N/A	N/A	1,635	1,635	N/A	N/A	406	406	N/A	N/A	623	623
Total Extra Power Required	MW	173	31	90	294	173	31	93	296	173	31	35	239
Total Capital Costs													
Total Extra Power	A$MM	263	61	151	475	263	61	155	479	263	61	68	392
Total Transport	A$MM	2,295	956	376	3,628	2,295	956	180	3,431	2,295	956	58	3,310
Total Injection	A$MM	0	0	19,140	19,140	0	0	2,333	2,333	0	0	4,850	4,850
Total On-Costs	A$MM	453	180	3,481	4,114	453	180	472	1,105	453	180	881	1,514
Total Cost	A$MM	3,011	1,197	23,148	27,357	3,011	1,197	3,140	7,348	3,011	1,197	5,857	10,066
Annual Operating Costs													
Total Cost	A$MM/yr	81	21	367	469	81	21	70	172	81	21	110	211
Total Decommissioning Costs													
Total Cost	A$MM	675	281	5,743	6,699	675	281	739	1,696	675	281	1,444	2,401
Present Value of All Costs													
Total Extra Power	A$MM	513	106	282	901	513	106	290	909	513	106	120	739
Total Transport	A$MM	1,879	780	315	2,974	1,879	780	155	2,814	1,879	780	57	2,716
Total Injection	A$MM	0	0	16,312	16,312	0	0	1,966	1,966	0	0	4,197	4,197
Total On-Costs	A$MM	342	136	2,629	3,106	342	136	356	834	342	136	665	1,143
Total Cost	A$MM	2,734	1,021	19,537	23,293	2,734	1,021	2,768	6,523	2,734	1,021	5,039	8,794
Specific Cost of CO_2 Injected													
Total Extra Power	A$/t	2.7	1.1	1.0	3.1	2.7	1.1	1.0	3.2	2.7	1.1	0.4	2.6
Total Transport	A$/t	10.0	7.8	1.1	10.3	10.0	7.8	0.5	9.8	10.0	7.8	0.2	9.4
Total Injection	A$/t	0.0	0.0	56.7	56.7	0.0	0.0	6.8	6.8	0.0	0.0	14.6	14.6
Total On-Costs	A$/t	1.8	1.4	9.1	10.8	1.8	1.4	1.2	2.9	1.8	1.4	2.3	4.0
Total Cost	A$/t	14.6	10.2	68.0	81.0	14.6	10.2	9.6	22.7	14.6	10.2	17.5	30.6
Specific Cost of CO_2 Avoided													
Total Extra Power	A$/t	2.8	1.1	1.0	3.2	2.8	1.1	1.0	3.2	2.8	1.1	0.4	2.6
Total Transport	A$/t	10.2	7.8	1.1	10.5	10.2	7.8	0.5	9.9	10.2	7.8	0.2	9.6
Total Injection	A$/t	0.0	0.0	57.0	57.6	0.0	0.0	6.9	6.9	0.0	0.0	14.6	14.8
Total On-Costs	A$/t	1.9	1.4	9.2	11.0	1.9	1.4	1.2	2.9	1.9	1.4	2.3	4.0
Total Cost	A$/t	14.8	10.2	68.3	82.3	14.8	10.2	9.7	23.1	14.8	10.2	17.6	31.0

Draft: Detailed storage cost estimates for Combined Source cases

Results from run 2009-0722-1607

RESULTS FOR CASE		North NSW & South Qld to Eromanga (Shallow)				North NSW & South Qld to Eromanga (Mid)				North NSW & South Qld to Eromanga (Deep)			
Case Details					TOTAL				TOTAL				TOTAL
Source	–	North NSW	South Qld	Junction B	North NSW & South Qld	North NSW	South Qld	Junction B	North NSW & South Qld	North NSW	South Qld	Junction B	North NSW & South Qld
Sink	–	Junction B	Junction B	Eromanga (Shallow)	Eromanga (Shallow)	Junction B	Junction B	Eromanga (Mid)	Eromanga (Mid)	Junction B	Junction B	Eromanga (Deep)	Eromanga (Deep)
Transport Distance	km	710	376	936	2,022	710	376	1,064	2,150	710	376	1,229	2,315
Annual CO_2 flows													
Injected	Mt/yr	33	18	52	52	33	18	52	52	33	18	52	52
Avoided	Mt/yr	33	18	49	49	33	18	49	48	33	18	48	48
Total CO_2 flows													
Injected	Mt	837	450	1,288	1,288	837	450	1,288	1,288	837	450	1,288	1,288
Avoided	Mt	826	448	1,229	1,215	826	448	1,221	1,207	826	448	1,210	1,196
Present Value of CO_2 flows													
Injected	Mt	187	100	288	288	187	100	288	288	187	100	288	288
Avoided	Mt	184	100	274	271	184	100	273	270	184	100	270	267
Transport Design													
Nominal Pipeline Outer Dia	mm	1,050	900	1,050	1050;900;1050	1,050	900	1,050	1050;900;1050	1,050	900	1,050	1050;900;1050
Total Length of Pipelines	km	710	376	936	2,022	710	376	1,064	2,150	710	376	1,229	2,315
Number of Compressor Stati	–	3	1	10	14	3	1	11	15	3	1	13	17
Total Compressor Power	MW	173	31	848	1,051	173	31	966	1,170	173	31	1,132	1,335
Formation Properties													
Injection Depth	m	N/A	N/A	1,200	1,200	N/A	N/A	1,700	1,700	N/A	N/A	2,000	2,000
Effective Permeability	mD	N/A	N/A	3,520	3,520	N/A	N/A	120	120	N/A	N/A	18	18
Formation Thickness	m	N/A	N/A	50	50	N/A	N/A	100	100	N/A	N/A	150	150
Formation Temperature	°C	N/A	N/A	88	88	N/A	N/A	100	100	N/A	N/A	108	108
Formation Pressure	kPa	N/A	N/A	11,930	11,930	N/A	N/A	16,890	16,890	N/A	N/A	19,890	19,890
Fracture Pressure	kPa	N/A	N/A	19,674	19,674	N/A	N/A	27,792	27,792	N/A	N/A	32,607	32,607
Injection Design													
Number of Wells	–	N/A	N/A	2,652	2,652	N/A	N/A	4,950	4,950	N/A	N/A	1,575	1,575
Well Spacing Distance	km	N/A	N/A	2	2	N/A	N/A	1	1	N/A	N/A	3	3
Number of Platforms	–	N/A	N/A	0	0	N/A	N/A	0	0	N/A	N/A	0	0
Distance to Platforms	km	N/A	N/A	1,184	1,184	N/A	N/A	1,618	1,618	N/A	N/A	912	912
Total Extra Power Required	MW	173	31	848	1,051	173	31	966	1,170	173	31	1,132	1,335
Total Capital Costs													
Total Extra Power	A$MM	263	61	1,018	1,342	263	61	1,138	1,462	263	61	1,301	1,625
Total Transport	A$MM	2,295	956	3,469	6,720	2,295	956	3,922	7,173	2,295	956	4,547	7,799
Total Injection	A$MM	0	0	11,046	11,046	0	0	25,966	25,966	0	0	11,376	11,376
Total On-Costs	A$MM	453	180	2,749	3,382	453	180	5,492	6,124	453	180	3,049	3,682
Total Cost	A$MM	3,011	1,197	18,282	22,491	3,011	1,197	36,517	40,725	3,011	1,197	20,273	24,481
Annual Operating Costs													
Total Cost	A$MM/yr	81	21	495	596	81	21	821	923	81	21	610	711
Total Decommissioning Costs													
Total Cost	A$MM	675	281	4,271	5,228	675	281	8,794	9,751	675	281	4,685	5,642
Present Value of All Costs													
Total Extra Power	A$MM	513	106	2,241	2,860	513	106	2,532	3,151	513	106	2,933	3,552
Total Transport	A$MM	1,879	780	2,911	5,570	1,879	780	3,288	5,947	1,879	780	3,815	6,474
Total Injection	A$MM	0	0	9,373	9,373	0	0	22,232	22,232	0	0	9,705	9,705
Total On-Costs	A$MM	342	136	2,075	2,552	342	136	4,146	4,623	342	136	2,300	2,778
Total Cost	A$MM	2,734	1,021	16,600	20,355	2,734	1,021	32,199	35,954	2,734	1,021	18,754	22,509
Specific Cost of CO_2 Injected													
Total Extra Power	A$/t	2.7	1.1	7.8	9.9	2.7	1.1	8.8	11.0	2.7	1.1	10.2	12.4
Total Transport	A$/t	10.0	7.8	10.1	19.4	10.0	7.8	11.4	20.7	10.0	7.8	13.3	22.5
Total Injection	A$/t	0.0	0.0	32.6	32.6	0.0	0.0	77.3	77.3	0.0	0.0	33.8	33.8
Total On-Costs	A$/t	1.8	1.4	7.2	8.9	1.8	1.4	14.4	16.1	1.8	1.4	8.0	9.7
Total Cost	A$/t	14.6	10.2	57.7	70.8	14.6	10.2	112.0	125.1	14.6	10.2	65.2	78.3
Specific Cost of CO_2 Avoided													
Total Extra Power	A$/t	2.8	1.1	8.2	10.5	2.8	1.1	9.3	11.7	2.8	1.1	10.9	13.3
Total Transport	A$/t	10.2	7.8	10.6	20.5	10.2	7.8	12.1	22.1	10.2	7.8	14.1	24.2
Total Injection	A$/t	0.0	0.0	34.1	34.5	0.0	0.0	81.5	82.5	0.0	0.0	35.9	36.4
Total On-Costs	A$/t	1.9	1.4	7.6	9.4	1.9	1.4	15.2	17.2	1.9	1.4	8.5	10.4
Total Cost	A$/t	14.8	10.2	60.5	75.0	14.8	10.2	118.1	133.4	14.8	10.2	69.4	84.3

Draft: Detailed storage cost estimates for Combined Source cases

Results from run 2009-0722-1607

RESULTS FOR CASE		**All NSW to East Darling (Mid)**				**All NSW to West Darling (Shallow)**				**All NSW to West Darling (Mid)**			
Case Details				No solution	**TOTAL**			No solution	**TOTAL**			No solution	**TOTAL**
Source	–	North NSW	South NSW	Junction C	All NSW	North NSW	South NSW	Junction C	All NSW	North NSW	South NSW	Junction C	All NSW
Sink	–	Junction C	Junction C	East Darling (Mid)	East Darling (Mid)	Junction C	Junction C	West Darling (Shallow)	West Darling (Shallow)	Junction C	Junction C	West Darling (Mid)	West Darling (Mid)
Transport Distance	km	546	205	369	1,120	546	205	658	1,409	546	205	558	1,309
Annual CO_2 flows													
Injected	Mt/yr	33	13	46	46	33	13	46	46	33	13	46	46
Avoided	Mt/yr	33	13	N/A	N/A	33	13	N/A	N/A	33	13	N/A	N/A
Total CO_2 flows													
Injected	Mt	837	322	1,160	1,160	837	322	1,160	1,160	837	322	1,160	1,160
Avoided	Mt	828	321	N/A	N/A	828	321	N/A	N/A	828	321	N/A	N/A
Present Value of CO_2 flows													
Injected	Mt	187	72	N/A	N/A	187	72	N/A	N/A	187	72	N/A	N/A
Avoided	Mt	185	72	N/A	N/A	185	72	N/A	N/A	185	72	N/A	N/A
Transport Design													
Nominal Pipeline Outer Dia	mm	1,050	700	N/A	N/A	1,050	700	N/A	N/A	1,050	700	N/A	N/A
Total Length of Pipelines	km	546	205	369	1,120	546	205	658	1,409	546	205	558	1,309
Number of Compressor Stati	–	3	1	N/A	N/A	3	1	N/A	N/A	3	1	N/A	N/A
Total Compressor Power	MW	140	22	N/A	N/A	140	22	N/A	N/A	140	22	N/A	N/A
Formation Properties													
Injection Depth	m	N/A	N/A	1,350	1,350	N/A	N/A	900	900	N/A	N/A	1,300	1,300
Effective Permeability	mD	N/A	N/A	70	70	N/A	N/A	150	150	N/A	N/A	100	100
Formation Thickness	m	N/A	N/A	150	150	N/A	N/A	100	100	N/A	N/A	100	100
Formation Temperature	°C	N/A	N/A	80	80	N/A	N/A	67	67	N/A	N/A	80	80
Formation Pressure	kPa	N/A	N/A	13,000	13,000	N/A	N/A	9,000	9,000	N/A	N/A	13,000	13,000
Injection Pressure	kPa	N/A	N/A	21,876	21,876	N/A	N/A	14,584	14,584	N/A	N/A	21,188	21,188
Injection Design													
Number of Wells	–	N/A	N/A	540,643	540,643	N/A	N/A	503,586	503,586	N/A	N/A	399,670	399,670
Well Spacing Distance	km	N/A	N/A	0	0	N/A	N/A	0	0	N/A	N/A	0	0
Number of Platforms	–	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Extra Pipeline Length	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Extra Power Required	MW	140	22	N/A	N/A	140	22	N/A	N/A	140	22	N/A	N/A
Total Capital Costs													
Total Extra Power	A$MM	220	45	N/A	N/A	220	45	N/A	N/A	220	45	N/A	N/A
Total Transport	A$MM	1,789	377	N/A	N/A	1,789	377	N/A	N/A	1,789	377	N/A	N/A
Total Injection	A$MM	0	0	N/A	N/A	0	0	N/A	N/A	0	0	N/A	N/A
Total On-Costs	A$MM	356	75	N/A	N/A	356	75	N/A	N/A	356	75	N/A	N/A
Total Cost	A$MM	2,365	497	N/A	N/A	2,365	497	N/A	N/A	2,365	497	N/A	N/A
Annual Operating Costs													
Total Cost	A$MM/yr	66	12	N/A	N/A	66	12	N/A	N/A	66	12	N/A	N/A
Total Decommissioning Costs													
Total Cost	A$MM	526	111	N/A	N/A	526	111	N/A	N/A	526	111	N/A	N/A
Present Value of All Costs													
Total Extra Power	A$MM	423	77	N/A	N/A	423	77	N/A	N/A	423	77	N/A	N/A
Total Transport	A$MM	1,469	309	N/A	N/A	1,469	309	N/A	N/A	1,469	309	N/A	N/A
Total Injection	A$MM	0	0	N/A	N/A	0	0	N/A	N/A	0	0	N/A	N/A
Total On-Costs	A$MM	268	56	N/A	N/A	268	56	N/A	N/A	268	56	N/A	N/A
Total Cost	A$MM	2,160	443	N/A	N/A	2,160	443	N/A	N/A	2,160	443	N/A	N/A
Specific Cost of CO_2 Injected													
Total Extra Power	A$/t	2.3	1.1	N/A	N/A	2.3	1.1	N/A	N/A	2.3	1.1	N/A	N/A
Total Transport	A$/t	7.9	4.3	N/A	N/A	7.9	4.3	N/A	N/A	7.9	4.3	N/A	N/A
Total Injection	A$/t	0.0	0.0	N/A	N/A	0.0	0.0	N/A	N/A	0.0	0.0	N/A	N/A
Total On-Costs	A$/t	1.4	0.8	N/A	N/A	1.4	0.8	N/A	N/A	1.4	0.8	N/A	N/A
Total Cost	A$/t	11.6	6.1	N/A	N/A	11.6	6.1	N/A	N/A	11.6	6.1	N/A	N/A
Specific Cost of CO_2 Avoided													
Total Extra Power	A$/t	2.3	1.1	N/A	N/A	2.3	1.1	N/A	N/A	2.3	1.1	N/A	N/A
Total Transport	A$/t	7.9	4.3	N/A	N/A	7.9	4.3	N/A	N/A	7.9	4.3	N/A	N/A
Total Injection	A$/t	0.0	0.0	N/A	N/A	0.0	0.0	N/A	N/A	0.0	0.0	N/A	N/A
Total On-Costs	A$/t	1.5	0.8	N/A	N/A	1.5	0.8	N/A	N/A	1.5	0.8	N/A	N/A
Total Cost	A$/t	11.7	6.2	N/A	N/A	11.7	6.2	N/A	N/A	11.7	6.2	N/A	N/A

