Indonesia's Abadi gas field – options and obstacles

Executive Summary

In May 2007, the Government of Indonesia (GOI) expressed its preference for the Inpex operated Abadi gas field to be developed in Indonesia rather than exported to the ConocoPhillips led Darwin LNG facility in Australia. Although a number of gas monetisation options have been proposed for Abadi, supplying an expansion train at the Darwin facility may offer the greatest opportunity for commercialising the large deepwater gas field, located in the Timor Sea. But is it too early to be ruling out development options for Abadi, and what stage is the development really at?

A number of development scenarios for the Abadi field have been suggested:

- Pipeline to an expanded Darwin LNG facility in Australia, some 440 kilometres to the south of the field
- Pipeline to Indonesia and a new Greenfield LNG project, supplying the export and/or domestic market
- Floating LNG (FLNG)
- Floating Methanol
- Floating Gas-to-Liquids (GTL) / Dimethyl Ether (DME)

The GOI favours FLNG or an onshore Indonesian development, allowing exploitation of the gas reserves within Indonesia. This ensures the GOI has control over the development, and maintains the recent political position of securing domestic gas supplies. However, there are considerable uncertainties which will affect the most cost effective development choice: the field is still being appraised and it has been suggested that there is considerable upside to the current 2P reserve estimate of 5 tcf; Inpex may be required to provide a percentage of gas supply to the domestic market in Indonesia; upon completion of the current appraisal programme, and an expected farm-down of interest by Inpex, the new entrant/s capabilities may influence the choice of development; and, there is speculation, given the fields location, that the structure may extend in to Australian waters.

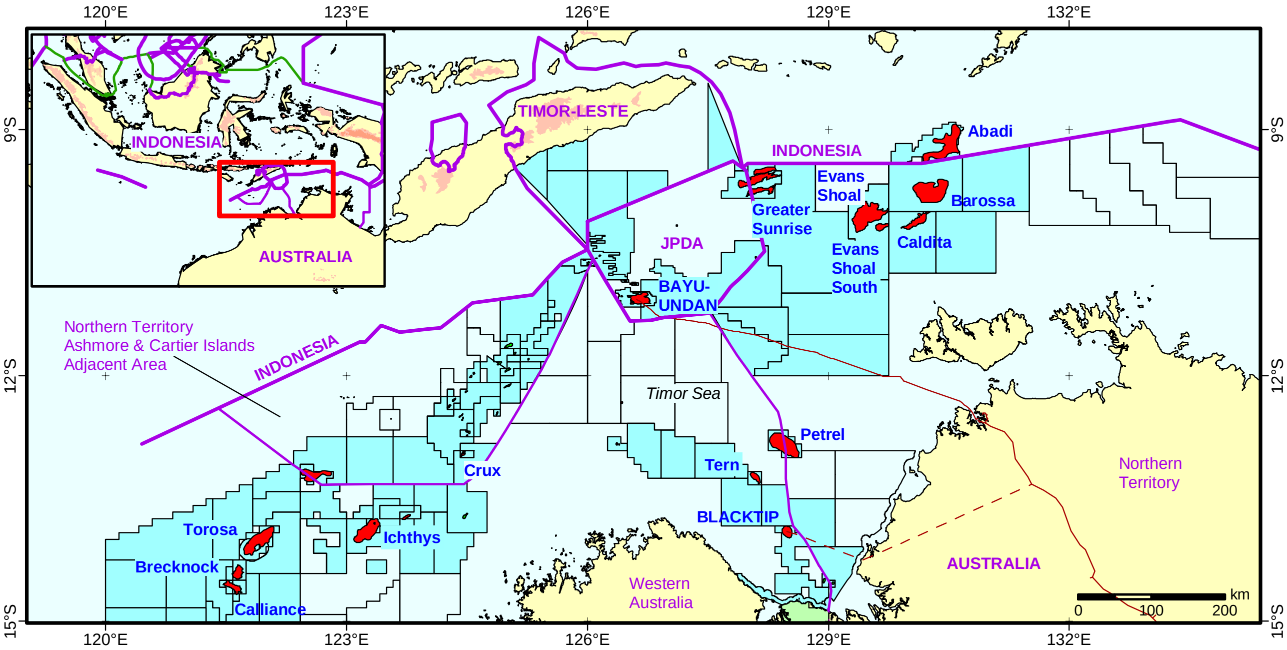
A potential FLNG or onshore Indonesian development, whilst being the preferred development option of the GOI, is not necessarily the most economic. Wood Mackenzie believes that the Darwin export option may be the only viable solution. However, even the economics of piped gas to Darwin are somewhat marginal based on our analysis, which suggests that a US$7/mmbtu FOB LNG breakeven price would be required. Given this, and the potential impact on revenues the GOI would receive, it is considered to be too early for Indonesia to be ruling out export options for Abadi.

