Revision 7 09/11/17 Issued as a Preliminary Draft

1.00 CTP Share Value Sensitivity Analysis?

Legend for bullets & abbreviations used throughout this document:

- ✓ Positive Indication
- Risk
- Information
- Idea
- Target

NGP1 Used for the NGP from Tennant Creek to Mount Isa end 2018
NGP2 Used for the proposed extension of NGP1 from Mount ISA to Wallumbilla End 2022?

Some useful links to give readers quick access to important parent document:

Double click on the link in the pdf to open the document. If computer permissions prevent this copy the link & paste it into your browser.

SOA Document…

https://hotcopper.com.au/threads/ann-scheme-booklet-independent-experts-report.3398352/

Annual Report Webinar Transcript…

https://hotcopper.com.au/threads/2017-annual-report-webinar-transcript.3748326/?post_id=27831549

2017 July-Sept Quarterly…

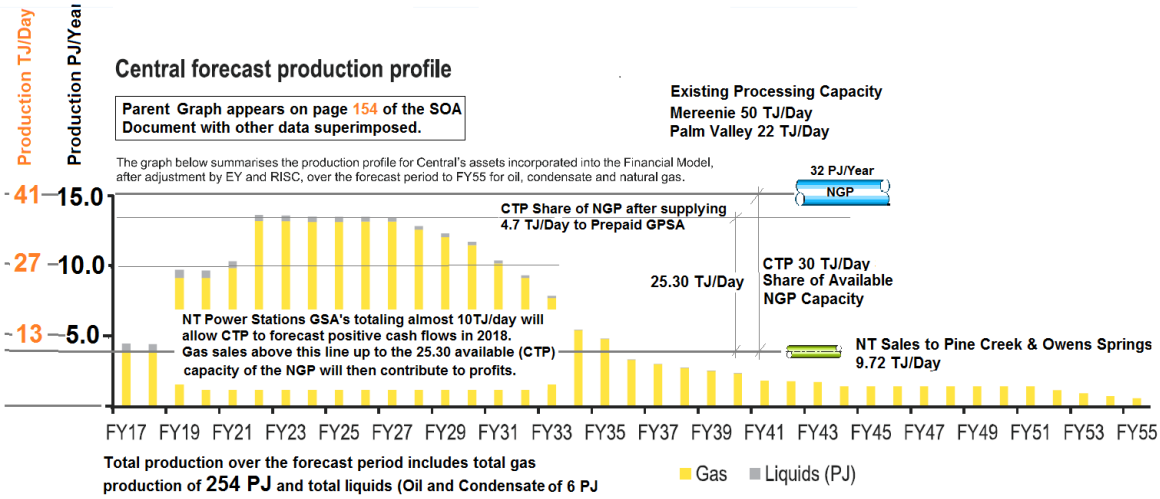
https://hotcopper.com.au/threads/ann-quarterly-activities-and-cashflow-report.3800739/

2017 Annual Report Review Presentation…

https://hotcopper.com.au/threads/ann-annual-report-review-presentation.3742449/

The following Montage was created to establish a simplified overview of Post NGP production using a parent graph taken from P254 of the SOA.

The graph is an approximate plot of the NGP capacity available to CTP to deliver gas to East coast markets and fulfil the MAC prepaid supply agreement of 4.7 TJ/day.



Using it as a frame of reference a basic Sensitivity Analysis spreadsheet model was used to review what if scenarios relating variables such as production cost haulage uncovered piping tariffs, production rates Etc.

The parent spreadsheet contains schematic representations of the pipeline pathways to markets at Sydney city gate and the Wallumbilla hub and provides an approximate comparison otf the competitiveness of CTP gas as compared with CSG.

