ROAM Consulting Pty Ltd
A.B.N. 54 091 533 621

Report (Plk00020) to

NATIONAL ELECTRICITY MARKET FORECASTING

Scenario Analysis Revisions for PNG Pipeline developments

22 February 2006

EXECUTIVE SUMMARY

ROAM Consulting has been asked by Powerlink to conduct a review of previous probabilities of market development scenarios, to be used in Powerlink's revenue reset application. ROAM previously completed the scenario analysis and selection process in September 2005, however with recent developments in the PNG Pipeline development, these probabilities have been reviewed to provide an accurate platform for Powerlink's revenue reset application process.

Papua New Guinea Gas Pipeline

There have been significant developments in the PNG Gas Pipeline project in the past six months. These include:

- Australian Gas Light (AGL) $4.5 billion gas sales agreement for 1500 petajoules over 20 years;
- AGL purchase of a 10% equity stake in the project for $530 million, an appreciation of $130 million since the previous valuation in July 2005;
- The Australian Corporation and Consumer Commission (ACCC) draft decision on joint marketing arrangements for the participants in the project, allowing for 16 years of Trade Practices Act immunity against anti-competitive trading.

The project is currently in the Front End Engineering Design (FEED) stage of the development, and is anticipated to reach a sanction decision in the first half of 2006, for financial close by the end of 2006, if applicable.

To allow for a positive sanction decision, it is expected that the PNG Gas pipeline will require at least 150 petajoules per annum of gas sales agreements. There are currently 79.5 – 134 petajoules of conditional contracts, as well as AGL's binding gas sales agreement of 75 – 95 petajoules. Although the initial agreement is for 1500 PJ over 20 years (or 75PJ/annum) AGL could commit a further 20 PJ/annum to the contract with its decision to install a 370MW combined cycle gas turbine at Townsville. The Townsville CCGT is targeting a commission date of 2009 to coincide with the first deliveries of PNG gas. Should the conditional agreements firm to binding gas sales agreements, a total of 154.5 to 229 petajoules per annum will help to provide for a positive sanction decision.

The development of the PNG pipeline is in competition with a number of alternative developments. Coal Seam Methane (CSM) is an increasingly prevalent form of natural gas derived from methane that is stored in the seams of coal mines. The production of CSM is currently relatively low. However, CSM reserves are considerable, approximately 224,000 to 292,000 petajoules of reserves in Queensland and New South Wales. CSM production has also increased rapidly from a low base, due to cost advantages drawn from its close geographical location to the Brisbane and Sydney gas markets and existing pipeline infrastructure. CSM is now producing 30% of Queensland's gas, and is forecast to produce 65% to 70% by 2007.

The Timor Sea and North West Shelf gas fields have considerable amounts of natural gas, and a recently signed agreement between Australia and East Timor has ended political uncertainty surrounding the development of the area's gas resources. However, these two gas-rich areas are considered to be predominantly associated with LNG exports. The construction of a $1.8 billion LNG facility in Darwin has reaffirmed this, despite the Northern Territory's Power and Water Corporation stating that it is working towards a gas sales agreement with the Blacktip gas development to supply NT domestic gas demand. The capital cost of a long distance pipeline between Timor gas or North West Shelf gas and South Eastern Australia and the attractiveness of LNG exports greatly reduces the possibility of supply from these gas fields in the medium term.

ROAM has concluded that a 50% likelihood is appropriate for the PNG Gas Pipeline Scenario. ABARE's supply and demand balance for natural gas indicates a supply shortage from 2012, requiring a minimum of 100 petajoules of supply from a 'Northern' supply source (either PNG or Timor) and CSM supply growing to 100PJ by 2020. Therefore, there is sufficient demand for the PNG Gas pipeline to proceed and for CSM to continue to expand. This is also confirmed in ACIL Tasman's 2004 report. However, given the large capital cost of the project, and the delayed history of the project, combined with competing CSM resources and the difficulties still ahead with securing the conditional agreements, ROAM believes the more conservative 50% probability is appropriate.

If the PNG Gas Scenario does proceed it would have a large bearing on the nature of new generation developed in the state. The probabilities ascribed to the project here therefore relate to the development of associated generation projects in Queensland. Plant such as Spring Gully, which will use coal seam methane as fuel, will become less likely whereas plant such as AGL's announced CCGT at Townsville in Ross will become more likely.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1) INTRODUCTION

Powerlink Queensland (Powerlink) is Queensland's monopoly Transmission Network Service Provider (TNSP) and is subject to regulation by the Australian Energy Regulator (AER). As a TNSP registered with the National Electricity Market Management Company (NEMMCO) and operating in the National Electricity Market (NEM), Powerlink's Maximum Allowable Revenue for the provision of prescribed services under the National Electricity Rules is determined by the AER.

ROAM Consulting has been asked to aid in the drafting of Powerlink's application to the AER by producing a probability matrix of potential future development scenarios, taking into account developments in the National Electricity Market (NEM) and the broader Queensland and Australian economies and the effect of these on the Electricity sector's growth.

ROAM had previously completed work for Powerlink, identifying forty (40) scenarios with appropriate probabilities given the likelihood of the occurrence of various events. This included:

- Inter-regional transmission developments, namely the upgrade of the Queensland – New South Wales Interconnector (QNI) which is currently under pre-Regulatory Test analysis;
- Electricity demand growth;
- Gas Supply options, namely the commissioning of the PNG Gas pipeline, which is currently undergoing front end engineering design (FEED) analysis before determining whether it is suitable for development;
- Greenhouse options, namely the advent of any government imposed carbon-abatement tax.

The previous work (Plk00019) was completed in mid-2005, and Powerlink has requested ROAM to update the scenario probabilities in light of recent developments regarding the PNG Gas pipeline.

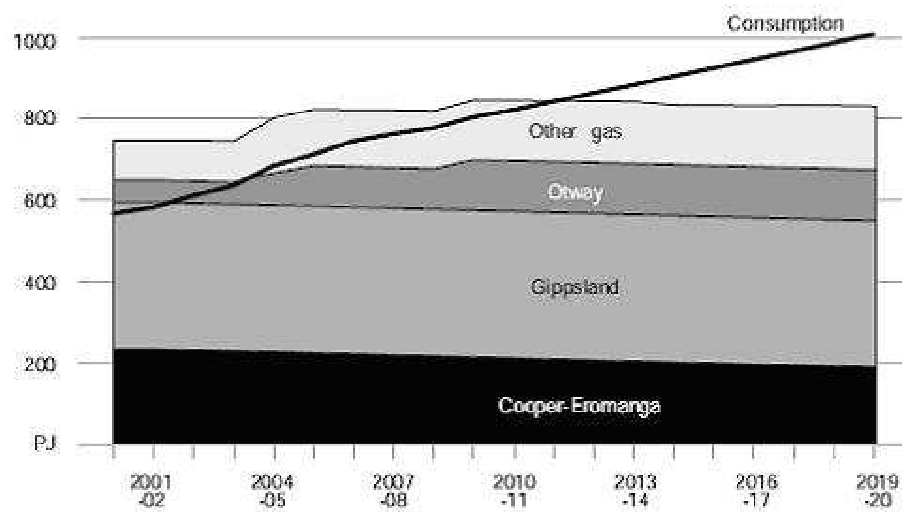
2) GAS MARKET

2.1) SUPPLY AND DEMAND BALANCE

In 2002, the Australian Bureau of Agricultural and Resource Economics (ABARE) conducted a study into the supply and demand for Eastern Australia's gas market. Australia has a large amount of natural gas reserves, especially from the Western Australian North West Shelf gas fields, and the gas fields in the Timor Sea north of the Northern Territory. Smaller gas reserves exist in the Eastern States. Papua New Guinea (PNG), north of Queensland, has substantial gas and oil reserves that Australian markets could utilise.

