DomGas
ALLIANCE

12 August 2008

Committee Secretary
Senate Select Committee on Fuel and Energy
Department of the Senate
PO Box 6100
Parliament House
Canberra ACT 2600

Dear Sir / Madam

The DomGas Alliance is pleased to provide a submission to the Committee's inquiry on the impact of higher petroleum, diesel and gas prices.

The DomGas Alliance

The DomGas Alliance was formed in 2006 in response to serious gas supply shortages and includes current and prospective gas users and gas infrastructure investors. Members include: Alcoa of Australia, Alinta, Dampier Bunbury Pipeline, ERM Power / NewGen Power, Fortescue Metals Group, Horizon Power, Newmont Australia, Synergy Energy, Verve Energy and Windimurra Vanadium.

Alliance members represent the majority of Western Australia's domestic gas consumption and gas transmission capacity, including smaller industrial and household users of gas. The Alliance works closely with the State and Federal Governments to promote competition and supply of gas for industry and households in Western Australia.

The importance of domestic gas supply

Australia is dependent on domestic gas to supply energy, support essential services, fuel industry and supply households. This is particularly the case in Western Australia where natural gas supplies 51% of the State's primary energy and 60% of electricity generation.

As demonstrated by the current Apache Energy emergency, industry is critically dependent on competitively priced gas to sustain operations and to compete in international markets.

Australia's demand for gas will continue to grow. A 2007 study by Economics Consulting Services concluded that Western Australia alone will require around 900 TJ/day of gas in the next 6 years to meet new and replacement demand, including 650 TJ/d of new gas. This is equivalent to the total size of the existing market for gas.

The study identified at least $23 billion in projects currently seeking gas for expansion or new developments. These comprise eight iron ore and nine other developments including alumina, nickel, molybdenum, vanadium, gold and ammonia projects. Failure to secure competitive gas supply could see the loss of 17 large projects involving over 15,000 potential construction jobs, 5000 permanent operating jobs and $9 billion in annual economic output.

Since 2007, expectations of future gas demand have further increased, including in relation to potential development in the State's Mid-west. The Alliance has engaged Economics Consulting Services to complete an updated study of future gas demand, which we will be pleased to provide the Committee once completed.

Rising natural gas prices are impacting Australian industry

Before the Apache Energy emergency, Western Australia was already experiencing a serious gas supply shortage. Current and prospective gas users are unable to secure long term gas supplies in substantial quantity. The price of such short term gas that is available has risen dramatically. Wholesale gas prices have tripled over the past 12-18 months with prices reported for recent gas sales now almost three times Eastern States prices on a delivered basis.

At the same time, oil and gas producers continue to expand exports of LNG, and Australian industry is experiencing increased competition for Australia's scarce energy resources with industry in China, India and Japan.

The domestic gas shortage and rising prices are impacting Australian industry through higher energy costs. This is eroding international competitiveness at a time when industry is already facing significant pressures from escalating labour and material costs, a rising Australian dollar, high interest rates and increased overseas competition.

The experience in Western Australia has consequences for industry in the Eastern States, particularly in the manufacturing, automotive and processing sector. Escalating gas prices in Western Australia reflect a long term strategy of oil and gas producers to increase prices to a notional "international" price based on LNG or international oil prices. This is despite there being no world price for gas with gas prices varying significantly between different countries and regions, and being tightly controlled in many countries, including China.

The development of LNG projects in the Eastern States and LNG pricing for domestic gas will therefore lead to dramatic price increases for manufacturers and industry - by over 300 per cent. This was recognised by a recent report by Commonwealth / State officials which warned:

> "The effects of price competition are already being felt in Western Australia. Gas prices in WA have increased to around double the prices in the Eastern market, where exports of gas are not presently viable."[1]

> "The announcement of two potential LNG terminals using CSM [coal seam methane] has the potential to impact on both supply and price in the Eastern gas market."[2]

A recent presentation by Origin Energy considered that access to international LNG markets is likely to result in significant increases in gas prices.[3] The National Generators Forum have also warned that LNG export developments in Gladstone, Queensland, could potentially double the price of gas in the eastern states from the current $3.50 per gigajoule:

> "We are worried that prices on the eastern seaboard will mirror the far higher export price, as is the case with domestic gas prices in WA, where an LNG export industry already exists."[4]

The Alliance understands that oil and gas producers in the Eastern States have also acted to withhold supply. For instance, the *Sydney Morning Herald* recently reported on Queensland Gas' proposed LNG project at Gladstone and that the company was limiting supply to domestic users to obtain higher LNG prices in the future. This included by shutting down new wells that might otherwise supply Australian industry.[5]

Australia only has limited reserves of natural gas, yet aspires to be the world's second largest LNG exporter

Claims by producers that Australia has "vast" or "over a hundred years" of gas are incorrect. Australia holds just over 2% of the world's natural gas resources, which represents little more than one year of world gas consumption. At the same time, Australia is aspiring to be the world's second largest gas exporter.

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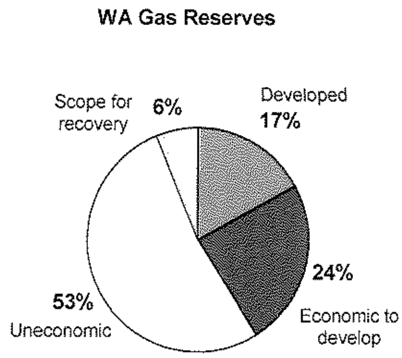
[1] Joint Working Group Report on Natural Gas Supply, p.16.
[2] Joint Working Group Report on Natural Gas Supply, p.9.
[3] Origin Energy, presentation ot Macquarie Conference, May 2008.
[4] 'Gas price under pressure', *The Australian*, 1 July 2008.
[5] 'Queensland Gas looks to high-value LNG', *Sydney Morning Herald*, 6 March 2008, available at: http://business.smh.com.au/queensland-gas-looks-to-highvalue-lng/20080305-1x7t.html?skin=text-only

Approximately 80% of Australia's natural gas resources are located in Western Australia which is estimated to have between 120-140 trillion cubic feet (Tcf) of gas resources. This estimate refers to "P50" resources with only a minimum 50% or higher probability of economic recovery.

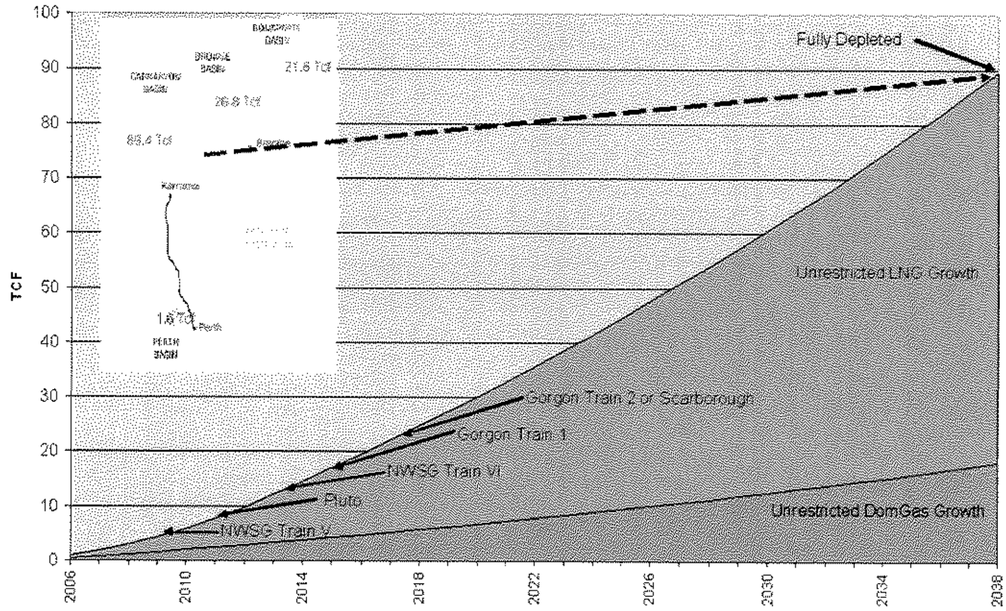
Importantly, only 17% of Western Australia's estimated natural gas resources relate to developed fields. The bulk of resources are located offshore and in deep water; there is no certainty these could commercially be developed. Many of the fields have gas quality issues which impact on development economics and environmental acceptability.



As recognised by the Commonwealth – States Joint Working Group Report on Natural Gas Supply, there are significant barriers to easily accessing and commercialising a significant proportion of Australia's reserves.[6]

The Alliance believes that gas resources in the Carnarvon Basin – which supplies the bulk of Western Australia's gas needs – could be fully depleted within 30 years. In addition, if producer targets for up to 60 million tonnes a year on LNG exports are realized, the bulk of gas will be committed under long term contract between 2015 and 2020. This will put at risk availability of clean energy for Australian industry.

Depletion of Western Australia's LNG resources



[6] Joint Working Group Report on Natural Gas Supply, p.7.

Natural gas must underpin Australia's transition to a low carbon economy

The Alliance believes that natural gas has a critical role in Australia's transition to a low carbon economy. In fact, natural gas is the only conventional energy source that can underpin this transition in the timeframes which are now envisaged.

Natural gas produces less than half the greenhouse emissions compared to coal. Combined cycle gas-fired plants and gas-fired cogeneration plants – utilising current available technology - constitute by far the most greenhouse efficient forms of non-renewable power generation.

Over its life, a new 350 megawatt per hour natural gas combined cycle plant will produce 30 million tonnes of carbon dioxide emissions, compared to 70 million tonnes for an equivalent coal power plant.[7] In terms of annual greenhouse gas emissions avoided, the difference is equivalent to removing 325,000 cars off the road.

Natural gas also underpins the development of greenhouse-friendly gas fired cogeneration plants. Cogeneration plants at alumina refineries in Western Australia for example generate steam which is used in the alumina refining process, as well as electricity for supply into the grid. Cogeneration plants can achieve at least 75% energy efficiency, compared with 30-50% for comparable coal fired generation.

For example, every tonne of alumina produced in Western Australia uses around half the energy and produces half the greenhouse gas emissions than if it was made in China - delivering significant global greenhouse benefits in addition to the greenhouse efficient power for domestic consumption.

Transformation of Australia's generation infrastructure to achieve the new greenhouse targets will require a massive commitment of capital and equipment. This could ultimately be the limiting factor in achieving these objectives.

Given that natural gas generation uses readily available technology, maximising new gas fired generation will limit the pressures on available resources of capital and equipment. Clearly this is dependent on the availability of reasonably priced gas to underpin such investment.

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[7] Simshauser, P. and Wild, P. (2007) 'The WA Power Dilemma', p.23; www.bbpower.com/media/299790/25907%20wa%20energy%20summit.pdf.

Natural gas and the associated gas transmission infrastructure is also critical to underpin any future expansion of renewable energy in Australia. Only natural gas plants can provide the peaking power capacity necessary to support renewable power such as wind and solar, and which makes renewable energy a feasible source of energy for the local market.

There are significant greenhouse risks for Australia

Availability and pricing of gas is, therefore, an issue of great strategic importance for Australia's climate change future. At current price levels in Western Australia, however, natural gas is no longer competitive with coal for base-load power generation and resource processing.

Escalating prices and the shortage of gas has already forced a number of WA resource and energy projects to switch to coal-fired energy. These include:

- the WA Government's recent announcement that it will build a coal-fired plant as opposed to an environmentally friendly gas-fired plant

- the Gindalbie Karara iron ore project; and

- Newmont Asia-Pacific's Boddington gold project

By increasing the cost of clean energy, rising gas prices undermine industry's ability to meet national greenhouse targets and dramatically increase the cost of any emissions trading scheme.

Removing gas from a competitive fuel mix will also lead to higher overall energy costs. Coal prices traditionally shadow gas prices. Rising gas prices will therefore result in higher coal prices - and higher fuel costs for power generation, and electricity costs for industry and households.

