Development Options for Timor Sea Gas: Analysis of Implications for Australia

A Report to the Northern Territory Government

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Prepared by

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Summary and key findings

This report has been prepared by ACIL Consulting for the Northern Territory Government to assist in the assessment of development options for natural gas from the Sunrise and Bayu-Undan projects in the Timor Sea.

ACIL has used its *GasMark* model to assess the implications for eastern states gas markets of new gas supply from the Timor Sea. Further, the Centre for International Economics (CIE) has applied its integrated model of the Northern Territory and rest of Australia economies to assess macroeconomic impacts of investment and of new gas supply to eastern states markets.

Three basic scenarios are assessed:

- No Timor Sea gas development
- Scenario A
- Scenario B

The scenario assumptions are detailed in Attachment A-1.

For the purposes of analysing the impacts of Timor Sea gas on the Eastern Australian gas market, Scenario B has been assessed both with and without PNG gas delivered to Australia.

Scenario A involves:

- Bayu-Undan gas piped ashore to the Darwin area by 2006
- Sunrise gas to an offshore floating liquefied natural gas (FLNG) plant by 2008; and
- No PNG gas to Australia.

Scenario B involves:

- Bayu-Undan gas piped ashore to the Darwin area by 2006
- Sunrise gas piped ashore to the Darwin area by 2008; and
- Cases with and without PNG gas piped to Australia.

ACIL *GasMark* model results

GasMark is a gas market simulation model developed by ACIL Consulting and designed to assist in analysing gas markets and understanding market dynamics. The model allows testing of differing assumptions regarding availability and pricing of gas production from different fields, transmission pipelines, network developments and market demand. From a consumer's point of view the model seeks to satisfy demand at minimum price, while from a gas producer's perspective it

seeks to allocate available supply so as to maximise netback margins after transportation costs, taking into account competitive alternatives.

The modelling shows that both Scenario A and Scenario B deliver significant benefits (in terms of expansion of the Australian gas market and improved price outcomes) when compared with the No Timor Sea Gas Case.

However, the benefits achieved under Scenario B are significantly greater than for Scenario A. Moreover, bringing both Bayu-Undan and Sunrise gas onshore stimulates markets not only in the Northern Territory but throughout the whole of Eastern Australia. Scenario B sees higher gas volumes than Scenario A delivered into both the Northern Territory and interstate markets. This creates a more competitive supply situation resulting in lower prices to industrial, commercial and residential consumers.

The Scenario B variant including PNG gas shows that, while PNG gas wins significant market volumes particularly in Eastern Queensland, it does so without adversely impacting on the market penetration of Timor Sea gas. The results show even greater increases in delivered gas volumes and average price reductions. Thus the modelling indicates that the two projects would be complementary, rather than mutually exclusive.

A further key finding is that bringing Sunrise gas onshore is essential to creating the benefits of Scenario B. The Bayu-Undan project would be capable of supplying an LNG project with a demand of 165 PJ/year and could supply a further 30 PJ/year for NT gas demand. However, the reserves base available to Bayu-Undan alone could not support production at the levels necessary justify the pipeline infrastructure needed to access interstate markets.

CIE macroeconomic results

CIE estimated the contribution of the Scenario A and B development packages and each of their components to the Northern Territory and Australian economies using an economy-wide integrated model of the Northern Territory and the rest of Australia. The model describes the composition of production and sales in the Northern Territory and rest of Australia economies, the links at the sector level between the two economies through trade and the links through exports and imports to the rest of the world.

In relation to its modelling of Scenario B, the CIE results are conservative because any new developments that take place after 2008 have been excluded. This means that the second phase developments, which begin operation after 2012, have not been modelled.

Nevertheless, as shown in Table 1, the annual economic benefits to the Northern Territory from Scenario B are expected to be substantially greater than those from Scenario A. Similarly, Table 2 shows the

additional national benefits, including the Northern Territory, from Scenario B over Scenario A.

Table 1: Additional economic benefits to the Northern Territory delivered by Scenario B over Scenario A

Economic indicator	Construction phase		Operations phase annual benefits
	2002-04 [a]	2005-07 [a]	
Gross State Product, including	$113.7m	$126.1m	$810.1m
Real investment	$890.2m	$712.6m	$34.2m
Household consumption	$50.4m	$63.6m	$115.8m
Net exports (imports) to other States	($244.4m)	($324.8m)	$5.8m
Net exports (imports) overseas	($557.9m)	($318.8m)	$651.6m
Employment (full-time equivalents)	2,179	1,488	1,892
NT Government revenue	$5.3m	$5.6m	$9.6m

Source: CIE
(a) Annual average over the three-year period

Table 2: Additional National benefits (including NT) delivered by Scenario B over Scenario A

Economic indicator	Construction phase		Operations phase annual benefits
	2002-04 [a]	2005-07 [a]	
Gross Domestic Product, including	$283.8m	$330.1m	$1021.3m
Real investment	$890.2m	$712.6m	$35.1m
Household consumption	$112.3m	$168.6m	$256.9m
Net exports (imports) overseas	($698.4m)	($545.2m)	$715.2m
Employment (full-time equivalents)	5,613	3,025	4,408
Government revenue	$89.7m	$108.7m	$110.4m

Source: CIE
(a) Annual average over the three-year period

1. *GasMark* modelling

GasMark is a gas market simulation model developed by ACIL Consulting and designed to assist in analysing and understanding the dynamics of the Eastern Australian gas market. The model allows testing of different assumptions regarding availability and pricing of gas production from different fields, transmission pipelines, network developments and market demand. From a consumer's point of view the model seeks to satisfy demand at minimum price, while from a gas producer's perspective it seeks to allocate available supply so as to maximise netback margins after allowing for transportation costs and taking into account competitive alternatives.

For the purposes of analysing the impacts of importing Timor Sea gas, three basic scenarios have been examined using *GasMark*:

- A base-line scenario in which no development of Timor Sea gas occurs;
- A scenario in which Sunrise gas is produced solely for processing in an offshore floating liquefied natural gas (FLNG) plant, while Bayu-Undan gas is landed in Darwin for supply to an onshore LNG facility and for local power generation (Scenario A); and
- A scenario in which both Sunrise and Bayu-Undan gas are piped to shore at Darwin, for use in a range of industrial applications in the Northern Territory. Transmission pipeline connections to Mount Isa and Moomba provide access to markets throughout Eastern Australia (Scenario B).

Details of the Scenario A and B assumptions are provided in Attachment A-1.

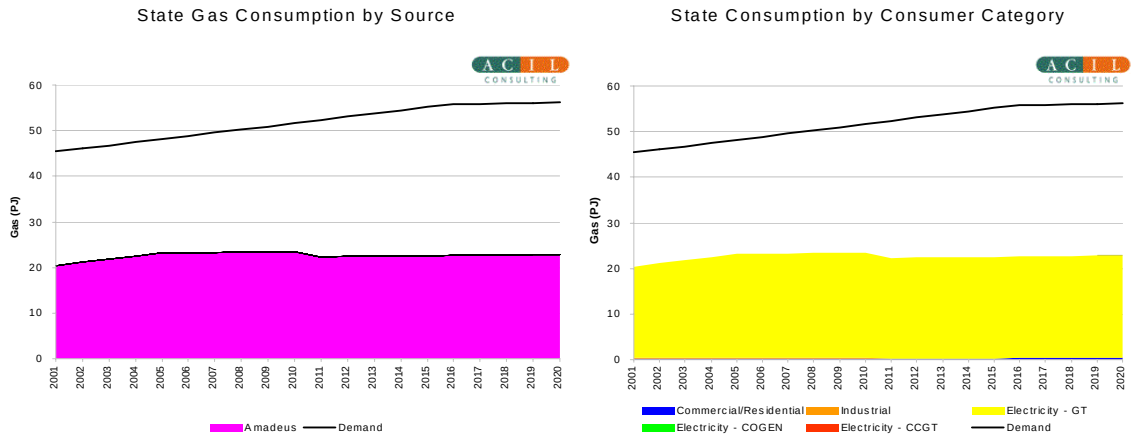
1.1 No Timor Sea Gas Scenario

Under the "No Timor Sea Gas" Scenario it is assumed that there is no development of the Timor Sea gas resources. As at present, the only gas supply available to the Northern Territory market is the Amadeus Basin in Central Australia.

