Public Version

Review of EAPL gas forecasts for the Moomba-Sydney pipeline

Prepared for Agility Management Pty Limited
on behalf of EAPL

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ACIL Tasman

Economics Policy Strategy

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Executive summary

The objective of this report is to determine whether, in ACIL Tasman's opinion, the EAPL methodology and the forecast volumes for the Moomba-Sydney Pipeline (MSP) are capable of meeting the regulatory criterion of the "best estimate arrived at on a reasonable basis".

Key considerations in ACIL Tasman's assessment of the possible gas flows in the Moomba-Sidney pipeline (MSP) are:

- forecasting of gas demand and supply over a 20 year period of time is a most imprecise task;
- the change in the historical pattern of gas deliveries into NSW (from Moomba) due to the existence of the EGP and contracts being entered into by AGL Wholesale Gas Limited (from Gippsland);
- the prospective future changes in the gas delivery patterns that are dependent on where and when new, competitive gas supplies will be sourced to meet demand;
- the possible responses to market developments by an increasing number of pipeline owners and gas producers;
- interpretation of public information about current and emerging contracts for the EGP and MSP;
- estimation of the impact of emerging technology such as CSM; and
- understanding the potential implications of more sophisticated market developments such a swaps.

A key outcome of ACIL Tasman's review of the EAPL forecasts is the potential impact of different scenarios about the timing and amounts of new gas discoveries that could influence flows on the MSP. Importantly, not only is the analysis of how NSW/ACT demand might be met significant for forecasting flows on the MSP, but also how Victoria demand is met, potentially by flows on the MSP via the interconnect.

As demonstrated in the report, the plausible outcomes may be significantly different — a single forecast of throughput on the MSP, such as that estimated by EAPL, needs to be developed with care bearing in mind the purpose of the forecast.

Taken as a whole, ACIL Tasman concludes that the EAPL forecast of gas flows through the MSP is based on sound methodology. Further, as the estimates fall within the bounds of the ACIL Tasman scenarios of future gas supply developed in this report, the EAPL forecast flows on the MSP are considered to be 'reasonable best estimates', reflecting a balanced outlook for supply of gas from northern and southern basins.

Nevertheless, ACIL Tasman has identified areas of the EAPL methodology and forecasts that should be given further consideration. These include:

- the methodology used by EAPL to apply ABARE forecast growth volumes for non-electricity gas demand to 2020 should be amended to apply ABARE's forecast growth rates to the EAPL 2003 base year demand, subject to ABARE growth rates post 2016 being reasonable;
- the methodology to extrapolate post 2020 (and post 2016 if ABARE growth rates are not reasonable) could take account of the experience in the Victoria gas market;
- some account may need to be made for new small co-generation being promoted by the NSW greenhouse benchmark scheme for electricity retailers, although the amounts are likely to be small; and
- some consideration may need to be given to the potential impact of Hunter Valley CSM on gas-fired electricity demand late in the period.

1 Introduction and methodology

ACIL Tasman has been engaged by Agility Management Pty Limited (acting as regulatory advisers on behalf of EAPL) to review the EAPL forecasts of gas transmission through the Moomba-Sydney Pipeline (MSP) for the period to 2023. The EAPL forecasts are being made in the context of the regulation of tariffs.

Consequently, in undertaking this task, ACIL Tasman's objective is to determine whether, in ACIL Tasman's opinion, the methodology and the forecast volumes are capable of meeting the regulatory criterion of the "best estimate arrived at on a reasonable basis".

There are four key areas of investigation that are required in order to make estimates of the gas volumes for the MSP through to 2023:

- forecasts of the non-electricity gas demand in NSW/ACT, including residential, commercial and industrial demand;
- forecasts of power generation gas demand in NSW/ACT;
- the allocation of NSW/ACT demand between MSP, the eastern gas pipeline (EGP) and local coal seam methane (CSM); and
- forecasts of gas flowing through the Victorian interconnect and, hence, some sections of the MSP.

ACIL Tasman observes that the forecasting of gas demand and supply over a 20 year period of time is a most imprecise task. Within this period of time several economic cycles may have taken place to influence demand, existing gas fields will have significantly lower remaining reserves, new gas fields will have been discovered, the configuration of the pipeline network will have changed and government policies will have changed. The set of 'best estimates arrived at on a reasonable basis' is large.

The following chapters of this report examine the 'appropriateness' of the EAPL methodology and the 'reasonableness' of the forecast volumes for each of the four key areas. In each chapter, ACIL Tasman's approach to the task has been to:

- familiarise itself with the EAPL forecasts;
- assess the methodology, assumptions and forecasts used by EAPL;
- seek clarification and further information from Agility on methodology, assumptions and forecasts; and
- apply a reality check to the EAPL forecasts using ACIL Tasman's methodologies and forecasts.

2 Non-electricity gas demand

Non-electricity gas demand is defined by EAPL to include consumption by the residential, commercial and industrial sectors of NSW and the ACT. EAPL (and ABARE) has excluded gas used in large-scale co-generation of electricity in industrial operations and conventional gas-fired electricity generation. However, EAPL's (and ABARE's) forecasting methodology (described below), which relies on historical ABARE data that includes existing small-scale gas co-generation, results in growth in small-scale co-generation in the industrial sector to be included in this non-electricity demand forecast.

2.1 Methodology for non-electricity demand

EAPL has used a two-stage methodology to estimate non-electricity gas demand:

- ABARE's forecasts of gas demand supplied to EAPL in March 2003 (unpublished) that is projected from 2000-01 historical data to 2019-20 (noting that, consistent with historical data, this ABARE forecast includes small-scale co-generation); and
- adjustment of the ABARE forecasts to take account of
  - the inclusion of ethane in the ABARE industrial forecasts, which is not relevant to natural gas demand that could be supplied via the MSP
  - the inclusion of gas demand for co-generation of electricity at Sithe Smithfield
  - the availability of historical gas demand data, which has been used by EAPL to adjust the ABARE forecasts downward in 2003 to match known pipeline deliveries into NSW for the years 2000 to 2002.

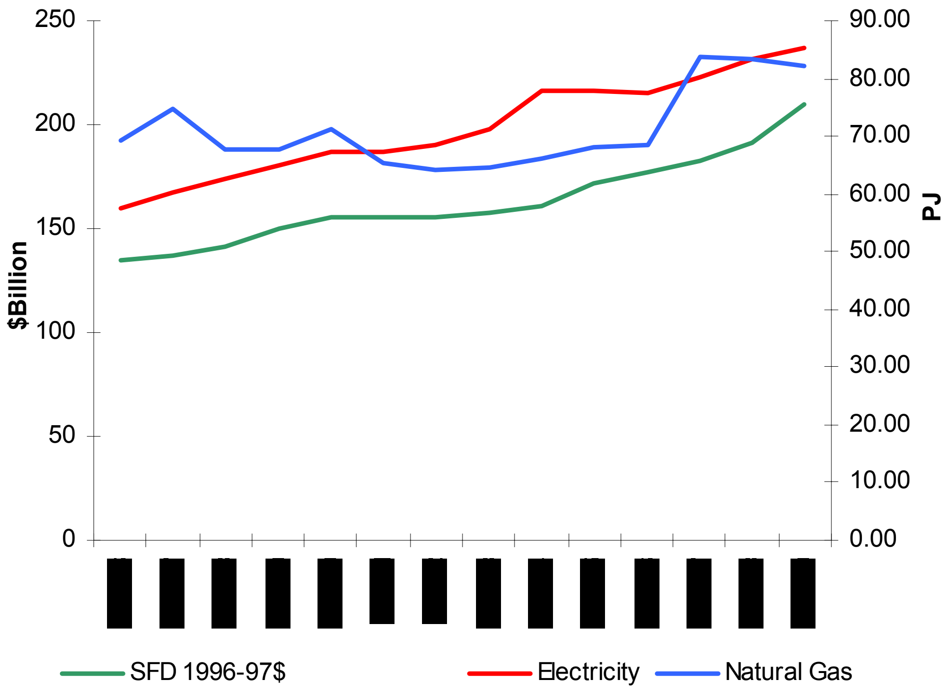
Using this methodology, EAPL have:

- subtracted the ethane and Sithe Smithfield demand from the ABARE forecast to 2020;
- used the ABARE volume growth in petajoules (PJ) over the period to 2020 (resulting in an average annual growth rate of about 2.2% over the 17 years compared with ABARE's 2% over 10 years);
- for the period to 2020, applied the volume growth to the base actual demand in 2003; and
- projected the post 2020 demand at 1% growth per annum on the assumption that, by this time, the gas market should be near saturation.

ACIL Tasman's view is that, in a long-term forecast of this type, the appropriate methodology is the use of macroeconomic forecasts of the type undertaken by ABARE. In making these macroeconomic forecasts, ABARE modelling is informed by historical trends and relationships between gas demand and drivers such as State Final Demand (SFD), population growth, relative energy prices and technological change. ABARE also uses information about major projects to inform the forecasts. For these reasons, ACIL Tasman also uses ABARE forecasts of these sectors of gas demand in its *GasMark* model of the eastern states gas market.

Nevertheless, it is worth reflecting on the aggregate nature of the forecast and the implications, particularly in the context of regulating tariffs. In broad terms, NSW gas demand is shared between residential, commercial and industrial consumption in the ratio 15:10:75 — that is, industrial demand is by far the largest gas use in the State. Figure 1 shows data comparing growth in NSW SFD with growth in the manufacturing sector's use of electricity and gas. While there is a clear positive correlation between SFD and electricity use, the relationship with gas use is less clear.

Figure 1: Trends in NSW gross final demand and energy use in manufacturing



Source: ABARE and ABS

This lack of relationship between gas use in NSW manufacturing and State economic growth helps explain the low overall rate of growth in gas demand forecast by ABARE (average 2%) compared with SFD of 3.2%.

In summary, ACIL Tasman agrees with the general approach that EAPL has adopted to forecast this segment of the gas market. However, there are two points of detail in the methodology used by EAPL that could be improved:

- EAPL have applied the ABARE forecast annual **volume** growth to the 2003 base volume out to 2020, whereas to be consistent with the macroeconomic modelling approach, it is the ABARE annual growth **rates** to 2020 that should be applied to the 2003 base volume
  - EAPL's methodology will marginally overestimate gas demand to 2020; and
- EAPL have applied a growth rate of [redacted] per annum post 2020 rather than extrapolate the ABARE growth rate. While it is expected that, as gas increases its penetration into all sectors, growth rates decline in comparison to general economic growth rates, nevertheless the average growth rate in gas demand would not abruptly fall from an average of 2% to [redacted] per annum
  - EAPL could examine a smoother transition to lower annual growth rates, and ACIL Tasman suggests a possible approach in section 2.2 below.

While the use of the ABARE forecast could be expected to deliver a reasonable best estimate of demand, it is worth commenting that demand may turn out to be higher or lower — the uncertainties about forecasting demand over 20 years should be recognised.

