CARNARVON PETROLEUM LTD (CVN)

Mining for Gas in the Bedout Sub-basin
Post recent drilling success, Carnarvon (“CVN”) (along with AWE.asx) is now one of the largest ‘independent’ owners of uncontracted gas in Western Australia. Having retained the rights to market the gas independently, this makes them an appealing target for a number of large domestic gas users. Add in a continued gas shortage in WA (which will become a crisis post 2026) and a very high liquids content in the Bedout Sub-basin, the takeover potential is compelling (especially for a mid to large mining operation). Unfortunately, to date the market continues to value CVN as a dry gas play, with commercialisation hostage to Quadrant’s broader portfolio requirements. This we believe is incorrect, and makes for an appealing investment opportunity, at the current share price the discovered gas has a value close to zero.

1: Not a dry gas play, liquids alone pay for the development
We believe CVN’s lacklustre share price performance is due to it being valued as a dry gas play. The Company has presented the dry gas Reindeer field as an analogous development in recent presentations, we believe Reindeer is not fully comparable. Reindeer had relatively poor economics and it is the liquids in a potential CVN development that is a key differentiator. In fact, the liquids component is so high the liquids cash flow comes close to paying for the whole development (the gas gets produced for free!). See Key Chart.

2: Continued gas shortage and marketing their own gas
A debate is raging between Australian Energy Market Operator (“AEMO”) and various independent consultants on whether WA will face a gas crisis next decade. We find the argument amusing, as WA consumers have been facing a gas crisis for a decade already, the market is inadequately supplied with reasonably priced gas.

3: Further upside beyond Roc/Phoenix/Phoenix South
The Bedout Sub-basin may prove to be a one off unique play in the context of the broader Roebuck Basin (source issues), however Sub-basin targets alone such as Dorado can still add considerably to the development potential. None of this future optionality seems factored into CVN’s current share price.

Source: Hartleys Research

Key Chart: NPV10 of Liquids only at various oil prices (P/PS/Roc development)

Source: Hartleys Research
SUMMARY MODEL

Carnarvon Petroleum

CVN

Share Price

$0.09

Key Market Information

Share Price

$0.09

Market Capitalisation

$98m

Current Cash est. (ex-royalty)

$60m

Issued Capital

1021.1m

ITM options

0.3m

Options

1.0m

Issued Capital (fully diluted ITM options)

1022.1m

Issued Capital (fully diluted all options)

1022.1m

EV

$35.1m

12Mth Price Target

$0.24

Projects

Project

Operator

CVN Interest

WA-435-P

Greater Phoenix

Quadrant Energy

20%

WA-437-P

Greater Phoenix

Quadrant Energy

20%

WA-436-P

Greater Phoenix

Quadrant Energy

30%

WA-438-P

Greater Phoenix

Quadrant Energy

30%

WA-521-P

Greater Phoenix

CVN

100%

WA-623-P

Buffalo

CVN

100%

WA-624-P

Muaraca

CVN

100%

WA-156-P(1)

Outtrim East

CVN

28.5%

BP-493

Cortebus

CVN

100%

EP-491

Cortebus

CVN

100%

EP-475

Cortebus

CVN

100%

TP-27

Cortebus

CVN

100%

Valuation Summary

AS m

Ac/share

Phoenix/South Phoenix/Rec Liquids

0

0.00

Phoenix/South Phoenix/Rec Gas

122

0.12

Other discovered

5

0.01

Exploration

51

0.08

Farm Cuts

0

0.00

Post Assn/ Safe Cont. Payments

0

0.00

Thai Royalty Stream

13

0.02

Cash less 1 yr spend

11

0.01

Sub-total

212

0.24

CVN.asx

Speculative Buy

Directors

Peter Leonardt

Chairman

Adrian Cook

Managing Director

Bill Foster

Non-executive Director

Dr Peter Moore

Non-executive Director

Substantial Shareholders

No substantial shareholders

Investment Summary

Carnarvon Petroleum (CVN) is a conventional oil & gas explorer with key assets off-shore north-west Australia. The company and its JV partner(s) have drilled 4 out of 4 successful E&A wells in the Greater Phoenix area (CVN 20% interest). The discovered resource now exceeds economic threshold levels (subject to South Phoenix testing). Very large follow up targets such as Dorado-1 could add considerably to scale of the development.

Expected News flow

2H17 Dorado-1 w ell

1H18 Phoenix South-3 well

Quarterly Cash Flow

FY16

FY17

3Q

4Q

1Q

2Q

Cash (Beginning)

100.0

95.5

87.7

65.1

A$m

Operating Cash flow

-2.9

0.0

0.0

0.0

Exploration/Development

0.0

-0.5

-2.0

-7.8

Corporate overheads

1.9

-0.0

-1.1

-0.7

Other

-4.4

2.5

-1.2

3.3

Cash (End)

95.5

87.7

65.1

58.9

Analysis: Aidan Bradley

Phone: 618 9263 2875

Sources: IRESS, Company Information, Hartleys Research

Last Updated: 12/04/2017
HIGHLIGHTS

We believe that CVN is being valued incorrectly by the market, as a potential medium sized dry gas development.

Reindeer is a useful analogy in terms of water depth, distance to infrastructure etc., but we believe Reindeer cannot be used as a direct comparison as this would potentially understate the potential value of CVN’s resource.

**Fig. 1: Reindeer gas field an analogy for Roc?**

<table>
<thead>
<tr>
<th>Resource (million boe)</th>
<th>Reindeer²</th>
<th>Roc¹</th>
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<tbody>
<tr>
<td>Revenue</td>
<td>US$3.4 bn</td>
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</tr>
<tr>
<td>Development and abandonment costs</td>
<td>(US$1.4 bn)</td>
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<tr>
<td>Operating costs</td>
<td>(US$0.5 bn)</td>
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<tr>
<td>Petroleum resource rent tax</td>
<td>(US$0.2 bn)</td>
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<tr>
<td>Cash flow before income tax</td>
<td>US$1.3 bn</td>
<td>(US$15/boe)</td>
</tr>
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</table>

Financial figures are gross, nominal amounts

Source: CVN

Discoveries to date (especially Phoenix South Caley) have contained a very high liquids content and is a game changer in terms of the economics of any potential development in the Sub-basin and a huge differentiator in comparison to the relatively poor economics of a dry gas field such as Reindeer.

**Fig. 2: Offshore Development Costs $/GJ of 2P Reserves**

Source: EnergyQuest
Reindeer required an outstanding gas contract from CITIC to underpin its development. Even so we calculate its NPV10 from start of development still to be negative.

