# Browse LNG Precinct

GOVERNMENT OF
WESTERN AUSTRALIA





Browse Liquefied Natural Gas Precinct
Strategic Assessment Report

(Draft for Public Review)
December 2010

# Appendix B-1

## Browse Basin Gas Technical Report Development Options Study
## Reports 1-3

Copy No.

# BROWSE BASIN GAS TECHNICAL REPORT
# DEVELOPMENT OPTIONS STUDY

## REPORT 1 of 3
## LNG PLANT SITE SELECTION VALIDATION

Prepared for

**THE NORTHERN DEVELOPMENT TASKFORCE**

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## INTRODUCTION

The Browse Basin, offshore of north-west Western Australia, holds substantial resources of natural gas. At the date of this report, there is no hydrocarbons production from the Basin and there are no hydrocarbons based projects that are either under construction or approved for construction. However, two of the Basin joint ventures, one operated by Woodside Energy Limited (Woodside), and the other by INPEX Browse Ltd (INPEX), are planning to use their known gas resources for "greenfields" land based Liquefied Natural Gas (LNG) projects[1] (**Figure 1**).

The two projects are based on total gas resources of approximately 27 Trillion cubic feet (Tcf). While some of these resources were discovered over thirty years ago, the basin is "gas prone" and has been relatively lightly explored. The level of exploration activity has increased in recent years and it is likely that other companies currently active in the area will eventually propose LNG projects using Browse Basin gas.

From a technical perspective, the "logical" sites for a land based LNG plant to receive, process and export Browse Basin gas are on the Northern and Southern Kimberley coast or on one of the islands off the coast **(Figure 2)**. The North Kimberley area is totally undeveloped, has no infrastructure and is an eco-tourist destination. The South Kimberley has some development (Broome and Derby), has minimal infrastructure and has several tourist destinations (Broome and Cape Leveque).

At the time of this report, both the Woodside and INPEX operated Joint Ventures have conceptualised their respective projects on a "stand alone" basis and have evaluated potential LNG processing sites on the basis of the individual requirements of those projects. Woodside has prepared a shortlist of several potential sites and INPEX has chosen the Maret Islands as its preferred site. Forecast total LNG production from the two projects is in the order of 20 to 25 Mtpa.

The Kimberley Northern Development Taskforce (Taskforce) is an inter-departmental body formed by the Government of Western Australia. The Project Manager is Mr. Gary Simmons from DoIR. The taskforce has been engaged to set the framework by which the State will protect and manage the important heritage, environment and tourism values of the Kimberley area while facilitating structured industrial development. The West Kimberley Subdivision of the Taskforce was established to manage across-government planning processes and stakeholder consultation in regard to selection and development of a suitable location or locations for the processing of Browse Basin gas reserves.

The Taskforce, through DoIR, has retained Gaffney, Cline & Associates (GCA) to provide independent advice on technical issues associated with the selection and development of onshore and offshore locations, for the processing of the Browse Basin gas. This advice is to be in the form of a report titled "Browse Basin Development Options Study" (The Study).

[1] During the course of the study Shell Development (Australia), (Shell) announced that it plans to develop the Prelude field, in the Browse Basin, using a floating LNG facility (FLNG) with no onshore processing facilities. The proposed development is described briefly in Section 2.4. Since it will not use an onshore processing hub it is not considered in the report

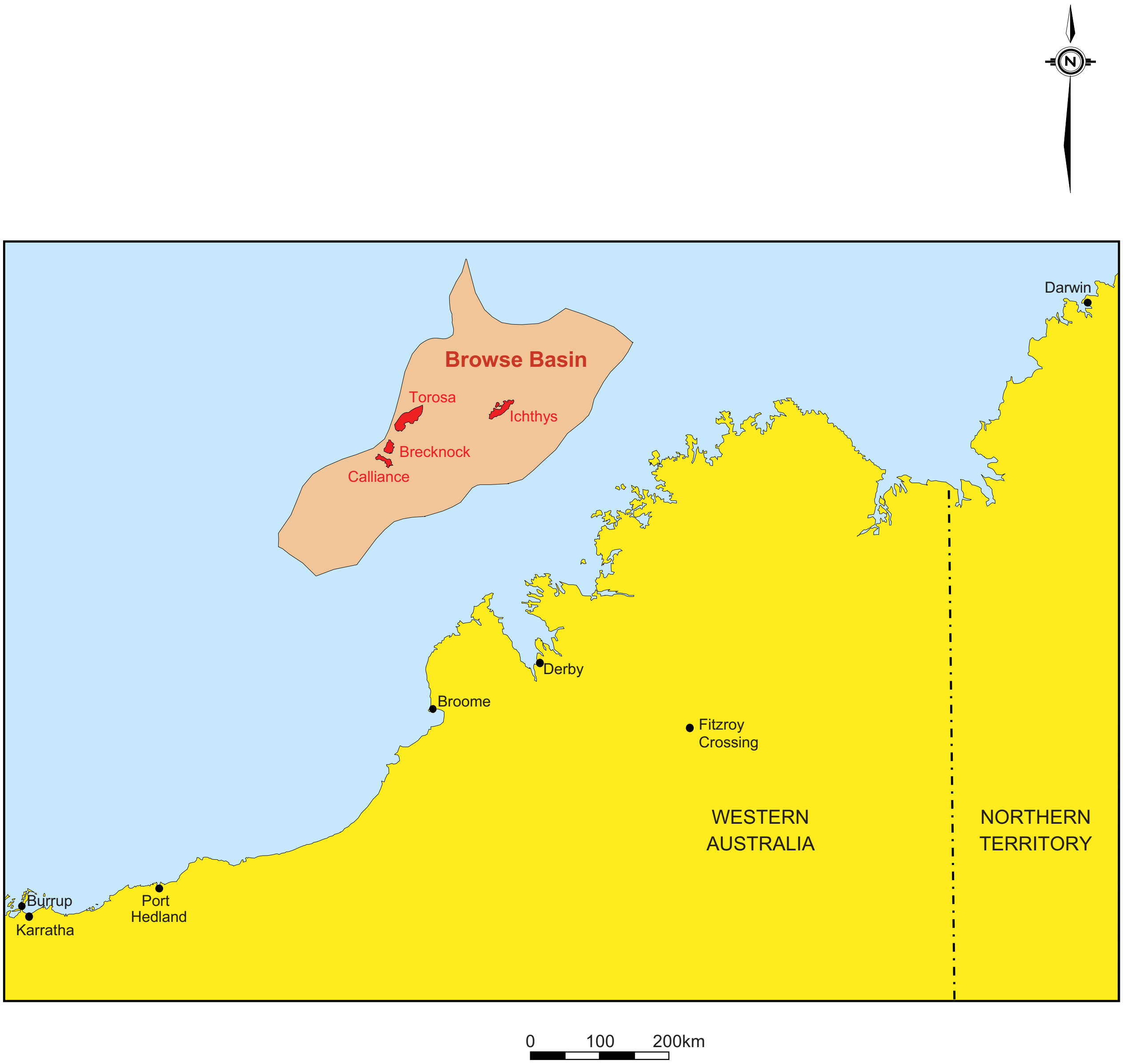
The objective of the Study is to review specific technical and economic issues surrounding the processing of existing and yet to be discovered resources at a common LNG plant location or hub. The study has been undertaken in three parts as follows:-

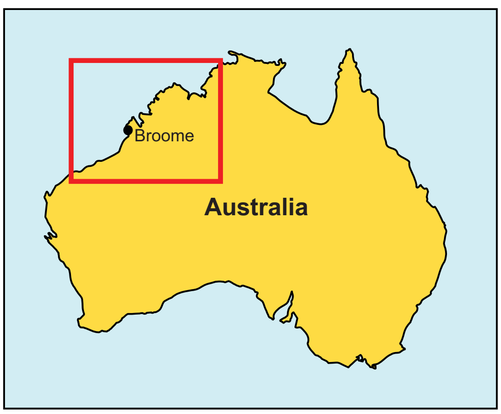
1. Review the existing site selection processes undertaken by Woodside and INPEX and provide commentary on the technical suitability of the sites considered to date in the context of a gas processing hub.

2. Consider and evaluate the key technical issues governing the offshore facilities required to develop Browse Basin Gas in the context of a gas processing hub.

3. Review the potential for an onshore infrastructure hub to support Browse Basin gas development and comment on the key technical, commercial and economic issues surrounding the co-location of the gas processing infrastructure at an onshore infrastructure hub.

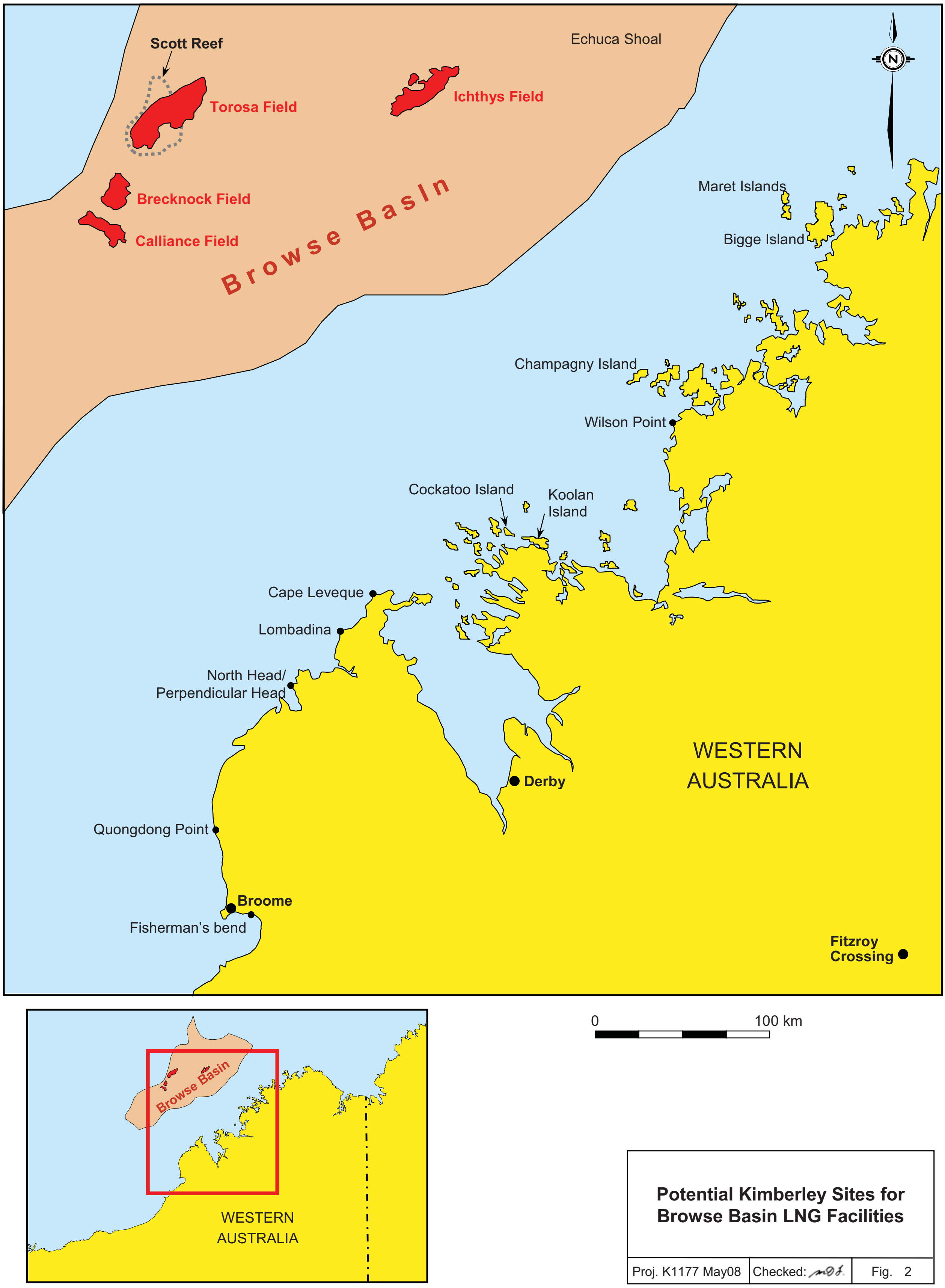
Separate reports will be prepared for each of the three areas of review outlined above. This, the first report, covers the site selection and suitability for an LNG hub, based on the information made available to GCA by DoIR, Woodside and INPEX. The full scope of work for this first report is shown in **Appendix I**.




**Browse Basin**
**Location Map**

| Proj. K1177 May08 | Checked: | Fig. 1 |
|---|---|---|




**Potential Kimberley Sites for Browse Basin LNG Facilities**

| | | |
|---|---|---|
| Proj. K1177 May08 | Checked: | Fig. 2 |

DOIR

## CONCLUSIONS

The scope of work provided for this study by DoIR lists a number of very specific points to be addressed. This has been done in detail in the relevant sections in the body of the report. GCA's "high level" conclusions and recommendations are summarised as follows:-

1. The site selection technical factors suggested by the industry for screening LNG sites are considered appropriate and comprehensive. Seismicity is an additional factor that could be used to further discriminate between sites in the Southern Kimberley and sites in the seismically less active Northern Kimberley.

2. Woodside has adopted a qualitative approach to evaluate potential sites against technical and non technical criteria. While Woodside's technical analyses are valid, more quantitative analysis is required to rank the potential sites.

3. INPEX adopted a quantitative approach to evaluate eleven potential sites against a range of technical and non technical criteria. .

4. INPEX and Woodside have evaluated the potential sites for a "stand alone" LNG development, requiring a maximum of ~300 hectares of available area. Generally, they have expressed their preference for sites closest to their respective fields.

5. GCA's remit was to consider site selection in the context of an LNG Hub. To undertake this assessment GCA has considered three Hub concepts for evaluation:-

    i. A **Single Operator LNG Hub** with up to 5 LNG trains that could be accommodated on a site of 360 hectares.

    ii. A **Multi Operator LNG Hub** with up to 10 LNG trains that could be accommodated on a site of 660 hectares.

    iii. A **Gas Processing Hub** which provides for a multi operator LNG Hub and several large scale Gas to Liquids (GTL) plants. This will require a minimum of 950 hectares.

    The three concepts provide the basis for "bracketing" the site area and marine requirements to be considered for evaluating options for a hub to process Browse basin gas. GCA is not advocating any particular concept, and there are many other valid hub configurations that could fit within the site areas defined above.

6. Of the indicative list of sites considered, locations that could accommodate a Gas Processing Hub, with over 950 hectares of technically suitable land with a manageable marine environment, are:

    i. **Northern Kimberley**:- Bigge Island, Wilson Point

    ii. **Southern Kimberley**:- Cape Leveque, North Head / Perpendicular Head, Lombadina (Packer Island), Quondong point and Fisherman's Bend.

    Of these sites, Wilson Point has the most favourable marine conditions.

7. While Scott Reef and Echuca Shoals are theoretically technically suitable for a Gas Processing Hub, there are too many technical "firsts" associated with their development to recommend either of them as the lynchpin for future production of the Browse Basin gas resources.

8. It is technically feasible to pipe Browse Basin gas to existing LNG Hubs at either Darwin or Burrup.

9. A firm and consistent vision of the hub does not yet exist amongst the stakeholders consulted by GCA. This needs to be addressed before the concept can be further progressed.

10. To progress technical analysis of site suitability for a hub development “pooling” of available information held by individual stakeholders supplemented by additional “on site” topographical, marine and geotechnical evaluation will be required.

It is noted that GCA’s scope of work covered only the technical aspects of the hub site selection. The conclusions above have not taken into account any of the socio-economic aspects of a hub selection including those arising from land ownership and environmental considerations.

# 1. SUMMARY

## 1.1 Study Methodology

Over the three weeks to 4th March, GCA project personnel met with representatives from the Northern Development Taskforce and representatives from the following companies:- Woodside Energy Limited, Shell Development Australia, INPEX, BHP Billiton Limited and Conoco-Phillips. GCA also met with the operator of the Cockatoo Island mine, Portman Iron Ore Ltd.

At the meetings, and subsequent to the meetings, Woodside and INPEX provided GCA with documentation pertinent to their stand alone projects. Use of the data by GCA was covered by normal industry confidentiality agreements.

Subsequent to these meetings the GCA study team convened in Singapore to analyse the data provided in the light of its own LNG experience and to prepare this report. Team members included personnel with extensive first hand experience at PT Arun, Ras Laffan, Sakhalin and Angola LNG. One of the team members also has an ongoing role in the planning of Angola's first LNG hub.

The evaluations conducted in this report are based on the expertise of the Team Members involved, leveraging public information and tools (including SRTM maps incorporated in the Google Earth® software), as well as the information provided by Browse basin tenement holders. Thompson Clarke Shipping (TCS) were retained by GCA to provide advice on the marine aspects of the study.

No site visits were undertaken and all estimation work has been done at a very high level, mostly by analogy.

## 1.2 Site Evaluation for Stand Alone LNG Projects

DoIR have requested the review of site selection processes used by Woodside and INPEX and to include the following aspects of site evaluation in this report:-

- Port suitability including metocean and offloading.
- Land Area requirements
- Site elevation and gradient
- Proximity to gas fields
- Distance to navigable waters
- Proximity of site to the coastline
- Pipeline approach
- Geotechnical conditions
- Proximity to existing infrastructure

GCA has reviewed all sites considered technically suitable by Woodside and INPEX against these criteria together with additional sites listed in the scope of work or subsequently requested for evaluation by DoIR (**Appendix I**).

GCA has not sought to identify and evaluate every site that shows promise of technical suitability as an LNG hub. The list of sites reviewed in this study should be considered as representative of potential Kimberley LNG hub sites.

While somewhat different approaches have been used by Woodside and INPEX (**Section 2.1**), their site evaluations have been conducted in a professional and logical manner, based on environmental, socio-economic and technical aspects. While there was considerable variation in the mix of qualitative and quantitative data available, it is considered that both operators incorporated the DoIR technical factors listed above into their evaluations. The variation in the outcomes of both evaluations appears to be due to the initial selection of sites, the significant influence of the distance to each operator's fields and different assessments of certain criteria, such as land area requirements and LNG carrier navigation.

However, GCA considers that the approach and criteria used by both Browse Basin operators for the technical evaluation of potential sites for stand alone LNG facilities are appropriate. GCA made an independent assessment for the different sites considered for two general technical factors: (1) port availability and navigability, which included water depth, current, wind speed, tides, wave height and general navigability, and (2) land availability and suitability which included topography, elevated areas, site gradient and soil or rock types.

The assessments made by Woodside and Inpex for these technical factors were then compared to those made by GCA. In most cases GCA agreed with one or both operators with no instances of GCA differing with both operators on any of the broad points of evaluation. There are however instances where GCA has differed from one operator. These are:-

- **Bigge Island**:- INPEX judged that the waters around the Island are not readily navigable by large vessels. However Woodside and GCA consider that, depending on the port location, a breakwater or dredging would allow access of LNG carriers.

- **Maret Islands**:- Woodside assessed the site as having insufficient land and unsuitable geotechnical characteristics. GCA and INPEX consider the land area adequate and have access to actual geotechnical data which confirms the site's suitability.

- **Koolan Island**:- Woodside consider the site to lie in water unsuitable for LNG carrier navigation owing to its proximity to King Sound. INPEX and GCA consider that Koolan Island has suitable marine conditions, with limited dredging and no breakwater required.

- **Cockatoo Island**:- Woodside consider the site to lie in water unsuitable for LNG carrier navigation owing to its proximity to King Sound. INPEX and GCA consider that Cockatoo Island has suitable marine conditions, with limited dredging and no breakwater required.

- **Cockatoo Island**:- INPEX considered that sufficient land was available should the area of the mine site be used in conjunction with a "Compact LNG" design, whereas Woodside and GCA estimate that the available area of approximately 250 hectares is insufficient to support a "stand alone" LNG facility.

### 1.3 LNG Hub Concepts

From GCA's meetings with stakeholders it was apparent that a common vision for the Browse LNG hub had not yet materialised. Although there are a number of alternatives that can be considered, for the purposes of this report, GCA has defined three concepts as the basis for arriving at the range of land and marine requirements that should reasonably be considered:-

- **Single Operator LNG Hub**:- A site operated by a single entity which has the capability to receive gas from a number of fields and operators. The hub processes gas to LNG, and stores and loads LNG on behalf of the field operators. An existing example of this concept is PT Arun in Indonesia. For this study a maximum of 5 LNG trains and support facilities requiring 360 hectares has been used as the basis for evaluation.

- **Multi Operator LNG Hub**:- A site that has common infrastructure, such as harbour, wharves, airstrip and camps which can be consolidated or shared, but where two or more operating entities independently receive and process gas to LNG and independently store and load LNG. An existing example could be the Burrup LNG developments, in which the NWSJV and Pluto will be operated independently. For this study, two independent operators with a maximum of 10 LNG trains and independent support facilities requiring 660 hectares have been used as the basis for evaluation.

- **Gas Processing Hub**:- A concept similar to the multi operator hub but which also provides for additional basic "value adding" processes such as Gas to Liquids (GTL), methanol or fertiliser production. An existing example is Ras Laffan with the caveat that petrochemicals production is not contemplated for the Browse Hub. For this study a total of a maximum of 10 LNG trains and a number of GTL based facilities have been used as the basis for evaluation. This concept requires 950 hectares or more.

The above concept has been used for the purpose of setting a basis for evaluating potential sites. The facilities ultimately located at such a site could differ markedly from those described.

No matter which of the above concepts is adopted, it has been assumed for the purposes of this study that the development of Brecknock, Calliance and Torosa gas condensate fields by the Woodside operated Browse Joint Venture; and the INPEX operated Ichthys gas condensate field, would be the "foundation" suppliers of gas to the Hub.

## 1.4 Site Evaluation For LNG And Gas Processing Hubs

A substantial amount of work has been undertaken by Woodside and INPEX to screen sites for their stand alone LNG projects. INPEX have performed preliminary geotechnical studies on their preferred Maret Islands site. Woodside have undertaken some geotechnical studies of the other sites they are considering. While both Woodside and INPEX are now actively considering hub concepts, they have not provided any data to GCA that evaluates sites for hub development. Evaluations of potential sites in the context of an LNG Hub, with higher land area requirements than for stand alone developments and consideration of the distances to all the potential upstream fields, will lead to different rankings and shortlisted sites.

DoIR has requested GCA to technically evaluate a number of potential hub sites against specific criteria listed in **Section 2.2**. This work is detailed in **Section 2.3** of the report and is summarised in **Table 1** below:-

**TABLE 1**

**SUMMARY OF SITE SUITABILITY FOR LNG AND GAS PROCESSING HUB**

| | Port Availability and Navigation | Land Availability and Suitability | | |
|---|---|---|---|---|
| | | Single Op. | Multi Op. | Gas Proc. |
| **North Kimberley** | | | | |
| Maret Islands | Y | Y | N | N |
| Bigge Island | Y | Y | Y | Y |
| Champagny Island East | Y | Y | N | N |
| Wilson Point | Y | Y | Y | Y |
| Koolan Island | Y | Y | N | N |
| Cockatoo Island | Y | N | N | N |
| **South Kimberley** | | | | |
| Cape Leveque | Y | Y | Y | Y |
| Lombadina (Packer Island) | Y | Y | Y | Y |
| North/ Perpendicular Head | Y | Y | Y | Y |
| Quondong Point | Y | Y | Y | Y |
| Fisherman's Bend | Y | Y | Y | Y |
| **Offshore Kimberley** | | | | |
| Scott Reef **(1)** | ? | n.a. | n.a. | n.a. |
| Echuca Shoals **(1)** | ? | n.a. | n.a. | n.a. |
| **Existing LNG Site** | | | | |
| Burrup (NWS & Pluto) | Y | Y**(2)** | N | N |

**Notes:-**
1. These sites are partially submerged and would be developed as "offshore" facilities.
2. There is insufficient land available in the Burrup area for a new Single Operator LNG Hub. GCA has assumed production would be integrated into existing gas processing hubs.

It is emphasised that the above sites have been evaluated on technical grounds only. Environmental, Land access and other community based issues have not been considered.

# 2. DISCUSSION

## 2.1 Woodside, INPEX, GCA Site Short Listing

### 2.1.1 Screening Criteria

The following considerations are based on GCA's review of the documentation made available by Woodside and INPEX. It is understood that both proponents have carried out significant analysis, which may not be reflected in the final documentation provided. GCA's comments with regards to the analysis done for site selection by both proponents are designed to highlight the different approaches adopted and provide the reader of this report with the background required to understand the different outcomes that have resulted from the analysis conducted by INPEX and Woodside.

It is important to note that the majority of the analysis conducted by INPEX and Woodside aims to identify the optimal location for a stand alone LNG facility, from the point of view of the development of each operator's Browse Basin fields. In particular, the relative locations of these fields will have a significant influence on each Operator's site preference. The outcomes of such analysis in the context of a Hub are therefore likely to be different.

Finally, one could consider that most sites are technically suitable for an LNG development. The ranking of these sites will be based on the relative costs associated to the preparation and operation of a given location. Indeed, for example, the additional costs linked incremental pipeline length could be compensated by the costs savings linked to reduced earth works required on a specific site, or similarly additional dredging might be mitigated by proximity to existing infrastructure for another site. Therefore, the final site selection will require the estimation of the major costs and the assessment of the impact of different sensitivities.

### 2.1.2 Woodside Site Selection

Woodside appears to have adopted a four-phase approach for site identification and assessment:

i. Identification of areas of interest, mainly within 500 kilometres of the Woodside fields; however locations within 1,000 kilometres were also noted (Burrup and Darwin);
ii. Desktop studies, literature reviews and meetings with key stakeholders to identify the potential issues with the sites identified;
iii. Flyover and/or visits to the potential physical sites to verify desktop studies and collate additional data;
iv. Assessment of each site against environmental, socio-economic, health, safety security and technical criteria to screen out unsuitable sites from further studies.

Woodside used the following technical criteria for the evaluation of potential onshore and island sites for stand alone LNG facilities:

- **Available Area**: sufficient available area for plant - 300 hectares for development preferred;

- **Site Elevation**: Land can be secured against flood and surge - site elevation at least 10 metres above Australian Height Datum (AHD) to avoid storm surge flooding;
- **Distance to Navigable Water**: Minimum dredging preferred with dredge spoil disposal options available. Minimum jetty lengths;
- **Maximum Slope**: no more than 5 degrees at plant location - minimise earth works disturbance and site preparation costs;
- **Proximity to Coastline**: cryogenic lines are a considerable expense. No more than 4 kilometres to loading facilities preferred;
- **Proximity to Fields**: offshore/onshore pipeline length as export pipelines are a major expense. Preference for having LNG plant as close as feasible to offshore field;
- **Geotechnical Conditions**: site soil type (need for piling) - prefer stable sands/rock to reduce piling requirements for LNG tanks and other equipment. Near shore ocean floor conditions for type of jetty piling;
- **Pipeline Location**: suitable beach and shore conditions for pipeline landing;
- **Carrier Navigation**: availability of sheltered water as docking facilities must be located within sheltered, navigable waters. Breakwater requirements should be minimised. Low ocean currents required for berthing and shipping ingress and exit. Wave heights and periods within acceptable range for berthing and port availability.

Woodside used the following technical criteria for the evaluation of potential offshore reef sites for stand alone LNG facilities:

- **Geotechnical Conditions**: suitable conditions for platform and/or GBS substructure installation;
- **Pipeline Location**: suitable shore crossing for main field pipeline to reef crossing;
- **Carrier Navigation**: availability of sheltered water as docking facilities must be located within sheltered, navigable waters. Breakwater requirements should be minimised. Low ocean currents (<2 knots) required for berthing and shipping ingress and exit;
- **Sheltered Water Location**: wave heights and periods within acceptable range for berthing and port availability;
- **Suitable Water Depth**: installation of Gravity Based Structures (GBS) substructures. Less than 20 metres water depth preferred for construction of GBS substructure;
- **Proximity to Fields**: minimising of main field pipeline lengths.

GCA considers these criteria are an acceptable basis for the technical evaluation of the potential sites for a stand alone development. While seismicity could have been included as an additional criteria, as a possible differentiator between the South Kimberley and the North Kimberley sites (**Appendix V**).

Other than “available area” all the criteria used by Woodside were valid for LNG Hub site selection. Land area requirements are addressed in detail in **Section 2.2.2**.

To allow further comparison of the relative merits of potential sites, detailed cost evaluation is required. In particular those costs linked to dredging, jetty length,

breakwater length and cut and fill will be required. These will have a significant impact on the final project costs (Capex & Opex) and timeline, which in turn could affect final site selection.

The outcome of this approach, based on the qualitative review of all the technical and non-technical criteria considered, has been the screening out of thirty five sites from the 41 identified initially. The remaining 6 sites were shortlisted by Woodside for further evaluation:

- Quondong Point
- James Price Point
- North Head
- Perpendicular Head
- Wilson Point
- Scott Reef (offshore)

These six sites meet appropriate technical criteria for a stand alone facility. GCA considers that a number of additional sites (see section 2.1.4) also meet the technical criteria.

### 2.1.3 INPEX Site Selection

INPEX appears to have adopted a six-phase approach for site identification and assessment:

i. Identification of potential sites for onshore LNG facilities;
ii. Initial screening of sites based on navigability, available area, minimal environmental disturbance and potential for community concern;
iii. Quantitative ranking of each site based on publically available information, using criteria related to access, physical environment, development considerations, commercial and marketing issues, environmental sensitivity;
iv. Flyover and/or visits to the potential physical sites to collate additional data;
v. Revised quantitative ranking of each site based on the additional data collected and using the same criteria as previously.
vi. Qualitative assessment of all initially identified sites, and ruling out of all technically unsuitable sites.

INPEX used a total of twelve technical criteria for ranking potential sites for stand alone LNG facilities. In additional to the technical criteria described below a number of non-technical features such as environmental impact, land tenure and cultural heritage were also considered. Desirable technical features were considered to be:

- **Road Access**: sites having easily upgradeable road access;
- **Sea Access**: sites with readily available sea access or gazetted as ports;
- **Air Access**: locations with existing airstrips capable of handling commercially chartered airplanes and helicopters;
- **Water Depth**: sites having sufficient water depth to meet the requirements of vessels for export of product;
- **Tides & currents**: Sites that afford some form of protection or have less tidal influence to minimise disruption to marine operations;

- **General Topography**: level sites with suitable geothechnical conditions for foundations;
- **Existing Infrastructure**: sites with existing infrastructure readily useable by the project;
- **Field Proximity**: proximity of site to Ichthys field or offshore facilities;
- **Technological Risk**: overall technical risk that may be site specific;
- **Hydrocarbon Storage**: sites with areas particularly suited for hydrocarbon storage;
- **Constructability**: locations presenting the opportunity to bring in large components or readily available fabrication work force;
- **Operability**: sites that can support a reasonable level of maintenance without significant logistical support.

GCA considers these criteria are an acceptable basis for the technical evaluation of the potential sites for a stand alone development. While seismicity could have been included as an additional criteria, as a possible differentiator between the South Kimberley and the North Kimberley sites (**Appendix V**).

GCA notes that INPEX has not highlighted a distinct criteria or explicit target for land area requirements. It appears nevertheless that land area has been considered in INPEX's study, and led to ruling out certain sites, such as Browse Island. INPEX has advised GCA that capacity expansion was not a corporate criteria at the commencement of the site assessment given the anticipated resistance to industrialisation in the Kimberley.

After the initial screening study, the top six sites were:

- Cockatoo Island
- Koolan Island
- Maret Islands
- Beagle Bay
- Cape Leveque
- Battery Point/Sampson Inlet

In addition to LNG facilities, INPEX has also assessed the potential suitability of the sites for other various downstream processes such as the manufacture of methanol, DME, ammonia/urea and GTL. Production of these alternative products was ultimately ruled out in favour of LNG.

A more detailed inspection and additional technical data for each of the sites led INPEX to rule out the following sites on technical grounds:

- <u>Cockatoo Island</u>
  Previously unavailable geotechnical information regarding the foreshore and near harbour geology was accessed confirming that the site is geotechnically unsuitable for the type of development that would be required for a gas processing facility.

- <u>Koolan Island</u>
  Mining activities on Koolan Island were resumed during the evaluation period, and as such, the site was no longer available.

- Beagle Bay
  The requirement for considerable civil works to develop the site was reconfirmed during 2004. The anticipated impact associated with such extensive civil work on coastal mangrove communities in particular, was determined to be sufficient to substantiate its elimination.

- Battery Point/Sampson Inlet
  The requirement for considerable civil works to develop the site was reconfirmed during 2004. The anticipated impact associated with such extensive civil work on coastal mangrove communities in particular, was determined to be sufficient to substantiate its elimination. It was also determined that Sampson Inlet was extensively used by the tourism and pearling industries

Based on both technical aspects, addressed in this study, and non technical aspects, not addressed in this study, INPEX identified Maret Islands as their preferred site for the installation of their LNG facilities. GCA understands that Cape Leveque was ruled out as a possible site, due to its distance from the Ichthys field and on non technical grounds. INPEX considered that the extra distance from the Ichthys field to Cape Leveque would require an offshore development with substantially more personnel offshore.

### 2.1.4 GCA site screening

The sites listed below comprise the Study's scope of work. The sites have been selected by the Taskforce from those previously shortlisted by Industry:-

- Maret Islands
- Wilson Point
- Scott Reef
- North Head / Perpendicular Head
- Lombadina (Packer Island)
- Quondong Point
- Koolan / Cockatoo Islands
- Burrup – Tie in to existing NWS facilities / Pluto

In order to ensure the evaluation of a comprehensive set of potential sites, GCA has identified, through the review of analysis performed by Woodside and INPEX, additional sites that could be technically suitable for LNG developments. These sites have therefore been reviewed in further detail in this report, in addition to the ones identified in the Study's scope of work.

Certain sites have been ruled out for non technical reasons by Woodside and/or INPEX, even though they were likely to be technically suitable. The following additional sites have therefore been incorporated to the scope of this report:

- **South Kimberley**
  - Fisherman's Bend:

- Ruled out by Woodside because of socio-economic (interference with Pearl industry, heritage sites) and environmental (proximity to Broome) issues.
- May be reconsidered as a potential site for the quality of its location (7 kilometres direct distance from Broome), its topography (fairly levelled elevation) and acceptable ocean conditions (protected deepwater, proximity to an established port).

➢ Cape Leveque:
  - Ruled out by Woodside because of societal and environmental issues.
  - May be reconsidered as a potential site for the quality of its location (road access and air strip), ocean conditions (deepwater less than 2 kilometres offshore and partially sheltered) and its acceptable topography.

- **North Kimberley**

  ➢ Bigge Island (North and South sections)
    - Ruled out by Woodside because of socio-economic and environmental issues.
    - May be considered as a potential site for the quality of its topography (over 300 hectares available) and ocean conditions (deepwater close to coast).

Certain sites have been ruled out for technical reasons, but would require further analysis to confirm this evaluation. The following sites have therefore been incorporated to the scope of this report:

- **North Kimberley**

  ➢ Champagny Island (East and West sections)
    - Ruled out by Woodside because of technical and socio-economic issues.
    - May be considered as a potential site for the quality of its topography (over 300 hectares available, requiring minimum earthworks) and ocean conditions (deepwater close to coast, requirement for a breakwater to be confirmed).

  ➢ Echuca Shoals
    - Ruled out by INPEX because of technical and environmental issues.
    - May be considered as a potential site for its proximity to the Ichthys field, but feasibility and reliability of such offshore development to be further evaluated.

In addition, GCA has reviewed the potential of the sites within King Sound. These sites, which have been ruled out by Woodside and/or INPEX due to strong currents and tidal ranges impacting LNG carrier access, include:

- Deepwater Point (Woodside and INPEX)
- Swan Point (Woodside)
- Skeleton Point (Woodside)
- Cunningham Point (Woodside)

- One Arm Point (Woodside)
- Sunday Straight Island (Woodside)
- Point Tourment (Woodside)

GCA's assessment of the sites within King Sound from a marine standpoint, based on LNG carrier access, has confirmed their unsuitability for LNG developments (**Appendix II**). Therefore, these sites have not been shortlisted for a further evaluation according to the study criteria.

## 2.2 Technical Issues Governing Site Selection

### 2.2.1 Distance to Navigable Water and Port Suitability

**Marine Facilities Availability**

Potential availability of a suitable port for LNG and associated products is critical for any LNG development. As LNG production is completely integrated and individual product flows cannot be isolated from one another, the inability to off-take any product, once available storage has been exhausted, will cause the reduction or interruption of LNG production. For example, since condensate is produced concurrently with the flow of gas, any disruption to the shipping of condensate, if no additional condensate storage is available, will disrupt LNG production. The same problem exists in the case of LPG extraction and storage.

Variable or low availability of marine facilities at a selected site, for example due to weather conditions, could be mitigated by increasing storage capacity for LNG and associated products. The extra storage would then allow full production rates at the LNG plant for a longer period. Indeed, LNG operators try to run the plant at an even pace, as the plant is cryogenic and therefore LNG production swings could cause thermal shock and equipment damage.

To ensure sufficient marine availability of marine facilities at a given site, one must consider wind factors, surge factors, potential incidence and potential impact of cyclones.

**Marine Facilities Concept**

To ensure LNG off-take flexibility, the marine terminal should typically be able to accommodate at least three types of LNG tankers: Membrane, Q-Flex and Q-Max.

In addition, the marine facilities are likely to have to accommodate condensate tankers and LPG tankers. However, the requirement to accommodate LNG tankers will depend on the development concept selected by the Operator(s). Indeed, the condensate could also be loaded offshore, typically through an SPM.

**TABLE 2**

**COMPARATIVE SHIP SPECIFICATIONS**

| Ship Size | Type | LOA m | Beam m | Draft m | DWT |
|---|---|---|---|---|---|
| 125,000m³ | ALSOC Moss Rosenberg | 272 | 47.3 | 11.4 | 66,800 |
| 145,000m³ | LNG membrane | 283 | 43.4 | 11.35 | 79,084 |
| 216,000m³ | LNG Q Flex | 315 | 50.0 | 12.0 | 106,900 |
| 266,000m³ | LNG Q Max | 345 | 53.8 | 12.0 | 125,600 |
| Aframax | Condensate Tanker | 238 | 42.0 | 14.9 | 105,215 |
| 85,000m³ | LPG Tanker | 230 | 36.6 | 11.62 | 54,500 |

A 15 meter draft berth box is recommended to accommodate the anticipated mix of vessels specified in **Table 2** This would also apply to the channel, which will need to be a minimum of 300 meters wide, and to the 700 meters swing basin (twice the LOA of Q Max vessels).

If there is insufficient depth to bring LNG tankers close to the coast, it is likely that a longer LNG berth will be required and / or a channel will need to be dredged. Marine engineering will define the optimum combination of jetty length and dredging requirements, from an economic and technical perspective.

Typically, jetty length and dredging requirements will increase project Capex as the distance from the LNG plant to navigable waters increases. Dredging may also have a significant Opex impact, depending on the rate of deposition of silt on the sea bed. Indeed, the channel may need to be dredged on a regular basis, as would be the case close to a river mouth where the silt build up can be significant.

The berths should be in the form of a T Jetty, facing the prevailing wind (i.e. blowing the vessels onto the berth) and parallel to the prevailing current. The overall length should be about 800 metres, with LNG/LPG facilities at one end and condensate facilities at the other. An indicative berth concept plan is displayed in **Appendix IV**.

In addition to the LNG, LPG and condensate off-take facilities, a construction dock will probably be required during the initial plant construction phase. This will allow some of the construction materials, including some very large pieces of equipment specific to LNG facilities, to be shipped to the site.

**Marine Facilities Traffic**

On a yearly basis, offloading the anticipated production of a stand alone LNG development is expected to require up to 200 LNG ships (12 to 24 Mtpa LNG, depending on average ship capacity), 40 condensate ships (75 kbbl or 10,000 tonnes daily) and 20 LPG ships (70 kbbl or 5,800 tons daily).

Should the terminal serve as a hub, the LNG vessel and cargo traffic is assumed to double, whereas the condensate traffic is expected to increase by about 40% and the LPG traffic to remain constant.

Should the Operators elect to extract and load the condensate offshore, the condensate tanker traffic at the LNG Hub would be substantially reduced. If only residual amounts (<2%) of the produced condensate were recovered at the LNG Hub, trucking of condensate from the site may be an alternative to shipping.

These assumptions have been made for the purpose of estimating comparative ship and cargo exports, based on the stand alone development of Ichthys field and a hub development incorporating Woodside operated production.

**TABLE 3**

**COMPARATIVE SHIP & CARGO EXPORTS**

| | LNG | | Condensate | | LPG | |
|---|---|---|---|---|---|---|
| | Ships (no) | Cargo (MM tons) | Ships (no) | Cargo (MM tons) | Ships (no) | Cargo (MM tons) |
| **Browse** | | | | | | |
| Stand alone development | 200 | 7.5 | 40 | 3.65 | 20 | 2.12 |
| Hub development | 400 | 15.0 | 55 | 5.02 | 20 | 2.12 |
| **Burrup** | | | | | | |
| Dampier comparison | 209 | 12.5 | 49 | 3.3 | 29 | 1.5 |

**Marine Facilities Sizing**

The “In Port Time” for all types of LNG and LPG tankers is likely to be a total of 24 hours. The “In Port Time” for the Aframax tanker for condensate is likely to be ~30 hours, based on the current practice at Dampier.

In Dampier, there is typically one berthing window daily for LNG tankers (due to wind factors) while Aframax condensate tankers will only sail at high water on each tide owing to their greater draft. Such ship movement restrictions are critical as the terminal operation functions with a “tank tops” policy, i.e. using storage capacity to its maximum.

In the context of a stand alone development, a combined loading berth would not be suitable for the proposed marine facilities, as this would imply 280 days occupancy per annum (around 76% berth occupancy), which is typically considered unsustainable. In addition, membrane type LNG ships require immediacy of access during the cyclone season, which could be problematic since the condensate tankers are likely to be alongside the berth longer than LNG ships. The minimum marine facilities should therefore include one LNG/LPG berth with a loading station for each product and one multipurpose berth with one loading station for condensate and general supplies. This would be consistent with established practices at Dampier.

In the context of a hub development, with approximately 500 berth days per annum to satisfy the projected ship volume, the minimum requirement would be one dedicated LNG/LPG berth and one multipurpose berth for condensate and general services. However, this would imply 68% average berth occupancy which is generally considered difficult to sustain. One additional LNG/LPG berth would allow lower average berth occupancy.

An SPM facility could only handle the condensate tankers (~20% of the traffic in a stand alone terminal and ~10% in a hub terminal) and is not likely to obviate the need for a second berth on the jetty.

The marine facilities should also accommodate additional tugs to secure the tankers, with a minimum of 5 tugs (including one in reserve), and a minimum of 6 tugs should the facilities include and SPM.

**Product Planning and Shipping**

LNG companies typically review the complete shipping and LNG storage as one comprehensive activity. Computer models are used to review numbers of LNG tankers needed based on delivery distances, LNG storage, LNG production rates and LNG buyer off-take. Therefore, LNG storage capacity would reflect the turn around time for the LNG tankers, the prevailing weather conditions, the buyers' requirement for LNG and the LNG production rates would be set to match these other parameters.

LNG has been in the past, and to some extent will continue to be, sold on the basis of long term (25 years) sales purchase agreements. On an annual basis the buyers will negotiate with the LNG producers the type of LNG delivery schedule they would like. For the buyers, this is to a great extent based on the requirement of their customers who will receive the re-gasified LNG.

Although most LNG sales and purchase agreements specify that the buyer shall take the LNG on an even off-take basis, this may not consistently be done. The buyers typically prefer to reduce their gas deliveries in the summer months when their own customers require less gas due to the warmer temperatures. During this period of lower LNG demand, the LNG producers typically carry out necessary maintenance on the LNG production facilities. During the winter months, the LNG demand is greater and thus LNG storage and shipping require very close coordination.

**Winds and Currents**

The North coast of Australia and adjoining sea area are under the influence of the North West and South East monsoon, and of the tropical cyclones that affect the area especially during the summer and early autumn months.