In the absence of policies to secure domestic gas supply, an emissions trading scheme would have limited effect in shifting energy use from carbon-intensive coal. The gas shortage and escalating prices will also undermine any State or national plans to increase the proportion of gas fired power generation, such as the Queensland Government's 13% gas fired power target.

Australia therefore faces a future where coal will be the only viable energy source for the bulk of Australia's needs, with or without an emissions trading scheme.

The need to promote competition and diversity of domestic gas supply

Given the importance of gas supply for Australian industry and households, the Alliance supports policies to promote competition and diversity of supply.

In particular, there is a need for State and Federal governments to:

- Strengthen the Retention Lease system to ensure that gas fields that can supply the domestic market are developed and that producers do not withhold supply. Greater transparency in the process is also needed to promote opportunity and third party participation.
- Remove anti-competitive selling arrangements whereby major gas producers currently sell jointly as a cartel to local customers.
- Establish a 2050 national energy security strategy, underpinned by a domestic reservation policy, to ensure competitive long term supply.
- Ensure domestic supply obligations are met.
- Ensure the original intent of the North West Shelf State Agreement is met in relation to new LNG export developments.
- Facilitate common user gas supply infrastructure to reduce project costs and promote development.
- Review tax and royalty arrangements to promote domestic gas exploration and development.
- Encourage and support the development of "tight gas" fields.
- Facilitate and expedite approvals processes for gas exploration and development.
- Eliminate unnecessary government imposts that act as a disincentive to gas exploration and development.
- Ensure that the Federal Government's trade negotiations support, or at the very least not undermine, Australia's long term energy security.

Additional background on these policy recommendations is provided by way of attachment, or by contacting the Alliance's Executive Officer, Gavin Goh. Gavin can be contacted on 0403 310 897 or gavin.goh@dbp.net.au.

The Alliance welcomes the opportunity to assist the Committee in its inquiry, to promote a secure and competitive gas future for Australian consumers.

Yours sincerely

Stuart Hohnen
Chairman

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The DomGas Alliance

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Members include: Alcoa of Australia, Alinta, Dampier Bunbury Pipeline, ERM Power / NewGen Power, Fortescue Metals Group, Horizon Power, Newmont Australia, Synergy Energy, Verve Energy and Windimurra Vanadium.

Alliance members represent the majority of Western Australia's domestic gas consumption and gas transmission capacity, including smaller industrial and household users of gas. The Alliance also represents a significant proportion of prospective demand for additional gas supplies.

The Alliance works closely with the State and Federal Governments to promote competition and supply of gas for industry and households in Western Australia.

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ATTACHMENT: POLICY RESPONSES TO PROMOTE COMPETITION AND DIVERSITY OF GAS SUPPLY

More stringent review of retention leases

Section 38B of the *Petroleum (Submerged Lands) Act 1967 (Cth)* provides for the grant of a Retention Lease over petroleum discoveries. This applies where a petroleum discovery proves to be currently non-commercial but has the potential to become commercial within 15 years.

The initial term of a Retention Lease is five years. This may be renewed provides it still meets the required uncommerciality criteria. A Retention Lease must be converted to a Production Licence when a reserve is commercial. Retention Leases are administered by the Joint Authority comprising both the Commonwealth and the State.

53% of WA's gas reserves are currently held under Retention Leases on the basis that they are uneconomic to develop. Further reserves are held in Exploration Licences which are close to expiry and are due to be converted to either Production Licences or Retention Leases

The Alliance supports more stringent government assessment of Retention Leases to ensure that they are not used by producers to withhold domestic gas supplies. The Commonwealth – State Joint Working Group on gas supply recommended more stringent assessment, and this has been supported by the Federal Resources and Energy Minister.

A review is also underway on how the policy might be applied in the future, including ways to improve transparency in the Retention Lease process, and to ensure that commerciality tests are stringently applied. A copy of the Alliance's submission is **attached**.

The Alliance believes that in the first instance, reserves held under Retention Leases should be assessed to determine whether they are capable of supplying the domestic market on a commercial basis. The Alliance also supports amendment of the administrative guidelines or legislation to further reinforce this expectation.

The Alliance supports greater transparency and disclosure in the retention lease process. There is currently no gazetting system which would make public the substance of a retention lease application, nor is there a formal procedure for third parties to participate. This provides for an asymmetry of information that exclusively benefits existing lease holders.

Greater transparency and disclosure will improve the underlying basis of decisions, encourage third party participation, subject application claims to greater scrutiny, strengthen the application of the commerciality test and promote opportunity and field development.

Remove anti-competitive joint selling arrangements

The North West Shelf Joint Venture producers – which supply almost 70% of the domestic market - currently sell gas to domestic customers through a joint selling entity North West Shelf Gas. This arrangement forces gas consumers to deal with a single entity rather than with individual Joint Venturers. This significantly reduces the number of sellers and, as a result, competition in the domestic market. Gas consumers are prevented by the Trade Practices Act from buying jointly.

The impact of joint selling is further exacerbated by the concentration in gas supply. Two operating entities (North West Shelf and Apache) supply close to 100% of the domestic market and control the developed fields that currently service the WA domestic market. The participants in the North West Shelf Gas Joint Venture hold the vast majority of undeveloped reserves in the Carnarvon Basin. The Synergies Economic Consulting Report recommended removing the joint selling arrangement to promote competition and supply in the domestic gas market.

The Alliance has written to the ACCC calling for a review of the joint selling arrangement. The matter is currently being investigated by the ACCC. In the absence of any authorisation, joint selling appears to be in breach of section 45 and 45A of the *Trade Practices Act 1974* which prohibits arrangements which substantially lessen competition. The Alliance is also concerned about joint selling becoming standing practice in other gas developments. Producers should not maintain selling arrangements that would have or be likely to have the effect of substantially lessening competition.

Review tax and royalty arrangements to promote domestic gas development

The Alliance supports a review of existing taxation and royalty arrangements to provide financial incentives for domestic gas developments. Under the Petroleum Resource Rent Tax (PRRT) which applies to Commonwealth waters, exploration expenditure in areas designated as frontier between 2004 and 2008 are eligible for a 150% uplift. Similar incentives should be considered to encourage inshore and onshore domestic gas developments.

The Alliance also supports mechanisms such as Flow Through Shares and any other arrangements which would lead to increased exploration in the inshore and onshore areas where fields amenable to development for the domestic market are most likely to be discovered.

The Alliance is currently completing a detailed review of tax and royalty arrangements with the view to recommending measures to encourage gas exploration and development for the domestic market. The Alliance will be pleased to provide a copy of the review to the Committee once completed.

Promote common user midstream infrastructure

Third party participation in – and multiple use of - midstream gas supply and processing infrastructure has the potential to facilitate new domestic gas developments by lowering investment barriers and costs.

The Alliance engaged energy consulting firm Wood McKenzie to conduct an analysis of opportunities for common use mid-steam gas gathering and processing facilities. The report concluded that there were significant benefits including lower barriers to entry, a more economically efficient use of capital leading to lower gas supply chain costs and increased transparency in the costs of supply.

Government can facilitate discussions between relevant stakeholders, and by improving transparency and disclosure in the retention lease system. An effective gas reservation policy would also ensure that any consolidation between domestic gas and LNG projects still delivers domestic gas supply. A copy of the Wood McKenzie report and Alliance policy paper is **attached**.

Promote development of onshore tight gas

WA potentially has 9-12 Tcf of 'tight gas' resources in the Perth Basin, located close to existing gas pipeline infrastructure. Tight gas currently accounts for around 30% of total gas production in the United States.

The State Government is examining opportunities to facilitate tight gas development, including by meeting current technology barriers. Alcoa and Latent Petroleum have recently partnered to evaluate and develop WA's first tight gas field – the Warro gas field. The Alliance supports these efforts and the need for the Commonwealth and State to explore financial incentives for tight gas development.

Ensure the original intent of the North West Shelf State Agreement is met with new LNG export developments

The North West Shelf State Agreement is scheduled in the *North West Shelf Gas Development (Woodside) Act 1977.* The Agreement was originally due to expire in 2010, but was extended in 1984 to 2025. The gas reservation commitments under the original agreement have been met by the North West Shelf Gas producers.

Since the initial State Agreement was negotiated in 1979 however, LNG exports from the NWSGJV will have increased by over 150% from the originally envisaged 6.5 million tonnes per annum, with further expansions foreshadowed. By comparison, supply to the domestic market by the NWSGJV has increased only marginally. Domestic users are unable to secure new gas supplies and prices have risen threefold.

Given the State's dependence on the NWSGJV for almost 70% of its domestic gas, and the fact that the JV parties continue to hold the bulk of the State's gas reserves, it is critical that continued expansion of LNG exports be matched by increased commitments to the domestic market.

It is important that the original intention of the Agreement – that of placing priority on the availability of gas to the WA domestic market – be maintained in the ongoing administration of the Agreement. The need for LNG contract extensions – and new developments such as LNG Train 6 mooted by Woodside - may provide the State with the opportunity to pursue further domestic gas supply commitments.

Domestic gas reservation

Claims by producers and government that Australia has abundant reserves of natural gas are incorrect. For an energy intensive economy, Australia holds just over 2% of the world's natural natural gas resources, yet aspires to be the world's second largest exporter of LNG.

Current estimates of natural gas reserves considerably overstate availability by failing to take into account: the practical viability of resources, the rapid expansion of LNG export production, or the contracting out of available resources under long term LNG contracts.

WA's 130 Tcf of estimated natural gas resources refers to resources with only a minimum 50% probability of recovery. Only 17% of WA's resources relate to developed fields. The bulk of resources are currently located deep offshore and have gas quality issues. There is no certainty that it would be economic to develop gas from remote reserves for the domestic market. If government and producer export targets of 50-60 million tonnes per annum of LNG are reached, the total existing resources of the Carnarvon Basin will be fully committed by 2015-2020. Once committed to long term LNG contracts, gas is unavailable to meet current and emerging needs of the local economy.

The Alliance believes that in the face of this, some form of reservations policy is necessary to secure long term domestic gas supply. The Alliance, therefore, supports the efforts of the WA government in this regard. The Alliance also supports the development of a unified State/Commonwealth position on reservations and a national energy security strategy to ensure competitive long term supply.

A report by Curtin University found that governments around the world are acting to ensure long term domestic gas security. Other countries with significant gas reserves are introducing policies to ensure that their domestic requirements are adequately provided for. The report also found that over 90% of world gas reserves are directly or indirectly controlled by national oil companies. Only 8% of world reserves are subject to full access by international oil companies – Australia represents a quarter of these reserves.

Establish a 2050 national energy security policy

The Alliance supports the need for a national energy security strategy to ensure long term competitive supply to local industry and households. A 2050 Vision and Strategy should be developed to ensure supply for the next 50-100 years. This should include three elements:

- Economic – the importance of gas supply for the State's mining, manufacturing and process industries

- Social – recognising the benefits to households and local communities on energy supply and on the prosperity created by downstream industries

- Environmental – the importance of gas supply in Australia's response on climate change

Facilitate and expedite approvals

The current approvals process and stringent demands placed on developments create significant barriers to entry for new players and serve to protect larger incumbent producers.

While efforts have been made in this area, there are opportunities for further streamlining of State and Federal approvals processes for new projects. The Alliance supports a review of existing approvals processes to identify opportunities for further streamlining.

Eliminate unnecessary government imposts

The promotion of a competitive gas market requires the elimination of unnecessary costs throughout the gas supply chain.

The Alliance encourages both State and Federal governments to examine the impact of all policies and regulations impacting on the gas supply chain, with a view to reducing unnecessary costs and inefficiencies.

Ensure the Federal Government's trade negotiations support, or at the very least not undermine, Australia's energy security

The Alliance is concerned that the Federal Government is currently contemplating treaty commitments which would underpin Japan and China's energy supply requirements.

Such commitments – and their implications for domestic law - could limit the ability of State and Federal governments to ensure Australia's energy security. They could also create unsustainable expectations on the part of trading partners, with consequential impacts on the administration of Australia's resource, energy and investment regimes.