Draft: Detailed storage cost estimates for Combined Source cases

Results from run 2009-0722-1607

RESULTS FOR CASE		All NSW to Cooper (Shallow)				All NSW to Cooper (Mid)				All NSW to Cooper (Deep)			
Case Details					TOTAL				TOTAL				TOTAL
Source	–	North NSW	South NSW	Junction C	All NSW	North NSW	South NSW	Junction C	All NSW	North NSW	South NSW	Junction C	All NSW
Sink	–	Junction C	Junction C	Cooper (Shallow)	Cooper (Shallow)	Junction C	Junction C	Cooper (Mid)	Cooper (Mid)	Junction C	Junction C	Cooper (Deep)	Cooper (Deep)
Transport Distance	km	546	205	1,193	1,944	546	205	1,104	1,855	546	205	1,020	1,771
Annual CO_2 flows													
Injected	Mt/yr	33	13	46	46	33	13	46	46	33	13	46	46
Avoided	Mt/yr	33	13	44	44	33	13	44	44	33	13	44	44
Total CO_2 flows													
Injected	Mt	837	322	1,160	1,160	837	322	1,160	1,160	837	322	1,160	1,160
Avoided	Mt	828	321	1,100	1,089	828	321	1,104	1,093	828	321	1,107	1,096
Present Value of CO_2 flows													
Injected	Mt	187	72	259	259	187	72	259	259	187	72	259	259
Avoided	Mt	185	72	246	243	185	72	246	244	185	72	247	245
Transport Design													
Nominal Pipeline Outer Diameter	mm	1,050	700	1,050	1050;700;1050	1,050	700	1,050	1050;700;1050	1,050	700	1,050	1050;700;1050
Total Length of Pipelines	km	546	205	1,193	1,944	546	205	1,104	1,855	546	205	1,020	1,771
Number of Compressor Stations	–	3	1	13	17	3	1	12	16	3	1	11	15
Total Compressor Power	MW	140	22	873	1,034	140	22	818	980	140	22	769	931
Formation Properties													
Injection Depth	m	N/A	N/A	1,950	1,950	N/A	N/A	2,250	2,250	N/A	N/A	2,500	2,500
Effective Permeability	mD	N/A	N/A	446	446	N/A	N/A	108	108	N/A	N/A	29	29
Formation Thickness	m	N/A	N/A	50	50	N/A	N/A	125	125	N/A	N/A	200	200
Formation Temperature	°C	N/A	N/A	106	106	N/A	N/A	120	120	N/A	N/A	132	132
Formation Pressure	kPa	N/A	N/A	19,410	19,410	N/A	N/A	22,410	22,410	N/A	N/A	24,890	24,890
Fracture Pressure	kPa	N/A	N/A	32,057	32,057	N/A	N/A	36,803	36,803	N/A	N/A	40,725	40,725
Injection Design													
Number of Wells	–	N/A	N/A	6,965	6,965	N/A	N/A	2,086	2,086	N/A	N/A	894	894
Well Spacing Distance	km	N/A	N/A	1	1	N/A	N/A	2	2	N/A	N/A	3	3
Number of Platforms	–	N/A	N/A	0	0	N/A	N/A	0	0	N/A	N/A	0	0
Total Extra Well Length	km	N/A	N/A	1,795	1,795	N/A	N/A	982	982	N/A	N/A	643	643
Total Extra Power Required	MW	140	22	873	873	140	22	818	818	140	22	769	769
Total Capital Costs													
Total Extra Power	A$MM	220	45	1,043	1,309	220	45	987	1,253	220	45	937	1,203
Total Transport	A$MM	1,789	377	4,436	6,602	1,789	377	4,103	6,270	1,789	377	3,786	5,952
Total Injection	A$MM	0	0	41,860	41,860	0	0	16,991	16,991	0	0	9,356	9,356
Total On-Costs	A$MM	356	75	8,379	8,810	356	75	3,908	4,339	356	75	2,492	2,923
Total Cost	A$MM	2,365	497	55,718	58,581	2,365	497	25,990	28,853	2,365	497	16,571	19,434
Annual Operating Costs													
Total Cost	A$MM/yr	66	12	1,114	1,192	66	12	621	698	66	12	459	537
Total Decommissioning Costs													
Total Cost	A$MM	526	111	13,623	14,260	526	111	6,207	6,844	526	111	3,867	4,505
Present Value of All Costs													
Total Extra Power	A$MM	423	77	2,302	2,803	423	77	2,168	2,668	423	77	2,047	2,548
Total Transport	A$MM	1,469	309	3,725	5,503	1,469	309	3,445	5,223	1,469	309	3,178	4,956
Total Injection	A$MM	0	0	35,981	35,981	0	0	14,561	14,561	0	0	8,001	8,001
Total On-Costs	A$MM	268	56	6,327	6,652	268	56	2,950	3,275	268	56	1,881	2,205
Total Cost	A$MM	2,160	443	48,335	50,938	2,160	443	23,124	25,727	2,160	443	15,107	17,710
Specific Cost of CO_2 Injected													
Total Extra Power	A$/t	2.3	1.1	8.9	10.8	2.3	1.1	8.4	10.3	2.3	1.1	7.9	9.8
Total Transport	A$/t	7.9	4.3	14.4	21.2	7.9	4.3	13.3	20.2	7.9	4.3	12.3	19.1
Total Injection	A$/t	0.0	0.0	138.9	138.9	0.0	0.0	56.2	56.2	0.0	0.0	30.9	30.9
Total On-Costs	A$/t	1.4	0.8	24.4	25.7	1.4	0.8	11.4	12.6	1.4	0.8	7.3	8.5
Total Cost	A$/t	11.6	6.1	186.6	196.6	11.6	6.1	89.3	99.3	11.6	6.1	58.3	68.4
Specific Cost of CO_2 Avoided													
Total Extra Power	A$/t	2.3	1.1	9.4	11.5	2.3	1.1	8.8	10.9	2.3	1.1	8.3	10.4
Total Transport	A$/t	7.9	4.3	15.2	22.6	7.9	4.3	14.0	21.4	7.9	4.3	12.9	20.3
Total Injection	A$/t	0.0	0.0	146.5	148.0	0.0	0.0	59.1	59.7	0.0	0.0	32.4	32.7
Total On-Costs	A$/t	1.5	0.8	25.8	27.4	1.5	0.8	12.0	13.4	1.5	0.8	7.6	9.0
Total Cost	A$/t	11.7	6.2	196.8	209.5	11.7	6.2	93.8	105.5	11.7	6.2	61.1	72.4

Draft: Detailed storage cost estimates for Combined Source cases

Results from run 2009-0722-1607

RESULTS FOR CASE		All Perth to Vlaming (Shallow)					All Perth to Vlaming (Mid)					All Perth to Vlaming (Deep)				
Case Details						TOTAL					TOTAL					TOTAL
Source	–	Perth South	Perth Central	Perth North	Perth Central	All Perth	Perth South	Perth Central	Perth North	Perth Central	All Perth	Perth South	Perth Central	Perth North	Perth Central	All Perth
Sink	–	Perth Central	Perth Central	Perth Central	Vlaming (Shallow)	Vlaming (Shallow)	Perth Central	Perth Central	Perth Central	Vlaming (Mid)	Vlaming (Mid)	Perth Central	Perth Central	Perth Central	Vlaming (Deep)	Vlaming (Deep)
Transport Distance	km	170	0	245	50	465	170	0	245	50	465	170	0	245	50	465
Annual CO_2 flows																
Injected	Mt/yr	5	1	2	8	8	5	1	2	8	8	5	1	2	8	8
Avoided	Mt/yr	5	1	2	8	8	5	1	2	8	8	5	1	2	8	8
Total CO_2 flows																
Injected	Mt	125	30	55	210	210	125	30	55	210	210	125	30	55	210	210
Avoided	Mt	125	30	55	210	209	125	30	55	210	209	125	30	55	209	209
Present Value of CO_2 flows																
Injected	Mt	28	7	12	47	47	28	7	12	47	47	28	7	12	47	47
Avoided	Mt	28	7	12	47	47	28	7	12	47	47	28	7	12	47	47
Transport Design																
Nominal Pipeline Outer Diam	mm	500	100	400	650	500;400;650	500	100	400	650	500;400;650	500	100	400	650	500;400;650
Total Length of Pipelines	km	170	0	245	50	465	170	0	245	50	465	170	0	245	50	465
Number of Compressor Stati	–	1	0	1	1	3	1	0	1	1	3	1	0	1	1	3
Total Compressor Power	MW	7	0	3	4	13	7	0	3	6	15	7	0	3	9	18
Formation Properties																
Injection Depth	m	N/A	N/A	N/A	1,800	1,800	N/A	N/A	N/A	2,130	2,130	N/A	N/A	N/A	2,630	2,630
Effective Permeability	mD	N/A	N/A	N/A	1,108	1,108	N/A	N/A	N/A	194	194	N/A	N/A	N/A	14	14
Formation Thickness	m	N/A	N/A	N/A	150	150	N/A	N/A	N/A	200	200	N/A	N/A	N/A	300	300
Formation Temperature	°C	N/A	N/A	N/A	65	65	N/A	N/A	N/A	75	75	N/A	N/A	N/A	88	88
Formation Pressure	kPa	N/A	N/A	N/A	18,170	18,170	N/A	N/A	N/A	21,470	21,470	N/A	N/A	N/A	26,542	26,542
Fracture Pressure	kPa	N/A	N/A	N/A	26,483	26,483	N/A	N/A	N/A	31,282	31,282	N/A	N/A	N/A	38,493	38,493
Injection Design																
Number of Wells	–	N/A	N/A	N/A	11,608	11,608	N/A	N/A	N/A	7,866	7,866	N/A	N/A	N/A	7,353	7,353
Well Spacing Distance	km	N/A	N/A	N/A	0	0	N/A	N/A	N/A	0	0	N/A	N/A	N/A	0	0
Number of Platforms	–	N/A	N/A	N/A	2,322	2,322	N/A	N/A	N/A	1,574	1,574	N/A	N/A	N/A	1,471	1,471
Distn Network Length	km	N/A	N/A	N/A	1,072	1,072	N/A	N/A	N/A	882	882	N/A	N/A	N/A	853	853
Total Extra Power Required	MW	7	0	3	4	4	7	0	3	6	6	7	0	3	9	9
Total Capital Costs																
Total Extra Power	A$MM	16	0	7	11	35	16	0	7	16	39	16	0	7	22	46
Total Transport	A$MM	198	0	211	126	534	198	0	211	126	534	198	0	211	126	534
Total Injection	A$MM	0	0	0	288,797	288,797	0	0	0	247,085	247,085	0	0	0	281,710	281,710
Total On-Costs	A$MM	38	0	39	51,141	51,218	38	0	39	43,759	43,836	38	0	39	49,889	49,965
Total Cost	A$MM	252	0	257	340,075	340,584	252	0	257	290,985	291,494	252	0	257	331,746	332,255
Annual Operating Costs																
Total Cost	A$MM/yr	5	0	3	5,766	5,774	5	0	3	4,935	4,943	5	0	3	5,629	5,636
Total Decommissioning Costs																
Total Cost	A$MM	58	0	62	85,016	85,136	58	0	62	72,742	72,862	58	0	62	82,930	83,050
Present Value of All Costs																
Total Extra Power	A$MM	26	0	11	17	54	26	0	11	25	62	26	0	11	36	73
Total Transport	A$MM	162	0	172	104	438	162	0	172	104	438	162	0	172	104	438
Total Injection	A$MM	0	0	0	250,297	250,297	0	0	0	214,148	214,148	0	0	0	244,168	244,168
Total On-Costs	A$MM	29	0	29	38,627	38,684	29	0	29	33,051	33,109	29	0	29	37,681	37,738
Total Cost	A$MM	217	0	212	289,045	289,474	217	0	212	247,327	247,756	217	0	212	281,988	282,417
Specific Cost of CO_2 Injected																
Total Extra Power	A$/t	0.9	0.0	0.9	0.4	1.2	0.9	0.0	0.9	0.5	1.3	0.9	0.0	0.9	0.8	1.5
Total Transport	A$/t	5.8	0.0	14.0	2.2	9.3	5.8	0.0	14.0	2.2	9.3	5.8	0.0	14.0	2.2	9.3
Total Injection	A$/t	0.0	0.0	0.0	5,337.5	5,337.5	0.0	0.0	0.0	4,566.7	4,566.7	0.0	0.0	0.0	5,206.8	5,206.8
Total On-Costs	A$/t	1.0	0.0	2.4	823.7	824.9	1.0	0.0	2.4	704.8	706.0	1.0	0.0	2.4	803.5	804.8
Total Cost	A$/t	7.8	0.0	17.3	6,163.8	6,173.0	7.8	0.0	17.3	5,274.2	5,283.4	7.8	0.0	17.3	6,013.3	6,022.5
Specific Cost of CO_2 Avoided																
Total Extra Power	A$/t	0.9	0.0	0.9	0.4	1.2	0.9	0.0	0.9	0.5	1.3	0.9	0.0	0.9	0.8	1.6
Total Transport	A$/t	5.8	0.0	14.1	2.2	9.4	5.8	0.0	14.1	2.2	9.4	5.8	0.0	14.1	2.2	9.4
Total Injection	A$/t	0.0	0.0	0.0	5,344.9	5,361.0	0.0	0.0	0.0	4,575.9	4,589.7	0.0	0.0	0.0	5,222.7	5,238.5
Total On-Costs	A$/t	1.0	0.0	2.4	824.8	828.6	1.0	0.0	2.4	706.2	709.6	1.0	0.0	2.4	806.0	809.7
Total Cost	A$/t	7.8	0.0	17.4	6,172.4	6,200.1	7.8	0.0	17.4	5,284.9	5,310.0	7.8	0.0	17.4	6,031.7	6,059.1