Inpex and Abadi

The Abadi gas field was discovered in 2000 and is Inpex's only operated asset in Indonesia. The multi tcf gas discovery lies in deepwater acreage beside the Australian maritime border. The field is remote from demand and supply centres in Indonesia. Although the field is located in Indonesian territorial waters, it lies just 400 kilometres off Australia's Northern Territory, and part of the structure may in fact extend across the maritime boundary.

Following initial appraisal drilling at the field in 2002, 2P reserves were placed at five tcf and 75 million barrels of oil. The structure is believed to be a fault bounded dome with the gas containing around 6-7.5% CO_2. A four well appraisal programme is currently underway at the field to test the quality and continuity of the reservoir and to determine the overall size of the recoverable reserve base. It has been suggested that the structure could contain between 8-10 tcf of recoverable reserves.

Abadi field location



Source: Wood Mackenzie Pathfinder

To move the development forward, Inpex is expected to seek a partner following full appraisal and reserve certification. The choice of partner will be influenced by the favoured development option of both Inpex and the GOI. The GOI's favoured option is an offshore FLNG facility allowing Abadi gas to be processed domestically.

Darwin could also be the site of a facility to handle output from the field. Inpex owns a 10.52% stake in the Darwin LNG facility and there is an attraction in sending Abadi gas to an expanded Darwin facility for liquefaction and export. Piping the gas to Darwin could provide more control over the output than it would from a facility located in Indonesia, although the GOI could dictate that an agreed volume of gas is reserved for the Indonesian market. Inpex also has a participating interest in the Ichthys gas/condensate field, located in the Browse Basin. The field is estimated to hold 2P reserves of 9.5 tcf plus 312 million barrels of condensate, and is a prime candidate for a future large scale LNG development. The project has been strengthened by the inclusion of Total, one of the world's leading LNG players. Ichthys does not have the same technical and geopolitical problems faced by Abadi and there is the possibility that Inpex could prioritise the Ichthys project over Abadi.

What are the commercialisation options?

With no local or regional market within close proximity, gas liquefaction, and transportation to a market via tanker, is understood to be the most viable option to monetise the gas. There are three potential locations which have been mooted for a LNG liquefaction plant.

Pipeline to Australia

The Abadi field is located around 440 kilometres from a ConocoPhillips led LNG project at Darwin, Australia. There is currently 3.2 mmtpa of LNG capacity at Darwin, with space available to add additional trains. The existing Darwin plant came online in February 2006.

A gas pipeline could be constructed from the Abadi field to the plant in Darwin. This option would take advantage of Abadi's proximity to the existing brownfield Darwin LNG site and could supply a five mmtpa LNG expansion train adjacent to existing facilities at Wickham Point. Any Wickham Point development will need the cooperation of ConocoPhillips, which has undeveloped equity gas reserves that it would rather see monitised through Darwin. However, Inpex itself has a 10.5% participating interest in the existing LNG facility and could assist with the alignment of equities between the Abadi gas resource and Darwin LNG project.

This development scenario would appear to provide the most cost effective opportunity for commercialisation of the gas but it also brings with it significant challenges. Any cross border development will face a set of complex issues which could result in project delays. The GOI has already made it clear that the export of Abadi gas is not their favoured option and could veto this development scenario unless an agreement is put in place to allocate LNG volumes to the Indonesian domestic market. There is also the added spice of competition from other significant gas/condensate fields in Australian waters such as Evans Shoal, Sunrise, Caldita and Barossa.

Under this development scenario, Wood Mackenzie forecasts first LNG sales post-2015.

Pipeline to Indonesia

There is no objection to an onshore LNG project in Indonesia, however, the 2,000 metre deep Timor Trough lies between Abadi and the nearest Indonesian island. The closest island which could facilitate a Greenfield LNG project is West Timor, which is approximately 800 kilometres distant, twice the distance to Darwin.

In addition to distance, there is an inherent country risk associated with investing in Indonesia, especially in a new, remote LNG project. Indonesia lost its status as the world's leading LNG exporter in 2005 following reduced output from its two LNG facilities, Arun and Bontang, due to declining production from some of its upstream supply fields. This has tainted Indonesia's LNG delivery reputation. The BP led Tangguh LNG project in Irian Jaya, due online in 2008, will go some way to improve this situation but new projects are now faced with the prospect of having to supply gas to the domestic market at prices below those commanded by LNG projects.