**Fig. 3:** NPV of Reindeer Gas Field

Source: Hartleys Research

Applying Reindeer as a direct benchmark may help explain why CVN’s share price performance remains so lack lustre post the outstanding drilling success it has had. The key differentiator for CVN is the high liquids content of its gas, an economics game changer. We do note that the gas and liquids potential of the Caley Sandstone in the Phoenix South discovery has yet to be fully proven.

**Fig. 4:** Liquids content Phoenix/South Phoenix and Roc

Source: Hartleys Research

In fact, the liquids component is so high the liquids cash flow comes close to paying for the whole development (the gas gets produced for free!).
Fig. 5:  NPV10 of Liquids only at various oil prices (P/PS/Roc development)

A second factor potentially behind the lacklustre share performance is that CVN is a smallish minority partner (20%) in a JV with the dominant (non-LNG) gas producer in WA, Quadrant Energy. There may be concerns that CVN will become hostage to Quadrant’s broader development plans and the Bedout Sub-basin discoveries are pushed down the development queue. However, a number of key projects underpinning Quadrant’s existing reserves and supply contracts are set to deplete middle of next decade and its recent exploration efforts have had mixed success. In fact, the Bedout Sub-basin has the potential to be the foundation asset* for Quadrant’s ongoing supply efforts next decade (*requires proving up of Caley resource in South Phoenix and/or Dorado discovery to place it top of the development queue).

Post drilling success at Roc and Phoenix South, Carnarvon (along with AWE.asx) is now one of the largest ‘independent’ owners of uncontracted gas in Western Australia. Having retained the rights to market the gas independently this alone makes it an appealing target for a number of large domestic gas users. Add in a continued gas shortage in WA (which will become a crisis post 2026) and a very high liquids content in the Bedout Sub-basin, the takeover potential is compelling (especially for a mid to large mining operation).

In the following chart, we highlight the implied acquisition gas price to a potential acquirer at various cash payments to CVN for its stake in Roc/Phoenix and South Phoenix only (assumes liquids content as before covers cost of development – i.e. NPV10 close to zero at a US$60/bbl long run oil price). The implied price of the gas would obviously fall or rise if oil prices are above or below US$60/bbl respectively, and/or the actual cost of funding the development is below or above the standardised 10% we used in our modelling.
Most mid to large gas users (or potential users as gas has not been easily accessible) in WA would jump over backwards to secure potentially 200bcf of gas at a price sub $3/GJ. However, that is exactly what you get in CVN if you pay < $250m or less (subject to Phoenix South-3 proving the recoverable gas and condensate as outlined in Figure 4). In our valuation of CVN we assume acquisition interest at the attractive implied price of $1.50/GJ level, this would likely rise post a successful appraisal with South Phoenix-3. CVN’s gas is also ideally located to supply this low-cost gas to existing customers at Karratha or Port Headland or supply new customers as far north as Broome.
This valuation alone excludes other exploration potential in the Bedout Sub-basin (including the large Dorado prospect) and play fairway extension into the Rowley Sub-basin (which we remain more sceptical on). Beyond the Roebuck Basin, CVN has used its experience here to build a portfolio of interesting potential farm out opportunities. While a gas consumer may not be interested in the exploration portfolio, it is potential additional value we believe is also not captured in the current CVN share price.
### Fig. 9: CVN Contingent and Prospective Resource

<table>
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<tr>
<th>Field</th>
<th>Reservoir Interval</th>
<th>Hydrocarbon</th>
<th>Contingent Resources</th>
<th>Prospective Resource</th>
<th>PoGS</th>
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<td></td>
<td></td>
<td></td>
<td>1C</td>
<td>2C</td>
<td>3C</td>
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<td>Roc</td>
<td>Lower Keaastren - Caley Sst</td>
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Source: CVN
Conclusion

To date we believe the the market continues to value Carnarvon ("CVN") as a dry gas play, with commercialisation hostage to Quadrant’s broader portfolio requirements. This is incorrect, and makes for an appealing investment opportunity.

In our valuation of 24c per share for CVN we make the following assumption;

- Successful appraisal of Phoenix South with the PS-3 well.

- For a relatively small company such as CVN, management recognise the potential benefit of selling the pre-development discovered resource to a larger user with a much lower cost of capital, rather than trying to develop the asset itself. The latter route is rarely the most rewarding for investors in small junior explorers.

- Larger gas users recognise the obvious potential in the Roc/Phoenix/Phoenix South discovery through CVN retaining the marketing rights to the gas and the high liquids content subsidising the full field development (at circa US$60/bbl oil).

- Gas user acquires CVN’s 20% stake in these discoveries for an implied gas price (to them) of A$1.50/GJ. Implies a cash payment to CVN of $122m.

- If a potential sale includes the unexplored prospects in the 4 Bedout sub basin licenses, then we would expect any transaction to either put a value on this potential resource up front, or as is more likely at the moment contain future contingency payments or a royalty to the seller upon attaining future milestones such as reserve upgrades or additional discoveries. We have seen such deal structures recently in transactions involving Exxon/Oil Search and Interoil in PNG where the blue-sky potential of the acreage changing hands is difficult currently to put a definitive value on. To be conservative we do not include any value for this potential in our current CVN valuation.

- We additionally include very little value for the large identified prospective resource beyond the Roc/Phoenix and Phoenix South discoveries. We value this net 164mmboe in the Bedout Sub-basin (now a proven oil and gas play with prospects such as Dorado on trend and in close proximity to a large discovered resource) at just $61m. A large discount to the EV per prospective resource of other listed WA/Perth Basin listed gas players.

- Finally, we also include no value for potential farm outs of Maraca, Buffalo, Cerberus and WA-521-P, all have some merit and are currently 100% leased by CVN.