The monsoonal winds drive the currents along the North West coast of Australia, which flow from the North or North East in the period September to February and with a weak counterflow from the South West from March to August. The time of the onset of the monsoon winds varies yearly. There is a low constancy of the predominant direction and the mean rate of the current in this season is less than 1 knot. Flows of 2 to 3 knots have been noted sometimes against the expected direction. During the North East flow, the currents reverse, as a counter current, in the region of the Eighty Mile Beach.

Beyond 60 miles from shore, the currents are East in winter and North West to North East in summer, with branches rotating clockwise sometimes from the North or North East with a current set East or sometimes South along the coast. The onshore component can be up to 2 knots but normally rates of ½ to 1 knot occur with a low constancy. During the month of February, the current is from an easterly direction with high constancy and rate of 1 knot. These change with the advent of autumn to a South West direction with a low constancy of about ½ knot. In winter months the currents are 1 knot in an easterly direction with a high constancy while in November, due to the transitional spring weather, the currents are negligible.

Numerous tidal streams exist in the area as a result of the neap and spring tides experienced in the approaches to the large bays and inlets. Winds in the area are generally smooth or slight except for the seasonal monsoon winds. The lighter North West monsoon produces mainly slight seas, but the tropical cyclones are capable of producing very rough conditions in a short period of time. South East Trade winds also known as the South East Monsoon blow from East and South on the North flank of the high pressure systems (anticyclones) from May to October and are at Beaufort force 4 to 5 wind speed.

The North West or West monsoon prevails in the area between December to February with January and February being the strongest months. It also gives rise to land and sea breezes, the former being a lighter offshore wind that forms around midnight and dies down after sunrise and the latter setting onshore during summer, increasing in the late afternoon to Force 4 and dying down soon after dusk.

Squalls are a common feature of the North West Australian waters and coastal areas during the hot and transition months. The hot season of the North West monsoon is preceded by sharp, short lived squalls of increasing frequency and intensity with gale force winds and thunderstorms.

Overall, the metocean conditions described above are not expected to be unsuitable for the LNG trade in the North and South Kimberley.

However, the coast between Hidden Island and Cape Leveque incorporates the entrance to King Sound, where numerous shoals, reefs & islands extend up to 50 miles offshore, with currents and tidal streams running between 6 and 10 knots with violent tide rips and eddies. The area is presently unsurveyed in many parts and is currently not safe for entry by large deep draught vessels such as Q Flex and Q Max LNG tankers. There is a large variation in the strong spring tides which can have a range between high and low water of up to 11m. Such conditions render navigation dangerous for the LNG trade.

**Tropical Cyclones and Storm Surge**

Violent tropical cyclone winds form over the North West Australia in the Timor and Arafura Seas mainly during November to April, with most frequent occurrence between January and March. North West Australia experiences on average about four to five tropical cyclones a year. They generate substantial currents that significantly alter the normal pattern. Fetch area, speed of advance and wind strength effect changes to currents. The choppiest weather off North West Australia is associated with the fresh and gusty South East Trade winds and very rough and mountainous seas heralding the advent of a tropical cyclone.

Tropical cyclones form as minor clockwise circulations in low latitudes in the vicinity of the Inter Tropical Convergence Zone (ITCZ) in the area between 10$^o$ – 20$^o$ south of the equator. They usually move in a West South West direction, and where conditions are favorable the cyclone will deepen and develop. Cyclones generate strong winds from 34 to 64 knots beyond which they are categorised as severe. Winds in excess of 125 knots have been recorded. Hurricane strength is reached by 30% of Australian tropical cyclones and is accompanied by strong winds, torrential rain and mountainous seas which may cause abnormal water levels and storm surge waves. They tend to travel West or South West off the North and North West coasts of Australia at speeds of about 5 to 10 knots and often re-curve towards the South East or South to cross the coast of North West Australia between Onslow and Broome.

However, the paths of cyclones are often erratic which make it hard to forecast exactly when and where a cyclone will cross the coast. This makes it difficult to predict how high the astronomical tide will be when the storm surge strikes since the difference between high and low water is only a few hours. Every cyclone that affects the coast produces a storm surge. This surge is the difference between the actual observed sea level and the predicted sea level. However, not all storm surges rise to dangerous levels. The height of the surge depends on:

- The intensity of the cyclone - as the winds increase, the sea water is piled higher and the waves on top of the surge are taller.
- The forward speed of the cyclone - the faster the cyclone crosses the coast, the more quickly the surge builds up and the more powerfully it strikes.
- The angle at which the cyclone crosses the coast - in general, the more head on the angle, the higher the surge. However, other angles can lead to local zones of enhanced surge in areas such as narrow inlets and bays.
- The shape of the sea floor - the surge builds up more strongly if the slope of the sea bed at the coast is shallow. If the sea bed slopes steeply, or if fringing reefs are present, then the surge will be less.
- Local topography - bays, headlands and offshore islands can funnel and amplify the storm surge.

Many parts of the Australian coastline are vulnerable to storm surge and hence this data is monitored at several locations around the coast by the Australian National Tidal Centre. The combination of storm surge and normal (astronomical) tide is known as a storm tide. The worst impacts occur when the storm surge arrives on top of a high tide. When this occurs, the storm tide can reach areas that might otherwise have been safe. This also causes pounding waves generated by the strong hurricane force winds. The area of sea water flooding may extend along the coast for over 100 kilometres with water pushing several kilometres inland if the local lay of land is low. The combined effects of the storm tide and waves can knock down buildings, wash away roads and run ships aground. This has impacts on recommended LNG site elevation, as detailed in **Section 2.2.3**.

It should be noted that typically Dampier suffers from 3 cyclones per annum in the period November to April. Normally vessels will vacate the port as soon as it is thought such conditions are likely to close the port. Typically, port operations will be adversely effected for up to 3 days when this happens. Prompt departure from the berth is not a problem for Moss Rosenberg LNG, condensate and LPG tankers but can be for membrane LNG tankers, which must complete loading before vacating the berth once

they are more than 10% loaded – this can normally be achieved in no more than 24 hours.

### 2.2.2 Land Area Requirements

**Development Concepts**

GCA has defined three main alternatives in the context of the land area required for an LNG Development:

- **Single Operator LNG Hub:-** A site operated by a single entity which has the capability to receive gas from a number of fields and operators. The hub processes gas to LNG, and stores and loads LNG on behalf of the field operators. For this study a maximum of 5 LNG trains and support facilities, within a single LNG plant, requiring 360 hectares has been used as the basis for evaluation.

- **Multi Operator LNG Hub:-** A site that has common infrastructure but where two or more operating entities independently receive and process gas to LNG and independently store and load LNG. For this study two independent operators with a maximum of 10 LNG trains and independent support facilities (except items such as airstrips for example, which would typically be shared), within two LNG plants, requiring 660 hectares has been used as the basis for evaluation.

- **Gas Processing Hub:-** A concept similar to the multi operator hub but which also provides for additional basic "value adding" processes such as Gas to Liquids (GTL), methanol or fertilizer production. For this study a total of a maximum of 10 LNG trains and a number of GTL based facilities (in this example, two GTL plants, one ammonia plant and one methanol plant) have been used as the basis for evaluation. This concept requires at least 950 hectares. More available space could allow for additional independent operators or GTL based facilities.

**General Area Requirements**

In the context of a Single Operator LNG Hub, GCA recommends to allocate a minimum area of 300 hectares for typical core facilities, such as LNG liquefaction plant, gas treatment facilities, storage tanks, lay down areas, power plant, utilities, onshore pipeline, marine centre and perimeter fence. In addition, an area needs to be allocated for support facilities, such as airstrip, construction camp, staff accommodation, medical facilities and central fire fighting station. This area would typically represent an additional 60 hectares. Therefore, the total area required for a Single Operator LNG Hub would be ~360 hectares.

In the context of a Multi Operator LNG Hub with two or more operators, the size of the core facilities would typically increase by 300 hectares for each additional operator. In the case of two operators, used as a basis for this Study, the size of the core facilities would double, reaching 600 hectares. Indeed, LNG operators, and LNG clients in particular in Asia, put a strong emphasis on the reliability of supply, which favours the concept that each LNG operator should be able to function independently. Each LNG operator would therefore prefer to control its storage, power, utilities, marine centre etc. On the other hand, many of the support facilities could be commonly used, in particular the airstrip, which represents a large part of the support area requirements, as well as medical facilities and central fire fighting station. For the purpose of this study, the area

required for support facilities for two operators is estimated to be 60 hectares, as in the case of a Single Operator LNG Hub. Therefore, the total area required for a Multi Operator LNG Hub would be ~660 hectares.

In the context of a Gas Processing Hub with two or more operators, the size of the core facilities would remain the same as in the case of a Multi Operator LNG Hub. In addition, 150 hectares will be required for two GTL plants (75 hectares per plant), 35 hectares for an ammonia plant and 60 hectares for a methanol plant. The area required for support facilities will also increase, in particular due to the requirement for additional power generation and accommodation for the operation of the gas based industries on site. This would typically represent 100 hectares, therefore, the total area required for a Gas Processing Hub would be a minimum of 950 hectares.

These area requirements have been used for screening purposes when examining possible gas processing hub locations.

**TABLE 4**

**GCA RECOMMENDED LAND AREA REQUIREMENTS (HECTARES)**

| | Single Operator LNG Hub | Multi Operator LNG Hub | Gas Processing Hub |
|---|---|---|---|
| Core facilities **(1)** | 300 | 600 | >600 |
| GTL plant | 0 | 0 | 150 |
| Ammonia plant | 0 | 0 | 35 |
| Methanol plant | 0 | 0 | 60 |
| Support facilities **(2) (3)** | 60 | 60 | 100 |
| **TOTAL** | **~360** | **~660** | **>950** |

**Notes:**

**(1)** Inclusive of:
- LNG liquefaction plant
- Gas treatment facilities
- Storage tanks
- Lay down areas
- Power plant
- Utilities
- Onshore pipeline
- Marine centre
- Perimeter fence

**(2)** Inclusive of:
- Construction camps
- Central fire station and workshops
- Accommodation for staff
- Hospital
- Airstrip for moving people and smaller equipment

**(3)** Inclusive of:
- Power generation for gas based industries

### LNG Plant Construction

Typical grassroots LNG plants take approximately 40 months to construct and require substantial manpower. The usual critical path is the construction of the concrete LNG storage tanks.

For example, it is not uncommon for grass roots plants in the Middle East to have 6,000 to 8,000 workers on site during the peak construction period. This peak would correspond to a point approximately 3 years into the construction period.

In Australia, with the use of modular construction, this manpower could be reduced to approximately 2,000 to 3,000 workers, but with a substantial increase in the construction labour required at South East Asian module fabrication sites. However, the manpower requirements will depend on the contracting strategy selected by the LNG Company.

**Construction Area Requirements**

The area requirement for construction activities is a function of the type of contracting strategy employed. For example, if a significant proportion of construction activities take place on site, the construction area requirements could be as high as 20% of the overall area. Large pipe fabrication requirements or pre casting of concrete would require large areas.

However, it is often more cost efficient to have parts of the plant constructed remotely and then have these modules shipped to the site. This represents considerably less assembly work and construction manpower than what would have been required with on site construction. This modular concept, where pipe fabrication is taking place offsite for example, also reduces the amount of area allocated to construction activities.

Therefore, construction area requirements will typically represent 20%, or less, of the total area allocated for the facilities.

**Construction Camps**

Under a typical Engineer Procure and Construct (EPC) contract used in the construction of LNG plants, it would be the responsibility of the contractor to provide the accommodation and recreational facilities required for his work force. It is also normally required for the EPC contractor to remove these facilities when the plant construction is complete. It is not unusual for the LNG plant operating company to reserve the right to purchase the camp at the end of construction. These facilities can be put to other uses such as training facilities or accommodation for large work groups during major LNG plant maintenance, when up to 200 additional workers could be required.

In the case of a common LNG hub it would be appropriate to retain the first construction camp for further use by other contractors to prevent camp re-construction and removal on a frequent basis. This should be a decision made early in the planning for a common LNG hub.

### 2.2.3 Site Elevation and Gradient

**Site Elevation**

Site elevation can be a critical factor in the selection of a suitable site on which to construct an LNG plant.

An LNG plant located at an elevation equal to the sea level would be exposed to potential flood damage in the event of storm surge. LNG plant equipment would be severely damaged by the ingress of water. It is also important to note that LNG buyers consider an LNG operator's ability to supply LNG on a reliable basis a critical factor in selecting that supplier. Installing an LNG plant at sea level where water damage due to storms or floods could occur would be seen as a significant risk by potential LNG buyers.

For example, an LNG storage tank in Hong Kong is being constructed at an elevation of 20 meters above sea level due to the concern over potential flooding during typhoons. This emphasizes the need for adequate elevation to minimize the risks of water damage and disruption of LNG production.

In the Kimberley area of Western Australia, an elevation of at least 10 to 15 meters above sea level would typically be considered acceptable.

**Site Gradient**

Site gradient is an equally essential criteria. Indeed, a significant elevation change resulting in steep slope would pose problems for plant construction and operation.

Modular construction would involve loads of up to 10,000 tons, whereas the heaviest load non modular construction would be approximately 1,000 tons. Self Propelled Modular Transporters, typically used to transport such equipment arriving by land or by sea, can typically operate with 10% gradients, but for large modules over 500 tonnes, this limit would be reduced to a maximum of 5% because of traction, Centre of Gravity (CoG) shift, ground surface issues etc.

From an operational point of view, having the plant at an elevation greater than the loading berths, which must be at sea level, would not be an issue. Typically, drainage of rain water on an elevated site would be effective, which is an asset in considering site selection.

Therefore a maximum site gradient of ~5% should be considered in site selection, mainly because of construction constraints. However, earth works can to some extent reduce the slope in the areas where heavy materials will be hauled, but at a significant cost especially if the site is rocky and requires a large amount of blasting.

### 2.2.4 Proximity to Gas Fields

The main impact of the distance between the plant site and the offshore gas fields is related to pipeline length.

**Pipeline Construction and Installation**

Pipelines from the offshore fields to the LNG facilities are a major expense and pipe procurement can lead to significant project delays. There are also some technical limitations to the maximum length of pipeline possible before booster compression is required. Technically, the current frontier for pipeline length is:

- Snøhvit – Raw Gas / multiphase pipeline – 143 kilometres
- Nam Con Son – Dehydrated Gas / two phase pipeline – 400 kilometres
- Langeled – Processed Gas / single phase pipeline – 1,200 kilometres

The distance from the gas fields to the LNG plant is mostly an economic and schedule issue. The longer the pipeline length the greater the cost and longer the procurement timeline will be. In addition, greater pipeline lengths also require additional compression. Indeed, pressure drop losses in the pipeline will increase with length and will necessitate additional compression to ensure the gas arrives at the required LNG Plant inlet pressure of approx 1,000psi (70bar). Additional compression platforms may be required

for pipeline lengths over ~500 kilometres, with an expected three compression platforms required for a distance of ~1,000 kilometres. These represent significant additional investments. The typical cost of a compression platform is in the range of US$200MM to US$400MM.

**Pipeline Operation**

In addition to the cost of original installation, longer pipeline length will also lead to increased annual maintenance and inspection costs. All subsea pipelines require annual inspection for both the external condition and the internal condition.

The internal pipeline condition is normally determined by the use of “intelligent pigs”. These are devices which travel through the pipe and are able to determine the internal condition of the pipeline. The normal areas of concern within a pipeline would be internal corrosion or possibly internal cracks on the steel surface due to either fatigue or from stresses induced by long unsupported pipeline spans.

External pipeline inspection is normally conducted to check for damage to the pipelines due for instance to ship anchors or fishing trawl boards. If pipelines have been trenched, external inspection would also reveal if the pipeline is actually in the trench or not. It is often difficult to lay pipelines directly in the trench that has been cut for installation, and essential to know to what extent the pipeline is not completely in the trench.

With multiphase pipelines, where gas is the major component, there will be liquid drop out as the pressure declines and the longer the pipeline the more this is likely to generate technical issues. Significant changes in sea floor elevations can also hold up liquids, resulting in liquid slugs, which operationally can be difficult to handle. These would typically also have an impact on the LNG related facilities, increasing the required size of the onshore “slug catcher”. Substantial flow assurance analysis by the operator is required.

The operation and maintenance of multiple compression stations offshore, which may be required depending on pipeline length, can have significant impacts on operating costs mainly due to the logistics of moving and accommodating personnel and personnel to the offshore locations.

**Distance to Gas Fields**

The length of the required pipeline will result in significant capital and operating costs for the upstream portion of the LNG project and have an impact on overall project economics. Such impact is not only the result of higher capital cost but also a significant increase in fuel consumption of the intermediate compression platforms, where needed, with accompanying increase in carbon footprint. Therefore, shorter pipelines would typically be preferred by LNG developers, with pipelines in the range of 400 to 500 kilometres typically being considered a maximum.

## TABLE 5

### DISTANCE FROM GAS FIELDS TO SHORTLISTED SITES
### (In a straight line, approximation in kilometres)

| | INPEX Ichthys | Woodside Browse (Scott Reef) |
|---|---|---|
| **North Kimberley** | | |
| Maret Islands | 200 | 340 |
| Biggie Island | 215 | 360 |
| Champagny Island East | 190 | 290 |
| Wilson Point | 220 | 320 |
| Koolan / Cockatoo Islands | ~250 | ~300 |
| **South Kimberley** | | |
| Cape Leveque | 280 | 290 |
| Lombadina (Packer Island) | 300 | 300 |
| North Head / Perpendicular Head | ~330 | ~300 |
| Quondong Point | 425 | 390 |
| Fisherman's Bend | 460 | 440 |
| **Offshore Kimberley** | | |
| Scott Reef | 150 | 0 |
| Echuca Shoals | 75 | 200 |
| **Existing developments** | | |
| Burrup (NWS & Pluto) | 1,020 | 910 |
| Darwin (Darwin LNG) | 830 | 980 |

### 2.2.5 Proximity of Plant Site to Coastline

The proximity of the LNG plant to the coast is important as it impacts LNG rundown lines and construction access.

**LNG Rundown Lines**

Typically there are two types of rundown lines:

- from the LNG production facilities to the LNG storage tanks,
- from the storage tanks to the LNG loading berth.

These lines are transporting LNG at cryogenic temperatures (approximately minus 165 degrees Celsius) and as such require special steel and also significant insulation in order to maintain the cold temperature.

LNG rundown lines typically cost in the range of US$25-30MM per kilometre. In addition to the significant costs, there are also technical issues if the lines are too long, which can cause gas to escape from the liquid LNG. Should this happen in the LNG rundown lines from the LNG production facilities to the LNG storage tanks, these would then contain excessive gas. The gas is however captured in the tank gas recovery system and is typically returned to the plant fuel gas system. Should this happen in the loading lines which transport the LNG from the storage tanks to the LNG tankers in the harbor, the excess gas would then typically be vented when loading. In some plants this gas is now captured and returned to the fuel gas system.

In considering sites for LNG facilities, a maximum distance of 5 kilometres from the LNG plant to the LNG storage tanks and another 5 kilometres from the LNG storage tanks to the loading berth are recommended. To minimize costs, it would be optimum to have the distance from the LNG plant to the tanks and from the LNG tanks to the LNG loading berth to be 1 kilometre each.

**Construction Access**

The proximity of the plant to the coastline will also impact the construction of the plant. In most cases, the plant construction will require the importation, by sea or road, of the construction materials and equipment. If importation is done by sea, then road transportation will be necessary from the construction dock to the LNG plant site. Construction materials can be considered in two distinct categories: major equipment (turbines, heat exchangers, vessels etc), and bulk materials (piping, fittings and other smaller equipment).

Bulk materials, for example pipes and fittings, are normally shipped in containers by container ship from overseas. Normally container ships will only call at specific ports designated as “ports of call” by their company and as a result the containers would need to be offloaded and then transported to the LNG site by barge or road.

In the case of major equipment or bulk materials transported by sea, the longer the distance from the plant to coastline, the more costly this ground transportation will be.


**LNG flow to tanker overview (Qatargas sample)**

| | | |
|---|---|---|
| Proj. K1177 May08 | Checked: | Fig. 3 |

**LNG Tanks**

The distance to the coastline will also have an impact on the location of the LNG storage tanks. Indeed, for safety reasons the LNG storage tanks are located at a minimum distance from the LNG plant. It is also customary to consider grouping all the necessary product tanks in one location. Depending on the adopted development concept, the incoming gas may contain condensate which must be separated, stabilized (excess gas removed) and stored at the LNG plant site. This could also be done directly offshore, before piping the gas, in some cases.

LPG's are also removed from the gas as part of the LNG production process. LNG is normally sold on the basis of the heating value of the gas. This can vary from country to country; however 1050 Btu's/ standard cubic foot is the value often used as a standard. To achieve this heating value requires the removal of LPG's. These LPG's are typically used as components of the refrigerant used to liquefy the gas and excess LPG can be extracted and sold separately.

A typical storage tank area in an LNG plant would include LNG, LPG and condensate storage tanks. Normally all these tanks would be grouped together at a specific distance from the LNG production facilities.

The tank area would also have containment walls as a separation from other products and to hold any spillage from the tanks in the event of catastrophic tank failure. Most LNG tanks are "full containment" which means that if the internal metal tank fails the LNG liquid would be contained by the outer concrete shell and no spillage to the atmosphere would occur.

**LNG Loading**

Some LNG vaporizes during normal LNG loading. The amount of gas liberated during loading is a function of the temperature of the ship's LNG tanks. Normally, LNG tankers will carry an LNG "heel" in the tanks. After LNG discharge at the receiving terminal, a small amount of LNG will be left in each LNG compartment in the ship. This heel of LNG serves two purposes, it allows gas to boil off from the liquid LNG which can be used as fuel for the LNG tanker boilers and it will be used to cool down the LNG tanks prior to arrival at the LNG loading port.

The temperature of the LNG tanks will directly affect the LNG loading rate. The LNG compartments in the LNG tanker can only be cooled down at a specific rate since the steel in the tanks cannot tolerate a fast temperature reduction. Faster than normal cooling down of the steel in the tanks could cause possible tank failure, resulting in LNG spillage. The LNG tanker can cool down the storage compartments by spraying LNG on the walls of the tanks and therefore making them ready for LNG loading.

If the tanks have not been reduced to an acceptable loading temperature by the tanker, then the only way to cool them down is to load LNG into the vessel and let it flash off in the tanks to reduce temperature. The gas would then be flared or recycled into the LNG plant system. It then takes much longer to load the LNG tanker. Normal LNG tanker loading can be achieved in ~12 hours (based on a tanker of 140,000 cubic meters) whereas the same tanker could take up to 24 hours to load if the tanker comes into port "hot" (minimum tank cool down by the tanker).

### 2.2.6 Pipeline Approach

The arrival of the offshore gas pipeline to the onshore LNG plant can encounter a range of technical challenges.

Should the selected site be surrounded by cliffs, and not have beaches, the pipeline approach may require significant earth works. This would be necessary to ensure an acceptable pipeline slope, failing which operational difficulties may arise, particularly if the arriving pipeline carries multiphase flows.

Should the selected site have suitable beaches, the pipeline would have to make a beach crossing. However, this can cause long term damage to the beach, disrupt the natural surroundings and the animal population if not handled properly.

Typical approaches would include burying the pipelines or elevating them over the beach and supporting them by an above ground structure. The latter would be highly visible and may not be acceptable from an aesthetic point of view. Cutting the beach and burying the pipeline would be the normal shore approach design; however care in design is needed to ensure that the tides do not uncover the pipelines, requiring future remedial action.

To remove this risk, constructing a culvert or subterranean tunnel through which to pass the incoming pipelines could be considered. This type of approach would also be very useful when considering future pipeline expansions for increasing LNG capacity of the existing plant, or bringing in new gas discoveries to the LNG plant for processing, as would likely be the case for an LNG hub.

An initial underground installation, with spare capacity for future lines, would eliminate the need for multiple beach disruptions and minimize the risks of the pipelines being unearthed and damaged.

### 2.2.7 Geotechnical conditions

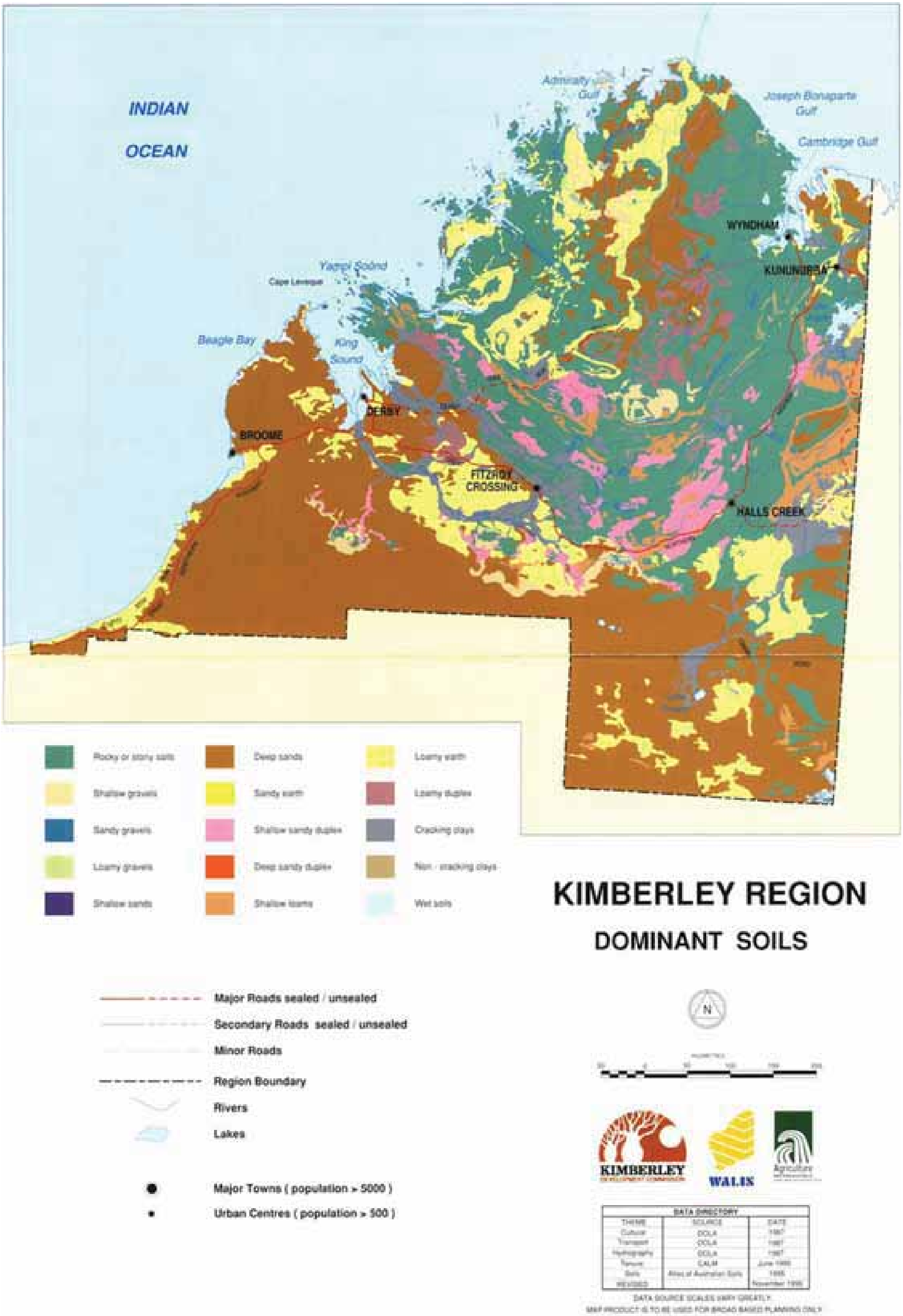
Geotechnical conditions can influence the choice of the LNG plant site and have significant impact on the subsequent costs. LNG facilities require substantial foundations that are able to withstand earthquake, cyclones etc. At the same time, earth works to get a level site are easier if the soil is relatively soft and does not require blasting.

If the site is particularly rocky, preparing the site would involve considerable blasting of the rock followed by reduction of the rock to a manageable size for use as fill. The positive aspect of a rocky site is that equipment foundations will be solid and require limited or no piling.

As a comparison, a site with a soft type of soil would require piling for most of the major equipment. It is possible to install LNG plant equipment on reclaimed land. In Qatar the LNG tanks for the RasGas project were installed on reclaimed land, which required 400 piles under each 130,000 cubic meter tank. This type of piling would increase the anticipated tank cost by approximately 10%. The LNG plant site in the Angolan LNG project, at the mouth of the river Congo, will be partially installed on reclaimed land. While this type of installation will increase the costs, it is technically feasible.

In economic terms, there will be an offset between the costs of rock removal versus another site where piling may be necessary prior to equipment installation. The type of terrain and the amount of cut and fill would need to be precisely assessed to evaluate the costs involved in preparing the site.

Most of the potential LNG sites considered in the Kimberley area have either deep sandy soils (pindan soil in the South Kimberley) or rocky / stony soils (in the North Kimberley) (**Figure 4**). The impacts of these would need to be considered in the estimation of the geotechnical works required to ensure suitability for LNG facilities.




| Kimberley Region Dominant Soils | | |
|---|---|---|
| Proj. K1177 May08 | Checked: | Fig. 4 |

### 2.2.8 Proximity to existing infrastructure

Existing infrastructure to assess would include: road access, port facilities, materials offloading facilities and laydown, construction camp, operations accommodation, airstrip, warehousing, supply base, marine offloading facility, access to quarry / construction materials, regional hospital facilities.

Consideration should also be given to services such as communications, utilities, law enforcement / security, customs and emergency response services.

**Roads**

The existence of infrastructure in the general area of a potential LNG plant site will have a significant impact on the selection of that particular site. For example the existence of heavy haul roads in the area would allow heavy modules to be delivered to the site with minimal expense, whereas other sites with no infrastructure would require the building and maintaining of roads at considerable cost and potential environmental impact. Existing roads would also allow the easy movement of personnel for both the construction phase and the operational phase of the project. The typical cost of an unsealed road is in the range of USD100 thousand per kilometre.

The onshore sites located in the South Kimberley will typically have some road access, which could require upgrading to become suitable to the transportation of heavy loads in all seasons. The onshore sites located in the North Kimberley will have very limited existing road access. These would require either the creation of new roads or the decision to transport all the material by sea, as would be the case for an offshore site.

**Airport**

Staffing an LNG plant in a remote location requires the operating company to make the decision whether to have their employees live close to the plant site accompanied by their families or to have the employees work on a rotational basis (fly in / fly out).

If the rotational basis is selected, at least 400 employees will be required to fill 200 positions at the plant (these numbers are for illustrative purposes only), due to the rotation and the requirement for additional personnel to cover vacation periods and sickness. The costs implied with this option could on the other hand offset the need to build a community to house the workers and their families. Building such a community will be a capital cost of the project, whereas the extra cost associated with having the workers on rotation will be an operating cost.

In either case, an existing airport close to the LNG plant site would be a substantial asset for the site selection, since the cost of constructing and operating an airport would not be required in the overall project costs. The typical cost of an airfield with appropriate capabilities and facilities is in the range of USD50 million.

Several airfields are in operation in the South Kimberley, close to the potential sites. Airfields also exist on the Koolan and Cockatoo islands in the North Kimberley, but would have to be built for the project in most other cases.

**Harbour**

Suitable facilities for export of products are one of the critical requirements for an LNG project. In the event that marine conditions prevent simple jetty structures for LNG and LPG loading, and in order to facilitate other activities such as tugs, pilot vessels and emergency response equipment, a conventional harbour may be required. The existence of a suitable harbour close to the potential LNG plant site would have a significant impact on the final selection of the LNG site.

During the construction phase of an LNG project, the existence of a harbour would also make the landing of construction materials easier and much less costly than having to construct a construction berth. In summary the existence of a harbour close to a potential LNG plant site could influence the selection of that site.

**Electric Power**

Electrical power is a key utility in the successful operation of an LNG plant. In remote locations, LNG plant operators would typically construct their own electrical power generation facilities. The power requirements of an LNG plant are dependent on the compressor drive philosophy adopted by the operator, with large gas turbine drives now being favoured to reduce costs. Direct power generation would also be reduced in these circumstances.

Capital expenditure on power generation could be removed from the owner's costs if there is existing electrical power available from a local power plant. From an operational point of view, an LNG plant operator might be reluctant to become reliant on an external supply of electrical power since the LNG reliability would then be tied to the reliability of the power generating company and would be a significant factor that could not be controlled by the LNG Company. The use of electrical power from a utility company could be a win-win for local industry and the LNG company who will be able to reduce the capital cost of the project by eliminating the power generation facility.

**Local Towns**

The existence of local towns close to a potential LNG plant site would have a positive impact on the site selection due to the availability of services, the possibility to house the permanent labour force for the LNG plant and potentially add to the community by moving employee's families.

There would also be some infrastructure surrounding the local town that would benefit the potential LNG project. During construction, there will be a large need for services for the very large construction work force, which could reach 3,000 employees. Rather than import all the necessary services, some could be provided by the local community. This would also allow the local community to develop some business opportunities for their own benefit.

The existence of a town close to a potential LNG plant site could be considered an asset for this location.

**Available Local Labour Pool**

One of the challenges in developing an LNG project and an LNG operating company is the sourcing of adequate labour to operate and maintain the plant. Locally available labour force would benefit the LNG plant operator.

In the context of the Kimberley, it is anticipated that the local labour pool would not be sufficient to meet all the LNG plant needs.


**Kimberley Region**
**Key Features**

| Proj. K1177 May08 | Checked: | Fig. 5 |
|---|---|---|

## 2.3 Sites Evaluation and Likely Technical Issues for an LNG Hub

### 2.3.1 North Kimberley: Maret Islands

**TABLE 6**

**MARET ISLANDS LNG SITE COMPARATIVE TECHNICAL EVALUATION**

<table>
<tr><th></th><th>Navigable water for LNG carriers</th><th>Port suitability</th><th>Land area requirements</th><th>Site elevation and gradient</th><th>Proximity to gas fields</th><th>Proximity of plant site to coastline</th><th>Pipeline approach</th><th>Geotechnical conditions</th><th>Proximity to existing infrastructure</th></tr>
<tr><td>Single Operator LNG Hub</td><td rowspan="3">Y</td><td rowspan="3">Y</td><td>Y</td><td rowspan="3">Y</td><td rowspan="3">Y</td><td rowspan="3">Y</td><td rowspan="3">Y</td><td rowspan="3">Y</td><td rowspan="3">N</td></tr>
<tr><td>Multi Operator LNG Hub</td><td>N</td></tr>
<tr><td>Gas Processing Hub</td><td>N</td></tr>
</table>

**Navigable Water for LNG Carriers & Port Suitability**

The Maret Islands have suitable marine conditions to support LNG operations. Breakwater, capital and maintenance dredging are probably unnecessary. Variability of depth contours around the island is to be noted, with deep water close inshore on North West and South West extremities of the Islands. These will probably affect berth and plant location.

For the purposes of this study, GCA estimates this site would require a ~500 meter jetty.

**Land Area Requirements**

The Maret Islands appear to have an area of ~360 hectares of usable land, which would be sufficient for a Single Operator LNG Hub, but would be unsuitable for a Multi Operator LNG Hub or a Gas Processing Hub. Precise surveying would be required to confirm the exact area of usable land.

In addition, the airstrip and accommodation would need to be at a safe distance from the processing facilities, which further constrains the development options on Maret Islands. To achieve this purpose, INPEX has proposed to place all process facilities on the South Island and all other facilities on the North Island.

**Site Elevation and Gradient**

The Maret Islands are relatively flat, with elevation ranging from sea level to ~35 meters, which would be acceptable for construction of facilities:

- North Island: ~150ha, with a peak elevation of ~35 meters
- South Island: ~210ha, with a peak elevation of ~25 meters

**Proximity to Gas Fields**

The Maret Islands are located ~200 kilometres from the INPEX operated Ichthys field and ~340 kilometres from the Woodside operated Browse (Scott Reef) fields. This distance does not present any specific issues in terms of pipeline construction.

For the purposes of this study, GCA estimates the pipeline length as the straight line distance from the fields to the site.

**Proximity of Plant Site to Coastline**

The plant site could be within one kilometre from the coastline, which is technically suitable.

**Pipeline Approach**

The capacity and size of the gas pipelines from the individual fields dictates that they would be run separately from each field with a separate landfall on the island. The normal construction technique for shore approaches appear to be viable at this location, although alternatives (such as underground culvert) could be considered to reduce disruption of the beach.

**Geotechnical Conditions**

The Maret Islands do not show any signs of erosion, flooding or weather impact. Geotechnical studies have been completed at the site, which have concluded that the geotechnical conditions on Maret Island are suitable for an LNG facility.

**Proximity to Existing Infrastructure**

The Maret Islands are relatively isolated with essentially no infrastructure in the vicinity. The closest significant harbour is Derby, ~420 kilometres from Maret Islands. The port of Broome is ~530 kilometres from Maret Islands. The closest airstrip for passenger transportation is located on Cockatoo Island which is 235 kilometres distant.

**Summary Evaluation**

The Maret Islands can accommodate a Single Operator LNG Hub, but could not accommodate a Multi Operator LNG Hub or a Gas Processing Hub due to the constraint of land area.

The Maret Islands would be technically suitable from a marine standpoint.

INPEX have suggested a development on Maret Islands that could ultimately produce up to 31.8 Mtpa of LNG from a Single operator LNG facility. This facility would have an initial LNG production of 8.4mtpa and could be expanded to the maximum capacity by adding trains. GCA concurs with this assessment.

### 2.3.2 North Kimberley: Bigge Island

**TABLE 7**

**BIGGE ISLAND LNG SITE COMPARATIVE TECHNICAL EVALUATION**

| | Navigable water for LNG carriers | Port suitability | Land area requirements | Site elevation and gradient | Proximity to gas fields | Proximity of plant site to coastline | Pipeline approach | Geotechnical conditions | Proximity to existing infrastructure |
|---|---|---|---|---|---|---|---|---|---|
| Single Operator LNG Hub | Y | Y | Y | Y | Y | Y | Y | Y | N |
| Multi Operator LNG Hub | | | Y | | | | | | |
| Gas Processing Hub | | | Y | | | | | | |

**Navigable Water for LNG Carriers & Port Suitability**

Bigge Island (North) has deep water at the Western edge of the island, but is exposed to the weather. This may require breakwater protection. Elsewhere shallow water exists that may require dredging and / or long jetties.

For the purposes of this study, GCA estimates this site would require a ~500 meter jetty.

**Land Area Requirements**

Bigge Island has over 950 hectares of available land. This is sufficient area for the development of a Gas Processing Hub.

**Site Elevation and Gradient**

Bigge Island appears to be terraced with elevations ranging from 15 to 45 meters on the North West coast of the island where the possible site has been identified. From available data, it appears that adequate land with acceptable gradient exists for the development of a Gas Processing Hub.

**Proximity to Gas Fields**

The Bigge Island potential LNG hub site is located 215 kilometres from the INPEX operated Ichthys field and 360 kilometres from the Woodside operated Browse fields. No insurmountable technical problems are anticipated in installing pipelines from these fields to the Bigge Island site.

For the purposes of this study, GCA estimates the pipeline length as the straight line distance from the fields to the site.

### Proximity of Plant Site to Coastline

There are no apparent technical issues regarding the possible distance of the plant site from the coast, since at this location a distance of approximately one kilometre would be anticipated.

### Pipeline Approach

The coast of Bigge Island has a few small sandy beaches which could serve as a landfall location for the incoming gas supply pipeline for a single LNG plant. It is not anticipated that installing the two lines necessary for a two plant LNG hub would be problematic. Multiple facilities that could be present in a major gas processing hub may be developed on a staggered basis and may source gas from different fields. In considering a master plan for the development of a gas processing hub it could be appropriate to consider an under ground culvert that would pass under the beach with all incoming lines then passed through the culvert or tunnel with minimum disruption to the beach.

### Geotechnical Conditions

Bigge Island terrain is weathered, with a rugged and rocky surface. Detailed survey work would be required to estimate the earth works involved in site preparation. Earth works required are assessed as substantial at this stage.

### Proximity to Existing Infrastructure

Bigge Island (North and South) is uninhabited and a stopping point for cruise and charter boats. The Island is located ~410 kilometres from Derby which has port facilities and the closest airstrip is located at Cockatoo Island which is ~230 kilometres from Bigge Island. There is no existing infrastructure on the island or the surrounding area that would assist an LNG development.

### Summary Evaluation

Bigge Island has adequate area to cover any of the possible development options. The land has some undulations and rocky surface which is expected to require substantial work for site preparation. There is no existing infrastructure on Bigge Island; this would have to be installed as an integral part of the project. Multiple pipeline beach crossings for a potential gas processing hub may require further study to develop a suitable technique which minimises or eliminates any damage to the beach. Bigge Island would be technically marginal from a marine standpoint.

### 2.3.3 North Kimberley: Champagny Islands

**TABLE 8**

**CHAMPAGNY ISLAND LNG SITE COMPARATIVE TECHNICAL EVALUATION**

| | Navigable water for LNG carriers | Port suitability | Land area requirements | Site elevation and gradient | Proximity to gas fields | Proximity of plant site to coastline | Pipeline approach | Geotechnical conditions | Proximity to existing infrastructure |
|---|---|---|---|---|---|---|---|---|---|
| Single Operator LNG Hub | Y | Y | Y | Y | Y | Y | N | Y | N |
| Multi Operator LNG Hub | | | N | | | | | | |
| Gas Processing Hub | | | N | | | | | | |

**Navigable Water for LNG Carriers & Port Suitability**

Champagny Island has deep water close to the coast but is exposed to strong currents, swells and seas and may therefore require a breakwater. Detailed marine surveying would be required to confirm LNG carrier access.

For the purposes of this study, GCA estimates this site would require a ~500 meter jetty.

**Land Area Requirements**

Champagny Island has a total usable area of approximately 360 hectares, due to the irregular shape of the land and the jagged coastline. This would be suitable for a Single Operator LNG Hub, and there would be options for limited expansion. However, the construction of a Multi Operator LNG Hub or a Gas Processing Hub would not be feasible.

**Site Elevation and Gradient**

The potential site for the installation of facilities has elevations ranging from 10 to 40 meters. The rest of the island has low elevations, which would not be suitable for the safe operation of an LNG plant. The island appears to be rocky with little or no sandy beaches. Site gradient would be acceptable for the movement of heavy construction equipment.

**Proximity to Gas Fields**

Champagny Island is located 190 kilometres from the INPEX operated Ichthys field and 290 kilometres from the Woodside operated Browse fields. There are no insurmountable pipeline issues surrounding gas lines from the offshore fields.

For the purposes of this study, GCA estimates the pipeline length as the straight line distance from the fields to the site.

**Proximity of Plant Site to Coastline**

The topography of the island is such that there will be no technical problems with the distance of the LNG plant from the shore, which is likely to be less than one kilometre.

**Pipeline Approach**

It appears that the coastline of the island is rugged with essentially no beaches which would make the landing of the pipeline onshore potentially technically challenging. In this type of terrain it may be necessary to carry out some blasting to allow an appropriate landfall for the incoming gas pipeline. Close study of this would be needed before making a decision to utilise the Champagny Islands as a possible LNG plant location.

**Geotechnical Conditions**

Minimum earthworks are anticipated on this site, as the island is relatively flat.

**Proximity to Existing Infrastructure**

There is no existing infrastructure on Champagny Island. Access would be by air and sea. An airstrip would have to be constructed. All construction equipment would have to be transported to the island by sea. The construction of a suitable offloading facility would also be required.

**Summary Evaluation**

Although the total surface of the Champagny Islands would almost meet the overall requirement for a Multi Operator LNG Hub, due to the geometry of the island it would not be possible to install two separate LNG plants.

It should also be noted that a considerable section of the area, which has not been selected for the LNG site, has an elevation insufficient for the safe operation of such an infrastructure.

The land fall for the incoming gas line would also be technically challenging.