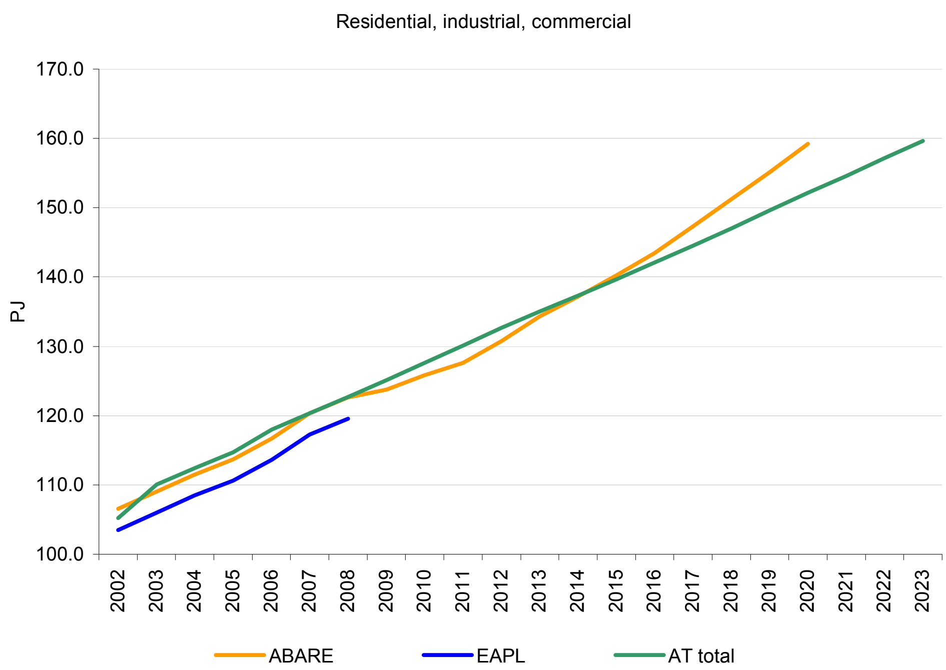
2.2 The forecasts of non-electricity demand

Figure 2 shows the comparable EAPL and ABARE forecasts, and an ACIL Tasman forecast that is based on a 2001 ABARE forecast. ACIL Tasman notes that:

- the EAPL and ABARE forecasts are compatible to 2020, taking account of the adjustment to reflect actual pipeline flows from 2000 to 2002;
- EAPL's use of [redacted] average growth post 2020 is apparent
  - after consultation with ACIL Tasman, Agility has identified that there is an error in the spreadsheet calculating the [redacted] growth which should be corrected by EAPL (the corrected data is shown in the figure); and

- the EAPL and ABARE forecasts show an upturn in demand from 2016 to 2020, which is not consistent with the known pattern of gas penetration in mature markets that sees slower rates of growth over time
  - the ACIL Tasman forecast (based on a 2001 ABARE forecast) shows the expected slow reduction in growth rate over time as the NSW market matures
  - suggesting the average growth rate now forecast by ABARE (and EAPL) may over-estimate demand in the last quarter of the period.

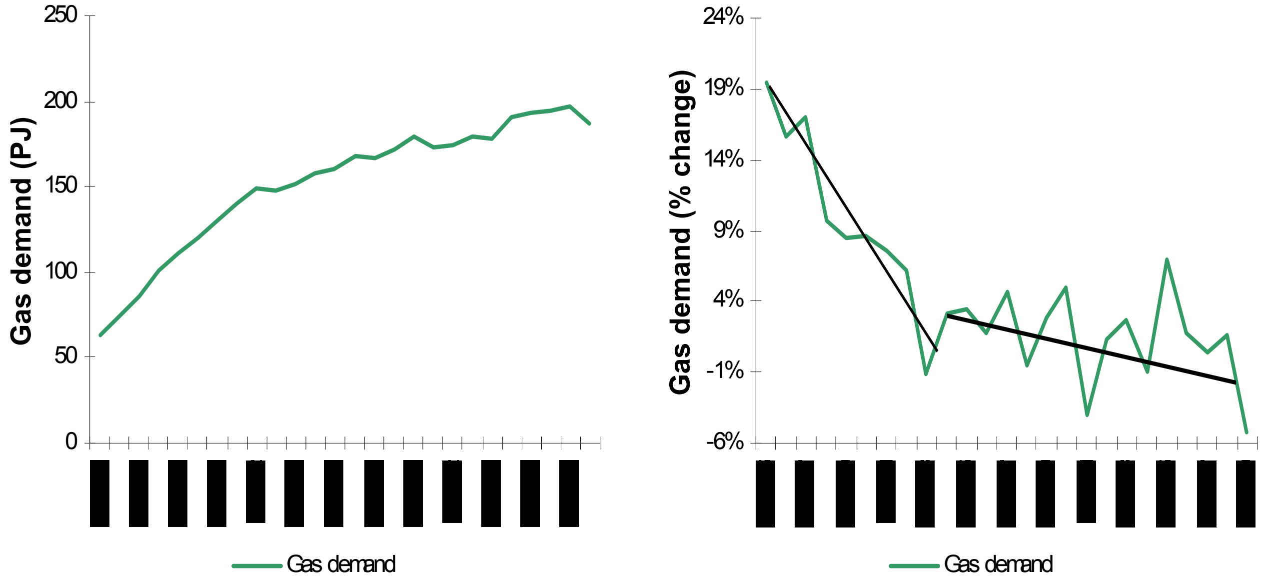
Figure 2: EAPL, ABARE and ACIL Tasman forecasts of non-electricity gas demand



Source: ACIL Tasman

ACIL Tasman suggests there are good indicators of trends in non-electricity gas demand growth rates in Victoria that should guide the trend in growth rates for NSW/ACT. Figure 3 shows the gas demand growth, and rates of growth, over the last 30 years in Victoria. It is apparent that the Victorian market has reached maturity by the early 1980's. Thereafter, the trend in gas demand growth rates is for a slow steady decline. ACIL Tasman would expect a similar trend in NSW/ACT gas demand growth rates over the next 20 years.

Figure 3: Victoria commercial, residential and manufacturing gas consumption



Source: ABARE, ACIL Tasman

ACIL Tasman concludes that the new ABARE forecast growth rates adopted by EAPL may overestimate non-electricity gas demand from around 2016 to 2020. EAPL should pursue this with ABARE. On the other hand, EAPL possibly underestimates demand from 2020-23 by using an average 1% growth rate from 2020, and this underestimate is compounded by the modelling error noted above.

A better approach might be, from 2016, to adopt the pattern of growth similar to that seen in the mature Victoria market. This pattern of growth suggests a growth rate of around 1.7% per annum from 2015-16, declining steadily to around 1% per annum from 2022-23.

3 Electricity gas demand

3.1 Methodology for electricity gas demand

3.1.1 EAPL

Following the deregulation of electricity markets and the creation of the National Electricity Market (NEM), macroeconomic modelling of potential fuel sources for electricity generation has not produced robust results. Rather, industry has relied on micro-economic models of generator bidding behaviour, such as ACIL Tasman's *PowerMark*, to understand the trends in the market.

In its forecast of gas demand for electricity generation in NSW and the ACT, EAPL has used an informal approach consisting of:

- use of the NSW Ministry of Energy and Utilities "Statement of System Opportunities" (SSO), published in June 2002, to determine the extra generation capacity required to meet the 'base probable' electricity demand to 2010/11;
- use of the greenhouse scenarios in the SSO that estimated gas-fired generation requirements for the whole NEM;
- conversion of the NEM gas-fired generation requirements to NSW requirements using NSW's share of total NEM electricity demand (being 37%);
- using market intelligence, construction of a schedule of 1125 MW of new gas-fired plant to be commissioned in NSW over the period to 2023 and estimation of the petajoules of gas demanded using appropriate operating assumptions; and
- making assumptions about the location of the new plant to determine whether the gas required for generation would be supplied via the MSP or the EGP.

While no formal model is used, EAPL's approach mirrors many of the steps incorporated in modelling of the NEM.

3.1.2 ACIL Tasman

ACIL Tasman uses its *PowerMark* model of the NEM to inform, among other things, decisions by clients about building new power stations and determining fuel sources for those new power stations. Attachment A provides a description of *PowerMark*.

ACIL Tasman uses the NEMMCO Statement of Opportunities (SOO) to develop electricity demand profiles for *PowerMark* (note: the NSW "Statement of System Opportunities" used by EAPL was derived by the NSW Ministry of Energy and Utilities from the 2001 SOO — a new MEU SSO is not yet available). The SOO for 2002 includes electricity demand scenarios that incorporate the effect of some government policies, and ACIL Tasman augments this where possible to reflect those government policies not accounted for in the SOO. For example, ACIL Tasman has taken account of the NSW greenhouse benchmark scheme (see section 3.1.3) and the Queensland 13% gas-fired generation scheme in its 'base case' modelling.

In essence, new electricity generating plant is determined in the modelling based on known plans to expand brownfield sites plus additions of new sites in each NEM region. ACIL Tasman's aim in modelling a 'base case' scenario is to schedule new capacity by NEM region in a manner that has the effect of keeping the load weighted wholesale NEM price across the regions at around $40/MWh, being the long-run new entrant price for gas-fired generation. This scheduling of new capacity is informed by the availability of fuel type and delivered price in each NEM region. The dispatch of each generator, and hence annual fuel use, is determined by the modelled bidding of that generator into the NEM pool.

ACIL Tasman's current 'base case' view about new capacity in NSW is shown in Table 1. That view is based on detailed annual modelling of the NEM to 2012 and 'spot' modelling of the year 2015. ACIL Tasman has not modelled later years in its current 'base case', but has extrapolated from 2015.

Table 1: Projected additions of new generating capacity in NSW

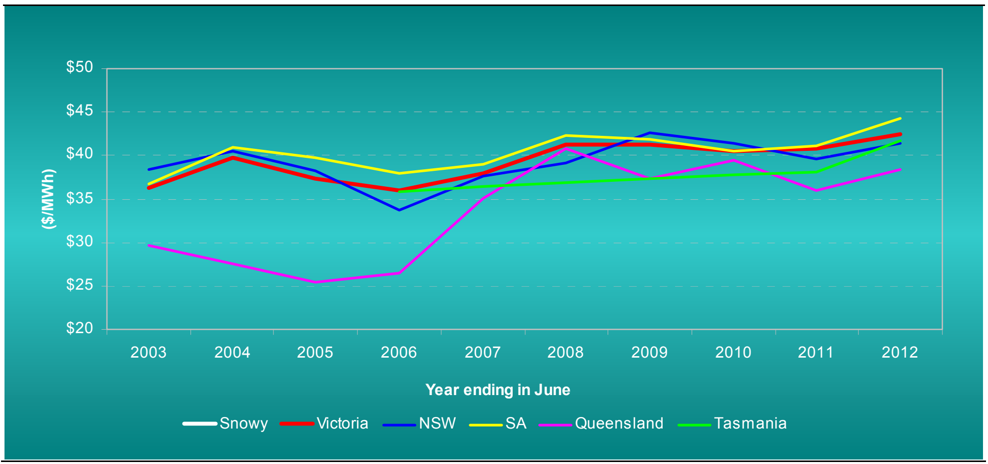
NSW 'base case' capacity schedule
Liddell U3 - return to full-time service in 2004
Liddell U4 - return to full-time service in 2005
Bayswater - +40MW per unit Nov 2005 – 2006
Munmorah U3 - return to full-time service in 2005
Wallerawang U7 - return from seasonal service in 2007
Munmorah U4 - return to full-time service in 2008
NE CCGT - 350MW in 2009
NE Peaker - 400MW in 2009
NE CCGT - 350MW in 2015
NE Coal – 600MW in 2016
NE CCGT - 400MW in 2018
NE Coal – 300MW 2018

Source: ACIL Tasman

Figure 4 is an example of a typical model output from our most recent *PowerMark*. The figure displays regional average electricity pool prices from 2003-2012. This represents our 'base case' view of the electricity market over the projection period.