- If there are any interested parties in doing a deal for CVN’s gas (and there surely are, AWE recently indicated there was indicated customer demand for their Waitsia gas greater than double the JV’s current 2P resource (which is currently 344Bcf)) then it would be a high-risk strategy for it to wait until after the Dorado exploration well in 2H17. So, we see an approach to CVN for its gas as highly likely in the next 6 to 12 months.
Fig. 10: Timing - Phoenix South-3 and Dorado resource potential

Source: Various

Fig. 11: CVN Valuation

<table>
<thead>
<tr>
<th>Asset</th>
<th>Type</th>
<th>WI</th>
<th>Gross mmboe</th>
<th>NPV/boe US$</th>
<th>Net Risked Value A$m</th>
<th>A$Share</th>
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<tbody>
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Source: Hartleys Research

Fig. 12: Key assumptions and risks for valuation

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<th>Assumption</th>
<th>Risk of not realising assumption</th>
<th>Downside risk to valuation if assumption is incorrect</th>
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<td>Low</td>
<td>High</td>
<td>Post the success of Roc and initial results from Phoenix South we now view a commercial gas development in the Bedout Sub-basin as highly likely. As a result, we expect there to be significant interest in CVN’s potential 20% stake in the project from a range of large gas users. In our valuation, we currently assume a conservative $122m valuation based on the likely transaction price a gas user would be willing to pay.</td>
</tr>
<tr>
<td>Successful appraisal of Phoenix South</td>
<td>Low</td>
<td>Moderate</td>
<td>CVN failed to fully test the Phoenix South Caley reservoir with Phoenix South-2. As a result, a further well (PS-3) will be required to firm up the resource. While there is some risk associated with every well, the key risk here is that the prospective resource is not as large as currently predicted by the company. In could in fact turn out to be larger, so there is upside risk as well.</td>
</tr>
<tr>
<td>Upside beyond Roc and Phoenix South</td>
<td>Medium</td>
<td>Low</td>
<td>We have included very little value for upside beyond what we see as the core Roc / Phoenix / Phoenix South development hub. So, large targets such as Dorado if they fail would individually have limited impact on our valuation, while offering significant upside in a success</td>
</tr>
</tbody>
</table>
We have included zero value for potential farm outs of acreage beyond the Bedout Sub-basin, although we view these positions as each having merit. While CVN has written down fully the value of their Thai Royalty, the recent rise in oil prices and our more positive longer term oil price outlook does in our opinion warrant including a modest value for this royalty.

Offshore exploration remains an expensive business even in this currently deflated oil environment. Wells in the Roebuck Basin for CVN and its JV partner can cost between US$50-80m gross. CVN had $60m in cash at the end of the last quarter, however this could fall below $15m by middle of next year (depending on the drilling programme). Securing sufficient capital to continue to participate in the JV is a risk, but given the attractiveness of the acreage it is the cost of this capital and not whether CVN can access it that is the key risk.

We believe that post the drilling results at Roc and Phoenix South, there is likely to be a commercial development in the Bedout Sub-basin. Future testing at Phoenix South and exploration at Dorado will determine the size, timing and value of the development. CVN remains to a certain degree hostage to Quadrants plans for the gas, but we believe it is towards the top of Quadrants queue to develop. Given the continued gas shortage in WA, we expect a major gas user to be interested in acquiring CVN’s equity interest in the development (when it is adequately de-risked). This will remove any concerns about how CVN can fund a development.

The key risks for Carnarvon Petroleum Ltd (like most junior oil & gas companies) is a combination of exploration success and performance of the production assets (if any). Other risks are earnings disappointments given the industry is volatile and earnings can disappoint due to cost overruns, project delays, cost inflation, environmental regulations, resource estimate errors. Although some disappointments can be short term and are only a timing issue, other disappointments can be materially value destructive and can sometimes overhang stocks for a long period of time (for example over-estimating long term flow rates). Such disappointments can be very difficult to predict and share price reactions can be severe and immediate upon disclosure by the company. High financial leverage (if it exists at that time) would add to the problem. Investing in explorers is very risky given the value of the company (exploration value) in essence assumes that the market will recognise a portion of potential value before the results of an exploration program are known, conscious that the ultimate chance of success is low (typically 1%-20%) and that failure is much more likely, in most cases.
MINING FOR GAS IN THE BEDOUT SUB BASIN

As outlined earlier we believe the exploration success to date in the Bedout Sub-basin will have attracted the attention of a number of medium and larger gas consumers in Northern West Australia.

Thought of initially as a prospective new oil play (with the Phoenix South-1 discovery in the Barrett Sandstone) the focus has shifted through the successful drilling of the deeper Caley Sandstone to its potential as a very large wet gas resource.

Success to date has almost guaranteed that a commercial development will proceed in the Bedout Sub-basin. The only question is how large will it be and as a consequence of this when will it be developed (size will likely determine where it fits in Quadrant’s queue of priorities).

To try and answer this question we take a look back at the history of the Sub-basin and broader Roebuck Basin to see how a potential multi TCF wet gas fairway was missed just 185km offshore Port Headland.

The Bedout Sub-basin is part of the broader Roebuck basin which along with the highly prospective Northern Carnarvon, Browse and Northern Bonaparte Basins forms the Westralian Superbasin.

Fig. 13: Location of the Roebuck Basin

Source: Hocking et al.
However, unlike the other 3 basins, the Roebuck Basin is very lightly drilled, as a result of a succession of failed wells.

**Fig. 14: Roebuck Basin - Lightly drilled**

A study of the old wells drilled in the basin highlight two key reasons for the failures, a lack of source rock across the basin and potential trap issues in the deeper Rowley Sub-basin. The Roebuck Basin lacks the thick marine Upper Jurassic source rocks that are found in the Northern Carnarvon Basin to the southwest.

Potential deeper Triassic source rocks had been intersected in wells drilled in the Bedout Sub-basin and on the Bedout High, and it was this potential that attracted CVN and partners back to the basin.

A second cause of failure seemed to be that the major, trap-forming structural events preceded the main phase of hydrocarbon generation and migration. However, this now seems to be potential a greater risk for the deeper Rowley Sub-basin than the Bedout.
Fig. 15: Basin well objectives and failure analysis