### 2.3.4 North Kimberley: Wilson Point

**TABLE 9**

**WILSON POINT LNG SITE COMPARATIVE TECHNICAL EVALUATION**

| | Navigable water for LNG carriers | Port suitability | Land area requirements | Site elevation and gradient | Proximity to gas fields | Proximity of plant site to coastline | Pipeline approach | Geotechnical conditions | Proximity to existing infrastructure |
|---|---|---|---|---|---|---|---|---|---|
| Single Operator LNG Hub | Y | Y | Y | N | Y | Y | Y | N | N |
| Multi Operator LNG Hub | | | Y | | | | | | |
| Gas Processing Hub | | | Y | | | | | | |

**Navigable Water for LNG Carriers & Port Suitability**

Wilson Point would be a technically suitable site from a marine standpoint. Neither capital nor maintenance dredging would be required; the jetty length is likely to be small. A breakwater would probably not be required.

For the purposes of this study, GCA estimates this site would require a ~500 meter jetty.

**Land Area Requirements**

Wilson Point is a coastal location, where available land is constrained by the steep slope of the terrain. There is sufficient land available to construct any of the types of hubs considered.

**Site Elevation and Gradient**

Wilson Point is an elevated site with cliffs on the shore line. The potential site elevation increases to 50 meters within 500 metres from the coast and significant elevation range (from 15 meters to over 110 meters within a 950 hectares site). The gradient for heavy construction equipment would be challenging as would be the overall construction effort. Considerable earth works would be required which would result in significant costs.

### Proximity to Gas Fields

Wilson Point is located 220 kilometres from the INPEX operated Ichthys field and 320 kilometres from the Woodside operated Browse fields. No technical issues are apparent with the pipelines required from these fields to the potential LNG plant site.

For the purposes of this study, GCA estimates the pipeline length to this site to be ~220 kilometres from the INPEX operated Ichthys field and ~320 kilometres from the Woodside operated Browse fields.

### Proximity of Plant Site to Coastline

The plant site is situated relatively close to the coast and no technical issues are envisioned in this context. The distance from the plant site to the coastline is likely to be less than one kilometre.

### Pipeline Approach

Several sandy coves exist which would allow the offshore pipeline to be landed in a beach environment. The cutting of the beach could be achieved with the necessary remedial work to restore the beach to its original state.

### Geotechnical Conditions

Significant earthworks are anticipated at Wilson Point, in part due to the cliffs and relief along the shoreline. These earthworks may be complicated by hard rocks in the area and possible fault lines.

### Proximity to Existing Infrastructure

Wilson Point is in a relatively remote area. The closest port would be Derby which is located ~270 kilometres from Wilson Point by sea. There are airports at Derby and Fitzroy Crossing which is ~330 kilometres by land from Wilson Point.

### Summary Evaluation

Wilson Point could be developed as a Gas Processing Hub; however site preparation would be difficult and would result in significant costs. Landfall of the offshore pipeline presents some issues however these can be overcome. The plant can be laid out in such a manner that the distance from the LNG tanks to the coast is kept within one kilometre.

There is no infrastructure in the area of Wilson Point, and further studies would be required to confirm the possibility of constructing a road into the location. Consideration would be given to use of marine access through an offloading facility for import of heavy construction equipment. Wilson Point would be technically suitable from a marine standpoint.

### 2.3.5 North Kimberley: Koolan Island

**TABLE 10**

**KOOLAN ISLAND LNG SITE COMPARATIVE TECHNICAL EVALUATION**

| | Navigable water for LNG carriers | Port suitability | Land area requirements | Site elevation and gradient | Proximity to gas fields | Proximity of plant site to coastline | Pipeline approach | Geotechnical conditions | Proximity to existing infrastructure |
|---|---|---|---|---|---|---|---|---|---|
| Single Operator LNG Hub | Y | Y | Y | N | Y | Y | N | Y | Y |
| Multi Operator LNG Hub | | | N | | | | | | |
| Gas Processing Hub | | | N | | | | | | |

**Navigable Water for LNG Carriers & Port Suitability**

The South side of Koolan Island presents suitable marine conditions and a breakwater or a long jetty would not be required. However, consultation with the iron ore mining Operator would be required to confirm the possibility of additional maritime traffic and berthing generated by the LNG operation, without disrupting current mining operations.

For the purposes of this study, GCA estimates this site would require a ~500 meter jetty.

**Land Area Requirements**

Koolan Island has an available area of more than 360 hectares, which would be sufficient for a Single Operator LNG Hub.

However, much of the land is reserved for hematite production, which recommenced in early 2007. The island is currently mined by Mount Gibson Iron (having taken over Aztec Resources in February 2007), which have a mining lease for ~12 years.

**Site Elevation and Gradient**

Koolan Island elevation increases to 150 meters within 2.3 kilometres from the coast, which would pose significant technical challenges for an LNG development.

**Proximity to Gas Fields**

The Cockatoo and Koolan Islands are located ~250 kilometres from the INPEX operated Ichthys field and ~300 kilometres from the Woodside operated Browse fields.

For the purposes of this study, GCA estimates the pipeline length to this site to be ~250 kilometres from the INPEX operated Ichthys field and ~310 kilometres from the Woodside operated Browse fields.

**Proximity of Plant Site to Coastline**

The development could possibly be located within reasonable distance from the coastline on Koolan Island (less than one kilometre), but with large elevation changes this needs confirmation through surveys.

**Pipeline Approach**

The island's topography poses difficulties for pipeline approach. Substantial excavation and / or tunnelling are likely to be required.

**Geotechnical Conditions**

Koolan Island has cliffs and steep sloping ground. A large portion of the land is occupied by mining activities. Very significant earthworks would be required for this site to be used for an LNG development.

**Proximity to Existing Infrastructure**

Koolan Island is 5 kilometres east southeast of Cockatoo Island and a distance of ~170 kilometres north of Derby by sea. There is currently a mining operation on the island. Koolan Island is readily accessible by sea and has a functional port. The airstrip is in good condition and could be used for personnel transport. The port on the other hand may require upgrading of the wharf.

**Summary Evaluation**

There is sufficient area on Koolan Island for a Single Operator LNG Hub. However, this site would require significant earth works to be made suitable for the installation of LNG facilities because of the Island's rough terrain, high elevations and steep slopes. These technical difficulties are compounded by mining operations currently underway on the island. Koolan Island would be technically suitable from a marine standpoint.

### 2.3.6 North Kimberley: Cockatoo Island

**TABLE 11**

**COCKATOO ISLAND LNG SITE COMPARATIVE TECHNICAL EVALUATION**

| | Navigable water for LNG carriers | Port suitability | Land area requirements | Site elevation and gradient | Proximity to gas fields | Proximity of plant site to coastline | Pipeline approach | Geotechnical conditions | Proximity to existing infrastructure |
|---|---|---|---|---|---|---|---|---|---|
| Single Operator LNG Hub | Y | Y | N | N | Y | NA | NA | NA | Y |
| Multi Operator LNG Hub | Y | Y | N | N | Y | NA | NA | NA | Y |
| Gas Processing Hub | Y | Y | N | N | Y | NA | NA | NA | Y |

**Navigable Water for LNG Carriers & Port Suitability**

Cockatoo Island would be a suitable site from a marine standpoint. Dredging is likely to be needed for shallow area of 10 meter depth at the west end, otherwise deep water is close to shore. A breakwater or a long jetty would not be required

For the purposes of this study, GCA estimates this site would require a ~500 meter jetty.

**Land Area Requirements**

Cockatoo Island has an area of ~250 hectares, which is insufficient for an LNG development.

Land area is further constrained by mining currently underway on the island, which extends down to 30 meters below sea level, behind a sea wall. This seam is expected to be mined until 2011, after which the focus may shift to mining lower grade ore in centre of Island. There is usually about 80 mine staffs on Island.

**Site Elevation and Gradient**

Cockatoo Island elevation increases to 45 meters within 500 meters from the coast.

**Proximity to Gas Fields**

The Cockatoo and Koolan Islands are located ~250 kilometres from the INPEX operated Ichthys field and ~300 kilometres from the Woodside operated Browse fields.

**Proximity of Plant Site to Coastline**

Not Applicable

**Pipeline Approach**

Not Applicable

**Geotechnical Conditions**

Not Applicable

There is almost no flat land on Cockatoo Island and any earth works is likely to require blasting.

**Proximity to Existing Infrastructure**

Cockatoo Island currently has an iron ore mining operation that is the only activity on the island. The island is currently served by a port and an airstrip which handles frequent charter flights. The island is readily accessible by sea and can be reached in 6 hours steaming time from Derby. All the logistical supplies for the mining operation are barged from Derby. In order to utilize the port and airstrip for the purposes of supporting an LNG project it would be necessary to upgrade the facilities. There is also an extensive road network on the island which was installed for the mining operations. This makes all parts of the island accessible by road. Cockatoo Island is a fly-in-fly-out operation, with normally ~80 people on the Island.

**Summary Evaluation**

There is insufficient available area on Cockatoo Island for an LNG development. This unsuitability is compounded by mining operations currently underway on the island. Cockatoo Island would be technically suitable from a marine standpoint.

### 2.3.7 South Kimberley: Cape Leveque

**TABLE 12**

**CAPE LEVEQUE LNG SITE COMPARATIVE TECHNICAL EVALUATION**

| | Navigable water for LNG carriers | Port suitability | Land area requirements | Site elevation and gradient | Proximity to gas fields | Proximity of plant site to coastline | Pipeline approach | Geotechnical conditions | Proximity to existing infrastructure |
|---|---|---|---|---|---|---|---|---|---|
| Single Operator LNG Hub | | | Y | | | | | | |
| Multi Operator LNG Hub | Y | Y | Y | Y | Y | Y | Y | Y | Y |
| Gas Processing Hub | | | Y | | | | | | |

**Navigable Water for LNG Carriers & Port Suitability**

Cape Leveque is exposed on the western side where there is deep water; it is sheltered to the east but would need dredging and / or a jetty of significant length.

For the purposes of this study, GCA estimates this site would require a ~1.5 kilometre jetty.

**Land Area Requirements**

Cape Leveque is a coastal site with over 950 hectares of available land. This would be adequate for the development of a gas processing Hub.

**Site Elevation and Gradient**

Elevations at the site range from ~15 to ~40 meters. The land rises from ~15 meters at the West boundary of the proposed site to a maximum height of ~40 meters at the mid point of the site and slope again to ~15 meters at the East boundary of the site. The site would be suitable for construction without large amounts of earth movement and the gradient would also allow movement of both heavy construction equipment and large modules.

**Proximity to Gas Fields**

Cape Leveque is situated ~280 kilometres from the INPEX operated Ichthys field and ~290 kilometres from the Woodside operated Browse fields. No technical issues are likely with the installation of the gas lines from the offshore fields.

For the purposes of this study, GCA has estimated the pipeline length to this site to be ~300 kilometres from the INPEX operated Ichthys field and ~290 kilometres from the Woodside operated Browse fields.

**Proximity of Plant Site to Coastline**

The proposed plant site is located at the western boundary approximately 1.5 kilometres from the coast; at the South West boundary the distance to the coast decreases to one kilometre.

**Pipeline Approach**

To the West there are extensive sandy beaches. To the South West of the site there is a small cove with a less extensive beach where pipeline crossing could be made. It is likely that a both a single LNG plant scenario and a two LNG plant site could accommodate the gas inlet pipeline crossing by cutting the beach and carrying out the necessary remedial work. With a large gas processing hub and the much larger number of possible pipelines which would also cross the beach it may be necessary to develop an alternative type of crossing which obviates the need for continuous disruption of the beach.

**Geotechnical Conditions**

Cape Leveque is a relatively flat site, which would require minimum earthworks.

**Proximity to Existing Infrastructure**

Cape Leveque is located ~185 kilometres from Broome and ~150 kilometres from Derby. There is a small airstrip close to Cape Leveque which could perhaps be upgraded to allow the transportation of personnel and smaller equipment. There is a road from Cape Leveque to Broome. This road would require significant upgrading to be used to haul heavy equipment required for construction.

**Summary Evaluation**

From a technical perspective Cape Leveque would be a suitable site for any of the three possible installations (Single Operator LNG Hub, Multi Operator LNG Hub, Gas Processing Hub). The land area is adequate and the site elevation and topography are such that earth works would not be too extensive and the gradient would allow the transportation of large modules.

There is some infrastructure, which includes a dirt airstrip that could be upgraded and a road from Broome. The road would need considerable upgrading to allow transportation of heavy equipment and personnel.

Cape Leveque would be technically marginal from a marine standpoint. Further consideration and survey work would be needed to optimise the marine operations and berthing facilities.

### 2.3.8 South Kimberley: Lombadina (Packer Island)

**TABLE 13**

**LOMBADINA (PACKER ISLAND) FOR LNG SITE COMPARATIVE TECHNICAL EVALUATION**

<table>
<tr><th></th><th>Navigable water for LNG carriers</th><th>Port suitability</th><th>Land area requirements</th><th>Site elevation and gradient</th><th>Proximity to gas fields</th><th>Proximity of plant site to coastline</th><th>Pipeline approach</th><th>Geotechnical conditions</th><th>Proximity to existing infrastructure</th></tr>
<tr><td>Single Operator LNG Hub</td><td rowspan="3">Y</td><td rowspan="3">Y</td><td>Y</td><td rowspan="3">Y</td><td rowspan="3">Y</td><td rowspan="3">Y</td><td rowspan="3">Y</td><td rowspan="3">Y</td><td rowspan="3">Y</td></tr>
<tr><td>Multi Operator LNG Hub</td><td>Y</td></tr>
<tr><td>Gas Processing Hub</td><td>Y</td></tr>
</table>

**Navigable Water for LNG Carriers & Port Suitability**

Lombadina (Packer Island) is wholly exposed to the weather and may require a significant breakwater to enclose the berth and probably the swing basin as well.

For the purposes of this study, GCA estimates this site would require a ~2 kilometre jetty.

**Land Area Requirements**

Lombadina has over 950 hectares of available land, adequate for the development of a gas processing Hub. The potential site could be located in several orientations due to the abundant land available. In the layout shown the distance from the coast has been kept to a minimum to reduce the length of the LNG loading lines which are very sensitive to cost.

**Site Elevation and Gradient**

The site elevation ranges of ~10 to ~25 meters and slopes downwards from the eastern boundary to the western boundary.

**Proximity to Gas Fields**

Lombadina is roughly equidistant from the INPEX operated Ichthys field and the Woodside operated Browse fields. Both are ~300 kilometres, in a straight line, from Lombadina.

For the purposes of this study, GCA estimates the pipeline length to this site to be ~310 kilometres from the INPEX operated Ichthys field and ~300 kilometres from the Woodside operated Browse fields.

**Proximity of Plant Site to Coastline**

Assuming a minimum 10 meter elevation for a potential LNG site would result in a distance of approximately 2 kilometres from the coast to the proposed plant site, which is acceptable.

**Pipeline Approach**

To the North side of a potential plant site there is a small beach where pipeline crossings could take place. In the event a plan was established for a gas processing hub, then some minimally intrusive method could be developed for establishing multi pipeline crossing of beaches.

**Geotechnical Conditions**

Lombadina is characterized by relatively level and sandy ground, behind a rocky foreshore. Substantial earthworks are not required to render this site suitable for an LNG development.

**Proximity to Existing Infrastructure**

Lombadina is located ~140 kilometres from Derby and ~180 kilometres from Broome. There are port facilities and airports located in both Derby and Broome. Lombadina is also accessible by road from Broome. Some upgrading of the road would be necessary for access to an LNG site for transportation of materials during construction and personnel. There is also a sealed airstrip ~15 kilometres to the North of the potential site. This airstrip could be upgraded for use during construction and for normal operations.

**Summary Evaluation**

Lombadina has adequate land available and the gradient of the land would allow construction vehicles access without significant site preparation. The distance to the coast is no more than 2 kilometres which is well within the maximum of 5 kilometres for LNG loading lines.

There is also an existing road and airstrip which can be used. The road will require upgrading to accommodate construction and transportation vehicles in all seasons. The airstrip would probably require upgrading depending on the type of aircraft which will use the strip.

Lombadina (Packer Island) would be technically marginal from a marine standpoint.

### 2.3.9 South Kimberley: North Head / Perpendicular Head

**TABLE 14**

**NORTH HEAD / PERPENDICULAR HEAD LNG SITE COMPARATIVE TECHNICAL EVALUATION**

| | Navigable water for LNG carriers | Port suitability | Land area requirements | Site elevation and gradient | Proximity to gas fields | Proximity of plant site to coastline | Pipeline approach | Geotechnical conditions | Proximity to existing infrastructure |
|---|---|---|---|---|---|---|---|---|---|
| Single Operator LNG Hub | Y | Y | Y | Y | Y | Y | Y | Y | Y |
| Multi Operator LNG Hub | | | Y | | | | | | |
| Gas Processing Hub | | | Y | | | | | | |

**Navigable Water for LNG Carriers & Port Suitability**

North Head is exposed to the weather and may require a jetty and breakwater of significant scale.

Perpendicular Head is exposed to the weather and may require a jetty of significant scale and possibly a breakwater as well. There is protected shallow water to the east in Pender Bay, where dredging and/or a long jetty would be needed.

For the purposes of this study, GCA estimates these sites would require a ~2 kilometre jetty.

**Land Area Requirements**

North Head and Perpendicular Head each have over 950 hectares of land available. This is sufficient land for the development of a gas processing Hub in the vicinity of North Head or Perpendicular Head.

**Site Elevation and Gradient**

North Head has an elevation range of ~10 to ~30 meters. The elevation increases from the coast in an easterly direction. The elevation does not pose a technical risk at this site.

Perpendicular Head has an elevation range of ~10 to ~40 meters. The terrain is steeper than the area at North Head. There are cliffs in the foreshore and some areas of steep slopes. Overall the cost of earthworks could be higher than North Head.

**Proximity to Gas Fields**

Both North Head and Perpendicular Head are located approximately 330 kilometres , in a straight line, from the INPEX operated Ichthys field. The distance from these potential sites to the Woodside operated Browse fields is approximately 300 kilometres.

For the purposes of this study, GCA estimates the pipeline length to this site to be ~370 kilometres from the INPEX operated Ichthys field and ~330 kilometres from the Woodside operated Browse fields.

**Proximity of Plant Site to Coastline**

The plant site would be one kilometre from the coast at the closest point. Based on this short distance there would be no issue with the length of the LNG loading lines to the jetty.

**Pipeline Approach**

There are some wide beaches close to Perpendicular Head however pipeline crossings could be made at locations where there would be minimal beach depth thereby minimising any disruption to the environment. This is also the situation at North Head.

If a gas processing hub is selected as the desired development scenario then a method for passing multiple lines under the beach to prevent extensive cutting of the beach may be beneficial to reduce environmental impact.

**Geotechnical Conditions**

North Head has generally level ground, and limestone is expected to be found at relatively shallow depth. Perpendicular Head has an undulating ground with a number of gullies passing through the area.

**Proximity to Existing Infrastructure**

North Head is located approximately ~25 kilometres north of Beagle Bay and can be accessed by road from Broome. The distance to Broome is ~135 kilometres while to Derby it is 125 kilometres. Being accessible by road from Broome would be an asset when considering both transportation of construction materials and personnel. Some upgrading of the road will be required to make available for all seasons. There is no airstrip in the close vicinity.

**Summary Evaluation**

There is adequate land at both Perpendicular Head and North Head to develop a gas processing hub. Of the two sites, North Head probably has the more level ground and would be less costly when considering site preparation.

Both sites have access to Broome via the existing road however some upgrading of the road would be necessary. There is no airstrip in the vicinity; therefore it is likely some type of airstrip would require construction as part of any overall development.

Perpendicular Head and North Head would be technically marginal from a marine standpoint.

### 2.3.10 South Kimberley: Quondong Point

**TABLE 15**

**QUONDONG POINT LNG SITE COMPARATIVE TECHNICAL EVALUATION**

| | Navigable water for LNG carriers | Port suitability | Land area requirements | Site elevation and gradient | Proximity to gas fields | Proximity of plant site to coastline | Pipeline approach | Geotechnical conditions | Proximity to existing infrastructure |
|---|---|---|---|---|---|---|---|---|---|
| Single Operator LNG Hub | Y | Y | Y | Y | Y | Y | Y | Y | Y |
| Multi Operator LNG Hub | | | Y | | | | | | |
| Gas Processing Hub | | | Y | | | | | | |

**Navigable Water for LNG Carriers & Port Suitability**

Quondong Point is an exposed site which will probably require construction of a breakwater of significant length. There are potential issues with currents.

For the purposes of this study, GCA estimates this site would require a ~1.5 kilometre jetty.

**Land Area Requirements**

Quondong Point has over 950 hectares of land available which would make it suitable for a gas processing hub. The proposed site could however require the re-routing of the road that runs North from Broome.

**Site Elevation and Gradient**

There are some cliffs close to shore and thereafter a plateau extends to the east rising from 5 meters to 25 meters at the existing road. To the east of the road the elevation increases from 25 meters at the road to 35 meters at a distance of 4 kilometres to the east.

**Proximity to Gas Fields**

Quondong Point is located, in a straight line, ~425 kilometres form the INPEX operated Ichthys field and ~390 kilometres from the Woodside operated Browse fields.

For the purposes of this study, GCA estimates the pipeline length to this site to be ~470 kilometres from the INPEX operated Ichthys field and ~420 kilometres from the Woodside operated Browse fields.

**Proximity of Plant Site to Coastline**

The distance to the coast could be within 2 kilometres. This distance, while technically suitable, could be reduced by re routing the road, which currently lies between the proposed plant site and the coast. The cost of LNG loading line could be as high as US$25MM/km.

**Pipeline Approach**

There is at least a 5 meter elevation increase from the beach to the higher ground close to the beach, which will complicate the pipeline land fall. On the North site of the potential site there is a sandy beach where the pipeline crossings could be made. A large gas processing hub will require careful planning to handle multiple pipelines crossing the beach.

**Geotechnical Conditions**

The site is expected to be relatively level and require limited earthworks. However; visual reports of potential erosion may require further investigation.

**Proximity to Existing Infrastructure**

Quondong Point is located 45 kilometres from Broome where there is both a port and an airport. Quondong Point is accessible by road from Broome which is beneficial for both construction and personnel movement. Personnel employed at the LNG plant could live in Broome and commute to work. Some upgrading of the road will be required to make available for all seasons. There is an airstrip in the Broome vicinity.

**Summary Evaluation**

Quondong Point presents a suitable site on which to construct and develop a gas processing hub. There is considerable suitable land available. Final site selection could necessitate the relocation of the Broome road if the site closest to the coast is selected.

The site is further from the offshore gas fields than most other sites in the Kimberley; however it is closer to Broome where both a port and airport exist. Broome could also be used for staff housing with the staff commuting daily to the site.

Quondong Point would be technically marginal from a marine standpoint.

### 2.3.11 South Kimberley: Fisherman's bend

**TABLE 16**

**FISHERMAN'S BEND LNG SITE COMPARATIVE TECHNICAL EVALUATION**

| | Navigable water for LNG carriers | Port suitability | Land area requirements | Site elevation and gradient | Proximity to gas fields | Proximity of plant site to coastline | Pipeline approach | Geotechnical conditions | Proximity to existing infrastructure |
|---|---|---|---|---|---|---|---|---|---|
| Single Operator LNG Hub | Y | Y | Y | Y | Y | Y | Y | Y | Y |
| Multi Operator LNG Hub | | | Y | | | | | | |
| Gas Processing Hub | | | Y | | | | | | |

**Navigable Water for LNG Carriers & Port Suitability**

Fisherman Bend has shallow water, requiring significant capital and maintenance dredging. No breakwater would be required.

For the purposes of this study, GCA estimates this site would require a ~2 kilometre jetty.

**Land Area Requirements**

Fisherman's bend is a coastal location with over 950 hectares of available land. This would be a technically adequate site for the development of a gas processing Hub.

**Site Elevation and Gradient**

This potential site has an elevation range of 15 to 35 meters. The site is fairly level. There are cliffs at the edge of the beach. This site topography does not present any significant technical challenges.

**Proximity to Gas Fields**

Fisherman's Bend is significantly further from the offshore gas fields than other North and South Kimberley sites. The straight line distance to the INPEX operated Ichthys field is ~460 kilometres whereas the distance to the Woodside operated Browse fields is ~440 kilometres.

For the purposes of this study, GCA estimates the pipeline length to this site to be ~540 kilometres from the INPEX operated Ichthys field and ~480 kilometres from the Woodside operated Browse fields.

**Proximity of Plant Site to Coastline**

Proximity of the site boundary to the coast is within 500 meters at the closest point. This short distance to the coast would result in minimum costs for the LNG loading lines.

**Pipeline Approach**

There are beaches close to the site and it appears pipeline landfall could be made at different points. There is a road running close to the coast so any pipeline landfall would require a road crossing to reach the intended site. Since this site could accommodate a full gas processing site there could be multiple pipeline crossing required. It would be very important to carefully plan where and how the beach crossings and the road crossings would be engineered. With potentially multiple pipelines coming ashore at one location a plan to minimise the disruption to the beach would be environmentally advantageous.

**Geotechnical Conditions**

This site is relatively level and extensive earthworks are not anticipated.

**Proximity to Existing Infrastructure**

Fisherman's Bend is located ~10 kilometres from Broome and as such has excellent access to both port facilities and an airport. There is also a potential for staff accommodation in Broome for both staff and their families, with significant potential cost benefits.

**Summary Evaluation**

From a technical view point, Fisherman's Bend would be a good location for a gas processing hub. There is adequate land with suitable topography.

Broome is ~10 kilometres away which would be a significant advantage from many respects. For example there is a port and airport in Broome which would significantly improve the efficiency of both the construction effort and the future operation of the plants in the gas processing hub. Staff could be housed in Broome, there are medical facilities etc in Broome which the staff and their families could benefit from.

There will be some challenges associated with the installation of the gas pipelines coming ashore since crossing the beach with minimum disruption and road crossing will require engineering and consultation with the local community.

Fisherman's Bend is significantly further from the offshore gas fields than other North and South Kimberley sites, which will have a substantial impact on offshore pipeline costs.

Fisherman's Bend would be technically marginal from a marine standpoint. The likely ongoing maintenance dredging will be an additional technical challenge associated with this site.

### 2.3.12 Offshore Kimberley: Scott Reef

**TABLE 17**

**SCOTT REEF LNG SITE COMPARATIVE TECHNICAL EVALUATION**

| | Navigable water for LNG carriers | Port suitability | Land area requirements | Site elevation and gradient | Proximity to gas fields | Proximity of plant site to coastline | Pipeline approach | Geotechnical conditions | Proximity to existing infrastructure |
|---|---|---|---|---|---|---|---|---|---|
| Single Operator LNG Hub | Y | NA | NA | NA | Y | NA | NA | NA | N |
| Multi Operator LNG Hub | | | NA | | | | | | |
| Gas Processing Hub | | | NA | | | | | | |

#### Navigable Water for LNG Carriers & Port Suitability

Scott Reef is comprised of two separate coral reef structures: North Scott Reef is almost fully enclosed and contains sheltered waters between 10 and 20m deep; while South Scott Reef is crescent shaped with water depths ranging from 10 to 70m - both reefs are of a considerable size and partially exposed at low tide. Sandy Islet at the western tip of South Scott Reef is emergent at high tide.

The reef crest provides protection from the prevailing metocean conditions, but tidal currents are strong between the North and South reefs. Passage between the North and South reef is via a 1 mile wide passage, close to the south side of North reef.

Woodside's evaluation of the metocean conditions indicate that Scott Reef marine approaches are adequately surveyed and that no technical issues would be expected for navigation of LNG, LPG or condensate carriers. The water depth and currents associated with the narrow channels at the entrance to the North reef lagoons preclude a development within the Northern lagoon, but a development external to the North reef, or within the Southern lagoon would be technically feasible. GCA has not reviewed the analysis of metocean conditions conducted by Woodside.

#### Land Area Requirements

It is envisaged that all facilities will be located within the sheltered lagoonal areas of Scott Reef using a combination of gravity based structures constructed of either steel or concrete, or conventional jacket structures.

#### Site Elevation and Gradient

This is an offshore development with no land requirement.

**Proximity to Gas Fields**

Scott Reef is ~150 kilometres from the INPEX operated Ichthys field and is directly above the Woodside operated Torosa field.

**Proximity of Plant Site to Coastline**

Not Applicable

**Pipeline Approach**

The reef platform is characterised by a steep slope which drops from the shallow water of the reef lagoonal areas to water of ~400m water depth. The pipeline / umbilical crossing of the reef slope is a challenge for a Scott Reef based development.

**Geotechnical Conditions**

In 2006/2007 the Browse Joint Venture executed a geophysical and geotechnical survey programme comprising a number of bore holes on Scott Reef. Woodside has stated that these surveys have allowed the development of a preliminary geological model and indicate that both gravity base structures and piled jacket structures could be feasible.

**Proximity to Existing Infrastructure**

Scott Reef, like the Maret Islands, is a remote location with no existing infrastructure. The closest ports and airports are located at Derby – 220 kilometres and Broome 440 kilometres. All access and logistics would be managed as for an offshore operation.

**Summary Evaluation**

Scott Reef is an offshore development. To date, not even a small single train LNG plant has been installed in this type of environment and the technology for floating or even platform mounted LNG plants has yet to be demonstrated. Any proposal to move directly to a “hub” using barge mounted facilities should be seriously questioned.

### 2.3.13 Offshore Kimberley: Echuca Shoals

**TABLE 18**

**ECHUCA SHOALS LNG SITE COMPARATIVE TECHNICAL EVALUATION**

| | Navigable water for LNG carriers | Port suitability | Land area requirements | Site elevation and gradient | Proximity to gas fields | Proximity of plant site to coastline | Pipeline approach | Geotechnical conditions | Proximity to existing infrastructure |
|---|---|---|---|---|---|---|---|---|---|
| Single Operator LNG Hub | ? | NA | NA | NA | Y | NA | NA | NA | N |
| Multi Operator LNG Hub | | | NA | | | | | | |
| Gas Processing Hub | | | NA | | | | | | |

**Navigable Water for LNG Carriers & Port Suitability**

Marine access would require further studies.

**Land Area Requirements**

This location is submerged therefore no land is available, requiring a similar development to Scott Reef.

**Site Elevation and Gradient**

Not Applicable

**Proximity to Gas Fields**

Echuca Shoals is located approximately 75 kilometres from the INPEX operated Ichthys field and ~200 kilometres from the Woodside operated Browse fields.

**Proximity of Plant Site to Coastline**

Not Applicable

**Pipeline Approach**

Not Applicable

**Geotechnical Conditions**

Not Applicable

**Proximity to Existing Infrastructure**

Echuca Shoals is located ~475 kilometres from Derby and ~520 kilometres from Broome. There are no facilities on the shoal and all future transportation would be by sea or helicopter.

**Site Overview**

Not Applicable

**Summary Evaluation**

Echuca Shoals is a submerged location with similar issues to Scott Reef. INPEX considered this site for its Ichthys project but ruled it out on the basis of the significant technical challenges presented.

### 2.3.14 Existing infrastructure: Burrup (NWS & Pluto)

**TABLE 19**

**BURRUP LNG SITE COMPARATIVE TECHNICAL EVALUATION**

| | Navigable water for LNG carriers | Port suitability | Land area requirements | Site elevation and gradient | Proximity to gas fields | Proximity of plant site to coastline | Pipeline approach | Geotechnical conditions | Proximity to existing infrastructure |
|---|---|---|---|---|---|---|---|---|---|
| Single Operator LNG Hub | Y | Y | Y | Y | Y | Y | Y | Y | Y |
| Multi Operator LNG Hub | | | N | | | | | | |
| Gas Processing Hub | | | N | | | | | | |

**Navigable Water for LNG Carriers & Port Suitability**

Burrup is a proven LNG site, and no marine complications are expected in the context of an additional development.

**Land Area Requirements**

It is acknowledged that development at the Burrup could either be a greenfield development, as discussed in this report, or an integrated development with the existing LNG plants which would be subject to commercial negotiations between the various interest holders. The scope of this study is purely the technical assessment of site suitability, and therefore excludes commentary on commercial matters.

In reviewing the available land in Burrup allocated for gas processing purposes it appears that Block "H" and "K" could be utilised for a stand alone LNG plant. There is sufficient land in these blocks on which to install a Single Operator LNG Hub. A Multi Operator LNG Hub or a Gas Processing Hub would require additional land.

At the time of this report it is understood that Woodside are evaluating the tie-back of the Browse Joint Venture gas fields to the North West Shelf gas plant.

**Site Elevation and Gradient**

It does not appear that site elevation would cause any significant technical issues.

**Proximity to Gas Fields**

Burrup is located ~1,020 kilometres from the INPEX operated Ichthys field and ~910 kilometres from the Woodside operated Browse gas fields.

**Proximity of Plant Site to Coastline**

There is no issue with the plant being close to the coast. This site has coastline as part of site boundary.

**Pipeline Approach**

The proposed site has coast line as a part of the site perimeter therefore gaining access to the sea for installation of a pipeline would not be problematic. The existing plants in Burrup have previously installed pipelines for gas supply so there exists a precedent for an acceptable method of bringing pipelines onshore. Similar techniques could be used for a new project. In an area where many pipelines come onshore, careful planning with all other stakeholders would be necessary.

**Geotechnical Conditions**

With the installation of other gas processing plants in this area the geotechnical conditions must be well known and any new plant constructor would have the benefit of that experience.

**Proximity to Existing Infrastructure**

Burrup is a gas processing area and there exists considerable infra structure that could be utilised by a company constructing a stand alone LNG plant.

**Summary Evaluation**

Single Operator LNG Hub could be built in the unallocated blocks “H” and “K”. There is sufficient area for an LNG plant and being close to a well developed gas processing area there would be the benefits of existing infra structure which would be attractive to a new entrant to the area. The major downside to the Burrup location for an LNG plant to serve the Ichthys and Browse fields will be the significant distance from the fields to Burrup (~1,020 kilometres from the INPEX operated Ichthys field and ~910 kilometres from the Woodside operated Browse fields). This would not only impact pipeline costs, but could also cause schedule delays waiting delivery of large amounts of line pipe.

# APPENDIX I

## RFT DOIR2271107 - SCOPE OF SERVICES – Extract

## RFT DOIR2271107 - SCOPE OF SERVICES – Extract

### LNG Plant Site Selection Validation

The objective of this area of the study is to review the site selection process undertaken by the various proponents, and provide commentary on the technical suitability of the various sites considered to date in the context of processing Browse Basin gas at an onshore hub location or locations.

The following studies are envisaged as part of the onshore site selection validation exercise:

Review LNG site selection process undertaken by industry.

a. Comment on technical basis for screening / shortlisting of sites, including:
   i. Port suitability (impact of metocean conditions and in particular currents on offloading availability);
   ii. Land area requirements for infrastructure hub development (including allowance for construction operations)
   iii. Site elevation (relative to storm surge) and gradient;
   iv. Proximity to gas fields;
   v. Distance to navigable water for LNG carriers;
   vi. Proximity of plant site to coastline;
   vii. Pipeline approach;
   viii. Geotechnical conditions; and
   ix. Proximity to existing infrastructure.

b. Given the following shortlist of potential LNG hub locations, comment on the likely technical issues that could be envisaged at each of the following sites:
   i. Kimberley – Maret Islands
   ii. Kimberley – Wilson Point
   iii. Kimberley – Scott Reef
   iv. Kimberley – North Head / Perpendicular Head
   v. Kimberley – Quondong Point
   vi. Kimberley – Koolan / Cockatoo Islands
   vii. Burrup – Tie in to existing NWS facilities / Pluto

c. Provide an indication of possible infrastructure costs to the W.A. Government for onshore developments at each of the proposed locations, including costs associated with:
   i. Potential upgrades to existing infrastructure (inc roads/airports etc);
   ii. Requirement for expansion or provision of new support services and associated infrastructure including hospitals, utilities etc;

d. Provide an assessment of the cost implications associated with the use of existing infrastructure (Burrup/Darwin) as opposed to a greenfield site in the Kimberley, this should include assessment of:
   i. The relative cost associated with delivery of gas to sites in the Kimberley as opposed to Burrup / Darwin sites;
   ii. Identification of potential cost savings attributable to evacuation of the Browse Basin gas via existing / planned assets at Burrup / Darwin sites; and
   iii. Potential cost premium associated with construction at Kimberley sites (particularly for the remote sites).

e. Provide commentary on the domestic gas potential for the sites under consideration.

# APPENDIX II

## MARINE & METEOROLOGICAL CONDITIONS AT KING SOUND & POINT TORMENT

## MARINE & METEOROLOGICAL CONDITIONS AT KING SOUND & POINT TORMENT

The coast between Hidden Island and Cape Leveque incorporates the entrance to King Sound, where numerous Shoal, reefs & islands extend up to 50 miles offshore. The currents and tidal streams in this area run between 6 and 10 knots with violent tide rips and eddies.

King Sound is bounded by the Buccaneer Archipelago, which lies in its NE approaches and consists of numerous islands, islets & rocks lying off the NW extremity of the peninsula separating Collier Bay from King Sound. The archipelago is divided into separate groups, the islands of which are connected to each other by reefs, which are dry at low water. This is due to the large variation in the strong spring tides which can have a range between high and low water of up to 11m.

King Sound is entered between the southern extremity of Hidden Island and Swan Point some 27 miles west and extends 60 miles SSE to the town of Derby at the entrance of the Fitzroy River. Depths of up to 16m lie in the fairway to about 20 miles from the headland. Thereafter the seabed Shoal gradually towards the shore in most places to NW of Point Torment, where the colour of the water is a discoloured dirty yellow, darkening to brown as Derby is approached, where it is filled with mud and sand. The area is presently unsurveyed in many parts and is currently not safe for entry by large deep draught vessels such as Q Flex and Q Max LNG tankers.

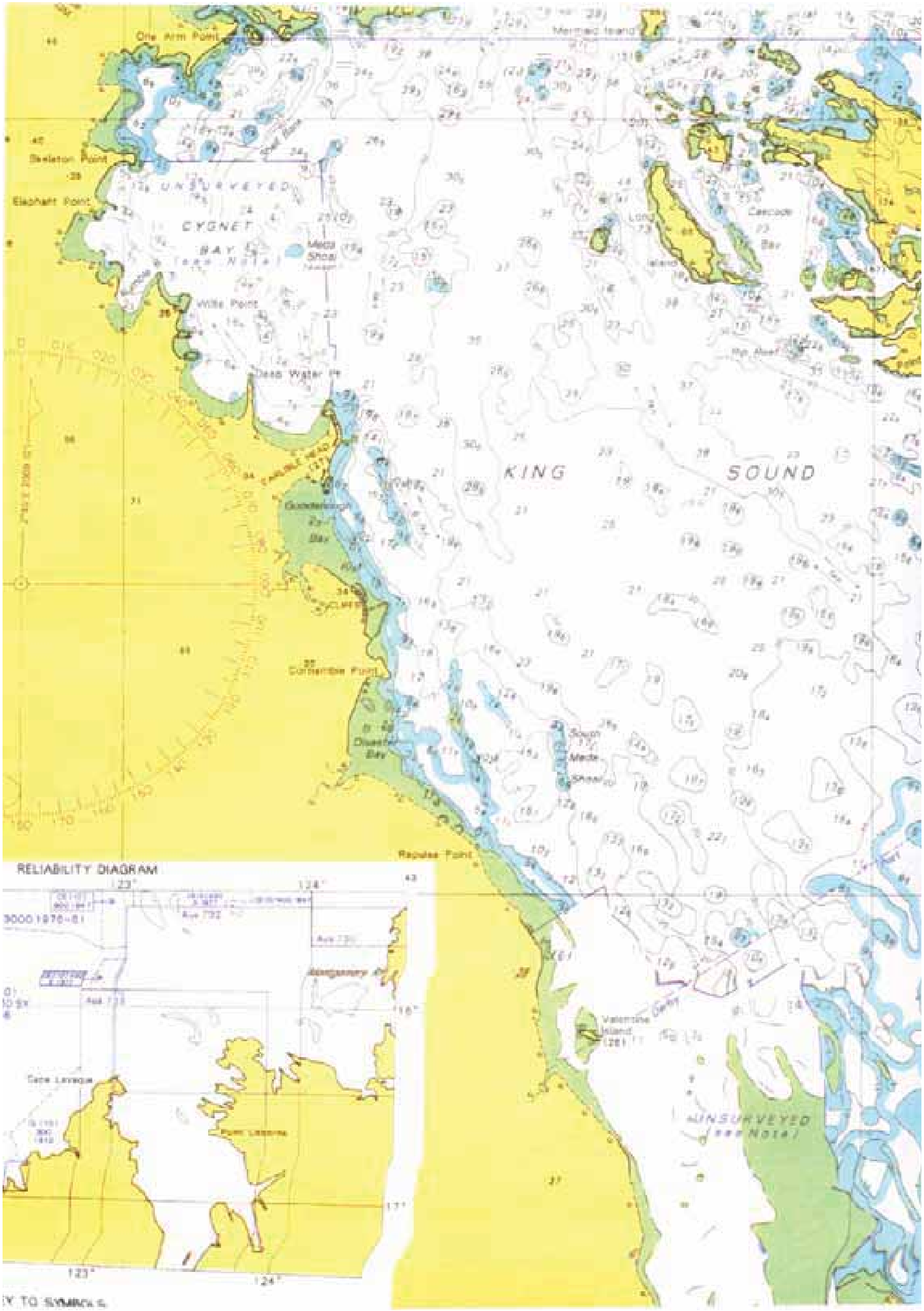
If any sites within King Sound are to be utilised, navigational safety would require that entry and exit from the Sound be confined to times of reasonable tidal flows and not be undertaken at night. This is in addition to the limitations that would be required for adverse wind conditions. Currently efficient navigational lights and buoy systems for LNG tankers are not provided.

In light of the above, King Sound is an area of very high risk for the navigation of large LNG & Condensate vessels. In addition there would almost certainly be significant delays that could not be built into forecast schedules. For these reasons Point Torment and all other sites in King Sound have been discarded as a likely LNG port for the purpose of this study.

### TYPICAL CURRENTS AND TIDES OF THE KIMBERLEY AREAS CONSIDERED FOR LNG FACITLITIES

| | South Kimberley | North Kimberley | Offshore Kimberley | King Sound |
|---|---|---|---|---|
| Current range (knots) | 0.5 to 5 | 1 to 5 | NA | **6 to 10** |
| Tidal range (meters) | Up to 7.1 | Up to 7.2 | NA | **Up to 11** |

**Note:** Information non available for Offshore Kimberley.




**King Sound Chart**

| Proj. K1177 May08 | Checked: | Fig - 1 |
|---|---|---|

# APPENDIX III

# STUDY ASSUMPTIONS

## Development Concept

- Gas dehydration can be done either onshore or offshore.
- In order to provide a basis for the comparison of costs to all sites, GCA has assumed that the condensate is treated and loaded offshore.
- LPGs extracted at the LNG plant.
- Offshore pipeline route from the field to the plant sites are considered to be in straight line. The impacts of unfavourable bathymetry on pipeline routes, which have not been studied in this report, could include longer pipeline lengths and slugging issues. However, no adverse bathymetry is anticipated in the area, which is expected to be typical continental shelf.

## Area

- ~360 hectares required for a single company LNG development (i.e. single operator, who could possible process the gas from different fields).
- ~660 hectares required for an LNG Hub development (i.e. operated by two companies with distinct facilities).
- >950 hectares required for a gas processing Hub (i.e. LNG Hub extending to incorporate gas processing facilities such as GTL, ammonia, methanol plants).
- A site elevation of at least 10 meters above sea level would typically be considered acceptable to be secure against storm surge.
- Fly in / fly out would be the preferred option.
- Power will be generated on-site to ensure sufficient plant reliability and uptime.

## LNG Technology

- Each LNG train has a capacity ranging from 3.4 to 7.5 Mtpa.
- LNG process is air cooled.