The low prices in Queensland in the next few years are the outcome of recent new coal capacity and the government's 13% gas scheme, which will bring forward new gas-fired generation that would have otherwise occurred later in the decade. ACIL Tasman expects prices to converge to around $40/MWh.

Figure 4: Regional average wholesale electricity prices 2003-2012



Source: ACIL Tasman

3.1.3 Implications of the NSW greenhouse benchmark scheme

In terms of gas use, ACIL Tasman's view is that the impact of the NSW greenhouse benchmark scheme for electricity retailers will be three-fold:

- 'above baseline' use of gas in existing gas-fired generators connected to the NEM grid will be encouraged by the ability to create and sell NSW Greenhouse Abatement Certificates (NGACs) at a premium above the market wholesale electricity price
  - the impact on gas use in NSW, however, will be negligible as the only existing gas-fired generator of note, Sithe Smithfield, is already operating at full capacity;
- investment in conventional gas-fired electricity generation or large-scale co-generation, whether in NSW or in other States connected to the NEM grid, will be made more profitable as NGACs are able to be sold for a premium above the market wholesale electricity price
  - ACIL Tasman's view is that the impact does not necessarily have the effect of bringing forward gas-fired generation in NSW

  - because new gas-fired generation is expected at an earlier date in both Queensland and South Australia (and possibly Victoria), sufficient NGACs are likely to be created by these plant (and investment in other eligible activities in NSW and elsewhere) before new generation is induced by the scheme in NSW
  - the proposals for large-scale co-generation at Botany Bay, Kurnell, Lake Illawarra and Port Kembla of the late 1990s remain dormant; and
- enterprises located in NSW will also be able to sell NGACs where they install co-generation plant to replace electricity purchased from the grid
  - ACIL Tasman is not aware of any specific modelling undertaken to estimate the impact of the NSW benchmark scheme on increased small-scale co-generation in NSW
  - however, in its work for the NSW Ministry of Energy and Utilities[1], Frontier Economics forecast that demand-side management, which is defined to include small-scale co-generation, might replace around 2,500 GWh of electricity generation in 2003 declining to around 500GWh by 2012
  - according to the listing of demand-side management opportunities identified by Frontier[2], the least-cost, and hence most likely to be first adopted, opportunities are in a variety of energy efficiency applications
  - small-scale co-generation is relatively expensive, and if it were to contribute 100GWh by 2012, would increase gas demand by about 1PJ per annum.

ACIL Tasman's conclusion is, on the modelling available, that the NSW benchmark scheme is unlikely to significantly increase demand for gas for electricity generation within NSW.

In terms of the EAPL methodology, it is recalled from Chapter 2 that the ABARE (and EAPL) forecasts on non-electricity gas demand include the forecast for increases in **existing** small-scale co-generation. In the absence of better information, it may be appropriate for EAPL to make some allowance (perhaps up to 1PJ per annum by 2012) for the potential increase in gas use by **new** small-scale co-generation induced by the NSW benchmarks scheme.

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1 *Benchmarks Position Paper: Greenhouse-related licence conditions for electricity retailers Appendix A*, MEU, December 2001.

2 ibid, Appendix B.

3.2 Forecasts of gas demand for electricity

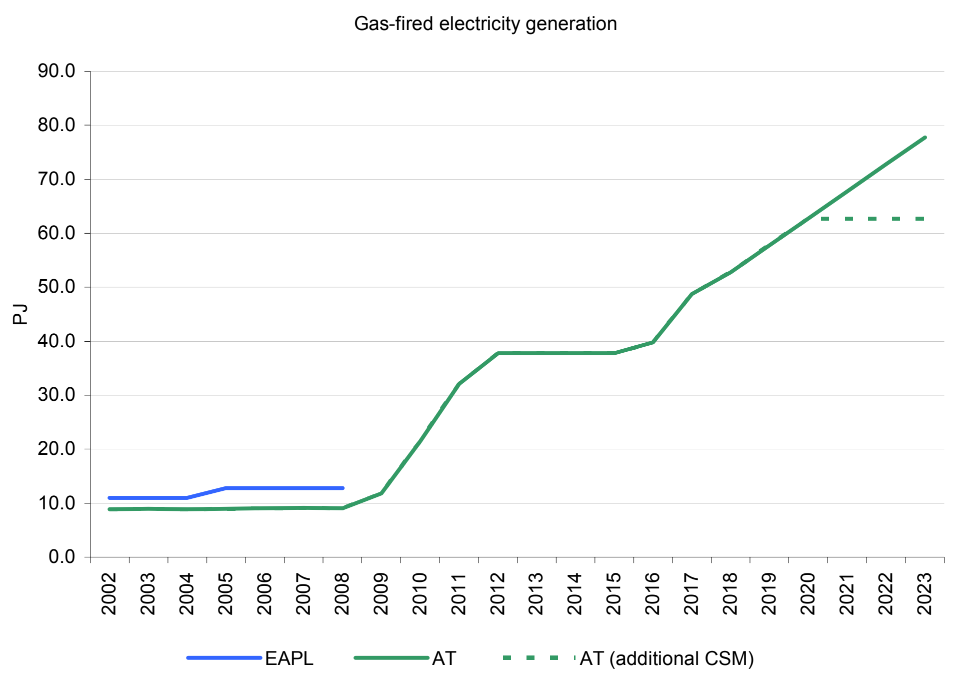
Figure 5 compares the EAPL and ACIL Tasman forecasts for gas for electricity generation in NSW/ACT. The following are noted:

- EAPL's informal methodology produces a forecast very similar to ACIL's formal model-based approach, demonstrating that the electricity market intelligence that underlies both approaches is similar;
- EAPL carries a gas demand for the Sithe Smithfield plant at 12.8PJ per annum, whereas ACIL Tasman has an estimate of 8.9PJ per annum that is outdated; and
- both forecasts are based on simple extrapolations beyond 2012.

On this analysis, the EAPL forecast is reasonable.

Neither the EAPL nor the ACIL Tasman forecasts recognise the potential for one of the new gas-fired generation plants projected for NSW to be fuelled by CSM, thereby by-passing both the EGP and the MSP. This possibility is represented on the ACIL Tasman forecast by the flat dashed line from 2019 onwards in Figure 5. The assumption is that the third CCGT scheduled could be sited in the Hunter Valley and fuelled by CSM. This possible outcome is discussed further in Section 4.2.1 below.

Figure 5: Gas demand for electricity generation in NSW/ACT



Data source: ACIL Tasman

4 Determining the share of NSW/ACT gas demand among MSP, EGP and CSM

4.1 Sharing methodology

This section contains a summary of the methodologies applied by EAPL and ACIL Tasman to estimate the shares of NSW/ACT gas demand accounted for by coal seam methane (CSM), EGP and MSP. Gas demand comprises non-electricity (residential, industrial, commercial) and electricity demand. The methodologies utilised by EAPL and ACIL Tasman to project gas demand for these categories have been described in Chapters 2 and 3, respectively.

The implications of transporting gas through the upstream section of the MSP (and the Victoria/NSW interconnect) to supply gas to meet Victoria demand are discussed in Chapter 5.

4.1.1 EAPL methodology for assigning demand to pipelines

EAPL has sequentially allocated gas demand to CSM and EGP, with the remainder of total NSW/ACT gas demand being allocated to the MSP.

The Sydney Gas CSM share of demand was assigned by forecasting two production stages. Stage 1 (2003 onwards) assumes increasing gas production rising to a peak delivery of 4.5 PJ per annum in 2008 [redacted].

Gas for electricity supplied through the EGP was allocated as follows:

- Tallawarra, a licenced power station site near Lake Illawarra, to be supplied from the EGP, since it is adjacent to that pipeline and it minimises electricity distribution charges; and
- additional increments of capacity (excluding Tallawarra) would be supplied [redacted] by the MSP and [redacted] by the EGP.

For non-electricity, the estimates of individual sources of gas throughput on the EGP were derived as follows:

- in NSW, historical gas loads taken over by the EGP (BHP Newcastle and Pt Kembla, Sithe, estimates for other foundation customers/retailers such as Energy Australia and Country Energy);
- plus estimates of EGP deliveries to regional NSW (Cooma, Bombala, Nowra) and to the ACT; and

- plus estimates of more recent load 'switching' – that is, new NSW retailers using the EGP and AGL Wholesale Gas supplementing its Moomba supplies with further gas from the EGP, as recently announced by AGL.

These individual sources were assumed to be held constant at a "base" level after 2003 (except for AGL Wholesale Gas, as set out below).

Growth in the EGP deliveries is then accounted for by:

- assuming that AGL Wholesale Gas has bought additional supplies from the Bass Strait producers via the EGP
  - these peak at [redacted] pa by 2009 and are held constant thereafter; and
- assuming the EGP captures [redacted] of non-electricity market growth in NSW and adding the EGP's estimated share of new gas for generation.

The total of the base EGP throughput plus growth from 2004 gives the total NSW/ACT demand supplied by EGP to 2023. MSP supply was then derived by subtracting gas supplied on the EGP and CSM from NSW/ACT demand.

4.1.2 ACIL Tasman methodology

ACIL Tasman has projected gas supply by pipeline through its *GasMark* model (see Attachment B for a description of the model). Potential demand has been assumed to remain constant, although actual demand met will depend on the delivered price of gas.

The timeframe being considered here (2002-2023) is a lengthy one in modelling terms. There is considerable uncertainty in dealing with such a timeframe. ACIL Tasman has dealt with the uncertainty by developing two potential scenarios of how the future gas market may unfold rather than relying on one projection. The scenarios are the northern gas supply scenario (Scenario 1) and the southern gas supply scenario (Scenario 2).

The main supply assumptions for Scenario 1 are set out in Table 2. In Scenario 1, northern gas fields are dominant due to relatively large discoveries of gas assumed in the Timor Sea and PNG, and pipeline delivery to Moomba. New discoveries and reserve additions in the Gippsland and Otway Basins are assumed to be limited by comparison.

The new discoveries for Gippsland total 1,015 PJ and for Otway offshore 200PJ to 2023. The assumed discoveries for Gippsland are consistent with the amount estimated in recent work by the US Geological Survey at the 95% confidence level[3]. This then is a conservative estimate for southern gas supply.

3 *Oil and Gas Resources of Australia 2000*, Geoscience Australia, 2001.