Floating LNG

The Indonesian Government has openly expressed that FLNG is the favoured development option for Abadi. This option would facilitate the development and exploitation of Abadi gas wholly within Indonesia and would give it control over which markets, domestic or export, the gas would be supplied to. But FLNG is a new development concept and it has yet to be proven to be commercially or technically feasible, not just for Indonesia, but on a world wide basis. There have been a number of FLNG projects proposed globally but none have moved to an investment decision due to costs associated with the development. While such a facility would enable liquefied gas to be loaded directly onto LNG carriers, saving the cost of an offshore pipeline, there are many obstacles to overcome before this could be a viable option:

- FLNG is commercially and technically unproven
- There are only two or three companies which have the technical capability to carry out a development of this magnitude
- The cost of the project is likely to be huge, significantly more than an onshore equivalent

These challenges could result in a long lead time to first production and a very expensive development. There are few companies which are technically capable of undertaking such a development and this will undoubtedly affect Inpex's choice of partner in the block. These technical challenges could significantly increase project cost, which will in turn have an impact on the project economics and hence commerciality.

Other development options

Although it is LNG options which have taken centre stage, Inpex is not totally committed to LNG as the only development option for the Abadi field. It has also been considering:

- Floating Methanol/LNG on Tassie Shoals – an alternative would be to develop floating methanol facilities to exploit the gas

- Floating GTL/DME – GTL is still an emerging industry but there has been increasing interest from companies in terms of assessing the commercial case for GTL and is believed to be under consideration by Inpex

The viability of these monetisation solutions is not clear. As with any large offshore infrastructure project, the costs associated with the development would be significant. Environmental hurdles as well as significant technical and commercial challenges would ensure a lengthy pre-development process. In addition, the Pearl GTL project in Qatar has recently suffered a huge cost increase due to industry cost inflation (both raw materials cost and EPC costs) which will no doubt impact Inpex's thoughts on the GTL development option.

An Upstream Development Scenario

A development plan for Abadi is expected to be submitted in 2008, following reserve certification and partner selection. Development scenarios are tentative at present and will largely be determined by reserve size. Wood Mackenzie has based its upstream economics on five tcf of gas and 75 million barrels of condensate, supplying a five mmtpa LNG facility. We have assumed that a fixed platform development will be required to provide power generation, compression and basic gas processing facilities. Full reserve exploitation will be made through the addition of a subsea template which could be tied back to the main production/processing facilities. It is assumed that 24 wells are drilled over the life of the field to maintain a production rate of 715 mmcfd. For the produced liquids, it is assumed that a small FSO will be leased at a cost of US$20,000/day.

Depending on the development scenario chosen, the upstream project may include a 440 kilometre multi-phase pipeline linking the Abadi platform to the Darwin LNG facility.

Table 1: Wood Mackenzie's Base Case Development Scenario for Abadi

Reserves(bcf)	Reserves (mmbbl)	Peak Prod'n ('000 b/d mmcfd year)	Capex without pipeline (US$m)	Capex with pipeline (US$m)	Opex (US$/boe
5000	75	11 715 2016	3000	4500	2.70

Source: Wood Mackenzie Pathfinder

What gas sales price is required?

In order to achieve an IRR of 12% for the upstream element of the Abadi development, we have calculated that based on the aforementioned development scenario, the upstream project will require the following price:

Table 2: Upstream gas price required for 12% IRR

	US$/mmbtu
Required upstream gas price for 12% IRR without pipeline	2.55
Required upstream gas price for 12% IRR including a pipeline to Darwin	4.41

Source: Wood Mackenzie Global Economic Model

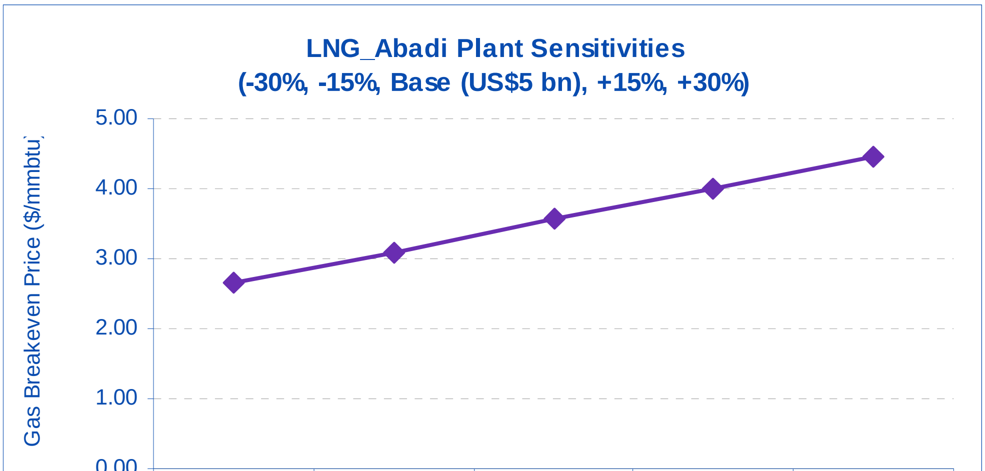
Liquids have been calculated at a 3% premium to Brent. Wood Mackenzie's Brent oil price assumption for 2007 is US$59.50/bbl, US$55.00/bbl in 2008, US$49.00/bbl in 2009, reverting to US$43.08/bbl in 2010 escalating at 2.5% from 2011 onwards. Discounted to 01/01/2008.