Draft: Detailed storage cost estimates for Combined Source cases

Results from run 2009-0722-1607

RESULTS FOR CASE		All Perth to North Perth Onshore (Shallow)					
Case Details							TOTAL
Source	–	Perth South	Perth Central	Perth Central	Perth North	Perth North	All Perth
Sink	–	Perth Central	Perth Central	Perth North	Perth North	North Perth Onshore (Shallow)	North Perth Onshore (Shallow)
Transport Distance	km	170	0	245	0	90	505
Annual CO_2 flows							
Injected	Mt/yr	5	1	6	2	8	8
Avoided	Mt/yr	5	1	6	2	8	8
Total CO_2 flows							
Injected	Mt	125	30	155	55	210	210
Avoided	Mt	125	30	154	55	209	208
Present Value of CO_2 flows							
Injected	Mt	28	7	35	12	47	47
Avoided	Mt	28	7	34	12	47	46
Transport Design							
Nominal Pipeline Outer Dia	mm	500	100	550	100	500	500;550;500
Total Length of Pipelines	km	170	0	245	0	90	505
Number of Compressor Stati	–	1	0	1	0	1	3
Total Compressor Power	MW	7	0	10	0	14	31
Formation Properties							
Injection Depth	m	N/A	N/A	N/A	N/A	1,500	1,500
Effective Permeability	mD	N/A	N/A	N/A	N/A	1,825	1,825
Formation Thickness	m	N/A	N/A	N/A	N/A	50	50
Formation Temperature	°C	N/A	N/A	N/A	N/A	57	57
Formation Pressure	kPa	N/A	N/A	N/A	N/A	15,132	15,132
Injection Pressure	kPa	N/A	N/A	N/A	N/A	22,256	22,256
Injection Design							
Number of Wells	–	N/A	N/A	N/A	N/A	12,525	12,525
Well Spacing Distance	km	N/A	N/A	N/A	N/A	0	0
Number of Platforms	–	N/A	N/A	N/A	N/A	0	0
Distribution Pipeline Length	km	N/A	N/A	N/A	N/A	854	854
Total Extra Power Required	MW	7	0	10	0	14	14
Total Capital Costs							
Total Extra Power	A$MM	16	0	23	0	32	72
Total Transport	A$MM	198	0	318	0	112	628
Total Injection	A$MM	0	0	0	0	45,876	45,876
Total On-Costs	A$MM	38	0	60	0	8,145	8,244
Total Cost	A$MM	252	0	402	0	54,165	54,819
Annual Operating Costs							
Total Cost	A$MM/yr	5	0	7	0	914	926
Total Decommissioning Costs							
Total Cost	A$MM	58	0	94	0	13,532	13,684
Present Value of All Costs							
Total Extra Power	A$MM	26	0	38	0	53	117
Total Transport	A$MM	162	0	260	0	92	514
Total Injection	A$MM	0	0	0	0	39,719	39,719
Total On-Costs	A$MM	29	0	46	0	6,152	6,226
Total Cost	A$MM	217	0	343	0	46,016	46,576
Specific Cost of CO_2 Injected							
Total Extra Power	A$/t	0.9	0.0	1.1	0.0	1.1	2.5
Total Transport	A$/t	5.8	0.0	7.5	0.0	2.0	11.0
Total Injection	A$/t	0.0	0.0	0.0	0.0	847.0	847.0
Total On-Costs	A$/t	1.0	0.0	1.3	0.0	131.2	132.8
Total Cost	A$/t	7.8	0.0	9.9	0.0	981.3	993.2
Specific Cost of CO_2 Avoided							
Total Extra Power	A$/t	0.9	0.0	1.1	0.0	1.1	2.5
Total Transport	A$/t	5.8	0.0	7.5	0.0	2.0	11.1
Total Injection	A$/t	0.0	0.0	0.0	0.0	851.0	855.7
Total On-Costs	A$/t	1.0	0.0	1.3	0.0	131.8	134.1
Total Cost	A$/t	7.8	0.0	10.0	0.0	985.9	1,003.4

RESULTS FOR CASE		All Perth to North Perth Onshore (Mid)					
Case Details							TOTAL
Source	–	Perth South	Perth Central	Perth Central	Perth North	Perth North	All Perth
Sink	–	Perth Central	Perth Central	Perth North	Perth North	North Perth Onshore (Mid)	North Perth Onshore (Mid)
Transport Distance	km	170	0	245	0	90	505
Annual CO_2 flows							
Injected	Mt/yr	5	1	6	2	8	8
Avoided	Mt/yr	5	1	6	2	8	8
Total CO_2 flows							
Injected	Mt	125	30	155	55	210	210
Avoided	Mt	125	30	154	55	209	208
Present Value of CO_2 flows							
Injected	Mt	28	7	35	12	47	47
Avoided	Mt	28	7	34	12	47	46
Transport Design							
Nominal Pipeline Outer Dia	mm	500	100	550	100	550	500;550;550
Total Length of Pipelines	km	170	0	245	0	90	505
Number of Compressor Stati	–	1	0	1	0	1	3
Total Compressor Power	MW	7	0	10	0	13	30
Formation Properties							
Injection Depth	m	N/A	N/A	N/A	N/A	2,250	2,250
Effective Permeability	mD	N/A	N/A	N/A	N/A	336	336
Formation Thickness	m	N/A	N/A	N/A	N/A	125	125
Formation Temperature	°C	N/A	N/A	N/A	N/A	78	78
Formation Pressure	kPa	N/A	N/A	N/A	N/A	22,681	22,681
Injection Pressure	kPa	N/A	N/A	N/A	N/A	33,259	33,259
Injection Design							
Number of Wells	–	N/A	N/A	N/A	N/A	15	15
Well Spacing Distance	km	N/A	N/A	N/A	N/A	9	9
Number of Platforms	–	N/A	N/A	N/A	N/A	0	0
Distribution Pipeline Length	km	N/A	N/A	N/A	N/A	28	28
Total Extra Power Required	MW	7	0	10	0	13	13
Total Capital Costs							
Total Extra Power	A$MM	16	0	23	0	29	69
Total Transport	A$MM	198	0	318	0	125	641
Total Injection	A$MM	0	0	0	0	135	135
Total On-Costs	A$MM	38	0	60	0	51	150
Total Cost	A$MM	252	0	402	0	341	995
Annual Operating Costs							
Total Cost	A$MM/yr	5	0	7	0	9	20
Total Decommissioning Costs							
Total Cost	A$MM	58	0	94	0	77	228
Present Value of All Costs							
Total Extra Power	A$MM	26	0	38	0	49	113
Total Transport	A$MM	162	0	260	0	103	525
Total Injection	A$MM	0	0	0	0	115	115
Total On-Costs	A$MM	29	0	46	0	39	113
Total Cost	A$MM	217	0	343	0	306	866
Specific Cost of CO_2 Injected							
Total Extra Power	A$/t	0.9	0.0	1.1	0.0	1.0	2.4
Total Transport	A$/t	5.8	0.0	7.5	0.0	2.2	11.2
Total Injection	A$/t	0.0	0.0	0.0	0.0	2.5	2.5
Total On-Costs	A$/t	1.0	0.0	1.3	0.0	0.8	2.4
Total Cost	A$/t	7.8	0.0	9.9	0.0	6.5	18.5
Specific Cost of CO_2 Avoided							
Total Extra Power	A$/t	0.9	0.0	1.1	0.0	1.0	2.4
Total Transport	A$/t	5.8	0.0	7.5	0.0	2.2	11.3
Total Injection	A$/t	0.0	0.0	0.0	0.0	2.5	2.5
Total On-Costs	A$/t	1.0	0.0	1.3	0.0	0.8	2.4
Total Cost	A$/t	7.8	0.0	10.0	0.0	6.6	18.6

RESULTS FOR CASE		All Perth to North Perth Onshore (Deep)					
Case Details							TOTAL
Source	–	Perth South	Perth Central	Perth Central	Perth North	Perth North	All Perth
Sink	–	Perth Central	Perth Central	Perth North	Perth North	North Perth Onshore (Deep)	North Perth Onshore (Deep)
Transport Distance	km	170	0	245	0	90	505
Annual CO_2 flows							
Injected	Mt/yr	5	1	6	2	8	8
Avoided	Mt/yr	5	1	6	2	8	8
Total CO_2 flows							
Injected	Mt	125	30	155	55	210	210
Avoided	Mt	125	30	154	55	209	208
Present Value of CO_2 flows							
Injected	Mt	28	7	35	12	47	47
Avoided	Mt	28	7	34	12	47	46
Transport Design							
Nominal Pipeline Outer Dia	mm	500	100	550	100	600	500;550;600
Total Length of Pipelines	km	170	0	245	0	90	505
Number of Compressor Stati	–	1	0	1	0	1	3
Total Compressor Power	MW	7	0	10	0	15	32
Formation Properties							
Injection Depth	m	N/A	N/A	N/A	N/A	3,000	3,000
Effective Permeability	mD	N/A	N/A	N/A	N/A	52	52
Formation Thickness	m	N/A	N/A	N/A	N/A	200	200
Formation Temperature	°C	N/A	N/A	N/A	N/A	99	99
Formation Pressure	kPa	N/A	N/A	N/A	N/A	30,265	30,265
Injection Pressure	kPa	N/A	N/A	N/A	N/A	44,263	44,263
Injection Design							
Number of Wells	–	N/A	N/A	N/A	N/A	23	23
Well Spacing Distance	km	N/A	N/A	N/A	N/A	7	7
Number of Platforms	–	N/A	N/A	N/A	N/A	0	0
Distribution Pipeline Length	km	N/A	N/A	N/A	N/A	35	35
Total Extra Power Required	MW	7	0	10	0	15	15
Total Capital Costs							
Total Extra Power	A$MM	16	0	23	0	33	73
Total Transport	A$MM	198	0	318	0	139	655
Total Injection	A$MM	0	0	0	0	339	339
Total On-Costs	A$MM	38	0	60	0	91	189
Total Cost	A$MM	252	0	402	0	602	1,256
Annual Operating Costs							
Total Cost	A$MM/yr	5	0	7	0	13	25
Total Decommissioning Costs							
Total Cost	A$MM	58	0	94	0	141	293
Present Value of All Costs							
Total Extra Power	A$MM	26	0	38	0	56	120
Total Transport	A$MM	162	0	260	0	115	537
Total Injection	A$MM	0	0	0	0	291	291
Total On-Costs	A$MM	29	0	46	0	68	143
Total Cost	A$MM	217	0	343	0	530	1,090
Specific Cost of CO_2 Injected							
Total Extra Power	A$/t	0.9	0.0	1.1	0.0	1.2	2.5
Total Transport	A$/t	5.8	0.0	7.5	0.0	2.4	11.4
Total Injection	A$/t	0.0	0.0	0.0	0.0	6.2	6.2
Total On-Costs	A$/t	1.0	0.0	1.3	0.0	1.5	3.0
Total Cost	A$/t	7.8	0.0	9.9	0.0	11.3	23.2
Specific Cost of CO_2 Avoided							
Total Extra Power	A$/t	0.9	0.0	1.1	0.0	1.2	2.6
Total Transport	A$/t	5.8	0.0	7.5	0.0	2.5	11.6
Total Injection	A$/t	0.0	0.0	0.0	0.0	6.2	6.3
Total On-Costs	A$/t	1.0	0.0	1.3	0.0	1.5	3.1
Total Cost	A$/t	7.8	0.0	10.0	0.0	11.4	23.5