Table 2: Gas resource assumptions for the northern gas supply scenario (Scenario 1)

Field name	Field #	Portfolio	Start year	Peak production (PJ/Year)	Peak year	Remaining reserves (PJ)	Total new discoveries, additions to reserves, 2002-2023 (PJ)
Gippsland	1	ESSO / BHPBilliton	1970	325	2010	7690	1015
SWQ	2	Santos	1994	120	2001	2255	690
CBSA	3	Santos	1969	160	2001	2516	460
Otw ay Onshore	4	Misc	1979	25	2004	155	140
Bow en/Surat	5	OCA/Santos	1970	20	1999	218	100
Amadeus	6	Magellan	1985	35	1999	488	0
Bayu Undan	7	Phillips/Woodside	2006	195	2007	4900	1550
PNG	8	PNG JV	2007	350	2010	6600	2375
CSM Bow en	9	Bow en	2000	40	2010	800	1160
CSM Surat	10	Surat	2001	30	2010	500	1650
CSM Sydney	11	Sydney	2001	12	2005	200	1100
Katnook	12	AWE	1997	20	2003	84	77
Otw ay Offshore	13	Woodside/Origin	2006	75	2006	1100	200
Bass	14	AWE/Cal Energy/Origin	2003	23	2004	378	110
Gilmore	15	Energy Equity	1998	1.0	2001	40	10
CSM Moranbah	16	CH4	2005	20	2006	500	450
Minerva	17	BHP Billiton	2004	55	2005	317	0
Timor Sea	18	Other	2007	300	2007	3400	900

Source: ACIL Tasman

The key supply assumptions behind Scenario 2 are set out in Table 3. Scenario 2 assumes much larger discoveries of gas in the Gippsland and Otway Basins compared with Scenario 1 (consistent with the US Geological Survey mean estimates for new discoveries of gas). The assumed discoveries and additions to reserves allow greater peak production in Scenario 2 for Gippsland (450 PJ per annum) and Otway Offshore (125 PJ per annum) relative to Scenario 1 (350PJ per annum and 75 PJ per annum respectively).

These new discoveries would have the effect of increasing the commercial risks of attempting to deliver Timor Sea gas to Moomba. The assumption is that, in the face of these risks, such a pipeline would not be built.

The prospects for PNG gas are, however, a different matter. Although there remains considerable uncertainty about the actual start-up date, ACIL Tasman's view is that PNG gas will be delivered to Queensland in the forecast period. Consequently, in both scenario 1 and 2 the option of PNG gas, or Queensland gas displaced by PNG gas, being sold into southern markets is available in the modelling.

ACIL Tasman has conducted *GasMark* model runs for each of the scenarios.

Table 3: Gas resource assumptions for the southern gas supply scenario (Scenario 2)

Field name	Field #	Portfolio	Start year	Peak production (PJ/Year)	Peak year	Remaining reserves (PJ)	Total new discoveries, additions to reserves, 2002-2023 (PJ)
Gippsland	1	ESSO / BHPBilliton	1970	450	2010	7690	4100
SWQ	2	Santos	1994	120	2001	2255	690
CBSA	3	Santos	1969	160	2001	2516	460
Otway Onshore	4	Misc	1979	25	2004	155	140
Bowen/Surat	5	OCA/Santos	1970	20	1999	218	100
Amadeus	6	Magellan	1985	35	1999	488	0
Bayu Undan	7	Phillips/Woodside	2006	195	2007	4900	0
PNG	8	PNG JV	2007	300	2010	6600	0
CSM Bowen	9	Bowen	2000	40	2010	800	1160
CSM Surat	10	Surat	2001	30	2010	500	1650
CSM Sydney	11	Sydney	2001	12	2005	200	1100
Katnook	12	AWE	1997	20	2003	84	77
Otway Offshore	13	Woodside/Origin	2006	125	2006	1100	1200
Bass	14	AWE/Cal Energy/Origin	2003	23	2004	378	110
Gilmore	15	Energy Equity	1998	1.0	2001	40	10
CSM Moranbah	16	CH4	2005	20	2006	500	450
Minerva	17	BHP Billiton	2004	55	2005	317	0
Timor Sea	18	Other	2007	200	2007	3400	0

Source: ACIL Tasman

Are the northern and southern gas scenarios plausible?

ACIL Tasman takes the view that there are many plausible scenarios that could be constructed for gas supply to NSW/ACT (and other markets) in the period to 2023. While there are very many variables to deal with, it is the case that the remaining reserves from existing discoveries of gas in the main basins — the Cooper/Eromanga, Gippsland, and Otway — are not sufficient to meet potential demand at current real prices beyond about 2010. Consequently, the size and timing of new discoveries of gas will have a significant bearing on how demand is met.

ACIL Tasman has constructed two plausible, regionally dominant scenarios of the potential sources of supply for NSW/ACT and Victoria gas markets. The northern supply scenario is triggered by low discoveries of gas in the Gippsland and Otway basins. The southern supply scenario demonstrates how large discoveries in these basins could delay new supply from the Timor Sea, but not from PNG, until after the forecast period.

Experience would suggest, however, that some middle course would probably eventuate through incremental change in gas reserves. For example, it may be that a combination new gas discoveries made in the Cooper/Eromanga, Gippsland and Otway Basins in a similar time period to continue a gradual shift from historical supply from the north (Moomba) toward a 'balance' between supply sources. Hence, the amounts of gas transported on the MSP versus the EGP are similarly influenced.

Consequently, ACIL Tasman's methodology may be seen as a means of estimating the bounds of reasonable forecast flows on the MSP.

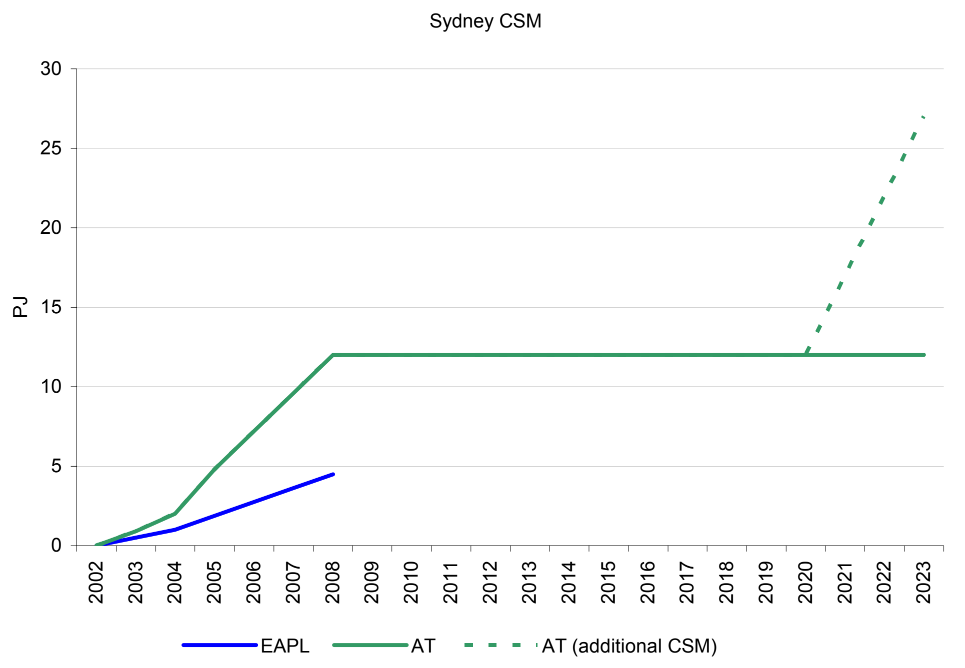
4.2 Forecast shares of NSW/ACT gas demand

4.2.1 CSM

Figure 6 shows the projected CSM supply by ACIL Tasman and EAPL, both of which are based on Sydney Gas Company information. Further, as discussed in section 3.2, ACIL Tasman has also raised the possibility of Hunter Valley CSM supplying a CCGT late in the period. CSM supply has been held constant across the two ACIL Tasman gas supply scenarios.

ACIL Tasman forecasts higher supply by CSM over the projection period compared with the EAPL forecast. ACIL Tasman's view is that, if the initial stages of production by the Sydney Gas Company proceed, then production would expand very quickly. In addition, based on the technological developments taking place in Queensland, there must be some possibility that a third CCGT scheduled for 2018 might be best sited in the Hunter Valley. If this were the case, then this would raise the opportunity for around 15PJ per annum of CSM to be utilised instead of natural gas by 2023, with implications for the MSP and/or the EGP.

Figure 6: Potential CSM supply



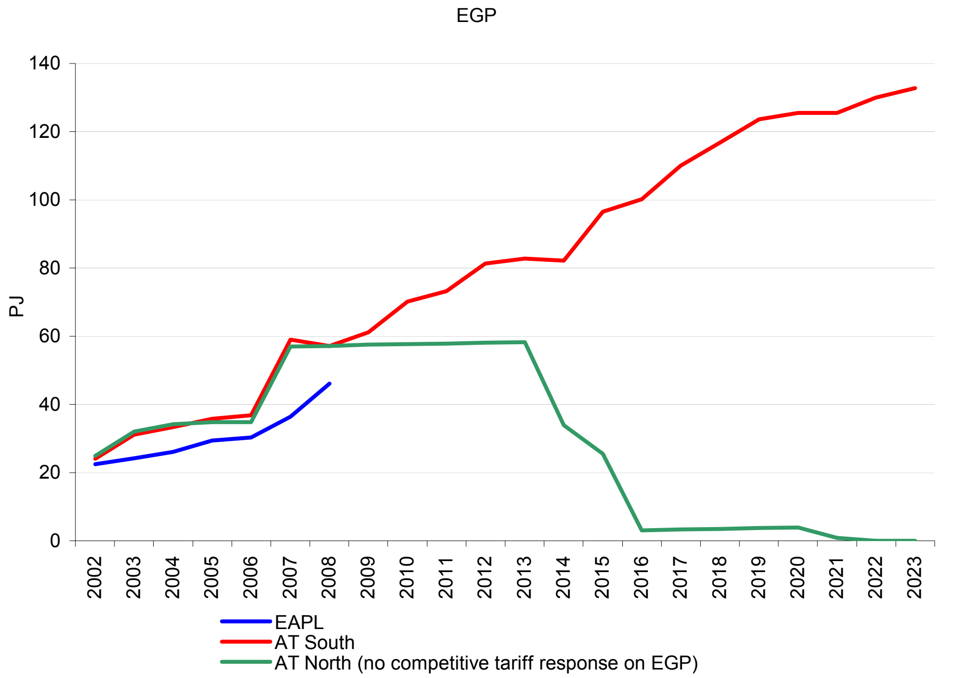
Data source: ACIL Tasman

4.2.2 EGP

Impact of gas supply scenarios

Figure 7 shows a comparison between the ACIL Tasman modelled scenarios and the EAPL forecasts for gas flows on the EGP. EAPL's methodology for forecasting market share results in a reasonably steady growth for EGP.