The results of this study indicated that Australia's demand for gas in the Eastern States is likely to outstrip supply from 2012, as demonstrated in Figure 2.1 below, which shows the supply from Eastern Australian gas fields with forecast gas demand. The study identified a generic Northern supply option of 100 petajoules per annum would be required from 2012-13 (from either PNG or the Timor Sea). Coal Seam Methane production is also forecast to increase to 100 PJ/a by 2019/20.

Figure 2.1 – Supply and Demand for Gas to 2019-20

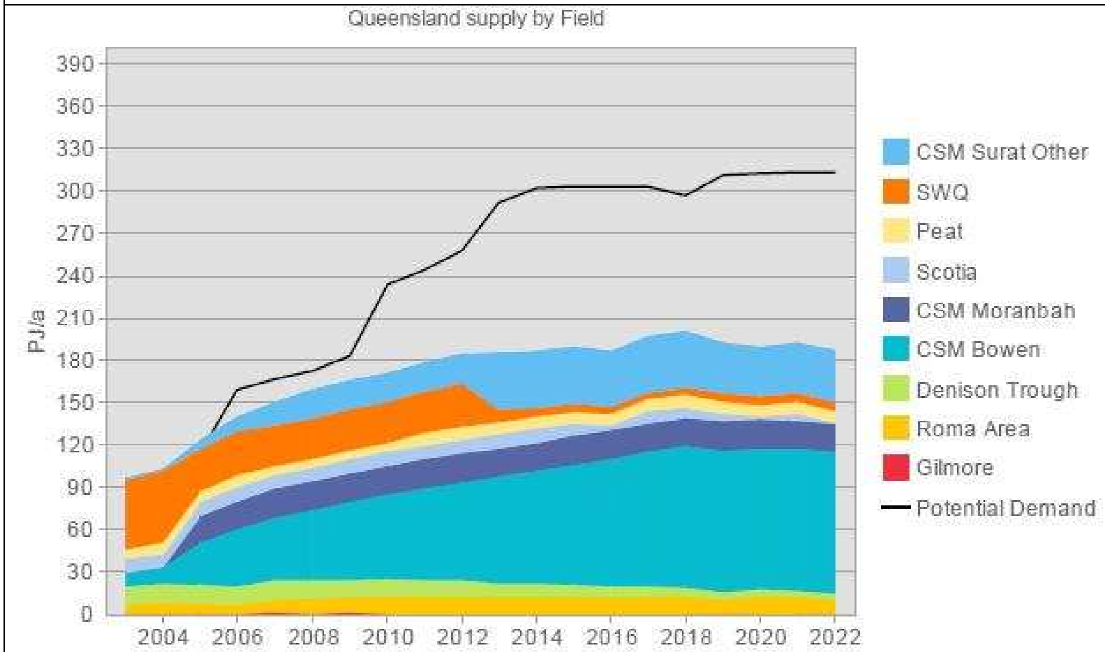


Source: ABARE

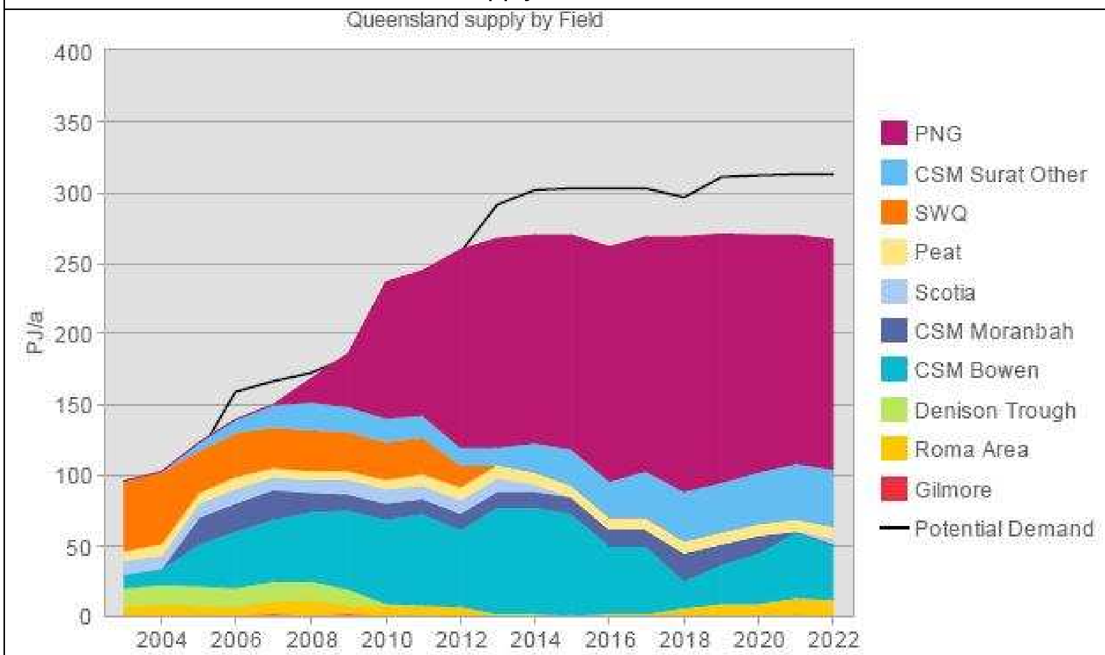
In 2004, ACIL Tasman produced a report including significant modelling of the gas market's supply and demand. Figure 2.2 below shows forecast gas supplies to Queensland until 2022, including supply levels from existing gas fields, coal seam methane sources, and PNG Gas. As mentioned, PNG Gas and Coal Seam Methane sources are forecast to provide a significant source of supply in the medium term. However there still is room for competition in the gas market, with shortfalls of supply still predicted even with the introduction of PNG Gas.

Figure 2.2 – Sources of Gas Supply for Queensland to 2019-22

Gas Supply **WITHOUT** PNG Gas



Gas Supply **WITH** PNG Gas



Source: ACIL Tasman, 'Economic impacts of the PNG Gas Project: an assessment of impacts in Australia at national, state and regional level', 17 November 2004

Queensland specifically is forecast to experience significant growth in gas demand. The ABARE report forecasts Queensland gas demand in 2020 to be triple the 2001 demand. This is in line with forecasts generated by ACIL Tasman. Furthermore, the Queensland Office of Urban Management reports that Queensland's gas demand is increasing at a rate of 4.3 per cent per year, above the national average of 3.8 per cent.