Draft: Detailed storage cost estimates for Combined Source cases

Results from run 2009-0722-1607

RESULTS FOR CASE		All Perth to North Perth Offshore (Shallow)					
Case Details							TOTAL
Source	–	Perth South	Perth Central	Perth Central	Perth North	Perth North	All Perth
Sink	–	Perth Central	Perth Central	Perth North	Perth North	North Perth Offshore (Shallow)	North Perth Offshore (Shallow)
Transport Distance	km	170	0	245	0	320	735
Annual CO_2 flows							
Injected	Mt/yr	5	1	6	2	8	8
Avoided	Mt/yr	5	1	6	2	8	8
Total CO_2 flows							
Injected	Mt	125	30	155	55	210	210
Avoided	Mt	125	30	154	55	209	208
Present Value of CO_2 flows							
Injected	Mt	28	7	35	12	47	47
Avoided	Mt	28	7	34	12	47	46
Transport Design							
Nominal Pipeline Outer Dia	mm	500	100	550	100	650	500;550;650
Total Length of Pipelines	km	170	0	245	0	320	735
Number of Compressor Stati	–	1	0	1	0	1	3
Total Compressor Power	MW	7	0	10	0	14	30
Formation Properties							
Injection Depth	m	N/A	N/A	N/A	N/A	1,000	1,000
Effective Permeability	mD	N/A	N/A	N/A	N/A	2,857	2,857
Formation Thickness	m	N/A	N/A	N/A	N/A	1	1
Formation Temperature	°C	N/A	N/A	N/A	N/A	25	25
Formation Pressure	kPa	N/A	N/A	N/A	N/A	8,000	8,000
Fracture Pressure	kPa	N/A	N/A	N/A	N/A	14,423	14,423
Injection Design							
Number of Wells	–	N/A	N/A	N/A	N/A	44	44
Well Spacing Distance	km	N/A	N/A	N/A	N/A	9	9
Number of Platforms	–	N/A	N/A	N/A	N/A	9	9
Distn Network Length	km	N/A	N/A	N/A	N/A	225	225
Total Extra Power Required	MW	7	0	10	0	14	14
Total Capital Costs							
Total Extra Power	A$MM	16	0	23	0	30	70
Total Transport	A$MM	198	0	318	0	532	1,048
Total Injection	A$MM	0	0	0	0	897	897
Total On-Costs	A$MM	38	0	60	0	258	357
Total Cost	A$MM	252	0	402	0	1,718	2,373
Annual Operating Costs							
Total Cost	A$MM/yr	5	0	7	0	28	40
Total Decommissioning Costs							
Total Cost	A$MM	58	0	94	0	421	573
Present Value of All Costs							
Total Extra Power	A$MM	26	0	38	0	50	114
Total Transport	A$MM	162	0	260	0	434	855
Total Injection	A$MM	0	0	0	0	778	778
Total On-Costs	A$MM	29	0	46	0	195	269
Total Cost	A$MM	217	0	343	0	1,457	2,017
Specific Cost of CO_2 Injected							
Total Extra Power	A$/t	0.9	0.0	1.1	0.0	1.1	2.4
Total Transport	A$/t	5.8	0.0	7.5	0.0	9.2	18.2
Total Injection	A$/t	0.0	0.0	0.0	0.0	16.6	16.6
Total On-Costs	A$/t	1.0	0.0	1.3	0.0	4.2	5.7
Total Cost	A$/t	7.8	0.0	9.9	0.0	31.1	43.0
Specific Cost of CO_2 Avoided							
Total Extra Power	A$/t	0.9	0.0	1.1	0.0	1.1	2.5
Total Transport	A$/t	5.8	0.0	7.5	0.0	9.3	18.4
Total Injection	A$/t	0.0	0.0	0.0	0.0	16.7	16.8
Total On-Costs	A$/t	1.0	0.0	1.3	0.0	4.2	5.8
Total Cost	A$/t	7.8	0.0	10.0	0.0	31.2	43.4

RESULTS FOR CASE		All Perth to North Perth Offshore (Mid)					
Case Details							TOTAL
Source	–	Perth South	Perth Central	Perth Central	Perth North	Perth North	All Perth
Sink	–	Perth Central	Perth Central	Perth North	Perth North	North Perth Offshore (Mid)	North Perth Offshore (Mid)
Transport Distance	km	170	0	245	0	320	735
Annual CO_2 flows							
Injected	Mt/yr	5	1	6	2	8	8
Avoided	Mt/yr	5	1	6	2	8	8
Total CO_2 flows							
Injected	Mt	125	30	155	55	210	210
Avoided	Mt	125	30	154	55	209	208
Present Value of CO_2 flows							
Injected	Mt	28	7	35	12	47	47
Avoided	Mt	28	7	34	12	47	46
Transport Design							
Nominal Pipeline Outer Dia	mm	500	100	550	100	650	500;550;650
Total Length of Pipelines	km	170	0	245	0	320	735
Number of Compressor Stati	–	1	0	1	0	1	3
Total Compressor Power	MW	7	0	10	0	14	31
Formation Properties							
Injection Depth	m	N/A	N/A	N/A	N/A	1,700	1,700
Effective Permeability	mD	N/A	N/A	N/A	N/A	294	294
Formation Thickness	m	N/A	N/A	N/A	N/A	400	400
Formation Temperature	°C	N/A	N/A	N/A	N/A	63	63
Formation Pressure	kPa	N/A	N/A	N/A	N/A	17,170	17,170
Fracture Pressure	kPa	N/A	N/A	N/A	N/A	24,369	24,369
Injection Design							
Number of Wells	–	N/A	N/A	N/A	N/A	17	17
Well Spacing Distance	km	N/A	N/A	N/A	N/A	15	15
Number of Platforms	–	N/A	N/A	N/A	N/A	4	4
Distn Network Length	km	N/A	N/A	N/A	N/A	136	136
Total Extra Power Required	MW	7	0	10	0	14	14
Total Capital Costs							
Total Extra Power	A$MM	16	0	23	0	31	71
Total Transport	A$MM	198	0	318	0	532	1,048
Total Injection	A$MM	0	0	0	0	718	718
Total On-Costs	A$MM	38	0	60	0	227	325
Total Cost	A$MM	252	0	402	0	1,509	2,163
Annual Operating Costs							
Total Cost	A$MM/yr	5	0	7	0	23	34
Total Decommissioning Costs							
Total Cost	A$MM	58	0	94	0	368	520
Present Value of All Costs							
Total Extra Power	A$MM	26	0	38	0	52	116
Total Transport	A$MM	162	0	260	0	434	855
Total Injection	A$MM	0	0	0	0	611	611
Total On-Costs	A$MM	29	0	46	0	171	246
Total Cost	A$MM	217	0	343	0	1,268	1,827
Specific Cost of CO_2 Injected							
Total Extra Power	A$/t	0.9	0.0	1.1	0.0	1.1	2.5
Total Transport	A$/t	5.8	0.0	7.5	0.0	9.2	18.2
Total Injection	A$/t	0.0	0.0	0.0	0.0	13.0	13.0
Total On-Costs	A$/t	1.0	0.0	1.3	0.0	3.7	5.2
Total Cost	A$/t	7.8	0.0	9.9	0.0	27.0	39.0
Specific Cost of CO_2 Avoided							
Total Extra Power	A$/t	0.9	0.0	1.1	0.0	1.1	2.5
Total Transport	A$/t	5.8	0.0	7.5	0.0	9.3	18.4
Total Injection	A$/t	0.0	0.0	0.0	0.0	13.1	13.2
Total On-Costs	A$/t	1.0	0.0	1.3	0.0	3.7	5.3
Total Cost	A$/t	7.8	0.0	10.0	0.0	27.2	39.4

RESULTS FOR CASE		All Perth to North Perth Offshore (Deep)					
Case Details							TOTAL
Source	–	Perth South	Perth Central	Perth Central	Perth North	Perth North	All Perth
Sink	–	Perth Central	Perth Central	Perth North	Perth North	North Perth Offshore (Deep)	North Perth Offshore (Deep)
Transport Distance	km	170	0	245	0	320	735
Annual CO_2 flows							
Injected	Mt/yr	5	1	6	2	8	8
Avoided	Mt/yr	5	1	6	2	8	8
Total CO_2 flows							
Injected	Mt	125	30	155	55	210	210
Avoided	Mt	125	30	154	55	209	208
Present Value of CO_2 flows							
Injected	Mt	28	7	35	12	47	47
Avoided	Mt	28	7	34	12	47	46
Transport Design							
Nominal Pipeline Outer Dia	mm	500	100	550	100	700	500;550;700
Total Length of Pipelines	km	170	0	245	0	320	735
Number of Compressor Stati	–	1	0	1	0	1	3
Total Compressor Power	MW	7	0	10	0	14	30
Formation Properties							
Injection Depth	m	N/A	N/A	N/A	N/A	2,400	2,400
Effective Permeability	mD	N/A	N/A	N/A	N/A	31	31
Formation Thickness	m	N/A	N/A	N/A	N/A	600	600
Formation Temperature	°C	N/A	N/A	N/A	N/A	82	82
Formation Pressure	kPa	N/A	N/A	N/A	N/A	24,200	24,200
Fracture Pressure	kPa	N/A	N/A	N/A	N/A	34,316	34,316
Injection Design							
Number of Wells	–	N/A	N/A	N/A	N/A	22	22
Well Spacing Distance	km	N/A	N/A	N/A	N/A	13	13
Number of Platforms	–	N/A	N/A	N/A	N/A	5	5
Distn Network Length	km	N/A	N/A	N/A	N/A	159	159
Total Extra Power Required	MW	7	0	10	0	14	14
Total Capital Costs							
Total Extra Power	A$MM	16	0	23	0	31	70
Total Transport	A$MM	198	0	318	0	582	1,098
Total Injection	A$MM	0	0	0	0	960	960
Total On-Costs	A$MM	38	0	60	0	278	377
Total Cost	A$MM	252	0	402	0	1,852	2,506
Annual Operating Costs							
Total Cost	A$MM/yr	5	0	7	0	28	39
Total Decommissioning Costs							
Total Cost	A$MM	58	0	94	0	454	606
Present Value of All Costs							
Total Extra Power	A$MM	26	0	38	0	51	115
Total Transport	A$MM	162	0	260	0	474	896
Total Injection	A$MM	0	0	0	0	818	818
Total On-Costs	A$MM	29	0	46	0	210	285
Total Cost	A$MM	217	0	343	0	1,553	2,113
Specific Cost of CO_2 Injected							
Total Extra Power	A$/t	0.9	0.0	1.1	0.0	1.1	2.4
Total Transport	A$/t	5.8	0.0	7.5	0.0	10.1	19.1
Total Injection	A$/t	0.0	0.0	0.0	0.0	17.4	17.4
Total On-Costs	A$/t	1.0	0.0	1.3	0.0	4.5	6.1
Total Cost	A$/t	7.8	0.0	9.9	0.0	33.1	45.1
Specific Cost of CO_2 Avoided							
Total Extra Power	A$/t	0.9	0.0	1.1	0.0	1.1	2.5
Total Transport	A$/t	5.8	0.0	7.5	0.0	10.2	19.3
Total Injection	A$/t	0.0	0.0	0.0	0.0	17.5	17.6
Total On-Costs	A$/t	1.0	0.0	1.3	0.0	4.5	6.1
Total Cost	A$/t	7.8	0.0	10.0	0.0	33.3	45.5