Figure 7: Forecast gas flow on the EGP



Source: ACIL Tasman

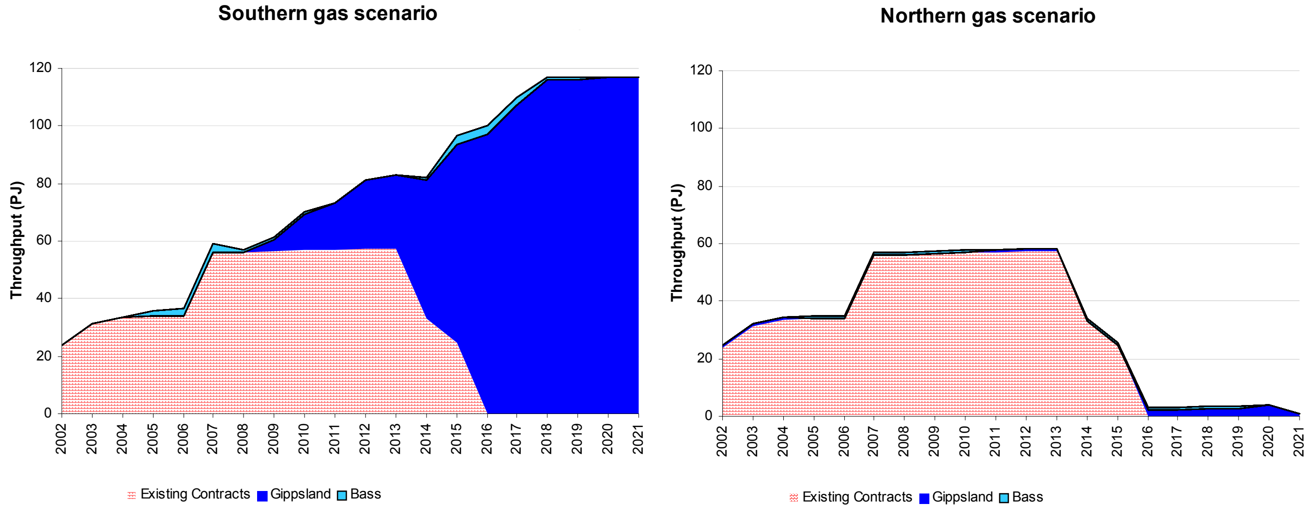
ACIL Tasman's methodology results in quite different outcomes that encompass the EAPL forecast. The *GasMark* results are best explained by examining the profile of contracts understood to be held by the EGP and by the two gas supply scenarios assumed by ACIL Tasman.

Figure 8 is the output from *GasMark* for the EGP under Scenarios 1 (right-hand chart) and 2 (left-hand chart). The charts show:

- the impact of the existing contracts estimated by ACIL Tasman, which make up the bulk of EGP supply in the first half of the period; and
- the impact in the later half of the projection period of the assumptions about northern and southern gas supply.

In ACIL Tasman's Scenario 1, significant new discoveries and reserve additions in the northern gas fields encourages the construction of a pipeline to supply Moomba with Timor Sea gas. The limited gas reserves in southern gas basins means that these producers prefer the higher margins of supplying gas to the Victoria market rather than competing with the new supplies, even though the latter are likely to be delivered at a higher price than current supplies. The outcome is to place significant downward pressure on EGP tariffs if the existing supply contracts are to be renewed (although no tariff response is included in these charts). In this case, the modelled flows on the EGP could be as low as a few petajoules by 2016.

Figure 8: EGP gas flows as estimated by GasMark – southern gas scenario left-hand chart and northern gas scenario right-hand



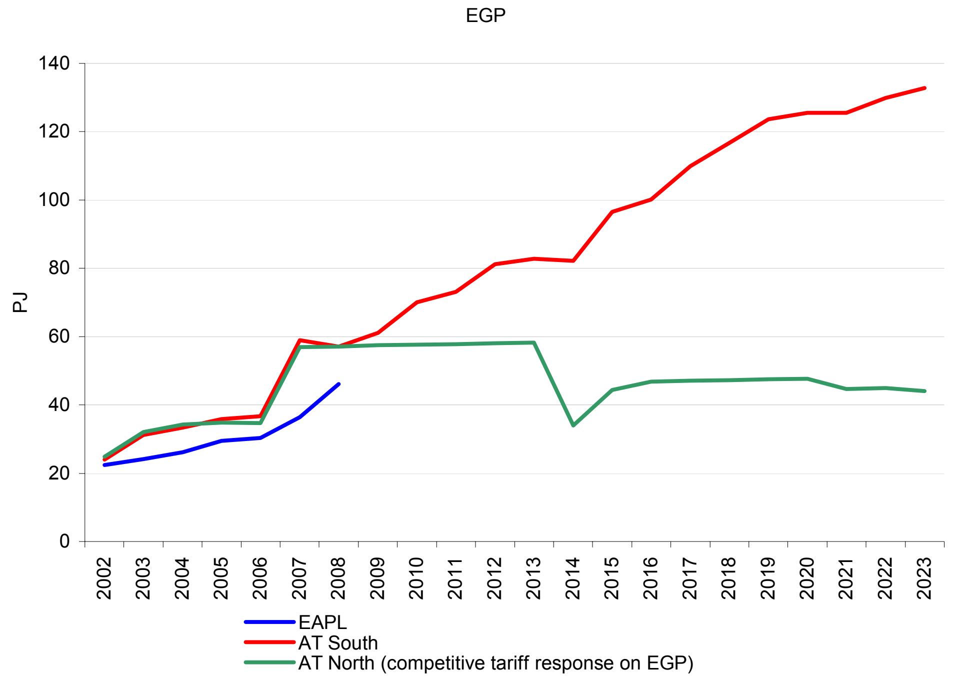
Data source: ACIL Tasman

Clearly, in the circumstances of the northern gas supply scenario, the EGP is not viable beyond about 2013. The more likely outcome would be for the EGP to respond with tariff concessions.

Figure 9 shows the effect of a competitive lowering of tariffs on the EGP in the northern gas scenario. Despite a competitive lowering of tariffs, supply on the EGP does not grow in the second half of the projection period. The key reason is again that the modest additions to reserves in the Gippsland and Otway Basins are directed by those producers to the higher returns to be had from the Victoria gas market.

In summary, the EGP is vulnerable in a scenario where there are limited new discoveries of gas in southern basins.

Figure 9: EGP gas flows – with tariff response in the northern gas scenario



Source: ACIL Tasman

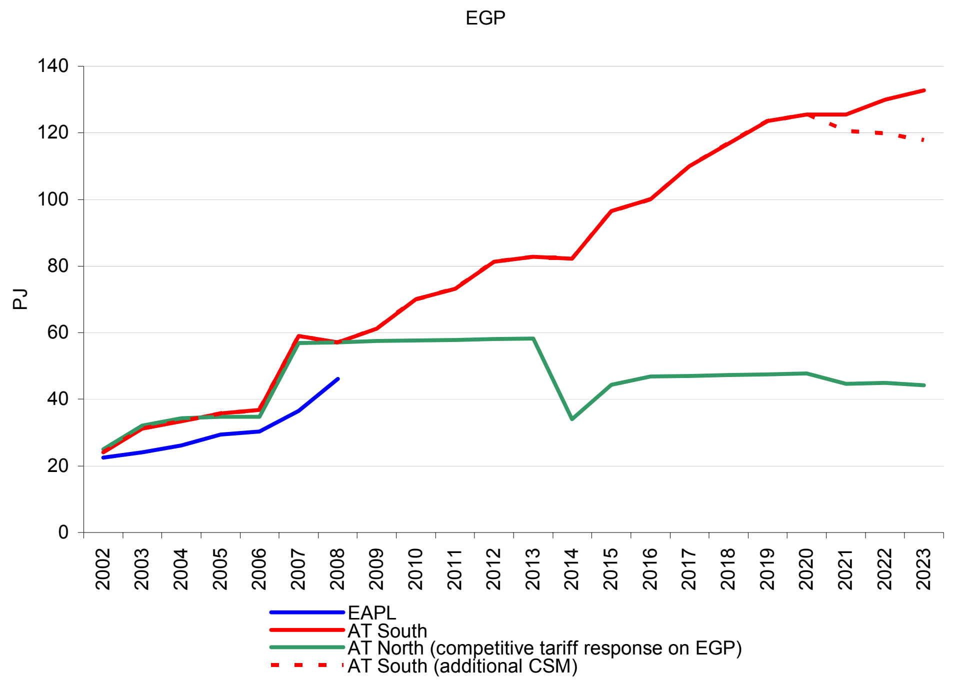
The point is clearly demonstrated in ACIL Tasman's Scenario 2, and shown in the left-hand chart of Figure 8. In this scenario, significant discoveries and additions to reserves in the Gippsland and Otway Basins discourage the construction of a pipeline to supply gas from the Timor Sea to Moomba. The competitively priced gas available from Gippsland, which is now excess to Victorian demand, would encourage producers to continue to capture NSW markets supplying gas on the EGP. Substantial penetration into southern markets by gas from the north would be delayed beyond the forecast period.

Impact of CSM

Figure 10 shows the potential displacement of supply on the EGP, in the southern gas scenario, from additional CSM being used for electricity generation late in the projection period.

This has not been modelled by *GasMark,* and the outcome shown would be subject to debate about whether the gas supply displaced would have been delivered by the EGP or by the MSP. ACIL Tasman's judgement is that, if it is gas displaced from the EGP, then this is most likely the case in the southern gas scenario. As already discussed, in the northern gas scenario, the EGP struggles to be competitive, and it is more likely that CSM replaces flows in the MSP in this scenario.

Figure 10: EGP gas flow – with EGP tariff response in the northern gas scenario and additional CSM supply in the southern gas scenario



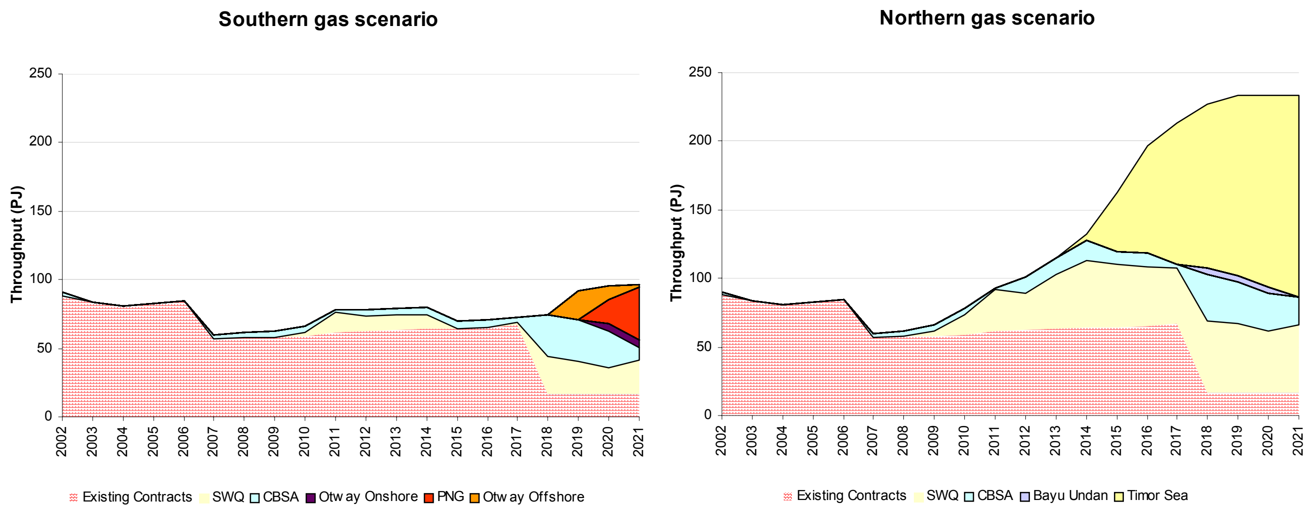
Source: ACIL Tasman

4.2.3 MSP

Impact of the gas supply scenarios

Figure 11 shows the *GasMark* modelled total flows (to meet NSW/ACT demand and to augment supplies to Victoria) on the MSP by source for each of the ACIL Tasman scenarios.