## Construction Approach

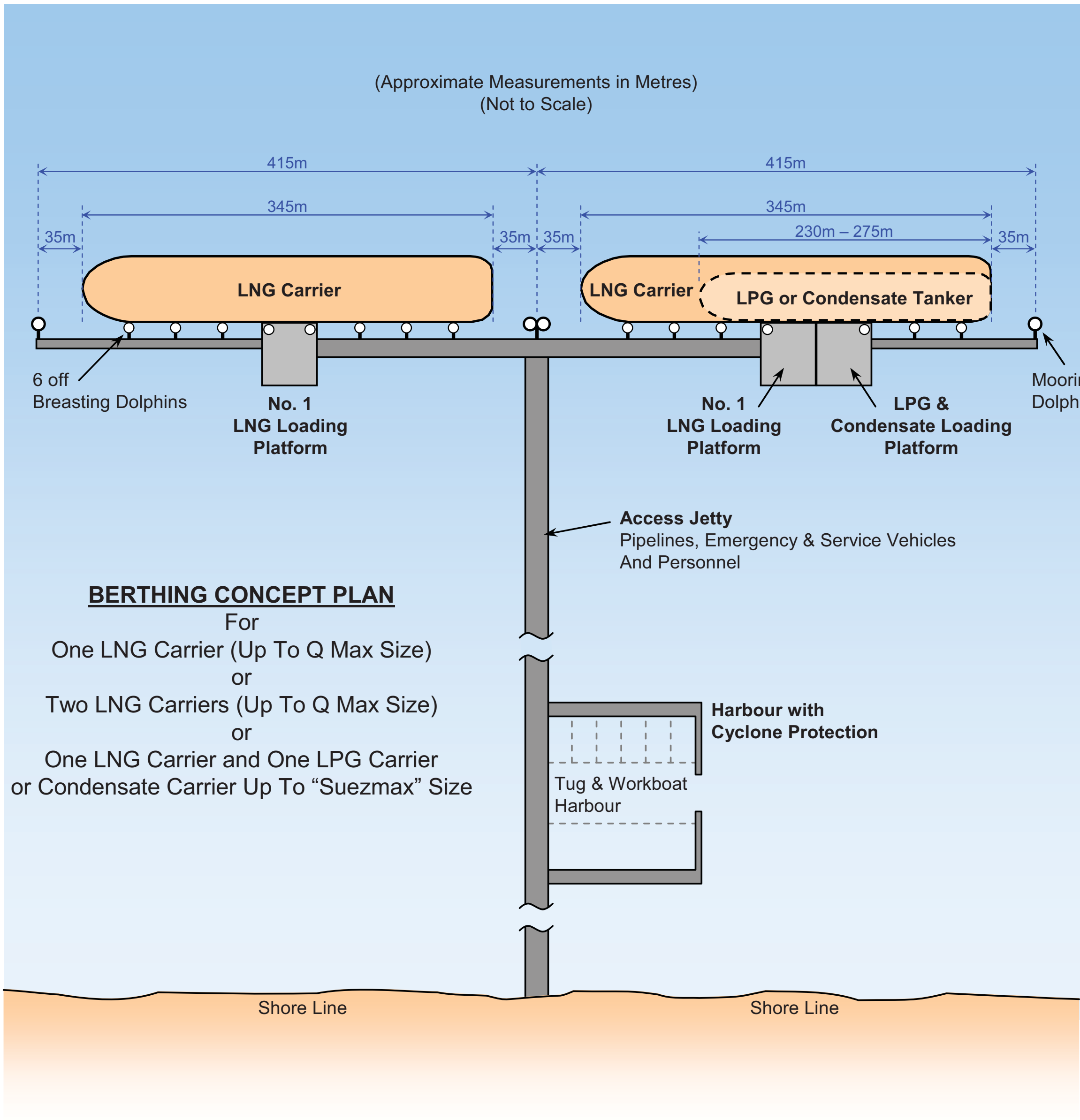
- Construction can be done using either modular or non modular (with on-site construction) items.
- Area required for construction is included in LNG Plant requirement and represents up to 20% of the total area required.

## Security and Legal Constraints

- LNG Plant should be able to withstand the “100 year storm” / major earthquake.
- LNG tanks are full containment.
- A security zone is required around the plant.

# APPENDIX IV

# BERTH CONCEPT PLAN

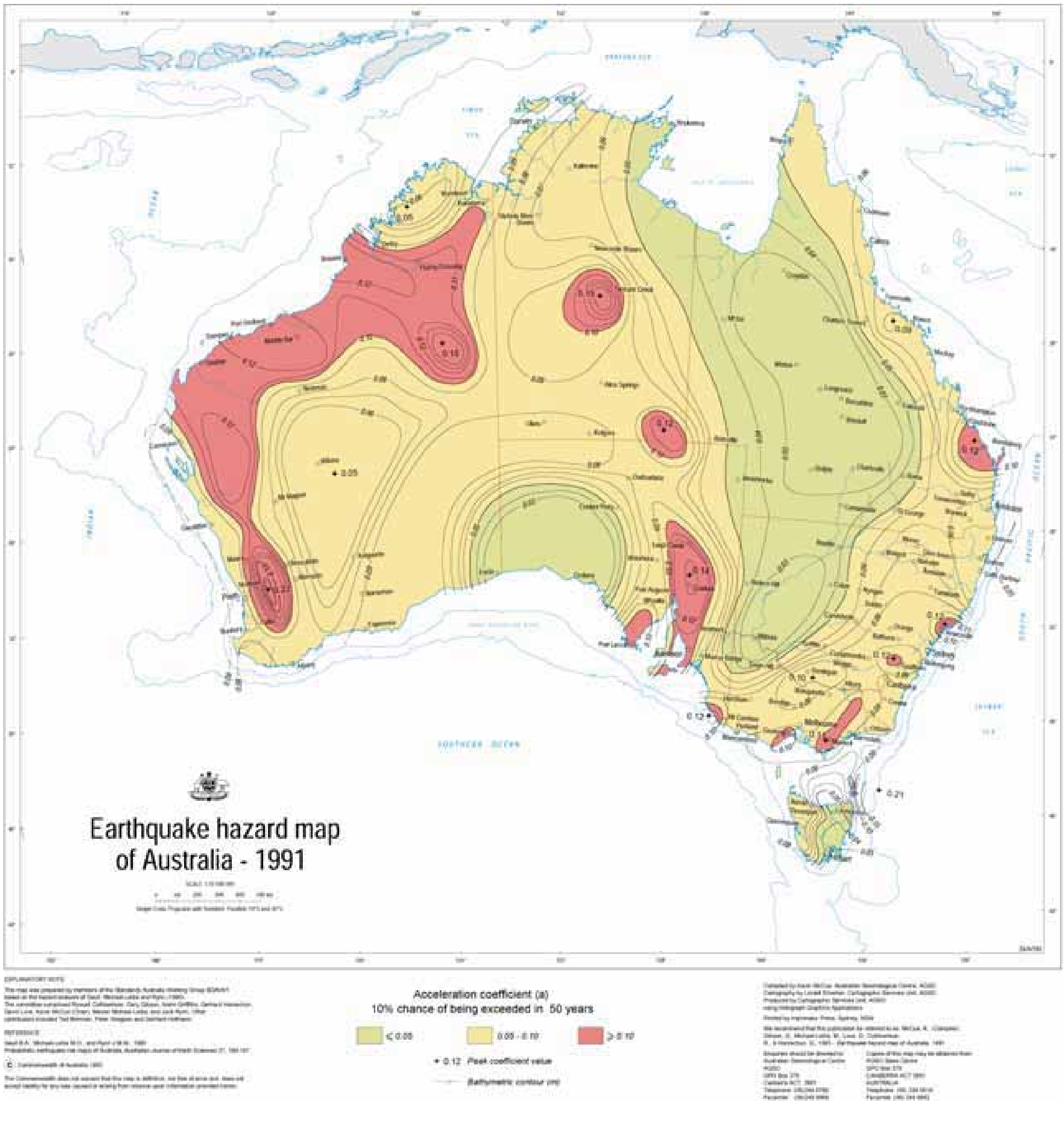



**Berthing Concept Plan**

| | | |
|---|---|---|
| Proj. K1177 May08 | Checked: | Appx IV-1 |

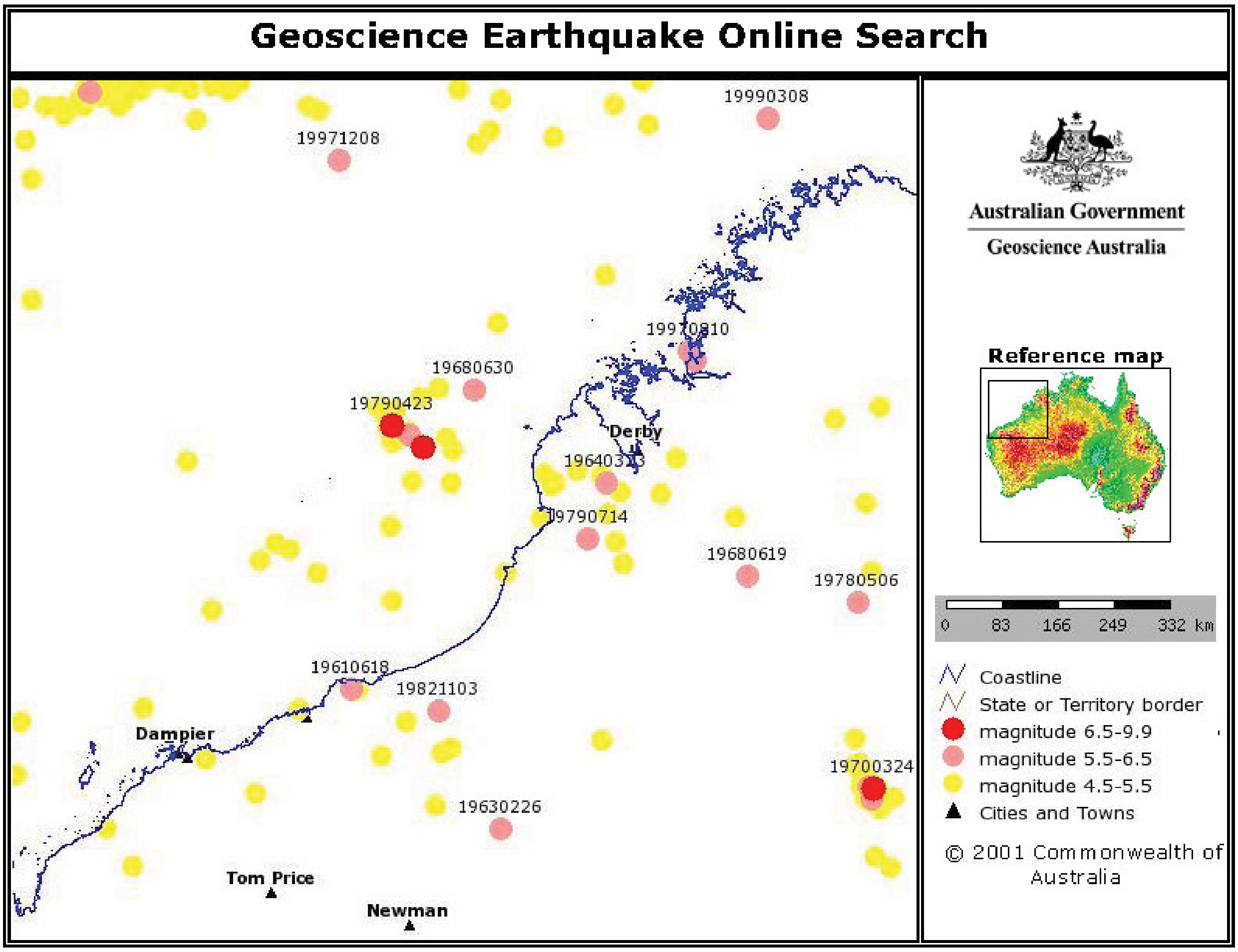
# APPENDIX V

# SEISMICITY OF AUSTRALIA




**Earthquake Hazard Map of Australia**

Proj. K1177 May08 | Checked: | Appx V-1




| | | |
|---|---|---|
| **Kimberley Region Earthquake Records** | | |
| Proj. K1177 May08 | Checked: | Appx V-2 |

# APPENDIX VI

## BROWSE BASIN WOODSIDE AND INPEX OPERATED FIELDS OVERVIEW

*(Source: Deloitte PetroView – as of 19 February 2008)*

# BROWSE BASIN WOODSIDE AND INPEX OPERATED FIELDS OVERVIEW

## Woodside CALLIANCE

- Operator: WOODSIDE PET LTD
- Status: Appraisal
- Discovery date: 2000.08.27
- Production start date (target): 2011.07.01
- Partners:
  - BHP BILLITON LTD (14.16%)
  - BP PLC (18.34%)
  - CHEVRON CORPORATION (18.34%)
  - ROYAL DUTCH SHELL (11.66%)
  - WOODSIDE PET LTD (37.50%)
- Reserves:
  - Initial Oil MMB 86.8
  - Initial Oil MCM 13800.1
  - Initial Oil Equiv MMB 771.2
  - Initial Oil Equiv MCM 122615.9
  - Initial Gas BCF 3969.7
  - Initial Gas BCM 112.4

## Woodside BRECKNOCK

- Operator: WOODSIDE PET LTD
- Status: Appraisal
- Discovery date: 1979.12.12
- Production start date (target): 2011.07.01
- Partners:
  - BHP BILLITON LTD (8.33%)
  - BP PLC (16.67%)
  - CHEVRON CORPORATION (16.67%)
  - ROYAL DUTCH SHELL (8.33%)
  - WOODSIDE PET LTD (50.00%)
- Reserves:
  - Initial Oil MMB 115
  - Initial Oil MCM 18283.5
  - Initial Oil Equiv MMB 1028.8
  - Initial Oil Equiv MCM 163565
  - Initial Gas BCF 5300
  - Initial Gas BCM 150.1

### Woodside TOROSA

- Operator: WOODSIDE PET LTD
- Status: Appraisal
- Discovery date: 1971.06.10
- Partners:
    - BHP BILLITON LTD (8.33%)
    - BP PLC (16.67%)
    - CHEVRON CORPORATION (16.67%)
    - ROYAL DUTCH SHELL (8.33%)
    - WOODSIDE PET LTD (50.00%)
- Reserves:
    - Initial Oil MMB 113
    - Initial Oil MCM 17965.6
    - Initial Oil Equiv MMB 2095.8
    - Initial Oil Equiv MCM 333199
    - Initial Gas BCF 11500
    - Initial Gas BCM 325.6

### INPEX ICHTHYS

- Operator: INPEX HOLDINGS INC
- Status: Appraisal
- Discovery date: 1980.12.16
- Production start date (target): 2012.07.01
- Partners:
    - INPEX HOLDINGS INC (76.00%)
    - TOTAL SA (24.00%)
- Reserves:
    - Initial Oil MMB 312
    - Initial Oil MCM 49604
    - Initial Oil Equiv MMB 1949.9
    - Initial Oil Equiv MCM 310003.3
    - Initial Gas BCF 9499.6
    - Initial Gas BCM 269

# APPENDIX VII

# GLOSSARY

## GLOSSARY

| | |
|---|---|
| ALSOC | Australian LNG Ship. operating Company Ltd. |
| bar | The bar (symbol bar), decibar (symbol dbar) and the millibar (symbol mbar, also mb) are units of pressure. The bar is still widely used in descriptions of pressure because it is about the same as atmospheric pressure. |
| Btu | The British thermal unit (BTU or Btu) is a unit of energy used in the power, steam generation, and heating and air conditioning industries. One BTU is approximately 1,054—1,060 kJ (kilojoules). |
| CGR | Condensate to Gas Ratio |
| DWT | DWT, for deadweight tones, is the displacement at any loaded condition minus the lightship weight. It includes the crew, passengers, cargo, fuel, water, and stores. Like Displacement, it is often expressed in long tons or in metric tons. |
| GCA | Gaffney, Cline & Associates |
| ha | A hectare (symbol ha) is a unit of area equal to 10,000 square meters, or one square hectometer, and commonly used for measuring land area. A 100 m square is one ha. |
| km | Kilometre(s) |
| LNG | LNG is natural gas that has been converted to liquid form for ease of storage or transport. Liquified natural gas takes up about 1/600th the volume of natural gas at a stove burner tip. It is odorless, colorless, non-corrosive, and non-toxic.<br>The liquefaction process involves removal of certain components, such as dust, helium, water, and heavy hydrocarbons, which could cause difficulty downstream, and then condensation into a liquid at close to atmospheric pressure (Maximum Transport Pressure set around 25 kPa (3.6psi)) by cooling it to approximately −163 °C (−260 °F). |
| LOA | Length Over All, commonly used to indicate maximum hull length of a vessel. LOA is the most commonly-used way of expressing the size of a boat. |
| LPG | Liquefied petroleum gas (also called LPG, LP Gas, or autogas) is a mixture of hydrocarbon gases used as a fuel in heating appliances and vehicles, as well as as an aerosol propellant and a refrigerant.<br>Varieties of LPG bought and sold include mixes that are primarily propane, mixes that are primarily butane, and the more common, mixes including both propane (60%) and butane (40%). |
| Mtpa | Million tones per annum |
| PPP | Public-Private Partnership, the operation of a service in the partnership of government and the private sector.<br>In some types of PPP, the government uses tax revenue to provide capital for investment, with operations run jointly with the private sector or under contract (see contracting out). In other types (notably the Private Finance Initiative), capital investment is made by the private sector on the strength of a contract with government to provide agreed services. Government contributions to a PPP may also be in kind (notably the transfer of existing assets). |
| psi | The pound per square inch or, more accurately, pound-force per square inch (symbol: psi or lbf/in$^2$ or lbf/in$^2$) is a unit of pressure or of stress. It is the pressure resulting from a force of one pound-force applied to an area of one square inch: 1 psi (6.894757 kPa) : Pascal (Pa) is the SI unit of pressure |
| SPM | Single Point Mooring are loading Buoys anchored offshore, which serve as a mooring point for tankers to (off)load gas or fluid products. They are the link between the geostatic subsea manifold connections and the weathervaning tanker. The main purpose of the buoy is to transfer fluids between onshore or offshore facilities and the moored tanker. |

| | |
|---|---|
| SRTM | The Shuttle Radar Topography Mission (SRTM) obtained elevation data on a near-global scale to generate the most complete high-resolution digital topographic database of Earth. SRTM consisted of a specially modified radar system that flew onboard the Space Shuttle Endeavour during an 11-day mission in February of 2000. SRTM is an international project spearheaded by the National Geospatial-Intelligence Agency (NGA) and the National Aeronautics and Space Administration (NASA). |
| Tcf | Trillion cubic feet |
| TCS | Thompson Clarke Shipping |
| WEL | Woodside Energy Limited |

Copy No. 1

# BROWSE BASIN GAS TECHNICAL REPORT
# DEVELOPMENT OPTIONS STUDY

## ADDENDUM TO REPORT 1 of 3
## LNG PLANT SITE SELECTION VALIDATION

**Prepared for**

**THE NORTHERN DEVELOPMENT TASKFORCE**

**August 2008**

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## TABLE OF CONTENTS

## INTRODUCTION

The Browse Basin, offshore of north-west Western Australia, holds substantial resources of natural gas. At the date of this report, there is no hydrocarbons production from the Basin and there are no hydrocarbons based projects that are either under construction or approved for construction. However, two of the Basin joint ventures, one operated by Woodside Energy Limited (Woodside), and the other by INPEX Browse Ltd (INPEX)[1], are planning to use their known gas resources for "greenfield" land based Liquefied Natural Gas (LNG) projects[2].

The two projects are based on total gas resources of approximately 27 Trillion cubic feet (Tcf). While some of these resources were discovered over thirty years ago, the basin is "gas prone" and has been relatively lightly explored. The level of exploration activity has increased in recent years and it is likely that other companies currently active in the area will eventually propose LNG projects using Browse Basin gas.

From a technical perspective, the "logical" sites for a land based LNG plants to receive, process and export Browse Basin gas are on the Northern and Southern Kimberley coast or on one of the islands off the coast. The North Kimberley area is totally undeveloped, has no infrastructure and is an eco-tourist destination. The South Kimberley has some development (Broome and Derby), has minimal infrastructure and has several tourist destinations.

At the time of this report, both the Woodside and INPEX operated Joint Ventures have conceptualised their respective projects on a "stand alone" basis and have evaluated potential LNG processing sites on the basis of the individual requirements of those projects. Woodside has prepared a shortlist of several potential sites and the Maret Islands are INPEX's preferred site. Forecast total LNG production from the two projects is in the order of 20 to 25 MMtpa.

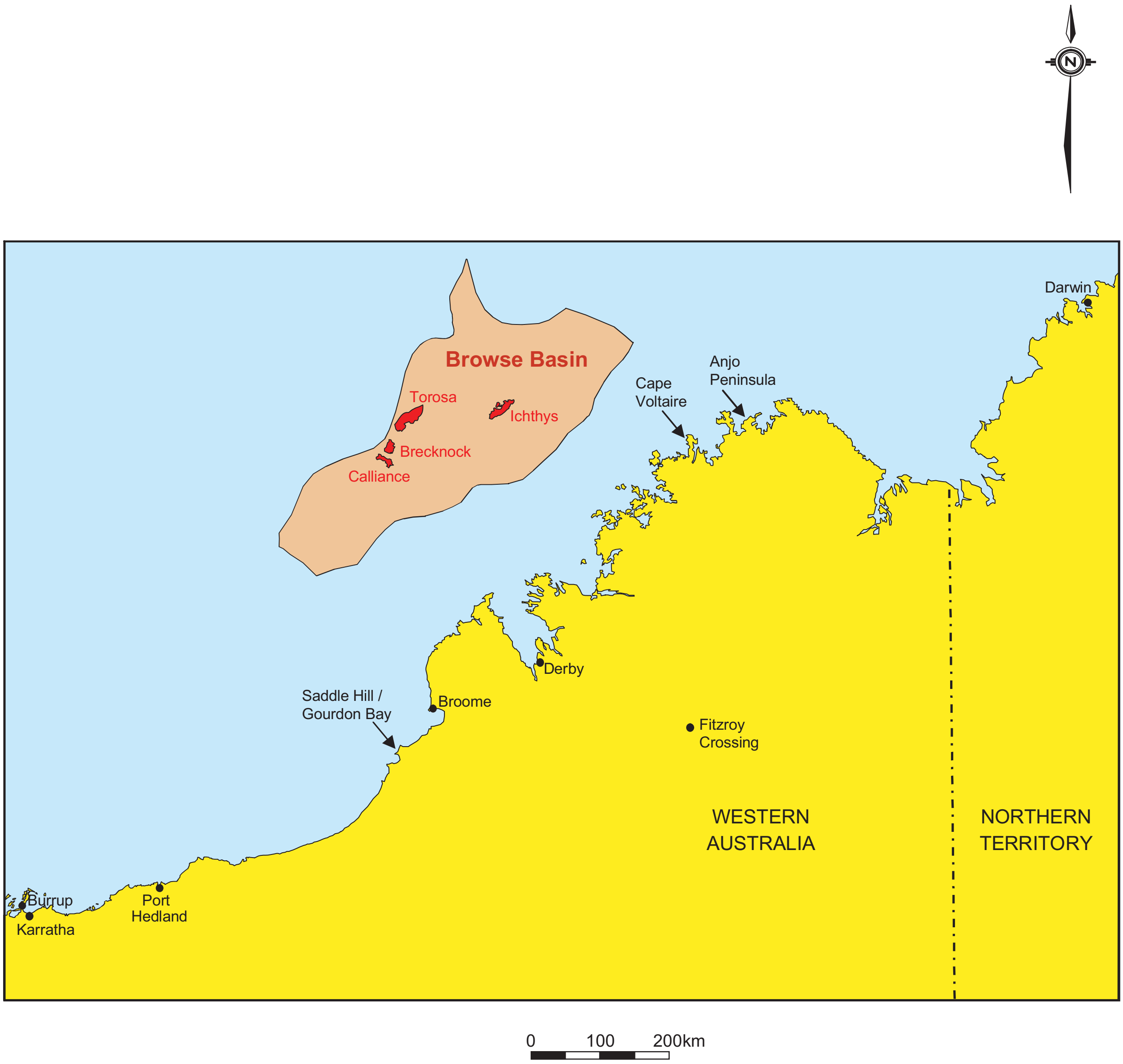
The Kimberley Northern Development Taskforce (Taskforce) is an inter-departmental body formed by the Government of Western Australia. The Project Manager is Mr. Gary Simmons from DoIR. The taskforce has been engaged to set the framework by which the State will protect and manage the important heritage, environment and tourism values of the Kimberley area while facilitating structured industrial development. The West Kimberley Subdivision of the Taskforce was established to manage across-government planning processes and stakeholder consultation in regard to selection and development of a suitable location or locations for the processing of Browse Basin gas reserves.

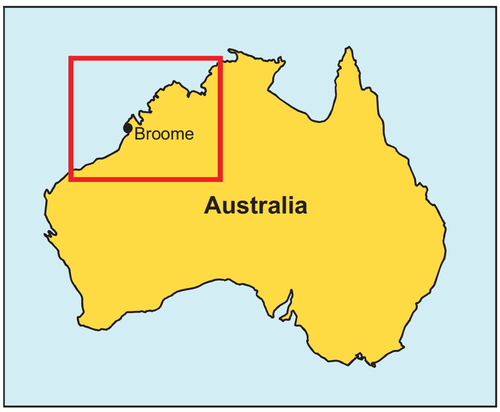
The Taskforce, through DoIR, has retained Gaffney, Cline & Associates (GCA) to provide independent advice on technical issues associated with the selection and development of onshore and offshore locations, for the processing of the Browse Basin gas. This advice is to be in the form of a report titled "Browse Basin Development Options Study" (The Study).

The objective of the first section of this Study is to review the technical issues surrounding the processing of natural gas resources at an LNG hub. In this context, GCA has provided commentary on the technical suitability of fourteen potential sites in May 2008 (Report 1) based on the information made available by DoIR, Woodside and INPEX. GCA has since been asked to evaluate three additional sites, Anjo Peninsula, Cape Voltaire and Gourdon Bay / Saddle Hill, using the same methodology as for the May 2008 report. This analysis follows and forms the "Addendum to Report 1".

[1] "Woodside" is used throughout this report to refer to the Woodside led Joint Venture (JV) and likewise for INPEX.

[2] During the course of the study Shell Development (Australia), (Shell) announced that it plans to develop the Prelude field, in the Browse Basin, using a floating LNG facility (FLNG) with no onshore processing facilities.




**Additional Potential Kimberley Sites for Browse Basin LNG Facilities**

| Proj. K1177.10 July08 | Checked: | Fig. 1 |
|---|---|---|

## CONCLUSIONS

The scope of work provided for this study by DoIR lists a number of very specific points to be addressed. This has been done in detail in the pages that follow. GCA's "high level" conclusions are summarised as follows:-

1. The three additional locations considered could accommodate a Gas Processing Hub. They each provide 950 hectares of technically suitable land and a manageable marine environment. The sites are:

    i. **Northern Kimberley**:- Anjo Peninsula, Cape Voltaire.

    ii. **Southern Kimberley**:- Gourdon Bay / Saddle Hill.

2. The Anjo Peninsula has particularly favourable marine conditions, whereas Gourdon Bay / Saddle Hill's marine conditions are very challenging.

3. Site preparation requirements are likely to be minimal for Gourdon Bay / Saddle Hill, acceptable for the Anjo Peninsula and very substantial for Cape Voltaire.

4. Overall, and taking only these three sites into consideration, the most appropriate location, from a technical perspective for LNG and gas processing facilities, is the Anjo Peninsula.

5. Further "pooling" of available information held by individual stakeholders supplemented by additional "on site" topographical, marine and geotechnical evaluation would confirm these conclusions.

6. The evaluation of the costs associated with a development at each of the proposed locations would provide additional differentiating factors supporting objective site ranking. In particular, pipeline length, marine and geotechnical work have a significant impact on project costs and their quantification would complement the technical analysis in this report.

It is noted that GCA's scope of work covered only the technical aspects of the hub site selection. The conclusions above have not taken into account any of the socio-economic aspects of a hub selection including those arising from land ownership and environmental considerations.

## 1. STUDY METHODOLOGY

The evaluations conducted in this report are based on the expertise of the Team Members involved, leveraging public information and tools (including SRTM maps incorporated in the Google Earth® software), as well as the information provided by Browse basin tenement holders. Thompson Clarke Shipping (TCS) were retained by GCA to provide advice on the marine aspects of the study.

GCA has adopted the same methodology as for the previous sites studied. No site visits were undertaken and all estimation work has been done at a very high level, mostly by analogy.

The specific site evaluation criteria and LNG Hub concepts are detailed in the previous report, entitled “REPORT 1 of 3 - LNG PLANT SITE SELECTION VALIDATION” and delivered to DoIR in May 2008.

DoIR has recently requested GCA to technically evaluate three additional potential hub sites against the specific technical criteria. This additional work, together with that from the original May study, is summarized in **Table 1**:-

## TABLE 1

## SUMMARY OF SITE SUITABILITY FOR LNG AND GAS PROCESSING HUB

| | Port Availability and Navigation | Land Availability and Suitability | | |
|---|---|---|---|---|
| | | Single Op. (1) | Multi Op. (2) | Gas Proc. (3) |
| **North Kimberley** | | | | |
| Anjo Peninsula | Y | Y | Y | Y |
| Cape Voltaire | Y | Y | Y | Y |
| Maret Islands | Y | Y | N | N |
| Bigge Island | Y | Y | Y | Y |
| Champagny Island East | Y | Y | N | N |
| Wilson Point | Y | Y | Y | Y |
| Koolan Island | Y | Y | N | N |
| Cockatoo Island | Y | N | N | N |
| **South Kimberley** | | | | |
| Cape Leveque | Y | Y | Y | Y |
| Lombadina (Packer Island) | Y | Y | Y | Y |
| North/ Perpendicular Head | Y | Y | Y | Y |
| Quondong Point | Y | Y | Y | Y |
| Fisherman's Bend | Y | Y | Y | Y |
| Gourdon Bay / Saddle Hill | Y | Y | Y | Y |
| **Offshore Kimberley** | | | | |
| Scott Reef **(4)** | ? | n.a. | n.a. | n.a. |
| Echuca Shoals **(4)** | ? | n.a. | n.a. | n.a. |
| **Existing LNG Site** | | | | |
| Burrup (NWS & Pluto) | Y | Y(5) | N | N |

**Notes:-**
1. An LNG Hub with a single LNG plant and up to 5 LNG trains that could be accommodated on a site of 360 hectares.
2. An LNG Hub with multiple LNG plants and up to 10 LNG trains that could be accommodated on a site of 660 hectares.
3. A Gas Processing Hub which provides for a multiple LNG plants and several large scale Gas to Liquids (GTL) plants. This will require a minimum of 950 hectares.
4. These sites are partially submerged and would be developed as "offshore" facilities.
5. There is insufficient land available in the Burrup area for a new Single Operator LNG Hub. GCA has assumed production would be integrated into existing gas processing hubs.

It is emphasised that the above sites have been evaluated on technical grounds only. Environmental, Land access and other community based issues have not been considered.

# 2. DISCUSSION

## 2.1 Sites Evaluation and Likely Technical Issues for an LNG Hub

### 2.1.1 North Kimberley: Anjo Peninsula

**TABLE 2**

**ANJO PENINSULA LNG SITE COMPARATIVE TECHNICAL EVALUATION**

<table>
<tr><th></th><th>Navigable water for LNG carriers</th><th>Port suitability</th><th>Land area requirements</th><th>Site elevation and gradient</th><th>Proximity to gas fields</th><th>Proximity of plant site to coastline</th><th>Pipeline approach</th><th>Geotechnical conditions</th><th>Proximity to existing infrastructure</th></tr>
<tr><td>Single Operator LNG Hub</td><td rowspan="3">Y</td><td rowspan="3">Y</td><td>Y</td><td rowspan="3">Y</td><td rowspan="3">Y</td><td rowspan="3">Y</td><td rowspan="3">Y</td><td rowspan="3">Y</td><td rowspan="3">N</td></tr>
<tr><td>Multi Operator LNG Hub</td><td>Y</td></tr>
<tr><td>Gas Processing Hub</td><td>Y</td></tr>
</table>

**Navigable Water for LNG Carriers & Port Suitability**

The Anjo Peninsula has a suitable marine environment to support LNG operations, with particularly favourable conditions on its East coast. Deep water is present close to the coast and the approach is sheltered from wind and swell.

Marine works are likely to require the construction of a ~2 kilometre jetty and the dredging of a ~5 kilometre channel. A breakwater would not be necessary. Maintenance dredging needs is not expected.

**Land Area Requirements**

The Anjo Peninsula is a coastal location with over 950 hectares of available land, which would be sufficient for the development of multiple LNG plants and gas processing facilities.

**Site Elevation and Gradient**

The Anjo Peninsula lies in irregular terrain with gentle slopes and elevations ranging from sea level to ~70 meters.

Several locations, with relatively flat sections of land within an elevation range of 30 to 40 meters, provide sufficient area for an LNG development and gas processing facilities.

Mountains are present further inland, reaching over 200 meters above sea level.

**Proximity to Gas Fields**

The Anjo Peninsula is located within ~350 kilometres from the INPEX operated Ichthys field and ~500 kilometres from the Woodside operated Browse (Scott Reef) fields. This distance does not present any specific issues in terms of pipeline construction.

For the purposes of this study, the distances between the gas fields and the potential sites are taken as the most direct offshore line between these points. This is likely to differ from the actual pipeline trajectory, which will be constrained by bathymetry and offshore geotechnical features.

**Proximity of Plant Site to Coastline**

The plant site could be within one kilometre from the coastline, which is technically suitable.

**Pipeline Approach**

There are several sandy beaches with gentle slopes on the Anjo Peninsula. These could be appropriate locations for pipeline crossings.

There are a number of tidal areas appearing to be covered in mangrove. Even though these may be suitable from a technical perspective, pipeline beach crossings in mangrove will require careful environmental assessment.

**Geotechnical Conditions**

The Anjo Peninsula displays signs of erosion along its coasts. The dominant soils are likely to be a combination of deep sands and stony soils. There are relatively flat sufficiently elevated areas for the installation of LNG facilities and no major earthworks are foreseen.

**Proximity to Existing Infrastructure**

The Anjo Peninsula is isolated with limited infrastructure in the vicinity.

Truscott Airbase, on the Anjo Peninsula, has a sealed airstrip (1,800m x 30m) with the capacity for a 70 seat jet to land. It has two helicopter hangars, full maintenance facilities and fuel capacity of 1 million litres. Three Briscoe helicopters currently operate out of there, servicing the gas fields to the north. The base is gearing up for five helicopters. There is accommodation for 60 people and modern mess. This base is on a lease between Wunambal Gaambera Aboriginal Corporation and the Aboriginal Lands Trust.

The Kalumburu Aboriginal Community, with a population of over 400 people, is ~50 kilometres to the South East. The closest formed road is over ~200 kilometres to the South. The closest port is Wyndham, ~240 kilometres to the South East.

**Summary Evaluation**

The Anjo Peninsula has sufficient land and suitable marine conditions, in particular on its eastern coast, to support multiple LNG plants and pas processing facilities. Several adequate locations can be considered for pipeline beach crossings. Extensive geotechnical work is not expected. The existing airstrip could be leveraged; however the creation of a port is likely to be required to handle facilities construction, due to the remote location of this site relative to existing ports and formed roads.

The Anjo Peninsula is a technically suitable site for LNG developments.

### 2.1.2 North Kimberley: Cape Voltaire

**TABLE 3**

**CAPE VOLTAIRE LNG SITE COMPARATIVE TECHNICAL EVALUATION**

| | Navigable water for LNG carriers | Port suitability | Land area requirements | Site elevation and gradient | Proximity to gas fields | Proximity of plant site to coastline | Pipeline approach | Geotechnical conditions | Proximity to existing infrastructure |
|---|---|---|---|---|---|---|---|---|---|
| Single Operator LNG Hub | Y | Y | Y | Y | Y | Y | Y | Y | N |
| Multi Operator LNG Hub | | | Y | | | | | | |
| Gas Processing Hub | | | Y | | | | | | |

**Note**: "Cape Voltaire" is used to identify the whole peninsula between Montague Sound and Walmesly Bay, extending to Voltaire Passage on its North Coast.

#### Navigable Water for LNG Carriers & Port Suitability

The West side of Cape Voltaire is very exposed and, despite the presence of deep water close to shore, would not provide suitable marine conditions to support an LNG development.

The East side of Cape Voltaire, though partially surveyed, is likely to provide an adequate marine environment. Navigational access to the eastern side of the Voltaire peninsula can be satisfactorily obtained from the north passing Troughton Island, then passing to the east of Long Reef and Tancred Bank, and then entering Admiralty Gulf.

#### Land Area Requirements

Cape Voltaire is a coastal location, where available land is constrained by the steep slope of the terrain, in particular in the North. There is sufficient land available to construct any of the types of hubs considered.

#### Site Elevation and Gradient

Site elevation ranges from sea level to ~130 meters, with steep sections along the West coast. However, there is over ~950 hectares of relatively flat ground to the South East of Cape Voltaire, with elevation comprised between ~15 and ~30 meters and limited gradient. This site would be acceptable for the construction of LNG facilities.

**Proximity to Gas Fields**

Cape Voltaire is located within ~260 kilometres from the INPEX operated Ichthys field and ~410 kilometres from the Woodside operated Browse (Scott Reef) fields. This distance does not present any specific issues in terms of pipeline construction.

**Proximity of Plant Site to Coastline**

The plant site could be within one kilometre from the coastline, which is technically suitable.

**Pipeline Approach**

There are few sandy beaches in Cape Voltaire, with a majority of small hills facing the sea front. Adequate pipeline land fall sites can be identified but may require significant earthworks.

Tidal areas and mangrove are present to the East of the Cape, which may constitute an environmental constraint impacting pipeline beach crossing.

**Geotechnical Conditions**

Cape Voltaire appears to have signs of erosion with uneven and deeply fissured rocky land. The dominant soils are likely to be a combination of stony soils and loamy earth.

There are sufficient elevated areas for the installation of LNG facilities. However, site preparation is likely to require substantial earthworks.

**Proximity to Existing Infrastructure**

Cape Voltaire is isolated with limited accessible infrastructure. The closest formed road is over ~250 kilometres to the South. The closest port is Wyndham, ~300 kilometres to the South East. The Mitchell Plateau unsealed airstrip is ~50 kilometres South.

**Summary Evaluation**

Cape Voltaire has sufficient area for the installation of LNG and gas processing facilities. Substantial earthwork is likely to be required to level the peninsula's rocky and weathered terrain. The East side of Cape Voltaire could provide suitable marine conditions for LNG related maritime traffic.

Cape Voltaire could be a technically suitable site. However, further land and marine studies would be required to evaluate site preparation needs and confirm the suitability of its partially surveyed the East coast.

### 2.1.3 South Kimberley: Gourdon Bay / Saddle Hill

**TABLE 4**

**GOURDON BAY / SADDLE HILL LNG SITE COMPARATIVE TECHNICAL EVALUATION**

<table>
<tr><th></th><th>Navigable water for LNG carriers</th><th>Port suitability</th><th>Land area requirements</th><th>Site elevation and gradient</th><th>Proximity to gas fields</th><th>Proximity of plant site to coastline</th><th>Pipeline approach</th><th>Geotechnical conditions</th><th>Proximity to existing infrastructure</th></tr>
<tr><td>Single Operator LNG Hub</td><td rowspan="3">Y</td><td rowspan="3">Y</td><td>Y</td><td rowspan="3">Y</td><td rowspan="3">Y</td><td rowspan="3">Y</td><td rowspan="3">Y</td><td rowspan="3">Y</td><td rowspan="3">Y</td></tr>
<tr><td>Multi Operator LNG Hub</td><td>Y</td></tr>
<tr><td>Gas Processing Hub</td><td>Y</td></tr>
</table>

**Navigable Water for LNG Carriers & Port Suitability**

Gourdon Bay / Saddle Hill is wholly exposed to the weather and swell. Significant initial and maintenance dredging, including the preparation of a ~15 kilometre channel, will be required. A significant breakwater of will be required to enclose the berth. This site will require a long jetty.

The marine conditions of Gourdon Bay / Saddle Hill are not favourable to support an LNG development. However, with very substantial investment in marine infrastructure, this site could be made suitable.

**Land Area Requirements**

Gourdon Bay / Saddle Hill is a coastal location with over 950 hectares of available land. This could constitute sufficient area for the development of a gas processing Hub.

**Site Elevation and Gradient**

The site is flat with elevations ranging from sea level to ~30 meters. Saddle Hill is surrounded by low lying areas, but has sufficient suitable land within elevations of ~15 meters to ~30 meters.

**Proximity to Gas Fields**

Gourdon Bay / Saddle Hill is located within ~530 kilometres from the INPEX operated Ichthys field and ~490 kilometres from the Woodside operated Browse (Scott Reef) fields. This distance does not present any specific issues in terms of pipeline construction.

### Proximity of Plant Site to Coastline

Suitably elevated land, over 15 meters above sea level, is within one kilometer of the North coastline and ~5 kilometers to the West. The gas processing facilities could be located within a technically acceptable distance from the coastline.

### Pipeline Approach

The West and South West of Saddle Hill appear to be tidal areas covered with mangrove. The North of this site would provide appropriate beach landing areas with gentle slopes and few visible signs of erosion.

### Geotechnical Conditions

The dominant soils of Saddle Hill / Gourdon Bay are likely to be a combination of deep sands and sandy earth. This site is relatively level, with few visible irregularities. Extensive earthworks are not anticipated.

### Proximity to Existing Infrastructure

There are some habitations and an unsealed airstrip on Saddle Hill / Gourdon Bay. The Bidyadanga Aboriginal Community is ~20 kilometres to the South West. The closest formed road is less than 20 kilometres to the East. The closest port and sealed airstrips are located in Broome, ~90 kilometres to the North West.

### Summary Evaluation

Saddle Hill / Gourdon Bay has adequate land to support LNG and gas processing facilities. Site topography is favourable and extensive earthworks are not expected. Proximity to existing infrastructure could facilitate the construction and operation of LNG facilities. Saddle Hill / Gourdon Bay is marginal from a marine standpoint. It is fully exposed and likely to require regular dredging.

Further marine studies would be required to quantify and optimize the jetty, breakwater and dredging configuration. The North coast of this site is more suitable than the West coast, especially from a marine and pipeline approach perspective.

# APPENDIX I

# GLOSSARY

## GLOSSARY

| | |
|---|---|
| bar | The bar (symbol bar), decibar (symbol dbar) and the millibar (symbol mbar, also mb) are units of pressure. The bar is still widely used in descriptions of pressure because it is about the same as atmospheric pressure. |
| Btu | The British thermal unit (BTU or Btu) is a unit of energy used in the power, steam generation, and heating and air conditioning industries. One BTU is approximately 1,054—1,060 kJ (kilojoules). |
| CGR | Condensate to Gas Ratio |
| DWT | DWT, for deadweight tones, is the displacement at any loaded condition minus the lightship weight. It includes the crew, passengers, cargo, fuel, water, and stores. Like Displacement, it is often expressed in long tons or in metric tons. |
| GCA | Gaffney, Cline & Associates |
| ha | A hectare (symbol ha) is a unit of area equal to 10,000 square meters, or one square hectometer, and commonly used for measuring land area. A 100 m square is one ha. |
| km | Kilometre(s) |
| LNG | LNG is natural gas that has been converted to liquid form for ease of storage or transport. Liquified natural gas takes up about 1/600th the volume of natural gas at a stove burner tip. It is odorless, colorless, non-corrosive, and non-toxic.<br>The liquefaction process involves removal of certain components, such as dust, helium, water, and heavy hydrocarbons, which could cause difficulty downstream, and then condensation into a liquid at close to atmospheric pressure (Maximum Transport Pressure set around 25 kPa (3.6psi)) by cooling it to approximately −163 °C (−260 °F). |
| LOA | Length Over All, commonly used to indicate maximum hull length of a vessel. LOA is the most commonly-used way of expressing the size of a boat. |
| LPG | Liquefied petroleum gas (also called LPG, LP Gas, or autogas) is a mixture of hydrocarbon gases used as a fuel in heating appliances and vehicles, as well as as an aerosol propellant and a refrigerant.<br>Varieties of LPG bought and sold include mixes that are primarily propane, mixes that are primarily butane, and the more common, mixes including both propane (60%) and butane (40%). |
| MMtpa | Million tones per annum |
| PPP | Public-Private Partnership, the operation of a service in the partnership of government and the private sector.<br>In some types of PPP, the government uses tax revenue to provide capital for investment, with operations run jointly with the private sector or under contract (see contracting out). In other types (notably the Private Finance Initiative), capital investment is made by the private sector on the strength of a contract with government to provide agreed services. Government contributions to a PPP may also be in kind (notably the transfer of existing assets). |
| psi | The pound per square inch or, more accurately, pound-force per square inch (symbol: psi or lbf/in² or lbf/in²) is a unit of pressure or of stress. It is the pressure resulting from a force of one pound-force applied to an area of one square inch: 1 psi (6.894757 kPa) : Pascal (Pa) is the SI unit of pressure |

| | |
|---|---|
| SPM | Single Point Mooring are loading Buoys anchored offshore, which serve as a mooring point for tankers to (off)load gas or fluid products. They are the link between the geostatic subsea manifold connections and the weathervaning tanker. The main purpose of the buoy is to transfer fluids between onshore or offshore facilities and the moored tanker. |
| SRTM | The Shuttle Radar Topography Mission (SRTM) obtained elevation data on a near-global scale to generate the most complete high-resolution digital topographic database of Earth. SRTM consisted of a specially modified radar system that flew onboard the Space Shuttle Endeavour during an 11-day mission in February of 2000. SRTM is an international project spearheaded by the National Geospatial-Intelligence Agency (NGA) and the National Aeronautics and Space Administration (NASA). |
| Tcf | Trillion cubic feet |
| TCS | Thompson Clarke Shipping |
| WEL | Woodside Energy Limited |

**Copy No.**

# BROWSE BASIN GAS TECHNICAL REPORT
# DEVELOPMENT OPTIONS STUDY

## REPORT 2 OF 3

## DEVELOPMENT CONCEPTS FOR DEVELOPMENT OF BROWSE BASIN GAS

**Prepared for**

**THE NORTHERN DEVELOPMENT TASKFORCE**

**May 2008**

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## INTRODUCTION

The Browse Basin, offshore of north-west Western Australia, holds substantial resources of natural gas. At the date of this report, there is no hydrocarbons production from the Basin and there are no hydrocarbons based projects that are either under construction or approved for construction. However, two of the Basin joint ventures, one operated by Woodside Energy Limited (Woodside), and the other by INPEX Browse Ltd (INPEX), are planning to use their known gas resources for "greenfields" land based Liquefied Natural Gas (LNG) projects[1] (**Figure 1**).