ABARE's 2002 report concludes that the eastern Australian gas market will be increasingly dependent on new sources of supply in the future if not within the next decade. This supply can come from a number of sources, with the PNG Gas pipeline, Coal Seam Methane (CSM), and the Timor Sea reserves being likely candidates in the medium term given moderate capital requirements. Pipelining gas from Western Australia is not currently a foreseeable option due to the high capital requirements of such a venture, and the LNG export capability of the North West Shelf.

2.2) PNG GAS

2.2.1) Background

The PNG Gas pipeline is an ambitious project to deliver natural gas from Papua New Guinea's extensive gas and oil fields to Queensland via a pipeline of approximately 3200km in length. The PNG Gas project participants (the Participants) are affiliates of Exxon Mobil, Oil Search, MRDC (a PNG company representing landowner interests) and Nippon Oil Exploration. The pipeline, if constructed, will be the largest in the southern hemisphere.

The Australian section of the pipeline will be constructed by a consortium comprised of Australian Gas Light (AGL) and a Malaysian company, Petronas Australia Pty Ltd. The consortium (APC) is also responsible for the front end engineering design (FEED) stage for the Australian component of the project.

The pipeline has had a turbulent history, failing to attract sufficient customers for an initial commissioning date of 2006. However the project has progressed steadily, despite the initial delays, and is now scheduled to begin gas flow by 2009. In October 2004 the project progressed to the front-end engineering design (FEED) stage. The FEED stage of the project includes:

- Technical work to optimise the upstream facilities and the finalisation of the design for the upstream, PNG pipeline and export facilities;
- Commercial work to finalise framing agreements relating to the project and initial work on government approvals and project financing;
- Gas marketing activities, designed to confirm sufficient firm sales contracts to support a project sanction decision.

The FEED stage of the development is scheduled for completion early in 2006, with a sanction decision and financial close by the second half of 2006.

The current likely pipeline route, as published on the Oil Search website, is shown in Figure 2.3 below.

Figure 2.3 – Possible Pipeline Configuration of PNG Gas

Source: Oil Search Limited

The Townsville to Ballera pipeline (which is shown dashed in Figure 2.3 above) has progressed to 'significant project' status with the Queensland Government. The $1 billion pipeline affirms plans to extend supply beyond Queensland to the southern states, and is currently progressing toward an environmental impact statement.

2.2.2) Environmental Implications for PNG Gas

In 2001 the Queensland Government introduced an initiative to require all electricity retailers and other liable parties to source 13% of electricity from gas-fired generation. The scheme began on 1 January 2005, and continues for 15 years.

Eligible fuels to generate Gas Electricity Certificates (GECs) include natural gas, coal seam methane, liquefied petroleum gas, and other waste gases. Gas Electricity Certificates are created and traded between eligible generators and electricity retailers (and other liable parties) in order for retailers to satisfy their 13% requirement. One megawatt-hour of electricity is equivalent to one Gas Electricity Certificate. GECs are traded up to a value of approximately $15.00/MWh.

The scheme has helped to increase demand for gas and gas-fired generation in the State.

With the recent Asia Pacific Partnership on Clean Development and Climate summit in Sydney this month, the issue of tackling climate change has increased visibility. Australia has agreed to meet its Kyoto targets, although is yet to ratify the international agreement.

The Kyoto Protocol is an agreement under which industrialized countries will reduce their collective emissions of greenhouse gases by 5.2% compared to the year 1990 (but note that, compared to the emissions levels that would be expected by 2010 without the Protocol, this target represents a 29% cut). The goal is to lower overall emissions from six greenhouse gases calculated as an average over the five-year period from 2008 to 2012.

Although Australia and the United States have not ratified the Protocol, the ratification by Russia in 2004 has ensured that the targets will be enforced. The Russian ratification ensured that the terms of the convention had been met - that more than 55 Parties to the convention accounting for over 55 per cent of emissions had ratified the protocol.

In order for Australia to meet its Kyoto obligation, a number of strategies may be adopted, in addition to the existing energy management strategies. Currently the New South Wales, Queensland and Federal Governments have programs in place to mitigate climate change. The Federal Government's Mandatory Renewable Energy Target (MRET) scheme imposes the requirement that 2% of all electricity generated is sourced from renewable energy. The New South Wales government's Greenhouse Gas Abatement Certificate (NGAC) Scheme and Queensland Government's Gas Electricity Certificate (GEC) Scheme also serve to reduce greenhouse gas emissions.

Australia could, however, go further and introduce a carbon trading scheme, or carbon tax. The European Union has in place an Emissions Trading Scheme (EU ETS) to allow nations which have low levels of carbon emissions to sell carbon credits to nations which have high levels of emissions. A similar strategy domestically could aid in Australia's efforts to meet Kyoto obligations.

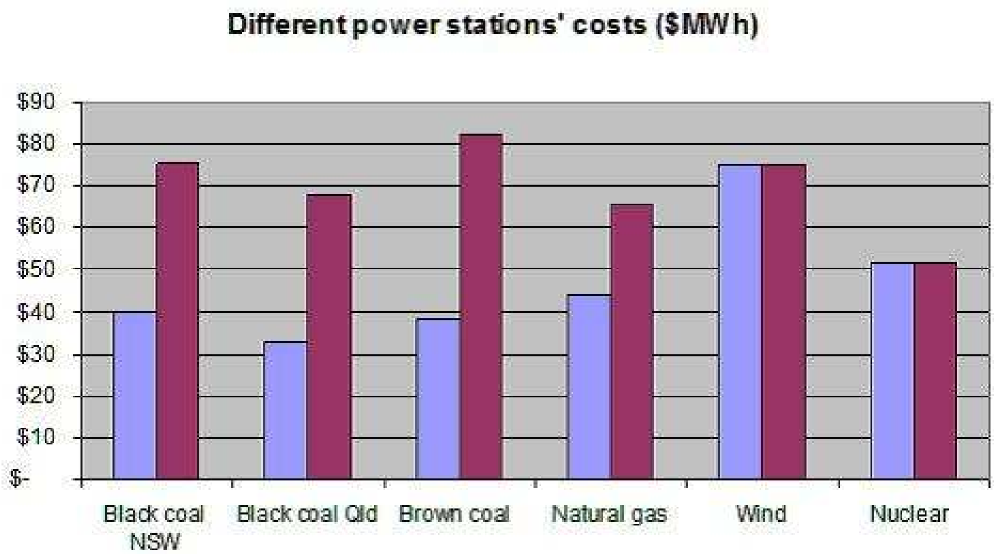
In a recent move, New Zealand has announced that it is not going to pursue a carbon tax due to the high costs of such a scheme. New Zealand's carbon tax was to be set at a relatively low level of $A14 per tonne of carbon emissions and was expected to add 6 per cent to electricity prices. New Zealand's Government has now decided to instead consider other ways to ensure New Zealand meets its commitments to cut greenhouse gas emissions.