Figure 11: MSP total gas flows – southern gas scenario left-hand chart and northern gas scenario right-hand chart

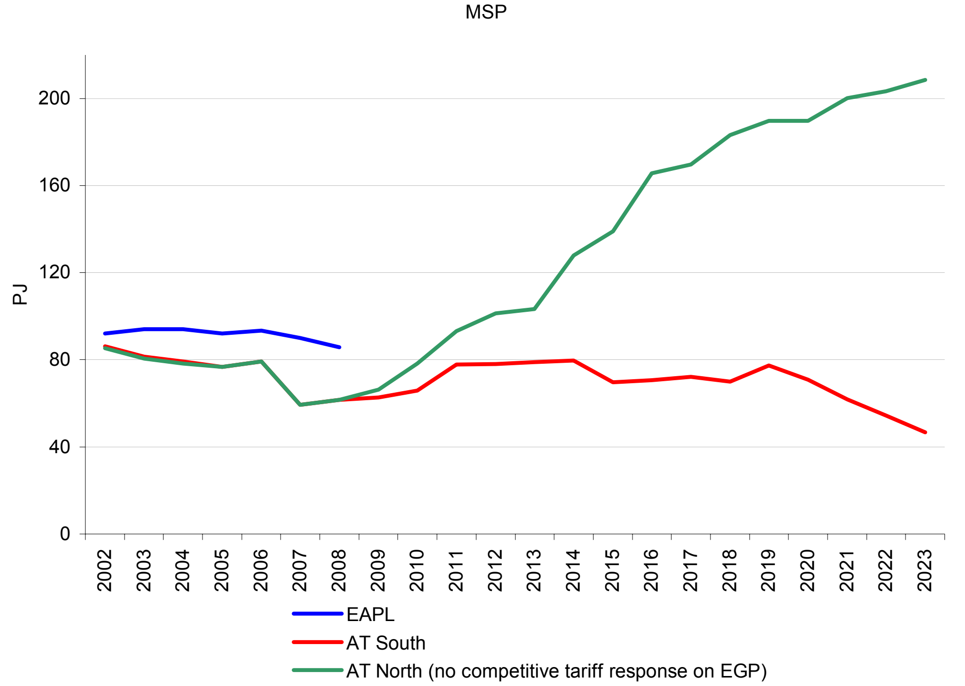


Data source: ACIL Tasman

For *GasMark,* the NSW/ACT demand for gas supplied through the MSP is represented by the Dalton – Wilton portion of the pipeline plus deliveries to central NSW and the ACT, net of deliveries to Victoria on the interconnector.

Taking these modelled gas flows, and removing the flows to Victoria, Figure 12 compares projected supply on the MSP by ACIL Tasman and EAPL to meet NSW/ACT demand. Consistent with the equivalent scenarios for the EGP, the ACIL Tasman forecasts show lower flows on the MSP in the first half of the period, and the two gas supply scenarios bound the EAPL forecast in the later part of the period.

Figure 12**:** Gas flows on the MSP to meet NSW/ACT demand

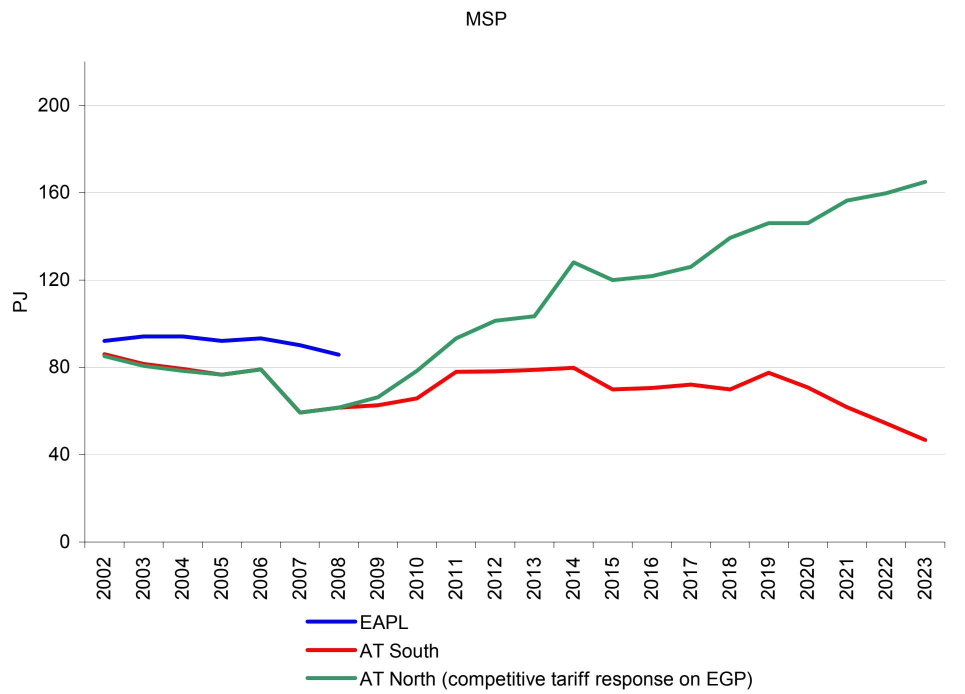


Source: ACIL Tasman

Figure 13 displays the effect of the competitive tariff response by the EGP to increase flows in the northern gas scenario. In this case, the ACIL Tasman scenarios more closely bound the EAPL forecast. Again, in the first half of the period, ACIL Tasman shows lower flows on the MSP (corresponding to ACIL Tasman's estimates of higher contracts on the EGP).

Equally, although not modelled by ACIL Tasman, in the southern gas scenario it might be expected that the MSP would respond to lower gas flows with a competitive tariff response.

Figure 13: Gas flows on the MSP to meet NSW/ACT demand – with a competitive tariff response on the EGP



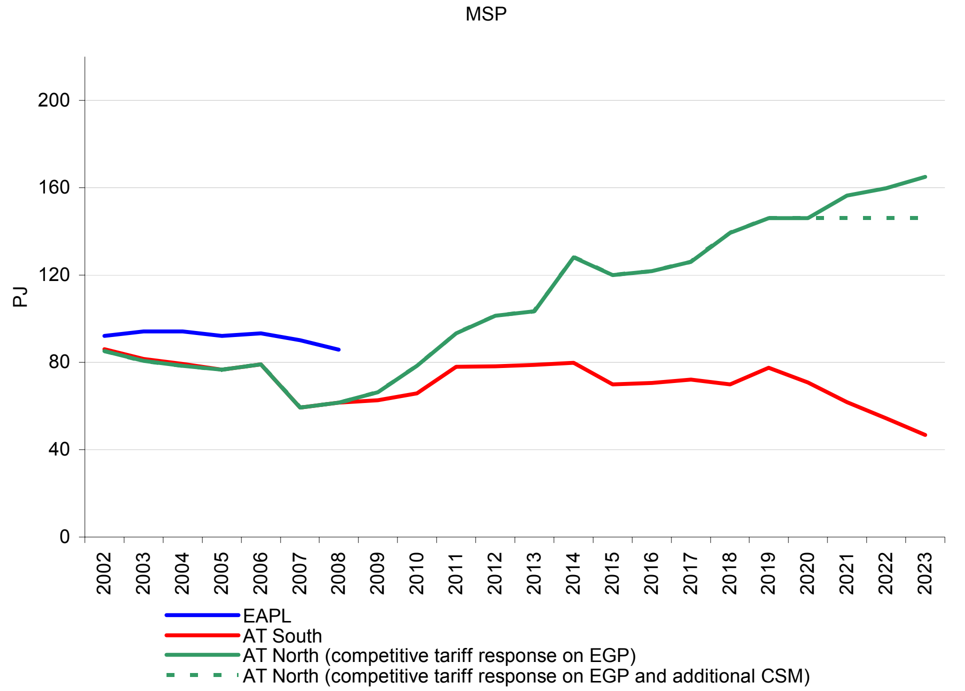
Source: ACIL Tasman

ACIL Tasman has commented on the risks to the EGP associated with limited new gas discoveries in southern basins. Figure 12 and Figure 13 show the risks to the MSP of significant new gas discoveries in these basins.

CSM impact

Figure 14 displays the impact of increased CSM supply in the northern scenario where there has already been a competitive tariff response on the EGP to the high northern gas supply. As discussed earlier, it is in these circumstances that the use of CSM to supply electricity generation is more likely to impact on the MSP (as opposed to the EGP).

Figure 14: Gas flows on the MSP to meet NSW/Act demand – with a competitive tariff response on the EGP and additional CSM supply



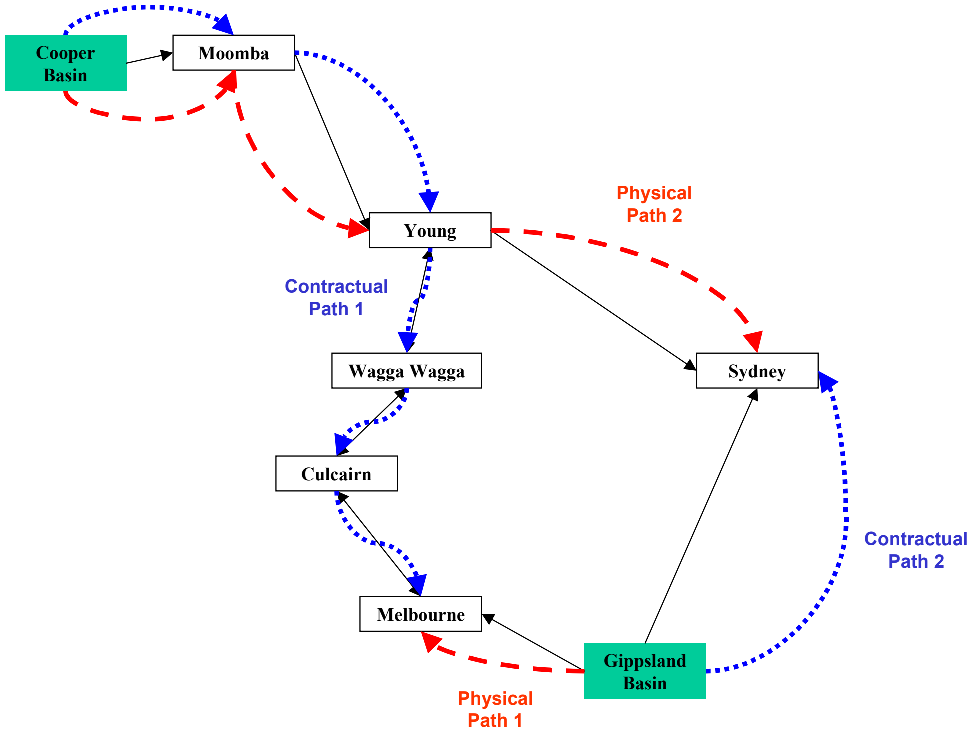
Data source: ACIL Tasman

Implications of swaps

Gas "swaps" have the potential to further complicate the picture with regard to pipeline flows, and hence revenues. A gas swap occurs when two suppliers enter into an agreement whereby each makes physical delivery to the other's customer such that both contractual supply commitments are fulfilled without the necessity of physical transport between the original supplier–customer pairs.

This can be illustrated with a hypothetical example (see Figure 15). In this example, two gas supply contracts are assumed to exist. The first relates to supply of gas from the Cooper Basin in South Australia to a customer in Melbourne, via the MSP mainline, the New South Wales–Victoria interconnector and the northern Victorian transmission system (the "contractual path" for Contract 1). The second is for supply of gas from the Gippsland Basin to a customer in Sydney via the EGP (the "contractual path" for Contract 2).