<table>
<thead>
<tr>
<th>Well</th>
<th>Spud date/operator</th>
<th>Water depth (m)</th>
<th>T.D. depth and age</th>
<th>Objectives</th>
<th>Hydrocarbons</th>
<th>Structure validity</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bedout-1</td>
<td>1971 Bexel</td>
<td>578</td>
<td>N.W.</td>
<td>Late Triassic sands in anticlinal dome with 4 way dip closure</td>
<td>None</td>
<td>Vioscous injected at base, призна good quality reservoir, but poor main seal (weakly).</td>
<td></td>
</tr>
<tr>
<td>East normad-1</td>
<td>1973 Shell</td>
<td>420</td>
<td>E. Jurassic</td>
<td>Upper and Middle Jurassic sands within an anticlinal feature</td>
<td>Gas show in Jurassic closure</td>
<td>Minor source rocks around T.D., but structure is young (Missourian to Recent).</td>
<td></td>
</tr>
<tr>
<td>Keraudren-1</td>
<td>1973 Nettance</td>
<td>344</td>
<td>M. Triassic</td>
<td>Middle Triassic and Jurassic sands in north tilting fault block</td>
<td>None</td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>L SZ 1</td>
<td>1970 Bexel</td>
<td>63</td>
<td>L. Carb</td>
<td>Dip closed hanging wall anticline</td>
<td>None</td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>Lagrange-1</td>
<td>1970 BP</td>
<td>147</td>
<td>L. Permian</td>
<td>Late Triassic sands in anticlinal dome with 4 way dip closure</td>
<td>Minor gas shows</td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>Lyshor-1</td>
<td>1971 Bexel</td>
<td>58</td>
<td>W. Permian</td>
<td>Jurassic sands within a hanging wall anticline</td>
<td>None</td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>Minjep-1</td>
<td>1974 Bexel</td>
<td>146</td>
<td>Jurassic</td>
<td>Fault bounded anticline</td>
<td>Minor gas shows</td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>MTJH-1</td>
<td>1984 Eino</td>
<td>1855</td>
<td>Devonian</td>
<td>None</td>
<td>None</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Neb-1</td>
<td>1991 Kupes</td>
<td>3132</td>
<td>M. Jurassic</td>
<td>Middle Jurassic sands in faulted anticlinal structures</td>
<td>Oil 1844</td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>Pounch-1</td>
<td>1983 Bexel</td>
<td>2420</td>
<td>E. Carb</td>
<td>Fault bounded anticline</td>
<td>None</td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>Portis-1</td>
<td>1983 Eino</td>
<td>1887</td>
<td>Devonian</td>
<td>PermCar in a closed fault associated with igneous intrusion</td>
<td>Oil shows in PermCar</td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>Phoenix-1</td>
<td>1980 BP</td>
<td>860</td>
<td>Triassic</td>
<td>Mid-Late Triassic set in fault bounded anticlinal structure</td>
<td>Fault shows in Triassic</td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>Phoenix-2</td>
<td>1982 BP</td>
<td>140</td>
<td>Triassic</td>
<td>Middle Triassic set in fault bounded anticlinal structure</td>
<td>Minor gas shows</td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>Wana-1</td>
<td>1973 ANX</td>
<td>2716</td>
<td>E. Carb</td>
<td>Devonian carbonates in partly fault controlled feature on basement high</td>
<td>None</td>
<td>None</td>
<td></td>
</tr>
</tbody>
</table>

Source: DMP

Unlike wells in the deeper parts of the basin, indicators from Bedout wells such as Phoenix-1 and Keraudren-1 in the 1970’s and early 80’s that drilled into the Triassic rocks enticed with gas and even oil shows in either poor structures or reservoir.
The source was there, it was just about finding the reservoir and structures. Hence the motivation for CVN and partners to revisit the Sub-basin in 2014 with the Phoenix South-1 well. The JV initially thought they were targeting a tight reservoir gas target.

The Locker Shale in Phoenix 1, Phoenix 2 and Keraudren 1 exhibited oil- and gas-prone source rock facies (Smith et al, 1999). The Locker Shale is in part age equivalent to the Kockatea Shale in the northern Perth Basin.

Fig. 16: Source rock indicators from prior basin wells

![Diagram showing stratigraphic columns and age equivalence](image-url)
Fig. 17: Petroleum Systems – Rowley and Bedout Sub Basins

Source: DMP
The following Figure 17 highlights the approximate location of the Phoenix South-1 discovery relative to the outline of the 'ancient' coastline.

**Fig. 18: Outline of ancient coastline**

The primary exploration targets in the basin are Lower to Middle Jurassic and deltaic-fluvial sandstones of the Depuch Formation and the Middle to Late Triassic fluvial sandstones of the Keraudren Formation.
So, what has turned around performance in the Roebuck Basin?

The key to the recent successes in the Bedout Sub-basin have been two-fold. Firstly, the now proven quality of the lower Triassic source rocks in this portion of the basin at least.

The oil column in the lower Keraudren Formation at Phoenix 1, the oil discovery at Phoenix South 1, and the gas discovery at Roc 1, are thought to have been charged from source rocks ‘within’ the Lower Triassic lower Keraudren Formation and possibly the Locker Shale (Pedley et al, 2015; Molyneux et al, 2015; Thomson et al, 2015).
But perhaps the real game changer was lifting the concerns about discovering high quality reservoirs through the drilling and subsequent testing of the Caley Sandstone.

**Fig. 21: Cross sectional Maps Bedout Sub-Basin**

Deep sections of the lower Kerauden Formation exist in the Bedout and Rowley Sub Basins. However, as flagged earlier concerns existed about the quality of the reservoir in the Barrett Sandstone.
It was the testing of the underlying Caley Sandstone with the Roc-2 well that changed the outlook for the Sub-basin. The controlled flow test on Roc-2 flowed at 51.2mmcf/d and 2,943 boe/d of condensate. Comparable to the best wells in the North West Shelf.

As a result, the Caley formation naturally became the principal reservoir target in the Sub-basin and was revisited by the Phoenix South-2 well, but unfortunately due to higher than expected reservoir pressures a full test could not be completed. However, the technical work that could be completed was still sufficient to underpin a resource upgrade for Phoenix South Caley, including upgrading the liquids component to a 56.8mmbbl mean prospective gross resource.
So far so good. Unfortunately, however the Roebuck Basin still has its challenges. While good source rock has now been proven in the Bedout Sub-basin (the Lower to Middle Triassic transgressive marine shales of the Locker Shale and the overlying Middle Triassic lower Keraudren Formation), concerns remain about similar in the broader Roebuck Basin.
Of the 10 wells drilled in the Rowley Sub-basin, (four were testing the East Mermaid structure in 1973 which had gas shows in the Jurassic (see Figure 14), but not the CVN Triassic play.

Woodside drilled Whitetail-1 (2003), and Huntsman-1 (2006) neither of which encountered hydrocarbons.

In 2014 Woodside drilled three deep-water wells in the Rowley Sub-basin - Hannover South-1, Steel Dragon-1 and Anhalt-1, targets were believed to be both Triassic-age and deeper Paleozoic-age reservoirs. All three were dry holes, and they and partner Shell walked away from their remaining 5 well commitment. Unlike results in the Bedout Sub-basin, Anhalt-1, ‘did not’ confirm the presence of Lower Triassic source rocks.

CVN has taken a block (WA-521-P) in the Rowley Sub-basin closer to shore, the location of the 2003 Woodside Whitetail-1 well. Whitetail-1 spudded in January 2003 and reached a total depth of 2504m in sandstones belonging to the Middle Jurassic Legendre Formation. The objective Legendre Formation reservoir sandstones were encountered water wet at 2362m. Huntsman-1 was drilled outside WA-521-P.