Figure 1 shows the potential demand and supply situation in the Northern Territory under this scenario.

Gas consumption in the Northern Territory grows very modestly from the current level and then declines slightly as production constraints in the Amadeus Basin fields begin to take effect. Almost all consumption occurs in the electricity generation sector. A significant level of demand – up to about 33 PJ – is not fulfilled, mainly because of the inability to service the existing load at the Gove alumina refinery (currently 25 PJ/year).

Figure 1: NT Demand and Supply for No Timor Sea Gas Scenario



The "potential demand" line in Figure 1 and subsequent charts represents the quantity of gas being sought by current and future gas consumers, subject to maximum price tolerance assumptions that are specified on a load-by-load basis. Note that under this scenario, a range of identified gas use opportunities (for example, in power generation and value added gas processing such as alumina processing) have been excluded from the set of potential loads because of the limited remaining life of reserves in the Amadeus Basin.

Figure 2: Total gas sales volumes, by State/Territory — No Timor Sea Gas Scenario

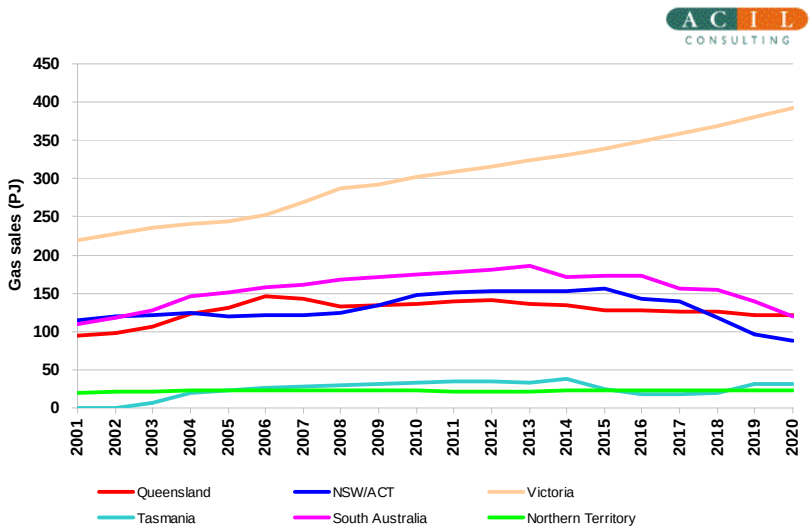


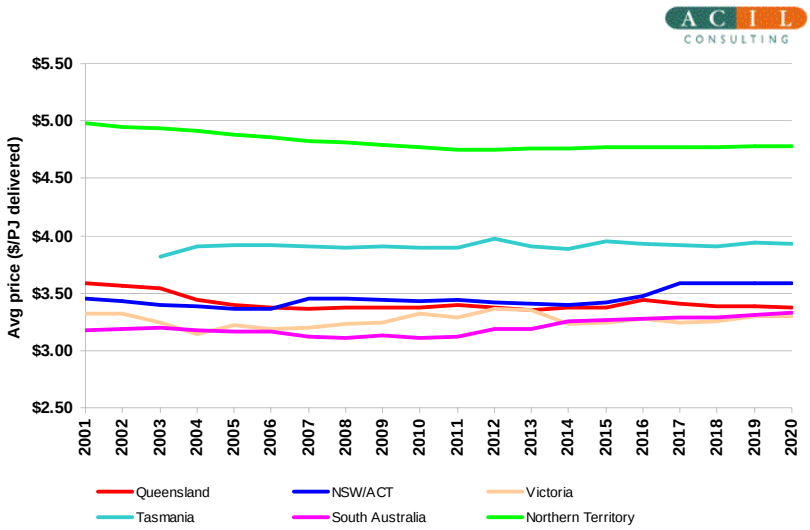
Figure 2 shows the total volumes of gas sold in each state and territory market under the No Timor Sea Gas Scenario.

Of particular note is the decline in gas deliveries into Queensland, New South Wales and South Australia as available sources in the Cooper Basin

of South Australia, and to a lesser extent South West Queensland, reach deliverability limits.

Figure 3 shows the average real price of gas (that is, in constant year 2001 A$/GJ) delivered into various markets under the "No Timor Sea Gas" Scenario.

Figure 3: Average real price of gas, by State/Territory — "No Timor Sea Gas" Scenario



Clearly the Northern Territory has a major price disadvantage relative to other state markets. This is due to the long transportation distance, together with relatively small market volume, which drives up average cost of transportation to the Darwin market. The key to achieving lower delivered gas prices for Northern Territory customers lies in economies of scale in gas production and transportation.

Prices in the southern states show real increases toward the end of the modelling period as supply constraints become more acute.

1.2 Scenario A

1.2.1 Introduction

Scenario A reflects the FLNG option for Sunrise Gas.

In this scenario it is assumed that 275 PJ/year of gas from Sunrise is dedicated to an FLNG plant, commencing in 2008. Up to 165 PJ/year of gas from Bayu-Undan is available for delivery to an onshore LNG plant, with a further 30 PJ/year available for consumption within the Northern Territory — principally for power generation.

Gove remains unconnected, nor is there any pipeline linkage to interstate markets. This is because the reserves available in Bayu-Undan alone are

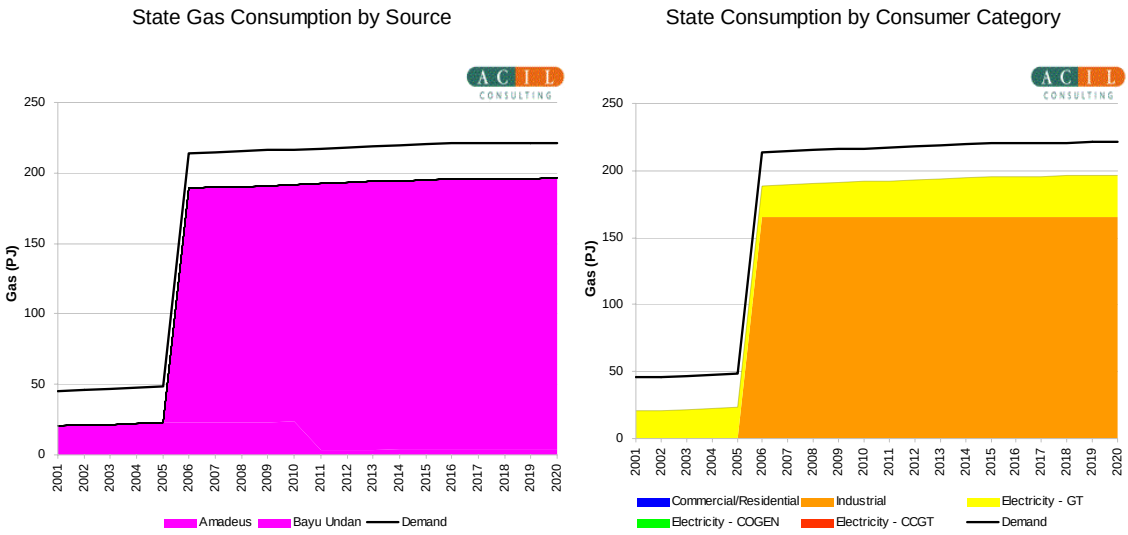
insufficient to support both the Darwin-based developments and interstate exports at viable levels.

The modelling shows that production from the Amadeus Basin declines significantly by 2011 to around 4 PJ/year, after which it supplies only small power generation loads in remote areas of the Territory. Most of the Territory's power generation demand is then met by Bayu-Undan gas. Consumption in the power generation sector rises from 20 PJ/year in 2001 to 31 PJ/year in 2020.

There is a gap between supply and potential demand due mainly to unmet demand of 25 PJ/year at the Gove alumina refinery.

Figure 4 shows NT gas consumption by source for Scenario A.

Figure 4: NT gas consumption by source for Scenario A



1.2.2 Volumes of gas sold – Scenario A

Figure 5 shows the volumes of gas sold into state and territory markets under this scenario, while Figure 6 shows the incremental gas sales volumes (compared to the No Timor Sea Gas Scenario).