The two projects are based on total gas resources of approximately 34 Trillion cubic feet (Tcf)[2]. While some of these resources were discovered over thirty years ago, the basin is "gas prone" and has been relatively lightly explored. The level of exploration activity has increased in recent years and it is likely that other companies currently active in the area will eventually propose LNG projects using Browse Basin gas.

From a technical perspective, the "logical" sites for a land based LNG plant to receive, process and export Browse Basin gas are on the Northern and Southern Kimberley coast or on one of the islands off the coast **(Figure 2)**. The North Kimberley area is totally undeveloped, has no infrastructure and is an eco-tourist destination. The South Kimberley has some development (Broome and Derby), has minimal infrastructure and has several tourist destinations (Broome and Cape Leveque).

At the time of this report, both the Woodside and INPEX operated Joint Ventures have conceptualised their respective projects on a "stand alone" basis and have evaluated potential LNG processing sites on the basis of the individual requirements of those projects. Woodside has prepared a shortlist of several potential sites and INPEX has chosen the Maret Islands as its preferred site. Forecast total LNG production from the two projects is in the order of 20 to 25 Mtpa.

The Kimberley Northern Development Taskforce (Taskforce) is an inter-departmental body formed by the Government of Western Australia. The Project Manager is Mr. Gary Simmons from DoIR. The taskforce has been engaged to set the framework by which the State will protect and manage the important heritage, environment and tourism values of the Kimberley area while facilitating structured industrial development. The West Kimberley Subdivision of the Taskforce was established to manage across-government planning processes and stakeholder consultation in regard to selection and development of a suitable location or locations for the processing of Browse Basin gas reserves.

The Taskforce, through DoIR, has retained Gaffney, Cline & Associates (GCA) to provide independent advice on technical issues associated with the selection and development of onshore and offshore locations, for the processing of the Browse Basin gas. This advice is to be in the form of a report titled "Browse Basin Development Options Study" (The Study).

[1] During the course of the study Shell Development (Australia), (Shell) announced that it plans to develop the Prelude field, in the Browse Basin, using a floating LNG facility (FLNG) with no onshore processing facilities. The proposed development is described briefly in Section 2.4. Since it will not use an onshore processing hub it is not considered in the report

[2] Conversion factors to convert values expressed in conventional oil field units to metric units are shown in Appendix III

The objective of the Study is to review specific technical and economic issues surrounding the processing of existing and yet to be discovered resources at a common LNG plant location or hub. The study has been undertaken in three parts as follows:-

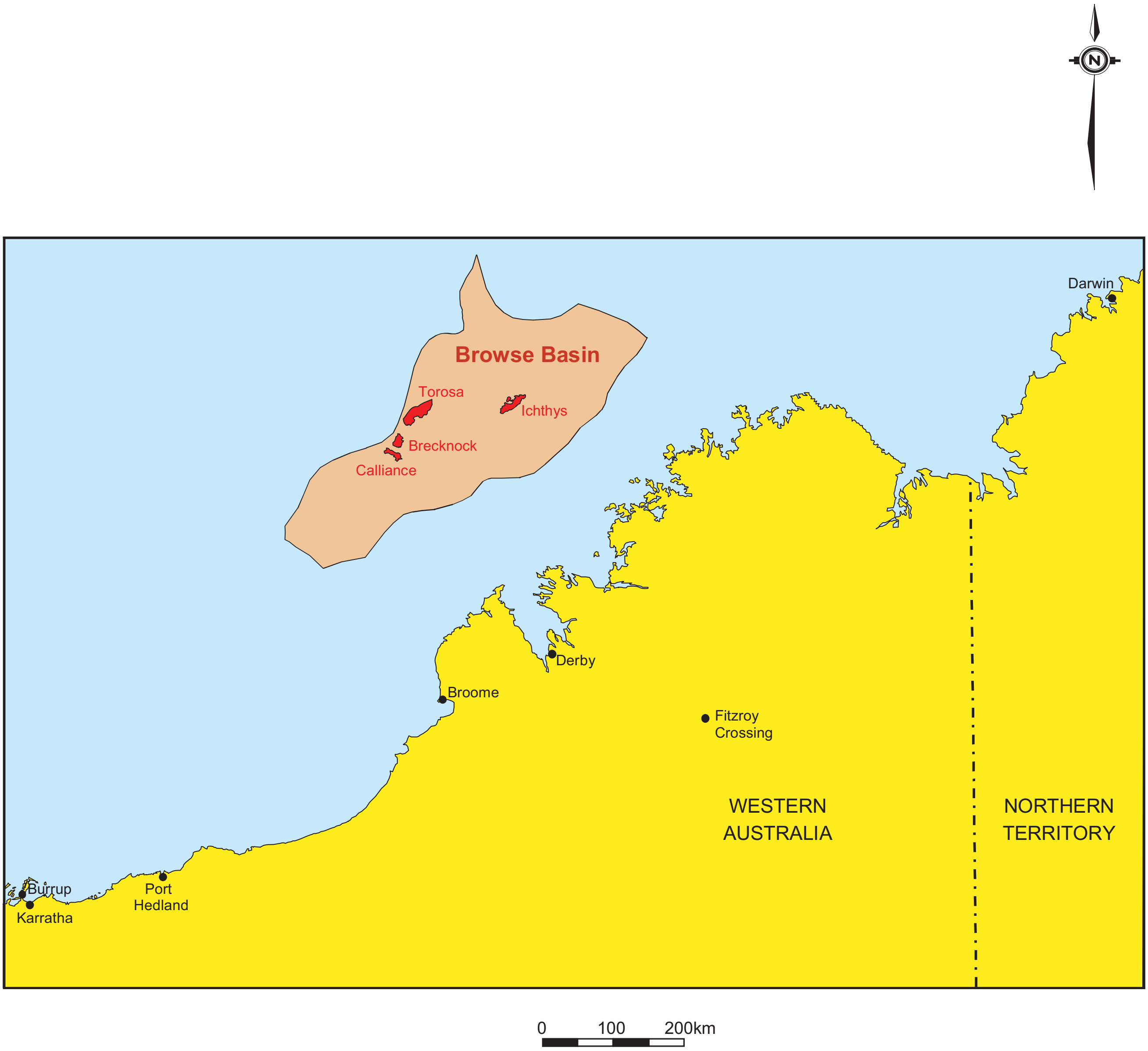
1. Review the existing site selection processes undertaken by Woodside and INPEX and provide commentary on the technical suitability of the sites considered to date in the context of a gas processing hub.

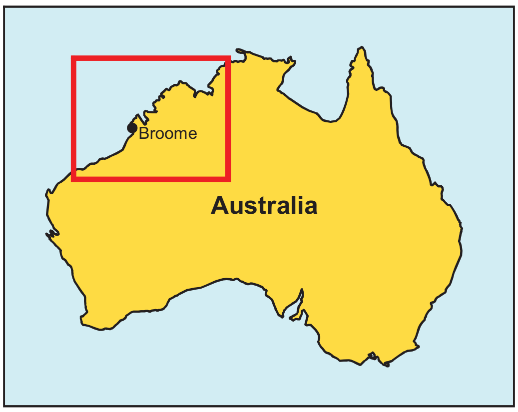
2. Consider and evaluate the key technical issues governing the offshore facilities required to develop Browse Basin Gas in the context of a gas processing hub.

3. Review the potential for an onshore infrastructure hub to support Browse Basin gas development and comment on the key technical, commercial and economic issues surrounding the co-location of the gas processing infrastructure at an onshore infrastructure hub.

Separate reports have been prepared for each of the three areas of review outlined above. This second report discusses key technical issues associated with development of the fields and identifies issues that may potentially constrain offshore developments to support an onshore hub.

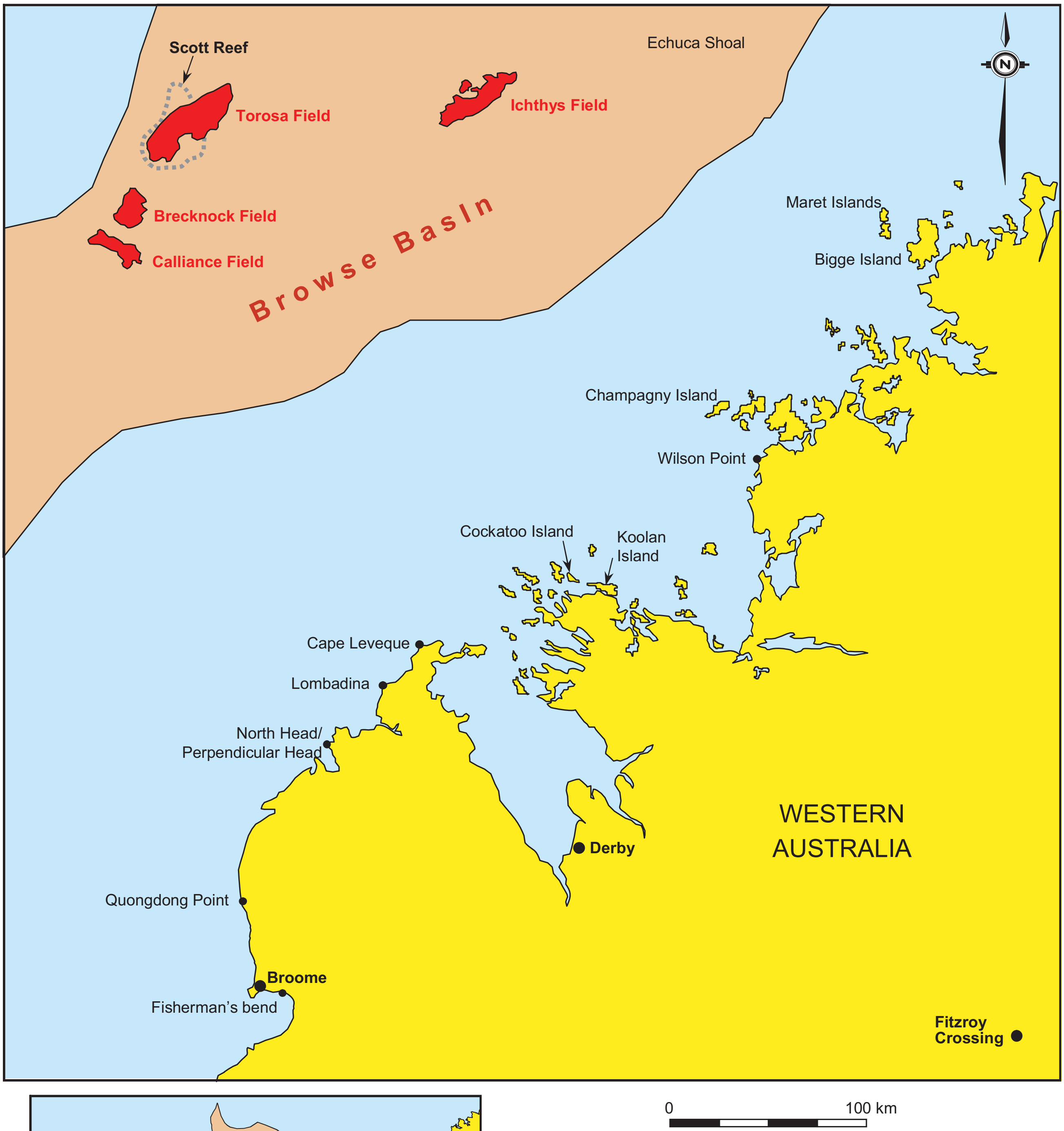
The scope of work for the second report is shown in **Appendix I**. A glossary is included in **Appendix II**.

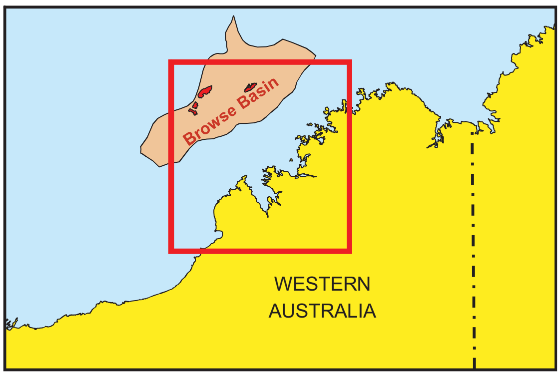



**Browse Basin**
**Location Map**

| Project: KK1177 May '08 | Checked: | Fig. 1 |
|---|---|---|




**Potential Kimberley Sites for Browse Basin LNG Facilities**

| Project: KK1177 May '08 | Checked: | Fig. 2 |
|---|---|---|

## CONCLUSIONS

- The main effect of the location of an onshore gas processing hub on offshore developments is on the length of the pipelines from the fields to the hub. For a single pipeline, this is likely to be in the order of A$4 million/km. In the extreme, the need for a long pipeline to shore could make development uneconomic.

- A lesser effect will likely be the currents and seafloor conditions in the vicinity of the shore which, while not changing the offshore development plans, will impact on the cost of pipelines to shore at the hub location. A detailed survey and bathymetric data will be required to identify pipe laying issues at each of the potential hub locations.

- With the exception of hubs located at Burrup or Darwin, other than the cost of the pipeline, hub location is likely to have little impact on offshore development plans.

- Darwin and Burrup are significantly further from the Browse fields than the other potential hub locations under consideration. If a hub is located at Darwin or Burrup, offshore platforms with compressors will be required along the pipeline routes and condensate will more likely be separated, stored and loaded offshore.

- If a hub were located at Burrup or Darwin, the availability of sufficient quantity of offshore pipeline is likely to be a critical schedule item.

- Where a field or platform is more than about 150 km from onshore facilities condensate will likely be separated from the gas and be either loaded offshore or sent to shore in a separate pipeline. The fields for both proposed developments are more than 150 km from the onshore gas processing hubs considered.

- Because fields in the Browse Basin are expected to contain high levels of carbon dioxide, gas developments will likely include an offshore platform, either fixed or floating, to dry the gas and make it non-corrosive to allow the use of carbon steel pipelines downstream of the platform.

- Whether the platform is placed over the field, to allow the use of dry wellheads and to minimise the length of flow lines, or in shallower water some distance from the field, will depend on water depth, geotechnical conditions at the field and the distance to water depth where a fixed platform can be built

- Well tubulars, flow lines and subsea manifolds upstream of the platform will likely be made of corrosion resistant alloy which is expensive.

- Although there is potential for different development projects to share offshore facilities this is considered unlikely, particularly in the early stages of the Basin development. The chance of this happening is largely independent of whether a hub or stand-alone onshore facilities is used. It is also largely independent of the location of an onshore gas processing hub.

# DISCUSSION

## 1. BROWSE BASIN

### 1.1 General

The Browse Basin is a large (180,000 km$^2$) basin located off the northwest coast of Western Australia. Water depths over the basin range from 20 m to more than 2,000 m. Large gas fields were discovered in the basin in the early 1970s but, in contrast to those in the North West Shelf, have remained undeveloped because of the longer distance to shore and deeper water. However, two Browse Basin joint ventures, one operated by Woodside and the other by Inpex are planning to develop their gas resources for LNG projects.

The eastern margin of the Bowen Basin comprises the Yampi Shelf, which consists of an eastward-thinning sequence of Mesozoic and younger sediments. The southern part of the basin comprises the Leveque Shelf, an offshore extension of the Kimberly Block. The Leveque Shelf separates the Browse Basin proper from the adjacent Fitzroy Graben and Rowley Sub-basin of the Canning Basin, (**Figure 3**).

The basin has two distinct depocentres, the Caswell and Barcoo Sub-basins. These depocentres contain in excess of 15 km sedimentary section and lie in 100 – 1,500 m water depth. The outer Browse Basin underlies the deep-water Scott Plateau. The carboniferous section is predominatly fluvio-deltaic and the Permian-Early Triassic section is marine. Early Cretaceous claystones provide a thick regional seal.

The basin is considered to be gas prone and despite the large fields already discovered has been relatively lightly explored. Reports by the US Geological Survey and Longley[3] support the view that the basin contains over 30 Tcf of undiscovered gas.

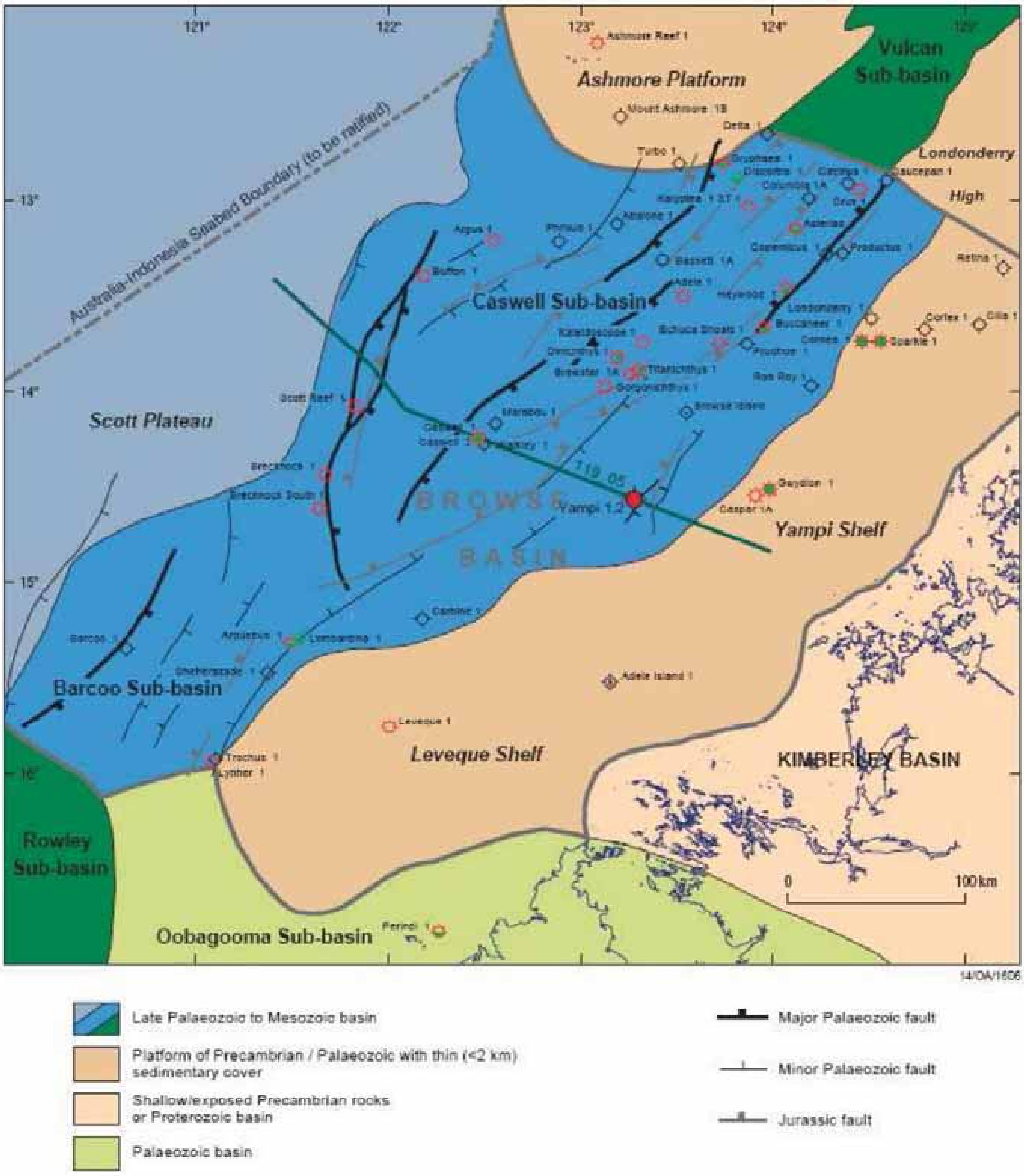
### 1.2 Fields in the Browse Basin

#### 1.2.1 Resources

Approximately 40 Tcf has been discovered in the Browse Basin. **Table 1** shows the discovered fields in the Browse Basin listed by DOIR with their estimated gas and condensate resources. (This table does not include all the discovered resource, for example Crux and Prelude).

A total gas resource base discovered and yet to be discovered in the order of 70 Tcf, would indicate that long term LNG capacity for gas from the Browse Basin would be in the range of 20 – 35 Mtpa. Based on recent announcements, some of this capacity might be located offshore.

[3] Longley, I.M. et al, 2002, The North West Shelf of Australia - a Woodside perspective, in The Sedimentary Basins of Western Australia 3, P27-28, Proceedings of WA Basins Symposium, Perth, Australia




| | | |
|---|---|---|
| **Browse Basin** | | |
| Project: KK1177 May '08 | Checked: | Fig. 3 |

**TABLE 1**
**FIELDS IN THE BROWSE BASIN - RESOURCES**

| Field | Permit | Operator | Gas P50 Tcf | Cond P50 MMbbl |
|---|---|---|---|---|
| Torosa | WA-30-R | Woodside | 11.4 | 121 |
| Brecknock | WA-29/32-R | Woodside | 5.3 | 109 |
| Calliance | WA-28/31 | Woodside | 4.0 | 87 |
| Ichthys | WA-285-P | Inpex | 9.5 | 315 |

**Notes:**
1. The Torosa field was formerly known as Scott Reef
2. The Calliance field was formerly known as Brecknock South
3. Ichthys includes both the Brewster and Plover reservoir units
4. In May 2008 Inpex revised Ichthys reserves upwards to 12.8 Tcf gas and 527 MMbbl condensate.

**TABLE 2**

**FIELDS IN THE BROWSE BASIN**
**CONDENSATE GAS RATIOS**

| | Bbl/MMscf |
|---|---|
| Torosa | 11 |
| Brecknock | 21 |
| Calliance | 22 |
| Ichthys | 33 |

**Notes:**
1. Based on the reserves reported by DOIR Ichthys, condensate ratio is 33 bbl/MMscf.
2. Based on the updated reserves reported by Inpex, May 2008, it is 41 bbl/MMscf.

Other fields have been discovered in the Browse Basin, but do not have resource volumes recorded by DOIR. The Crux Field, operated by Nexus Energy in AC/P23, was discovered in 2000. Nexus has since drilled three appraisal wells on the field. Following the drilling of Crux 2ST in 2007, GCA estimated the gas and condensate resource of about 2 Tcf with 66 MMbbl condensate (Best estimate).

The Echuca Shoals field in WA-377-P, also operated by Nexus, was discovered in 1983. The field is located in close proximity to the Ichthys field. In 2007, Shell discovered the Prelude field with an estimated 2-3 Tcf, in WA-371-P next to Ichthys. The Argus field was discovered in 2004. The Argus field was reported to have poor porosity and permeability.

### 1.2.2 Torosa, Brecknock, Calliance

The Torosa, Brecknock and Calliance gas condensate fields are located approximately 290 km off the Kimberly coast, 400 km NW of Broome, in the Browse Basin, in petroleum retention leases and permits WA-R-2, WA-TR/5, WA-28-R, WA-29-R, WA-30-R, WA-31-R, WA-32-R and WA-275-R. The permits and leases are held by Woodside Petroleum Ltd, BHP Billiton Petroleum Pty Ltd, BP PLC, Chevron Corporation and Royal Dutch Shell PLC. Details of the interests in the different leases and shown in **Appendix IV**. The fields are estimated to contain approximately 20.7 Tcf gas and 317 MMbbl condensate.

The Torosa field (previously known as Scott Reef) was the first field discovered in 1971. Brecknock was discovered in 1979 and Calliance (formally Brecknock South) in 2000. Part of the Torosa field lies beneath Scott Reef but the rest of it and the other two fields are in water depths of 400 – 700 m. The Torosa and Calliance fields are about 70 km apart. The Brecknock field is between the two.

The condensate content varies from field to field with Calliance having the highest condensate ratio. The average across the three fields is 17 bbl/MMscf. Carbon dioxide content is in the range 4% - 12%. Resource volumes for each of the fields are shown in **Table 1**.

### 1.2.3 Ichthys

The Ichthys Field is in exploration permit WA-285-P R1. The permit is held by Inpex Corporation 76% and Total E&P Australia 24%. The field is located approximately 230 km from the mainland and 440 km north of Broome in 260 – 280 m water depth. The field is approximately 40 km long and 20 km wide.

The field was discovered by the Dinichthys-1, Gorgonichthys-1 and Titanichthys-1 wells in 2000 – 2001. The field contains two sandstone reservoir units, the upper early Cretacious Brewster Member and the lower early-mid Juassic Plover formation.

The field is estimated to contain 12.8 Tcf gas and 527 MMbbl condensate. It contains two reservoir units, the Brewster and the Plover formations. The Brewster gas is condensate rich with a gas condensate ratio of about 53 bbl/MMscf and a carbon dioxide content of 8.5%, while the Plover gas contains about 12 bbl/MMscf condensate and has a carbon dioxide content of 17%. The carbon dioxide is believed to be of volcanic origin.

### 1.2.4 Crux

The Crux field, located in AC/P23, is approximately 150 km to the northeast of Ichthys. Interests in the field are held by Nexus 85%, and Osaka Gas 15%. The field is made up of four distinct reservoir units, the Montara formation, Plover formation, and Nome formation “A” and “B” sands. At the reservoir level the field forms a Y-shaped structure that trends in a SW-NE orientation and is bounded by faults trending in approximately the same direction.

Four wells have been drilled on the field. Crux-4, the most recent well, was completed only earlier this year. Following the drilling of Crux 2ST in 2007 GCA was asked to estimate the gas and condensate resource. GCA's Best estimate of the gas resource was about 2 Tcf gas with 66 MMbbl condensate.

In early 2007, Nexus sold the rights to the gas, excluding condensate, to Shell Development (Australia). The gas sales agreement enables Nexus to undertake a gas recycle project to recover condensate until 31 December 2020, at which time Shell will assume ownership of the permit and will have the right to the gas and any remaining condensate.

### 1.2.5 Prelude

The Prelude field in the northern part of the Browse Basin, was discovered by Shell in 2007. The field is located in WA-371-P in 250 m water depth. The field is estimated to have 2-3 tcf gas. There is very little information regarding the Prelude field in the public domain.

# 2. FIELD DEVELOPMENTS

## 2.1 Brecknock, Calliance and Torosa Field Development

Current development plans by the Operator, Woodside, are at a very preliminary stage and a number of possible development options are still under consideration. These all revolve around production of about 15 Mtpa LNG using two or three LNG trains.

Notional upstream development plans are described in the Browse Upstream Development prepared for the EPBC Act Referral of Proposed Action, February 2008[4] (**Figure 4**).

The base case notional development plan is to develop jointly the three fields using a combination of subsea wellheads (that is with wellheads on the sea floor) and dry wellheads based on floating platforms such as tension leg platforms (TLPs). Subsurface well centres would be located on North Torosa, South Torosa, Brecknock and Calliance development area and a floating platform, with dry trees, installed at each of the well centres at North Torosa and at Calliance. Pipelines would take production from each of the subsurface well centres to a floating platform where bulk water would be removed, treated and disposed of.

The fluids (gas and condensate) would then flow by pipeline to a processing platform located in shallower water, 80 – 120 m water depth. The platform, which could be either a steel jacket or a concrete gravity structure (CGS), would be located about 110 km from Torosa and about 60 km from Brecknock and Calliance. On the platform condensate would be separated and stabilized[5] for loading offshore, gas would be dried and sent by pipeline to shore for processing. If the platform was a concrete gravity structure stabilized condensate would be stored in the base of the platform before being loaded onto tankers though a loading buoy for transport to markets. If the platform was a steel jacket, a floating storage and offloading (FSO) vessel would be employed to store condensate before being loaded onto tankers. Compression would likely be installed on the platform later in the life of the project when reservoir pressure declined. The Browse joint venture is still actively considering a number of different offshore development options and onshore sites as potential locations for onshore processing facilities.

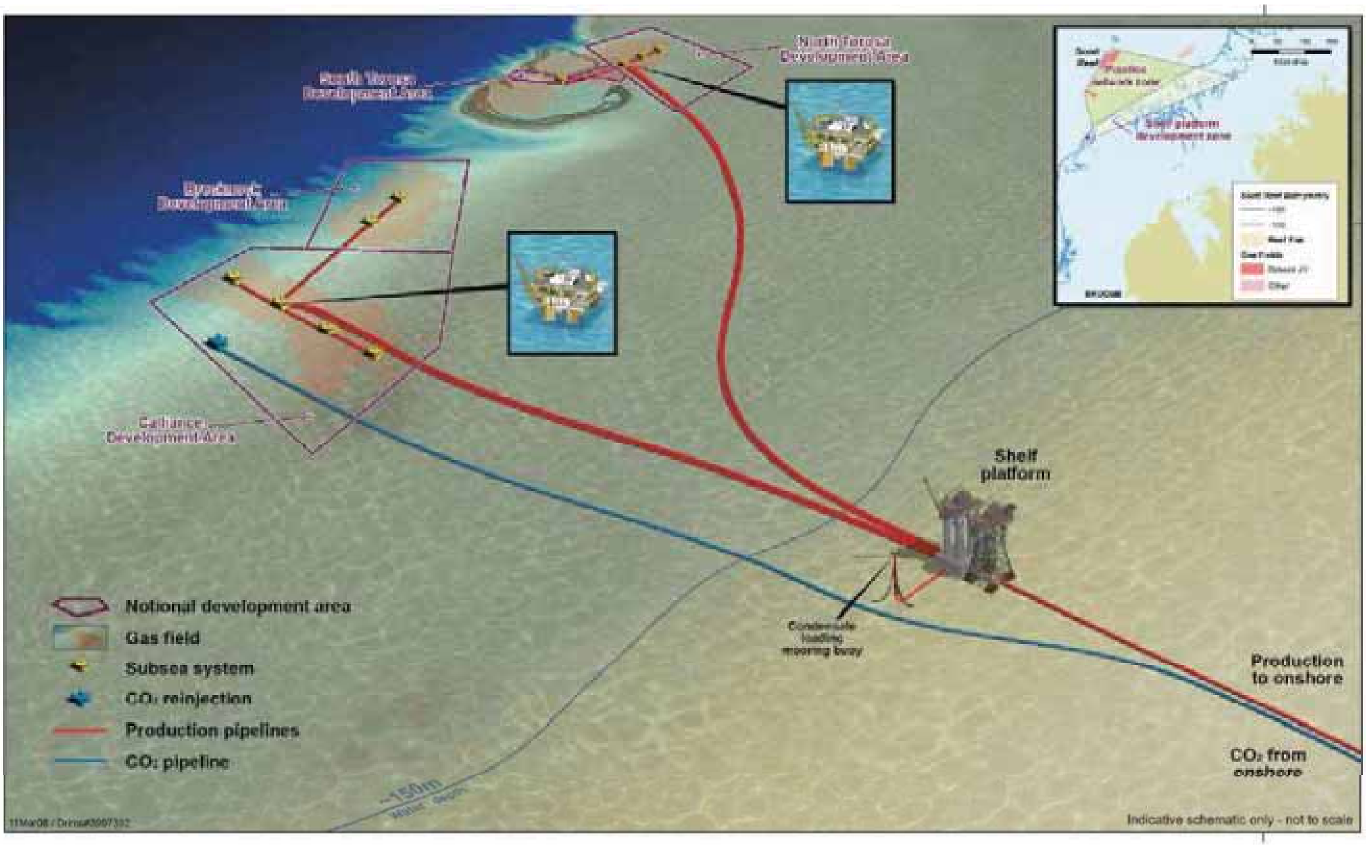
It is proposed, subject to feasibility studies and the relevant commercial/regulatory framework, that carbon dioxide removed from the produced gas will be geosequestrated offshore, possibly back into one of the fields to be produced

## 2.2 Ichthys Field Development

Current plans by the Operator are to develop the Ichthys Field to produce 8.4 Mtpa LNG with associated condensate and LPG. The field will be developed, using subsea wells and manifolds, producing to a floating central processing facility (CPF) in the form of a semi submersible platform (**Figure 5)**. At the CPF, liquids will be separated from the gas and condensate and water separated. The gas and condensate will be dried and then transported to the onshore processing facilities in separate pipelines. Produced water will be cleaned and discharged overboard. Provision will be made for installation of compression facilities at a later time.

[4] Available at Woodside.com.au

[5] Condensate is stabilised to reduce its vapour pressure to allow it to be stored at and transported in tankers. The condensate is heated and the pressure reduced to allow gas dissolved in the condensate to be removed.




**Indicative Woodside Operated Development**

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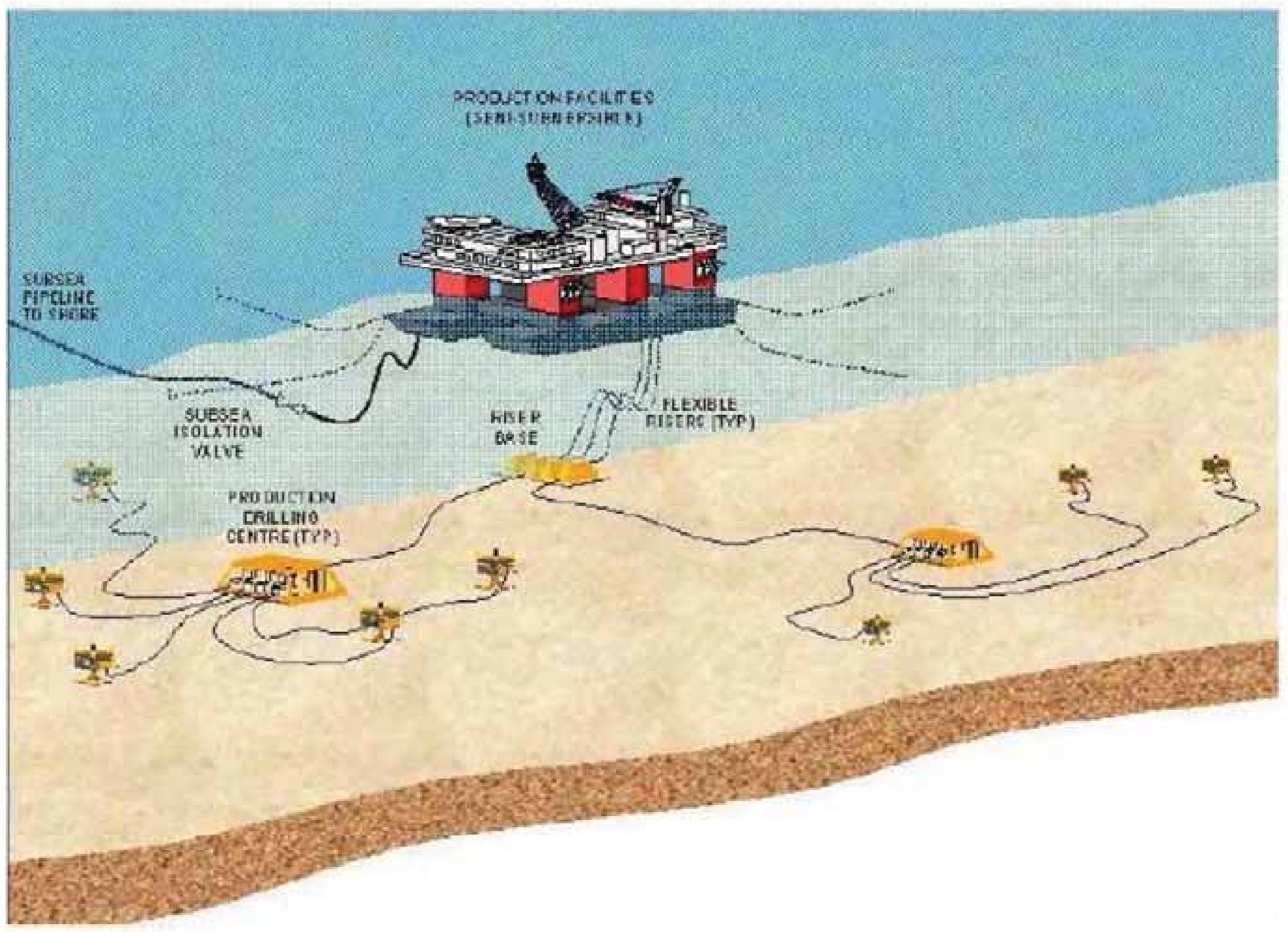



**Inpex**

**Development Concept**

| Project: KK1177 May '08 | Checked: | Fig. 5 |
|---|---|---|

Gas will be produced at a constant rate of about 1.4 Bcf/d until production starts to decline after 20 to 30 years. Condensate production will commence at over 70,000 bbl/d and will decline over time as the reservoir pressure decreases. LPG production will remain at 40,000 – 50,000 bbl/d while the Brewster reservoir is being produced and will then decline as increased amounts of gas are drawn from the Plover reservoir.

Inpex plan to initially develop the Brewster reservoir unit, since it has a significantly higher condensate content. As the pressure in the reservoir falls over time, it is anticipated that compression will be installed, followed by development of the Plover reservoir unit. It is anticipated that a total of 35 – 40 wells will be required over the life of the field.

Inpex has conducted an extensive site selection survey and determined that the Maret Islands are the most suitable location for the gas liquefaction facilities. The gas and condensate pipelines from the CPF to the Maret Islands will be approximately 190 km. The following processing facilities are proposed for Maret Island:

- Further gas drying
- Carbon dioxide removal
- LPG extraction, propane and butane separation and storage
- Condensate stabilization and storage
- Gas liquefaction and storage

It is proposed to dispose of carbon dioxide through biosequestration, that is planting trees.

It is envisaged that two ship berths will be provided, one dedicated to LNG loading and the other for shared LNG, propane, butane and condensate loading.

## 2.3 Crux Field Development

Nexus Energy, operator of the Crux Field, plan a gas recycle project on the Crux Field to recover condensate. Four wells have been drilled on the field, environmental approval has been received and a preliminary development plan submitted to the regulator. FID is expected in 3Q 2008.

The project will consist of gas production from subsea wells, to a floating production storage and offloading vessel (FPSO) where gas will be processed to recover condensate. The gas will then be recompressed and injected back into the reservoir. Stabilised condensate will be stored on the FPSO and transferred from the FPSO to tankers for transport to market. A gas recycle rate of 900 MMscf/d is planned, which will produce a peak condensate rate of 32,700 bbl/d.

The rights to the hydrocarbon remaining in the field at the end of 2020, after the gas recycle project, pass to Shell Development (Australia) which will have the right to extract the gas and any remaining condensate.

## 2.4 Prelude Field Development

In April 2008, Shell announced that it proposed to develop the Prelude Field, in the northern section of the Browse Basin, using a floating LNG facility. The field is in approximately 250 m water depth. Prelude, in W-371-P, was discovered by Shell in 2007. The FLNG facility will be designed to produce 3.5 Mtpa LNG plus LPG and condensate. All the gas processing and product storage will be on the facility and the products will be loaded directly from the FLNG facility into tankers. There will be no pipelines to shore.

The facility will be moored to the seabed via a turret, around which the facility can weathervane. The steel substructure will be approximately 480 m long and 70 – 80 m wide. Gas will be produced from the reservoir using either subsea wells, connected to subsea manifolds or wells with dry wellheads located on a wellhead platform. Reservoir fluid will flow from the wells to the FLNG facility, via flowlines and flexible risers used to accommodate the motions of the FLNG facility. All gas processing that is normally done on shore will be done on the FLNG facility.

# 3. FACTORS EFFECTING OFFSHORE GAS DEVELOPMENTS

## 3.1 Introduction

There are a number of factors that affect the choice of components that make up an offshore development. These interact with each other and to understand how the choice of an onshore hub location might effect an offshore development it is necessary to understand the impact of these factors. The factors considered are:

- Water depth
- Carbon dioxide content
- Condensate content
- Reservoir drive mechanism
- Distance to land
- Hydrate formation

These factors are outside the control of the developer and present challenges of different degrees of magnitude that must be resolved to arrive at a successful development.

In most cases, there are a number of alternative developments that can successfully develop a field and the challenge is to find the option with the lowest capital and operating cost that meets the necessary operating, safety and environmental criteria.

The ways in which the location of an onshore hub might effect offshore development are discussed in **Section 4**.

## 3.2 Water Depth

One of the main decisions to be made when planning an offshore development is whether the wells will be completed above sea level or on the sea floor. Wells completed above sea level are less costly to drill, work over and for wire line operations. However, in order to complete a well above sea level, it is necessary to have a platform above sea level and support structure for the wells. The platform can be fixed to the sea floor, or a floating platform held in place with tethers to the seafloor. Wells completed at the sea floor do not need a large support structure but are more expensive to drill and work over. They also need some form of remote control system to control the flow of fluid from the well.

Water depth is the main determinant as to whether field development wells have dry trees, or wet trees on the sea floor. In shallow water almost invariably, a simple fixed platform is built to allow wells to be completed with dry trees. In many cases, for a field in shallow water where a platform is built, process equipment is installed on the platform. In other cases, the platform might contain only wellheads and all the fluid produced from the wells is transported either to shore or to another platform for processing. In some cases, where a large number of wells are required for a field that covers a large areal extent, more than one platform will be built. Frequently, it is the need to process gas or oil close to the field, combined with a desire for dry trees that supports a decision to install some form of platform.

As water depth increases, the cost of a platform to support dry trees increases and a point is reached where it is more economic to use subsea completions. Conventional steel jacket platforms have been installed in water depths up to about 400 m. For example, the Bullwinkle platform completed by Shell in the Gulf of Mexico in 1991 in 412 m water depth, the

Harmony platform installed in 1992 by ExxonMobil in 366 m water depth in the Santa Barbara Channel and the Pompano platform installed by BP in 393 m water depth, also in the Gulf of Mexico.

A CGS is an alternative to a steel jacket platform. The Troll A CGS was installed by Shell in the Norwegian North Sea in 303 m water in 1996. CGSs have the advantage that the base can be used for storage, for example for condensate or oil if offshore loading of liquids is to be used.

In more recent years, technology has advanced with respect to subsea completions and alternatives to steel jacket platforms, making it unlikely that steel jacket platforms or CGSs will in future be used in water depths greater than 300 m. For water depths between 150 m and 300 m operators have a choice between steel jacket platforms, CGSs and the alternatives discussed below. See **Figure 6**.