Finder Exploration, one of the key players in the recent success of the Bedout Sub-basin have outlined their own estimations for the potential extent of the oil and gas kitchens in the Basin (which don’t extend into the Rowley Sub-basin).
Pathfinder Energy who we believe are still trying to secure a farm out deal for their blocks to the North East of South Phoenix / Roc, in comparison believes the Keraudren Play extends into their WA-479-P and WA-487-P licenses as outlined in Figures 27 and 28. The East Mermaid-1 well on the boundary of both blocks did not test this Triassic play.
CVN’s WA-521-P is to the North West of Phoenix South and CVN (100%) will also be seeking a farm out deal. CVN is hopeful given there is no oil prone Lockyer Shale there is source in the Keraudren formations and overlying Jurassic, which obviously from prior results remains a key risk (i.e. the lack of hydrocarbon shows in wells on the Bedout High (Bedout-1 and Lagrange-1) and within the Rowley Sub-basin (Anhalt-1, Steel Dragon-1, Hannover South-1, East Mermaid-1, Whitetail-1 and Huntsman-1). Basin modelling (O’Brien et al, 2003) does indicate that the known Lower Triassic source rocks in the Bedout Sub-basin may be
presently expelling hydrocarbon liquids in the outer Rowley Sub-basin and on the flanks of the Bedout High, offering some hope for WA-351-P and Bedout High targets such as Bandy (see Figures 19 and 30).

Fig. 30: **Bedout versus Rowley Sub Basins**

Source: DMP
Fig. 31:  Rowley Sub Basin – WA-521-P

Source: CVN
Given the evidence to date we remain sceptical about the potential of the broader Roebuck Basin beyond the very unique conditions in the Bedout Sub-basin. Luckily for CVN and Quadrant there is considerable prospect runway in the Sub-basin for them to pursue.

Exploration Catalyst #1: Phoenix South-3

The most important well for CVN and Quadrant to drill will be Phoenix South-3, the testing of the Caley Sandstone that Phoenix South-2 failed to fully test because of the overpressure conditions encountered. As outlined earlier the testing that was able to be completed did result in a significant resource upgrade, most importantly to the liquids component. Assuming Phoenix South-3 (1H18) confirms these expectations, we outlined earlier the economics of a potential wet gas development of this size (i.e. liquids cover the cost of development at US$60/bbl oil prices and the gas component we currently value at $122m net to CVN (our base case assumes this is achieved through a transaction with a Miner or other large domestic gas user)).

Phoenix South-2 testing also suggested there could be a stratigraphic component to the Caley structure which could again materially increase the current reported resource size further, see Figures 9 & 33.
Exploration Catalyst #2: Dorado

The next well the JV is planning to drill is the ‘giant’ Dorado prospect, see Figure 9. Success at Roc, Phoenix and potentially Phoenix South would possibly provide the JV with a TCF of gas and over a hundred million barrels of condensate. Success at Dorado Caley would increase this further by upwards of 50%. Hydrocarbon shows encountered in the underlying Milne Sandstone while drilling Roc-1 and Roc-2 has also offered up the potential for a large multi-TCF resource within this formation. This formation however remains unproven and untested.
Fig. 35: **Key Well 2: Dorado – large structure on trend with Roc**

![Map showing Dorado Prospect with Roc structure on trend]

Source: CVN

Fig. 36: **Key Well 2: Dorado – Caley and Milne potential**

![Bar chart showing volumes below in mmboe]

All volumes below are mmboe – net to Carnarvon – 2C or Pmean as applicable

1 – Roc Caley 2C: 15.6 mmboe
2 – Roc Caley Pmean: 5.6 mmboe
3 – Phoenix South Barrett 2C: 4.8 mmboe
4 – Phoenix South Caley Pmean: 21.5 mmboe
5 – Phoenix South Hove Pmean: 16.9 mmboe
6 – Dorado Caley Pmean: 25.4 mmboe
7 – Dorado Milne Pmean: 92.8 mmboe
8 – Roc Satellites, Phoenix, Beudy, Bottler, Peng, West of PS Pmean: 42.3 mmboe

Source: CVN
Fig. 37: **Dorado – Trap the key risk**

Roc-2 flow test 2016

Source: CVN

Exploration Catalyst #3: Rowley Sub-basin farm out (extension of Bedout play)

We outline earlier the main exploration risks inherent in the Rowley Sub-basin and hence the likelihood of the Bedout Sub-basin success extending into CVN’s WA-521-P block. So, for now we remain sceptical, but the industry had been wrong on the Bedout, so we remain open to another surprise!

Fig. 38: **WA-521-P – Rowley Sub Basin**

Source: CVN
Exploration Catalyst #4: Commercialising acreage beyond the Phoenix project.

Beyond the Bedout Sub-basin CVN has a number of potential exciting opportunities. The Outtrim East-1 oil discovery was targeting oil in the Pyrenees Member. The pre-drill expectation was to discover sufficient recoverable oil that when combined with other regional discoveries (Blencathra-1 and Corowa-1) would be sufficient to underpin an economic development (estimated by CVN to be recoverable oil in the 13-15mmbbl range). CVN and their partner Quadrant have not finalised their study of this discovery and integrated development, with the focus naturally on the success of the Bedout acreage.

The company is also actively seeking a farm out for their 100% owned Buffalo, Cerberus and Maracas acreage, all of which have some merit.

Cerberus – Triassic source rocks analogous to proven oil-proven source rocks at Phoenix, Roc and the Perth Basin

Buffalo – immediately East of the giant Bayu-Undan gas condensate field. The block contains the depleted 20mmbbl Buffalo oil field and the undeveloped oil discoveries in the Bluff-1 and Buller-1 wells.

Maracas – Following up success of early Triassic play types in the Bedout Sub-basin, WA-425-P has the potential for a similar pre-Jurassic play on the flanks of the Dampier Barrow Sub-basin

However, for now we include no value for this potential deal making in our current valuation.
Fig. 40: CVN Portfolio

Source: CVN
GAS MARKET – FUTURE DEFICIT OR SURPLUS?
A debate is raging between AEMO and various independent consultants on whether WA will face a gas crisis next decade. We find the argument amusing, as WA consumers have been facing a gas crisis for a decade already, the market has been inadequately supplied with reasonably priced gas for a long time. The result is that gas consumption in Western Australia has been capped.

Current Overview of the WA Gas Market and conflicting outlooks

Fig. 41: WA Gas Market – Current Production, Pipeline and Storage Capacity

- WA supply has been dominated for two decades by gas from the NWS through the Karratha Gas plant. This provided the cheap baseload supply to the Ammonia, Alumina and other minerals processing sectors, which combined make up close to 40% of the States gas consumption

- Growing demand for gas (and electricity) from the less price sensitive mining sector has been largely supplied by gas operated by Quadrant (the ex-Apache Australia) through their two processing facilities at Varanus Island and Devils Creek and also BHP through their Macedon facility.