Figure 5: Total gas sales volumes, by State/Territory — Scenario A

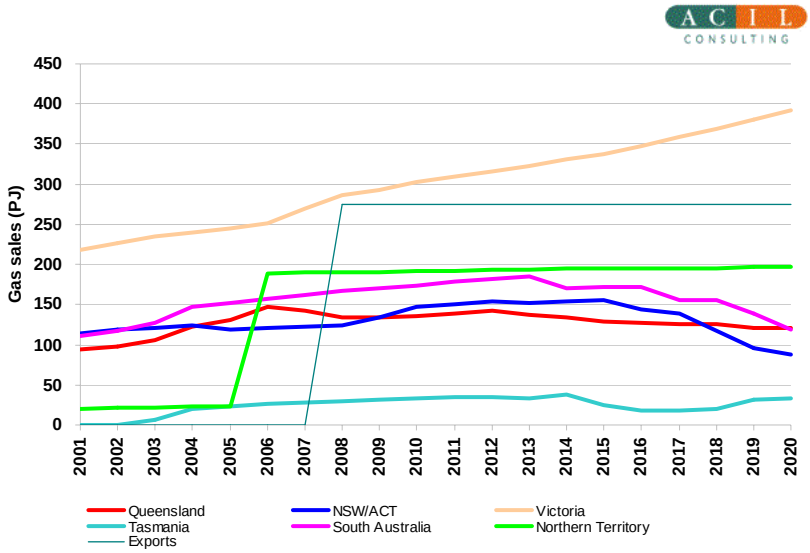
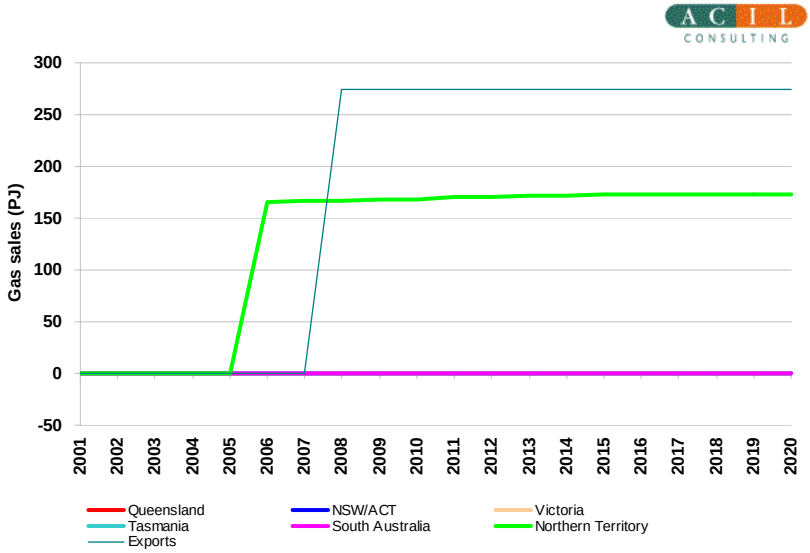


Figure 6: Incremental gas sales volumes, by State/Territory — Scenario A

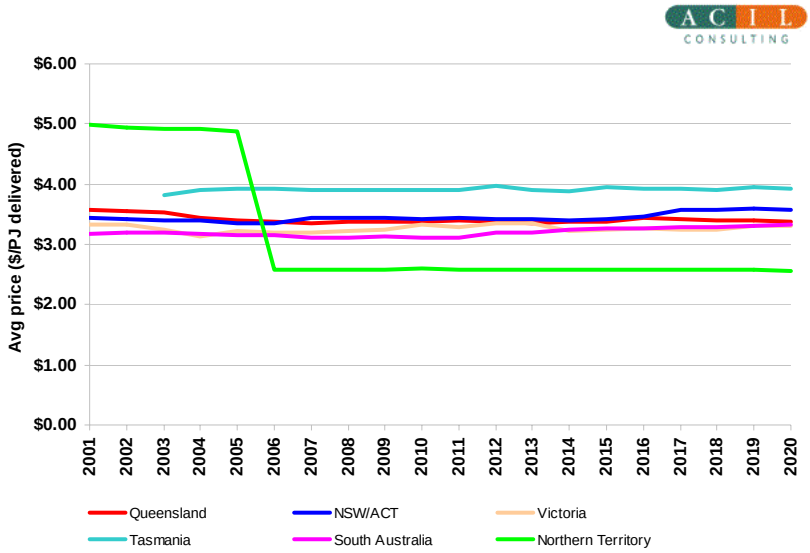


As expected in view of the lack of pipeline interconnection to southern states, Scenario A does not result in any change to outcomes in markets other than Northern Territory and exports of LNG.

1.2.3 Average Delivered Price of Gas – Scenario A

Figure 7 shows the impact on average delivered prices for Scenario A. Connection of Bayu-Undan gas to Darwin has a dramatic effect on gas prices in the Northern Territory, with the average delivered gas price falling to around half current levels. No other state market is impacted by this scenario.

Figure 7: Average real delivered gas prices for Scenario A



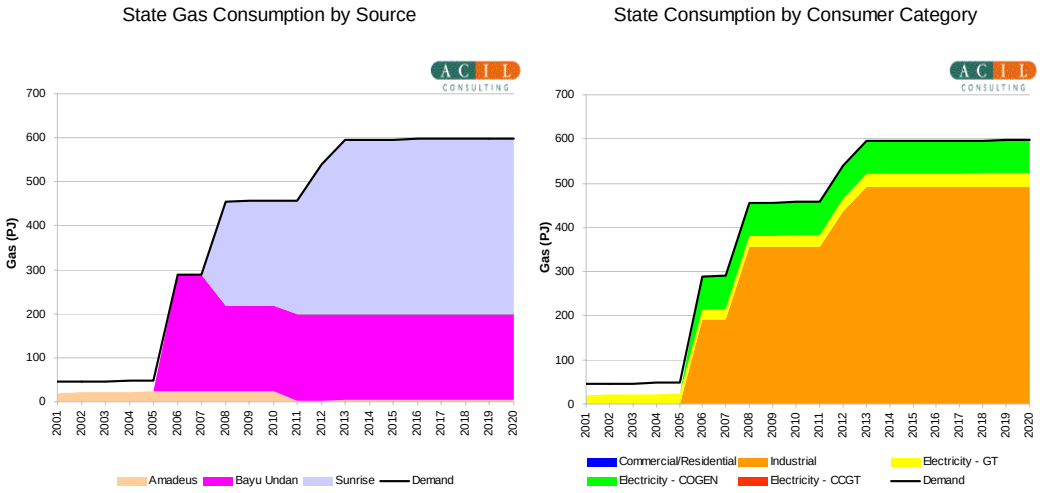
1.3 Scenario B without PNG

1.3.1 Introduction

Scenario B reflects the case where all gas production from Sunrise and Bayu-Undan is piped ashore to Darwin.

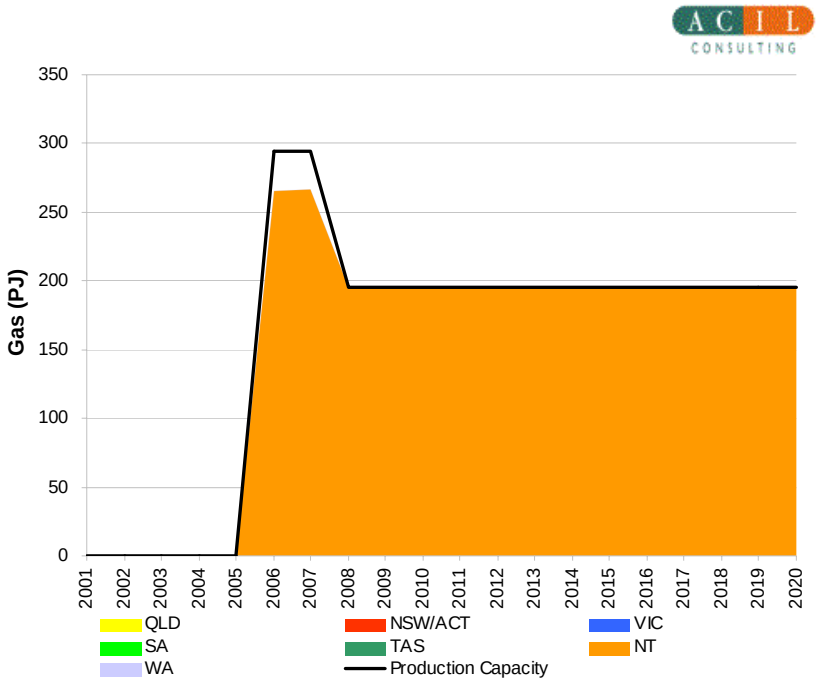
As shown in Figure 8 all anticipated demand in the Northern Territory is met once Bayu-Undan gas is available in Darwin from 2006.