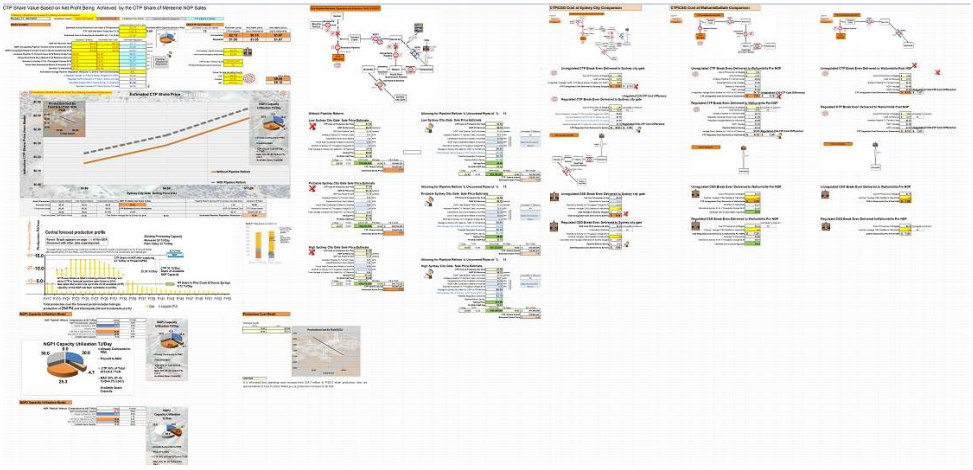
The industry CGG benchmark for CSG production cost at the gate is $5.70 Ex Field but I have used $1.00 less as I have reason to believe that future competition may achieve this figure.

As recent CTP presentations have stated, the outcome appears to be quite favourable to CTP.

- With models like this the whole thing ends up being a probabilistic bell curve and I think that we should not get too carried away with the low probability tails on either side of the bell representing the worst and best scenarios and concentrate on targeting the middle.

  The model excludes the contribution to share value of CTP assets other than Mereenie Palm Valley Dingo and possibly Ooraminna because on the basis of the SOA at their present stage of development on a bad day they are worth very little because of the timeframes needed for monetisation. This doesn't mean that CTP won't have a fair chance of blue sky in the future once we get the NGP1 initiative up and running.

  A range of different pathways to market for both CTP gas and CSG costed for regulated and unregulated tariffs can be compared simultaneously.



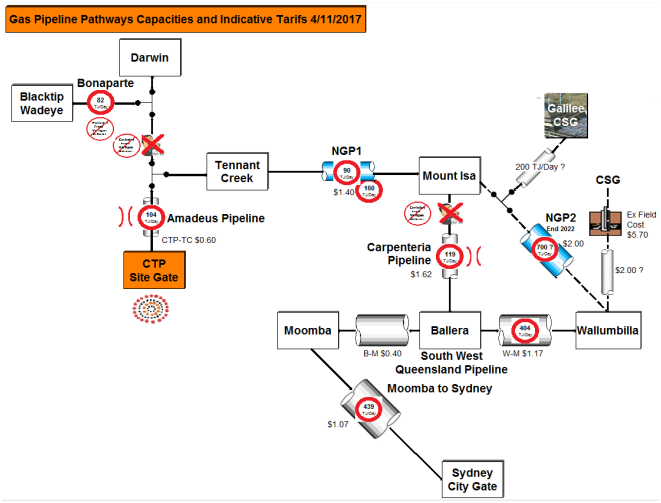
The model focuses on Gas delivered to the Sydney city gate market where, providing we can keep our production cost at the CTP site gate to about $1.50, we should have **cost advantage over CSG from QLD in the vicinity of $1.50/GJ** and to Wallumbilla where it also appears to compete favourably on an equal footing with the most competitive CSG.

CSG-CTP Cost Advange			
Uncovered % Discount Applied	Post NGP1 (2018)	Post NGP1 (2018)	Post NGP2 (20122)
15	CTP to Sydney	Ctp to Wallumbilla	Ctp to Wallumbilla
Unregulated	$1.63	-$0.81	-$0.02
Regulated	$1.51	$0.02	-$0.02

Revision 7 09/11/17 Issued as a Preliminary Draft

The simplified diagram below shows the pathways to market after the NGP (NGP1) and its announced extension to Wallumbilla (NGP2) are ready for first gas late 2018 and 2022 respectively.

These representations have been christened “Pinball diagrams” because someone exclaimed that our pathway to market resembled a pinball machine!



You can see from the above that the CTP pathway to market flows down nominal 100 TJ/day pipes and 30 TJ/day is already taken up on the NGP1 and first round 200K of the Carpentaria leaving us with 60TJ/day for MAC/CTP to split.