Draft: Detailed storage cost estimates for Combined Source cases

Results from run 2009-0722-1607

RESULTS FOR CASE		All Perth to Lesueur Sst (Shallow)						All Perth to Lesueur Sst (Mid)						All Perth to Lesueur Sst (Deep)					
Case Details							TOTAL						TOTAL						TOTAL
Source	–	Perth South	Perth Central	Perth North	Perth Central	Junction D	All Perth	Perth South	Perth Central	Perth North	Perth Central	Junction D	All Perth	Perth South	Perth Central	Perth North	Perth Central	Junction D	All Perth
Sink	–	Junction D	Perth Central	Perth Central	Junction D	Lesueur Sst (Shallow)	Lesueur Sst (Shallow)	Junction D	Perth Central	Perth Central	Junction D	Lesueur Sst (Mid)	Lesueur Sst (Mid)	Junction D	Perth Central	Perth Central	Junction D	Lesueur Sst (Deep)	Lesueur Sst (Deep)
Transport Distance	km	60	0	245	160	20	485	60	0	245	160	20	485	60	0	245	160	20	485
Annual CO_2 flows																			
Injected	Mt/yr	5	1	2	3	8	8	5	1	2	3	8	8	5	1	2	3	8	8
Avoided	Mt/yr	5	1	2	3	8	8	5	1	2	3	8	8	5	1	2	3	8	8
Total CO_2 flows																			
Injected	Mt	125	30	55	85	210	210	125	30	55	85	210	210	125	30	55	85	210	210
Avoided	Mt	125	30	55	85	209	209	125	30	55	85	209	208	125	30	55	85	208	207
Present Value of CO_2 flows																			
Injected	Mt	28	7	12	19	47	47	28	7	12	19	47	47	28	7	12	19	47	47
Avoided	Mt	28	7	12	19	47	47	28	7	12	19	47	47	28	7	12	19	47	46
Transport Design																			
Nominal Pipeline Outer Dia	mm	450	100	400	400	450	450;400;450	450	100	400	400	500	450;400;500	450	100	400	400	500	450;400;500
Total Length of Pipelines	km	60	0	245	160	20	485	60	0	245	160	20	485	60	0	245	160	20	485
Number of Compressor Stati	–	1	0	1	1	1	4	1	0	1	1	1	4	1	0	1	1	1	4
Total Compressor Power	MW	5	0	3	5	8	20	5	0	3	5	13	25	5	0	3	5	5	18
Formation Properties																			
Injection Depth	m	N/A	N/A	N/A	N/A	1,380	1,380	N/A	N/A	N/A	N/A	2,965	2,965	N/A	N/A	N/A	N/A	4,550	4,550
Effective Permeability	mD	N/A	N/A	N/A	N/A	300	300	N/A	N/A	N/A	N/A	36	36	N/A	N/A	N/A	N/A	7	7
Formation Thickness	m	N/A	N/A	N/A	N/A	180	180	N/A	N/A	N/A	N/A	1,215	1,215	N/A	N/A	N/A	N/A	2,250	2,250
Formation Temperature	°C	N/A	N/A	N/A	N/A	54	54	N/A	N/A	N/A	N/A	98	98	N/A	N/A	N/A	N/A	142	142
Formation Pressure	kPa	N/A	N/A	N/A	N/A	13,920	13,920	N/A	N/A	N/A	N/A	29,920	29,920	N/A	N/A	N/A	N/A	45,910	45,910
Fracture Pressure	kPa	N/A	N/A	N/A	N/A	20,142	20,142	N/A	N/A	N/A	N/A	41,216	41,216	N/A	N/A	N/A	N/A	62,291	62,291
Injection Design																			
Number of Wells	–	N/A	N/A	N/A	N/A	22,826	22,826	N/A	N/A	N/A	N/A	23	23	N/A	N/A	N/A	N/A	33	33
Well Spacing Distance	km	N/A	N/A	N/A	N/A	0	0	N/A	N/A	N/A	N/A	4	4	N/A	N/A	N/A	N/A	3	3
Number of Platforms	–	N/A	N/A	N/A	N/A	0	0	N/A	N/A	N/A	N/A	0	0	N/A	N/A	N/A	N/A	0	0
Total Pipeline Length	km	N/A	N/A	N/A	N/A	673	673	N/A	N/A	N/A	N/A	20	20	N/A	N/A	N/A	N/A	25	25
Total Extra Power Required	MW	5	0	3	5	8	8	5	0	3	5	13	13	5	0	3	5	24	24
Total Capital Costs																			
Total Extra Power	A$MM	12	0	7	14	18	52	12	0	7	14	29	62	12	0	7	14	49	83
Total Transport	A$MM	67	0	211	142	31	450	67	0	211	142	34	453	67	0	211	142	34	453
Total Injection	A$MM	0	0	0	0	74,707	74,707	0	0	0	0	304	304	0	0	0	0	1,652	1,652
Total On-Costs	A$MM	14	0	39	28	13,232	13,312	14	0	39	28	65	145	14	0	39	28	307	387
Total Cost	A$MM	93	0	257	183	87,988	88,521	93	0	257	183	431	964	93	0	257	183	2,042	2,575
Annual Operating Costs																			
Total Cost	A$MM/yr	3	0	3	4	1,491	1,501	3	0	3	4	11	21	3	0	3	4	42	51
Total Decommissioning Costs																			
Total Cost	A$MM	20	0	62	42	21,992	22,115	20	0	62	42	99	223	20	0	62	42	496	619
Present Value of All Costs																			
Total Extra Power	A$MM	19	0	11	22	29	81	19	0	11	22	47	99	19	0	11	22	84	136
Total Transport	A$MM	56	0	172	117	27	372	56	0	172	117	29	374	56	0	172	117	29	374
Total Injection	A$MM	0	0	0	0	64,730	64,730	0	0	0	0	262	262	0	0	0	0	1,432	1,432
Total On-Costs	A$MM	11	0	29	21	9,994	10,054	11	0	29	21	49	109	11	0	29	21	232	292
Total Cost	A$MM	86	0	212	159	74,781	75,238	86	0	212	159	387	844	86	0	212	159	1,777	2,234
Specific Cost of CO_2 Injected																			
Total Extra Power	A$/t	0.7	0.0	0.9	1.1	0.6	1.7	0.7	0.0	0.9	1.1	1.0	2.1	0.7	0.0	0.9	1.1	1.8	2.9
Total Transport	A$/t	2.0	0.0	14.0	6.1	0.6	7.9	2.0	0.0	14.0	6.1	0.6	8.0	2.0	0.0	14.0	6.1	0.6	8.0
Total Injection	A$/t	0.0	0.0	0.0	0.0	1,380.4	1,380.4	0.0	0.0	0.0	0.0	5.6	5.6	0.0	0.0	0.0	0.0	30.5	30.5
Total On-Costs	A$/t	0.4	0.0	2.4	1.1	213.1	214.4	0.4	0.0	2.4	1.1	1.0	2.3	0.4	0.0	2.4	1.1	4.9	6.2
Total Cost	A$/t	3.1	0.0	17.3	8.4	1,594.7	1,604.4	3.1	0.0	17.3	8.4	8.3	18.0	3.1	0.0	17.3	8.4	37.9	47.6
Specific Cost of CO_2 Avoided																			
Total Extra Power	A$/t	0.7	0.0	0.9	1.1	0.6	1.7	0.7	0.0	0.9	1.1	1.0	2.1	0.7	0.0	0.9	1.1	1.8	2.9
Total Transport	A$/t	2.0	0.0	14.1	6.2	0.6	8.0	2.0	0.0	14.1	6.2	0.6	8.0	2.0	0.0	14.1	6.2	0.6	8.1
Total Injection	A$/t	0.0	0.0	0.0	0.0	1,383.8	1,389.6	0.0	0.0	0.0	0.0	5.6	5.6	0.0	0.0	0.0	0.0	30.8	30.9
Total On-Costs	A$/t	0.4	0.0	2.4	1.1	213.6	215.8	0.4	0.0	2.4	1.1	1.0	2.4	0.4	0.0	2.4	1.1	5.0	6.3
Total Cost	A$/t	3.1	0.0	17.4	8.4	1,598.6	1,615.1	3.1	0.0	17.4	8.4	8.3	18.2	3.1	0.0	17.4	8.4	38.2	48.2

Draft: Detailed storage cost estimates for Combined Source cases

Results from run 2009-0722-1607

RESULTS FOR CASE		All Perth to Bunbury Trough (Shallow)					
Case Details							TOTAL
Source	–	Perth South	Perth Central	Perth North	Perth Central	Junction D	All Perth
Sink	–	Junction D	Perth Central	Perth Central	Junction D	Bunbury Trough (Shallow)	Bunbury Trough (Shallow)
Transport Distance	km	60	0	245	160	20	485
Annual CO_2 flows							
Injected	Mt/yr	5	1	2	3	8	8
Avoided	Mt/yr	5	1	2	3	8	8
Total CO_2 flows							
Injected	Mt	125	30	55	85	210	210
Avoided	Mt	125	30	55	85	209	208
Present Value of CO_2 flows							
Injected	Mt	28	7	12	19	47	47
Avoided	Mt	28	7	12	19	47	47
Transport Design							
Nominal Pipeline Outer Dia	mm	450	100	400	400	400	450;400;400
Total Length of Pipelines	km	60	0	245	160	20	485
Number of Compressor Stati	–	1	0	1	1	1	4
Total Compressor Power	MW	5	0	3	5	12	24
Formation Properties							
Injection Depth	m	N/A	N/A	N/A	N/A	1,100	1,100
Effective Permeability	mD	N/A	N/A	N/A	N/A	1,535	1,535
Formation Thickness	m	N/A	N/A	N/A	N/A	300	300
Formation Temperature	°C	N/A	N/A	N/A	N/A	46	46
Formation Pressure	kPa	N/A	N/A	N/A	N/A	11,100	11,100
Fracture Pressure	kPa	N/A	N/A	N/A	N/A	15,666	15,666
Injection Design							
Number of Wells	–	N/A	N/A	N/A	N/A	401	401
Well Spacing Distance	km	N/A	N/A	N/A	N/A	1	1
Number of Platforms	–	N/A	N/A	N/A	N/A	0	0
Distribution Network Length	km	N/A	N/A	N/A	N/A	114	114
Total Extra Power Required	MW	5	0	3	5	12	12
Total Capital Costs							
Total Extra Power	A$MM	12	0	7	14	27	60
Total Transport	A$MM	67	0	211	142	28	448
Total Injection	A$MM	0	0	0	0	1,121	1,121
Total On-Costs	A$MM	14	0	39	28	208	288
Total Cost	A$MM	93	0	257	183	1,384	1,917
Annual Operating Costs							
Total Cost	A$MM/yr	3	0	3	4	26	36
Total Decommissioning Costs							
Total Cost	A$MM	20	0	62	42	338	462
Present Value of All Costs							
Total Extra Power	A$MM	19	0	11	22	43	95
Total Transport	A$MM	56	0	172	117	25	369
Total Injection	A$MM	0	0	0	0	967	967
Total On-Costs	A$MM	11	0	29	21	157	218
Total Cost	A$MM	86	0	212	159	1,192	1,649
Specific Cost of CO_2 Injected							
Total Extra Power	A$/t	0.7	0.0	0.9	1.1	0.9	2.0
Total Transport	A$/t	2.0	0.0	14.0	6.1	0.5	7.9
Total Injection	A$/t	0.0	0.0	0.0	0.0	20.6	20.6
Total On-Costs	A$/t	0.4	0.0	2.4	1.1	3.4	4.6
Total Cost	A$/t	3.1	0.0	17.3	8.4	25.4	35.2
Specific Cost of CO_2 Avoided							
Total Extra Power	A$/t	0.7	0.0	0.9	1.1	0.9	2.1
Total Transport	A$/t	2.0	0.0	14.1	6.2	0.5	7.9
Total Injection	A$/t	0.0	0.0	0.0	0.0	20.7	20.8
Total On-Costs	A$/t	0.4	0.0	2.4	1.1	3.4	4.7
Total Cost	A$/t	3.1	0.0	17.4	8.4	25.5	35.5

RESULTS FOR CASE		All Perth to Bunbury Trough (Mid)					
Case Details							TOTAL
Source	–	Perth South	Perth Central	Perth North	Perth Central	Junction D	All Perth
Sink	–	Junction D	Perth Central	Perth Central	Junction D	Bunbury Trough (Mid)	Bunbury Trough (Mid)
Transport Distance	km	60	0	245	160	20	485
Annual CO_2 flows							
Injected	Mt/yr	5	1	2	3	8	8
Avoided	Mt/yr	5	1	2	3	8	8
Total CO_2 flows							
Injected	Mt	125	30	55	85	210	210
Avoided	Mt	125	30	55	85	209	208
Present Value of CO_2 flows							
Injected	Mt	28	7	12	19	47	47
Avoided	Mt	28	7	12	19	47	47
Transport Design							
Nominal Pipeline Outer Dia	mm	450	100	400	400	500	450;400;500
Total Length of Pipelines	km	60	0	245	160	20	485
Number of Compressor Stati	–	1	0	1	1	1	4
Total Compressor Power	MW	5	0	3	5	10	23
Formation Properties							
Injection Depth	m	N/A	N/A	N/A	N/A	2,550	2,550
Effective Permeability	mD	N/A	N/A	N/A	N/A	100	100
Formation Thickness	m	N/A	N/A	N/A	N/A	1,200	1,200
Formation Temperature	°C	N/A	N/A	N/A	N/A	86	86
Formation Pressure	kPa	N/A	N/A	N/A	N/A	25,730	25,730
Fracture Pressure	kPa	N/A	N/A	N/A	N/A	35,062	35,062
Injection Design							
Number of Wells	–	N/A	N/A	N/A	N/A	13	13
Well Spacing Distance	km	N/A	N/A	N/A	N/A	7	7
Number of Platforms	–	N/A	N/A	N/A	N/A	0	0
Distribution Network Length	km	N/A	N/A	N/A	N/A	19	19
Total Extra Power Required	MW	5	0	3	5	10	10
Total Capital Costs							
Total Extra Power	A$MM	12	0	7	14	24	57
Total Transport	A$MM	67	0	211	142	34	453
Total Injection	A$MM	0	0	0	0	133	133
Total On-Costs	A$MM	14	0	39	28	34	114
Total Cost	A$MM	93	0	257	183	224	758
Annual Operating Costs							
Total Cost	A$MM/yr	3	0	3	4	7	16
Total Decommissioning Costs							
Total Cost	A$MM	20	0	62	42	49	173
Present Value of All Costs							
Total Extra Power	A$MM	19	0	11	22	39	91
Total Transport	A$MM	56	0	172	117	29	374
Total Injection	A$MM	0	0	0	0	114	114
Total On-Costs	A$MM	11	0	29	21	25	86
Total Cost	A$MM	86	0	212	159	208	665
Specific Cost of CO_2 Injected							
Total Extra Power	A$/t	0.7	0.0	0.9	1.1	0.8	1.9
Total Transport	A$/t	2.0	0.0	14.0	6.1	0.6	8.0
Total Injection	A$/t	0.0	0.0	0.0	0.0	2.4	2.4
Total On-Costs	A$/t	0.4	0.0	2.4	1.1	0.5	1.8
Total Cost	A$/t	3.1	0.0	17.3	8.4	4.4	14.2
Specific Cost of CO_2 Avoided							
Total Extra Power	A$/t	0.7	0.0	0.9	1.1	0.8	2.0
Total Transport	A$/t	2.0	0.0	14.1	6.2	0.6	8.0
Total Injection	A$/t	0.0	0.0	0.0	0.0	2.4	2.5
Total On-Costs	A$/t	0.4	0.0	2.4	1.1	0.5	1.8
Total Cost	A$/t	3.1	0.0	17.4	8.4	4.4	14.3