It is critical that Australia's Free Trade Agreement negotiations support and not undermine Australia's energy security.

DOMGAS ALLIANCE

PROMOTING DOMESTIC GAS SUPPLY THROUGH COMMON-USE INFRASTRUCTURE

2 April 2008

SUMMARY

- The DomGas Alliance supports measures to increase supply, to reduce costs and to increase competition in the domestic gas market.

- One means of achieving this is by promoting the development of common-use gas supply infrastructure.

- The Alliance engaged energy consulting firm Wood McKenzie to assess the potential benefits of common-use mid-stream gas gathering and processing infrastructure to gas suppliers and end users.

- The Report found significant benefits in developing common-use mid-stream infrastructure. These benefits include:

  - lower barriers to entry for gas suppliers leading to increased competition;

  - a more economically efficient use of capital leading to lower gas supply chain costs; and

  - increased transparency in the costs of supply.

- Two development scenarios in the Carnarvon Basin were examined:

  - three independent developments with their own gas gathering and processing facilities; and

  - one integrated development with common-use infrastructure.

- Wood Mackenzie concluded that common-use infrastructure could reduce capital costs by almost half – with potential savings as high as $1 billion.

- An analysis of gas fields in the Carnarvon Basin found multiple opportunities for integrated development through shared infrastructure.

- Three international case studies of alternative approaches were also examined by the Report - Norway, United Kingdom and the United States Gulf of Mexico

- Wood Mackenzie concluded that the Norwegian experience had been the most successful in terms of the development and success of common-use mid-stream gas supply infrastructure. Key characteristics include:

  - common-use infrastructure owned by a combination of state and gas supplier joint ventures;

  - the infrastructure is regulated and operated on open access principles;

  - the gas supply market is highly competitive with joint venture partners marketing independently; and

  - the terms of access to mid-stream processing and transmission of gas supply is transparent to suppliers and users.

- The Alliance supports the promotion of common-use mid-stream infrastructure to facilitate gas field development provided that any such consolidation of gas field development delivers increased supply to the domestic market.

BACKGROUND

The DomGas Alliance supports measures to increase supply, to reduce costs and to increase competition in the domestic gas market. One means of achieving this is by promoting the development of common-use gas supply infrastructure.

The Alliance engaged energy consulting firm Wood McKenzie to assess the potential benefits of common-use mid-stream gas gathering and processing infrastructure, to gas suppliers and end users.

Current condition

Currently, midstream gas gathering and processing facilities are scaled and built to support individual projects. This has the potential to lead to sub-optimal development with little integration. The likely end result is to increase project costs and make development of some gas fields uneconomic.

A significant component of the total costs of a new offshore development is the cost of midstream gas gathering pipelines – which rise the further gas fields are located from shore - and the associated gas processing facilities.

Shared-use infrastructure could cut project costs by almost half

The Report examined two development scenarios involving the development of gas fields in the Carnarvon Basin with a typical distance of 150 km to shore.

Scenario One: three independent 100 terrajoules / day (TJ/d) developments, each with separate pipelines and processing facilities

Scenario Two: one integrated development utilising one common gathering trunkline and a processing plant of 300 TJ/d capacity

The Report found that by consolidating developments into an integrated development with common-use facilities, capital costs could be reduced by almost half. This could deliver potential savings as high as $1 billion.

	Scenerio One **Integrated System Capex ($m) 300 TJ/d**	**Scenario Two** **Stand Alone Capex ($m) 100 TJ/d x 3 fields**	**Timing**
Pipeline to Shore Costs			
Field A – Initial 100 TJ/d	$555 (150 km x 20")	$445 (150 km x 16")	Year 1
Field B – Subsequent 100 TJ/d	$111 (50 km x 12")	$445 (150 km x 16")	Year 3
Field C – Subsequent 100 TJ/d	$111 (50 km x 12")	$445 (150 km x 16")	Year 5
Gas Processing Costs			
300 TJ/d Plant	$400		Year 1
100 TJ/d Plant		$250 x 3	Years 1, 3, 5
Total Capex	**$1, 177**	**$2,085**	

There are numerous integration opportunities in the Carnarvon Basin

The Report identified the following fields which are likely to be looking primarily at the domestic gas market:

- Reindeer, Caribou, Gnu
- Julimar / Brunello
- West Tryal Rocks
- Maitland
- Spar
- Macedon

Wood Mackenzie acknowledged that Apache Energy's Varanus Island and proposed Devil's Creek project demonstrate good use of common hub facilities. They commented, however, that the Varanus Island facility is currently at near capacity, but could accommodate additional gas post-2014 as John Brookes production starts to decline.

Wood Mackenzie concluded that the following integration opportunities do exist in the Carnarvon Basin:

- Reindeer, Caribou, Gnu and Corvus – planned for development through the proposed Devil's Creek processing plant

- Julimar area, Maitland area and Spar provide the basis for a potential gathering and processing hub (possibly in conjunction with the Devil's Creek development)

- Fields such as Macedon and West Tryal Rocks with high levels of inerts do present difficulties for shared infrastructure, although these are not insurmountable

Wood Mackenzie identified a number of large gas fields with the potential to support stand-alone LNG developments:

- Pluto, Xena
- Greater Gorgon
- Wheatstone, Iago
- Scarborough

In their view the LNG focus and scale made integration unlikely, although they acknowledged that integration of domgas and LNG would likely provide some synergies – particularly in view of domestic gas reservation commitments.

Gas development prospects	Potential for integration
Reindeer / Caribou / Gnu / Corvus	Plans for Devils Creek processing plant
Macedon, West Tryal Rocks	Gas quality issues need to be managed
Julimar area, Maitland area, Spar	Potential gathering and processing hub
Pluto, Greater Gorgon	LNG projects with DomGas commitments
Wheatstone / Iago, Scarborough	Potential stand-alone large gas dvpments

Experience in other markets

Three case studies in international markets were examined by the Report - Norway, United Kingdom and the United States Gulf of Mexico

Wood Mackenzie concluded that third party access to mid-stream infrastructure has resulted in greater gas connectivity and gas flow.

<u>Norway</u>

Norway proved to be the most successful in terms of the development and success of common-use mid-stream gas supply infrastructure. Norway's situation is comparable with WA in that gas must in most instances first come to shore to be processed and then be transported to markets which are typically a long distance away.

Key characteristics of Norway include:

- common-use infrastructure owned by a combination of state and gas supplier joint ventures;
- the infrastructure is regulated and operated on open access principles;
- the gas supply market is highly competitive with joint venture partners required to market independently; and
- the terms of access to mid-stream processing and transmission of gas supply is transparent to suppliers and users.

United Kingdom

In Wood Mackenzie's view the structure which exists in the United Kingdom is less than ideal. In both the United States and the United Kingdom, mid-stream gas infrastructure evolved mainly with arms length negotiations and arrangements are as a result not fully transparent.

Key characteristics of the United Kingdom arrangements include:

- access to infrastructure is not regulated by government bodies and is instead by negotiation between counter parties;

- pipelines have been built as independent systems and gas cannot move between alternative terminals – this reduces security of supply since if one pipe or terminal becomes inoperable, there is no other route to the market for the associated gas;

- security of supply continues to grow as an issue – as the United Kingdom moves from being a net exporter to a net importer; and

- a new Infrastructure Code of Practice will help improve access for new suppliers by providing access to historical and current terms and conditions.

United States

Wood Mackenzie advises that the United States Gulf of Mexico (GOM) midstream sector comprises 23,000 km of off-shore gas pipelines, connecting over 45,000 wells. Capacity of the offshore GOM system is currently 20 bcfd, however, it currently averages only around 9 bcfd.

Key characteristics:

- the United States GOM midstream sector evolved under differing levels of regulation – initially regulated and evolving into completely private owned systems;

- it has evolved into a broadly interconnected system with significant surplus capacity to current gas flows;

- to achieve higher utilization, GOM producers have now made efforts to bring greater transparency into their systems; and

- these efforts have aided connectivity and gas flow in a mature gas basin which would otherwise be facing declining flows on lower utilization of existing infrastructure.

	Norway	United Kingdom	United States Gulf of Mexico
Owners of Midstream Assets	Gassled owns assets JVs by assets mostly producers	Private ownership JVs of mostly producers	Private ownership Producers, pipeline companies, independents
Key Drivers for Development	Exports UK and Europe (98%) Gas to shore, processed, then exported. Zonal system	DomGas (94%) Some exports (6%)	Abundant on-shore industry Unregulated gas price
Regulation of Mid-stream	Gassled regulated by Minister of Petroleum & Energy Open Access Terms	Mild. Dept Trade and Industry grant licences to construct and operate Not open access	None post 1992 Order 636
Role of Government	Initially controlled all sales, now regulates access	Laissez faire	Initially fledged the industry by assuring cost recovery, later deregulated completely
Gas on Gas Competition	Good. JV members must market independently	Excellent. NBP Hub pricing Domgas, Import Pipes & LNG	Excellent. Henry Hub pricing DomGas, Import Pipes & LNG
Transparency	Excellent – regulated and transparent	Modest. 2004 Infrastructure Code of Practice, producers aid in capacity, rates, etc	Moderately so. Over capacity results in mid-stream players dealing
Barriers to entry	Few. Capital and regulated rates of return on facilities	ICOP helps. Declining supplies problematic	Low. Just need supply. Available capacity abundant

DomGas Alliance position

The Alliance supports the promotion of common-use mid-stream gas gathering and gas processing infrastructure to facilitate gas field development.

The Commonwealth and State Governments have a critical role in promoting common use gas supply infrastructure. This can be by:

- Recognising the impact that common user infrastructure can have on field viability when evaluating company submissions in respect to the issue or extension of Retention Leases

- Improving transparency and disclosure in the Retention Lease system to promote opportunities for gas field consolidation by potential developers

- Facilitating discussions between producers, infrastructure operators and gas users on opportunities for common use infrastructure

- Assisting with land access and approvals required to facilitate the development of common user facilities

- Improving competitive outcomes by requiring independent marketing by Joint Venture partners – as in the case of Norway

- Continuing to reinforce the obligations of producers to meet the requirements of the domestic gas market

DOMGAS
ALLIANCE

WESTERN AUSTRALIA'S GAS SUPPLY CRISIS: THE FACTS

August 2008

Is WA experiencing a crisis in domestic gas supply?

Setting aside the current gas supply emergency precipitated by the fire at Apache Energy's processing plant, current and prospective gas users are unable to secure long term gas supplies in substantial quantity. The price of such short term gas that is available has risen dramatically.

What is the impact of the gas shortage?

The shortage is threatening billions of dollars of project developments which are dependent on gas supply for energy. Projects are at risk of going offshore or interstate because of the shortage of gas. A number of projects have been forced to turn to coal-fired power as their only available option. The DomGas Alliance continues to be approached by new project developers unable to secure gas supplies.

What is the value of projects currently seeking gas?

At least $23 billion in projects are currently seeking gas for expansion or new developments. These comprise eight iron ore and nine other developments including alumina, nickel, molybdenum, vanadium, gold and ammonia projects. Failure to secure competitive gas supply could see the loss of 17 large projects involving over 15,000 potential construction jobs, 5000 permanent operating jobs and $9 billion in annual economic output.

How important is domestic gas supply for the WA economy?

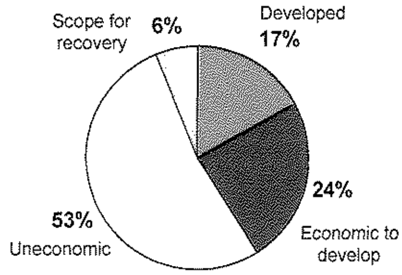
Western Australia is the most energy and gas-dependent economy in Australia. Natural gas supplies half of WA's primary energy requirements. Natural gas also fuels 60% of the State's electricity generation. Access to natural gas is critical for the State's manufacturing, processing and mining industries, which support thousands of jobs.