The likelihood of the introduction of such a significant change to Australia's Energy Policy is low whilst the current Government remains in power. The current political climate enjoys a buoyant economy, and such a change would increase electricity costs and dampen the Australian economic outlook. Although at a State level there is increasing support, with Victoria leading the calls to implement some form of national greenhouse scheme, the existing Coalition government is unlikely to change its current position.

If the Kyoto Protocol is ratified by Australia and comes into force, it is considered highly likely that Australia will participate in an international emissions trading scheme in order to reduce the total burden on the economy of meeting the Kyoto target. Whilst the present Coalition Government will not ratify the Protocol, the Federal Opposition would ratify the agreement.

Any such trading scheme could impact upon the demand for gas, and the PNG Gas project. National adoption of a greenhouse trading scheme would entail a cost. Currently, European Union Allowances (EUAs) are traded at around €25.00 (€25.55 at time of writing) per tonne of carbon dioxide, which is approximately $41.00/t$CO_2$. Figure 2.4 below estimates the costs of electricity with and without the sort of additional charges implicit if Australia adopted a scheme similar to the EU ETS and left other schemes in place. The estimates are based on the carbon dioxide content of the different fuels.

Figure 2.4 – Australian Power Generation Costs with EU Tradable Rights Prices



Source: Institute of Public Affairs

Clearly from Figure 2.4 above, the competitiveness of gas-fired generation would significantly improve if such a scheme is introduced. This would in turn increase the demand for gas considerably, as natural gas is less greenhouse-intensive than coal or other fossil fuels.

2.2.3) Recent Developments

Australian Gas Light Equity Stake and Sales Agreement

Australian Gas Light (AGL) has pushed forward a 10% equity purchase in the PNG Pipeline project from Oil Search and finalised its conditional sales agreement. The deal is approximately six months ahead of schedule, and AGL announced it was "an important step towards a project sanction decision, which is targeted in 2006". The gas sales agreement involves the supply of 1500 petajoules over 20 years, and is valued at approximately $4.5 billion.

The 10% equity stake, which incorporates 20 million barrels of oil, is valued at $530 million, an increase of $130 million since the previous valuation in July 2005. The 10 per cent stake in the project is acquired via:

- 11.9 per cent stake in Kutubu (Petroleum Development Licence 2);
- 66.7 per cent stake in Gobe (Petroleum Development Licence 4);
- Oil, Gas and condensate reserves in excess of 110 million barrels of oil equivalent;
- Oil Search however retains operating rights over all projects.

The equity deal does allow for uncertainty in the progress of the project, with payments of the equity share to be made at acquisition completion, project sanction and financial close. Therefore, whilst the AGL binding agreement should give PNG momentum towards the expected sanction decision this year, it also incorporates risk mitigation measures for AGL should the PNG pipeline not proceed (be that in its current form or altogether).

The sales agreement combines with AGL's previous announcement of a 370MW combined cycle gas turbine power station in Townsville, to be commissioned from 2009 to coincide with the first deliveries of gas from the PNG pipeline. The AGL Townsville station announcement meant the abandonment of a similar Enertrade station, which was to be fuelled by Coal Seam Methane (CSM). The 370MW station will require approximately 20 petajoules per annum, sourced from its wholesale gas portfolio, which will include the 75 PJ/a from the PNG pipeline. Should it proceed, AGL may renegotiate its Gas Sales Agreement to increase sales to 95 PJ/a to incorporate the Townsville station's gas demand.

Required Customer Base for Sanction approval

In recent months, the PNG Gas pipeline has had a flurry of activity relating to its potential customer base, with the signing of a number of key (conditional) sales agreements, and culminating in the announcement of Australian Gas Light's (AGL) equity interest in the programme.

In order for the project to be sanctioned, it is anticipated that the level of sales agreements must be at least 150 petajoules per annum. The proposed maximum capacity of the pipeline is approximately 300 petajoules per annum. Currently, Oil Search reports on its website that sales agreements (conditional except for AGL) total 154.5 – 229 petajoules per annum. Sales agreements currently include the following participants:

Table 2.1 – PNG Gas Customer Base

Customer	Gas Supply (PJ/a)
Energex (Comalco and others)	14 -50.5
AGL	75 – 95
Queensland Alumina	12 – 30
CS Energy	10
Alcan Alumina Refinery (Gove, NT)	43.5
Total	154.5 - 229

It is anticipated that the supply arrangement with AGL will speed the signing of other binding gas sales agreements. Peter Botten, Managing Director of Oil Search, has said:

"(The AGL equity sale and gas sales agreement) is a significant vote of confidence in the project and a major step in assuring this project reaches sanction. It will

provide further momentum to close other gas sales agreements with new and existing customers as project certainty increases."

Australian Competition and Consumer Commission Draft Decision on Joint Marketing Activities

On 14 December 2004 an application was made to the Australian Competition & Consumer Commission (ACCC) for authorisation of the joint marketing of gas produced by the project. Authorisation is a process whereby immunity is granted from legal action by the ACCC or any other party for certain arrangements or conduct that might otherwise breach the Trade Practices Act 1974.

According to the ACCC application, both the Participants and their financiers require the legal certainty of authorisation before funds will be committed to the project. The applicants stated that without authorisation they will not proceed with the project within the foreseeable future.

The ACCC considers that substantial public benefits will arise as a result of the project proceeding. While the project is likely to enjoy a large share of the Queensland market, the ACCC considers that it is likely that coal seam methane, other sources of natural gas and alternative forms of energy will provide some competitive constraints on the project.

The ACCC accepts that there is a net public benefit and proposes to grant authorisation to joint marketing undertaken within a framework of confidentiality and ring-fencing arrangements.

The ACCC is not confident that a net public benefit would continue over such a long term as the life of the project (approximately 30 years). Accordingly, the ACCC proposes that authorisation will expire 16 years from the date of authorisation. The ACCC further proposes that authorisation will apply to future participants in the project under certain circumstances.

Other Developments

Santos, another of Australia's largest gas producers and part owner of the Cooper Basin gas development, is currently undergoing talks with Oil Search and the Papua New Guinea Government regarding the prospect of becoming a stakeholder in the project. Santos is the operator and chief stakeholder in the Moomba gas processing plant, which is connected to the key markets of Sydney, Brisbane, Adelaide and Mt Isa. The pipeline network continues through Sydney to the largest Australian gas market of Melbourne and Victoria.

Santos already has an equity stake in the PNG gas fields, with a 31.0% interest in the PDL1, which contains the majority of the large Hides gas field. A 9.4% interest is also held in the producing SE Gobe oil field where the successful SE Gobe 11 appraisal well was drilled in May 2005.

By securing Santos as an equity partner, the PNG pipeline would have a more secure access arrangement with this crucial pipeline network. Whilst the content of the discussions between Santos, Oil Search and the PNG government are not public knowledge, recent media reports suggest that negotiations surround the processing of the gas.