- Gorgon and Wheatstone will in the future to a large extend replace the NWS whose original domestic gas obligations are ending.

Fig. 42: Gas production by facility

Source: GBB
The vast majority of WA’s gas currently is produced from the North West Shelf and is initially delivered to market through the Dampier, Pilbara and Karratha access pipelines.

**Fig. 43: Current WA gas market balance**

WA gas supply is therefore obviously highly concentrated. However, the most surprising feature of the WA gas market is also how concentrated gas demand is by user and industry. Retail and other small industrial users make up less than 10% of total consumption. We believe close to 80% of end users (either direct gas or gas fired electricity generation) are in the mining and minerals processing sectors (Ammonia manufacturing makes up a further 10-11%).

**Fig. 44: Gas consumption by region**

Source: GBB
Carnarvon in their recent corporate presentations have outlined the looming gas market deficit. The AEMO however, have changed their view between the November 2015 and December 2016 GSOO reports.

Source: ACIL Allen

Source: CVN
Fig. 47: November 2015 – rising prices expected post 2021

The AEMO in their latest analysis now believes (along with the Major offshore gas producers such as Woodside, Chevron etc.) that the gas market will now be adequately supplied post 2020.

Fig. 48: December 2016 - WA gas market AEMO Gas supply versus Demand

As a result, the AEMO downgraded the long run domestic gas price forecast as outlined in Figure 43 below, with the AEMO now siding with the large offshore LNG producers in predicting ample supply post 2020.
This view conflicts with various independent consultants who either forecasts a growing supply deficit.

..or others who forecast enough supply to meet continued slow rates of growth in demand. However in our opinion the sources of this supply growth remains highly uncertain and risky (Gorgon Phase 2, Canning Basin etc.)
As mentioned previously we find the argument about whether we are entering a gas crisis as amusing, as WA consumers have been facing a gas crisis for a decade already, the market has been inadequately supplied with reasonably priced gas for a long time. The result is that gas consumption in Western Australia has been capped.

We believe as a result of this shortage gas consumption particularly from the mining sector has not been able to reach the level of true underlying demand. What spare gas there was available was controlled by the Oil Majors and/or ring fenced for LNG export. This should make the gas now discovered by smaller independents such as AWE and CVN particularly attractive to large miners wishing to save costs and wean themselves of diesel (the latter been the main beneficiary of the gas shortage as the huge margins earned by fuel retailers in the past decade would testify to – see the results of Caltex over the number of past years as evidence of this).

The WA domestic gas market has been an inefficient market since the mid 1980’s. Prior to the start-up of the North West Shelf, the WA gas market was a very small market with circa 100TJ/d of onshore production supplying the local manufacturing sector. The start-up of the North West Shelf and the Government enforced 15% reservation policy revolutionised the market (and created almost 600TJ/s of what we would describe artificially low priced gas). This cheap gas allowed the development of domestic gas power generation, minerals processing, a chemicals sector and gas for residential usage.

So, for almost 20-25 years the WA gas market was in structural oversupply, resulting in two decades of ‘artificially’ low prices, which over time only slowly stimulated demand. Two decades that can be categorised as a ‘demand crisis’.
As a result of these low prices, investment in domestic gas exploration was muted, allowing demand to slowly catch up with supply.

Source: APPEA, BREE, GoWA, SKM
The mining development boom since 2004 started to bring the market back into balance. The Varanus Island explosion in 2008 pushed the market into deficit.

The market has been in a structural deficit since as we will see below, resulting in the actual consumption of gas being significantly below the underlying demand requirements of consumers (forcing them to either lower energy throughput and/or seek alternatives, diesel being the main beneficiary). See Figure 55 for the DMP’s forecast of future demand from 2009 versus what actual demand occurred due to the lack of reasonably priced gas (we would argue that reasonable is in the A$6-8/GJ range – sufficient to provide a reasonable return to multi hundred bcf offshore projects and any sized onshore project in the Perth Basin, while being cheaper than alternatives such as diesel for consumers).

Potential demand in 2017 will likely undershoot actual consumption by 600-700TJ/d, mostly from the mining sector. While a proportion of this ‘undershooting’ is likely explained by overly optimistic assumptions on new projects etc. by the DMP, we still...
estimate (based on diesel consumption growth by the mining sector etc. over the past decade that realistically somewhere between 200-270TJ/d of potential demand was choked and failed to materialise because of the lack of available supply.

**Fig. 56: Forecast supply and DMP natural gas consumption (TJ/d)**

Source: DMP 2009

The WA gas market having experienced a Demand Crisis for twenty years from the mid 1980’s has now spent the last 10 years in a severe Supply Crisis. The latter has been due to a number of factors including – too much gas being sold to uncompetitive industries, subsidised by poor policy (reservation policy when combined with weak retention lease licensing), the boom in LNG exports, LNG projects with marginal economics (i.e. no domestic gas from Pluto, declining input to the NWS etc.).

**Fig. 57: Export versus Onshore Supply Growth**

Source: AWE
Unfortunately, we are not optimistic these market inefficiencies will be corrected anytime soon, making the low-cost gas resource owned by smaller independents such as CVN (low cost due to the liquids content) and AWE (low cost onshore) extremely attractive to large energy users in the Mining sector. These users have two options, continue to rely on 3rd parties to provide them the supply in an environment of poor regulations and competing export routes (obviously risky) or move upstream and secure the gas for themselves and control the supply and cost (which Alcoa in WA has been very active on – deals with EGO, BRU, TSV and Quadrant over recent years, if not always successful).

Given similar gas market dynamics in both East and West Coast Australia we have no sympathy at all for gas consumers who find themselves now short supply by relying solely on 3rd parties to supply them reasonably priced gas. As evidenced on the East Coast at the moment, gas consumers are in uproar due to the shortage of cheap gas and seeking Government intervention. Yet little over a decade ago many TCF’s of coal seam gas could be purchased in the ground in Queensland for a few cents a GJ (before the Gladstone LNG gas rush).