Figure 15: Hypothetical gas swap scenario



Data source: ACIL Tasman

Depending on the nature of the transportation arrangements relating to the two gas supply contracts, it may be commercially attractive for the producers to enter into a swap arrangement that would result in:

- some or all of the Sydney customer's contractual entitlements being supplied by gas from the Cooper Basin producer, delivered via the MSP mainline (the "physical delivery path" for Contract 2); and
- some or all of the Melbourne customer's contractual entitlements being supplied by gas from the Gippsland Basin producer, delivered via the southern Victorian transmission system (the "physical delivery path" for Contract 1).

Under this swap arrangement, gas notionally delivered from the Cooper Basin into Melbourne would not travel across the interconnector or the northern Victorian transmission system into Melbourne, and could therefore potentially avoid transmission charges for those systems. Similarly, the gas notionally delivered from the Gippsland Basin into Sydney would not travel across the EGP, and would avoid charges for use of that system.

Whether or not there is a commercial incentive to enter into a swap arrangement will depend among other things upon the nature of the transportation contracts associated with the counter-party gas sales agreements. In the example set out above, there may be no advantage to be gained from the swap if both contracts have associated ship-or-pay commitments to the operators of the pipeline on the contractual pathways. In such circumstances, the swap will only occur if the price differential available is sufficient to meet any ship-or-pay costs and still yield a margin to the parties entering into the swap arrangement. However, to the extent that the transportation agreements contain flexibility provisions that allow the producers, without incurring any penalty, to vary the quantities of gas submitted for transportation, a swap arrangement could allow transportation costs to be avoided.

In the extreme, the gas sales contracts could be settled without making any corresponding agreements for transport on the contractual pathways, in anticipation of a swap arrangement being negotiated. For example, in the hypothetical situation described above, the Cooper Basin producer could enter into Contract 1 for sale of gas into Melbourne without making any transportation arrangements involving use of the interconnector or the northern Victorian transmission system if, at the time of entering into the contract, the swap arrangement was anticipated.

Some of the same principles apply to backhaul transportation: gas supply contracts involving backhaul transportation may simply act to reduce the physical forward haul flow through the relevant pipeline (and therefore, potentially, the revenues attributable to that pipeline).

ACIL Tasman's modelling using *GasMark* does not routinely take into account gas swaps. For modelling purposes, it is assumed that allocations of gas from a producer to a customer occurs via the least cost available pipeline path or, in the case of existing contracts, via the specified pipeline path. Calculated pipeline flows and revenues therefore reflect an assumption that physical delivery of all gas allocations occurs via the least-cost path (effectively the "contractual path"). Swap arrangements have the potential to modify the modelled pipeline flows, and therefore the implied revenue outcomes for particular pipeline segments. Each swap arrangement is likely to result in increased flows in one or more pipelines, at the expense of flows in another pipeline or pipelines. However, the net result of increased use of swaps will be to allow producers and consumers to optimise physical transportation of gas in the satisfaction of supply contracts. This will in turn reduce total payments for pipeline transportation — that being the underlying rationale for the use of swap agreements.

As the number of alternative gas suppliers in eastern Australia rises and the level of interconnection of the transmission pipeline network increases further, more opportunities for swaps will arise and the use of swap mechanisms will become more widespread. The overall effect will be to increase the efficiency of the system by offering additional flexibility in contracting arrangements. However, pipelines such as the MSP, which are part of an integrated pipeline network connecting major markets in Sydney, Melbourne, Adelaide and potentially Queensland markets, as well as all the major gas supply sources in central and southern Australia, could face increasing revenue risk as a result of an increased use of swap arrangements.

4.3 Conclusion

The discussion in Chapter 4 has highlighted many of the uncertainties and complexities that exist in attempting to forecast how south-east Australian demand could be met from transportation of gas on an evolving pipeline system over a 20 year period. The difficulties of forecasting flows on a single, but pivotal, pipeline such as the MSP include:

- forecasting the demand that will eventuate given the delivered price of gas;
- estimation of remaining gas reserves, and most importantly the location, amounts and timing of additions to these reserves;
- forecasting possible responses to market developments by an increasing number of pipeline owners and gas producers;
- interpretation of public information about current and emerging contracts for the EGP and MSP;
- estimation of the impact of emerging technology such as CSM; and
- understanding the potential implications of more sophisticated market developments such a swaps.

As demonstrated in the analysis, the plausible outcomes may be significantly different — a single forecast of throughput on the MSP, such as that attempted by EAPL, needs to be developed with care bearing in mind the purpose of the forecast.

ACIL Tasman's conclusion is that the EAPL forecast of the way in which NSW/ACT demand might be met with gas flows through the MSP is based on sound methodology. Further, as the estimates sit within the bounds of the ACIL Tasman scenarios, the EAPL forecast flows on the MSP are considered to be 'reasonable'.

5 Quantity of gas on the Victoria/NSW interconnect

5.1 Interconnect methodology

Chapter 4 dealt with how estimated NSW/ACT gas demand is forecast to be met by the MSP. The resulting forecast estimates flows on the MSP on its 'downstream' sections. However, the 'upstream' section of the MSP may also be used to supply gas to Victoria. In this respect, via the Victoria interconnect, the MSP may compete with the SEAGAS pipeline and, less likely, the EGP.

Any flows on the interconnect have a positive effect on utilisation levels for the MSP. Northbound flows will result in transportation through the downstream section of the pipeline, through the Wagga Wagga to Young lateral and from Young to Sydney. Southbound flows will result in transportation through the upstream section of the pipeline from Moomba to Young and through the Young to Wagga Wagga lateral to Victoria.

EAPL has reviewed the history of forward and backhaul flows over the interconnect, and current contracts by shippers. EAPL's assessment of future intentions based on this history is that the southbound flows are likely to decline and northbound flows increase over time.

Overall, however, the flows on the interconnect are expected by EAPL to increase. These flows are essentially bi-directional and reflect a near neutral balance of north and south-bound traffic.

ACIL Tasman uses its *GasMark* modelling to estimate interconnect flows. Consequently, the forecasts are overwhelmingly influenced by the northern and southern gas reserves scenarios discussed above. It should also be noted that, being an annual model, *GasMark* is not able to fully reflect flows across the interconnector that are related to seasonal changes in demand and short-term supply opportunities.

Consequently, *GasMark* is less reliable in modelling the interconnect flows in detail over the course of a year than would the 'bottom-up' approach adopted by EAPL. However, *GasMark* can identify circumstances where the role of the interconnect may change fundamentally, particularly in response to substantial changes in gas supply.

5.2 Interconnect forecasts

Figure 16 and Figure 17 show the EAPL and ACIL Tasman forecasts for the Victoria interconnect and the 'upstream' section of the MSP, respectively. The flows on the interconnect are the sum of the north and south-bound traffic in each year. The key points to note from these charts are:

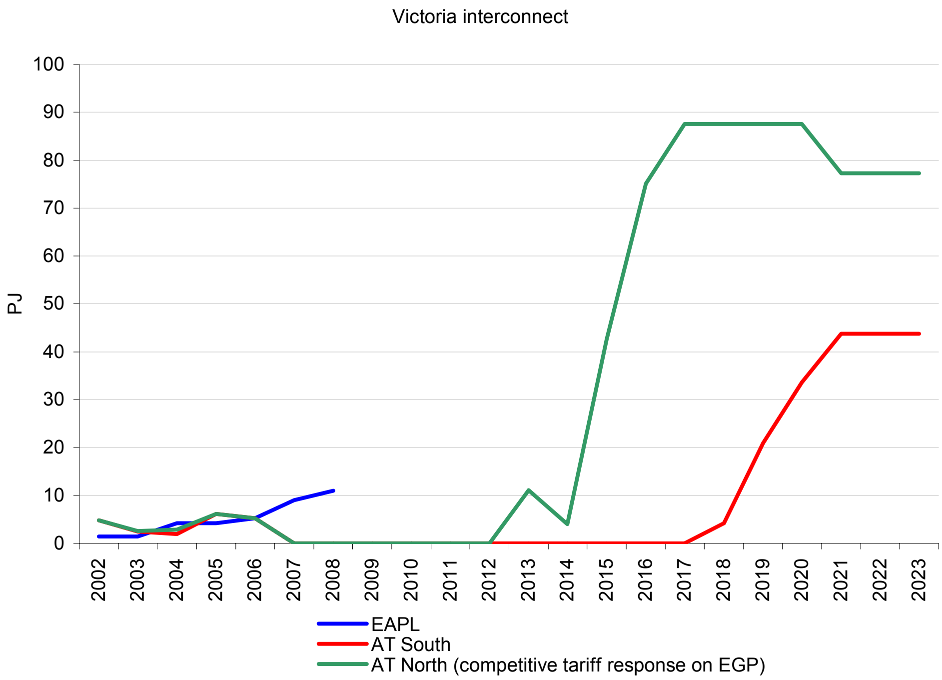
- the EAPL forecast for the interconnect shows a steady increase in flows to [redacted] (based on recent history), and from then on remain constant;
- in later years, ACIL Tasman forecasts are strongly influenced by the gas source scenarios, whereby the northern gas scenario would have significant quantities of Timor Sea gas finding its way to Victoria (no flows north)
  - whereas the southern gas scenario would have significant quantities of Otway and some Gippsland gas flowing north (no flows south)
  - remembering that, as an annual model, *GasMark* does not model the detail of season flows;
- the zero flows on the interconnect forecast by ACIL Tasman in the periods 2007-2012 (northern gas scenario) and 2007-2017 (southern gas scenario) are strongly influenced by the assumption made in these *GasMark* simulations that contracts are renewed for periods of five years and do not reflect seasonal flows;
- the ACIL Tasman forecasts imply a capacity upgrade for the interconnect after 2012, although clearly this would not be economically feasible if contracts could be secured for only five years; and
- an influence on the gas flows on the interconnect in a northern gas scenario is the role of the SEAGAS pipeline connecting Victoria and South Australia[4]. Like the Victoria interconnect, the SEAGAS pipeline is modelled by *GasMark* to carry significant quantities of gas to Victoria in the northern gas scenario.

Overall, the *GasMark* results highlight some shortcomings of the model for the interconnect pipeline. However, importantly, the *GasMark* results also show the potential for a fundamental change in the role of the interconnect should gas supply be dominated by northern or southern sources of gas.

On balance, however, the EAPL approach provides reasonable results associated with a balanced supply of gas from northern and southern gas basins. As discussed earlier, over this time period the opportunity to use swaps could influence expected physical flows.

[4] *GasMark* modelling suggests the EGP would not competitive with an upgraded Victoria interconnect and SEAGAS.