Figure 8: NT gas consumption by source and customer category for Scenario B



It is assumed under this scenario that Bayu-Undan produces at a high initial level in order to support early development of new gas-based industries prior to delivery of Sunrise gas. After 2008, maximum production from Bayu-Undan is assumed to revert to a sustainable level of around 195 PJ/year. Figure 9 shows the Bayu-Undan production profile. All production is consumed within the NT. The major loads are for LNG production, electricity generation for the aluminium industry and the Gove alumina refinery.

Figure 9: Bayu-Undan Production for Scenario B

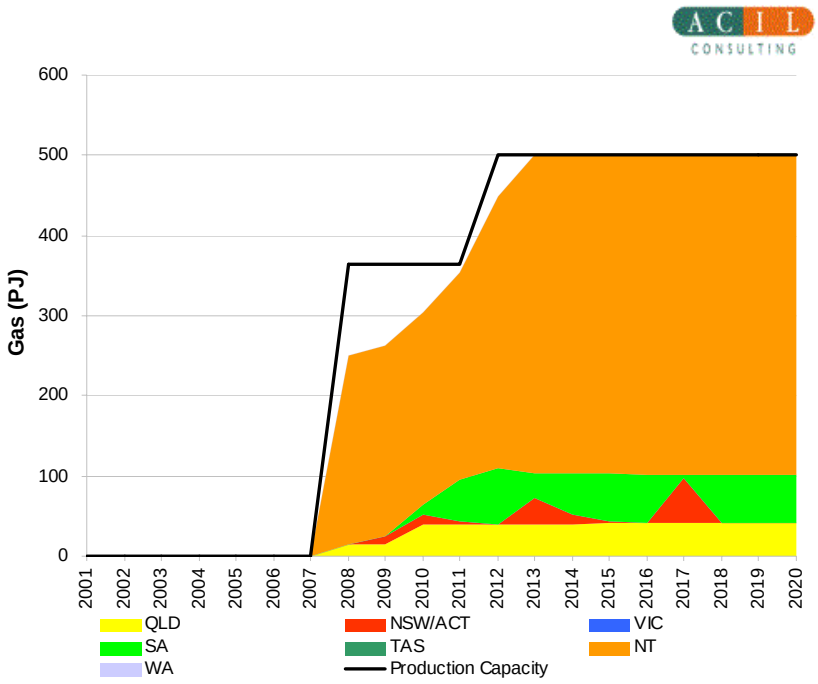


Production and market placement of Sunrise gas is illustrated in Figure 10. Most production is consumed within the Northern Territory at the onshore LNG plant, alumina and aluminium production, in petrochemical production (post 2012) and in power generation. Consumption of Sunrise gas in the Northern Territory rises from 237 PJ/year in 2008 to a constant level of approximately 400 PJ/year by 2013.

In addition there will be deliveries of around 100 PJ/year into interstate markets:

- Deliveries to Queensland (Mount Isa market) commence at approximately 14 PJ/year in 2008 and 2009, rising to around 40 PJ/year from 2010;
- Substantial quantities of up to 61 PJ/year are consumed in South Australia from 2010; and
- Variable quantities of up to 57 PJ/year are delivered into New South Wales and the Australian Capital Territory from 2009.

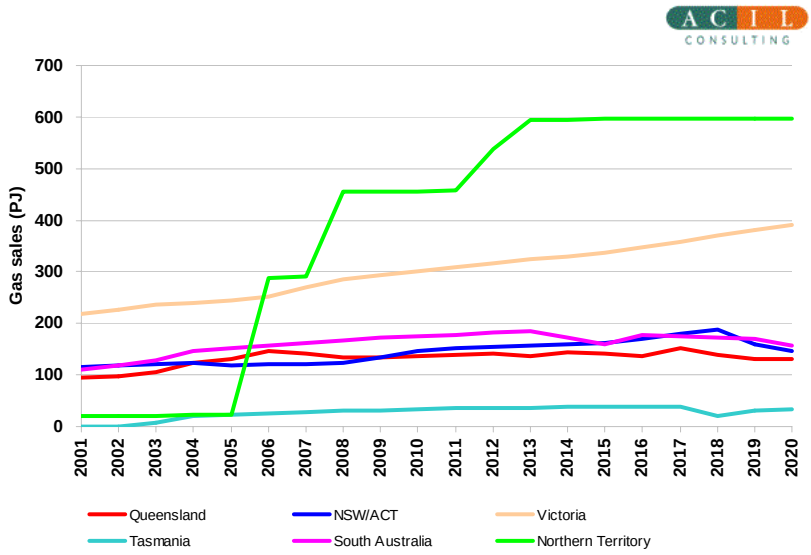
Figure 10: Sunrise Production for Scenario B



1.3.2 Volumes of gas sold – Scenario B

Figure 11 shows the aggregate volumes of gas sold into state and territory markets under Scenario B, while Figure 12 shows the incremental gas sales volumes (compared to the No Timor Sea Gas scenario).

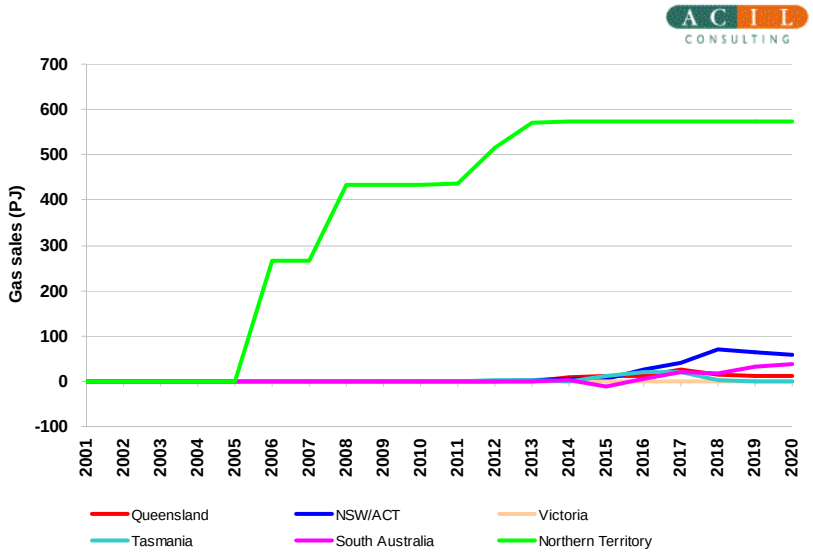
Figure 11: Total gas sales volumes, by State/Territory — Scenario B



In this case the greatest volume increases occur in the NSW/ACT market where up to 71 PJ/year of additional gas is sold. In the South Australian

market up to 38 PJ/year extra gas is sold. Queensland also benefits in more modest fashion with up to 25 PJ/year of additional gas being sold.

Figure 12: Differential gas sales volumes, by State/Territory — Scenario B



1.3.3 Average Delivered Price of Gas – Scenario B

All state and territory markets benefit from the greater availability of Timor sea gas which characterises Scenario B. This is generally reflected in lower average delivered prices. However, some caution must be exercised in interpreting average price results as they can be misleading. For example, in Tasmania the modelling shows an increase in average prices towards the end of the modelling period. This occurs because some high priced but low margin markets that would otherwise not be provided with gas can now be serviced as a result of the increased availability of supply. In this case, while no individual load pays any more as a result of having Timor Sea gas available (and some may pay less), the average price may rise.