Is demand for gas expected to grow?

WA's demand for gas continues to grow rapidly. Western Australia will require around 900 TJ/day of gas in the next 6 years to meet new and replacement demand, including 650 TJ/d of new gas. This is equivalent to the total size of the existing market for gas.

Does WA have abundant reserves of gas?

WA Gas Reserves



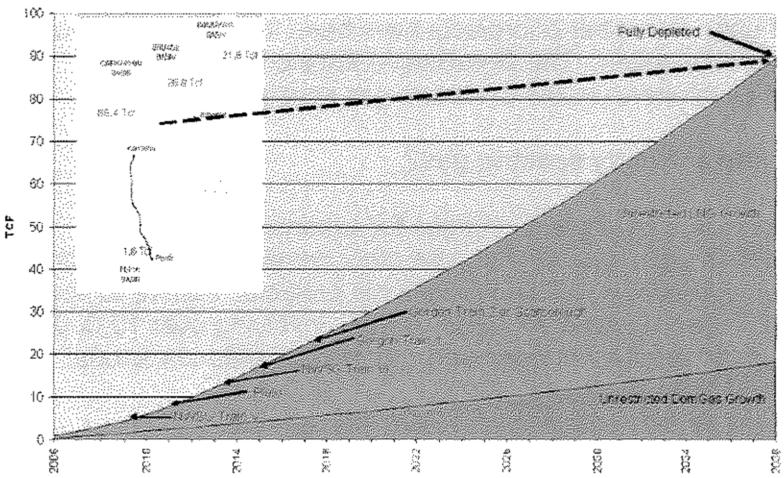
Claims that WA has over 100 years of gas are incorrect. WA only has around 130 Tcf of natural gas reserves – based on a 50% probability of recovery.

Only 17% of WA's reserves relates to developed fields. The bulk of reserves are located offshore and in deep water. Many of the fields have gas quality issues which impact on development economics. There is no certainty that it will be economic to develop all of these gas reserves.

Despite holding just over 2% of world natural gas reserves, Australia aspires to be an "LNG superpower" and the world's second largest gas exporter. The bulk of these resources are located in Western Australia.

When are resources likely to be exhausted?

Western Australia's natural gas resources could be fully depleted within 30 years. In addition, if government and producer export targets of 50-60 million tonnes per annum of LNG are reached, the total existing resources of the Carnarvon Basin will be fully committed by 2015-2020. When gas resources are committed as long term LNG export contracts, they are unable to meet current and emerging needs of the local economy.



Have gas prices risen significantly? How do gas prices compare with the rest of Australia?

According to press reports of recent contracts, WA wholesale gas prices have almost tripled over the past 12-18 months. Prices reported for recent gas sales in WA are now almost three times Eastern States prices on a delivered basis.

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Shouldn't domestic prices reflect international LNG prices?

There is no international price for gas. Gas prices vary significantly between different countries and reflect local conditions such as resource endowments. In fact, domestic gas prices in major gas exporting countries are around $US1 / GJ, compared to around $8 / GJ for LNG export.

At present, some WA users are paying more for WA gas than overseas customers of WA gas. There is no basis for WA domestic gas prices reflecting prices in energy-hungry countries such as Japan and China.

Will gas and electricity prices rise for households and businesses?

Households and businesses face sharply rising gas and electricity prices. Any rise in the price of domestic gas will lead to significantly higher gas prices for WA households and businesses.

Natural gas also fuels 60% of the State's electricity generation. At historical prices, the cost of domestic gas accounts for almost half of base load power generation costs.

In April 2008, the State Government announced domestic electricity charges will rise by 10 per cent in 2009-10 with further annual increases to be phased in over a six to eight-year period. The increase in electricity charges for consumers is due in part to significant increases in the cost of supplying electricity, particularly domestic gas prices.

What is the cause of the current gas crisis?

The gas shortage is caused by fundamental structural failure in the market. There are only two major suppliers with one - the North West Shelf Joint Venture – supplying two-thirds of the total market. This results in a lack of competition and a concentration in supply. Gas producers have focused on maximising LNG exports at the expense of the domestic market.

What is the ownership of the North West Shelf Joint Venture?

The North West Shelf Joint Venture comprises six companies - Shell, BP, Chevron, Woodside, BHPB and Mitsui/Mitsubishi – and includes some of the world's largest oil companies.

How does the North West Shelf Joint Venture sell to WA customers?

The six joint venturers market gas to WA customers through a joint selling arrangement. Under the arrangement, customers have to deal with a single entity and cannot negotiate with individual producers. The arrangement substantially lessens competition by significantly reducing the number of sellers in the domestic market.

How important is natural gas for the State's response to climate change?

Natural gas produces around 45% less CO_2 compared to coal. Gas-fired cogeneration and combined cycle gas turbines are the most greenhouse efficient forms of non-renewable power generation. Natural gas will play a key role in Western Australia's transition to a low carbon economy and will enable the State to meet greenhouse reduction targets while maintaining growth and employment.

Is the gas shortage forcing industry to switch to coal?

At current prices, gas is no longer competitive with coal for baseload power generation and most resource processing. In recent months, a number of resource and energy development projects have been forced to switch to coal-fired energy.

What are the long term greenhouse risks?

At the same time that local industry is switching to coal, gas producers continue to expand exports of WA's clean energy reserves as LNG – a process which is itself energy and greenhouse intensive. This has long term implications for the State's carbon footprint and global greenhouse emissions.

Is government action justified?

Urgent government action is needed to promote gas supply and a more competitive supply market. In particular, the Alliance supports:

- strengthening the retention lease system to ensure that gas fields that can supply the domestic market are developed
- removing anti-competitive joint selling arrangements whereby the North West Shelf Gas producers sell jointly to individual consumers
- ensuring domestic supply obligations are met
- the need for a national energy security strategy, underpinned by a domestic reservation policy, to ensure long term competitive supply for local industry and households
- facilitating common user gas supply infrastructure to reduce project costs and promote development
- supporting domestic gas exploration and development through tax and royalty arrangements
- encouraging the development of "tight gas" fields
- facilitating and expediting approvals
- eliminating unnecessary government imposts

Why shouldn't the market be allowed to correct itself?

There is an absence of a competitive market for gas as a result of the joint selling arrangements of the North West Shelf JV and a concentration in supply. The companies involved in the North West Shelf - either individually or through other joint venture arrangements – control the bulk of the undeveloped reserves in the Carnarvon Basin. Until joint selling is addressed, a competitive gas supply market is unlikely to arise.

Don't recent announcements of studies for new gas developments indicate the market is working?

While recent announcements are welcome, they do not represent potential new production which could come anywhere near meeting Western Australia's requirement for almost 900 TJ/day in new and replacement gas in the next 6 years. Of this, around 650 TJ/day will be required for expansion in electricity generation and new resource development projects.

Is pipeline capacity a constraint on supply? Does Western Australia need a second gas pipeline?

Pipeline capacity is not at issue. The current gas shortage is due to the shortage of domestic gas entering the pipeline, and not the transmission capacity of the pipeline itself.

Since 2005, Dampier Bunbury Pipeline (DBP) have committed $1.8 billion to expanding the pipeline. The pipeline has already been duplicated for about 50% of its length. The Stage 5B Expansion Project recently announced will result in the pipeline being duplicated for close to 80% of its length by mid-2010. Capacity of the pipeline can be increased in less time than it takes to build a major gas using facility, such as a power station or major resource development.

Neither of the gas emergencies in January 2008 or June 2008 related to the Dampier to Bunbury Natural Gas Pipeline. They were instead caused by an electrical fault at the North West Shelf Gas processing plant, and by a fire at Apache Energy's Varanus Island processing plant.

Does the Alliance support a gas reservation policy?

If government and producer export targets of 50-60 million tonnes per annum of LNG are reached, the total existing resources of the Carnarvon Basin will be fully committed by 2015-2020. Once committed to long term LNG contracts, gas is unavailable to meet current and emerging needs of the local economy.

The Alliance believes that in the face of this, some form of reservations policy is necessary to secure long term domestic gas supply. The Alliance therefore supports the efforts of the WA government in this regard. The Alliance also supports the development of a unified State/Commonwealth position on reservations and a national energy security strategy to ensure competitive long term supply.

Is a long term energy security strategy needed?

The Alliance supports the need for a national energy security strategy to ensure long term competitive supply to local industry and households.

A 2050 Vision and Strategy should be developed to ensure supply for the next 50-100 years.

This should include three elements:

- Economic – the importance of gas supply for the State's mining, manufacturing and process industries
- Social – recognising the benefits to households and local communities on energy supply and on the prosperity created by downstream industries
- Environmental – the importance of gas supply in Australia's response on climate change

Who are the DomGas Alliance?

The DomGas Alliance was formed in 2006 in response to serious gas supply shortages and includes current and prospective gas users and gas infrastructure investors.

Members include: Alcoa of Australia, Alinta, Dampier Bunbury Pipeline, ERM Power / NewGen Power, Fortescue Metals Group, Horizon Power, Newmont Australia, Synergy Energy, Verve Energy and Windimurra Vanadium.

Alliance members represent the majority of Western Australia's domestic gas consumption and gas transmission capacity, including smaller industrial and household users of gas. The Alliance also represents a significant proportion of prospective demand for additional gas supplies.

The Alliance works closely with the State and Federal Governments to promote competition and supply of gas for industry and households in Western Australia.

erm power energy solutions

NewGen Power

WINDIMURRA VANADIUM

verve ENERGY

FMG

ALCOA

synergy

DBP Dampier Bunbury Pipeline

HORIZON POWER

Alinta

NEWMONT The Gold Company

REPORT

DomGas Alliance Group

WA Midstream Gathering and Processing Review with Global Analogues

March, 2008

David Bradley / Ian Angell / Andrew McManus
Wood Mackenzie

Strictly Private and Confidential

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March 2008

Wood Mackenzie

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1. Review Study Objectives

The DomGas Alliance's (DGA) goals include increasing gas availability, connectivity and competitiveness for domestic gas end-users in Western Australia. One means of reaching achieving these goals is by enhancing gas resource connectivity and production in the Carnarvon Basin. The DGA seeks to explore opportunities to achieve these goals by encouraging and enabling greater transparency and efficiency in the gathering and processing of gas, which could possibly be facilitated by common use of such mid-stream facilities.

The DGA seek to better understanding international examples of common-use mid-stream gas gathering and processing facilities which have realized these goals of enhanced gas resource connectivity, production and competitiveness in other international gas sectors. The objective of this study is to understand how other regimes have evolved, and what the key criteria have been for enabling efficient, and timely, connection and production of gas resources.

The methodology employed for this study involved:

- Generating concepts to be investigated through an initial framing workshop with the DGA and Wood Mackenzie;
- Examining concepts identified and analogues for common use comparable mid-stream gas gathering and processing facilities globally;
- Understanding the evolution of these systems and the key criteria or events required for them to become utilized by multiple producers;
- Considering and evaluating synergies possible with common use facilities versus stand alone developments;
- Considering the applicability of other regimes to the Carnarvon Basin context;
- Considering jurisdictional, regulatory, and other issues which government and industry might have to address in applying such concepts in WA;
- Undertaking a work-shop with representatives of the DGA to review the analogues and history of other regimes, and to consider and explore related and new business models and legislation which would enable the DGA's goal. Measuring various solutions in terms of do-ability and attractiveness.

In this report, Wood Mackenzie provides a summary of the analysis and insight of other comparable global regimes which enjoy common use gas gathering and processing facilities. International analogues are reviewed including the history of how relevant regimes have evolved, and resulting benefits enjoyed. This report follows a summary slide presentation which was utilized to facility Workshops and summary findings.

2. Global Analogues

In this study, Wood Mackenzie considered internationally mature gas market systems where gathering and processing is undertaken in an open and competitive manner utilizing tolling and common use faculties. Wood Mackenzie's data base and analytical coverage are global. In order to narrow the focus to the most relevant regimes, Wood Mackenzie undertook to identify the three most relevant mid-stream regimes globally. For each of the selected regimes, Wood Mackenzie then undertook to provide a chronology of the regulation and effectiveness of these regimes, as well as the key factors which aided development of these regimes.