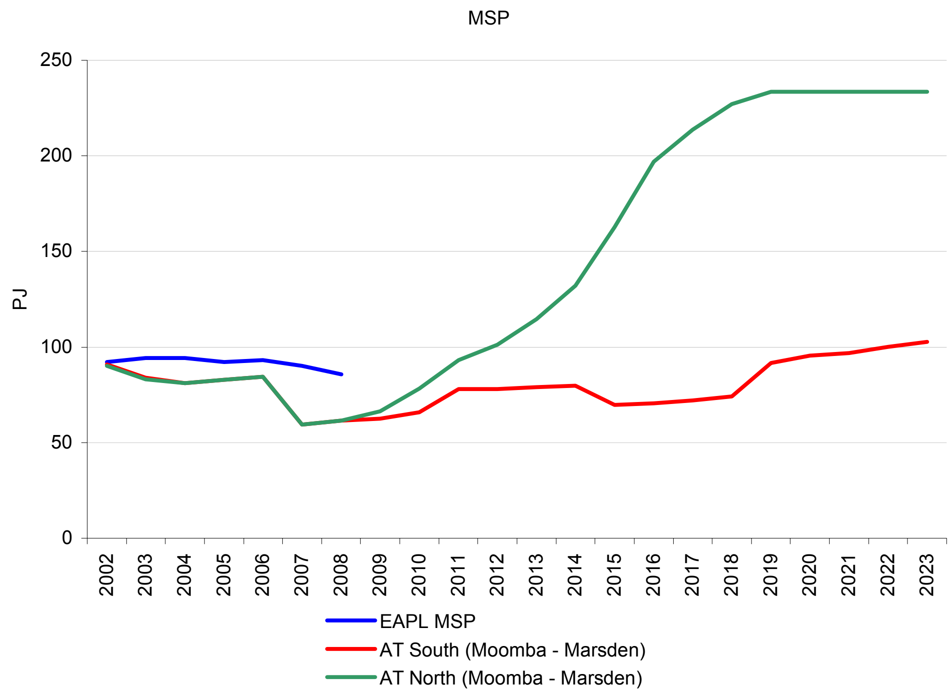
Figure 16: Forecast of total interconnect flows (competitive tariff response by the EGP in the northern scenario)



Source: ACIL Tasman

The influence of the ACIL Tasman gas reserves scenarios on the interconnect is highlighted by the forecasts for gas flows on the section of the MSP upstream of the NSW/ACT gas markets. Figure 17 shows that the EAPL forecast falls between the ACIL Tasman scenarios, and is therefore a reasonable estimate of the expected flows on the MSP.

Figure 17: ACIL Tasman and EAPL forecast of MSP – with flows to Victoria and EGP tariff response in the northern scenario



Source: ACIL Tasman

While the EAPL forecast may be thought to represent a reasonable 'average' of the possible outcomes, the potential is for the EAPL forecast to materially overestimate flows in the MSP (as compared to ACIL Tasman's southern gas scenario). Alternatively, they may significantly underestimate the MSP flows (as compared to ACIL Tasman's northern gas scenario), at least for the 'upstream' section of the pipeline that might facilitate delivery of gas to Victoria.

However, as discussed in Chapter 4, the two ACIL Tasman scenarios represent plausible extremes, and that the actual outcome is likely to be one with more 'balance' between northern and southern gas supplies. The EAPL forecast is one such 'balanced' scenario that produces reasonable forecasts for flows on the MSP.

A PowerMark

A.1 Description of the model

PowerMark is a complex model with many unique and valuable features. It provides insights into:

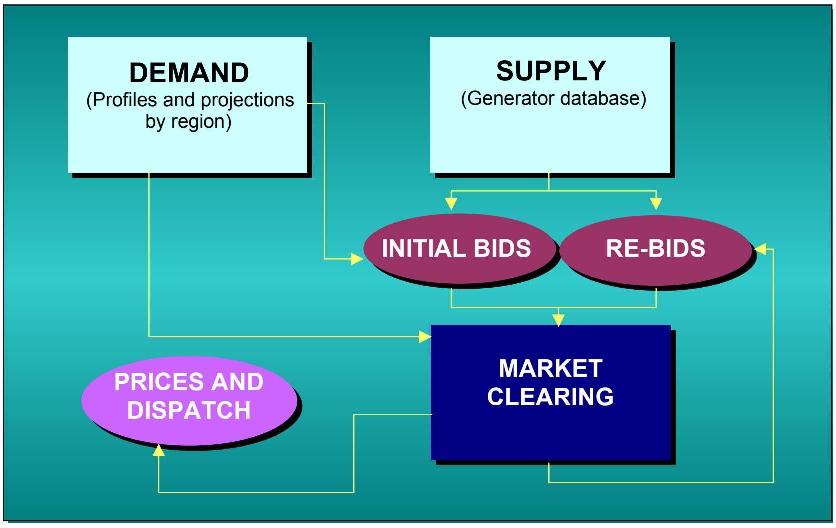
- Generator bidding behaviour;
- Market power;
- Network and generation capacity constraints;
- Pool price trends and price volatility;
- Revenue streams attributable to generation units and inter-regional connections;
- Demands for coal, gas and other fuels; and
- The cost outlook for buyers of wholesale electricity.

Like other pool market models, *PowerMark* is a simulator that attempts to emulate the settlements mechanism of the NEM. In this process, offers from generators are stacked in ascending price order until the market's demand for the period is met. The price of the last offer accepted becomes the reference price for that period and is paid to all generators for their accepted offers.

The unique attribute of *PowerMark* is its optimisation of generator offers, a computationally intensive exercise in which generation portfolios have successive opportunities to maximise uncontracted net revenues (contracts are assigned to generators by algorithms within the model). This feature of *PowerMark*, which distinguishes it from all other existing market models, provides a reliable capacity to replicate past market outcomes (prices, station dispatch and interconnector flows). A testament of that has been its use in evaluating successive insurance claims for major plant failures at Loy Yang B and Loy Yang A over the past two years.

Figure 18 is a simplified diagrammatic representation of the model and its method of combining input data from the supply and demand modules to produce a price and dispatch result for each region and power station for each period.

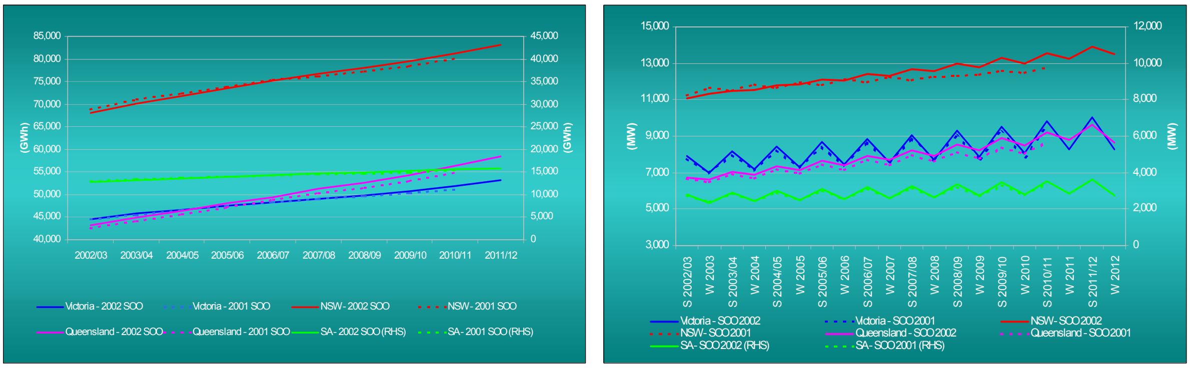
Figure 18: ACIL Consulting Electricity Market Model – *PowerMark*



A.2 Major data inputs

Figure 19 shows the projected sent-out annual energy requirements by region and the seasonal demand on capacity (the projected peak winter and summer demands). Details are provided in Table 4 and Table 5.

Figure 19: LHS - Projected annual energy requirements (GWh), RHS - comparison of projected peak winter and summer demands (MW)



Source: ACIL Tasman, based on Transgrid, VENCorp, ESIPC, Powerlink and NEMMCO SOO 2002

Table 4: Projected annual sent-out energy requirements (GWh)

	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12
Victoria	44,611	45,774	46,627	47,548	48,309	49,034	49,711	50,647	51,933	53,172
NSW	68,020	70,110	71,910	73,500	75,120	76,690	78,090	79,540	81,180	83,140
SA	12,766	13,164	13,574	13,969	14,388	14,658	14,951	15,258	15,589	15,813
Queensland	43,207	44,985	46,462	48,007	49,459	51,308	52,636	54,358	56,291	58,475
Tasmania	10,357	10,474	10,600	10,712	10,841	10,943	11,076	11,209	11,345	11,470

Source: ACIL Tasman with Transgrid, VENCorp, ESPIC and Powerlink

Table 5: Comparison of projected sent-out peak winter and summer demands (MW)

	Victoria	NSW	SA	Queensland	Tasmania
S 2002-03	7,931	11,077	2,813	6,719	1,462
W 2003	6,997	11,309	2,324	6,622	1,621
S 2003-04	8,196	11,465	2,905	7,045	1,479
W 2004	7,167	11,526	2,408	6,878	1,641
S 2004-05	8,438	11,796	3,013	7,357	1,497
W 2005	7,308	11,828	2,478	7,146	1,659
S 2005-06	8,671	12,098	3,103	7,635	1,513
W 2006	7,437	12,072	2,547	7,417	1,679
S 2006-07	8,869	12,401	3,192	7,903	1,531
W 2007	7,558	12,308	2,602	7,682	1,697
S 2007-08	9,066	12,694	3,269	8,241	1,546
W 2008	7,720	12,553	2,658	7,927	1,716
S 2008-09	9,288	12,988	3,354	8,538	1,565
W 2009	7,878	12,769	2,716	8,211	1,736
S 2009-10	9,542	13,271	3,442	8,893	1,584
W 2010	8,075	13,005	2,785	8,479	1,757
S 2010-11	9,810	13,565	3,533	9,198	1,603
W 2011	8,256	13,240	2,852	8,798	1,777
S 2011-12	10,060	13,905	3,621	9,619	1,620
W 2012	8,259	13,514	2,729	8,639	1,769

Source: ACIL Tasman with Transgrid, VENCorp, ESPIC and Powerlink

B GasMark

The ACIL Gas Model, *GasMark*, has been developed to allow analysis of the effects of changes in gas supply, demand and pipeline infrastructure on the distribution and pricing of gas. At present, the model covers Eastern Australia only. However, its coverage is being extended to incorporate Western Australia. The model has a 20-year forecast time horizon and incorporates information on ten gas markets in Eastern Australia and production from nine existing and potential gas fields.

The ten gas markets analysed in the model are: Northern Territory, Mt Isa, Townsville, Gladstone, Brisbane, New South Wales Country, Newcastle, Sydney, Victoria and South Australia.

The nine existing and potential gas production fields which are incorporated are; Timor Sea (Bonaparte Basin), Palm Valley (Amadeus Basin), South Australian (Cooper Basin), South West Queensland (Cooper and Eromanga Basins), Queensland (Surat Basin /Denison Trough), Coal Seam Methane, Bass Strait (Gippsland Basin), Victoria and South Australia (Otway Basin) and Papua New Guinea.

The production potential of each field is assessed taking into consideration the P2 and P3 reserves, the probability of further discoveries, existing and past levels of production and the production to reserves ratio. This involves a degree of subjectivity that takes into account the past performance of the particular operator and any public announcements. Reserves and the probability of new discoveries are based on data published by the Bureau of Resource Sciences, updated by ACIL assessments of public data.

The Model produces forecasts of supply sources into each market by attempting to satisfy the uncontracted gas market requirements at the lowest possible price and the highest return to producers. From the model results, gas flows on each pipeline and delivered prices into each market can be estimated.

The model layout is shown in the following diagram.

ACIL Consulting's Eastern Australian Gas Model Layout