ROAM considers the project's sanctioning decision should not rely on the decision of Santos to join. With the project being a substantial national asset for PNG, worth between US$3 billion and US$ 5 billion in NPV terms according to a study done by ACIL Tasman in 2002, it would be unlikely that the project is hinged on the capital delivered by a deal with Santos. Further to this, the PNG Government has set aside $US140 million for the project, which could fund a 15% stake. Therefore, should the Santos discussions fall through, the Government of PNG may move to fill the gap.

2.3) COAL SEAM METHANE

According to ABARE, Coal Seam Methane (CSM) represents a potential resource that is over 10 times greater than all the conventional natural gas reserves in eastern Australia combined. For example, Tri-Star Petroleum reports that the CSM reserves in the Bowen and Surat basins in Queensland are between 124,000 and 192,000 petajoules. ABARE reports that New South Wales coal seam reserves are also approximately 100,000 petajoules.

Coal Seam Methane therefore represents a resource that can provide a significant amount of natural gas for an extended period. Furthermore, the resources are located close to the gas markets of Sydney and Brisbane, thereby having locational benefits and reduced capital costs in transportation compared to other projects, including the PNG Gas pipeline.

A major impediment to the uptake of CSM however is the geological instability of the drilling process, limiting flow rates to lower levels than traditional forms of natural gas. Drilling efforts for CSM have also tended to produce lower levels of gas per well than traditional natural gas fields, thereby increasing capital costs.

Currently, Coal Seam Methane production levels are limited. In New South Wales, there are currently three operations producing CSM. According to the New South Wales Department of Primary Industries,

- Eastern Star Gas operates the Narrabri Power project, supplying CSM to the 12MW Wilga Park Power Station, under a 10 year agreement with Country Energy;
- Sydney Gas operates the Camden Gas project, including 21 production wells supplying up to 4.5 PJ/a. The next stage of development, currently underway, will increase production to 100 wells supplying an additional 10 PJ/a;

- The Tower and Appin collieries in the Southern Coalfields of the Sydney Basin use methane drained from mine workings to generate electricity at a 97MW facility, the world's largest coal seam methane generation project.

In Queensland, a number of operations are currently exploring and producing CSM. According to the Queensland Department of Natural Resources and Mines,

> *'Total CSG production increased to approximately 27 Petajoules (PJ) in 2004. This equates to about 25% of Queensland's current gas demand, and is a dramatic increase from around 2 PJ in 1998 and about 11 PJ in 2001.'*[1]

The Queensland Department of Energy reports that currently coal seam methane supplies approximately 30% of the State's gas, and by 2007 it is anticipated that 65% to 70% of the State's gas will be supplied by CSM.

ROAM considers that whilst CSM may become a more prevalent supply of fuel in the future, coal seam methane production levels are not at a point where CSM can be directly competitive with the PNG Gas pipeline development. That is also the stated view of Exxon Mobil. Furthermore, according to supply-demand forecasts for gas (see Figure 2.2), there exists a level of demand beyond what the PNG pipeline will deliver that CSM can fill.

2.4) TIMOR GAS AND NORTH-WEST SHELF GAS PIPELINES

Substantial natural gas reserves are located in the Timor Sea and off the North West Shelf of Western Australia. Whilst pipelines from these sources would provide longer-term solutions, capital costs (especially for the Western Australian gas producers) associated with pipeline infrastructure and alternative gas markets render these options as unlikely to proceed in the medium term.

The North West Shelf in Western Australia holds Australia's largest gas reserves, totalling approximately 60,000 PJ from the Bonaparte and Browse Basins, and a further 80,000 PJ from the Carnarvon Basin. Substantial infrastructure is already in place, with extensive mining and processing plants in service. The gas fields however are used primarily for Liquefied Natural Gas (LNG) exports. In 2000–01, ABARE reports that Australia exported 413 petajoules or about 7.6 million tonnes of LNG from the North West Shelf. ABARE's latest assessment is for Australian LNG exports to increase to 20 million tonnes by 2010–11 and then to increase further to 26 million tonnes by 2019–20.

The LNG industry in Australia is now valued in excess of $15.0 billion annually, with exports to Japan and Korea as major contributors. The LNG industry is set to expand, with the recently signed Timor Sea Treaty. The removal of impediments to development of the Bayu-Undan project has resulted in the construction of a $1.8 billion LNG plant in Darwin.

[1] Department of Natural Resources and Mines, *Coal Seam Gas Developments,* February 2005

In a recent development, Australia and East Timor have signed an agreement on revenue sharing from the Greater Sunrise gas field. Historically, the field has been the centre of a political dispute surrounding the revenue sharing arrangements between Australia and the newly-independent East Timor. The new arrangement will split revenues 50/50 between the two nations, and allows development of the gas field, the largest oil and gas field in the region, to proceed. Whilst this development will allow an increase in production of gas from the Timor Sea, the field is earmarked for LNG exports to Asian customers, and should not impact upon the domestic supply demand balance for gas.

In another recent announcement, the Northern Territory's Power and Water Corporation has signed a Heads of Agreement, a precursor to a Gas Supply Agreement, for the supply of gas from the Blacktip gas field, to meet the Territory's long-term gas supply requirements from 2009. The Northern Territory gas supply is currently sourced from the Amadeus Basin in Central Australia. The agreement binds Power and Water Corporation and Eni Australia, majority stakeholder in the Blacktip gas development, to work exclusively together to conclude the necessary commercial terms to develop a Gas Sale Agreement (GSA).

ROAM concludes that, whilst the Timor gas fields and the North West Shelf gas fields offer long term stable supply options for natural gas to the Eastern States gas markets, the value of LNG exports and existing LNG infrastructure will provide minimal opportunity to pipeline natural gas from these resource hubs beyond the potential supply of the Northern Territory's domestic demand. The Timor and North West Shelf gas fields all possess locational advantages to LNG exports, being next to major shipping lanes and close to Asian customers. Therefore, in the medium term ROAM does not anticipate any prospect of a competing pipeline project from either of these resources to the Eastern Australian gas centres.

2.5) PNG GAS PROBABILITY

Given the recent developments in the market pertaining to the PNG Gas pipeline, ROAM recognises the need to revise the probabilities given in the previous Plk00019 report.

The PNG Gas participants presently have sufficient conditional agreements to anticipate a positive sanction decision after the front-end engineering design work is completed, assuming all the conditional agreements become binding. The move by AGL to proceed with their conditional sales agreement, committing to a $4.5 billion Gas Sales Agreement (GSA) of 1500 PJ over 20 years, combined with a $530 million 10% equity stake in the project, is a strong endorsement of the project. This should result in the firming of further conditional agreements. A major task of the FEED process is the marketing process to convert conditional agreements to binding agreements. However, there are a number of stumbling blocks ahead.