Figure 13 to Figure 18 show the impact of availability of Timor Sea gas on average real delivered gas prices in the various state and territory markets under Scenario B. The Northern Territory is a major beneficiary of lower prices with average price reductions of around $2.30/GJ. Queensland and South Australia see sustained lower average prices up to 9c/GJ and 10c/GJ respectively. Victoria and NSW/ACT also benefit albeit to a lesser extent.

Figure 13: Average real delivered gas prices and price differential in Northern Territory — Scenario B

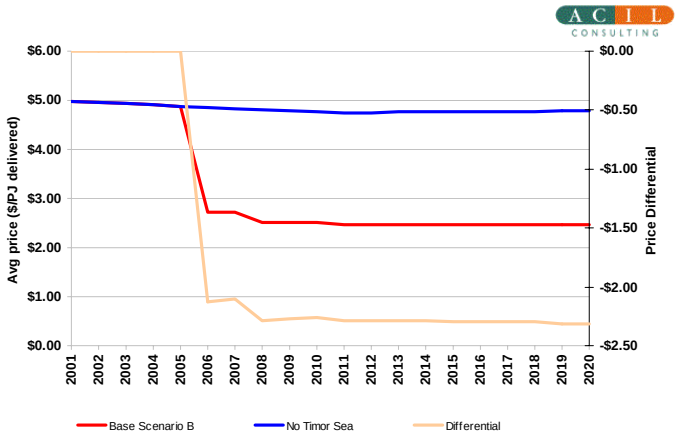


Figure 14: Average real delivered gas prices and price differential in Queensland — Scenario B

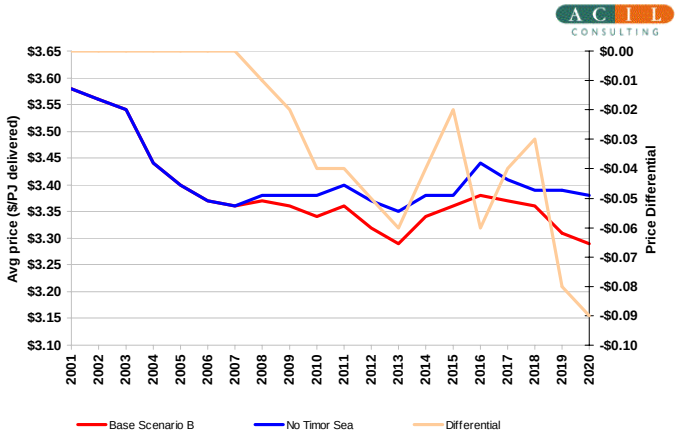


Figure 15: Average real delivered gas prices and price differential in NSW/ACT — Scenario B

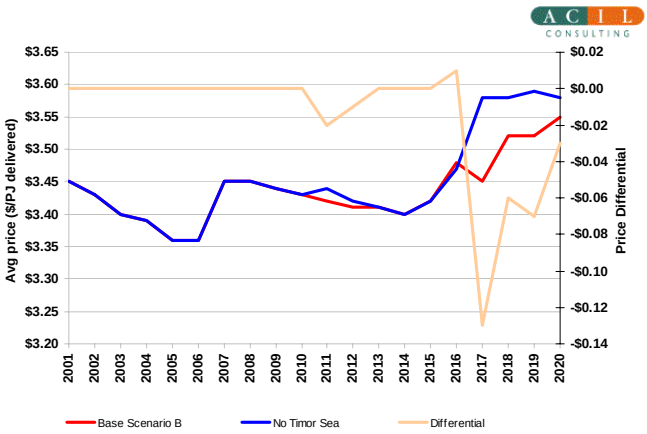


Figure 16: Average real delivered gas prices and price differential in Victoria — Scenario B

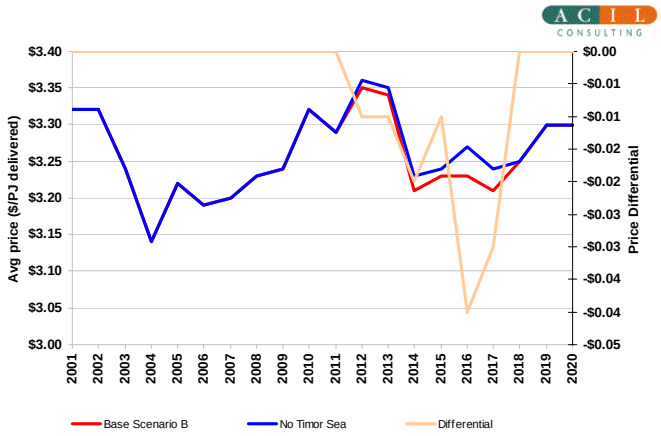


Figure 17: Average real delivered gas prices and price differential in Tasmania — Scenario B

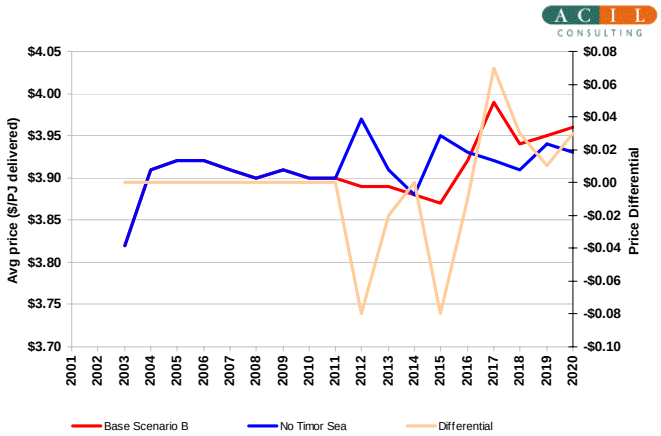
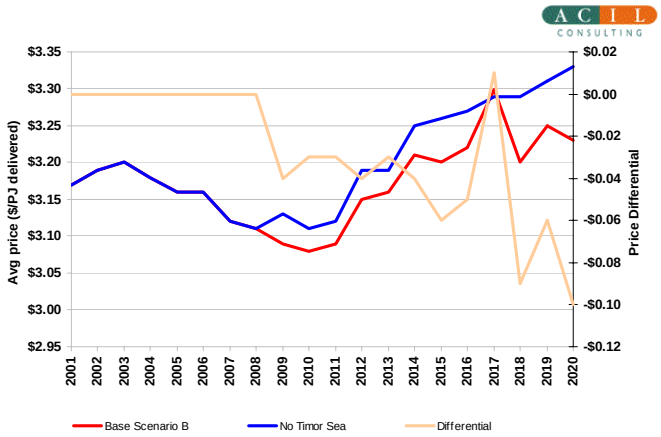


Figure 18: Average real delivered gas prices and price differential in South Australia — Scenario B



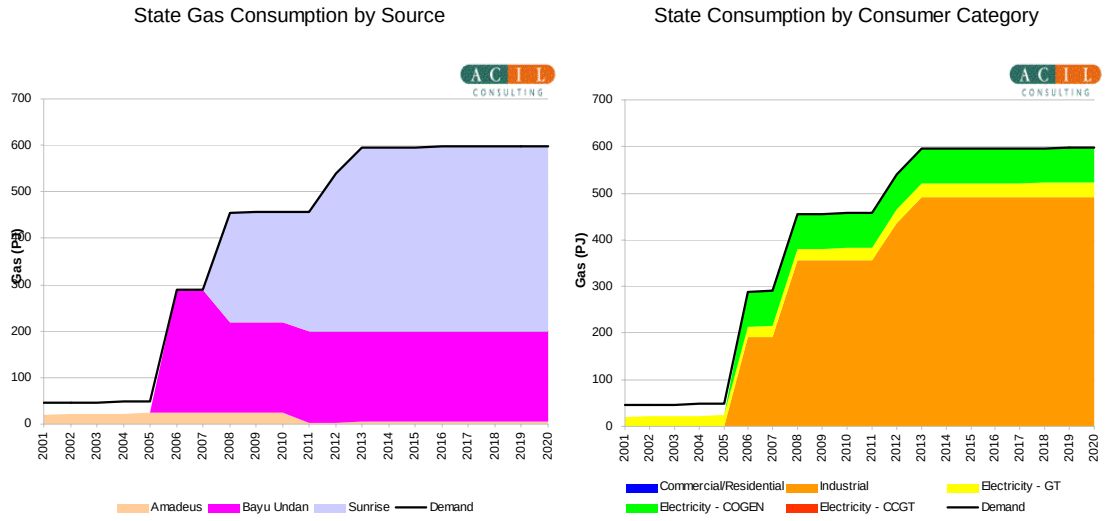
1.4 Scenario B with PNG

1.4.1 Introduction

This scenario again reflects the case where all gas production from Sunrise and Bayu-Undan is piped ashore to Darwin. The modelling assumptions are identical to the previous scenario except that the PNG gas project is assumed to proceed with gas deliveries commencing in 2006.