A summary is then provided highlighting what has worked and what has not worked to facilitate greater gas flows. In Wood Mackenzie's opinion, the three most relevant regimes are the US Gulf of Mexico, the UK, and Norway.

The follow section reports explore each of these mid-stream regimes:

2.1 Norway

Introduction

The first licensing round was held in 1965 between Norsk Hydro and Elf and six other French companies. At the time, attention was focused on the southern North Sea area, the impetus being the massive Groningen gas discovery in the Netherlands. However, the focus soon shifted to oil and the deeper waters of the central and northern North Sea, upon the discovery of Ekofisk. Ekofisk was developed by Phillips together with Norsk Hydro and the original licensees. The lack of transport opportunities to potential markets in the UK or continental Europe meant that the original production strategy proposed for the field was based on gas flaring. Although this approach was accepted on other continental shelves, the Norwegian authorities were strongly opposed to burning off these resources and began to examine potential landing sites. Gas transport from the Norwegian continental shelf was originally organised in various joint ventures.

From the beginning, Norway saw oil and natural gas as a national asset to be managed carefully. A generally healthy macroeconomic situation and near full employment meant that limiting inflation was a key concern. An additional aim was to ensure the development of a strong domestic industry. Initially there was no state involvement. Statoil, the state owned oil company, was formed in 1972 and held a 50% interest in all production licenses awarded after 1972 until 1993. Since then, and particularly since 1996, there has been a shift towards less state participation in licenses.

The continued growth of Norwegian production led to the signing of several significant sales agreements, such as Troll in 1986. Following this, the Norwegian government established a special Gas Negotiating Committee (GFU). Comprising Statoil, Hydro and Saga Petroleum[1], this body was given the job of co-coordinating sales under long-term contracts to the western European countries. The GFU negotiated contracts irrespective of the source of the gas. The Ministry of Petroleum and Energy then assigned production to fields to deliver the required contract quantities. Companies operating in Norwegian waters were represented on the Gas Supply Committee (FU), who met with the GFU to ensure efficient resource management. The aim was to develop Norway's fields in the most cost efficient basis possible.

The following graphic summarizes the conception of the Norwegian midstream sector:

[1] Saga was acquired by Norsk Hydro in 1999

Wood Mackenzie | Energy

Norway mid-stream sector CONCEPTION

History	First license in 1965 Discovery of Ekofisk by Phillips and Norsk Hydro, oil production became the primary focus and gas was flared suggested Government opposed flaring and producer JV's began to organize gas transportation
Owners of Midstream Assets	Producer JV's State participation came in via Statoil, formed in 1972 holding 50% interest in all production licences
Key Drivers for midstream development	Oil production and Government resistance to producer JV's **suggestions of flaring gas caused push to get gas to markets** Gas sales opportunities were focused on exports to Europe rather than meeting DomGas needs
Regulation	1972 The National Petroleum Directorate NPD is set up to regulate offshore operations 1972 Den Norske Stats Oljeselskap A/S (split to Statoil and Petoro in 2001) saw government receive 50% interest in all production licences – **hence indirect purview & influence** 1978 Responsibility for petroleum matters passes to the new Ministry of Petroleum and Energy Government influence was through requirement to approve production plans
Role of Government	Influence asserted through approvals of production plans Influence asserted through state company ownership in licences

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EVOLUTION:

The following slide summarizes the evolution of the gas mid-stream sector in Norway:

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Norway mid-stream gas sector EVOLUTION to present

Chronology and Changes	1977 / 1978: First gas sales to Germany and UK. Producers negotiated directly with users and developed first trunk-lines 1986: Government formed GFU (Gas Negotiating Committed) to negotiate all export contracts. GFU allocated volume sales to specific fields to supply. • **The government also set up the FU (Gas Supply committee), consisting of the largest owners to met with GFU and ensure efficient cost based resourced management.** 2001 GFU abolished due to European Union competition authority pressure, enabling open access and requiring individual producer equity holder gas marketing. Gassco created in May 2001 to operate and develop existing & future gas pipeline and treatment facilities for all producers
Owners of Midstream Assets	Gathering, processing and transmission facilities originally owned by producer JV's **and some other parties (ex Europipe)** *With 2002 disbanding of GFU, mid-stream assets are now owned by Gassled, and operated independently by Gassco*
Key Drivers for midstream development	Export opportunities to Continental Europe More recently the increasing possibility of supply LNG
Regulation	Initially trunk-lines were built direct to markets on negotiated terms 1986 creation of Gas Negotiating Committee (GFU) saw government allocating where gas would flow Today, Gassled JV provides gas gathering, processing and transmission services under regulated open access principals under Minister of Petroleum and Energy
Role of Government	Formed Gas Negotiating Committed (GFU) to co-ordinate sales contracts to western European countries *Minister of Petroleum and Energy then assigned production to fields to supply contracts* Operating Companies formed Gas Supply Committee (FU) to ensure efficient resource management with GFU

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CURRENT SITUATION:

In June 2001, after sustained pressure from the European Union (EU) competition authorities and the threat of large fines to Statoil and Norsk Hydro, Norway abolished its centralised gas sales organisation (GFU). The European Union aimed to open the European market to competition by giving major gas companies and qualified buyers access to gas transmission and distribution pipelines, stores and liquefaction plants. The directive also specified that natural gas companies and buyers must have access to pipelines in the production system, including landfall pipelines from the NCS. As a member of the associated European Economic Area agreement, Norway was bound to comply. The EU attacked contractual arrangements originally agreed by the GFU on the grounds that they thwarted competition. Individual equity holders in gas-producing fields now have the responsibility for marketing and selling their own gas (Statoil Hydro sells the State's gas).

The break up of the old sales mechanisms led to the development of Gassco in May 2001, which effectively became the operator of the gas network on 1 January 2002. Gassco was established to operate the gas pipeline network and treatment facilities which serve all producers. Gassco's responsibilities can be split into three roles:

- **Operatorship.** As operator, Gassco is responsible for operating the Norwegian gas transport system on behalf of joint ventures/companies (owners).
- **Developing the gas transport system.** This covers Gassco's role in planning future pipelines and transport-related facilities (processing plants and receiving terminals).
- **Allocating infrastructure capacity.** Gassco allocates available capacity at any given time in the pipelines and transport-related facilities.

Regulated infrastructure

The Norwegian upstream pipeline network is the most extensive one in the world. 6600 km of pipelines are available to all producers of gas on the Norwegian continental shelf. Most of this network is now organised in a single ownership structure, Gassled JV, a joint venture between oil and gas companies on the Norwegian continental shelf. The gas flows from about 50 offshore production installations directly to the receiving terminals in Germany, France, Belgium and the UK, or to the onshore processing plants. Operationally, the integrated upstream pipeline network lays the basis for a considerable degree of flexibility. Gas flows from various sources can be optimised in the commingled stream to offer the right quality of Norwegian gas. This is accomplished by coordinating transport in the rich and dry gas pipelines, and in treatment plants and terminals. The flexibility of this infrastructure means that gas production can be varied to optimise oil recovery and the companies' individual gas sales portfolio. The Gassled partnership serves as the formal owner of the Norwegian gas transport infrastructure. It makes suggestions as to development of the network, which the owners then agree upon.

Access to the Gassled transportation system is given on non-discriminatory, objective and clear terms to all natural gas undertakings and eligible customers with a need for transportation. Standard Terms and Conditions apply to all holders of capacity. Gassco also provides an online service to manage booking requests and allocate primary market capacity within the Gassled system. Bookings for monthly and annual capacity requirements are taken twice a year, with short-term capacity available daily. Gassco also operates a secondary, inter-shipper capacity market. It introduced and an open system with tariffs to replace the former closed system. There are five separate tariff areas with an entry-exit principle for allocation, each having corresponding tariffs[2]. This ensures efficient operation of the upstream pipeline network and, in addition, flexibility for the shippers who may change exit or entry points if capacity is available. A government principle is that value creation

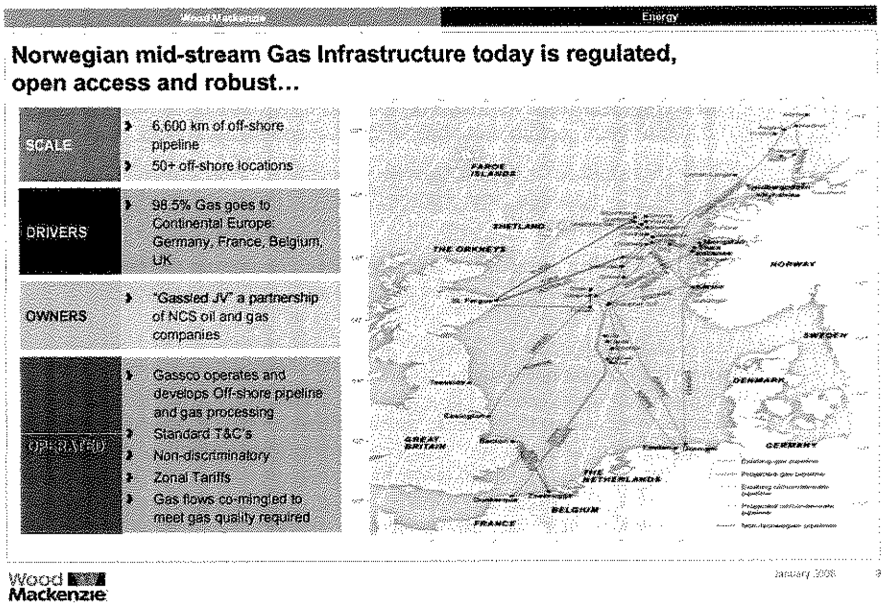
[2] Tariffs for the use of the upstream pipeline network are stipulated by regulation and are available at www.gasviagassled.no

should occur in the field and not in the transportation stage. Therefore transport is thoroughly regulated to prevent pipeline owners from earning an excessive profit through transport operation. The aim is to ensure that appropriate incentives are offered for exploration, field development and marginal production through the provision of regulated transportation costs and equal rights of access.

Non-regulated infrastructure

While the vast majority of the Norwegian pipeline system (particularly the export system) is regulated by Gassco, some additional infrastructure is operated on a joint venture basis. Access to this non-regulated infrastructure is by negotiation, with guidance by the MPE to what it considers as a reasonable rate of return that the owner of the pipeline system should apply.

The following slide summarizes the Norwegian gas infrastructure today:



CONCLUSIONS AND KEY POINT SUMMARY:

- Nearly all Norwegian gas is exported. An extensive pipeline network links Norwegian fields with four key markets. Gas can be transported through the network to different terminals, offering a degree of flexibility and security of supply. However it does mean that there is a greater reliance on certain key junction points than in the UK.
- Diversity of supply has been further increased through the potential to ship LNG to distant markets.
- The pipeline system is tightly regulated by Gassco, a state owned company. The company acts as a neutral provider of access for all companies wishing to use the gas network. Information regarding the network is provided equally to all shippers.
- Tariffs and terms of access are non-discriminatory and are set across the whole network, ensuring an even playing field. However there is little competing infrastructure and nearly no other route to market for gas except via the Gassled system.
- Gas sale contracts are now negotiated directly between the buyer and the field operator and this has served to strengthen the competitive nature of supply.