RESULTS FOR CASE		All Perth to Bunbury Trough (Deep)					
Case Details							TOTAL
Source	–	Perth South	Perth Central	Perth North	Perth Central	Junction D	All Perth
Sink	–	Junction D	Perth Central	Perth Central	Junction D	Bunbury Trough	Bunbury Trough
Transport Distance	km	60	0	245	160	20	485
Annual CO_2 flows							
Injected	Mt/yr	5	1	2	3	8	8
Avoided	Mt/yr	5	1	2	3	8	8
Total CO_2 flows							
Injected	Mt	125	30	55	85	210	210
Avoided	Mt	125	30	55	85	209	208
Present Value of CO_2 flows							
Injected	Mt	28	7	12	19	47	47
Avoided	Mt	28	7	12	19	47	46
Transport Design							
Nominal Pipeline Outer Dia	mm	450	100	400	400	500	450;400;500
Total Length of Pipelines	km	60	0	245	160	20	485
Number of Compressor Stati	–	1	0	1	1	1	4
Total Compressor Power	MW	5	0	3	5	5	18
Formation Properties							
Injection Depth	m	N/A	N/A	N/A	N/A	4,000	4,000
Effective Permeability	mD	N/A	N/A	N/A	N/A	7	7
Formation Thickness	m	N/A	N/A	N/A	N/A	2,100	2,100
Formation Temperature	°C	N/A	N/A	N/A	N/A	127	127
Formation Pressure	kPa	N/A	N/A	N/A	N/A	40,360	40,360
Fracture Pressure	kPa	N/A	N/A	N/A	N/A	54,458	54,458
Injection Design							
Number of Wells	–	N/A	N/A	N/A	N/A	34	34
Well Spacing Distance	km	N/A	N/A	N/A	N/A	4	4
Number of Platforms	–	N/A	N/A	N/A	N/A	0	0
Distribution Network Length	km	N/A	N/A	N/A	N/A	32	32
Total Extra Power Required	MW	5	0	3	5	21	21
Total Capital Costs							
Total Extra Power	A$MM	12	0	7	14	45	78
Total Transport	A$MM	67	0	211	142	34	453
Total Injection	A$MM	0	0	0	0	1,066	1,066
Total On-Costs	A$MM	14	0	39	28	203	283
Total Cost	A$MM	93	0	257	183	1,347	1,880
Annual Operating Costs							
Total Cost	A$MM/yr	3	0	3	4	29	39
Total Decommissioning Costs							
Total Cost	A$MM	20	0	62	42	324	447
Present Value of All Costs							
Total Extra Power	A$MM	19	0	11	22	76	128
Total Transport	A$MM	56	0	172	117	29	374
Total Injection	A$MM	0	0	0	0	923	923
Total On-Costs	A$MM	11	0	29	21	153	213
Total Cost	A$MM	86	0	212	159	1,182	1,639
Specific Cost of CO_2 Injected							
Total Extra Power	A$/t	0.7	0.0	0.9	1.1	1.6	2.7
Total Transport	A$/t	2.0	0.0	14.0	6.1	0.6	8.0
Total Injection	A$/t	0.0	0.0	0.0	0.0	19.7	19.7
Total On-Costs	A$/t	0.4	0.0	2.4	1.1	3.3	4.6
Total Cost	A$/t	3.1	0.0	17.3	8.4	25.2	34.9
Specific Cost of CO_2 Avoided							
Total Extra Power	A$/t	0.7	0.0	0.9	1.1	1.6	2.8
Total Transport	A$/t	2.0	0.0	14.1	6.2	0.6	8.1
Total Injection	A$/t	0.0	0.0	0.0	0.0	19.8	19.9
Total On-Costs	A$/t	0.4	0.0	2.4	1.1	3.3	4.6
Total Cost	A$/t	3.1	0.0	17.4	8.4	25.4	35.3

Appendix 8 Exploration, appraisal and development costs for the Surat Basin

Surat Basin Sensitivity Analyses - Exploration, appraisal and development costs

Case SQld & NNSW to Surat at 51.5 Mt/yr

RESULTS FOR CASE	Unit	Combo 10ss	Combo 10sm	Combo 10sd	Combo 10ss	Combo 10sm	Combo 10sd	Combo 10ss	Combo 10sm	Combo 10sd	Combo 10ss	Combo 10sm	Combo 10sd	Combo 10ss	Combo 10sm	Combo 10sd
Source		North NSW & South Qld	North NSW & South Qld	North NSW & South Qld	North NSW & South Qld	North NSW & South Qld	North NSW & South Qld	North NSW & South Qld	North NSW & South Qld	North NSW & South Qld	North NSW & South Qld	North NSW & South Qld	North NSW & South Qld	North NSW & South Qld	North NSW & South Qld	North NSW & South Qld
Sink		Surat (Shallow)	Surat (Mid)	Surat (Deep)	Surat (Shallow)	Surat (Mid)	Surat (Deep)	Surat (Shallow)	Surat (Mid)	Surat (Deep)	Surat (Shallow)	Surat (Mid)	Surat (Deep)	Surat (Shallow)	Surat (Mid)	Surat (Deep)
Discount date		Undiscounted			Discounted to 1 Jan 2010			Discounted to 1 Jan 2010			Discounted to 1 Jan 2021			Discounted to 1 Jan 2021		
Discount rate	%	0%			7%			12%			7%			12%		
Annual CO_2 flows																
Injected	Mt/yr	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Avoided	Mt/yr	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51
Total CO_2 flows																
Injected	Mt	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288
Avoided	Mt	1,267	1,267	1,271	1,267	1,267	1,271	1,267	1,267	1,271	1,267	1,267	1,271	1,267	1,267	1,271
Present Value of CO_2 flows																
Injected	Mt	1,288	1,288	1,288	233	233	233	83	83	83	490	490	490	288	288	288
Avoided	Mt	1,267	1,267	1,271	229	229	230	81	81	82	482	482	484	283	283	284
Present Value of Costs																
A) Present Value of EA&D Costs																
Pre-exploration costs	A$MM	69	69	69	64	64	64	62	62	62	N/A	N/A	N/A	N/A	N/A	N/A
Exploration costs	A$MM	276	276	276	231	231	231	206	206	206	N/A	N/A	N/A	N/A	N/A	N/A
Appraisal & development costs	A$MM	348	348	348	204	204	204	144	144	144	N/A	N/A	N/A	N/A	N/A	N/A
Total costs	A$MM	693	693	693	500	500	500	411	411	411	N/A	N/A	N/A	N/A	N/A	N/A
B) Present Value of CO&D Costs																
Total costs	A$MM	45,772	13,339	17,752	13,478	3,825	5,134	6,696	1,875	1,875	28,369	8,052	10,806	23,293	6,523	8,794
C) Present Value of All Costs																
Pre-exploration costs	A$MM	69	69	69	64	64	64	62	62	62	N/A	N/A	N/A	N/A	N/A	N/A
Exploration costs	A$MM	276	276	276	231	231	231	206	206	206	N/A	N/A	N/A	N/A	N/A	N/A
Appraisal & development costs	A$MM	348	348	348	204	204	204	144	144	144	N/A	N/A	N/A	N/A	N/A	N/A
Total CO&D costs	A$MM	45,772	13,339	17,752	13,478	3,825	5,134	6,696	1,875	1,875	28,369	8,052	10,806	23,293	6,523	8,794
Total costs	A$MM	46,465	14,032	18,445	13,978	4,325	5,634	7,107	2,286	2,286	28,369	8,052	10,806	23,293	6,523	8,794
Specific Cost of CO_2 Injected																
A) EA&D Costs per Tonne of CO_2 Injected																
Pre-exploration costs	A$/t	0.1	0.1	0.1	0.3	0.3	0.3	0.7	0.7	0.7	N/A	N/A	N/A	N/A	N/A	N/A
Exploration costs	A$/t	0.2	0.2	0.2	1.0	1.0	1.0	2.5	2.5	2.5	N/A	N/A	N/A	N/A	N/A	N/A
Appraisal & development costs	A$/t	0.3	0.3	0.3	0.9	0.9	0.9	1.7	1.7	1.7	N/A	N/A	N/A	N/A	N/A	N/A
Total costs	A$/t	0.54	0.5	0.5	2.15	2.15	2.15	4.97	5.0	5.0	N/A	N/A	N/A	N/A	N/A	N/A
B) CO&D Costs per Tonne of CO_2 Injected																
Total costs	A$/t	35.6	10.4	13.8	57.9	16.4	22.1	81.0	22.7	30.6	57.9	16.4	22.1	81.0	22.7	30.6
C) Total Cost per Tonne of CO_2 Injected																
Pre-exploration costs	A$/t	0.1	0.1	0.1	0.3	0.3	0.3	0.7	0.7	0.7	N/A	N/A	N/A	N/A	N/A	N/A
Exploration costs	A$/t	0.2	0.2	0.2	1.0	1.0	1.0	2.5	2.5	2.5	N/A	N/A	N/A	N/A	N/A	N/A
Appraisal & development costs	A$/t	0.3	0.3	0.3	0.9	0.9	0.9	1.7	1.7	1.7	N/A	N/A	N/A	N/A	N/A	N/A
Total CO&D costs	A$/t	35.6	10.4	13.8	57.9	16.4	22.1	81.0	22.7	30.6	57.9	16.4	22.1	81.0	22.7	30.6
Total costs	A$/t	36.1	10.9	14.3	60.1	18.6	24.2	86.0	27.7	35.6	57.9	16.4	22.1	81.0	22.7	30.6
Specific Cost of CO_2 Avoided																
A) EA&D Costs per Tonne of CO_2 Avoided																
Pre-exploration costs	A$/t	0.1	0.1	0.1	0.3	0.3	0.3	0.8	0.8	0.8	N/A	N/A	N/A	N/A	N/A	N/A
Exploration costs	A$/t	0.2	0.2	0.2	1.0	1.0	1.0	2.5	2.5	2.5	N/A	N/A	N/A	N/A	N/A	N/A
Appraisal & development costs	A$/t	0.3	0.3	0.3	0.9	0.9	0.9	1.8	1.8	1.8	N/A	N/A	N/A	N/A	N/A	N/A
Total costs	A$/t	0.55	0.5	0.5	2.18	2.2	2.2	5.05	5.1	5.0	N/A	N/A	N/A	N/A	N/A	N/A
B) CO&D Costs per Tonne of CO_2 Avoided																
Total costs	A$/t	36.1	10.5	14.0	58.8	16.7	22.3	82.3	23.1	31.0	58.8	16.7	22.3	82.3	23.1	31.0
C) Total Cost per Tonne of CO_2 Avoided																
Pre-exploration costs	A$/t	0.1	0.1	0.1	0.3	0.3	0.3	0.8	0.8	0.8	N/A	N/A	N/A	N/A	N/A	N/A
Exploration costs	A$/t	0.2	0.2	0.2	1.0	1.0	1.0	2.5	2.5	2.5	N/A	N/A	N/A	N/A	N/A	N/A
Appraisal & development costs	A$/t	0.3	0.3	0.3	0.9	0.9	0.9	1.8	1.8	1.8	N/A	N/A	N/A	N/A	N/A	N/A
Total CO&D costs	A$/t	36.1	10.5	14.0	58.8	16.7	22.3	82.3	23.1	31.0	58.8	16.7	22.3	82.3	23.1	31.0
Total costs	A$/t	36.7	11.1	14.5	61.0	18.9	24.5	87.4	28.1	36.0	58.8	16.7	22.3	82.3	23.1	31.0

Appendix 9 Expected Value analyses for the Surat Basin

Surat Basin Expected Value Analyses
South Qld & North NSW to Surat at 51.5 Mt/yr

		North NSW & South Qld to Surat (shallow)				North NSW & South Qld to Surat (mid)				North NSW & South Qld to Surat (deep)			
Carbon Price	POS	NPV of EA&D and CO&D costs	NPV of Expl costs	EV	**Minimum Carbon Price**	NPV of EA&D and CO&D costs	NPV of Expl costs	EV	**Minimum Carbon Price**	NPV of EA&D and CO&D costs	NPV of Expl costs	EV	**Minimum Carbon Price**
A$/t	%	A$ milliong	A$ million	A$ million	**A$/t**	A$ milliong	A$ million	A$ million	**A$/t**	A$ milliong	A$ million	A$ million	**A$/t**
0	38%	-7,107	267	-2,866		-2,286	267	-1,035		-2,939	267	-1,283	
20	38%	-5,454	267	-2,238		-633	267	-406		-1,286	267	-654	
40	38%	-3,801	267	-1,610		1,020	267	222		367	267	-26	
60	38%	-2,148	267	-982		2,673	267	850		2,020	267	602	
80	38%	-495	267	-354		4,326	267	1,478		3,673	267	1,230	
100	38%	1,158	267	274	**91**	5,979	267	2,106	**33**	5,326	267	1,858	**41**
120	38%	2,811	267	902		7,632	267	2,734		6,979	267	2,486	
140	38%	4,464	267	1,531		9,285	267	3,362		8,632	267	3,114	
160	38%	6,117	267	2,159		10,938	267	3,991		10,285	267	3,743	
180	38%	7,770	267	2,787		12,591	267	4,619		11,938	267	4,371	
200	38%	9,423	267	3,415		14,244	267	5,247		13,591	267	4,999	