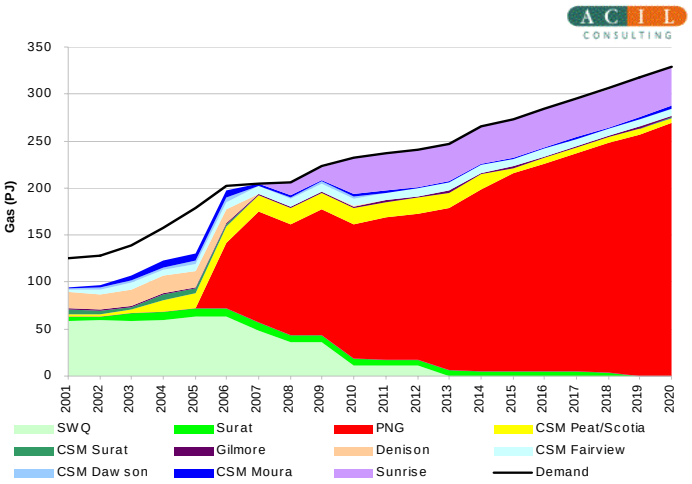
Under this scenario all Northern Territory demand is satisfied once Timor Sea gas becomes available from 2006 (Figure 19). The patterns of supply and consumption within the Northern Territory are identical to those under the "without PNG" case (compare Figure 8).

Figure 19: Northern Territory gas consumption by source and consumer category for Scenario B with PNG gas.



With regard to supply in other states, the outcomes for Scenario B with PNG gas are generally similar to those without PNG gas, with the exception of Queensland. In Queensland, the introduction of PNG gas provides a major boost to overall supply such that all of the identified potential demand in Queensland is satisfied (Figure 20). In both cases, Timor Sea gas is supplied into the Mt Isa market. However Timor Sea gas is unable– in either case, under the model assumptions – to reach consumers in Eastern Queensland at prices likely to be sustainable in the market. Hence the modelling indicates that the PNG project does not displace Timor Sea gas. Instead, the two projects are found to serve essentially different markets – PNG in coastal Queensland and Timor Sea in northwest Queensland and the southern States.

Figure 20: Queensland demand and supply for Scenario B with PNG Gas



1.4.2 Volumes of gas sold – Scenario B with PNG

Figure 21 shows the aggregate volumes of gas sold into state and territory markets under Scenario B without PNG, while Figure 22 shows the incremental gas sales volumes (compared to the No Timor Sea Gas Scenario).

In this case both the Northern Territory and Queensland markets show major increases in gas sales volumes. The differential impacts in the southern states are similar to those observed under the "without PNG" case.

Figure 21: Total gas sales volumes, by State/Territory — Scenario B with PNG gas

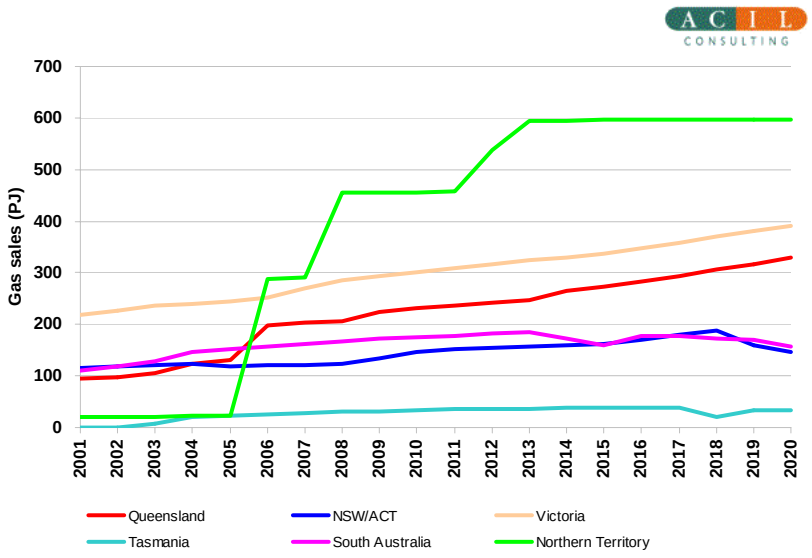
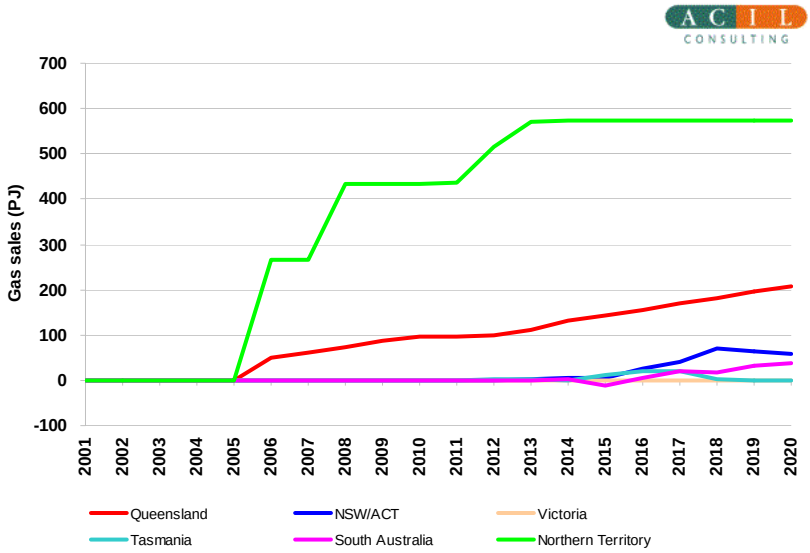


Figure 22: Differential gas sales volumes, by State/Territory — Scenario B with PNG gas



1.4.3 Average Delivered Price of Gas – Scenario B with PNG

Figure 23 to Figure 28 show the impact of availability of Timor Sea gas on average real delivered gas prices in the various state and territory markets under Scenario B with PNG gas. The NT is again major beneficiary of lower gas prices in this scenario. Queensland also sees strong reductions in average prices. In NSW/ACT, Victoria and South Australia average prices also decline, but to a lesser extent than in the Northern Territory and Queensland. In Tasmania average prices actually increase toward the end of the modelling period, because some high priced but low margin markets that would otherwise not be provided with gas are able to be serviced.