The following table summarizes the effectiveness of the current Norwegian mid-stream sector in satisfying the objectives of the DGA:

Energy

Summary score card of Norway mid-stream sector structure

Diversity of Supply	50+ producers JV's , 10+ bcfd flowing Can ship to different terminals in Europe Multiple routes to markets – **improves diversity and reliability**
Competitiveness of Supply	Now very competitive. Previously centralized with one negotiator (GFU), but after 2001 was disbanded in lieu of individual equity owner gas marketing Gathering, processing and transmission to markets now at known and common tariffs = a level playing field
Lower threshold for entry of new suppliers	Yes. State now less involved in competing for licenses, allowing increasing diversity of supplier JV's Gathering and processing infrastructure on open access terms
Transparency	Gassco stated goal to work impartially to ensure system access Gassco is a neutral provider allowing common access to infrastructure Tariffs, Terms and Conditions are public and non-discriminatory
Gas on Gas competition	Working well as individual JV parties compete with others to sell into multiple markets Interconnectivity of system can also allows for continuance of gas flow via alternative route when segment constraints exist

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2.2 UK

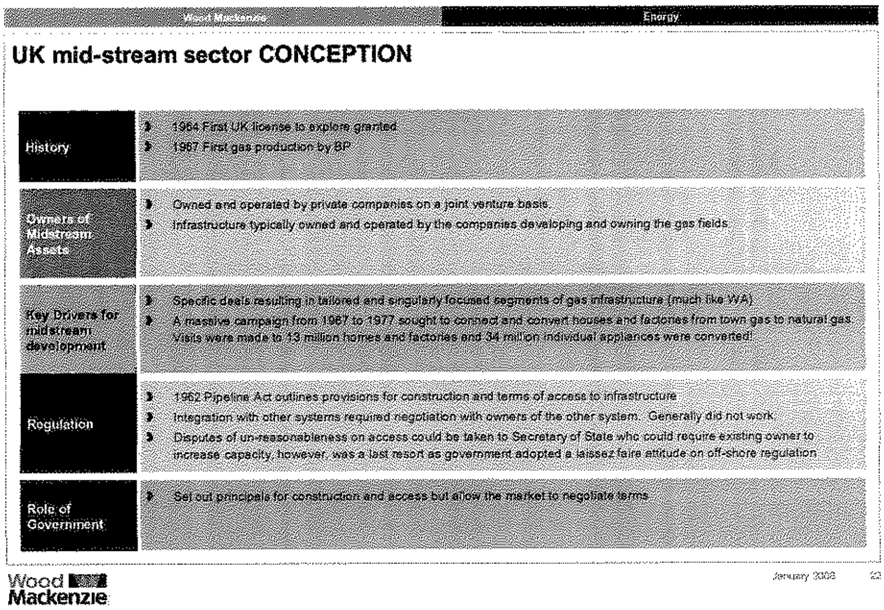
INTRODUCTION

The first licenses on the UK Continental Shelf were granted in 1964. The first gas field to go into production was West Sole in the southern North Sea in 1967, operated by BP. At the time the British government was preoccupied with a crippling balance of payments crisis and adopted a fast depletion policy. This meant that it moved to attract foreign companies and their expertise, with the aim of discovering and developing reserves as quickly as possible. The producers were put under enormous pressure to get oil and gas flowing quickly, with the result that UK production increased rapidly.

Offshore infrastructure (including terminals) in the UK were generally constructed, owned and operated on a joint venture basis by private companies, who in most circumstances were developing offshore natural gas fields. Over the course of the 40 years that the UKCS has been in production, an extensive network of offshore infrastructure has developed to bring natural gas to the beach. Construction of, and terms of access to, infrastructure is regulated by the Pipelines Act 1962. However, since pipeline systems were generally privately owned, licensees wishing to connect new pipelines into existing pipeline systems or to interconnect existing pipeline systems generally needed to negotiate contractual arrangements with the existing pipeline owners. Disputes could be brought before the Secretary of State, who could require an existing pipeline owner to increase capacity within a pipeline and undertake modifications. However this was generally seen as a last resort after negotiations had failed and overall the government adopted a relatively laissez faire attitude towards the regulation of the offshore industry.

The Conservative government of 1979-1997 pursued a policy of privatisation and liberalisation. As a consequence, the Government no longer has the ability to directly control the energy markets. As such, other than having an economic interest in the development of natural gas through the imposition of acreage rental, royalties and certain taxes, the State does not participate directly in natural gas production. The UK no longer has a State petroleum company, and natural gas development is carried out entirely by private companies or foreign State-owned companies under licenses granted by the Secretary of State.

The following slide summarizes the conception of the UK mid-stream sector:



EVOLUTION

Pipeline and terminal facilities

There are four main pipeline systems in the UK that carry natural gas from offshore platforms to coastal landing terminals:

- First, the Shearwater-Elgin Line (SEAL), operated by Total, transports gas from the Shearwater-Elgin area to the landing terminal at Bacton, England.
- Second, ExxonMobil operates the Scottish Area Gas Evacuation (SAGE), which transports associated natural gas from UKGS fields to the landing terminal at St. Fergus, Scotland.
- Third, the Central Area Transmission System (CATS), operated by BP, links fields in the Graben area of the UKCS to Teeside, England.
- Finally, Shell operates the Far North Liquids and Gas System (FLAGS) linking associated gas deposits in the Brent oil system with St. Fergus.

Overall, in the UKCS, there are currently 13 pipeline systems facilitating production export in the Central and Northern North Sea, and 25 pipeline systems serving the Southern Gas Basin and the Irish Sea.

Great Britain has seven main onshore terminals which receive gas from the North Sea and other fields along with imported gas, these terminals are located at: St. Fergus, Easington, Theddlethorpe, Barrow, Bacton, Point of Ayr and Teesside. Gas pipelines have typically been built as discrete lines from offshore fields to the beach (i.e. the landing point at the UK shore). There are no offshore connections between pipelines, and therefore moving gas directly to alternative terminals is not an option at present. Ownership ranges from sole ownership by Total at the Total St Fergus terminal to over 10 owners at Sage St Fergus.

Key import and export infrastructure facilities

- As pipeline infrastructure spread across the Northern Sea, natural gas imports commenced in 1977 from the Norwegian part of the Frigg field in the Northern North Sea. Smaller fields in the vicinity of Frigg were tied in subsequently. Further gas imports commenced in 1985 from the Norwegian part of the Statfjord field.
- In 1992, the UK first commenced gas exports. UK volumes from the Markham field, which straddles the UK/Dutch median line, were transported through Dutch offshore infrastructure into continental markets. Volumes were, however, relatively small.
- Interconnector to Belgium – In early 1992, the Department of Energy brought together BP, British Gas, Conoco, Elf, Norsk Hydro and Statoil to study the idea of a cross-channel natural gas interconnector. It was originally conceived to be solely an export line and became operational in 1998. Import capacity was upgraded to 16.5 bcm in December 2005 and 23.5 bcm in October 2006.
- An export interconnector linking Scotland to Ireland was built in 1993 with an original capacity of 3 bcm, since raised to 6.6 bcm. Rapid demand growth in Ireland led to the construction of a second interconnector in 2002. An additional interconnector linking Scotland to Northern Ireland was constructed in 1996 with a capacity of 1.8 bcm.
- The BBL import pipeline from the Netherlands to the UK came on-stream in December 2006 with a capacity of 15 bcm.

- The Langeled pipeline, came on-stream in October 2007 (second leg) with a capacity of just under 30 bcm. The pipeline links the recently discovered Norwegian field, Ormen Lange, with the Easington terminal.
- Total import capacity is around 100 bcm.

The following summarizes the evolution of the UK midstream sector:

Energy

UK mid-stream gas sector EVOLUTION to present

Chronology and Changes	Private off-shore infrastructure ownership & laissez faire Government policy stymied efficient mid-stream asset integration 1996 Infrastructure Code of Practice introduced as widespread belief that fair and reasonable terms NOT offered 2004 50 producers support Infrastructure Code of Practice (ICOP) to facilitate utilisation of infrastructure on fair terms
Owners of Midstream Assets	Private with owners ranging from one to ten per discreet asset Assets typically developed independently without advantages of integration
Key Drivers for midstream development	Domestic market demand growth – particularly in Residential and Commercial needs Opportunities to export some volumes of gas to Europe (more important recently) 2004 ICOP commitment to fairness and transparency regarded as positive in minimizing cost and time to negotiate access Accessing spare capacity regarded as crucial to produce remaining smaller fields from mature basin
Regulation	Conservative government of 1979 – 1997 further withdrew from energy market control Secretary of State continues to issue licences to private and foreign companies building gas infrastructure The Petroleum Act of 1998 had purview over the construction and operation of offshore infrastructure Terms of the production licence and field development programme have to be approved by the Department of Trade and Industry (DTI), also regulating the operation of offshore infrastructure. Focused on Safety to Build and Operate ...
Role of Government	Laissez Faire Conservative government of 1979 – 1997 further diminished governments involvement and purview

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CURRENT SITUATION

Access to infrastructure is not regulated by government bodies such as Ofgem (the Office of Gas and Electricity Markets) or the DTI (Department of Trade and Industry). Instead, access is by negotiation between counter parties. As a consequence, the UK North Sea has developed with a variety of gas contract types and a complex ownership of reserves and infrastructure. This led to the widespread perception that fair and reasonable terms of access had not always been offered in a timely fashion. In response to this, an initial Infrastructure Code of Practice was introduced in 1996.

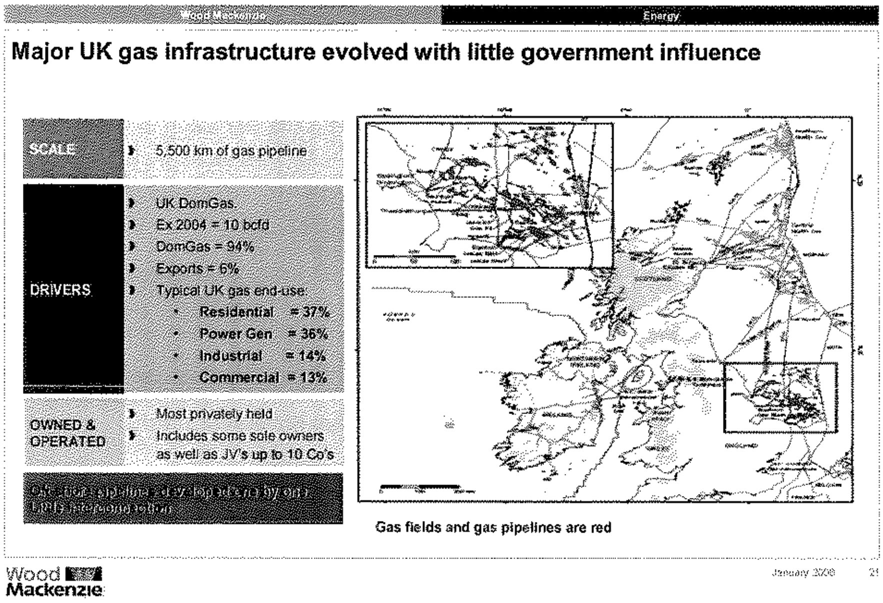
In 2004, over fifty North Sea oil and gas companies pledged their support for the re-launched Infrastructure Code of Practice (ICOP), which was designed to remove one of the prime obstacles believed to be hampering development of new UK oil and gas fields. Its purpose is to facilitate the utilisation of infrastructure for the development of remaining UKCS reserves through agreements for access on fair and reasonable terms, where risks are reflected by rewards. The Code applies to all infrastructure on the UK, Continental Shelf, onshore gas terminals and oil stabilisation facilities. By their endorsement of the Code, parties make a commitment to be guided by its principles and procedures, which aim to:

- Improve guidance
- Demonstrate fairness
- Increase transparency
- Assist in dispute resolution

The results were reviewed in 2006 by the United Kingdom Offshore Operators Association (UKOOA) and the survey confirmed a positive impact in several areas. For example, more high-level information on access, capacity, infrastructure availability, indicative tariffs, service levels and specifications is now available on a centralised website[3]. Additionally, more information on the terms and conditions of recently concluded deals is published. The UKOOA concluded that the code was helping to minimise the costs and time involved in negotiations.

Abiding by the Code should become more and more important as deals become more complex and the range of companies operating on the UK Continental Shelf becomes more diverse. Pooling or making spare capacity available to smaller fields is crucial, particularly when field-dedicated lines are not economically viable (e.g. West of Shetland, where small fields will be unable to support their own infrastructure).