Based on the uncertainties surrounding the GTL, DME and methanol development options, we have focused our economic analysis on the LNG monetisation options.

To determine the LNG sales price required to generate a 12% return for the liquefaction plant, we have calculated a range of break even prices for a generic LNG facility based on the following assumptions:

- five mmtpa LNG plant with a base case capital cost of US$1000/tonne (US$5 billion) and an operating cost of US$0.22 per mmbtu
- The LNG facility is subject to a tax rate of 35% with an initial five year tax holiday. Capital costs are depreciated in a straight-line over a 20 year period

A breakeven analysis of the LNG plant has been carried out under five capital cost scenarios (base case of US$5 billion, -15%, -30%, +15% and +30%). This sensitivity analysis generated the following results: Note that this does not include the cost of the gas.



	-30%	-15%	0%	+15%	+30%
Capex	2.66	3.10	3.56	4.01	4.47

Source: Wood Mackenzie Global Economic Model

The range of LNG commercialisation options can be approximately aligned to these capex scenarios.

An expansion at Darwin will be lowest cost option for the liquefaction plant. The -30% capex case is an appropriate analogue for the brownfield expansion plant. On this basis, the full project breakeven price (discounted at 12%) is around US$7/mmbtu. This includes the upstream development with a pipeline to Darwin.

Due to the length of pipe required and the challenges associated with pipe laying, the cost of the upstream development with a pipeline across the Timor Trough to an Indonesian island is significantly higher than that for the Darwin option. In addition, a greenfield LNG project in Indonesia will cost significantly more than an expansion at Darwin where there will be synergies and hence cost savings. Using the base case liquefaction breakeven gas price, and taking into account the upstream development with pipe across the trench, the full project breakeven price for this development option will be in the region of US$10/mmbtu, assuming the pipeline cost will be double the cost of the pipeline to Darwin.

With a differential of US$1.86/mmbtu between the upstream solution with, and without a pipeline to Darwin, the floating solution on first look appears positive. However, while the technical and commercial challenges surrounding the floating solution are largely unknown they will be significant. The cost of the floating facility is highly uncertain with some estimates as high as US$2000/tonne. We believe that the lowest possible cost for the floating solution would be in the region of US$1,300/tonne. At US$1,300/tonne, the liquefaction plant would require a price of US$4.47/mmbtu as shown in the +30% case above. In addition to the breakeven price of the upstream development, this equates to just over US$7/mmbtu, roughly equivalent to the Darwin solution. However, the Darwin solution is based on proven development concepts and the risks, both commercially and operationally are significantly less. In addition, the reality is that the floating solution is likely to cost considerable more than our +30% case noted above.

Conclusion

Inpex's choice of partner will be critical and will, along with the GOI, influence potential development scenarios for the field. Potential partners could include ConocoPhillips who may look to protect its interests in other nearby Australian projects. Taking a stake in Abadi will allow it to exhert its influence over timings for development, should the gas be allowed to supply a Darwin plant expansion. Alternatively, Total may strenghten its existing partnership with Inpex in Indonesia and build on its recent acquisition of an interest in the Ichthys project. Shell has also been accumlating acreage nearby and has significant LNG experience and technical capabilities which could push forward a FLNG scenario.

It is clear that the GOI is eager for Abadi to be developed within Indonesian waters and as a result, it may be some time before a solution is found to suit all interested parties, and before first gas is seen from Abadi. Indeed, the most economic option, based on our analysis, would be to pipe the gas to facilities at Darwin in Australia and this may well be the only viable economic option available. However, even the economics to Darwin look marginal and Inpex are considering options outside of LNG, including floating methanol, GTL and DME. We consider that it is too early to make a decision on the most appropriate development concept or indeed, rule out potential options.

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