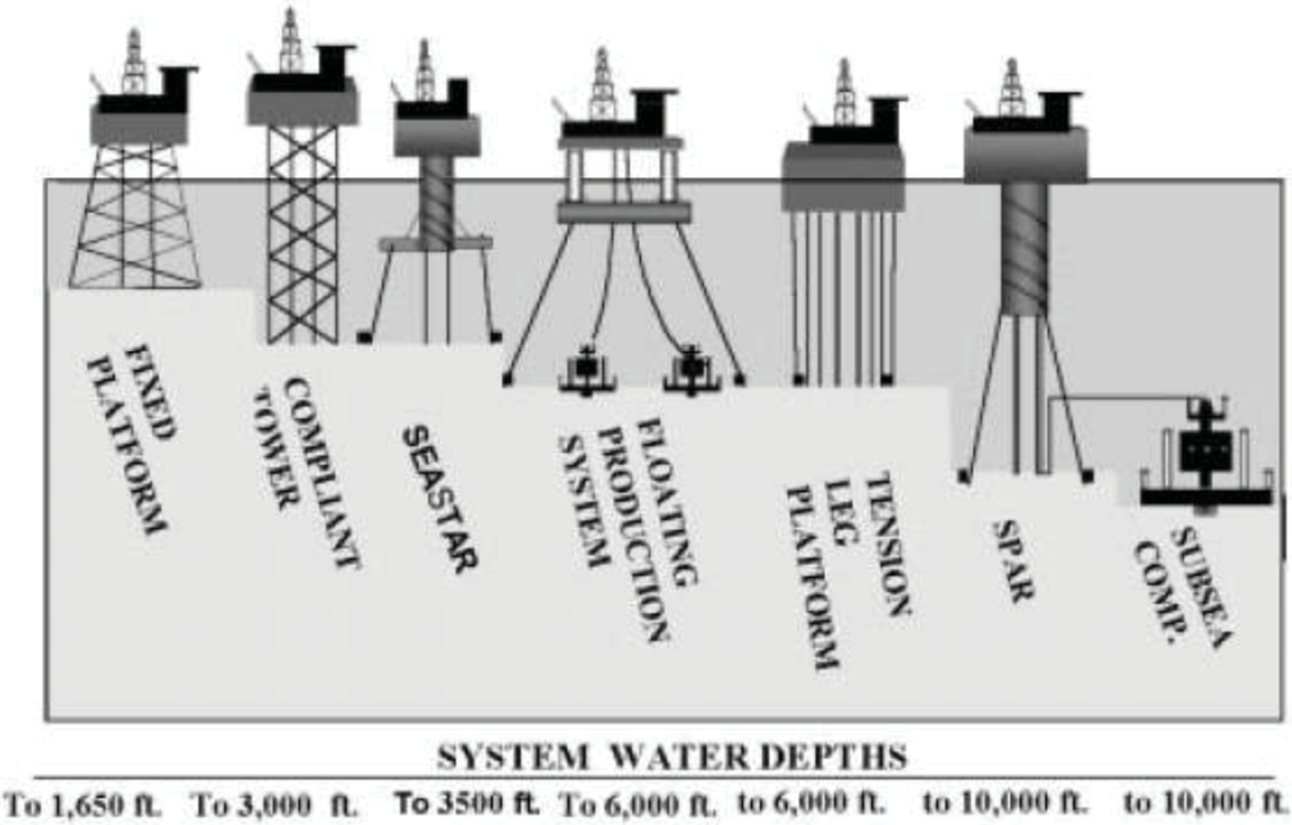
A number of different platform options have been used for fields in deeper water. For production of oil from fields in deep water by far the most common type of development is the use of subsea wells producing to an FPSO, where the FPSO is usually ship shaped, and in many cases is a converted crude tanker. Gas and water are separated from the crude on the FPSO, the crude is stabilized to make it suitable for transport, water is cleaned and discharged overboard and the gas is either flared or reinjected back into the reservoir. This is appropriate for crude production where the use of an FPSO obviates the need for a pipeline to shore but is not suitable for gas production. It is not possible to store large volumes of gas offshore and gas is not transported by ship, unless it is first liquefied, so a pipeline is required to carry gas to shore either for liquefaction, conversion to a shippable product such as methanol, or for domestic distribution.

Compliant towers have been used in water depths of 300 m to about 900 m. A compliant tower is a narrow flexible tower with a piled foundation that supports a conventional deck for drilling and operations. Compliant towers have been used in the Gulf of Mexico.

Another option for water depths greater than about 300 m is a tension leg platform. Tension leg platforms have been installed in water depths up to 1,200 m. They consist of a floating structure held in place by vertical, tensioned tendons connected to the seafloor by pile secured templates. They have limited vertical motion and allow the use of dry wellheads and provide a platform for process equipment.

A third option is a floating production system (FPS) which consists of a semi-submersible that has drilling and production equipment. It is anchored to the sea floor with a number of mooring chains to keep it on location. The wellheads are located on the seafloor and produce to the FPS through flexible risers designed to accommodate the motion of the FPS. FPSs can be used in water depths up to about 2,300 m.

Another option is a spar platform. A spar platform consists of a large-diameter single vertical cylinder supporting a deck. The hull is moored with a taut catenary system of lines anchored to the sea floor.




| Offshore Production Systems | | |
|---|---|---|
| Project: KK1177 May '08 | Checked: | Fig. 6 |

Tension leg platforms (TLPs), compliant towers, and spars have all been used in deep water and allow wells to be completed with dry wellheads. FPSOs, mini TLPs and FPSs allow process facilities to be installed in deep water, but do not cater for dry wellheads. In these cases, subsea wells are used with flexible flowlines led to the FPSO, mini TLP or FPS. The deepest installation of a form of platform to date is Na Kika semisubmersible FPS, in the Gulf of Mexico in over 1,900 m water depth.

Subsea completions are used when only a limited number of wells are required and the wells can be tied back to a nearby platform, where the water is deep and the use of subsea wells is less expensive than a structure supporting dry wellheads or where the water depth is such that installation of a structure to support dry wellheads is not feasible. Subsea completions have been installed in water depths over 2,000 m, for example Coulumb in 2,300 m water depth in the Gulf of Mexico.

History has shown that the type of offshore production systems used in deep water depends on the geographic area it is to be installed in, and the operator, as much as it does on the function it is to perform or the nature of the field and process conditions.

Water depth over the Browse basin ranges from about 20 m to over 2,000 m so it can be expected that any of the above mentioned options could be used for development of fields in the basin.

The Brecknock, Calliance and Torosa fields are in water depths of 400 – 700 m, apart from a section of the Torosa field which is directly below Scott Reef. This means that, from a technical point of view, all or part of the Torosa field could be developed using dry well heads and facilities located on Scott Reef. For Brecknock and Calliance, the water depth is too great for steel jacket platforms or CGSs, so if the use of dry well heads was planned, the choice of a structure to support the well heads would be a compliant tower or TLP. The other alternative is to use subsea well heads. The referral under the EPBC Act submitted by Woodside describes subsea wellheads and TLPS for the development of the Woodside operated project. See **Section 2.1**.

### 3.3 <u>Carbon Dioxide Content</u>

Carbon dioxide and water form carbonic acid which is corrosive. All the fields in the Browse Basin that are currently under consideration for development contain sufficient carbon dioxide, where steps have to be taken to control corrosion.

There are four methods of preventing corrosion caused by carbon dioxide:

- Use of corrosion resistant alloy
- Drying the gas
- Use of corrosion inhibitor
- Removal of carbon dioxide

### 3.3.1 Use of Corrosion Resistant Alloy

Corrosion resistant alloy is intrinsically capable or resisting corrosion by wet acid gas. Where gas is corrosive due to the presence of carbon dioxide, it is usual to have production tubing in the wells made of corrosion resistance alloy (CRA). This is especially so where subsea well heads are used, since workovers are expensive.

CRA materials can also be used for flow lines and trunk lines. Since the cost of CRA is generally of the order of 5 times the cost of carbon steel pipeline material it is usual to use the CRA material as a cladding in the pipelines rather than use pipelines made of solid CRA. Generally the industry tends to use CRA pipelines for shorter lengths and smaller diameters. The use of long CRA clad pipelines becomes prohibitively expensive, especially for large diameter lines.

### 3.3.2 Gas Drying

If gas containing carbon dioxide is dried, the dry gas becomes non-corrosive. The conventional way of drying gas is to separate liquid hydrocarbons from the gas and contact the gas with triethylene glycol (TEG). The liquid hydrocarbons (condensate) are dried using gravity separation of water or a density based process, such as hydrocyclones. The resultant water stream is cleaned and discharged overboard. In order to dry gas to make it non-corrosive, it is necessary to have some sort of platform, fixed or floating, to support the process equipment. Because the drying process involves rotating equipment and a heat source, a platform where gas is dried has historically been manned and is a substantial structure.

### 3.3.3 Corrosion Inhibitors

Corrosion inhibitors have been developed that reduce the rate of corrosion caused by carbon dioxide. The effectiveness of the corrosion inhibitors depends on the temperature of the gas, the gas composition and other factors such as the gas and liquid velocities in the line. The effectiveness of corrosion inhibitors rely on continuous injection of the inhibitor and good distribution of the inhibitor in the line. They are sometimes used in conjunction with additional wall thickness in the pipeline to allow for a limited amount of corrosion.

### 3.3.4 Removal of Carbon Dioxide

Carbon dioxide is removed using a process similar to that used to dry gas except that the gas is contacted with an amine solution instead of triethylene glycol. In an offshore environment, it is almost invariably less expensive to dry gas rather than remove carbon dioxide.

### 3.3.5 Relevance of Carbon Dioxide to proposed Developments

All the fields in the current proposed developments have sufficiently high levels of carbon dioxide, where development plans have to be made to accommodate it. It is an important factor driving the development plans. The EPBC referral prepared by Woodside, on behalf of the Browse Joint Venture states that gas will be processed on an offshore platform, such that it can be transported via a transmission line to an onshore LNG facility. It is presumed that such processing will include gas drying. Inpex plans to dry Ichthys gas on the CPF prior to transmission to Maret Island.

Part of the plans to accommodate carbon dioxide, include plans for disposal of carbon dioxide removed from the gas. Inpex proposes to dispose of carbon dioxide through biosequestration, that is planting trees. It is unlikely that hub location will influence this plan.

The Woodside operated project propose, subject to feasibility studies and the relevant commercial and regulatory framework, to geosequester carbon dioxide removed from the produced gas offshore, possibly back into one of the fields to be produced. If this were to be the case, the main impact of a hub location on carbon dioxide disposal would be on the length of the pipeline used to carry carbon dioxide to the offshore field. Plans by the Woodside operated project for carbon dioxide disposal appear, at this stage, to be in the early stages of development.

## 3.4 Condensate Content

A high condensate content of a gas adds considerable value to the gas. The condensate is recovered from the gas, stabilised, and sold as a separate product. The Crux gas recycle project relies entirely on the value of the recovered condensate for its economic justification.

However, a development of gas containing condensate needs to take account of the condensate in its design. Whenever two phases (gas and condensate) or three phases (gas condensate and water) flow through long pipelines a liquid phase builds up in the pipeline and exits in the form of slugs. This leads to unstable operation of the pipeline, the gas and liquid flow rate from the pipeline is not steady which can make operation of the liquefaction facilities difficult and necessitates a large volume of high pressure storage (slug catchers) to allow the liquid slugs to accumulate and be processed through stabilization facilities at a steady rate.

The problems associated with two phase or three phase flow in pipelines depend on the length of the pipeline, the changes in elevation of the pipeline, the condensate content of the gas, pigging frequency and the changes of gas throughput rate. Major slugging is associated with increases in gas rate when large volumes of liquid are swept from the pipeline. Slugging occurs when a subsea pipeline carries two or three phases to a platform or to an onshore processing plant.

The Ichthys field has a higher condensate content than Torosa, Brecknock or Calliance, about 53 bbl/MMscf versus an average of about 17 bbl/MMscf for Torosa, Brecknock and Calliance. These levels are high enough where condensate build up in two phase or three phase pipelines has to be considered.

## 3.5 Reservoir Drive Mechanism

The energy to produce gas from a reservoir can either come from the expansion of the gas in the reservoir, or the presence of an aquifer pressurising the gas in the reservoir.

In the case where the energy is provided by the expansion of gas in a reservoir, the reservoir pressure decreases, as gas is produced which in turn leads to a reduction of the wellhead pressure. This means that at some point in the depletion of the field, it is necessary to install compression to increase the pressure of the gas into the processing facilities. Where the pipeline from the field to the onshore processing facilities is relatively short, compression is usually installed at the plant inlet. However, where the pipeline from the field is long, it is usually

more efficient to install compression as close as possible to the field. In some cases, this necessitates installing a platform to support the compression facilities.

There are several points regarding offshore compression that should be noted:

- Despite development work being done on the installation of subsea compression, it is still in the experimental stage;
- It is not possible to compress liquid, so liquid must be separated from gas before gas is compressed. The liquid may then be recombined with the gas in a single pipeline or transported in a separate liquids line;
- Offshore compression facilities are almost invariably manned.

Where the field has a strong aquifer drive, it may not be necessary to install compression, however in this case, wells will start to produce water near the end of the life of the field and wet wells will need to be shut in and facilities will need to be designed to handle increased volumes of water.

Information regarding the reservoir drive mechanism for the fields in the proposed developments has not been provided to GCA. However, it is expected that compression will be installed for both developments during the project lives.

## 3.6 Distance To Land

### 3.6.1 Introduction

Historically, gas processing facilities have been land based. In most cases, this is because gas is distributed and sold through an onshore distribution system to an onshore market, as for example gas from offshore Bass Strait fields goes by pipeline to onshore gas processing plants for distribution and sales in eastern Australia and Tasmania. Also where gas has been converted to a liquid product such as methanol or LNG, for transport to an overseas market, the conversion or liquefaction has been carried out in a land based plant.

However, as gas fields are developed that are further offshore and pipelines to shore get longer pipeline costs increase, so there is an incentive to convert the gas to liquid product such as methanol or LNG in offshore facilities and ship the product directly to markets from offshore facilities.

### 3.6.2 Offshore Processing

Compared to gas, oil requires little processing before it can be shipped and it is now common practice to develop offshore oil fields, distant from shore, using FPSOs where all the processing is carried out on the FPSOs. There have been several proposals to build floating LNG plants or methanol plants, which obviates the need for pipelines to shore. To date, however these have not eventuated, but for cases where the gas is to be converted to a liquid product, where pipelines to shore based facilities become longer, the incentive to do all the gas processing offshore will increase.

Shell plans to develop the Prelude field in the Browse Basin, using a FLNG facility. See **Section 2.4**. Shell is also reported to have proposed the use of a floating LNG plant to develop the Sunrise field in the Timor Sea. BHP Petroleum built a small methanol plant in Victoria in the 1990s to test technology for installing a floating methanol plant to process solution gas from offshore oil fields or small offshore gas fields.

### 3.6.3 Increased Pipeline Length and Diameter

A second impact of increased distance to land is increased pressure drop in pipelines to shore. This may be counteracted by increasing the pipeline diameter or installing compression offshore; both of which are expensive for long pipelines.

Where a pipeline carries a liquid phase increased, pipeline length increases the amount of liquid held in the pipeline and increases the size of liquid slugs that exit the pipeline.

Where a field is developed using subsea completions with no offshore fixed or floating platform, as well as the trunk line carrying wellhead fluid from the field, there will be a number of small pipelines going to the wellheads and manifolds. These smaller lines going to the wellheads will carry fluids such as hydrate inhibitor, corrosion inhibitor, hydraulic fluid for operating subsea valves and exhaust for returning used hydraulic fluid. There will also be an umbilical carrying electric control cables. The length and cost of these smaller lines also increases as fields are developed further from shore.

### 3.6.4 Compression

Where an offshore gas pipeline is longer than 250 – 350 km, then it is likely to be less expensive to install compression on a platform at a mid point, rather than increase the pipeline diameter. This will depend on water depth and pipeline diameter.

### 3.6.5 Impact of Hub location

The prime impact of the hub location on the offshore development will be through the increase or decrease it makes to the distance from the fields to the processing hub.

## 3.7 <u>Hydrates</u>

At high pressures and low temperatures methane forms a solid structure with water, a little like dirty slushy ice, called hydrates. When hydrates form in a pipeline they block the line and have to be removed.

When conditions are suitable for hydrate formation, steps are taken to prevent its formation. Three methods are commonly used to prevent hydrate formation in gas pipelines:

- Remove water from the pipeline
- Injection of methanol
- Injection of glycol

Removal of water requires surface facilities. See **Section 3.3.2** for a discussion of water removal and gas drying.

Injection of glycol or methanol into a pipeline is effective in preventing hydrate formation. In recent years, monoethylene glycol (MEG) has become the most commonly used hydrate inhibitor. Wherever the aqueous phase is removed, it is processed to recover the MEG, which is then recycled to be used again. There is a small amount of MEG which is not recovered, the cost of which contributes to operating costs.

For wells in deep water with low water temperatures at the well head provision is usually made to inject MEG at the wellhead. This then requires a pipeline from the MEG recovery facility to the wellheads.

Both proposed developments will have to make provision to prevent hydrate formation.

# 4. EFFECT OF DISTANCE TO ONSHORE HUB ON OFFSHORE FACILITIES

## 4.1 Introduction

The onshore processing hub will be located at the coast and for all hub locations in the Kimberly represents the first opportunity to locate processing facilities on land. Land based facilities are considerably less expensive than offshore facilities.

As a hub is located further from a field, the cost of the offshore facilities increases and the type of development that is the least cost changes as the distance increases.

For a gas processing hub located at Darwin or on the Burrup Peninsula, rather than lay a pipeline direct to the hub, it might be less expensive to lay a pipeline from the field to a point on the coast, closer to the field, and then lay an onshore pipeline to the hub. However, unless gas is processed at the point where the line goes ashore, the fact that part of the pipeline is onshore is likely to make little difference to the offshore development plan.

The effect of the distance to the processing hub depends primarily on the water depth at the gas field and the corrosivity of the gas.

## 4.2 Fields in Shallow Water

Large gas fields in water depths up to 150 – 250 m are likely to have a fixed platform, either a steel jacket or CGS, on the field to allow dry wellheads to be used. The choice between the use of a steel jacket or a CGS depends on geotechnical conditions at the field and cost. The cost of a CGS is highly dependent on a suitable construction site being available. A CGS has the additional benefit of offering storage for liquids in the base of the structure.

In the Browse Basin, it is considered most likely that gas will contain carbon dioxide in which case, the gas and condensate will likely be dried on the platform, so that the gas becomes non-corrosive and allows the use of carbon steel pipelines to shore. This also obviates the need to inject hydrate inhibitor downstream of the platform.

For fields where the gas is not corrosive, carbon steel pipelines can be used and the full well fluid sent directly to shore with all processing done onshore.

Compression would not usually be needed initially, but would be added on the platform later in the field life as reservoir pressure declines.

In the Browse Basin for fields close to the gas processing hub, there would likely be a single large diameter pipeline to shore. After being dried on the platform the gas and condensate would be recombined and sent to shore in a single pipeline as a two phase mixture. As the distance of the field to the onshore hub increases the length of the pipeline to shore increases and because the pressure drop in the pipeline increases as the length increases the diameter of the pipeline would also increase to offset the increased pressure drop.

The increased size of the pipeline, both length and diameter, causes increased liquid hold up in the pipeline which leads to increased slug size. Ultimately as the distance increases it becomes less costly to separate the condensate from the gas on the platform and either lay a separate condensate line to the shore or load the condensate onto tankers offshore. This overcomes slugging and increases the capacity of the gas pipeline. Ultimately when the field is a very long way from shore one of more intermediate compression stations would be installed

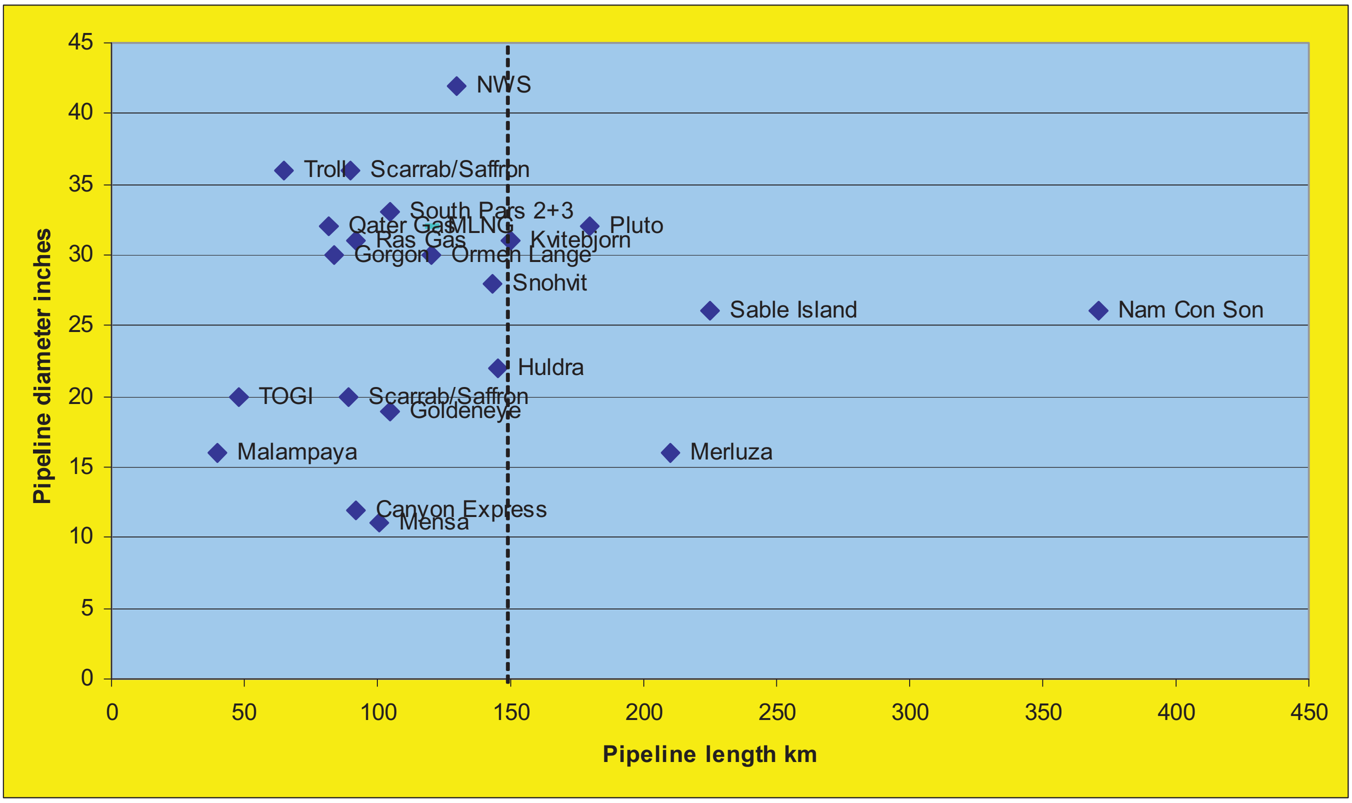
on platforms to boost gas pressure and allow the pipeline diameter to be reduced. If compressors are used offshore condensate has to be separated from the gas before it is compressed

**Figure 7** shows the length and diameter of existing and planned major gas condensate pipelines. **Figure 8** shows the distance and condensate gas ratio. The figures show that there a number of lines up to about 150 km length, some with quite large diameters and some with high condensate gas ratios. However there are a limited number of gas lines longer than 150 km. There does not appear to be any relationship between the length and condensate gas ratio or diameter, for example, it does not appear that the longer pipelines are lower diameter or lower condensate gas ratio as might be expected.

In summary, for fields in the Browse Basin in water depth up 150 - 250 m, it is likely a platform will be built at or near the field to allow dry wellheads and the gas to be dried and the effect of increasing distance to the hub will be to:

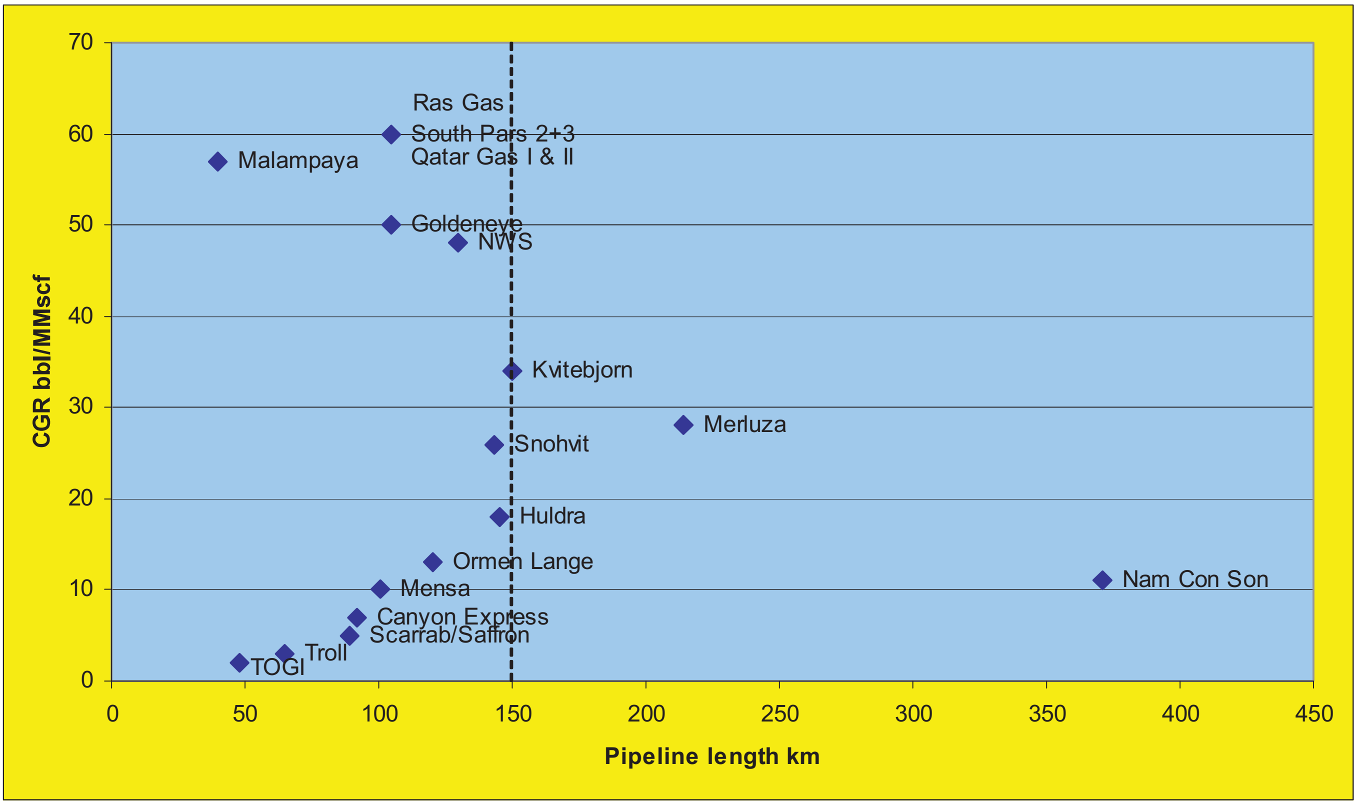
- Increase the length of the gas pipeline to shore.
- Increase the diameter of the gas pipeline to shore.
- Change the optimum development from one where the condensate and gas are sent to shore in a single pipeline to one where the gas and condensate are separated on the platform and either sent to shore in separate pipelines, each carrying only a single phase, or the gas is sent to shore while the condensate is stored and loaded into tankers offshore.

The fields in the two proposed development projects are in water depths over 250 m (except for a portion of Torosa which is below Scott Reef). Both developments propose to separate condensate on an offshore platform. The Woodside operated project proposes to store and load condensate offshore while the Inpex operated project plans to transport the condensate to shore in a dedicated pipeline. See **Sections 2.1** and **2.2**.




**Offshore Multiphase Gas Pipelines - Length and Diameter**

| Project: KK1177 May '08 | Checked: | Fig. 7 |
|---|---|---|




**Major Offshore Gas Pipelines – Length and Condensate/Gas Ratio**

| Project: KK1177 May '08 | Checked: | Fig. 8 |
|---|---|---|

### 4.3 Fields in Deep Water

The reasons to install platforms for fields in deep water are the same as those for fields in shallow water, that is the benefit of having dry wellheads and the need to remove carbon dioxide to make the gas non corrosive. However, the main difference is that any type of platform in deep water is much more expensive than those in shallow water, for the same deck load. This introduces the option for fields in deep water of installing subsea wellheads in the deep water and laying flow lines from the wells to a platform in shallower water.

If a field is sufficiently close to shore, it is possible to use subsea well completions, gather the gas with subsea manifolds and send the full well stream to shore in a single pipeline. The Snohvit field, in the North Sea, in 340 m water depth, containing up to 8% carbon dioxide, was developed this way. The pipeline, carrying the full production fluid is 143 km long. Because there are no surface facilities near the field control of the subsea facilities, glycol injection for hydrate inhibition, and injection of corrosion inhibitor were also issues that had to be addressed. In many cases fields in deep water are a long way from shore and this is not possible. A pipeline length of about 150 km is probably an upper limit for this type of development. For fields with pipelines longer than this it will likely be necessary to have some form of fixed or floating platform to support processing and control facilities.

Where it is necessary or less expensive to have some sort of offshore platform the location of the platform and the type of platform are considered together. If a platform is located over the field it minimizes the length of the flow lines or risers to the platform. In the Browse Basin this is important because the gas is expected to contain carbon dioxide which will cause it to be corrosive. This means that flow lines containing hot fluid flowing from the wells will likely need to be made of corrosion resistant alloy which is expensive. Minimising the length of the flow lines or risers reduces the cost. Offsetting this however is the fact that the water depth usually decreases towards the shore so if a structure is placed over the field it is in deeper water (and therefore more expensive) than if it is placed away from the field towards the shore. Depending on the type of platform chosen, if the platform is placed over the field it can also be used as a drilling platform and can enable the use of dry wellheads.

The length of the main pipeline to shore does not impact on the choice or location of offshore platform chosen to support gas drying facilities and/or dry wellheads.

In summary for fields in the Browse Basin in water depths over 250 m if the distance to shore is greater than about 150 km, it is likely a platform will be built at or near the field to allow the gas to be dried and possibly to allow the use of dry wellheads. Once a platform of some type is installed, as part of a development of a gas field in deep water, the same issues regarding two phase flow in a long pipeline to shore arise. Therefore the effect of increasing distance to a hub is the same as that for fields in shallow water, namely

- Increases the length of the gas pipeline to shore.
- Increase the diameter of the pipeline to shore.
- Change the optimum development from one where the condensate and gas are sent to shore in a single pipeline to one where the gas and condensate are separated on the platform and either sent to shore in separate pipelines, each carrying only a single phase, or the gas is sent to shore while the condensate is stored and loaded into tankers offshore.

Both the proposed developments are in water depths over 250 m and are more than 150 km from shore. Both the Inpex operated venture and the Woodside operated venture propose to build offshore processing platforms of some type. The Inpex operated joint venture proposes to use a floating CPF in the form of a semisubmersible platform in the vicinity of the Ichthys field while the Browse joint venture could use a conventional steel jacket or CGS located some distance from the field in 80 – 120 m water depth.

Given that all the hub locations under consideration are more than 150 km from the fields and both projects plan to use a platform of some kind, the main effect of the distance from the fields to the onshore processing hub for the proposed projects is the length of the pipeline to the hub. If the hub were to be at Darwin or Burrup, compression platforms would also be needed because of the pipeline length.

The estimated relative lengths and costs of the pipelines to the different hub locations addressed by the study (described in the 1st report), along with the different infrastructure costs are shown in **Appendix VI**.

If the distance to shore is less than about 150 km, the option exists to flow the full well stream directly to shore in a single pipeline.

### 4.4 Gas with High Carbon Dioxide Content

To date, the major gas fields discovered in the Browse Basin have a high carbon dioxide content, greater than 4 %. The carbon dioxide content in the major fields discovered in the Browse Basin is shown in the following table:

**TABLE 3**

**CARBON DIOXIDE CONTENT**
**OF MAJOR FIELDS IN BROWSE BASIN**

| | |
|---|---|
| Torosa, Brecknock, Calliance | 4 – 12% |
| Ichthys Brewster<br>Plover | 8.5%<br>17% |
| Crux | 10.5% |

Gas with high carbon dioxide content, greater than about 3 – 4 % is corrosive, when water is present. When in contact with carbon steel, the rate of corrosion is significantly increased at high temperature. Since the well fluids in the reservoir are hot, this means that if carbon steel is used high corrosion rates are experienced in the production tubing in the well and in the well flow lines until the gas has cooled to sea temperature or until water is removed from the gas. For this reason CRA is used for these applications.

Because the cost of CRA flowlines is 5 times the cost of carbon steel flow lines there is a cost incentive to either cool the fluid as quickly as possible or to remove the water. Since removing the water is more beneficial than cooling the fluid, in most cases the gas is dried as soon as possible. This can only be done using facilities on some form of platform. Technology is being developed to separate liquid from gas in subsea separators but to dry the gas surface facilities are required.

In some cases the platform is placed over the field so that the length of CRA flow lines is minimized. In other cases, for example in deep water, it is more cost effective to place the platform in shallower water and to use CRA flow lines to the platform.

The distance of the platform from the field depends on a cost trade off between increased cost of CRA flow lines versus decreased cost of the platform as it is placed further from the field in shallower water.

If the platform is placed some distance from the field it is usually more cost effective to collect the flow lines in one or more manifolds and lay one or two pipelines to the platform.

If the platform is located away from the field liquid slugs will form in the pipeline(s) carrying the well fluid to the platform. Liquid can be separated from gas on the platform in large separators or recently subsea separators have been developed to separate gas from liquid in vessels at the base of the platform. To prevent large liquid slugs arriving at the platform the gas rate in the pipeline(s) to the platform should be kept as steady as possible.

As a platform is placed further from a field, to be located in shallower water, the size of liquid slugs arriving at the platform increases so increased high pressure storage is needed to store the liquid slugs. This increases the cost of moving further from the field.

If the separated condensate is to be stored and loaded offshore then it will have to be stabilized offshore to make it suitable for transport. The stabilization facilities will be sized for a certain throughput rate and so high pressure condensate storage will be required to ensure the throughput rate does not exceed the design capacity.

If separated condensate is to be transported to shore for stabilization, storage and loading minimal condensate storage is required on the offshore platform. The condensate can be transported to shore in a single liquid phase condensate line or it can be mixed with the gas and the gas and condensate can be transported in a large two phase pipeline.

For fields with a high carbon dioxide content the distance of a gas processing hub from the field has minimal impact on the location of an offshore platform with respect to the field.

### 4.5 Gas with Low Carbon Dioxide Content

If the produced fluid has a low carbon dioxide content, then acid gas corrosion is not an issue and all tubulars and flow lines can be made of carbon steel and there is not the same need to dry the gas to allow the use of carbon steel.

In this case an offshore platform might be installed to:

- Dry the gas to prevent hydrate formation;
- Remove condensate from gas to allow a single phase gas pipeline to shore.
- Install compression to allow lower diameter pipeline to shore; or
- Install compression late in field life to allow the reservoir pressure to drawn down to increase gas recovery.

These issues are all issues that have to be addressed for all fields to find cost efficient solutions.

# 5. OFFSHORE CONDENSATE STORAGE AND LOADING

## 5.1 Storage Size

Because fields discovered to date in the Browse Basin have a high $CO_2$ content, offshore platforms will be installed to dry the gas to make it non-corrosive. In order to dry the gas, it is necessary to first separate all liquid condensate and water from the gas. Once the condensate has been separated there are three options for the condensate:

- Mix it with the dry gas and transport it to shore with the gas in a two phase pipeline
- Pipe it to shore in a single phase condensate pipeline
- Stabilize it offshore and store it and load it offshore

The pros and cons and the limitations of sending the condensate to shore in a two phase pipeline are discussed in **Section 3.4**.

The choice between sending the condensate to shore in a single phase condensate pipeline versus offshore stabilization, storage and loading is based primarily on cost.

Condensate can be pumped long distances through a pipeline carrying only condensate. If the condensate contains wax which precipitates at the operating temperature of the pipeline then a chemical will need to be added to prevent wax deposition. A scraper pig may also be run through the line at regular intervals to remove wax deposited on the pipe wall. Both of these options add to operating costs but are well established technology.

If the condensate is to be stabilized, stored and loaded offshore the main decision to be made is the form of storage to be used. Condensate in Australia is usually transported in Aframax tankers that carry about 100k tonnes. Storage may be sized so that there is sufficient storage for one full load plus a certain number of days to allow for ship slippage or inability to load. The extra number of days used to size the required storage depends on ship reliability, weather conditions at the loading point and the onstream time required for the gas production. For LNG production a very high onstream time is required so 6 – 10 days extra production would be allowed for in sizing the storage. This means that the size of the storage depends to some degree on the condensate production rate.

It is common with gas condensate reservoirs for the condensate production rate to decrease over time, even when the gas production rate is held constant. This is due to the pressure in the reservoir decreasing and condensate becoming liquid in the reservoir and not flowing with the gas to the wells. In such situations storage sized for the initial condensate rate will have surplus capacity later in the field life.

It should be noted that the size of the storage does not relate to the distance from a hub to the field or to the condensate loading point.

## 5.2 Storage Type

### 5.2.1. Floating Storage and Offloading

Offshore stabilized liquid storage is most frequently provided by use of a Floating Storage and Offloading (FSO) system. For offshore oil production crude processing facilities are placed on the vessel so the vessel is a floating production storage and offloading vessel (FPSO). These floating storage systems are ship shaped and may be either purpose built or converted crude tankers. They may be used in conjunction with any type of fixed structure (such as a steel jacket or compliant tower) or floating (such as a semi-submersible) platform. They may be used in any water depths where moorings and risers can be installed. The FSO / FPSO in the deepest water to date is in the order of 2,000 m, installed offshore Brazil and Angola.

In deep water the riser design is highly specialised, becoming a critical component of the production train. It is normal for deepwater oil production to combine processing and storage capability, leading to most deepwater applications being FPSOs.

Where floating storage is used in shallower water, in conjunction with fixed platform, the storage vessel is moored a safe distance from the platform and connected to the platform by a subsea pipeline and riser. Typically a Catenary Anchor Leg Mooring (CALM) buoy is used for the mooring though variants such as Single Anchor Leg Moorings (SALMs) or turret moorings may be used. Calms are probably the preferred choice for areas requiring continuous station keeping in all weather conditions.

There are many CALM/SALM systems used throughout the world, particularly in the North Sea. The Legendre FSO off the Western Australia coast is turret moored.

If used for a Browse LNG development a FSO would likely remain permanently moored and continuously manned with a small crew except during severe cyclonic activity.

FSOs are well tried and generally should have an availability of 98% except for interruptions for cyclonic weather. Storage could be expected to be a minimum of 10 days production of 300,000 bbl whichever is the greater.

### 5.2.2 Concrete Gravity Structure

An alternative to using a FSO for offshore condensate storage is to use a CGS. This could be simply a concrete storage tank that sits on the sea floor or a concrete platform with integrated storage that sits on the sea floor. A platform would have processing equipment, such as gas and condensate drying equipment, condensate stabilization facilities and well control equipment on it. In contrast to a FSO a CGS is restricted in the water depth in which it can be used. The deepest CGS to date is the Troll platform in the North Sea in 303 m water. CGSs have been used in the North Sea. Two have been used in Australia for the Tuna and Wandoo platforms.

A CGS can be used when soil conditions are unsuitable for a piled steel jacket. They also have high load carrying capacity and so can support large processing equipment.

A CGS is used in conjunction with a mooring buoy to load tankers, similar to a FSO.

The choice between a CGS and a platform of some type with a FSO is an economic decision and is not affected by the distance of a hub from the field or the condensate loading facility.

### 5.2.3 Shared Offshore Storage and Loading Facilities

If two fields in the Browse Basin close to each other, say within 50 km, are developed there is the potential to share certain offshore facilities. Historically, such sharing is more likely if the fields are operated by the same company or held by the same joint venture parties. It is uncommon for the development of fields held by different joint ventures to be designed to share common offshore facilities.

Facilities that could be shared include condensate storage and loading facilities. A possible scenario is two or more fields in the Browse Basin, containing high levels of carbon dioxide, are developed and a platform of some type is installed for each field to dry the gas and separate condensate. If the platforms are more than about 150 km from shore the condensate would be either piped to shore in a separate pipeline or stored offshore and loaded offshore. If the two platforms are relatively close then it is possible condensate storage and loading facilities could be shared.

If condensate storage is to be shared it is likely that the stabilisation facilities would also be shared. It is much cheaper to build one large plant to stabilise condensate than to build two small plants with the same total capacity. If a concrete gravity structure was used for condensate storage then the stabilisation facilities would be located on the CGS. If a FSO was used the stabilisation facilities would be located on the FSO. The two condensate products would most likely be mixed but could also be stored as separate products.

If storage facilities were shared then loading facilities would also be shared.

It would also be possible for each development to have its own condensate storage facilities but to share loading facilities.

There should be no metering or fiscal allocation issues if loading facilities and/or storage facilities are shared by different projects. If the projects share stabilisation facilities the separate condensate streams to the stabilisation facilities would be “live” condensate, that is, containing dissolved gases. For accurate measurement the stream should be a single phase liquid stream which should not be a problem. The stream would be sampled periodically so that the condensate sold could be allocated back to the fields from whence it was sourced.

If only the storage or loading facilities were shared, the condensate streams to the facilities would be suitable for transportation, that is with a low vapour pressure. Measurement would not be a problem. Again the stream would be sampled periodically for allocation of the condensate sold back to its source.

The sharing of offshore storage or loading facilities is unlikely to be influenced by the use of a gas processing hub or the distance of a hub to the fields.

The Inpex operated Ithchys field is some 150 km from the Woodside operated Torosa, Brecknock and Calliance fields and it is unlikely that there will be any sharing of offshore facilities irrespective of whether or not there is an onshore gas processing hub or where a standalone liquefaction plant might be located.

Where offshore facilities overseas are shared by different joint ventures, this has usually occurred during the life of the facility, frequently late in its life when it is no longer being used at its full capacity.

# 6. FIELD LIFE ISSUES

## 6.1 Operational Life of Initial Offshore Facilities

LNG projects are designed to operate at capacity for in excess of twenty years. Three of the very early LNG plants in the world; Camel plant in (Algeria started production 1964), Kenai plant in Alaska (started production 1969) and the Brega plant in Libya (started production 1970) are all still operating. These plants are all onshore and are supplied from onshore gas fields.

The life of the offshore facilities installed as part of an initial Browse Basin LNG project will likely be determined by the size of the reserves available and the capacity of the liquefaction facilities. Historically a greenfields LNG project has consisted of two LNG trains. In many cases additional trains have subsequently been added to the initial two, as for example with the NWS project. In some cases additional fields have been developed to supply gas to an expanded plant.

The design life of the offshore facilities should be chosen based on the reserves of the fields that they serve with some thought given to the exploration potential in the area.

It has frequently been found possible to extend the life of facilities beyond their design life by modification or by a change in operating conditions.

## 6.2 Field Life Overlap Issues

The different fields to be developed for Browse Basin LNG will almost certainly have different field lives. Even within a project fields or reservoirs are likely to be developed sequentially. For example for the Ichthys field it is likely that the more liquids rich Brewster formation will be developed ahead of the Plover formation, while for the Torosa/Brecknock/Calliance fields it is likely that the more liquid rich field(s) will be developed first. It is likely that each project will be designed for sequential development and provision made for future tie-ins to the initial facilities.

Each of the fields or reservoirs will have a different field life and the producing periods will overlap. For example if, in the Woodside operated project, the Calliance field is the first to start production then the next field would normally start production when the production rate from the Calliance field starts to decline and can no longer meet the capacity of the liquefaction plant, or if the capacity of the liquefaction plant is increased.

Differences in field life and overlap of field or reservoir production periods is a normal part of large offshore projects and are not expected to produce any particular issues.

As stated previously GCA considers it unlikely that the two initial proposed projects will share any offshore facilities.