Some assumptions used in the model:-

- The model makes the simplified assumption that CTP is now cash flow positive with our current nominal 10TJ/day NT sales Etc. and that 25 TJ of gas down the NGP will drive profits. It has provision to nominate a plug in amount for the estimated annual profit/loss from other CTP Operations.
- I contacted APA today & checked the published unregulated rates and added $0.40 for Ballera to Moomba which the SOA seems to have missed and updated APA indicative haulage rates.
- The NGP1, being a new pipe, is not covered by regulation.
- There is a question mark as to whether the regulation of the Amadeus and Carpentaria pipelines will be politically and legally feasible so I have generally excluded them from regulatory consideration.
- Hopefully our gas will not need the full N_2 NGP removal tariff on but we will have to wait until we have the drilling results to see.

> It is my opinion that, if we can Certify enough reserves & flow rates, we may be able to negotiate a MOU for a long term discount with APA on the published haulage rates as a safety net in case pipeline reform is not implemented in time for NGP first gas late 2018.

The graph below taken from the Sensitivity Model shows the potential impact on the share price of production costs, N2 removal, haulage, pipeline reform, selling price, TJ/Day sold to East coast markets over a range of nominated selling prices at Sydney city gate.

The printout below uses 15% pipeline reform discount on published uncovered tariffs may be IMO possible through negotiation rather than sitting around waiting for regulation.

- The Global variables are entered into the yellow squares and the live graphs respond accordingly.

Revision 7 09/11/17 Issued as a Preliminary Draft

Input Dashboard for Global variables:

- The first thing that was clear was that that CTP would need to achieve more than a $9.00 Sydney city gate selling price to really make money.

Regardless of the inherent inaccuracy of this simplified business model it serves to show just how sensitive CTP's profitability is to any change in the fundamental parameters and to market sentiment affecting the P/E ratio.

- Communication related to improving shareholder sentiment needs to be targeted.In the model below a P/E ratio of 10 was used in line with comment at the AGM webinar and a 15% reduction in non NGP piping tariffs was used together with a cost of production of $1.50/GJ

Please treat the output below with caution but in any case using the pathways and tariffs above you can do your own arithmetic.

Graph Parameters	Without Pipeline Reform	With Pipeline Reform	Wallumbilla Selling Price	NGP Profitable Gas Sales TJ/Day		Pipeline Reform Saving CTP to Sydney City Gate $/GJ	Valuation PE Ratio
Estimated Share Prices from Model	$0.16	$0.18	$8.50	25.30		0.22	10.00
Estimated Share Prices from Model	$0.29	$0.32	$9.50	CTP Estimated Cost of Production		NGP N2 Removal Tariff	No. of CTP Shares Issued
Estimated Share Prices from Model	$0.48	$0.51	$11.00	$1.50		$0.72	705,697,647.00
Total Uncovered Tariff Site to Sydne	$0.22		Post Reform Haulage Site to Sydney city gate		$4.87	Nominated Pipeline Regulation Reduction %	15.00

2.00 My own view of CTP's Strategic Plan

Having achieved positive cash flow from the 2 NT power station GSA's CTP has successfully raised the finance (In conjunction with a 50% contribution from MAC on the Mereenie wells) to fund the 4 well Appraisal drilling program which has the potential to establish certified 2P net to Central reserves of 352.9-541.4 PJ.

This increased reserve certification is expected to pave the way for CTP to raise finance for additional drilling and supportive gas processing infrastructure both to supply approx.10TJ/day needed to meet the Pine Creek and Owen Springs power station GSA's as well as an additional 50% share of Mereenie production of 60TJ/day to sell gas to use all of the available NGP capacity in late 2018.

Since profits will primarily come from the gas that they supply to the East Coast Market, CTP's primary focus is to have their 30 TJ/day of gas ready to deliver to East Coast Client/s.

IMO the following targets need to be KPI's that CTP reports on monthly to shareholders.