Firstly, it would be a further endorsement if Santos were to join the project. The Moomba processing facility, operated by Santos, is important for PNG gas to flow to the southern states, where gas demand is highest. Santos is currently in talks to acquire liquids processing rights for the gas, although this is currently earmarked for the Kutubu Condensate Processing Facility in Papua New Guinea and there has been reluctance thus far to relinquish these rights.

Furthermore, the 43.5 petajoule per annum conditional sales agreement with the Alcan Alumina Refinery is worthy of note. The spur required to supply Alcan's refinery, situated in Gove, Northern Territory, would increase the capital cost of the project. Whether PNG Gas absorbs these costs (which is expected), or the final Gas Sales Agreement passes on these costs to Alcan may determine whether conversion from the existing liquid fuels to Natural Gas will be cost effective for the refinery. Alcan recently cancelled an agreement to pipeline natural gas from the Timor gas fields, due to difficulties in developing pipeline infrastructure through the Kakadu region of the Northern Territory.

The Alcan demand is a significant part of the existing customer demand for PNG Gas. Whilst it would be in the interests for the project to retain this demand and come to a binding sales agreement, the additional costs associated with the spur to Gove will negatively impact upon the price competitiveness of PNG Gas. Although the project is anticipated to capture a considerable amount of surplus demand in the gas market, this will depend upon the price competitiveness of the project, especially considering the increasing uptake of coal seam methane. Of course, if the Participants were to attempt to pass on the costs of the spur to Gove to Alcan, the demand from the Alcan refinery may be at risk, although this is unlikely as it is expected that the price for gas will be uniform for all customers.

Given all of these considerations, ROAM believes that the PNG Gas Scenario has a 50% likelihood of proceeding. If it is indeed successful, PNG Gas would have a large bearing on the nature of new generation developed in the state. The probabilities ascribed to the project here therefore relate to the development of associated generation projects in Queensland.

2.6) OUTCOMES IF PNG GAS IF COMMITTED

If the PNG Gas Pipeline gains a positive sanction decision, and proceeds to commitment, there will be minimal effects on the scenario analysis provided by ROAM in the previous (Plk00019) report, since the possibility of PNG proceeding has been factored into the scenario analysis previously conducted.

ROAM has produced scenario probabilities given the likelihood of the PNG Gas project proceeding. There are a total of 20 scenarios given the (previous) 20% likelihood of the project proceeding, and another 20 scenarios given the (previous) 80% likelihood of the project being delayed, deferred or withdrawn.

If the PNG Gas project is committed, clearly half of the scenarios provided by ROAM can be disregarded. However there may be follow-on effects from the commissioning of the pipeline beyond those included in the previous scenarios. A number of possible implications of the development may affect the development of the Powerlink network in the forecast period.

Firstly, should the Pipeline proceed, it is highly likely that the announced Australian Gas Light (AGL) 370MW CCGT in Townsville will proceed.

Depending upon access rights that will be determined by the Gas project participants, further development may result from the commissioning of the project. Although the pipeline may stifle coal seam methane production in the initial years, the new pipeline infrastructure may bring forward planned gas fields due to increased access to the gas transportation network. This may similarly increase the likelihood of other CCGT or cogeneration plants in the State.

A full State-wide analysis would need to be performed, with significant modelling and integrated resource planning, in order to fully determine the full implications of the commissioning of the PNG Gas Pipeline. At this stage, whilst ROAM has changed its likelihood of the project proceeding to 50%, there is still uncertainty surrounding the likely commissioning date of the development. Whilst the planned commissioning date is at present 2009, the Front End Engineering Design work is scheduled to be completed in Quarter One 2006, with a sanction decision to be made by Quarter Two 2006. If this timetable is strictly complied with, and the participants also achieve project financial close by the end of 2006, then the commissioning date of 2009 remains a possibility. However, speculation has begun to arise as to whether a 2010 commissioning date is more appropriate.

A delay in the commissioning of the PNG project, if it proceeds, could also have flow on effects to such projects as the Townsville 370MW CCGT, even though AGL has said it will proceed with the development with or without PNG gas.

3) Scenario Probability Update

Given the changes in probability of the PNG Gas scenario, ROAM includes a brief update to the scenario probabilities given in the Plk00019 report. Detail of the individual scenarios is not included in this update, however can be found in the original Plk00019 report.

Given the increased likelihood of an expanded supply of natural gas to Queensland, it is necessary to re-evaluate the probabilities of proposed generating stations going ahead. A number of potential or proposed stations were included in the Plk00019 report, including various gas fired stations throughout the State. With the increased supply of gas, these stations will more likely proceed, as an increase in supply will result in sustainable lower gas prices due to the increase in competition. However, those stations earmarked for CSM as fuel may diminish in likelihood, as PNG Gas may reduce gas competition temporarily.

Figure 3.1 below shows the probability of each station proceeding as shown in the Plk00019 report (i.e. before the updates included in this report). Figure 3.2 shows the updated probability of these proposed stations.

Figure 3.1 – Station Commitment Probabilities (Plk00019 probabilities)