Figure 23: Average real delivered gas prices and price differential in Northern Territory — Scenario B with PNG gas

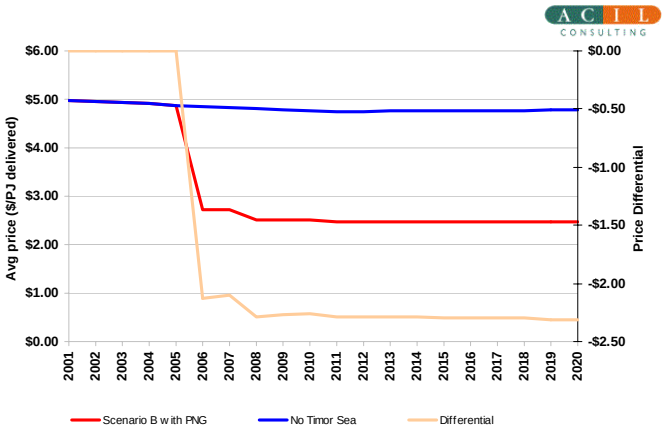


Figure 24: Average real delivered gas prices and price differential in Queensland — Scenario B with PNG gas

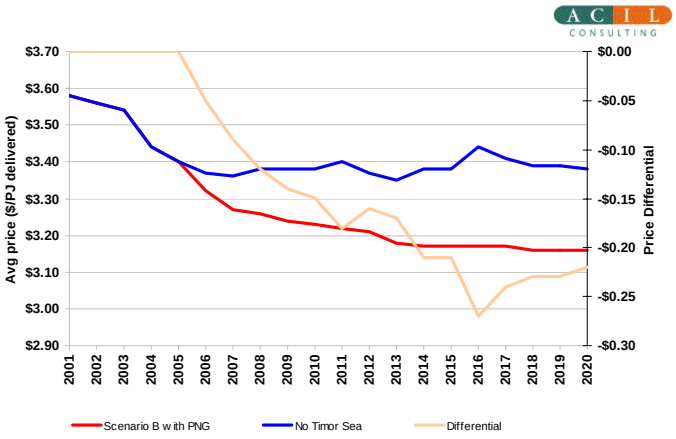


Figure 25: Average real delivered gas prices and price differential in NSW/ACT — Scenario B with PNG gas

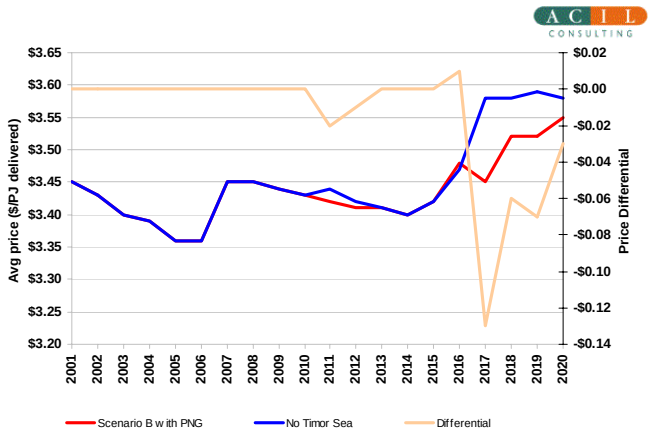


Figure 26: Average real delivered gas prices and price differential in Victoria — Scenario B with PNG gas

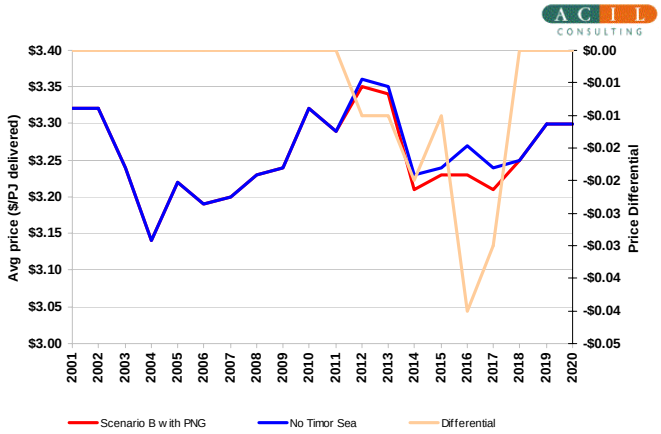


Figure 27: Average real delivered gas prices and price differential in Tasmania — Scenario B with PNG gas

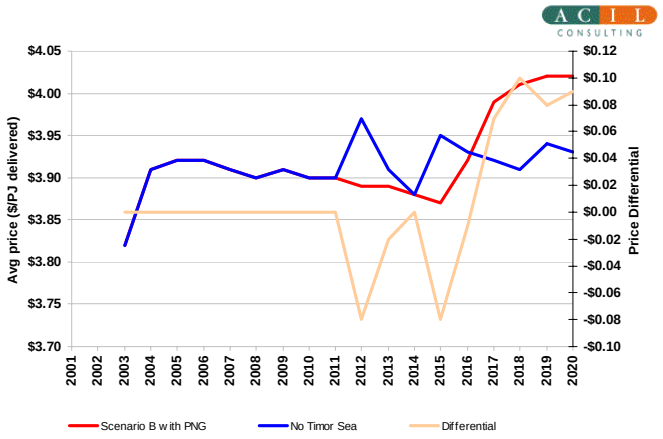
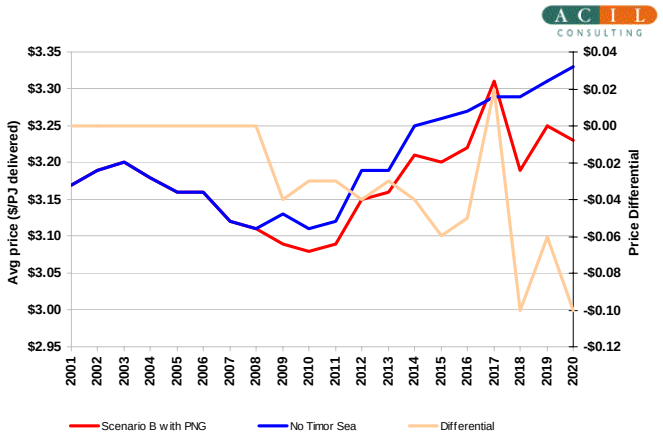


Figure 28: Average real delivered gas prices and price differential in South Australia — Scenario B with PNG gas



2. CIE macroeconomic modelling

The Centre for International Economics was commissioned to estimate the contribution that Scenarios A and B (with PNG gas) would make to the Northern Territory and Australian economies, compared to the base-line case where no Timor Sea gas is developed. CIE has used its integrated model of the Northern Territory and rest of Australia economies.

The CIE model distinguishes 60 sectors of production in each economy (Northern Territory and rest of Australia), including oil and gas production, methanol production, the aluminium industry, gas pipeline transmission activities, electricity generation and the various upstream and downstream industries providing capital and current inputs to production of goods and services to meet the needs of consumers. It accounts for all sectors of production in the Northern Territory and hence Northern Territory net income, which is referred to as gross state product (GSP), and all sectors in the rest of Australia, and hence Australia's national income (GDP).

Each sector in the Northern Territory and rest of Australia economies can source its inputs from suppliers in the Northern Territory, suppliers in the rest of Australia and from overseas (imports). Similarly, each sector's products can be sold to industries and households in the Northern Territory, the rest of Australia and to export markets.

As well as identifying the cost and sales structures of each industry, the model accounts for the various taxes and charges the Northern Territory and Commonwealth governments levy throughout the economy to raise revenue.

By including, at a detailed level, representations of the interactions between sectors, the model is able to assess the direct and flow on effects of the scenarios and their components on the performance of industries, employment opportunities, government revenue, macroeconomic performance and living standards. It accounts for how much of the benefits remain in the Northern Territory and how much flow to the rest of Australia and overseas.

CIE use the Northern Territory – rest of Australia model to analyse the impact of the construction and operations phases of the scenarios and their components. Two periods of the construction phase are modelled — 2002/04 and 2005/07. The operations phase is modelled at 2008. The modelling outcomes are estimated by imposing the new investment associated with the scenarios as a "shock" to the Northern Territory and rest of Australia economies.

The CIE analysis focuses on a selection of economic variables likely to be of relevance to decision makers in coming to grips with the economic effects of the scenarios. Key variables of interest are:

- value added (which is GSP for the Northern Territory and GDP for the rest of Australia and Australia as a whole);
- living standards (measured in terms of increase in real consumption expenditure) of Northern Territory and Australian households;
- labour market performance;
- trade between the Northern Territory and rest of Australia, and between Australia and overseas; and
- government revenue (Northern Territory, Australia).

2.1 Scenario A

The development assumptions under Scenario A are as set out in Attachment A-1.

Table 3 shows the macroeconomic impacts of the Scenario A development on the Northern Territory and the Australian economies. The operations phase from 2008 is estimated to contribute **annually**:

- an increase of 35% to NT GSP and, for the whole of Australia, a $3 billion increase in GDP;
- an increase in real investment in the NT economy of $48 million;
- net overseas exports from the NT of over $2,700 million;
- a permanent employment boost of 3,264 in the NT and almost double that figure for Australia; and
- increased NT Government revenues of $18 million and Commonwealth revenues of over $110 million.