In any highly regulated, competitive (versus other domestic users and export projects), fragmented and geographically dispersed gas market it is foolhardy for any large user of gas not to be actively involved in hedging their exposure (either financially (which is difficult to do in Australia) or physically. The gas supply crisis we have experienced in WA over the past decade will continue to worsen over the next decade, reaching crisis point in the middle of the next decade when the NWS and Quadrant’s current major domestic supply projects deplete. The next wave of Japanese underpinned LNG projects (the LNG market in WA moved from boom to bust based on Japanese contracting, the last period of which was 2008-2011, given contract terms of 15-20 years we would expect the market for LNG to be booming again in the second half of the next decade), if a reservation policy still exists will likely provide supply to the 3-4 largest domestic users (see below) but still leave the market short.

In the best-case scenario for WA gas markets in the latter part of the next decade, ‘existing’ LNG plants will likely supply the next wave of Japanese LNG buying (improving on the economic outcome for these facilities versus the inefficient multi-competing project building of the last boom)

Fig. 58: LNG Plant Spare Capacity as plants come off plateau production

Source: Wood Mackenzie
So, if the economics of these projects allow, and the gas reservation policy still exists, this resulting domestic supply will likely underpin the demand of the large Alumina, Ammonia and Power Generators (as occurred in the past). However, as again occurred in the past this leaves everyone else to find alternative sources of supply with once again very few companies exploring for domestic gas given the market uncertainties that will still exist.

**Fig. 59: WA’s largest gas consumers**

<table>
<thead>
<tr>
<th>Company</th>
<th>Facility</th>
<th>2014 Consumption</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alcoa</td>
<td>Alcoa Pinjarra</td>
<td>30.3 PJ 8.5%</td>
</tr>
<tr>
<td>Yara Pilbara Holdings</td>
<td>Yara Pilbara Liquid Ammonia Plant</td>
<td>28.4 PJ 7.9%</td>
</tr>
<tr>
<td>Alcoa</td>
<td>Alcoa Wagerup</td>
<td>26.0 PJ 7.2%</td>
</tr>
<tr>
<td>Alcoa</td>
<td>Alcoa Kwinana</td>
<td>24.8 PJ 6.9%</td>
</tr>
<tr>
<td>Alinta</td>
<td>Pinjarra Cogeneration</td>
<td>22.8 PJ 6.4%</td>
</tr>
<tr>
<td>South32, Japan Alumina, Sojitz Alumina</td>
<td>Worsley Alumina</td>
<td>18.6 PJ 5.2%</td>
</tr>
<tr>
<td>ICG, Sumitomo</td>
<td>NewsGen Kwinana CCG1</td>
<td>16.6 PJ 4.6%</td>
</tr>
<tr>
<td>Synergy, Origin Energy</td>
<td>Worsley Cogeneration</td>
<td>11.8 PJ 3.3%</td>
</tr>
<tr>
<td>Rio Tinto</td>
<td>Yurrali Maya Power Station</td>
<td>10.7 PJ 3.0%</td>
</tr>
<tr>
<td>Wesfarmers</td>
<td>CSBP Ammonia Prod. Fac.</td>
<td>9.2 PJ 2.6%</td>
</tr>
<tr>
<td>Alinta</td>
<td>Port Hedland Power Station</td>
<td>8.2 PJ 2.3%</td>
</tr>
<tr>
<td>Synergy</td>
<td>HEGT</td>
<td>7.9 PJ 2.2%</td>
</tr>
<tr>
<td>Synergy</td>
<td>Cockburn Power Station</td>
<td>7.8 PJ 2.2%</td>
</tr>
<tr>
<td>Synergy</td>
<td>Pinjarra Power Station</td>
<td>7.7 PJ 2.1%</td>
</tr>
<tr>
<td>Other large users</td>
<td></td>
<td>79.6 PJ 22.2%</td>
</tr>
<tr>
<td>Small users</td>
<td></td>
<td>41.4 PJ 11.5%</td>
</tr>
<tr>
<td>Residential</td>
<td></td>
<td>7.2 PJ 2.0%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td><strong>358.8 PJ 100%</strong></td>
</tr>
</tbody>
</table>

Source: GBB 2015

So, coming across large gas resources held by smaller independents such as currently held by AWE and CVN is a rarity and it would be remiss of a large mining operation not to be interested in gaining control of this resource to be master of their own future supply (even if some exploration and appraisal risk still exists, but we believe this is more than adequately captured in CVN’s discounted share price).
POSTSCRIPT – IS THERE A SOLUTION FOR THE WA GAS MARKET TO IMPROVE ITS EFFICIENCY?

We believe there might be, although it will be readily dismissed by most. Since the mid 1980’s the WA Domestic Gas market has swung from a demand to supply crisis. Over the last decade demand has been choked from the market by the lack of reasonably priced gas, with actual consumption undershooting significantly potential gas demand.

Fig. 60: Forecast supply and DMP natural gas consumption (TJ/d)

This is despite an enormous volume of discovered and potential conventional gas offshore WA (ignoring unconventionals).

Fig. 61: Western Australia Proven and Prospective Resources

Source: DMP 2009
Across the other side of the continent, the East Coast of Australia is entering its own decade or more long phase of demand destruction. This is a result of the start-up of their own 3 LNG export projects at Gladstone.

**Fig. 62: Eastern Australia Gas Demand and Resources**

As a result of the turning on off these LNG plants the price of available wholesale gas on the East Coast has been rising rapidly since the LNG projects were sanctioned.

**Fig. 63: NSW & ACT large Industrial customer gas price components**

And the pace of increase has accelerated in the past 18 months based on spot prices as the projects turned on.
This price rise has occurred despite the oil price being close to decade lows. Once oil prices start to recover, East Coast gas prices (now linked to International oil pricing through the nature of the LNG contracts signed) will likely increase in parallel.

Further upward pressure on prices is coming from the fact that nearly all the low costs CSG gas has been reserved for the LNG export projects. Over time domestic gas consumers will have no option but to contract gas from sources higher up the supply curve (if this gas is made available by producers at all).
Fig. 66: Aggregate gas supply for the East Coast for 2018 ($/GJ)

Source: Simshauser and Nelson (2014)

Fig. 67: East Coast gas supply cost curve

Source: Strike Energy

Fig. 68: CSG production cost curve

Source: RMLS, March 2016
So, the dual result of the start-up of the LNG projects at Gladstone has been rising prices (with no formal gas reservation policy yet in place to artificially cap them) and the physical shortage of gas supply (producers unwilling to develop the higher cost gas in their portfolios and reserving the lower cost gas for LNG export). This sounds very similar to the market that has developed already in the West.

The result already has been a severe erosion of gas consumption, initially in gas fired power generation and now in commercial and industrial use. The impact on the former led to higher power prices, but was largely ignored by politicians and the popular media. The impact on the latter which has a more direct impact on jobs etc. has woken up the media and politicians of all colours to the gas crisis that has been developing for the past 5 years.
The result is that East Coast Gas consumption is not expected to return to 2010 levels until at least 2040!