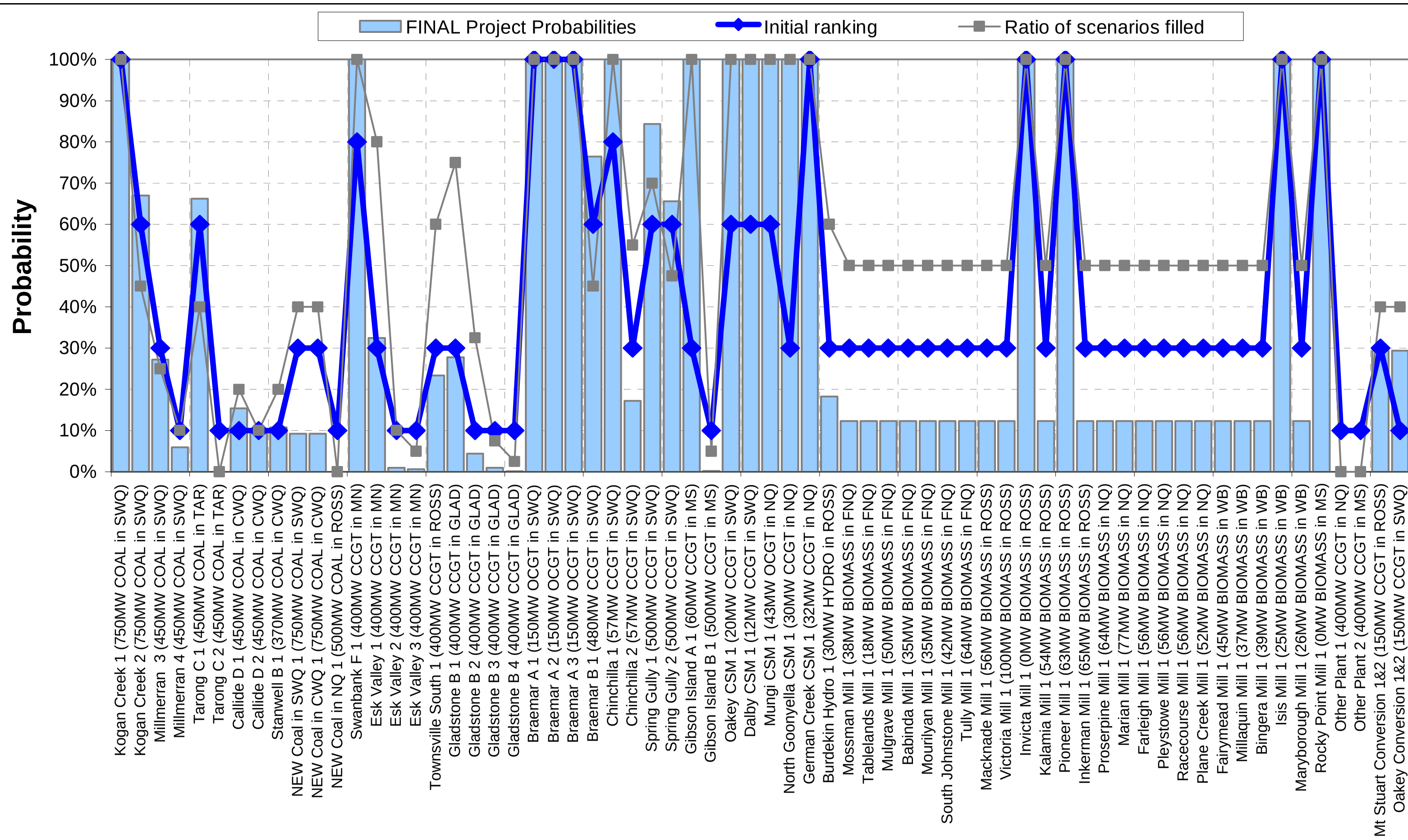
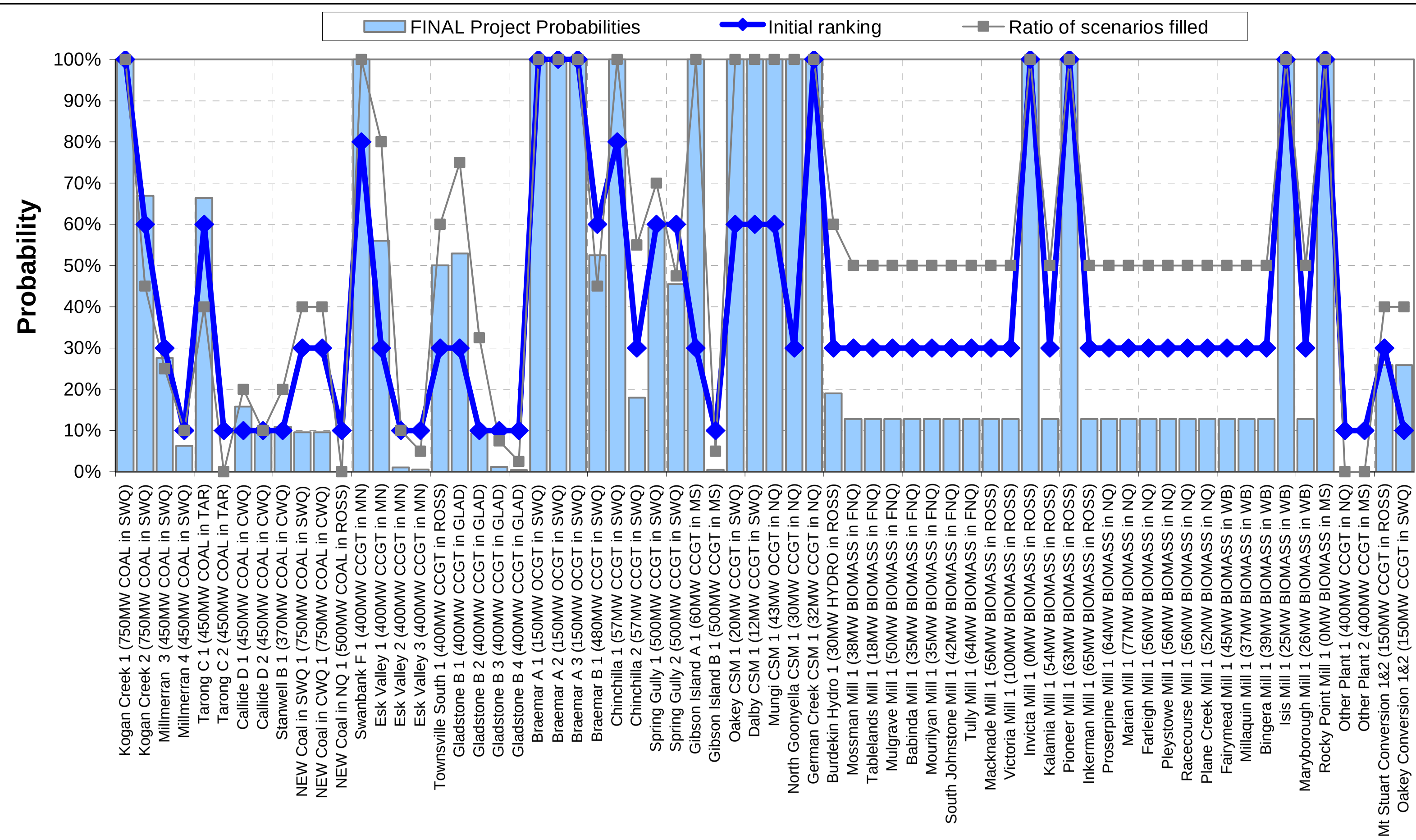


Figure 3.2 –Station Commitment Probabilities (updated probabilities)



As can be seen in the figures above, the probabilities of the following stations have changed by a noteworthy level:

- Townsville South 1 (**up** to approx 50% from approx 23%)
- Spring Gully 1 (**down** to approx 59% from approx 85%)
- Spring Gully 2 (**down** to approx 46% to approx 65%)
- Braemar B 1 (**down** to approx 53% from approx 77%)
- Esk Valley 1 (**up** to approx 56% from approx 32%)
- Gladstone B 1 (**up** to approx 53% from approx 28%)

Furthermore, ROAM has updated each of the 40 identified scenarios' individual probabilities. This is shown in Table 3.1 below. Please see the Plk00019 report for further descriptions for each scenario's definition.