Each of the initial projects will be planned to develop certain fields, for example the Woodside operated project - the Torosa, Brecknock and Calliance fields, and the Inpex operated project - the Ichthys field. These fields are discovered and appraised and at the time of FID the joint venture will consider that sufficient is known about the fields to make an investment decision. The project proponents will be confident making a certain amount of pre-investment for activities that will take place later in the project development. It can be anticipated that for each project a large amount of investment will take place, after the initial investment, for example for drilling wells, installing subsea equipment, and installing compression. A certain amount of pre-investment will likely be made to reduce the cost of these subsequent activities.

However, if offshore processing or transportation of third party gas is not firmly contracted at the time of FID it is unlikely that significant pre-investment will be made for the possibility of it eventuating in the future.

# 7. MULTIPLE DEVELOPMENT PHASES

In the past, Australian LNG projects have been developed in phases, typically a train at a time, as markets are secured (North West Shelf JV) or as gas reserves are proved up (Darwin LNG). However, as the market for LNG has become “deeper”, and where the gas resources are sufficient, there is a movement to the initial development using large multiple trains to achieve economies of scale (Gorgon).

Both Inpex and Woodside are proposing to follow this path by committing to multiple train initial developments and to production profiles that substantially commit their resource base as currently defined.

Within this broad framework, issues associated with the phasing of the development of Browse Basin gas resources can be considered as follows:-

## 7.1 Development for Initial Plateau Production

Both Inpex and Woodside have planned initial developments with raw gas production rates in the order of 40Mm$^3$/day or greater. For each project, the central offshore processing facility required to separate the gas and condensate and to remove water from both streams will be very large. The size of the individual facilities, combined with the distance separating the two projects, make it very unlikely that any economies of scale could be realized by combining the two facilities into one.

For each of the “foundation” projects, a pipeline of diameter 42 to 48 inches will be required to transport gas from the offshore treating facility to the onshore plant. Laying pipelines of this diameter in the prevailing water depth is approaching the limit of available technology. A single gas pipeline serving both pipelines is very unlikely.

From a technical standpoint, and with the exception of condensate evacuation, there are no potential advantages to be realized by combining any of the offshore elements of the foundation projects. Given this situation, there are no “inter project” phasing issues to address.

Evacuation of condensate from the offshore facilities offers some opportunity for synergies and therefore has potential impact on phasing. This opportunity has the form of a single FSO, or a single pipeline to shore to handle condensate production from both the foundation projects.

## 7.2 Development for Maintenance of Plateau Production

Within each of the two foundation projects, additional producing wells will be required as the initial wells deplete the areas of the reservoir they access. Gas compression will be required to be added to the offshore processing facility as overall reservoir pressure declines. Within each of the foundation projects, these two ongoing requirements are interdependent and the phasing of the additional wells and the installation of process compression will be subject to ongoing optimisation; beginning with the pre- FEED studies.

## 7.3 Major Additional Developments

Should ongoing exploration in the Browse Basin yield a discovery or discoveries sufficient to support a development comparable to either of the foundation projects, the offshore elements of that development could be expected to proceed independently for the same reasons as outlined for the foundation projects in **paragraphs 7.1** and **7.2** above. Given the anticipated demand for LNG, it is unlikely that such a discovery could be "held over" to "back fill" the foundation project's facilities as production from those projects came off plateau.

## 7.4 Small Incremental Developments

Existing smaller discoveries, such as Crux, will either be "held over" to backfill the foundation projects facilities or be aggregated to the point where they can provide a resource base sufficient to support a "stand alone "development.

In summary and from a technical standpoint only, there are no substantial "inter project" phasing issues that would impact the foundation projects. Within each project no abnormal intra project phasing issues are foreseen.

However there are other considerations, such as availability of materials and construction resources which, given the size of the foundation projects and the number of similarly sized competing projects, will have a significant impact on the "interproject" phasing.

# 8. PIPELINE CONSTRUCTION AND INSTALLATION

## 8.1 General

Because of the long pipelines, high gas flow rates and water depths, the major gas pipelines for Browse Basin LNG developments are likely to be a major technical challenge. In dealing with specific issues of Browse Basin potential pipelines, the major factors to be considered are those related to water depth and geotechnical conditions.

Generally large diameter pipelines (say 40" O.D.) are placed on the sea bed from a specialised lay barge. The principal cost elements are the cost of the pipe and the hire rate for the lay-barge and its operating crew. Any factor, such as weather or metocean conditions, which slows the rate of laying increases costs dramatically. Mobilisation and demobilisation are a significant part of the cost which means that shorter pipelines are disproportionately more expensive per kilometre than longer ones.

The first factor to consider is water depth. Continuous lengths of pipe are laid from the rear of the pipe lay vessel, in what is referred to as an S lay configuration, reflecting the shape of the pipe as it comes off the pipe lay vessel, bending as it descends vertically and becoming horizontal again as it is laid on the sea bed. (In specialised situations of very deepwater this may be a J lay configuration in which the pipe is laid vertically into the sea). The mechanical design of the system is such as to dictate a maximum radius for the bends in the S configuration. These radii are controlled by maintaining a tension in the pipeline, created by the lay vessel pulling with engines or anchors against the pipeline. Such operation effects the forward speed of the vessel, and hence the greater the pipeline depth the slower the lay vessel speed and the greater the duration of the operation, directly effecting the cost.

The pipe may also require a concrete weight coating to provide stability since pipelines above about 12" may be buoyant in sea water. This considerably affects the required tension, affecting the lay rates compared with a plain pipe and hence the cost of the laying operation.

There are three principle zones along the pipeline route to consider –

- near platform zone, in relatively deep water
- main length of the line from the platform towards the reception facilities which may be on land or another floating/fixed structure, and
- shore approaches

## 8.2 Near Platform Zone

In the near platform area pipelines are normally buried to depths of approximately 2 metres for protection against dropped objects. If anchors are a hazard, burial may be to around 5 metres. There are number of different techniques for creating the trench in order to bury a pipeline, from ploughs pulled by the lay barge to powerful water jetting systems, including excavation equipment on vessels. Each has its cost and productivity depending on the nature of the seabed.

In the platform area the nature of the termination of the pipeline connection to the platform facilities will also involve high unit costs since specialised hyperbaric welding teams and supporting vessels may be needed to make the connections.

## 8.3 Main Pipeline Length

Along the pipeline route it is not normally necessary to bury the pipeline if water depths are in excess of say 60 m. The pipeline is laid directly onto the sea bed, remaining stable by virtue of its concrete weight coating. However, if the sea bed area is subject to strong lateral currents, there can be a risk of pipeline mobility which must be counteracted by stabilising the pipeline. This can be carried out in a variety of ways, most commonly by burying the pipeline or by dumping rock onto the line, or by some form of captive system to pin the line to the sea bed. The choice of the preferred option is dictated by cost which is substantially affected by the nature of the sea bed, varying from exposed hard rock through to soft sand or silt. In light sand and silt, burial can be effected relatively cost effectively by a submarine plough towed by the lay barge. In other cases a trenching vessel will excavate a trench and the pipeline will be laid into it, becoming covered by sediment with time. Naturally the ease with which these collateral operations are carried out dramatically effects the overall cost since the ultimate lay rate is linked to them.

A major concern along the pipeline route will be continuity of the sea bed to provide continuous support. Often localised sea bed features can occur which could result in sections of the pipeline being unsupported and having to span over substantial distances. This can lead to weakness in the pipeline integrity and would normally be avoided by selection of an alternative, though longer route.

## 8.4 Shore Approaches

Below about 60 m water depth, and for onshore approaches, pipelines should be buried to depths of over 1 metre as protection principally against trawler boards from fishing activity. Close to shore the pipe cannot be laid by a lay barge due to water depth considerations and special shore approach work has to be set up to pull the pipeline into the beach. Pipeline pull machinery, coffer dams and excavated channels will be needed to carry this out. The pipeline would normally be buried right across the beach and the near land terrain, with special attention being given to restitution of the impact of the work. In special cases where the shore approach involves traversing cliffs and other hard rock features, or crosses areas of special interest, then horizontal drilling could be employed or tunnels excavated to take pipelines. As well as the impact of these activities on cost, often the mobilisation and demobilisation of special equipment to remote areas will add considerably to the implementation costs.

## 8.5 Processing Sites Comparison

All of these factors will be present to some extent affecting the cost of the pipelines serving the Browse basin gas fields. At this stage, without detailed survey and bathymetric data, it is not possible to identify specific construction issues for each of the potential hub sites, nor comparative differences between alternative pipeline routes serving different possible landfalls. One exception to this is the identification, in general qualitative terms, of the impact of different near shore conditions for each site location affecting the cost of the shore approaches since these ranges from sandy beaches to high cliffs.

**Appendix VI** shows the costs estimated by GCA for pipelines from the proposed developments operated by Woodside and Inpex to the different potential onshore processing sites. It is estimated that 40 inch diameter line will cost in the order A$4 million/km. The main effect of the location of an onshore gas processing hub on offshore developments is on the length of the pipelines from the fields to the hub.

### 8.6 Equipment Availability

In deep water such as in the vicinity of the Woodside and Inpex operated fields, the maximum diameter of pipelines that can be laid will be limited to about 40 inch diameter. Even then there are a very limited number of pipelay vessels that can lay pipe of this diameter in deep water. The availability of these vessels can impact on project schedule.

In shallower water, less than about 300 m, the large pipelay vessels are capable of laying pipelines up to about 48 inch diameter. There is also a larger selection of vessels for laying lines 40 inch diameter and below in shallower water. The availability of a suitable pipelay vessel is less likely to impact on project schedule in these circumstances.

If Darwin or Burrup were selected as the processing hub the availability of sufficient pipe for the offshore pipelines would be a critical schedule issue. The Browse Basin fields proposed for LNG development are 800 – 1000 km from Burrup or Darwin and obtaining large diameter high pressure pipe for this distance could impact on the project schedule.

# APPENDIX I

## RFT DOIR2271107 - SCOPE OF SERVICES – EXTRACT

**RFT DOIR2271107 - SCOPE OF SERVICES – Extract**

**Review of Proposed Concepts for the Development of the Browse Basin Gas Reserves**

It is envisaged that any offshore development of the Browse gas fields to evacuate the Browse Basin to a common onshore location will comprise a combination of:

- Subsea wells tied back to in-field or near-field production facilities;
- Floating production facilities located in deepwater areas;
- Fixed production facilities in shallow (~150m) water depths;
- A number of in-field flowlines, and intrafield pipelines to connect processing facilities; and
- Large diameter pipeline/s to transport gas to the onshore processing capacity.

While it is acknowledged that the decisions surrounding the configuration of the in-field facilities is a complex proposition that will be the subject of review in conjunction with the approval of the field development plan for each individual resource, it is important to understand the feasibility of the tieback of multiple fields to a common onshore gas processing hub.

The objective of this area of study is therefore to consider and evaluate the key technical issues that may potentially constrain the offshore development to support the onshore hub, including but not limited to:

- Maximum multiphase flow tieback distances, i.e. maximum distance from wellheads to the first processing facility;
- Location and configuration of condensate handling, storage and export facilities;
- Likely combinations of offshore production facilities; and
- Limitations in terms of pipeline configurations and capacities for the gas trunkline to shore.

Management of liquids recovered from the gas stream is understood to be a critical enabler to the hub development. A number of alternate strategies are available for the treatment and export of condensate recovered from the gas fields including:

- Multiphase flow of unprocessed wellstream fluids to shore;
- Offshore condensate separation and a separate condensate pipeline to shore;
- Offshore condensate removal with an offshore FSO (Floating Storage and Offloading) facility for condensate storage and export to trading tankers;
- Offshore condensate removal with storage in a CGS (Concrete Gravity Storage) with condensate export via a Catenary Anchor Leg Mooring buoy.

Given the range of potential condensate export strategies:

- Provide commentary on the relative merits of each of the above alternatives;
- Comment on likely required storage volume for offshore storage; and
- Implications in terms of metering and fiscal allocation of shared offshore storage and offloading facilities.

Given a typical offshore facility design life of 30 years, provide commentary on the following:

- Likely operational life of the offshore facilities envisaged as part of the initial development of the Browse basin;
- Comment on any potential issues surrounding the difference (if any) of the anticipated field life overlap between fields;
- Comment on any potential issues surrounding multiple phases of development around the offshore facilities and the implications this may have on the decision to progress with either fixed or floating facilities.

A number of in-field and intra-field pipelines are envisaged to transfer fluids to/from production facilities, provide discussion on:

- Maximum tieback distances, and operational issues including:
  - Wax / hydrate management strategies
  - Liquids (slug volume) management
  - Corrosion control and integrity management
- Pipeline construction and installation issues related to geotechnical, high tidal and extreme weather events;

For the export pipeline/s to shore, provide commentary on likely issues to be considered including:

- Likely sizing of the initial export pipeline/s to shore, including identification of constraints in terms of pipeline diameter / compression configuration;
- Likelihood of single phase gas pipeline/s to shore, with condensate recovery offshore as opposed to multiphase line/s to shore; and
- Operational constraints for installation of large diameter pipelines given the range of water depths anticipated from either fixed or floating production facilities

# APPENDIX II

# GLOSSARY

# GLOSSARY

| | |
|---|---|
| ALSOC | Australian LNG Ship. operating Company Ltd. |
| bar | The bar (symbol bar), decibar (symbol dbar) and the millibar (symbol mbar, also mb) are units of pressure. The bar is still widely used in descriptions of pressure because it is about the same as atmospheric pressure. |
| Btu | The British thermal unit (BTU or Btu) is a unit of energy used in the power, steam generation, and heating and air conditioning industries. One BTU is approximately 1,054—1,060 kJ (kilojoules). |
| CALM | Centenary Anchor Leg Mooring |
| CGR | Condensate to Gas Ratio |
| CGS | Concrete Gravity Structure |
| CRA | Corrosion resistant alloy |
| DWT | DWT, for deadweight tones, is the displacement at any loaded condition minus the lightship weight. It includes the crew, passengers, cargo, fuel, water, and stores. Like Displacement, it is often expressed in long tons or in metric tons. |
| EPBC | Environmental Protection and Biodiversity Conservation Act |
| FPS | Floating Production System |
| FPSO | Floating Production, Storage and Offloading System |
| FPS | Floating Production System |
| GCA | Gaffney, Cline & Associates |
| ha | A hectare (symbol ha) is a unit of area equal to 10,000 square meters, or one square hectometer, and commonly used for measuring land area. A 100 m square is one ha. |
| km | Kilometre(s) |
| LNG | LNG is natural gas that has been converted to liquid form for ease of storage or transport. Liquified natural gas takes up about 1/600th the volume of natural gas at a stove burner tip. It is odorless, colorless, non-corrosive, and non-toxic.<br>The liquefaction process involves removal of certain components, such as dust, helium, water, and heavy hydrocarbons, which could cause difficulty downstream, and then condensation into a liquid at close to atmospheric pressure (Maximum Transport Pressure set around 25 kPa (3.6psi)) by cooling it to approximately −163 °C (−260 °F). |
| LOA | Length Over All, commonly used to indicate maximum hull length of a vessel. LOA is the most commonly-used way of expressing the size of a boat. |
| LPG | Liquefied petroleum gas (also called LPG, LP Gas, or autogas) is a mixture of hydrocarbon gases used as a fuel in heating appliances and vehicles, as well as as an aerosol propellant and a refrigerant.<br>Varieties of LPG bought and sold include mixes that are primarily propane, mixes that are primarily butane, and the more common, mixes including both propane (60%) and butane (40%). |
| MEG | Monoethylene glycol |
| Mtpa | Million tones per annum |
| PPP | Public-Private Partnership, the operation of a service in the partnership of government and the private sector.<br>In some types of PPP, the government uses tax revenue to provide capital for investment, with operations run jointly with the private sector or under contract (see contracting out). In other types (notably the Private Finance Initiative), capital investment is made by the private sector on the strength of a contract with government to provide agreed services. Government contributions to a PPP may also be in kind (notably the transfer of existing assets). |

| | |
|---|---|
| psi | The pound per square inch or, more accurately, pound-force per square inch (symbol: psi or lbf/in² or lbf/in²) is a unit of pressure or of stress. It is the pressure resulting from a force of one pound-force applied to an area of one square inch: 1 psi (6.894757 kPa) : Pascal (Pa) is the SI unit of pressure |
| SALM | Single Anchor Leg Mooring |
| SPM | Single Point Mooring are loading Buoys anchored offshore, which serve as a mooring point for tankers to (off)load gas or fluid products. They are the link between the geostatic subsea manifold connections and the weathervaning tanker. The main purpose of the buoy is to transfer fluids between onshore or offshore facilities and the moored tanker. |
| SRTM | The Shuttle Radar Topography Mission (SRTM) obtained elevation data on a near-global scale to generate the most complete high-resolution digital topographic database of Earth. SRTM consisted of a specially modified radar system that flew onboard the Space Shuttle Endeavour during an 11-day mission in February of 2000. SRTM is an international project spearheaded by the National Geospatial-Intelligence Agency (NGA) and the National Aeronautics and Space Administration (NASA). |
| Tcf | Trillion cubic feet |
| TCS | Thompson Clarke Shipping |
| TEG | Triethylene glycol |
| TLP | Tension Leg Platform |
| WEL | Woodside Energy Limited |

# APPENDIX III

# CONVERSION FACTORS

## CONVERSION FACTORS

| | |
|---|---|
| To convert Tcf to Gm3 multiply by | 28.3 |
| To convert MMbbls to GL multiply by | 0.159 |

# APPENDIX IV

## DETAILS OF INTERESTS IN WOODSIDE OPERATED PROJECT

## DETAILS OF INTERESTS IN WOODSIDE OPERATED PROJECT

| | WA-28-R | WA-29-R | WA-30-R | WA-31-R | WA-32-R | WA-275-P | WA-R/2 | TR/5 |
|---|---|---|---|---|---|---|---|---|
| Woodside Energy Ltd | 25% | 25% | 50% | 50% | 50% | 25% | 50% | 50% |
| BHP Petroleum (North West Shelf) Pty Ltd | 20% | 20% | 8 ⅓% | 8 ⅓% | 8 ⅓% | 20% | 8 ⅓% | 8 ⅓% |
| BP Developments Australia Pty Ltd | 20% | 20% | 16 ⅔% | 16 ⅔% | 16 ⅔% | 20% | 16 ⅔% | 16 ⅔% |
| Chevron Australia Pty Ltd | 20% | 20% | 16 ⅔% | 16 ⅔% | 16 ⅔% | 20% | 16 ⅔% | 16 ⅔% |
| Shell Development Australia Pty Ltd | 15% | 15% | 8 ⅓% | 8 ⅓% | 8 ⅓% | 15% | 8 ⅓% | 8 ⅓% |

# APPENDIX V

## DETAILS OF MAJOR MULTIPHASE OFFSHORE GAS PIPE LINES

## DETAILS OF MAJOR OFFSHORE MULTI PHASE GAS PIPE LINES

| | Length (km) | Diameter (in) | CGR (bbl/MMscf) | Depth (m) | Prod. start |
|---|---|---|---|---|---|
| Goldeneye | 105 | 20 | 50 | 120 | 2004 |
| Huldra | 145 | 22 | 18 | 120 | 2001 |
| Kvitebjorn | 150 | 30 | 34 | 190 | 2004 |
| Malampaya | 40 | 16 | 57 | 850-40 | 2001 |
| Mensa | 101 | 12 | 10 | 1600 | 1997 |
| Merluza | 210 | 16 | 28 | 130 | 1993 |
| Nam Con Son | 371 | 26 | 11 | 180 | 2002 |
| NWS (1) | 130 | 42 | 32 | 125 | 1985 |
| Ormen Lange | 120 | 30 | 13 | 1100 | 2007 |
| Pluto | 180 | 36 | 10 | 850-85 | 2010 |
| Qatar Gas | 82 | 32 | 60 | 50 | 1996 |
| Scarrab/Saffron | 89 | 20 | 5 | 89 | 2003 |
| Snohvit | 143 | 28 | 26 | 345 | 2005 |
| South Pars 2+3 | 105 | 32 | 60 | 65 | 2002 |
| TOGI | 48 | 20 | 2 | 300 | 1991 |
| Troll | 65 | 36 | 3 | 300 | 1995 |

# APPENDIX VI

## GCA ESTIMATED PIPELINE AND INFRASTRUCTURE COSTS

The relative costs of co-locating the Ichthys and Browse projects at the potential sites for a single or multi operator LNG hub have been assessed. This analysis has been undertaken at a very high level, focusing on quantifying the cost differences between the candidate sites for an LNG hub. The main differentiating costs relate pipelines and compression platforms, with infrastructure and site preparation costs having less impact. The costs used for different scenarios should be considered as having an error band in the range of +100% / -50%. The results are summarised in the table below:-

**GCA ESTIMATED PIPELINE AND INFRASTRUCTURE COSTS – US$ MILLION**

| | Offshore | | | | Onshore |
|---|---|---|---|---|---|
| | Pipelines | | Compressor platforms | Total offshore | Infrastructure* & site prep |
| | From Ichthys | From Browse Project | | | |
| North Kimberley | | | | | |
| Maret Islands ** | 800 | 1,360 | | 2,160 | 696 |
| Bigge Island | 860 | 1,440 | | 2,300 | 756 |
| Champagny Island East ** | 760 | 1,160 | | 1,920 | 816 |
| Wilson Point | 880 | 1,280 | | 2,160 | 721 |
| Koolan Island | 1,000 | 1,240 | | 2,240 | 3,151 |
| South Kimberley | | | | | |
| Cape Leveque | 1,200 | 1,160 | | 2,360 | 726 |
| Lombadina (Packer Island) | 1,240 | 1,200 | | 2,440 | 865 |
| North Head / Perpendicular Head | 1,480 | 1,320 | | 2,800 | 801 |
| Quondong Point | 1,880 | 1,680 | | 3,560 | 783 |
| Fisherman's Bend | 2,160 | 1,920 | | 4,080 | 679 |
| Offshore Kimberley | | | | | |
| Scott Reef | 600 | | | 600 | 1706 |
| Echuca Shoals ** | 300 | 800 | | 1,100 | 1706 |
| Existing developments | | | | | |
| Burrup (NWS & Pluto) | 4,080 | 3,640 | 1,200 | 8,920 | 286 |
| Darwin (Darwin LNG) | 3,320 | 3,920 | 1,200 | 8,440 | 286 |

* Infrastructure includes jetty, breakwater, harbour, airport/helipad, roads
** Suited only to single operator LNG Hub

The Northern Kimberley sites of Bigge Island, Wilson Point and the Southern Kimberly site of Cape Leveque offer the least expensive technically acceptable overall options to accommodate a full gas processing hub.

Within the accuracy of this exercise, the other South Kimberley sites listed have broadly similar technical challenges, and offer the second least expensive option. All have the land available to expand to a full gas processing hub. However, costs increase very significantly as the distance from the fields to these sites increase:

Expansion of existing facilities or the creation of new sites at the Burrup Peninsula or Darwin for a foundation Browse development are clearly the least economic options because of the cost of the trunklines and compression required to transmit the gas an extra 600 to 800 km.

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# BROWSE BASIN GAS TECHNICAL REPORT
# DEVELOPMENT OPTIONS STUDY

## REPORT 3 of 3
## ONSHORE LNG HUB DEVELOPMENT

**Prepared for**

**THE NORTHERN DEVELOPMENT TASKFORCE**

**June 2008**


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## INTRODUCTION

The Browse Basin, offshore of north-west Western Australia, holds substantial resources of natural gas. At the date of this report, there is no hydrocarbon production from the Basin and there are no hydrocarbons based projects that are either under construction or approved for construction. However, two of the Basin tenement holders, Woodside Energy Limited (Woodside) and INPEX Browse Ltd (INPEX), are planning to use their known gas resources for “greenfield” Liquefied Natural Gas (LNG) projects[1].

The two projects are based on total gas resources of approximately 34 Trillion cubic feet (Tcf). While some of these resources were discovered over thirty years ago, the basin is “gas prone” and has been relatively lightly explored. The level of exploration activity has increased in recent years and it is likely that other companies currently active in the area will eventually propose LNG projects using Browse Basin gas.

From a technical perspective, the “logical” sites for a land based LNG plant to receive, process and export Browse Basin gas are on the Northern and Southern Kimberley coast or on one of the islands off the coast. The North Kimberley area is totally undeveloped, has no infrastructure and is an eco-tourist destination. The South Kimberley has some development (Broome and Derby), has minimal infrastructure and has several tourist destinations (Broome and Cape Leveque).

At the time of this report, both the Woodside and INPEX operated Joint Ventures have conceptualised their respective projects on a “stand alone” basis and have evaluated potential LNG processing sites on the basis of the individual requirements of those projects. Woodside has prepared a shortlist of several potential sites and INPEX has chosen the Maret Islands as its preferred site. Forecast total LNG production from the two projects is in the order of 20 to 25 MMtpa.

The Kimberley Northern Development Task Force (Taskforce) is an inter-departmental body formed by the Government of Western Australia. The Project Manager is Mr. Gary Simmons from the Department of Industry and Resources (DoIR). The Taskforce has been engaged to set the framework by which the State will protect and manage the important heritage, environment and tourism values of the Kimberley area while facilitating structured industrial development. The West Kimberley Subdivision of the Taskforce was established to manage across-government planning processes and stakeholder consultation in regard to selection and development of a suitable location or locations for the processing of Browse Basin gas reserves.

The Taskforce, through DoIR, has retained Gaffney, Cline & Associates (“GCA”) to provide independent advice on technical issues associated with the selection and development of onshore and offshore locations, for the processing of the Browse Basin gas. This advice is to be in the form of a report titled “Browse Basin Development Options Study” (The Study).

The objective of the Study is to review specific technical and economic issues surrounding the processing of existing and yet to be discovered resources at a common LNG plant location or hub. The study has been undertaken in three parts as follows:-

[1] During the course of the study, Shell Development (Australia) announced that it plans to develop the Prelude field, in the Browse Basin using a floating LNG facility (FLNG) with no onshore processing facilities.

1. Review the existing site selection processes undertaken by Woodside and INPEX and provide commentary on the technical suitability of the sites considered to date in the context of a gas processing hub.

2. Consider and evaluate the key technical issues governing the offshore facilities required to develop Browse Basin Gas in the context of a gas processing hub.

3. Review the potential for an onshore infrastructure hub to support Browse Basin gas development and comment on the key technical, commercial and economic issues surrounding the integration of the LNG facilities and services at an onshore infrastructure hub.

Separate reports have been prepared for each of the three areas of review outlined above. This, the third report, covers the potential technical, economic and commercial issues and benefits for an onshore LNG Hub. The full scope of work for this third report is shown in **Appendix I**. A glossary is included as **Appendix III**.

## CONCLUSIONS

The scope of work provided for this study by DoIR lists a number of specific points to be addressed. This has been done in the relevant sections in the body of the report. GCA's "high level" conclusions and recommendations are summarized as follows:-

1. It is technically feasible for LNG Hub participants to share ancillary services (required to support the Health, Safety of the personnel onsite as well and ensure compliance with Environmental regulations), support infrastructure (required to support operations, such as airstrips and construction areas), essential infrastructure (required to store and load LNG and its by-products) and core processing facilities (main gas receiving, treating and processing facilities).

2. Higher degrees of integration of onshore facilities typically imply more complex technical challenges. These in turn can be resolved through increased levels of cooperation, detailed operating agreements and provision of adequate dispute settlement mechanisms.

3. Significant cost savings, up to $US2 billion of Capital expenditure (Capex) on an initial installed cost of $US13.5 billion and up to $290 million of yearly Operating expenditure (Opex) saving, may be achievable through the integration of facilities within an onshore LNG Hub. This assessment is based on a notional two project LNG hub with each project having two 4.5 MMtpa LNG trains. Overall, cost savings increase with integration, although the major cost items, which are the core process facilities, offer the minimum savings from integration.

4. The establishment of one Hub operating company, providing access to the common facilities and services, is essential to integration success and the realization of cost saving.

5. The main barriers to uptake of an LNG Hub for the Woodside and INPEX operated Joint Ventures are likely to be the acceptance of a single party as operator for the whole facility, the difficulty to attain cooperation among competitors and the definition of an acceptable cost allocation mechanism for the common facilities and services. In addition, individual Browse Basin operators may perceive their participation in a hub as a factor that has potential to significantly delay their LNG production and reduce their control over LNG operations.

6. Potential future Browse Basin LNG proponents may perceive that the LNG Hub structure provides a "first mover's advantage" which can impair the economics of new projects.

7. Once the degree of integration of onshore hub facilities and services has been defined, the technical and commercial challenges can be mitigated through:-

    i. the definition of infrastructure investment roles for Government and Operators,

    ii. the consultation of Hub stakeholders to define cost allocation principles,

    iii. the thorough documentation of operating and conflict resolution procedures.

Such discussions could be facilitated by an independent third party and be supported by a study of international best practices.

8. The active engagement process between Government, current and potential Browse Basin Industry Players and other interested stakeholders could be articulated as follows:-
    i. provision of a timeline for completion of the engagement process, allowing Browse Basin tenement holders to assess potential impacts on development deadlines,
    ii. definition and sharing of the Government's vision for LNG developments in the Kimberley, in particular the roles of the different stakeholders involved and the expected extent of the gas processing facilities,
    iii. agreement on the expected degree of integration of onshore and offshore facilities and services,
    iv. selection of preferred LNG Hub onshore sites for further studies,
    v. assessment of potential appropriate commercial models,
    vi. identification of an LNG Hub common facilities operator. The operator could be an existing Browse Basin stakeholder with LNG experience or a specially created entity.

These steps will constitute the foundations of a "master plan" for current and future Browse Basin LNG developments.

It is noted that GCA's scope of work covered only the technical and economic aspects of the creation of an onshore hub. The conclusions are not intended to reflect the opinions expressed by the LNG Hub stakeholders, but considerations to be taken into account in a structured engagement process.

# 1. SUMMARY

## 1.1 Methodology

This, the third report, is largely based on the expertise of the GCA project team members involved. The team members include personnel with extensive first hand experience at PT Arun, Ras Laffan, Sakhalin and Angola LNG. One of the team members also has an ongoing role in the planning of Angola LNG's first LNG Hub.

The report is structured to review the technical, economic and commercial feasibility of five potential hub scenarios. These scenarios reflect the logical degrees of integration. As specified in DoIR's Scope of Services (**Appendix I**), the review of potential commercial models for an onshore infrastructure hub has been excluded from this study.

While the technical views of Browse Basin stakeholder have been incorporated into this and the two previous GCA reports, the views on integration expressed in this report have been developed independently by GCA. For the purposes of this study, condensate stripping and offloading has been expected to be done offshore. All cost estimation work has been done at a very high level, mostly by analogy.

## 1.2 Appropriateness and Feasibility of Sharing Onshore Facilities

Technically, all facilities and services (described in more detail in **Table 1**) can be shared in the context of an LNG Hub supporting several offshore developments.

It is common practice in existing LNG Hubs to have shared ancillary services and support infrastructure which achieves significant economies of scale. With proper systems and procedures in place, this approach can be adopted without reducing each Operator's autonomy or generating additional risks to LNG production reliability.

Sharing essential infrastructure presents some technical challenges, in particular related to compatibility of technologies and fair capacity allocation procedures in the event of equipment failure. These challenges can be overcome by actively engaging LNG Hub stakeholders and documenting mutually acceptable approaches. Essential infrastructure has successfully been shared in other LNG Hubs, generating significant economies of scale. However, Operators tend to be more reluctant to share this type of infrastructure, and perceive such an approach as a reducing their control over the LNG production process.

Sharing core processing facilities presents significant challenges. In particular the variation in raw gas composition between different stakeholders can be an issue. For example, carbon dioxide ($CO_2$) contents ranges from 4% to 12% for Woodside operated fields and 8% to 17% for INPEX operated fields. Another issue that complicates the sharing of core LNG processing facilities is the potential difference in LNG specifications required by the customers of each LNG operator, as LNG plants can be tailored to their expected customer base and their LNG heating value requirements. Finally, control by the individual operators over the process of LNG production is further reduced.

## 1.3 Potential Onshore Facilities Integration Implications

The decision to share certain onshore facilities needs to be supported by a long term vision for the LNG Hub. This will help define adequate sizing of the facilities, suitable cost allocation and appropriate operating procedures. These factors will determine the common

foundations of the LNG Hub, and greatly influence its attractiveness to the Industry, in particular to tenement holders entering the hub at later stages. Integration principles will have to be perceived as fair and void of “first mover’s advantage” dispositions.

The successful integration of onshore facilities will require a more active engagement process between stakeholders than that required by independent “stand alone” developments. This typically requires significant Government involvement and extensive Industry consultation. The optimum outcome would be the establishment of one LNG Hub operating company that would provide all the facilities and services determined for the selected degree of integration.

### 1.4 Potential Cost Savings

Cost savings are referenced in absolute terms based on a notional investment of $US 13.5 Billion for each of two independent, separately located and operated LNG plants, each having two 4.5 MMtpa LNG trains. Assuming the two plants are brought together in a single location, cost savings may vary from approximately $US 85 million through to $US 2,120 million dependent on the degree of integration within the hub.

### 1.5 Possible Industry Concerns

The main barriers to uptake of an LNG Hub for the Woodside and INPEX operated Joint Ventures are likely to be the risk of delaying initial LNG production, the loss of full control over LNG operations and the requirement for cooperation among competitors.

The LNG operators’ ability to deliver LNG on a reliable basis is one of the most important features of marketing LNG, since the buyers have domestic and industrial users who depend on a steady supply of gas. With an independent LNG plant operated by one company, complete control over plant reliability and LNG delivery rests with the LNG operator. Introducing shared facilities operated by others removes some of the LNG plant operators’ ability to fully guarantee LNG supplies. This introduces additional risk from his perspective.

It will be necessary to convince the LNG proponents that the LNG Hub will be operated by a competent and experienced company which will provide reliable services. It will also be necessary to demonstrate to the LNG operators that the use of common facilities will generate significant cost savings for them.

The LNG operators will perceive a commercial risk proportional to the integration of facilities and services. It is likely that sharing key processing and gas liquefaction facilities will not be the Industry’s preferred approach, due to different technology preferences by individual operators, varying feed gas compositions; possible differences in LNG sales specifications and the potential commercial risk.

These barriers to uptake could however be mitigated by the benefits linked to economies of scale, joint procurement and coordinated construction, in particular in the current “tight” labour market.

# 2. DISCUSSION

## 2.1 Potential Integration Levels

### 2.1.1 Inventory of Typical Onshore Facilities and Services

Four categories of onshore facilities and services are typical to LNG developments:

- **Core Processing Facilities:** main gas receiving, treating and processing facilities.
- **Essential Infrastructure:** infrastructure required to store and load LNG and its by-products.
- **Support Infrastructure:** infrastructure required to support the operation of the core facilities and essential infrastructure. Depending on onshore development location, this infrastructure may already exist, for example a development in the close vicinity of Broome may not require its own airfield.
- **Ancillary Services:** services required to ensure the Health, Safety of the personnel onsite as well as the compliance with Environmental regulations (HSE).

The main components of these categories are summarized in **Table 1**. For the purposes of the study, this list is indicative and intended to highlight the major facilities and services components. Far more exhaustive breakdowns will be required as specific hub concepts are matured.

**TABLE 1**

**TYPICAL ONSHORE FACILITIES AND SERVICES CLASSIFICATION**

| Ancillary Services | Support Infrastructure | Essential Infrastructure (4) | Core Processing Facilities |
|---|---|---|---|
| Security | Offices | LNG and other storage tanks | LNG train(s) |
| Catering | Accommodation | Warehouse / stores | Slug catcher |
| Fire fighting | Airfield (2) | Essential utilities (1) | |
| Emergency Response | Non essential utilities (3) | Laboratory | |
| Training | Port facilities | Power generation | |
| Medical | | | |
| Health, Safety and Environment | | | |

**Notes:-**
1. Essential utilities are cooling water (if needed), and nitrogen etc.
2. Depending on the site chosen for the onshore LNG development, an airfield may be required.
3. Waste treatment facilities.
4. In addition, the creation of one common facility for the disposal of the $CO_2$ liberated from the LNG gas processing facility is technically feasible and could be considered at later stages of Hub design. If geosequestration is the selected disposal method, then sharing the facilities and pipelines for injecting $CO_2$ at a remote location could generate significant cost savings. This would also ensure consistency in $CO_2$ disposal methods and facilitate monitoring by the appropriate Australian authorities.

This inventory is designed to identify discreet blocks of facilities and services that can be shared across several LNG developments.

### 2.1.2 Notional Integration Scenarios

Theoretically, there is an infinite range of sharing or integration scenarios that could by contemplated by potential hub users.

At one end of the spectrum, sharing of core processing facilities represents the highest degree of integration. At the other end, sharing of ancillary services represents the minimal degree of sharing. No sharing of facilities or services is the "base" case against which integration options can be evaluated.

For the purposes of this study, GCA has selected five integration scenarios that are appropriate for consideration at this stage of Browse Basin LNG development. **Table 2** summarizes the five main scenarios which are appropriate to two or more "co-located" onshore LNG developments.

**TABLE 2**

**ONSHORE FACILITIES AND SERVICES INTEGRATION SCENARIOS**

| Degrees of Integration | Ancillary Services | Support Infrastructure | Essential Infrastructure | Core Processing Facilities |
|---|---|---|---|---|
| **Base Case** | Not shared | Not shared | Not shared | Not shared |
| **Case A** | **Shared** | Not shared | Not shared | Not shared |
| **Case B** | **Shared** | **Shared** | Not shared | Not shared |
| **Case C** | **Shared** | **Shared** | **Shared** | Not shared |
| **Case D** | **Shared** | **Shared** | **Shared** | **Shared** |

**Note:** It should be noted that some of the essential infrastructure (such as LNG storage) could not be practically shared unless the core processing facilities are also shared.

These scenarios are not exhaustive. For example, the LNG proponents could decide to share only the gas processing facilities, and not the other infrastructure or services. However it is logical to assume that, if there is a willingness to share "Core processing facilities" and / or "Essential infrastructure" technical and commercial agreement will have already been reached on the sharing of "Ancillary services" and / or "Support infrastructure.

The scenarios selected above are based on actual LNG Hubs where LNG stakeholders have found incentives to achieve various degrees of facilities sharing. Examples include Ras Laffan Industrial City in Qatar, Egyptian LNG in Egypt and Atlantic LNG in Trinidad. These examples are summarised in **Table 3**.

**TABLE 3**

**ONSHORE FACILITIES INTEGRATION ANALOGIES**

| Analogies | Description |
|---|---|
| Ras Laffan Industrial City | - Site and common facilities (jetty, storage tanks etc) are typically owned by a single company designed for this purpose<br>- Core processing facilities as well as certain other services and infrastructure are owned and operated typically by the gas fields/LNG plant operators |
| Egyptian LNG / Atlantic LNG | - Site and common facilities (jetty, storage tanks etc) are typically owned by a single company designed for this purpose<br>- Trains are owned by individual LNG companies, which may involve several shareholders, typically the gas fields operators<br>- Construction, staffing and operation of the trains and common facilities are typically managed by a single operating company designed for this purpose |
| Angola LNG | - All feed gas from three of four sources enters the plant inlet facilities via individual pipelines<br>- After reaching the plant, all gas treatment is common through gas processing, liquefaction and storage |

**Note:** Each individual analogy can typically relate to several of the cases described in this study, based on the degree of integration achieved.

The study of these analogies confirms the potential for different degrees of integration for onshore LNG facilities and services.

The potential technical issues related to each of these cases are studied in more detail in the following section.

## 2.2 Review of the Technical Feasibility of Different Levels of Integration

The scenarios reviewed are described in **Table 2**. They step through increasing levels of integration. The base case, which does not involve sharing any facilities or services, can be considered as “equivalent” to stand alone LNG development. The base case is therefore technically feasible and does not require further investigation.

The individual components of ancillary services, support infrastructure, essential infrastructure and core processing facilities are listed in **Table 1**.

### 2.2.1 Technical Issues - Case A

In this case, only the ancillary services are shared across the multiple LNG facilities co-located within an LNG Hub. Typical ancillary services cover the areas of security, catering, fire fighting, emergency response, medical, training as well as Health, Safety and Environment (HSE). In most respects, the provision of ancillary services constitutes an operating cost, with minimal relative capital cost.

This scenario would typically involve a separate Company with the responsibility of providing these ancillary services to the LNG plants. In other LNG Hub locations (Ras Laffan Industrial City for example) a central service provider has been established by the national oil company. This central service provider typically runs all the non LNG company activities at the LNG Hub. This model has proven to be very effective and could be adopted for the operation of non LNG company activities in a Browse Basin LNG Hub.

At Ras Laffan Industrial City in Qatar, several common services are supplied to the LNG operating companies. These services cover the areas of security, safety, medical, training etc. The cost for these services is recovered from the LNG plant operators on the basis of actual costs plus a minimal uplift. These services are provided on a much larger scale than any individual company might justify on a “stand alone” basis, which generates significant economies of scale. One of the key success factors of such a configuration relates to the reliability of the third party supplying these services and its ability to develop trust with its customers. To this effect, at Ras Laffan Industrial City, the services supplier would provide the LNG plant operators with complete access to its financial statements through open audit.

The following paragraphs discuss in detail the services to be provided, any technical issues around the provision of the services, how they could be accessed, paid for, and integrated with the LNG plant(s) operation.

**Security**

LNG plants constitute major capital investment and a strategic asset providing energy to buyers, potentially domestic and overseas. Most LNG is sold on a long term contracted basis with penalties for failure to deliver cargoes. The failure to deliver contracted LNG cargoes also seriously affects the credibility of the plant as a reliable supplier, which can make the sale of subsequent LNG volumes more difficult. Ensuring adequate security is one of the measures required to safeguard the ongoing operation of the LNG facilities.

Security is normally achieved by surrounding the plant boundary by a high security fence with closed circuit television (CCTV) cameras to monitor fence security at all times. In

addition, security personnel patrol the facility and manned security gates control the access of approved personnel to the facility.

In the context of an LNG Hub, where facilities of several operators are located within a common area, it would be impractical for separate LNG facilities to have their own security procedures and personnel due to the difficulty of coordinating such a combined effort. It is more effective and cost efficient to have one common security provider for the overall common boundary and internal facilities. This also ensures consistent security standards and procedures are applied to all entities within the LNG Hub facility.

Careful consultation with each LNG Company involved in the LNG Hub is required to establish a common security capability. This ensures that each company's internal security requirements are satisfied. Once a common security policy and necessary procedures have been agreed, it is also necessary to determine a suitable method to allocate the costs for these services. Allocating these costs on a "non profit" basis is generally considered a fair approach. In effect, all costs would be allocated to each LNG plant operator on some equitable basis. These costs are mainly the initial Capex required to establish the installation of the security equipment and the annual Opex to cover personnel costs related to the operation and administration of the security force.

An alternate to internal provision of the security capability is to contract the security of the LNG Hub to a well established security company. This option may be perceived less favourably by the LNG Companies, which could prefer to have full control on their internal security provider, instead of using a more independent external company. This would require detailed discussion with the LNG operating companies prior to initiating any contract with an external security company.

In summary, sharing security services, either provided internally or externally, is technically feasible and does not pose any major issue.

**Catering**

Staff catering facilities will be required by each LNG plant operator. It is a common practice in the LNG industry to contract catering out to a professional service provider. It is however necessary to provide the catering company with the facilities to prepare and serve the food. A mess hall / kitchen facility would typically be constructed as part of the overall LNG plant facilities. In the case of an LNG Hub, it will be economically effective to build one common catering facility to handle the staff from all Operators. However, this facility would need to be centrally located and within walking distance for all Hub personnel.

As in the context of sharing security services, it will be important to determine exactly who the catering entity will be and how the catering facilities will be built. The allocation of the capital cost required to build the mess hall / kitchen could be handled in different ways. For example the LNG companies could make a capital contribution to the building of the catering facility and the operating costs would only reflect the cost of staff, utilities, catering supplies etc. Future LNG companies locating at the LNG Hub would be required to pay a capital contribution, based on some formula and the original partners would receive a portion to compensate for the sunken costs they have already incurred. A second option would be to build the capital cost recovery into the cost of meals so the LNG Hub service company would be able to recover capital cost through this mechanism.

There are no identifiable technical issues associated with the development of shared catering facilities and services.