- Minimum **selling price of $9.00 at Sydney city gate**.
- **Gas Production costs** ex field (Excluding N2 removal) max **$1.50/GJ.**
- **Need for N2 removal** at $0.72C/GJ or expected proportional savings.
- Satisfactory progress towards Mereenie **Surface facilities being ready on time** to process 30 TJ net to CTP to NGP by first gas date late 2018.
- Realistic L2 schedule to first gas down the NGP1 to inspire shareholder confidence.
- Backup negotiations with APA and HOA related to confirmation of 60 TJ haulage capability to Sydney city gate until 2022.
- Development of a communication policy to create positive shareholder sentiment.
- Quarterly reports (Ideally Monthly) showing:
    - Cost of Production/GJ
    - % of GSA's Supplied, .
    - Simplified profit/Loss indication for period.

    We don't have to restrict our thinking to the minimum statutory requirements!

The above target list is by no means exhaustive but the focus should be on eliminating or mitigation all obstacles to CTP business success leaving us only with the 4 well appraisal program drilling risk.

3.00 Can CTP Deliver enough Gas to the NGP?

What Prospect is there of moderate Success resulting from the 4 Well Horizontal Drilling Appraisal Program?

- ✓ First Up the 2017 Q3 Report Page 2 "Testing of the Stairway Sandstone at Mereenie from the previously drilled West Mereenie 15 continues free flowing gas at sustainable rates (Previously stated to be 1.1 TJ/Day) with a low nitrogen content of 2.6%. **Additional recompletion opportunities have been identified**." This at least means we look like getting some gas from the existing (NW Mereenie?) wells.
- ✓ Given the considerable body analysis ($4M worth) that has been undertaken here is a reasonable chance that the current 4 well Appraisal drilling program (Across Mereenie, Palm Valley and Ooraminna) will result in the certification of additional reserves which combined with Central's existing total 2P Reserves of 125.9 PJ would give total potential 2P Reserves, net to Central, of between 352.9 – 541.4 PJ. The bottom end of the new reserve certification target is pretty exact.

- ✓ A successful horizontal drilling program would increase the confidence that Mereenie should sustain a production rate of say 60 TJ/day (30 TJ/day net to CTP). It is my guess that if we successfully target a natural fracture, that we will have a pretty good idea of the outcome pretty early in the piece.

- ✓ 2017 Q4 P8 shows a concept for the well design. I appreciate the information which is well worth reading and should generate some shareholder confidence but how about tell us which well pads are being used to drill?
- ✓

An extract from 2017 Q1 Report P8.

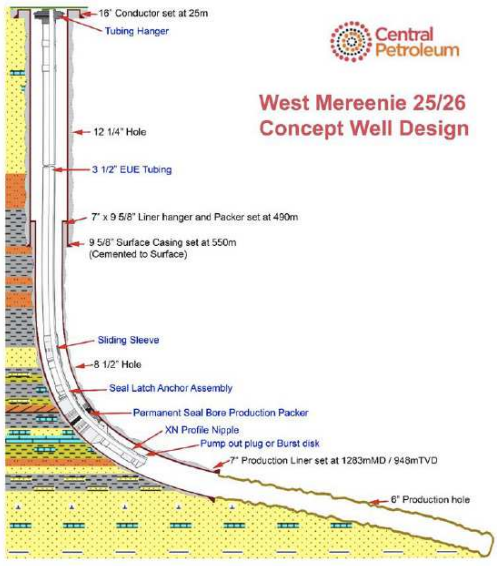
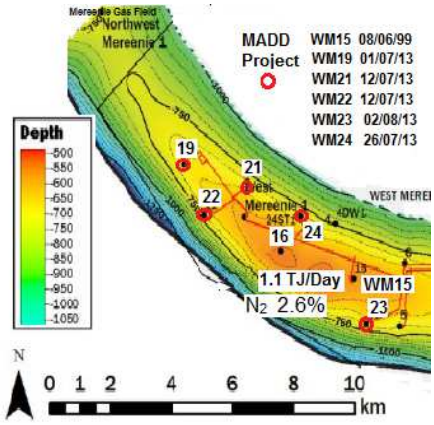