Table 3.1 – Scenario Probability Update

Scenario	Scenario Definition	Previous Probability (Plk00019)	Updated Probability
1	L50 - QNI - NO PNG - NO TAX	12.1%	7.9%
2	L50 - QNI - NO PNG - TAX	1.7%	1.1%
3	L50 - QNI - PNG - NO TAX	2.6%	6.8%
4	L50 - QNI - PNG - TAX	0.4%	1.1%
5	L50 - QNI++ - NO PNG - NO TAX	5.8%	3.8%
6	L50 - QNI++ - NO PNG - TAX	0.8%	0.5%
7	L50 - QNI++ - PNG - NO TAX	0.9%	2.3%
8	L50 - QNI++ - PNG - TAX	0.2%	0.5%
9	M50 - QNI - NO PNG - NO TAX	16.7%	10.9%
10	M50 - QNI - NO PNG - TAX	2.2%	1.5%
11	M50 - QNI - PNG - NO TAX	3.9%	10.1%
12	M50 - QNI - PNG - TAX	0.6%	1.5%
13	M50 - QNI++ - NO PNG - NO TAX	9.0%	5.9%
14	M50 - QNI++ - NO PNG - TAX	1.3%	0.9%
15	M50 - QNI++ - PNG - NO TAX	2.2%	5.6%
16	M50 - QNI++ - PNG - TAX	0.3%	0.8%
17	M10 - QNI - NO PNG - NO TAX	10.3%	6.7%
18	M10 - QNI - NO PNG - TAX	1.2%	0.8%
19	M10 - QNI - PNG - NO TAX	1.9%	4.9%
20	M10 - QNI - PNG - TAX	0.3%	0.7%
21	M10 - QNI++ - NO PNG - NO TAX	5.8%	3.8%
22	M10 - QNI++ - NO PNG - TAX	0.8%	0.5%
23	M10 - QNI++ - PNG - NO TAX	1.1%	2.9%

24	M10 - QNI++ - PNG - TAX	0.2%	0.5%
25	M50++ - QNI - NO PNG - NO TAX	5.2%	3.4%
26	M50++ - QNI - NO PNG - TAX	0.7%	0.4%
27	M50++ - QNI - PNG - NO TAX	1.1%	2.9%
28	M50++ - QNI - PNG - TAX	0.2%	0.4%
29	M50++ - QNI++ - NO PNG - NO TAX	2.6%	1.7%
30	M50++ - QNI++ - NO PNG - TAX	0.4%	0.3%
31	M50++ - QNI++ - PNG - NO TAX	0.6%	1.6%
32	M50++ - QNI++ - PNG - TAX	0.1%	0.3%
33	H50 - QNI - NO PNG - NO TAX	3.1%	2.0%
34	H50 - QNI - NO PNG - TAX	0.5%	0.3%
35	H50 - QNI - PNG - NO TAX	0.8%	2.0%
36	H50 - QNI - PNG - TAX	0.1%	0.3%
37	H50 - QNI++ - NO PNG - NO TAX	1.6%	1.1%
38	H50 - QNI++ - NO PNG - TAX	0.3%	0.2%
39	H50 - QNI++ - PNG - NO TAX	0.5%	1.2%
40	H50 - QNI++ - PNG - TAX	0.1%	0.2%
	Total	**100%**	**100%**

4) CONCLUSIONS

ROAM has been commissioned by Powerlink to conduct a review of previous probabilities of market development scenarios, to be used in Powerlink's revenue reset application. ROAM previously completed the scenario analysis and selection process in September 2005, however with recent developments in the PNG Pipeline development these probabilities have been reviewed to provide an updated platform for Powerlink's revenue reset application analysis.

There have been significant developments in the PNG Gas Pipeline project in the past six months. Australian Gas Light (AGL) has completed a $4.5 billion gas sales agreement for the purchase of 1500 petajoules over 20 years. AGL has also purchased a 10% equity stake in the project for $530 million, an appreciation of $130 million since the previous valuation in July 2005.

The Australian Competition and Consumer Commission (ACCC) has produced a draft decision on joint marketing arrangements for the participants in the project. The decision allows for 16 years of Trade Practices Act immunity against anti-competitive trading, allowing the participants to agree on common terms and pricing for the gas supplied by the pipeline. The Participants had previously stated that without a positive decision from the application the pipeline would not proceed. Whilst the Commission allowed 16 years in its draft decision, it was not prepared to allow the full 30 year life of the project due to uncertainties on the project's benefits beyond the 16 year timeframe.

The project is currently in the Front End Engineering Design (FEED) stage of the development, and is anticipated to reach a sanction decision in the first half of 2006, for financial close by the end of 2006, if applicable.

To allow for a positive sanction decision, it is expected that the PNG Gas pipeline will require at least 150 petajoules per annum of gas sales agreements. There are currently 79.5 – 134 petajoules of conditional contracts, as well as AGL's binding gas sales agreement of 75 – 95 petajoules. Although the initial agreement is for 1500 PJ over 20 years (or 75PJ/annum) AGL could commit a further 20 PJ/annum to the contract with its decision to install a 370MW combined cycle gas turbine at Townsville. The Townsville CCGT is targeting a commission date of 2009 to coincide with the first deliveries of PNG gas. Should the conditional agreements firm to binding gas sales agreements, a total of 154.5 to 229 petajoules per annum will help to provide for a positive sanction decision.

The development of the PNG pipeline is in competition with a number of alternative developments. Coal Seam Methane (CSM) is an increasingly prevalent form of natural gas derived from methane that is stored in the seams of coal mines. The production of CSM is currently relatively low. In Queensland and New South Wales, the two states with the most prevalent levels of CSM, only 31.5 PJ per annum of CSM is produced, plus the equivalent amount to supply a 10MW power station. However, CSM reserves are considerable, approximately 124,000 to 192,000 petajoules of reserves in Queensland and 100,000 petajoules in New South Wales. CSM production has also increased rapidly and is now producing 30% of Queensland's gas demand.

Coal Seam Methane has locational advantages over other more conventional sources of natural gas. CSM wells are by and large located relatively close to existing pipeline infrastructure. The major CSM gas fields are located near to the Sydney and Brisbane markets, and therefore have a cost advantage over other natural gas sources. However, production difficulties exist due to geological instability associated with extracting the methane from the coal seams, and the size of each well is relatively small compared to traditional natural gas wells.

The Timor Sea also has considerable amounts of natural gas, and is the centre of a recently signed agreement between Australia and East Timor ending the political uncertainty surrounding the gas fields of the area. However despite the recent announcement of the Blacktip gas field supplying the Northern Territory's domestic demand from 2009, the majority of the gas from this region is earmarked for liquefied natural gas (LNG) export to Asian customers. This is further affirmed with development of a $1.8 billion LNG plant in Darwin.

ROAM has concluded that a 50% likelihood is appropriate for the PNG Gas Pipeline Scenario. ABARE's supply and demand balance for natural gas indicates a supply shortage from 2012, requiring a minimum of 100 petajoules of supply from a 'Northern' supply source (either PNG or Timor) and CSM supply growing to 100PJ by 2020. Therefore, there is sufficient demand for the PNG Gas pipeline to proceed and for CSM to continue to expand. This is also confirmed in ACIL Tasman's 2004 report. However, given the large capital cost of the project, and the delayed history of the project, combined with competing CSM resources and the difficulties still ahead with securing the conditional agreements, ROAM believes the more conservative 50% probability is appropriate.

If the PNG Gas Scenario does proceed it would have a large bearing on the nature of new generation developed in the state. The probabilities ascribed to the project here therefore relate to the development of associated generation projects in Queensland. Plant such as Spring Gully, which will use coal seam methane as fuel, will become less likely whereas plant such as AGL's announced CCGT at Townsville will become more likely.