**Fire Fighting**

The first line of fire fighting is usually hosted in the LNG Operator's Operations Department and the resources used are typically plant and maintenance personnel. In the event of a major fire, the additional resources of a fire fighting service would be needed. Since the distance from a fire fighting facility to any LNG plant within the LNG Hub would be short, this service could certainly be shared.

It is important for the LNG plant Operators to be in agreement with the centralised facility concept since the safety of their plant depends on the effectiveness of this concept. Having the capability to fight major fires in LNG plants requires well trained fire fighters with adequate fire fighting equipment. Having independent fire fighting equipment and personnel in each LNG plant within an LNG Hub will involve higher costs without improving service quality. However, implementing this concept for each LNG plant operator will require considerable cooperative effort with the service provider. It is important to determine at a very early stage how this effort will be managed.

In setting up such a system it will be very important to establish common equipment requirements and engineering standards to avoid different LNG plants from having different specifications for fire fighting systems within their plant. It will also be important to understand and clarify where the responsibility to maintain and test the fire fighting systems will be allocated. All these types of decisions must be made with the initial LNG plant developers at the LNG Hub and must then be passed on to any LNG company wishing to locate at the LNG Hub. By carrying out this standardisation, the requirements for spare parts, for example, will be reduced and lead to economies of scale compared to each plant having their own specifications, equipment and fire fighting services.

As for the other ancillary services, it will be necessary to engage LNG Hub stakeholders to define the allocation of costs for the common facilities.

**Emergency Response**

LNG plant operators must have in place emergency response procedures to react to any major incident at their facility. The fire fighting capability is an essential part of the emergency response. The overall emergency response plans typically include the method the company would employ to react to all types of emergency situations. These could include plant fires, personnel injury, shipping emergencies, car accidents, loss of plant power, communications, medical emergencies etc. The emergency response plans would also include a process for information dissemination to the necessary government agencies etc.

In the case of a central LNG Hub with multiple LNG plant operations, it will be recommended to have a coordinated approach for emergency response. In the context of a major incident or of an incident requiring specific knowledge, more resources and adequate expertise are likely to be available than if emergency response is not coordinated.

A central emergency response centre could be set up as part of the responsibility of the company coordinating the provision of ancillary services. It is very important to include

the LNG plant operators in the development of such systems to ensure that they are satisfied with the emergency response services and that the procedures meet all their internal requirements. Part of the responsibility of the central emergency response organisation will be to test the response effectiveness through regular emergency response drills. These drills would need to be conducted to test each individual LNG plant's ability to respond and also the coordination of response to an LNG Hub incident.

The main potential technical issue with developing a common emergency response service would be to ensure all plants have compatible communication systems to allow the free flow of information throughout the LNG Hub. In addition, the external emergency communication procedure needs to be defined and agreed by the LNG operators.

**Training**

Every LNG plant operator requires a training program to train personnel new to the LNG industry and to carry out regular training for all their staff to ensure that all the competencies for operating a successful LNG company are developed. Suitable training facilities, allowing the installation of specialist operations and maintenance training equipment for example, are also required.

In the context of an LNG Hub, it would be logical and cost effective to consider providing a centralised training facility and common training where appropriate. Common training facilities operated by a central training provider could support the competency development of all LNG Company staff. Some very general training modules could be common. Operator training, which is dependent on the type of process control system at the LNG plant, would likely be handled by each operator.

The provision of a common training facility would eliminate the need for individual training facilities at each LNG plant within the LNG Hub. If the common training facility is provided by a central company providing the ancillary services, the cost recovery for the facilities could be recovered from the individual operators or through annual charges based on facility usage.

The main potential technical issue with this type of common training facility could be the requirement for different training equipment to support all process control systems used by each plant. This type of issue reduces the incentive to share training services, as there would be limited economies of scale compared to having these process training models at each plant. Another potential issue would be the high level of coordination required to ensure that potential surges in training needs for each Operator (at plant start up for example) do not disrupt the training required by the other Operators.

**Medical**

It is normal for all LNG plants to have some type of medical facilities. These would normally be provided to cover the need for routine medical examinations for their staff and also to handle any type of medical emergency in the plant. Maintaining an adequate level of industrial hygiene is also important in any LNG facility and requires medical oversight. To achieve these objectives, investments in adequate medical facilities, equipment and personnel need to be made.

In the case of an LNG Hub, it would be cost effective to consider common medical services, which could provide more comprehensive medical facilities than individual plant medical facilities. It would be important however for the facility to cover the needs of all LNG operators and any special requirements they might have. One central company could provide these services, similarly to the other ancillary services.

There are no anticipated technical issues with this type of common medical facility and medical services. It would be necessary to determine how the costs associated with the medical facility would be recovered.

**Health, Safety and Environment**

Each LNG Company would normally have a comprehensive HSE program with the appropriate staff to oversee and implement the program. In the case of an LNG Hub it would be appropriate for the individual operators to have their own HSE programs with their own staff to implement and monitor them.

However, there could be one central HSE organization in charge of ensuring overall compliance for the entire LNG Hub. For example, the central HSE group could establish monitoring stations in the LNG Hub and the surrounding vicinity to ensure air and water emissions meet the mandated Australian standards.

There are no anticipated technical issues associated with the establishment of a common LNG Hub HSE group. It may be in the interest of the government of Western Australia (WA) to mandate an independent service provider to constitute this HSE oversight group. However, this may be perceived as an additional cost by the LNG Hub Operators.

### 2.2.2 Technical Issues - Case B

Case B progresses one integration step further than the previous case in that it envisages sharing support infrastructure in addition to ancillary services.

This case would involve much larger capital and operating expenses than in Case A. The operation and financing of these facilities would need extensive consultation with the potential LNG Hub plant operators. Cost allocation for both Capex and Opex will require the establishment of several legal agreements with the LNG plant operators and the central facility company involved in establishing the facilities. Typical approaches for cost allocation in this type of configuration are described in more detail in Case C.

The following will address the practicality, potential technical issues and possible cost recovery scenarios of establishing common support facilities.

**Offices**

It is possible to consider one common office building for all LNG plant operators at the LNG Hub. This could save the individual companies Capex since there would be economies of scale in a larger office building.

There are however some significant difficulties that would be encountered in this type of central office complex.

LNG operators have highly sensitive LNG sales and marketing data and computer systems which are often proprietary to their company. A common office building would have to accommodate a complete secure separation between the areas occupied by different companies, to ensure information confidentiality.

Determining the size of the office building would also be a challenge since it requires accurate knowledge of the manpower of the organizations to be housed. In addition, LNG plants are likely to be built at different times, which means that some Operators may need to invest in the central office building before they are ready to occupy the premises.

There will also need to be provisions made for future expansion of the office building to handle future LNG companies establishing themselves at the LNG Hub. This requirement will impact the selection and sizing of office utilities and will require an estimate of the possible future additions.

Individual LNG operators will most likely want to have their operations and maintenance personnel located in their plant, to ensure a close connection between staff and plant operations. Therefore the personnel located in the central office would most probably be administrative staff and management.

Since individual companies normally have distinct office space requirements, often depending on the level of the personnel occupying the office, it would be appropriate to offer the office building in a shell form. Individual companies would then be able to outfit their office space as needed. The same is true for the individual communication and computer systems.

Providing common office space should not present any major technical issues, however the location of the building should be determined as part of an overall LNG Hub Master Plan. It will be necessary to locate the office at a safe distance form the operating plants.

**Accommodation**

LNG Hub accommodation requirements are conditioned by the manpower levels of each LNG plant. Assuming an initial plant size of 9 MMtpa, in a remote location, it is reasonable to estimate manpower requirement of approximately 450 employees. With multiple plants, manpower requirements would exceed 900 employees. Housing and recreational facilities will need to be designed to accommodate this work force.

Completely different types of accommodation and recreational infrastructure would be required for a “bachelor camp” or for the housing of the work force and their families.

If the decision is taken to have the work force on a rotational basis, only bachelor accommodation and recreational facilities will be required. However, the LNG company will need to double the number of staff to ensure 24/7 coverage. This has a large financial impact, as the most significant component of a typical LNG operating budget is manpower.

In the case of a remote LNG Hub, where employees are accompanied by their families, an extensive community and large facilities would be required to provide an acceptable living environment. This would typically result in much higher capital expenditure for

accommodation. However, higher Capex could be more than offset by reduced transport and manpower requirements leading to lower Opex.

The decision by each company to work on a rotation basis or to have the employees' families in accommodation close to the LNG Hub must be taken at an early stage and should be consistent for all existing and future LNG plant operators. It is noted that recent practice for remote Australian resource development projects is to use "fly in – fly out" construction and operations workforces.

Accommodation could be shared by the employees of the LNG companies operating within the LNG Hub. The company overseeing the LNG Hub could be responsible for developing these common accommodation and recreational facilities. Capex could be provided by the LNG companies, accommodation Opex could be recovered through regular daily accommodation charges. It would also be logical to combine the catering services described in Case A with the accommodation and recreational facility to optimise costs.

There are no technical issues linked to sharing accommodation facilities in an LNG Hub.

**Non Essential Utilities**

Non essential utilities would certainly be ideal candidates for sharing. Typical "non essential" utilities are water for drinking, irrigation of surroundings, and sewage treatment. Supply of all these from a central facility in the LNG Hub removes the need for the LNG plant operators to install and operate facilities for water supply, treatment and delivery. The water from the waste treatment plant can normally be used for the purpose of irrigation of the vegetation surrounding the plants.

Financing the construction and paying for the facility running costs of the common non essential utilities would require the cooperation of the LNG plant operators with the entity established to develop the service and operate the facilities.

The central provision of common "non essential utilities" does not present any specific technical issues.

**Port Facilities**

The installation of port facilities represents a very large capital expenditure. However, the cost of the port facilities will depend on the marine conditions at the LNG Hub location.

In the State of Qatar, port facilities were installed at Ras Laffan Industrial City at a cost of US$1 Billion (1995). The port was constructed in such a manner that two LNG berths were installed with provision for several additional berths. Such an approach and front end investment requires a clear vision for the future of the LNG Hub so that the long term port usage can be estimated and planned for. In Qatar, the port was made available to the LNG companies. However, it was the responsibility of the LNG companies to outfit the berths to make them suitable for berthing and loading of LNG tankers. In addition, construction berths to allow off loading of construction material and product specific berths (sulphur, propane, butane and condensate) were included in the port design. In the Qatar situation, the port Capex (apart from the costs of outfitting the berths) was the responsibility of the Government of Qatar. These costs were recovered

through port usage fees for the LNG companies and berthing fees paid by the ships berthing in the port.

One benefit of having a common port facility is that all shipping, tugs and pilotage requirements are coordinated through one party. In addition, having multiple LNG berths in one port increases the potential LNG plant reliability since problems with one berth will still allow LNG loading through the second berth.

The development of a port for the common use of multiple LNG companies would require careful consultation with the companies to ensure adequate berth availability.

Some sites may be better suited than others to accommodate large common port facilities. However, there are no intrinsic technical issues linked to sharing port facilities. The concept of one port for usage by multiple LNG producers is proven, with operations in Qatar and other LNG plants around the world.

**Airfield**

Depending on the location of the LNG Hub, it may well be necessary to install a dedicated airport. An airport could be developed to serve multiple LNG plant operators using the hub. The airport would need to be administered and operated to meet minimum safety and availability requirements. This could be outsourced to a company not related to the LNG operation. Indeed, most LNG companies prefer not to have to assume the responsibility for an activity that falls well outside their core competencies.

The cost of constructing and operating an airport, and the provision of air services, would be the subject of negotiations between the airport company and the LNG plant operators who would use the airport for personnel and cargo transfer.

No technical issues are foreseen in the construction and operation of an airport, assuming appropriate land can be located within the proximity of the LNG Hub.

### 2.2.3 Technical Issues - Case C

Case C is Case B with the addition of Essential Infrastructure. This takes the integration concept to a higher level than that described in Cases A and B. The prospect of sharing essential infrastructure might be of concern to an LNG plant operator. Indeed, the operator needs to fulfil LNG cargoes from a system where a critical part of the LNG manufacturing and shipping process is not fully within his control.

The Ras Laffan Industrial City in Qatar has several shared facilities, which include LNG tanks. The LNG densities produced from both Qatargas and Ras Gas trains in Ras Laffan Industrial City are similar, therefore minimizing the risks associated with the common storage of different LNG streams. In addition, the incoming gas streams, coming to each of the LNG train operators, are produced from similar reservoirs and have very similar compositions.

The model for recovering the costs of these facilities is based on both a capital cost component and an operating cost component. The recovery of the capital cost component of an LNG tank, for example, involves the LNG plant operator paying the capital portion of the facility which he needs access to. For example, if one LNG plant operator requires access to 30% of the common LNG tank facility, he is then required to

pay 30% of the overall capital cost. In addition, the LNG plant operator needs to commit to a certain quantity of through put. The recovery of the operating cost component is then determined based on the costs of operating and maintaining the portion of the facility being used by the specific LNG plant operator. This approach can be applied for recovering the costs of all major facilities shared by multiple users.

It is important to note that economies of scale will be realized on Opex for common facilities, as one common work force will be operating the facility instead of multiple work forces operating individual facilities, such as LNG storage tanks for example. Spare parts and maintenance procedures are also optimized in this configuration, as opposed to being duplicated by multiple operators.

Having common LNG, condensate and sulphur storage tank facilities can also provide significant operating flexibility for LNG plant operators. The unused storage capacity can then be periodically re-allocated to any operator with high LNG production at that point in time.

The LNG plant operators' access to the facilities and the establishment of usage priorities will be of paramount importance. Indeed, the LNG plant operators have LNG delivery obligations, which have large financial penalties for failure to deliver contracted volumes.

The operation and maintenance of these shared facilities may also be of concern to the plant operators, as these will be out of their direct control.

The following will describe the equipment defined as "essential infrastructure", the operational and business issue that may exist with sharing this equipment and the potential financial implications. Any technical issues will also be noted.

**LNG and Other Storage Tanks**

LNG storage requirements are typically based on LNG production rates, forecasted LNG sales, shipping schedules and harbour access. LNG operators would normally design the LNG storage to hold approximately seven days of production. In the event of ship delay, this is usually considered sufficient storage to avoid complete shut down of the LNG plant, which would have to occur once the storage tanks are full. LNG plants are not easily shut down or started up once shut down, so the optimum operating practise is to ensure the LNG storage have enough spare capacity to avoid "tank tops" situations.

The use of common LNG storage facilities presents a significant technical issue and potential safety risk. Two different LNG streams from different plants with differing LNG densities can generate two distinct LNG layers in the common LNG tank. LNG liquid normally "weathers" in the tanks, which means that vapour is released from the liquid due to heat increase in the tank. The vapour is typically recovered and returned to the plant LNG fuel system. In the case of two layers of LNG in the same tank, the heavier layer sinks and the lighter layer rises. Both layers give off vapour; however the lower layer vapour cannot be released into the tank vapour system because of the hydrostatic head of the top layer. The top layer density increases as the LNG gives off vapour and at some point the two layers approach the same density. This causes LNG "roll over", as the two layers mix rapidly and the lower layer gives off large amounts of vapour. If the tank relief system cannot handle the excessive gas volume, there is a risk for tank

explosion. In the context of a Browse Basin LNG Hub, the use of common LNG tanks is unlikely to be an issue if the LNG densities from the different LNG operators are similar.

Sharing LNG storage facilities between multiple LNG operators is also expected to be difficult, due to the different timing of the LNG projects. In such a configuration, the first LNG operator or the common facility operator may have to pre-invest in LNG tankage for the second LNG operator, in order to realise economies of scale. LNG tanks represent significant capital expenditures, which are in excess of US$ 50 million per tank. Although the timing and cost of LNG storage tankage is not a technical issue, it does constitute a potential commercial risk.

In the case of shared LNG tanks, clear procedures will need to be developed for allocation of LNG from the different plants. Sampling and measurement of the LNG delivered to the plants from the different operators will also need to be precisely monitored.

**Warehouse / Stores**

Sharing a common warehouse facility should be technically feasible, as long as each company can have a secure area allocated to them for their storage requirement.

It is necessary to consider two different types of spares for potential storage sharing:

- Spares which are not equipment specific and could be considered “consumables”, (gaskets, lube oil, filters, bolts etc).
- Capital spare parts for specific equipment.

Consumables and their allocated storage facilities can be shared without generating any major technical difficulty. Unless the separate LNG plants have identical equipment and utilise the same LNG liquefaction technology, sharing capital spare parts for major LNG plant equipment is not feasible and would be uneconomical.

**Essential Utilities**

The supply of essential utilities does not present any significant technical issues. All LNG plants require supplies of nitrogen to purge gas lines in the event of maintenance. In addition, should sea water cooling be used in the LNG processing facilities, it would be possible to utilise one common facility.

**Laboratory**

Laboratory facilities in LNG plants are mainly used for verifying the quality of the LNG loaded on the tankers, which is essential to define the value of the cargo. Indeed, LNG is sold on the basis of British thermal units (Btu) delivered. The total Btu’s delivered to an LNG tanker is determined by multiplying the heating value of a sample of the LNG being loaded (Btu/standard cubic meter) by the volume of LNG delivered on board the vessel.

Using one common laboratory for several LNG plants would not be problematic technically. The other tests carried out by the laboratory, like determining water quality for example, do not pose any technical issue for integration either.

**Power Generation**

Electrical power requirements for LNG plants can be considerable. Individual LNG plants usually prefer to be self sufficient and install the necessary power generation plant. This is based on the objective to be a reliable LNG supplier and the thought that dependence on an external source for the supply of electrical power constitutes a risk. Indeed, in such a context, the LNG company is not in complete control of the overall LNG manufacturing process. In addition, local power stations can rarely supply the large electricity requirements of an LNG plant.

It would be logical to combine the power requirements for multiple LNG plants in one power generation facility within the LNG Hub, leading to economies of scale. In addition, one large power generation plant could provide more security of electricity supply, as it could accommodate the requirement for sparing electrical generation equipment to cover breakdowns of essential equipment. The LNG plant operators would need to ensure that the operation and maintenance of the power plant is handled by a competent entity, reliably providing steady power supply and higher levels during peak times.

The method of distributing power to each LNG plant in the event of a reduction of electricity production is an issue that would require thorough consultation with the participating LNG companies. In the event of the central power plant having to shed load, there would need to be a clear procedure for power shedding that was equitable to all LNG plants.

Similarly to the other issues developed in this section of the report, distribution and recovery of Capex and Opex will need to be agreed with the potential LNG plant operators.

The only major potential technical problem would be the compatibility of the centralised power plant to supply the necessary power at the levels and frequency required by the LNG plants. The limitations to power supply should also be well understood by the different plant operators.

### 2.2.4 Technical Issues - Case D

Case D represents maximum integration of facilities.

Both the Angola LNG facility and the Atlantic LNG facility in Trinidad represent operations where a degree of integration beyond Case C has been achieved.

In the case of Atlantic LNG, each of the four operating trains has different sources of feed gas. However, the trains are not exclusively dedicated to one source, with some trains taking a mix of feeds. The ownership of the individual trains in some cases bears no relation to the ownership of the gas. LNG storage is not in dedicated facilities. Atlantic LNG is the operator of the site on behalf of the individual LNG train owners. The earnings from the operations, referred to as a quasi – tolling basis, are calculated by Atlantic LNG via a complex allocation procedure.

For Atlantic LNG, this modus operandi grew from the initial investment decisions where LNG facilities were conceptually new and it was important to develop economies of scale. In the early days of LNG projects, the Atlantic LNG project succeeded at least

partially as a result of an enlightened government policy on tax incentives, which was also probably fundamental in the development of a single integrated hub facility.

Angola LNG is entirely different, and its character as a single integrated plant for a number of gas suppliers stems from its use of associated gas from offshore operations. Supplies of associated gas from individual fields are limited, and the feeds from a number of fields must be combined to allow an initial single train to be developed. Now that the principle has been established it is likely that future LNG expansion in the area will also be through the existing plant.

**LNG Train(s)**

LNG trains are normally composed of two main components, a gas treating and dehydration section and an LNG liquefaction section. The gas treating and dehydration section of the train removes components of the gas that cannot be allowed into the liquefaction section ($CO_2$, hydrogen sulphide, mercury and water). The design of the gas treating section of an LNG train is based on the composition of the incoming gas stream. This section can be designed to accommodate small variations in gas composition, but cannot tolerate compositions greater than design once established. This makes the mixing of various gas compositions a significant technical problem, which could result in equipment failure, reduction in effective plant capacity or producing LNG that would be off specification and unsalable. LNG plants typically do not have the ability to re-run LNG to bring it back to specification.

Where mixed feeds are proposed, a more robust process is selected to accommodate the likely feed composition variations. The Phillips Cascade Process or various of its derivatives use individual refrigeration loops (compared to the Mixed Refrigerant Cycles using complex mixtures whose refrigerant properties are adjusted to match the condensing characteristics of the feeds). This may lead to a less efficient process, but one which is inherently more capable of dealing with composition variations away from the design point.

It can be acceptable for one operator to build a dedicated train to process gas from a second operator. In this case, there would only be one LNG plant, but each train dedicated to processing specific types of gas from different fields. This is a common practice, implemented in Indonesia at both the Arun and Bontang gas plants, and as identified above in a different format, for Angola LNG and Atlantic LNG.

**GTL Plant**

Similarly to LNG trains, multiple companies sharing common GTL facilities would be problematic from both commercial and technical aspects.

A possible scenario that would be acceptable to gas suppliers, would be for one GTL plant to be operated by one company but processing gas supplies from others. Similar technical issues would exist as a result of varying gas composition from multiple gas fields.

**Slug Catcher**

Slug catchers are normally sized based on the anticipated liquid quantity in the incoming gas. Forecasting future gas volumes and liquid content would be required to design a slug catcher that could be expanded and shared by multiple users.

Existing LNG plants expand their LNG production capacity and often have to enlarge their slug catcher to accommodate increased gas and liquid volume. Sharing a slug catcher across several users is technically feasible but likely to require pre-investment of capital.

**Condensate Treating Facility**

The condensate can either be stripped from the produced gas offshore or at the onshore LNG plant. In the onshore scenario, the slug catcher would separate condensate from the incoming gas stream and from the water. The condensate then needs to be stabilised in order to meet shipping specifications. This is necessary since during the voyage the gas will tend to evaporate from the condensate and the receiving customer will have lost some of the cargo due to evaporation. This would have an economic impact since one volume was loaded but a lesser volume was received by the purchaser. The normal standard used in limiting this evaporation is the use of a Reid Vapour Test (RVP). To achieve the necessary RVP level, it is necessary to treat the condensate to reduce the volume of any entrained gas. This is normally achieved by heating the condensate and removing the necessary volume of gas.

It would certainly be possible to have a condensate treating facility that is shared by multiple users. However, sharing such a facility does not generate significant cost savings as, although there would be some economies of scale, there would typically need to be additional pipelines from the individual plants to the central condensate facility which could offset the benefit achieved.

## 2.3 Review of the Economic Incentives of Different Levels of Integration

### 2.3.1 Indicative Cost of Main Onshore Facilities

The estimates of savings for the various major categories are based on a notional total investment cost of US$ 13.5 billion for two independent, physically segregated plants. These represent typical investment costs for two plants each of two trains of 4.5 MMtpa LNG capacities (9 MMtpa per plant). This is assumed as an initial development size to evaluate the cost savings, recognising that each operator may have a somewhat different approach.

**TABLE 4**

**FACILITIES AND SERVICES**
**POTENTIAL CAPEX SAVINGS FOR INTEGRATED FACILITIES**

| Categories | Savings on Two Integrated Plants Compared with Two Separate Plants | |
|---|---|---|
| | US$ Million | Percentage of Total Costs |
| Ancillary services | 85 | 1% |
| Support infrastructure | 475 | 4% |
| Essential infrastructure | 1160 | 8% |
| Core processing facilities | 400 | 3% |
| **TOTAL** | **2,120** | **16%** |

Based on the preliminary stage of this study, accuracy should be taken as +40% / -30%. All costs are based on mid 2008 estimated prices.

### 2.3.2 Sizing of Facilities in Each Integration Case

Each category of saving as shown in **Table 4**, is made up of savings from a combination of sources which are described below, for the major areas of savings.

**Ancillary Services**

There are no substantial Capital items contained within the ancillary services, with most of the potential cost savings arising from reductions in Opex (**Table 5**).

**Shared Infrastructure**

There are significant cost savings to be realised in the Support Infrastructure by integration of the two plants into a single hub development. The optimisation of space usage for the site will reduce the cost of site infrastructure, roads and fencing. There will be no necessity for duplication of airstrips, for example, or the facilities for marine offloading and hence direct savings will be achieved equivalent to the cost associated with the provision of these items in full for one plant.

A hub facility will permit accommodation for the participating personnel to be grouped into a single entity, rather than two autonomous locations with subsequent reduction in cost through more efficient use of resources.

With a single hub development, several of the non critical buildings could be grouped together, further saving through optimisation of resources.

**Essential Utilities**

The main item in the essential utilities category is power generation. Two large base load LNG plants will require very large power generation facilities of approximately 125 Megawatts (MW) installed each, which if combined into a single integrated plant, could be implemented as base load combined cycle gas turbine (CCGT) power plants with a different sparing provisions. This leads to substantial cost reduction opportunities, which could possibly be enlarged even further by incorporating power supply into the regional infrastructure.

Similar arguments apply to Cooling Water (if used), Nitrogen, Air and other utilities which could all be supplied “across the fence” from larger units built with economies of scale.

Essential plant utilities such as the flare and blowdown systems, drainage and liquid waste disposal systems can all successfully be served by a single resource rather than two separate resources, providing economy of scale. There is a side issue associated with this, in that logically such integration arrangements are best suited to a single operatorship for all of the plant facilities and require accurate forecasting of gas volumes to be processed at the onshore Hub.

The LNG loading and other liquid product loading can be integrated through a single jetty. Even if full integration is not carried out (effectively through mixing of products or mixing of feed), the major costs impact of two jetties for separate developments can possibly be reduced to a single jetty serving both. This must be tempered with cautionary note since detailed studies of shipping and site will need to be carried out to confirm this assumption.

If it is assumed that the LNG and other liquid products can be stored in an integrated facility with mixing of the products, and that LNG roll over risks can be mitigated, then substantial saving is possible from optimisation of the number of LNG tanks. Typically two separate facilities may require four LNG tanks, whilst an integrated facility of the same capacity may be served by three tanks.

Thus this category of integration offers the scope for maximum cost saving, recognising that much detailed analysis needs still to be complete to fully confirm the assumptions made herein on integration.

**Core Facilities**

This reference is to the main process facilities, which in this example refers to four equal trains of 4.5 MMtpa LNG production capacity. There is little economy of scale possible since each train is likely to be designed and built close to the limit of LNG technology. Savings are possible in procurement charges, design and engineering and construction management if each train is of the same design. This may yield only a small saving and assumes that such similarity of design would be achieved by mixing the feedstock to the plant or otherwise setting a common design. This is a fundamental principle which must be agreed by the owners.

Greater saving would however ensue to the Opex charge in this case if a single operator were nominated.

### 2.3.3 Considerations on Opex saving

The overall Opex is simply and approximately estimated at an average cost approaching US$ 500 million per annum per plant for two independent plants. Two independent plants in distinct separate locations would require entirely independent operating teams for every facet of the operation, from maintenance, ship loading, plant supervision, control room, security etc.

**Table 5** gives an indicative breakdown of these costs for a 9 MMtpa plant.

**TABLE 5**

**ASSESSMENT OF OPEX AND OPEX SAVING FOR AN INTEGRATED HUB FACILITY**

| Categories | Average Annual Cost for Two Independent Plants US$ Millions | Savings on two integrated plants compared with two separate plants | |
|---|---|---|---|
| | | US$ Million | Percentage of total costs |
| Operations and maintenance | 600 | 210 | 35% |
| Transport, logistics and freight | 200 | 60 | 30% |
| Consumables | 50 | 0 | 0% |
| Support Services | 25 | 5 | 20% |
| General and Administrative | 25 | 5 | 20% |
| Insurance | 100 | 10 | 10% |
| **TOTAL** | **1,000** | **290** | **29%** |

This indicative breakdown shows potential for a 29% reduction in Opex resulting from integration of the two plants into a single operator hub.

## 2.4 Possible Industry Concerns

### 2.4.1 Commercial Incentives and Challenges to Integration

One of the major challenges from a commercial perspective will be the method of charging for the use of common facilities and services.

With common services, the Capex component will normally be small and the majority of the costs will be Opex. For the LNG proponents the costs will need to be attractive enough to be competitive with what it would cost them to provide the same facilities on an independent basis.

On the large shared facilities where the Capex costs will dominate and the Opex costs will be much lower, the challenge will be to develop a method of investment and cost recovery. The common facilities could be installed and financed by the LNG Hub operating company with these cost being recovered through tolling charges. Some companies may prefer the tolling charge method since this will be an Opex cost for them and may be more attractive than contributing to Capex costs. Allocation of charges will be a challenge, whether Capex or Opex, for the original LNG operators. A clear cost recovery method will also need to be defined for any subsequent LNG operator moving into the LNG Hub. To ensure the acceptance of the LNG Hub facilities sharing concept, it will be necessary to make the participation by LNG proponents commercially attractive.

There will be several technical and procedural challenges to the integration of LNG operating companies into the common facilities provided by the LNG Hub. Major LNG operators have very strict engineering standards and operating procedures specifically designed for their company. It will be a key step to have multiple operators agree to the specifications and procedures to be employed in any common facilities. It will be essential to have compatibility between the LNG Hub operator and the LNG plant operators with regard to engineering and equipment specifications. The LNG operators will also be concerned with the competency and reliability of the Hub operators, since the reliability of the LNG deliveries will depend on these factors. It will also be important for the LNG Hub operator to demonstrate that adequate spare parts and appropriate maintenance procedures are in place to ensure high equipment reliability.

Sharing common facilities will also require extensive legal negotiations to ensure all parties are satisfied with the services they will receive and the types of risk they may be exposed to. This legal process can be lengthy and incur significant costs.

The LNG Hub can be structured to be attractive to the LNG companies. This can be achieved through several potential policy and communication measures, such as:

- Pre-investing in LNG Hub infrastructure, such as port facilities for example, which reduce the LNG operator's investment requirements.
- Providing economic incentives through tax treatment.
- Demonstrating the cost savings that can be achieved by sharing specific facilities and services.
- Demonstrating the operating flexibility that can be gained by sharing facilities, such as LNG and condensate storage tanks for example.

In the State of Qatar, the Ras Laffan Industrial City is an example of a planned industrial complex which houses multiple LNG projects with many common facilities. This industrial area was conceived and developed by the national oil company of Qatar, Qatar Petroleum. At an early stage, the Ras Laffan Industrial area was selected to be developed for gas based industries. Economic incentives, in the form of tax breaks, were provided to the LNG companies, attracting them in this area. In addition, the existence of a planned industrial area with some initial infrastructure, including comprehensive port facilities, a road network and a common services company operating and administering the complete industrial complex, played a significant role in gaining the industry player's buy-in. It was also demonstrated and clearly communicated to the potential LNG companies that economies of scale existed in many areas and that the individual operators would benefit from the facilities sharing concept.

### 2.4.2 Possible Engagement Process between Government and Industry

The following outlines a possible approach for the Government to define its visions for Browse Basin LNG.

An initial step would be for the Government to select and further develop the LNG Hub concept outlining the possible degrees of integration, possible Hub location etc. This step would be followed by the development of a detailed implementation strategy for the selected integration cases including organizational concepts, possible options for commercial structures and capital financing plan options.

The following sequence could be considered to engage the Industry:

i. provision of a timeline for completion of the engagement process, allowing Browse Basin tenement holders to assess potential impacts on development deadlines,

ii. definition and sharing of the Government's vision for LNG developments in the Kimberley, in particular the roles of the different stakeholders involved and the expected extent of the gas processing facilities,

iii. agreement on the expected degree of integration of onshore and offshore facilities and services,

iv. selection of preferred LNG Hub onshore sites for further studies,

v. assessment of potential appropriate commercial models,

vi. identification of LNG Hub common facilities operator. This could be a Browse Basin stakeholder with proven LNG operating experience.

Successful engagement will require the Northern Development Task Force and other Government representatives as appropriate to meet individually and collectively with potential Browse Basin LNG producers and with potential Hub operators to discuss the Hub concept, the Hub location, the proposed degree of integration, the appropriate cost structure and possible commercial principles.

# APPENDIX I

## RFT DOIR2271107 – SCOPE OF SERVICES – Extract

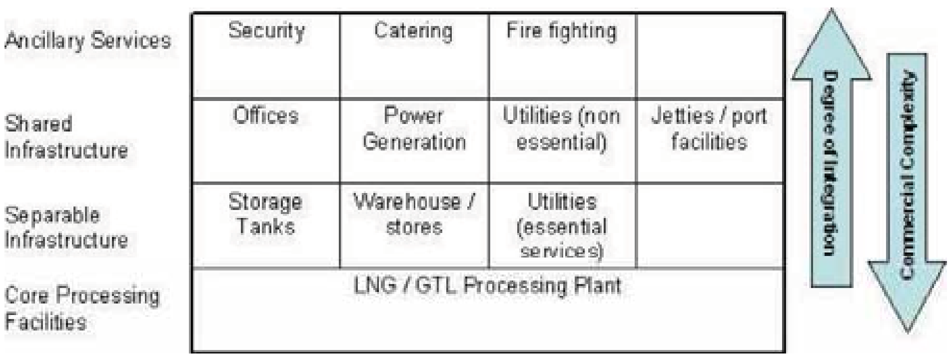
## RFT DOIR2271107 – SCOPE OF SERVICES – Extract

### Onshore Infrastructure Hub Development

The objective of this study is to review potential for a development based on an onshore infrastructure hub, and provide commentary on the feasibility issues from a Technical, Commercial, and Economic perspective.

A number of potential models are available for the establishment of joint infrastructure for the multi-proponent use.

- Review the appropriateness and feasibility of sharing facilities, this should include a review of the various elements of the infrastructure; and
- Provide commentary on the potential implications of varying degrees of integration of the onshore facilities.




Provide commentary on attractiveness of the hub to industry, including an estimate of the potential cost savings attributable to a joint development as opposed to multiple standalone developments.

This should include:

- Identification of potential infrastructure cost savings through use of a multi-user facility; and
- Consideration of potential cost savings attributable to likely economies of scale associated with co-location.

Provide commentary on the likely barriers to uptake of the industrial site from industry, including both current proponents, and identification of potential issues for future (prospective) companies in terms of both access to the site and future expansion.

NOTE: The scope of this study excludes a review of potential commercial models for the onshore infrastructure hub. The critical issue to be resolved in the short term is the development of an engagement process between: Government, Industry, and other interested stakeholders to identify the most suitable model.

# APPENDIX II

# COMMENTARY ON DOMESTIC GAS POTENTIAL

## COMMENTARY ON DOMESTIC GAS POTENTIAL

### Summary

For the Woodside and INPEX LNG projects as currently envisaged, the total gas reserved under the Western Australia gas reservation policy is estimated to be about 3,840 PJ. Over the 20 year life of the projects, this equates to an average domestic gas rate of 192 PJ/year.

Technically this volume of gas is sufficient to support one or more of the following:-

- Domestic gas sales via connection to the the Dampier to Bunbury Natural Gas Pipeline (DBNGP).
- Domestic gas sales to a large scale local user in the Northern Kimberley region not co-located with the LNG Hub (eg;- Minerals processing facility).
- Feedstock to GTL, Ammonia or Methanol plants co-located with the LNG Hub (i.e., the gas processing hub).

Sites that could accommodate the above options are tabulated below. Also shown is the estimated cost of a pipeline to connect each of the sites to the DBNGP (**Table I**):-

**TABLE I**

**SUMMARY OF DOMESTIC GAS CONSIDERATIONS**

| | GTL, Ammonia, Methanol | Domestic Gas | DomGas to Dampier (US$MM) |
|---|---|---|---|
| Maret Islands | N | Y | 2,095 |
| Bigge Island | Y | Y | 1,918 |
| Wilson Point | Y | Y | 1,799 |
| Koolan Island | N | Y | 1,633 |
| North Head | Y | Y | 1,281 |
| Fishermans Bend | Y | Y | 1,105 |

As can be seen from the above table, if piping of domestic gas to Dampier is a consideration in site selection, then it will have a significant influence.

### Discussion

This section addresses the potential to utilize gas domestically from each of the potential hub sites under consideration.

In October 2006 the Western Australian Government announced a gas reservation policy that requires LNG project proponents to reserve gas equal to 15% of LNG production, from export projects, for domestic use. This reservation is a condition of access to Western Australian land for the process facilities. This reservation requirement was introduced to provide continued certainty that Western Australian consumers will have ongoing access to supplies of natural gas. The method by which proponents meet their obligation will be

negotiated on a case by case basis and will include the option of meeting the obligation from a different source.

**Table II** shows the average gas production rate over a 20 year period to utilize reserved gas equal to 15% of the LNG produced, over 20 years for each of the proposed LNG projects.

**TABLE II**

**15% GAS RESERVATION**

| | Woodside Project | INPEX Project | Total |
|---|---|---|---|
| Reserved gas, PJ | 2,460 | 1,380 | 3,840 |
| Average gas rate over 20 yrs, PJ/yr | 123 | 69 | 192 |

There are three main options available for an LNG proponent to sell gas to the domestic market from its reserved volume:

1. Produce gas from a different source. This could be from a field where the LNG proponent has an interest or could be by the proponent buying gas from another field and onselling it to the domestic market.
2. Provide gas to a large gas user such as a methanol plant or gas-to-liquids plant situated in WA.
3. Provide gas to the existing WA domestic gas distribution system by connecting to the Dampier to Bunbury Gas Pipeline (DBNGP).

**1 - Produce gas from different source**

The governments stated policy is to allow producers maximum flexibility including consideration of providing gas from a different source. This option is not effected by the location of a gas processing hub and is not addressed in this study.

**2 - Provide gas to large gas consumer located in the Kimberley or Pilbara**

It would appear that if gas was sold to a large gas consumer in the Kimberley or Pilbara region, such as a methanol plant, this would satisfy the government's gas reservation policy but it is not clear that it would bring additional benefits to the state over and above those flowing from an LNG development and would not provide certainty that Western Australia gas consumers would have continued access to natural gas.

For most of the potential hub sites under review this option would alleviate the need to install a long trunk line to connect to the DBNG and the existing WA gas distribution system.

It is expected that any large gas user in the Kimberley or Pilbara region would be producing a product that can be shipped to export markets, such as methanol, diesel, beneficiated iron ore or fertilizers. Another alternative would be the production of minerals.

Approximate gas usage for large (world scale) gas projects is shown in the following **Table III**:

**TABLE III**

**GAS USAGE RATES FOR LARGE GAS CONSUMERS (PJ/YR)**

| Plant type | Gas usage rate |
|---|---|
| GTL plant | 140 |
| Methanol plant | 55 |
| Ammonium plant | 21 |
| Minerals processing facilities **(1)** | 40 |

**Note:**
1. Similar to Gove

A comparison of **Tables II and III** show that if the gas reservation for the INPEX project was 15% then it could potentially supply large minerals processing facilities.

Either project could supply a world scale methanol plant or several world scale ammonia plants. It appears that a GTL plant is the only large gas user likely to utilize 15% of the gas reserved for domestic consumption from both projects over a reasonable time period.

It is not necessary for a large domestic gas user to be located at the same location as gas liquefaction facilities, for example Burrup Fertilizers ammonia plant is located on the Burrup Peninsula rather than on Varanus Island where the gas is processed. However, the cost of supplying gas will be less, if the user is located close to the gas source, that is at a hub.

**3 - Connection to the DBNGP**

If gas reserved for domestic sales is produced to the DBNGP it can then be made available to any existing gas user in WA and is likely to be the best option for providing continued access for Western Australian consumers to natural gas.

In considering this option GCA has considered that facilities are sized to deliver the reserved gas over a period of 20 years, when the volume of reserved gas is equal to 15% of the LNG exported. This is at a rate of 192 PJ/yr as shown in **Table II**. This compares with WA's current gas demand of approximately 330 PJ/yr. It should be noted that because it is expected that the gas throughput will build with time the reserved gas will not be produced in 20 years.

For smaller rates a gas line from the Kimberley area could connect to the Burrup to Pt. Hedland pipeline at Pt Hedland. However the capacity of this line is limited to about 65 PJ/yr so for 192 PJ/yr a new line to the Burrup Peninsula is required.

Pipeline costs were estimated for a gas transmission line from five potential hub sites to the Burrup Peninsula. The cost of transporting gas from each of the hub sites to the Burrup Peninsula was then estimated. These hub sites cover the range of suitable sites

and allow the transportation cost from any of the suitable sites to be estimated. The sites considered ranged from Maret Islands in the North to Fishermans Bend in the South.

### *Pipeline Costs*

Pipeline lengths and the estimated approximate cost of pipelines from the potential hub sites under consideration are shown in the following table. The costs include costs for offshore sections where necessary and also compression stations.

**TABLE IV**

**DOMGAS PIPELINES SUMMARY**

| Potential sites | Length (kms) | Cost (US$MM) |
|---|---|---|
| Maret Islands | 1,313 | 2,095 |
| Bigge Island | 1,279 | 1,918 |
| Wilson Point | 1,200 | 1,799 |
| Koolan Island | 1051 | 1,633 |
| North Head | 860 | 1,281 |
| Fishermans Bend | 730 | 1,105 |

### *Transportation costs*

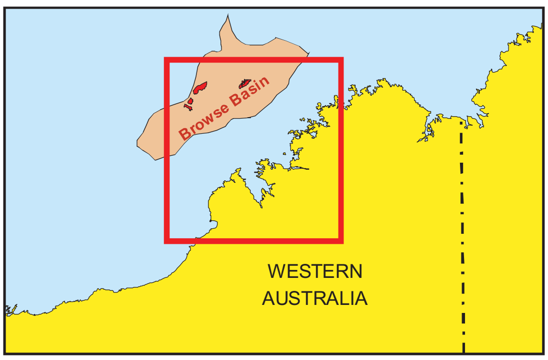
The cost of transporting gas to the domestic market from the hub sites to the DBNGP at the Burrup Peninsula was estimated by providing for a 10% nominal after tax return on the pipeline over a 20 year period. The estimated transportation charge was based on the initial pipeline throughput being about 100 TJ/d and building at 9% p.a. transportation costs are shown in the following table.

**TABLE V**

**DOMESTIC GAS TRANSPORTATION COSTS ($/GJ)**

| Potential sites | Costs ($/GJ) |
|---|---|
| Maret Islands | 3.00 – 4.00 |
| Wilson Point | 2.50 – 3.50 |
| Koolan Island | 2.30 – 3.30 |
| North Head | 1.70 – 2.70 |
| Fisherman's Bend | 1.50 – 2.50 |

The costs shown in **Table V** above, compare with zero transportation cost for gas from a LNG Hub on the Burrup Peninsula.


**Indicative Route of Potential DOMGAS Pipelines from Selected Kimberley Sites**

| Proj. K1177 Jun 08 | Checked: | Fig. 1 |
|---|---|---|

# APPENDIX III

# GLOSSARY

## GLOSSARY

| | |
|---|---|
| Btu | British thermal units |
| Capex | Capital expenditure |
| CCGT | Combined cycle gas turbine |
| CCTV | Closed circuit television |
| $CO_2$ | Carbon dioxide |
| DBNGP | Dampier to Bunbury Gas Pipeline |
| DoIR | Department of Industry and Resources |
| DomGas | Domestic Gas |
| GCA | Gaffney, Cline & Associates |
| GJ | Gigajoule (PJ = $10^9$ J) |
| GTL | Gas to liquids |
| HSE | Health, Safety and Environment |
| JV | Joint Venture |
| km(s) | Kilometre(s) |
| LNG | Liquefied Natural Gas |
| MMtpa | Million tons per annum |
| MW | Megawatts |
| Opex | Operating expenditure |
| p.a. | Per annum |
| PJ | Petajoule (PJ = $10^{15}$ J) |
| PJ/yr | Petajoule per year |
| RVP | Reid Vapour Test |
| $/GJ | Dollars per gigajoule |
| Tcf | Trillion cubic feet |
| TJ | Terajoule (PJ = $10^{12}$ J) |
| TJ/d | Terajoules per day |
| US$MM | Million US dollars |
| WA | Western Australia |