Appendix 10 All results with 7% real discount rate

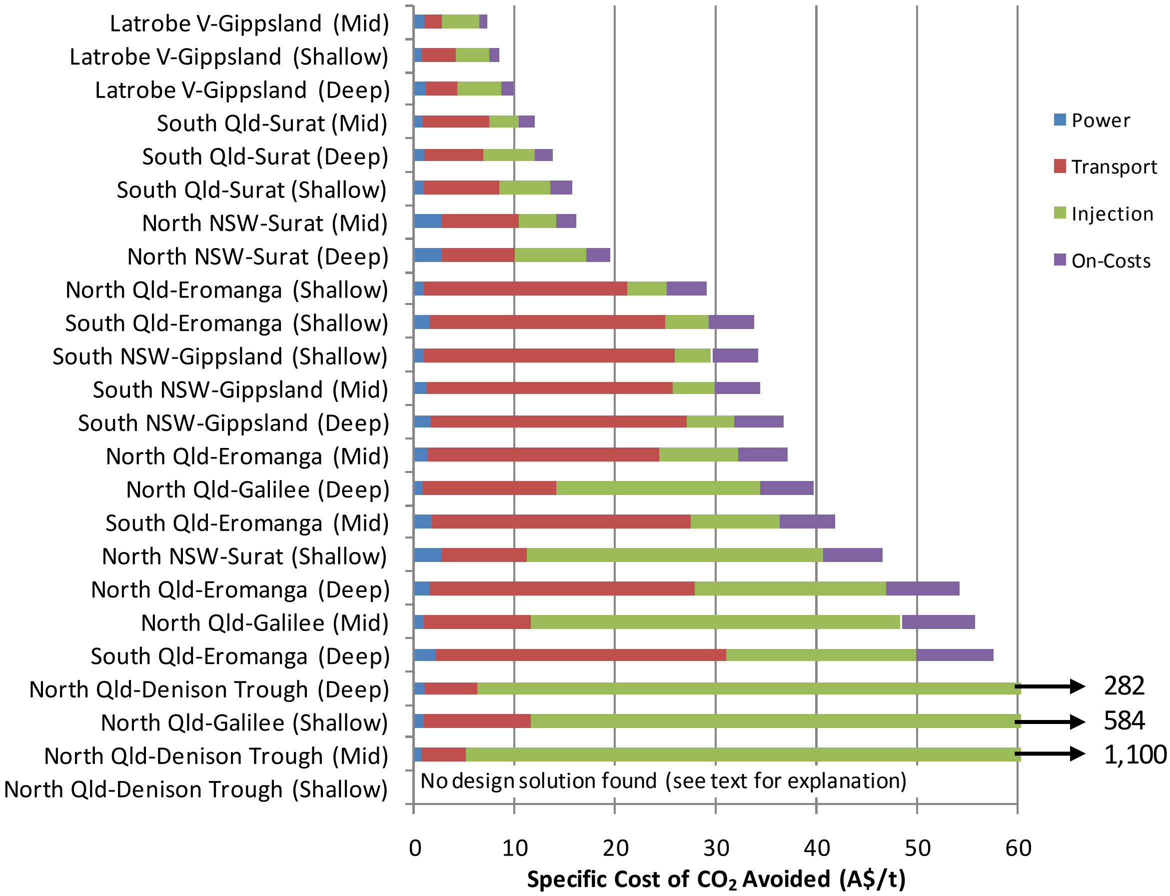


Figure 16 – Ranking of single source cases with 7% real discount rate

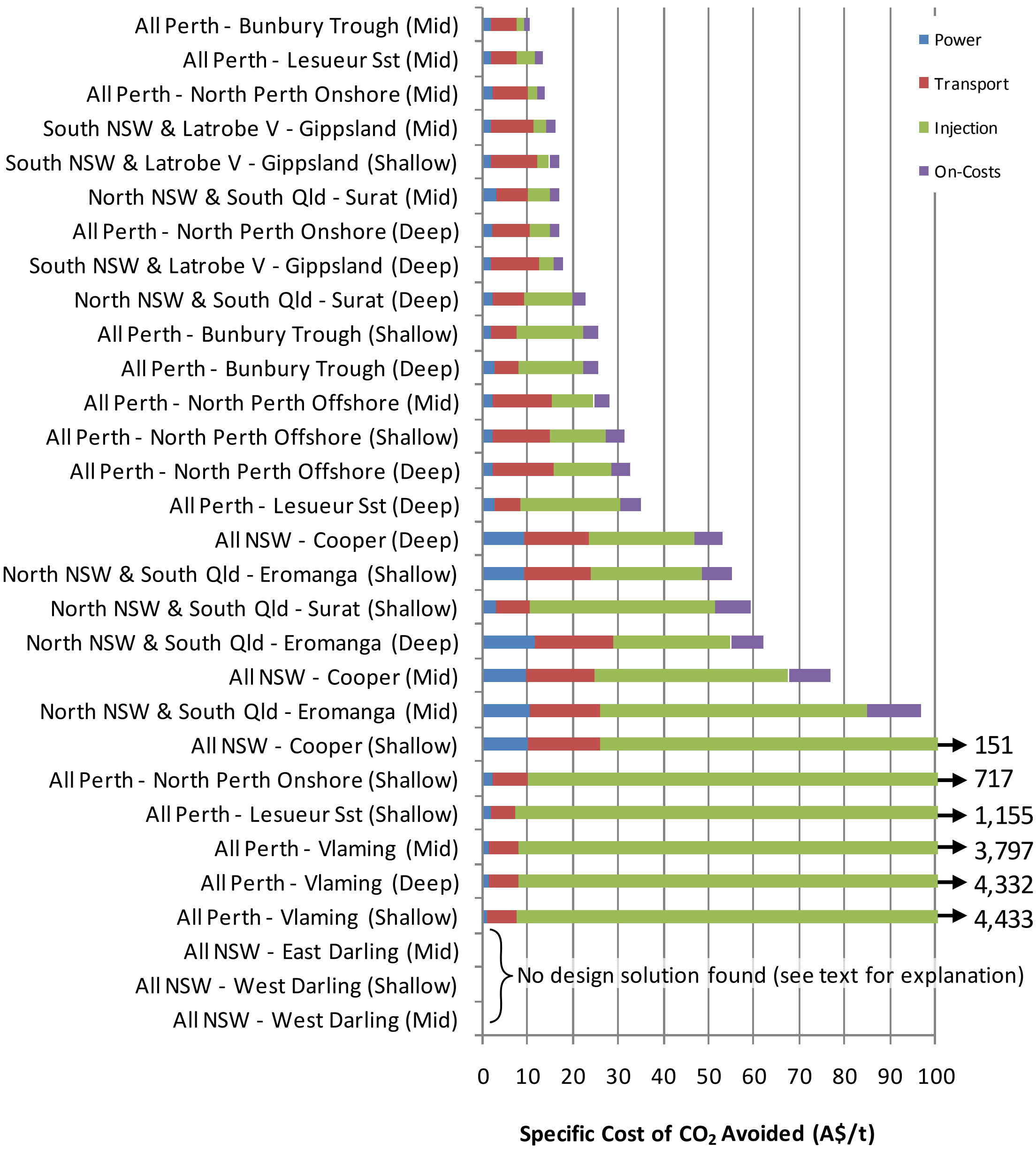


Figure 17 – Ranking of combined source cases with 7% real discount rate

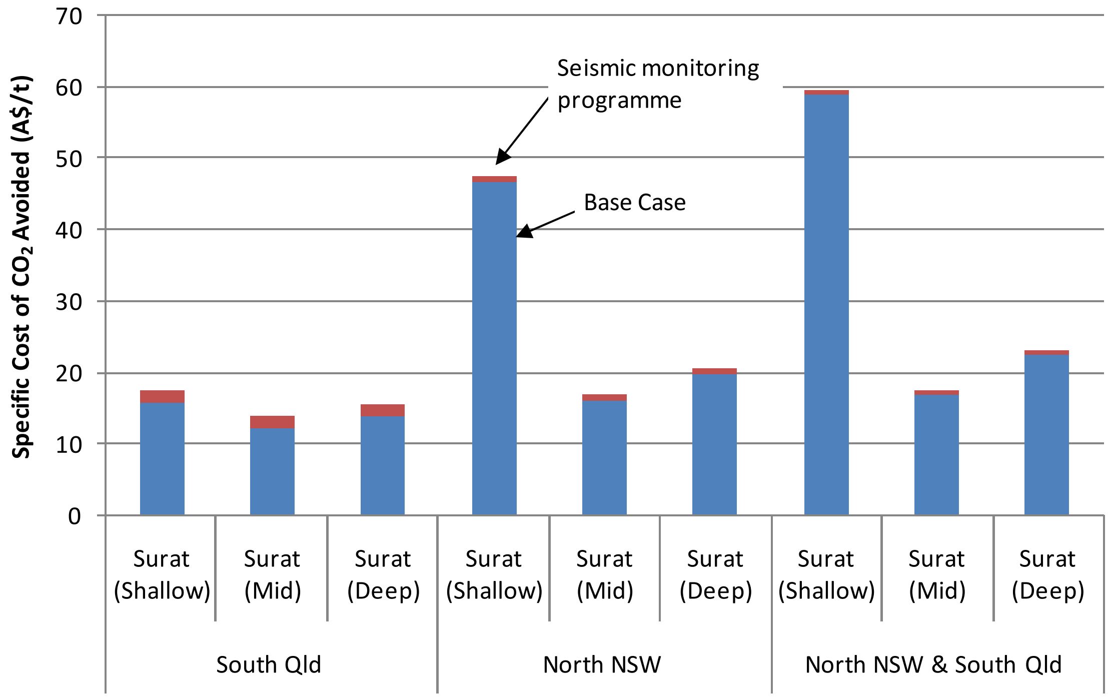


Figure 18 — Effect of adding a seismic monitoring programme on the specific cost of CO_2 avoided with 7% real discount rate

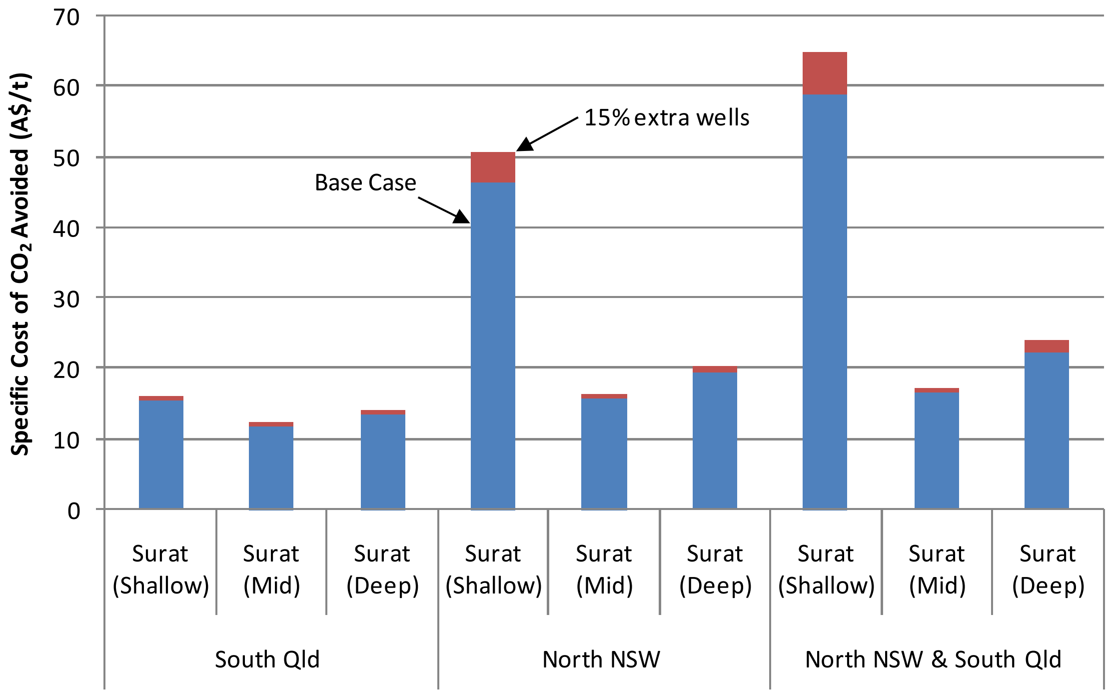


Figure 19 — Effect of 15% extra wells on the specific cost of CO_2 avoided with 7% real discount rate

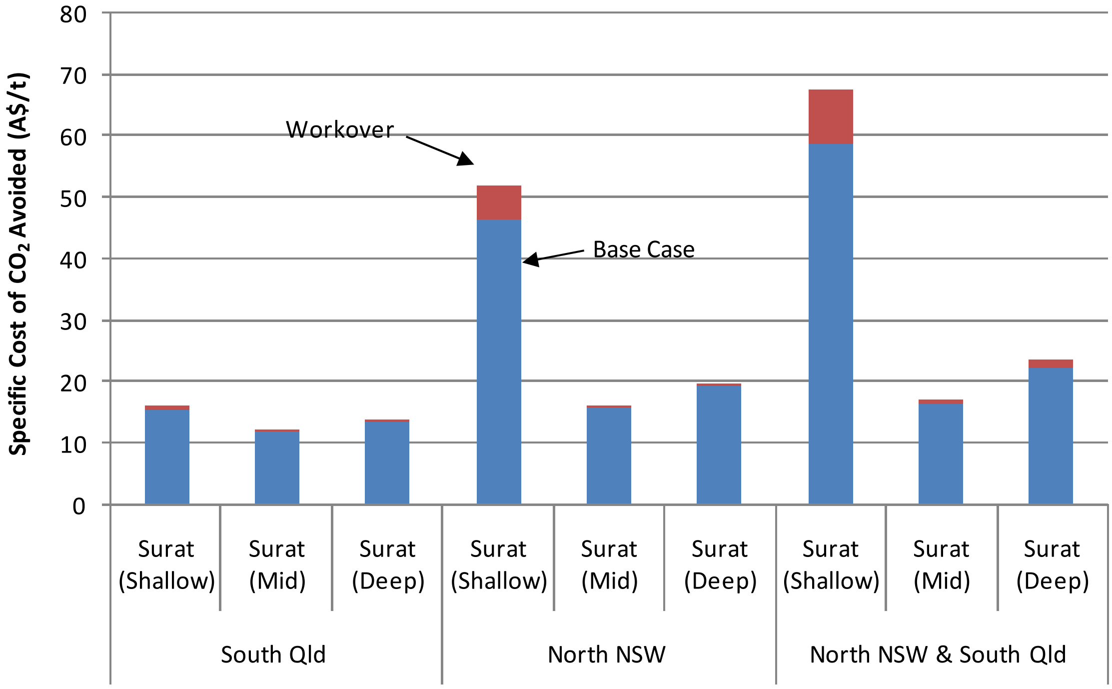


Figure 20 — Effect of well workovers on the specific cost of CO_2 avoided with 7% real discount rate