The current UK midstream sector is summarized below:

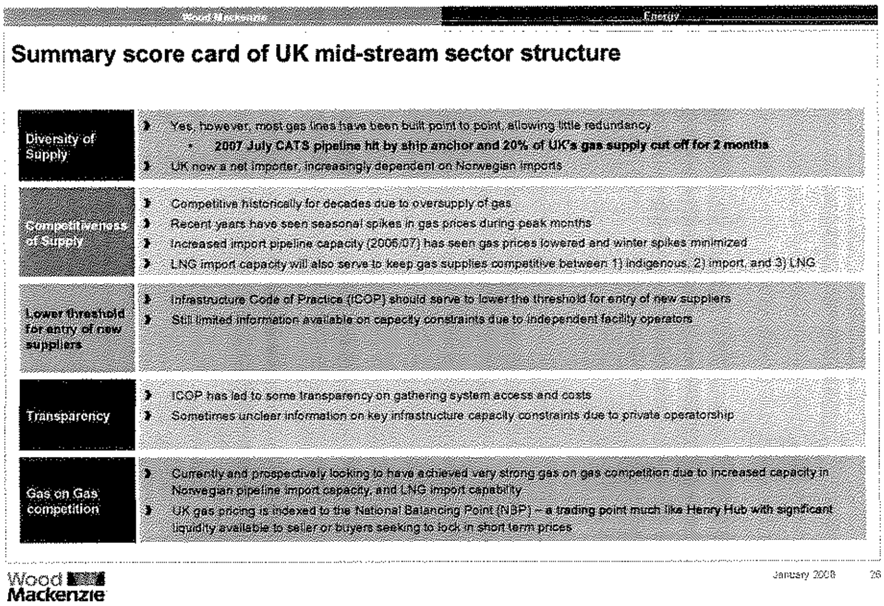


[3] (www.ukdeal.co.uk).

CONCLUSIONS AND KEY POINT SUMMARY:

- ❑ Pipelines have been built as distinct lines, and as such gas cannot move to alternative terminals. This reduces security of supply since if one pipe or terminal goes down, there is no other route to market for the associated gas. For example in July 2007, the CATS pipeline shut after being hit by a ship's anchor. This pipeline system supplies about 20% of the UK's gas to the Teeside terminal. Field operators were unable to get their gas to market for two full months.
- ❑ Security of supply is growing all the time as an issue, as the UK is moving from being a net exporter to a net importer of gas. The UK will become increasingly dependent on Norwegian gas imports. The close vicinity of the UK and Norwegian gas networks means that the potential to tie-in Norwegian to UK infrastructure exists to facilitate imports.
- ❑ The Infrastructure Code of Practice (ICOP) should serve to improve access for new suppliers, since they will now have access to historical and current terms and conditions.
- ❑ While there is an increasing amount of information available in the public domain, there is still significantly less data available than in Norway, for example, with regards to capacity constraints and unplanned outages. This has been a frequent bone of contention with traders in the UK. For example, some terminal operators do not comment on day-to-day problems, leaving those terminal equity owners at an advantage in the market.
- ❑ There has been significant growth in recent years in gas-on-gas competition in the UK, particularly with the development of LNG regasification terminals and the coming on-stream of import pipelines such as the BBL and Langeled.

The current UK mid-stream sector in satisfying the objectives of the DGA:



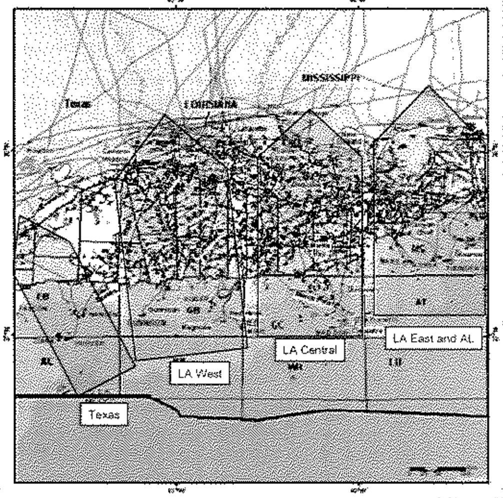
2.3 US Gulf of Mexico

The current US Gulf of Mexico (GOM) midstream sector current comprises 23,000 kilometers of off-shore gas pipelines, connecting over 45,000 wells. Capacity of the off-shore GOM system is currently 20 bcfd, however, averages only approximately 9 bcfd. The following illustration captures the scale, drivers, and ownership structure of the current US GOM gathering systems:

Energy

US Gulf of Mexico (GOM) off-shore gas corridors

SCALE	23,000 km off-shore gas pipes 157 companies operate Capacity to shore 20 bcfd Average throughput to shore 8-9 bcfd 45,000+ wells
DRIVERS	60+ bcfd US market Coastal Petrochem industry etc Coastal gas storage and Hubs
OWNED	48% interstate pipeline owned 5% pipeline affiliates 47% producers
OPERATED	Most off-shore pipelines and on-shore processing operated by owners: pipes and producers



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The US GOM midstream sector evolved under differing levels of regulation; initially highly regulated and evolving into completely private owned systems. The following two tables summarize how the GOM's midstream sector was conceived and evolved to present:

Energy

US GOM mid-stream sector CONCEPTION

History	1940's off-shore gas discovered and production begins 1950's Minerals Management Service (MMS) awards first Outer Continental Shelf (OCS) acreage leases 1970's GOM production peaks at 16 bcfd
Owners of Midstream Assets	Primarily Gas Pipeline companies as they provided a "bundled service" to gas end-use buyers • **End users effectively paid for pipelines and midstream assets to the well-head through regulated gas prices which recovered costs of pipelines as well as cost of gas under different dedication contracts**
Key Drivers for midstream development	WW II drove industry US gas demand substantially, which initially was served from on-shore sources • **1950's opening of Outer Continental Shelf exploration leases** • **Resulted in GOM boom in 1950's and 1960's to fuel on-shore industry and pipeline needs** Producers were incentivised to develop reserves, or not, based on regulated prices within field dedication contracts
Regulation	Federal regulation was heavy from the 1930's for fear of Utility monopoly power. Transmission companies were primary gas buyers and final sales price was regulated, but allowing a rate of return on the pipeline assets • **1935 Federal Trade Commission regulated interstate pipelines** • **1938 Natural Gas Act regulated construction and transportation of natural gas across state lines which included off-shore** State regulation for in-state gas sales and infrastructure – making for a dichotomy of gas pricing as coastal industry grew
Role of Government	Facilitated exploration through allowing leases Controlled delivered costs by regulating pipelines (which also captured the cost to connect to off-shore gas)

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US GOM mid-stream gas sector EVOLUTION to present

Chronology and Changes	1973 Arab oil embargo, rising oil prices, and cold winters drove intrastate spot gas prices to \$5 - \$10/GJ while regulated interstate gas prices remained below \$1.00/GJ. Gas shortage resulted 1978 Natural Gas Policy Act provided for phased deregulation of natural gas between 1979 – 1987 1985 FERC Order 436 caused pipelines to offer transportation services 1992 FERC Order 636 ended pipeline gas retail and de-regulated gas gathering and processing
Owners of Midstream Assets	Ownership shifted from primarily pipelines to primarily producer owned gathering and processing facilities 1990's - some niche mid-stream unregulated "Field Services" companies entered the gathering and processing space The intrastate industry developed (1950s-1970s), and post Order 636 on intrastate side, producers have paid directly for a larger and larger % of G&P services, and obtained more control as a result.
Key Drivers for midstream development	Commercially driven negotiations resulted, rather than "all in the rate base" mentality of previous era Un-regulating mid-stream gathering allowed producers greater control, leading to more timely gas disposition accelerating oil production. Also ended the sometimes unworkable interstate pipeline flow allocations to off-shore producers • **Accelerated the exploration of deeper off continental shelf fields**
Regulation	1992 FERC Order 636 removed interstates from gas wholesale role, and de-regulated mid-stream gathering and processing • **Gathering and Processing unregulated. Commercially negotiated between producers and markets**
Role of Government	Initially allowed pipelines reasonable rates of return on assets yet while controlling consumer prices Over-time the flow on effect of pipeline capacity allocations to upstream producers caused limitations to oil and gas exploration. Activities increased after mid-stream de-regulation.

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The US GOM mid-stream sector has evolved into broadly interconnected system with significant surplus capacity to current gas flows. Much like the UK system which has also entered into a maturity as a gas basin, GOM producers have now have made efforts to bring greater transparency into their systems. These efforts have aided the connectivity and gas flow in a mature gas basin which would otherwise be facing declining flows on lower utilization of existing infrastructure.

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Summary score card of US GOM mid-stream sector structure

Diversity of Supply	Excellent. Includes numerous indigenous sources including conventional and non-conventional, as well as imported piped gas and more recently the re-establishment of four LNG receiving terminals. 5 new LNG terminals to be completed by 2010, and 2 new offshore LNG/gas off-loading buoys.
Competitiveness of Supply	Good gas on gas competition As demand has increased and indigenous supplies tightened, gas prices have risen, attracting LNG and piped imports
Lower threshold for entry of new suppliers	New suppliers can typically negotiate reasonably and promptly access to existing capacity Production in deep Gulf or in areas of no existing infrastructure will have approvals processes similar to Australia
Transparency	Moderately so. Off-shore gathering and on-shore processing facilities are unregulated and many are privately owned Many gathering and processing facility owners offer defined services for known stated fees Declining GOM production likely to result in competition where redundant alternatives exist, possibly lowering costs
Gas on Gas competition	Strong, yet more importantly, gas demand is likely to exceed gas supply in future years resulting in a seller market.

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2.4 Summary of All Three Regimes Reviewed

The following table summarizes all three mid-stream regimes reviewed in context of the key criteria

Energy

Summary of current mid-stream analogues

	Norway	UK	US GOM
Owners of Midstream Assets	Gassled owns assets JV's by assets mostly producers	Private ownership JV's of mostly producers	Private ownership Producers, Pipeline Co's, independents
Key Drivers for Development	Exports UK & Europe (98%) Gas to shore, processed, then exported. Zonal system	DomGas (94%) Some exports (6%)	Abundant on-shore industry Unregulated gas price
Regulation of Mid-stream	Gassled regulated by Minister of Petroleum & Energy Open Access Terms	Mild. Dept Trade and Industry grant licenses to construct and operate. Not open access	None post 1992 Order 636
Role of Government	Initially controlled all sales, now regulates access	Laissez Faire	Initially fledged the industry by assuring cost recovery, later deregulated completely
Gas on Gas Competition	Good. JV members must market independently	Excellent. NBP Hub pricing DomGas, Import Pipes, & LNG	Excellent. Henry Hub pricing DomGas, Import Pipes, & LNG
Transparency	Excellent – regulated and transparent	Modest. 2004 Infrastructure Code of Practice, producers aid in capacity, rates etc.	Moderately so. Over capacity results in mid-stream players dealing
Barriers to entry	Few. Capital and regulated rates of return on facilities	ICOP helps. Declining supplies problematic	Low. Just need supply. Available capacity abundant

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3. Common Use Economics

This section explores the advantages which may be realized if off-shore gathering and processing facilities were built in a more integrated manner rather than in the traditional piece meal manner. It was important that the scenarios modeled by realistic to the Carnarvon basin. The DomGas Alliance Group was consulted on the volume and distance assumptions that should be considered. Contemporary Australian oil and gas analogues were then utilized to aid in the cost estimation of the various identified scenarios.

3.1 Size of Gas WA Gas Market

To determine the most relevant size of off-shore and gathering developments to be estimated and modeled, a realistic view of the size of the available gas market was needed. Towards this end, Wood Mackenzie and Energy Consulting Services estimates are summarized in the following graphic:

Energy

Common Use Metrics – What are appropriate considerations?...
1) Size of DomGas market...