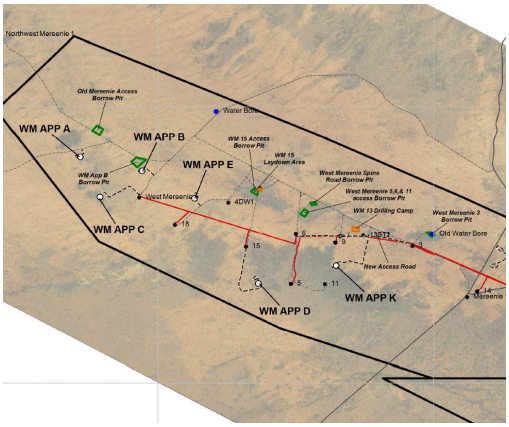
Figure 4: West Mereenie 25/26 Concept Well Design

- Whilst there is a fair degree of optimism that the horizontal drilling initiative will be successful and **CTP have emphasised repeatedly that there are no guarantees**.

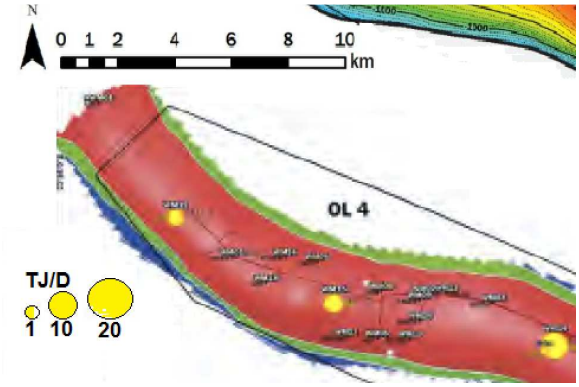
  NW Mereenie has already been drilled as part of the Santos MADD (Mereenie Appraisal and Development Drilling) project undertaken during 2013.
  This link to the Environmental plan has a pretty good map of NW Mereenie and even shows the borrow pits Etc.

https://dpir.nt.gov.au/__data/assets/pdf_file/0007/258694/SantosMereenieAppraisalDevelopmentDrilling.pdf





- ✓ West Mereenie flow rates from CTP presentations:-



- ✓ Info on the original Mereenie Lower Stairway Info in the SOA P224 and 227

We note that Central has been progressing studies into the natural fracture distribution within the Lower Stairway sandstone. These studies, based on outcrop, FMI log data and structural analysis indicate the natural fractures have a preferred orientation and location around areas of maximum curvature in the field which would be favorable for oriented drilling to maximize the intersection of productive reservoir. If this concept is proven by appraisal drilling, then the chance of commercial production will increase materially.

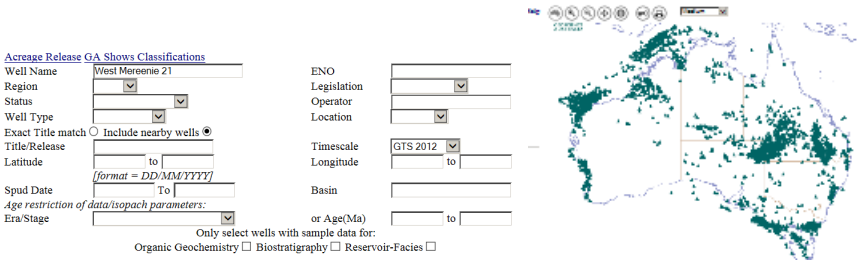
Should the successful development of the Lower Stairway resources occur, it is also estimated that three additional wells are drilled to target the acceleration of 2P gas reserves.

Central's original development concept calls for the Lower Stairway wells to be a slim hole design to enable the utilisation of smaller, lower cost rigs as the wells are shallow at less than 1000 m depth. However recent work by Central has indicated the potential to drill high angle wells drilled underbalanced and/or with air oriented to maximise the intersection with natural fractures. In this scenario, the laterals are anticipated to be in the order of 500-700m requiring a two well proof of concept well program prior to development. The high angle well option has the potential to significantly reduce the well count to in the order of 20 albeit more expesnive wells. If pursued, this option could potentially reduce capital costs by approximately $50 million.