Fig. 71: Domestic East Coast demand depressed for two decades

![Chart showing total annual gas consumption by sector, 2016 to 2036.](image)

Source: AEMO

In fact, we believe current long run price forecasts could be understated if as we expect the LNG projects (especially GLNG) have significantly overstated the deliverability of their CSG fields and hence understated the cost of supply for their contracted offtake volumes (assuming it can be delivered at all).

Fig. 72: Delivered wholesale gas price forecast – base case

![Chart showing delivered wholesale gas price forecast.](image)

Source: Core Energy
So, Australia now has got two inefficient and malfunctioning gas markets on both the West and East Coasts. Would connecting them together, make for a more efficient market overall, we believe so. A case of two wrongs making a right.

As we have shown earlier Western Australia has a surplus of gas resources already accumulated and remains relatively lightly explored (why find more gas when you cannot commercialise it!).

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**Fig. 73:** East Coast supply by cost – base case

Source: Core Energy Group

**Fig. 74:** Price outlook in high case ($/GJ)

Source: Core Energy
Currently the only option for gas explorers in WA is to try and sell it into the relatively small WA gas market or export it by LNG (WA LNG is high up the cost curve and hence is heavily reliant on Japanese buyers whose contracting only takes place every 15-20 years, a long time to wait between developments!).

The East Coast is a much larger domestic market in crisis, with long term demand expected to decline due to a lack of available gas. The impact this will have on the overall economy, jobs etc. politicians and others are only now (5-8 years too late) waking up to.

The East Coast already has available pipeline infrastructure and in the West we have almost double the gas plant capacity when compared to domestic consumption (so >800TJ/d of spare processing capacity).
Fig. 77: Gas plant capacity in WA

Source: AEMO and GBB data

Fig. 78: Location of Existing East Coast Transmission Pipelines

Source: Core Energy Group
A pipeline from WA ending in Moomba with truck lines servicing SA, Victoria and NSW would be approximately 5,000km in length.

A baby when compared to the West-East China pipelines which stretch close to 9,000km, are 40-48in in diameter and carry 30bcm/a of gas (circa 1.2Tcf). The reported cost of WEPP II & III are in the US$20-22bn range.

**Fig. 79: West-East China Pipelines**

Source: CNPC

The distance is more comparable the controversial Keystone XL ‘oil’ pipeline in North America which stretches 3,456km and is estimated to cost close to US$7bn (36in oil pipe).

The relatively small NGP pipeline here in Australia was reported to be costing $800m for a 14in pipeline to deliver 120TJ/d from the NT to East Coast markets. Initial estimates from the operator was that the capacity could be increased to 200TJ/d for a couple of hundred million dollars more. In reality the lack of gas supply in NT has them now downscaling their plans to a 12in pipe to deliver initially just 90TJ/d.

We have done some rough modelling to see if a West to East Coast pipeline has any merit. We have assumed 500TJ/d of capacity and looked at a range of pipeline construction costs. We have also assumed offshore operators in WA will require a minimum of a $5/GJ price at the wellhead to develop the gas.

Based on these simple metrics it would seem a pipeline developed by a commercial operator may struggle (assuming they require a 7% or greater WACC). However, a Government sponsored pipeline financed at 5% would likely be able to deliver large volumes of gas in the range of A$8.50-9.50/GJ.

There is an even more bullish case, given the direct (upstream royalties and taxes) and indirect (jobs, GDP growth) benefits of having adequate gas supply on both the West and East coasts, a pipeline could be fully Government sponsored and be
built on the basis of a 0% WACC (the return on investment comes through the
direct and indirect benefits outlines before). In this case the gas could potentially
be delivered for circa $8/GJ.

Our own version of a West-East pipeline would seem to be a win-win for all
concerned.

WA State Government – would benefit from increased gas development activity
and a boost to WA Economic activity through increased availability of gas.

WA Gas Consumers – do not have to lose out, in fact they would likely gain. They
would be able to bid for gas at East Coast prices minus the pipeline tariff. As part
of building the pipeline, offshore retention lease terms would have to be tightened
so that operators could not blame a lack of commercial opportunity for not
developing gas fields. Use it or lose it would have to be strictly enforced.

WA gas operators – those that simply want to hold the gas in the ground waiting
for the once every 15-20 years Japanese fed LNG contracting boom may be
disappointed. The pipeline would open up East Coast gas markets (in addition to
WA domestic and LNG export) as another viable commercial alternative. We have
assumed a well head price of $5/GJ in our modelling, which is pretty close to the
LNG netback price assuming a US$55-60/bbl oil price. So not the super returns
expected to be achieved during the once every two decades Japanese LNG
buying frenzy (they can still be captured at those times) but a reasonable return all
the same.

Federal Government – would help solve the East Coast gas supply crisis and
generate an adequate return on the pipeline through increased offshore production
and related taxes and a boost to National GDP from increased gas availability for
industry. An additional benefit is that it would bring forward the development of
WA’s offshore gas reserves. A reserve that may be under threat from rapid
developments in renewable energy technology, and as a result in 15-20 years
facing the possibility that the market for such gas may have diminished or
disappeared, and it becomes a stranded resource (some in the oil and gas
industry may view this as unlikely, but given the pace of developments in the
renewable sector, it has to be a consideration).

So, while this West-East pipeline review might just seem like a bit of fun for
an Oil & Gas analyst to whittle away his time on, the merits of the pipeline
(assuming our costings are somewhere close to the mark) actually do seem
quite compelling. In the meantime, any major gas consumers wanting to
make sure they are not disadvantaged by the continued gas shortages in WA
and now the East Coast Australia, have no choice but to either compete for
what 3rd party gas is available in the market or be more proactive and go now
and acquire their own upstream production. This stark choice facing gas
users brings us back to CVN, and underpins our positive outlook for the
company.
Fig. 80: Delivered cost of WA offshore gas to the East Coast

Source: Hartleys Research
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- **Accumulate** Share price appreciation anticipated but the risk/reward is not as attractive as a “Buy”. Alternatively, for the share price to rise it may be contingent on the outcome of an uncertain or distant event. Analyst will often indicate a price level at which it may become a “Buy”.
- **Neutral** Take no action. Upside & downside risk/reward is evenly balanced.
- **Reduce / Take profits** It is anticipated to be unlikely that there will be gains over the investment time horizon but there is a possibility of some price weakness over that period.
- **Sell** Significant price depreciation anticipated.
- **No Rating** No recommendation.
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