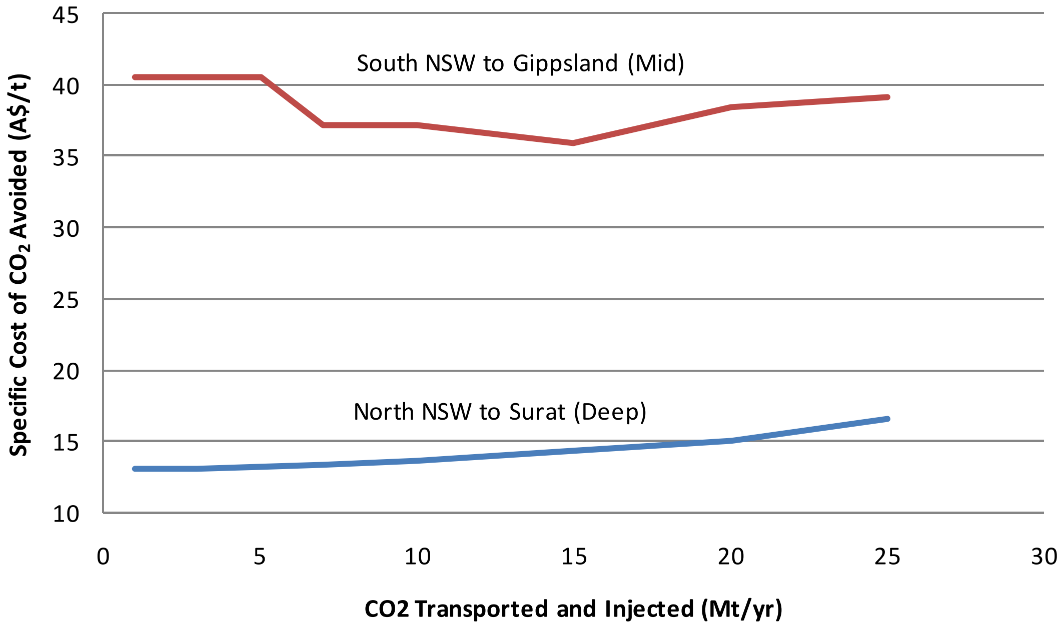


Figure 21 — Effect of changing capacity on the cost of CO_2 avoided with 7% real discount rate

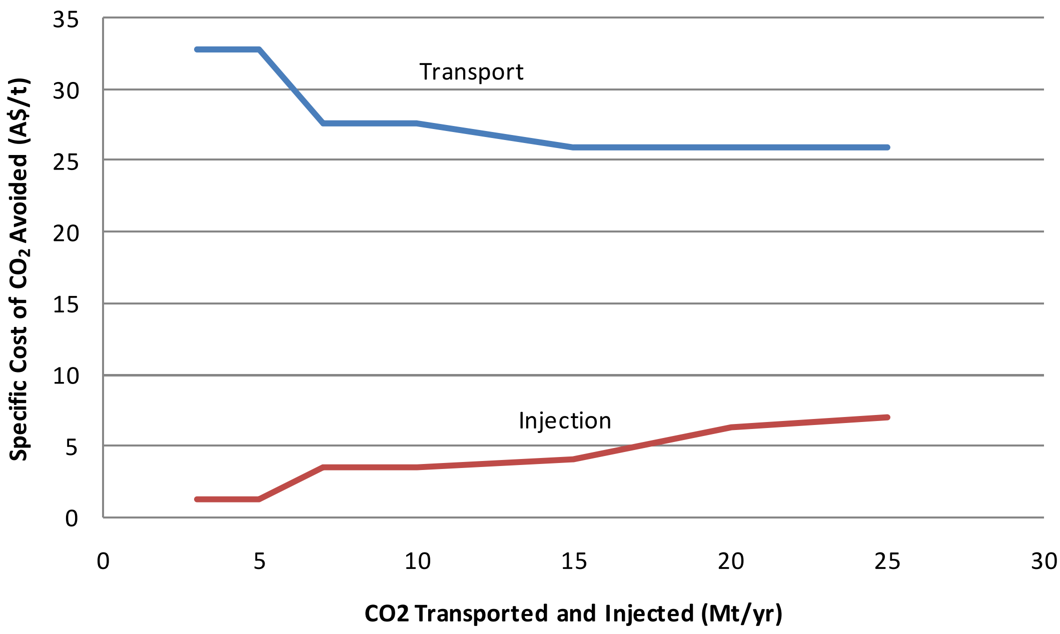


Figure 22 — Effect of changing capacity on the cost of transport and injection for the South NSW to Gippsland (Mid) case with 7% real discount rate

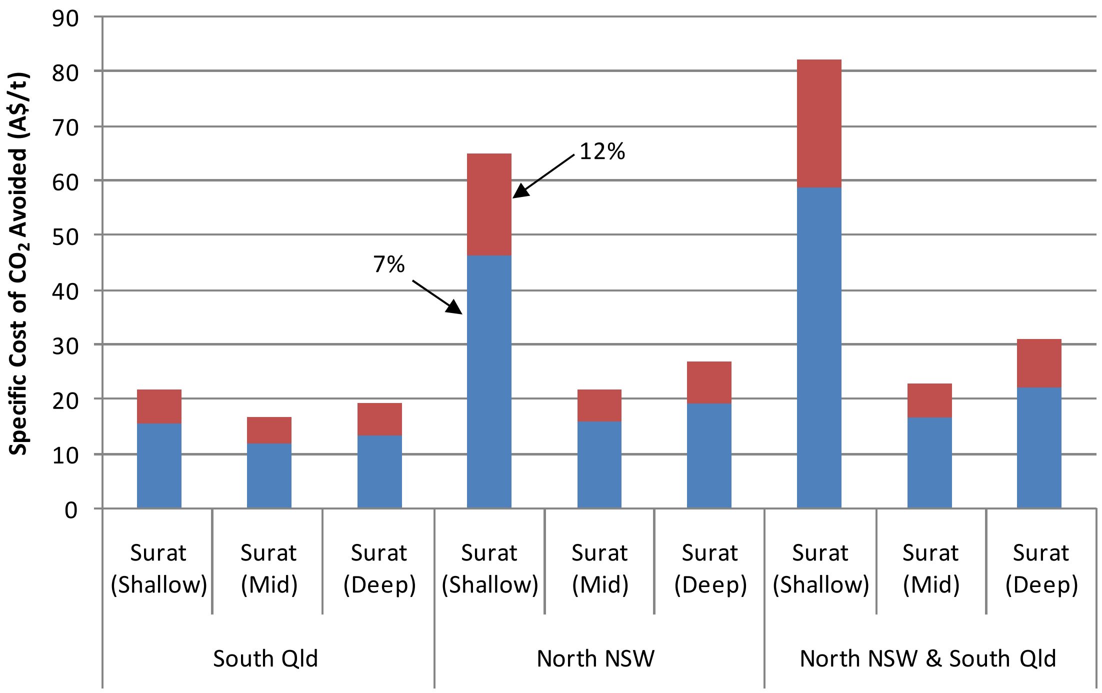


Figure 23 — Effect of discount rate on the specific cost of CO_2 avoided with 7% real discount rate as base case

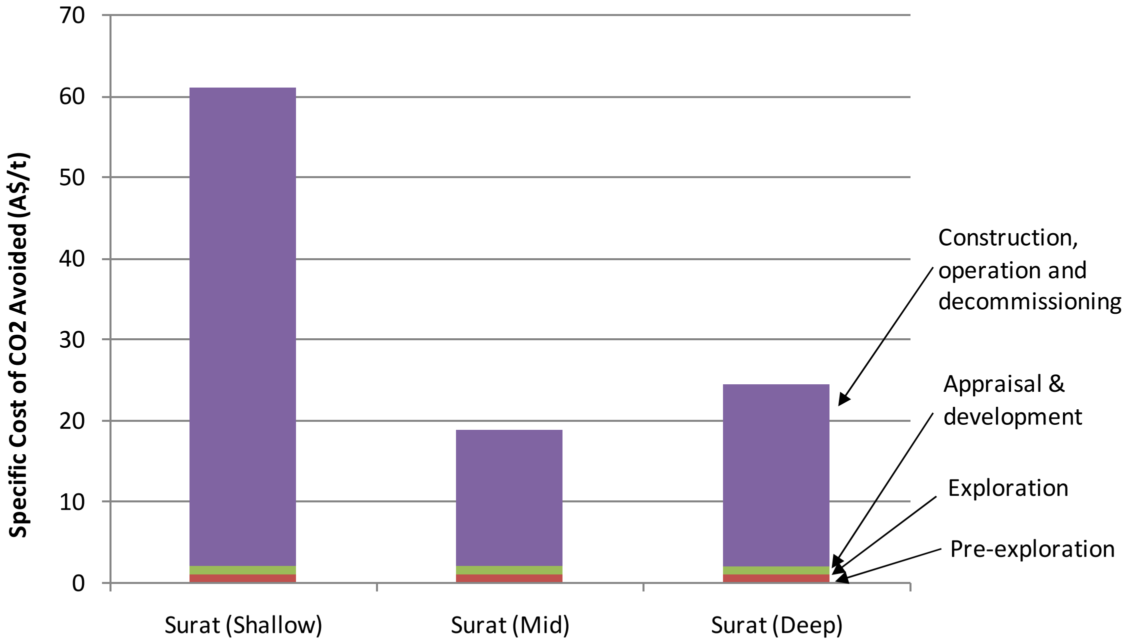


Figure 24 — Cost breakdown with the addition of exploration, appraisal and development costs with 7% real discount rate

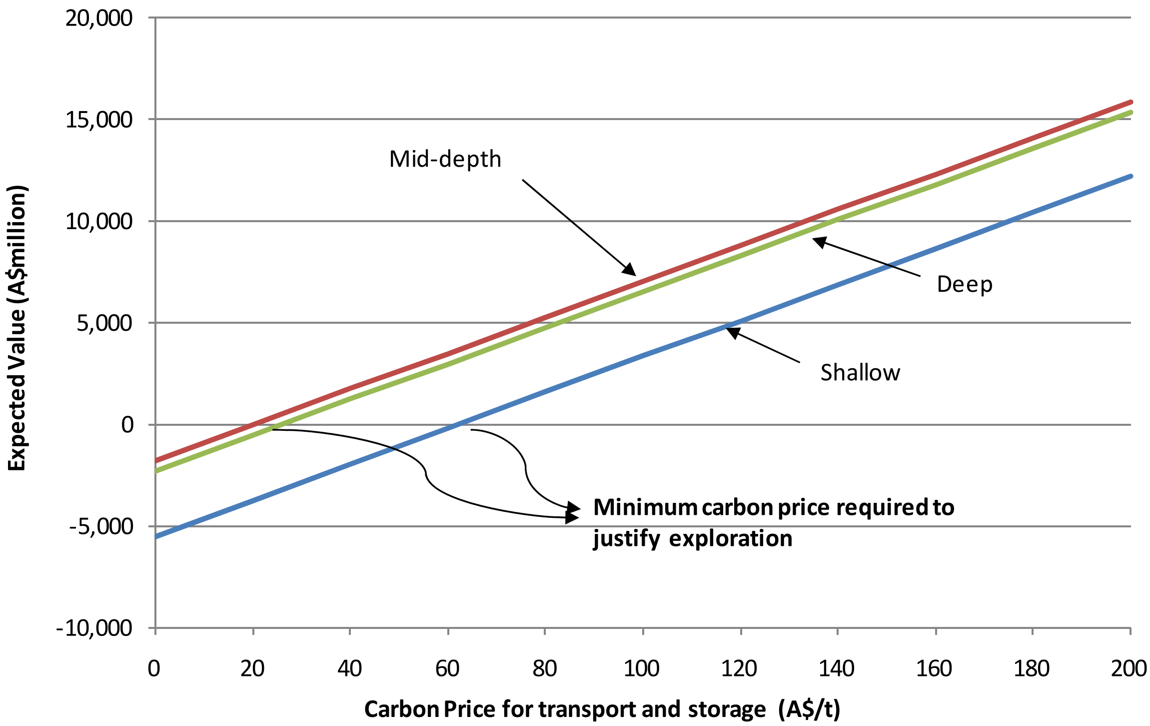


Figure 25 — Expected value analyses with 7% real discount rate

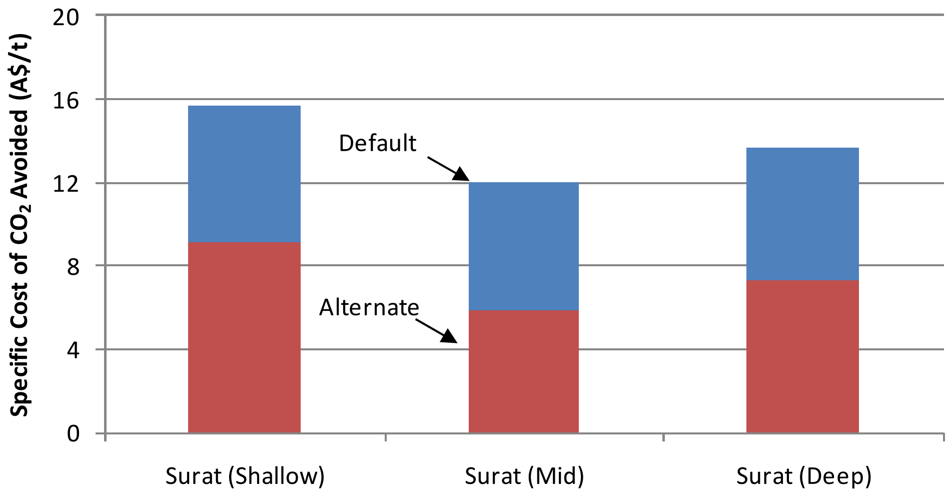


Figure 26 — Effect on cost of changing source location with 7% real discount rate