Table 3: Scenario A construction and operations impacts on the economy

			Investment phase		Operations phase
			2002-04(a)	2005-07(a)	2008
Gross domestic product	NT	%	2.49	5.64	35.85
		$m 2000	190.94	432.25	2747.64
	Australia	%	0.07	0.16	0.50
		$m 2000	394.73	945.02	3002.68
Real investment	NT	%	61.60	107.40	2.24
		$m 2000	1318.20	2298.28	47.95
	Australia	%	0.94	1.64	0.07
		$m 2000	1318.20	2298.28	93.51
Household consumption	NT	%	2.42	5.86	6.12
		$m 2000	83.33	201.97	210.85
	Australia	%	0.04	0.11	0.11
		$m 2000	148.10	375.59	403.00
Exports interstate	NT	%	0.34	0.77	0.27
		$m 2000	3.42	7.82	2.75
Exports overseas	NT	%	-0.25	-0.56	89.24
		$m 2000	-7.86	-17.59	2825.73
	Australia	%	-0.20	-0.42	2.24
		$m 2000	-233.04	-493.58	2661.14
Imports interstate	NT	%	12.18	26.71	6.61
		$m 2000	443.40	972.26	240.80
Imports overseas	NT	%	84.52	121.00	11.05
		$m 2000	724.90	1037.81	94.79
	Australia	%	0.65	0.96	0.12
		$m 2000	800.71	1189.17	153.66
Employment	NT	%	3.04	6.74	3.84
		Persons	2588.68	5739.70	3264.47
	Australia	%	0.07	0.17	0.08
		Persons	5995.73	13939.31	6199.24
Consumer price index	NT	%	1.37	3.26	0.46
	ROA	%	0.03	0.09	0.02
Government revenues	NT	%	0.52	1.37	0.99
		$m 2000	9.47	24.97	18.0
	Australia	%	0.06	0.13	0.07
		$m 2000	110.65	254.05	133.79

Source: CIE NT-Australia model and CIE calculations. (a) Three year annual average.

2.2 Scenario B

The development assumptions under Scenario B are set out in Attachment A-1. Note that the additional developments identified for the post-2012 period (relating to petrochemical and ammonia/urea production) are not included for purposes of macroeconomic modelling. Possible expansion of the Gove alumina facility in this period is also excluded. In these regards, the modelling assumptions are considered to be conservative.

Table 4 shows the macroeconomic impacts of the Scenario B development on the Northern Territory and the Australian economies. The modelling excludes the second phase of development in Scenario B in the period 2008-12, and the results are consequently conservative for this scenario. The operations phase from 2008 is estimated to contribute **annually**:

- an increase of 46% to NT GSP and, for the whole of Australia, an increase of over $4 billion in GDP;
- an increase in real investment in the NT economy of $82 million;
- net overseas exports from the NT of over $3,300 million;
- a permanent employment boost of 5,156 in the NT and almost double that figure for Australia; and
- increased NT Government revenues of $27 million and Commonwealth revenues of $210 million.

Table 4: Scenario B construction and operations impacts on the economy

			Investment phase		Operations phase
			2002-04(a)	2005-07(a)	2008
Gross domestic product	NT	%	3.97	7.28	46.41
		$m 2000	304.66	558.37	3557.69
	Australia	%	0.11	0.21	0.67
		$m 2000	678.56	1275.08	4024.02
Real investment	NT	%	103.20	140.70	3.84
		$m 2000	2208.41	3010.88	82.16
	Australia	%	1.57	2.15	0.09
		$m 2000	2208.41	3010.88	128.59
Household consumption	NT	%	3.88	7.71	9.48
		$m 2000	133.69	265.61	326.60
	Australia	%	0.07	0.15	0.19
		$m 2000	260.36	544.23	659.91
Exports interstate	NT	%	0.51	0.99	35.26
		$m 2000	5.16	10.05	356.79
Exports overseas	NT	%	-0.40	-0.70	111.32
		$m 2000	-12.58	-22.15	3524.94
	Australia	%	-0.27	-0.57	2.89
		$m 2000	-320.94	-678.84	3434.71
Imports interstate	NT	%	18.94	35.69	16.18
		$m 2000	689.53	1299.26	589.09
Imports overseas	NT	%	149.02	157.64	16.60
		$m 2000	1278.10	1352.01	142.37
	Australia	%	1.14	1.26	0.17
		$m 2000	1411.20	1549.05	212.03
Employment	NT	%	5.60	8.49	6.06
		Persons	4768.22	7228.02	5156.52
	Australia	%	0.14	0.21	0.13
		Persons	11608.52	16964.08	10607.12
Consumer price index	NT	%	2.12	4.11	0.45
	ROA	%	0.06	0.11	0.01
Government revenues	NT	%	1.37	0.99	1.51
		$m 2000	14.8	30.54	27.58
	Australia	%	0.10	0.18	0.12
		$m 2000	200.36	362.75	244.21

Source: CIE NT-Australia model and CIE calculations. (a) Three year annual average.

Attachment A1. Development options for Timor Sea Gas

A1.1 FLNG development option

Table 5 sets out the products and capital investment arising from a FLNG development of Sunrise gas. In the case of Bayu-Undan, this is identical to the option recommended by the Northern Territory Government. In the case of Sunrise, the FLNG development is being presented by Shell as the preferred option.

The following corresponds to Scenario A in the gas market and macroeconomic modelling.

Table 5: FLNG development option — Scenario A

Project Development	Gas PJ/annum	Total Liquids in Field mmbbls	Investment A$Million	Product
PRODUCTION				
Bayu-Undan - gas field	195	0	2,700	Natural gas to shore
Bayu-Undan - condensate	0	400		Condensate/LPG for export
Sunrise - gas field	275		1,500	Natural gas offshore
Sunrise - condensate		320		Condensate/LPG for export
Pipeline to shore (B-U only)			1,200	26"
CONSUMPTION				
Floating LNG (Sunrise gas)	-275		5,500	Export of gas (5mtpa)
Onshore LNG (Bayu-Undan gas)	-165		2,000	Export of gas (3mtpa)
NT grid (Bayu-Undan gas)	-30		0	Electricity (substitution)
Balance	*0*	*720*	*12,900*	

A1.2 Integrated development option

optimise the national interest.

Table 6 sets out the products and capital investment arising from the integrated development of Timor Sea gas. This is the development option that the Northern Territory Government recommends to the Commonwealth as most likely to deliver outcomes that will optimise the national interest.

Table 6: Integrated development option — Scenario B

Project Development	Gas PJ/annum	Total Liquids in Field mmbbls	Investment A$Million	Product
PRODUCTION (2006)				
Sunrise - gas field	365		2,000	Natural gas to shore
Sunrise - condensate		320		Condensate/LPG for export
Bayu-Undan - gas field	195		2,700	Natural gas to shore
Bayu-Undan - condensate	0	400		Condensate/LPG for export
Pipeline to shore (Networked)			2,000	B-U 26",Sunrise 36",Shared 36"
CONSUMPTION				
Onshore LNG - Plant 1	-165		2,000	Export of gas (3mtpa)
Onshore LNG - Plant 2	-165		1,000	Export of gas (3mtpa)
Aluminium smelter and power	-75		3,450	Aluminium (0.468mtpa)
NT grid	-30		0	Electricity (substitution)
Gas to Gove	-25		200	Electricity (substitution)
Interstate Pipeline			1,300	
Interstate gas sales	-100			Sales gas to Mt Isa and Moomba
Balance	*0*	*720*	*14,650*	
ADDITIONAL PRODUCTION (from 2012)[1]				
New gas field or Sunrise extension	136		800	Natural gas to shore

1 This additional production is included in the *GasMark* modelling, but not the CIE economic modelling.

Pipeline Link (if necessary)			300	26"
CONSUMPTION				
Petrochemical plant - Plant 1	-55		750	For export/domestic (1.5mtpa)
Petrochemical plant - Plant 2	-55		750	For export/domestic (1.5mtpa)
Ammonia/Urea Plant	-26		577	Exports/domestic (0.31mtpa)
Balance	*0*	*0*	*3,177*	