- DomGas market available for new gas supplies

	Conservative	ECS
1. Current pent up demand (TJ/d 2007)	200	648
2. Market growth (TJ/d/a 2008 on)	50	
3. Contract expiration (50 TJ/d/a post 2012?)	50	245
Estimates of unsatisfied demand by 2013 TJ/d	600	893
+Annual Gas demand needs (Market growth + Contract expiration)	+100 TJ/d/a	+150 TJ/d/a

- Conclusion: Gathering and processing facilities of at least 300 mmcfd capacity are needed now followed by annual additions of 100 mmcfd/a
- Recommended Analysis – **Illustrate Capital Efficiency possible for:**
  - Three unique field developments (3 x 100 mmcfd), versus:
  - One initially oversized pipeline and processing plant (1 x 300 mmcfd), followed by two subsequent field tie-ins

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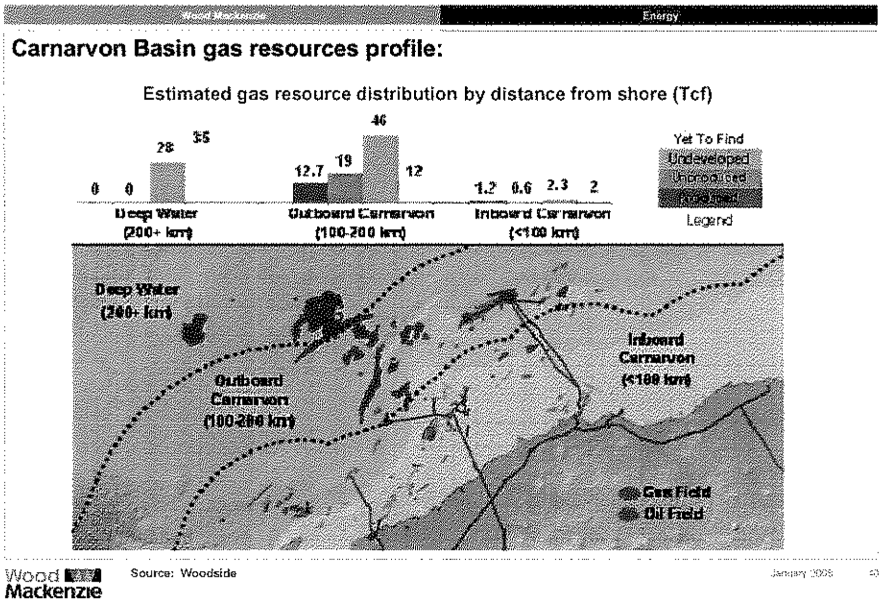
As a result of the above analysis, it was determined that gathering and processing facilities in the future will likely be needed on the scale of 100 TJ/d. Accordingly, our analysis sought to examine the synergies of building three separate 100 TJ/d gathering lines and processing plants, as opposed to one 300 TJ/d gathering trunk and processing plant.

3.2 Carnarvon Basin Gas Resource Distance to Shore

The distance to shore of the potential gas fields is important in order to estimate the likely gathering pipeline costs – which comprise a significant portion of the total project cost. The following graphic sourced from the DomGas Alliance Group and Woodside, summarizes the size and distance to shore of typical Carnarvon Basin gas fields.



In considering the typical gas field distance to shore in the Carnarvon basin, it was determined that our analysis would be based upon gas resources which were 150 km from shore. The agreed reasonable and representative analysis would therefore look at two opposing development scenarios:

1) Three x 100 mmcfd developments;
   a. 3 x 150 km trunklines, and
   b. 3 x 100 mmcfd processing plants
2) One 300 mmcfd trunkline and processing plant;
   a. 1 x 150 km, 300 mmcfd trunkline
   b. 2 x 50 mmcfd, 100 mmcfd subsequent trunklines (tied in off-shore)
   c. 1 x 300 mmcfd on-shore processing plant

3.3 An Example Estimated Synergies Possible

The following table captures Wood Mackenzie's capital estimates of the two opposed development scenarios considered, i.e. three independent 100 mmcfd developments from 150 km off-shore, as well as one integrated development utilizing one common gathering trunkline and processing plant of 300 mmcfd capacity.

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Example of synergies which could exist...

	Integrated System Capex (A$mill) 300 mmcfd	Stand Alone (Bits and Pieces!) Capex (A$mill) 100 mmcfd x 3 fields	Comments / Timing
Pipeline to Shore Costs:			
Field A – Initial 100 mmcfd	$ 555 (150 km x 20")	$ 445 (150 km x 16")	Year 1
Field B - Subsequent 100 mmcfd	$ 111 (50 km x 12")	$ 445 (150 km x 16")	Year 3
Field C - Subsequent 100 mmcfd	$ 111 (50 km x 12")	$ 445 (150 km x 16")	Year 5
Gas Processing Costs:			
300 mmcfd Plant	$ 400		Year 1
100 mmcfd Plant		$ 250 x 3	Year 1, 3, 5
Total Capex	$ 1,177	$2,085	

Consolidating projects could potentially cut capital costs nearly in half!
Timing and Gas Quality are critical considerations...

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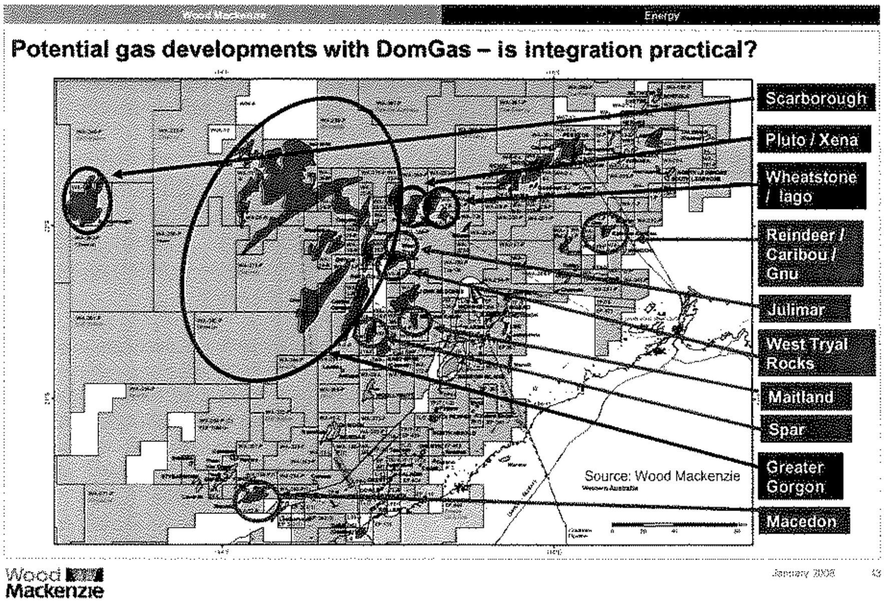
The conclusion of this hypothetical analysis was that by consolidating three independent developments of 100 mmcfd capacity into on common 300 mmcfd group of facilities, total capital savings could potentially be cut nearly in half.

Obviously, any realistic effort to combine different gas fields into common facilities would have to consider other pragmatic issues such as gas quality and operators intended timing to commercialize the resource. For example, gas fields comprising high condensate "sweet" gas could not practically be commingled with high CO_2 or H_2S gas (sour) fields. However, it is Wood Mackenzie's strong view that, in many cases, common facilities in the Carnarvon Basin could be utilized to gather and process gas, as has occurred on Varanus Island.

3.4 Potential Carnarvon Basin Field Consolidation

As can be seen in the following graphic, many of the known gas fields in the Carnarvon Basin are large enough and unique enough that they will necessarily should be developed independently of other fields – those fields are highlighted in blue on the following illustration.



Some integration opportunities do exist in the Carnarvon Basin and were identified as follows:

Known Gas Development Prospects	Potential for integration
Reindeer / Caribou / Gnu / Corvus	Plans for Devils Creek processing plant
Macedon, West Tryal Rocks	Gas quality issues
Julimar area, Maitland area, Spar	Potential gathering and processing hub
Pluto, Greater Gorgon	LNG Projects with DomGas commitments
Wheatstone / Iago, Scarborough	Potential stand-alone large gas developments

In summary, there are multiple fields that lend themselves to integrated development through shared infrastructure, such as Reindeer area, Julimar area, and Maitland /Spare areas. Some fields have clearly differing gas quality issues which will make for difficulties in sharing common infrastructure such as Macedon and West Tryal Rocks.

Integration of DomGas and LNG would likely provide some synergies, as well as challenges. Specifically, utilizing common facilities would usually realize economies of scale synergies, however, the pragmatics of administering differing tax and accounting treatment for a commingled stream may complicate matters. Furthermore, integrating fields into common facilities which have two differing potential sales markets may result in related gas suppliers seeking to sell only to the higher of the two markets. Additionally, commingling of gas streams for common gathering and processing would likely create challenges in scheduling and allocation of capacity in the event of curtailments. Finally, in the event of interruption of gas flow, the potential consequences (for example liquidated damages) may be vastly different between DomGas sales versus LNG sales.

4. Summary and Conclusions

From the analysis of the three global analogue regimes chosen, several conclusions can be made which are of some relevance to Western Australia as summarized below:

Midstream third party access: Third party access to mid-stream (gathering and processing) infrastructure has resulted in greater gas connectivity and gas flow. This is evidenced by Norway's regime where mid-stream regulation requiring open access terms now provides a flexible network with cost transparency. Norway's regime also seems to fit will with WA as the gas must in most instances first come to shore to be processed and then travel to markets which are typically a long distance away.

Midstream systems requiring negotiation with private owners are not ideal: The US and UK examples show that gas mid-stream infrastructure evolved mainly with arms length negotiations, and are not fully transparent. In the UK and US, transparency has resulted only after the regional area became very mature and the gathering assets were facing the prospects of declining use. Note both the US and the UK mid-stream sectors have capacities in excess of 10 bcfd. Western Australia currently sees off-shore gas flows of approximately 3 bcfd, arguably still a fledging production area. The following table summarized what was relevant for WA from the mid-stream analogue review:

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Summary and Conclusions of mid-stream analogue review

What was relevant for WA?

Ownership	Mid-stream assets today, globally, are privately owned, mostly by producers & pipeline companies
Drivers for Growth in Mid-stream assets	Large markets! DomGas or Exports
Regulation	Only Norway's mid-stream remains regulated today requiring Open Access. UK and US mid-stream are now unencumbered by access regulation, however, both are in an over capacity situation with declining reserves. US and UK producers are therefore motivated to make capacity available to third parties
Role of government	All governments studied effectively controlled or regulated the mid-stream sector by one means or another in the early days. Once, markets were well established, deregulation or laissez faire regulation evolved. Is WA arguably in early days?
Gas on Gas competition	Strong in all markets – Hubs are a good bell-weather! Norway aids competition further by requiring independent marketing of JV members. Is Norway an appropriate model for WA?
Transparency	Government can create initially (via regulation and open access provisions), once surplus capacity exist (ex UK and US), then producers are motivated to organize and market their surplus capacities.

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Independent gas marketing within JV groups also appears to enhance gas flow: This has been the requirement in Norway, which is arguably the world most exemplary gathering regime if measured by the DomGas Alliance Groups objective criteria.

Integration opportunities do exist in the Carnarvon Basin: This study identified and mapped numerous examples where known gas fields have or will prospectively provide synergies. Integration opportunities are described in Section 3.4. In summary, the Reindeer, Julimar and Maitland/Spar areas could be synergistically combined. It should be acknowledged that Apache Energy's Varanus Island and proposed Devil's Creek project demonstrate good use of common hub facilities. The Varanus Island facility is near its capacity today, however, could likely accommodate additional gas post 2014 as John Brookes starts to decline.

Integration of DomGas and LNG would provide synergies: Gathering and processing synergies could obviously result if projects were combined, however, some challenges would result. Accounting and taxation treatments can differ depending on the location of the gas field and the ultimate market for the gas. These differences should be investigated and if possible aligned to ensure that producers are equally motivated from a tax treatment perspective.