- Well Completion Reports for nearby existing NW Mereenie Wells Can be looked up on the Geoscience Australia Site-

http://dbforms.ga.gov.au/www/npm.well.search

https://dpir.nt.gov.au/__data/assets/pdf_file/0005/255389/STRIKE_UserGuide.pdf



Found 2 Santos PDF's for WM 19 and WM 23

http://geoscience.nt.gov.au/gemis/ntgsjspui/bitstream/1/86500/1/WM19_Well_Completion_Report.pdf

http://www.geoscience.nt.gov.au/gemis/ntgsjspui/bitstream/1/86523/1/WM23_Basic_WCR.pdf

- ✓ The 2017 Q1 Report says "Additional recompletion opportunities have been identified" and they probably will perform in a similar fashion to WM 15 but every little bit helps.
  - Here is the link to its WCR (Well Completion Report for West Mereenie 15 which contains quite a lot of information and original flow rates.

    http://www.geoscience.nt.gov.au/gemis/ntgsjspui/bitstream/1/84350/1/WM15_WellCompletionReport.pdf

    Interesting to note the original DST came in at roughly 1.32 TJ/day.
    Extract from WM15 WCR

(e) Testing

There was one drillstem test conducted at West Mereenie 15. The interval 1332m to 1351m was straddle tested after wireline log acquisition utilising inflatable packers. This test resulted in a stabilised gas flow to surface measured at 1.26 MMCFD through a ½" choke. Details are included as Appendix IV. In addition 7 open hole flow tests were run as summarised in the table below and in Appendix IV.

- ✓ It looks like they are going to be new wells started on the drill pads of existing wells which presumably makes them easier to connect to the gathering pipework and after some research I now support not milling the casing & deviating from existing wells.

- ✓ My understanding is that past drilling operations in this area that have successfully intersected natural fractures have shown high sustainable gas flows for considerable periods and this looks promising. Apparently the stairway showed good initial pressure during past drilling.
- ✓ Apparently horizontal drilling at Palm Valley that intersected a natural fracture gave spectacular results until it was fracked and the propping agent acted to constrict the flow.

What Risks were Identified in the SOA Document in relation to the Lower Stairway Development much of which underpins my call for a publishing a realistic L2 schedule ?

SOA P 227

- Development of the Lower Stairway resources is forecast to start in FY 2019 in order to maximise througput into the NGP. This timeline is however very aggressive and could easily slip by 12 months or more.

- In addition, little or no production impact has been forecast by the operator during the installation of new plant and equipment.

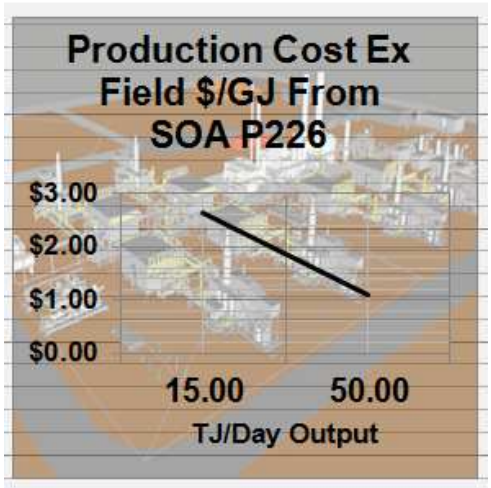
  While it may be possible that annual quantities remain relatively consistant, it is likely that some impact on production would occur during the installation of new equipment. If the NGP is delayed then it is likely that this will impact on the ability of Central's Gas to reach these markets.

- Decommissioning and abandonment of Mereenie 2P resource Development Scope is estimated at $80M.

- As outlined in the SOA the appraisal and associated reserve certification, funding and execution of drilling/infrastructure works will require a very aggressive schedule to be ready for first NGP gas late 2018.

- If CTP does not fill the pipe from day 1 it is money down the drain not monetisation down the pipe.

  The Sensitivity model indicates that the share price is impacted if we don't fill the NGP and production costs/GJ increase with lower output.



Google earth plan view of Mereenie surface facility with coordinates.

- There appears to be a difference between the 2017 AGM Webinar comments:

> "*We anticipate that over time we will be spending more money on the processing facilities but it will not be a critical path to us selling it (Gas) there is existing present 50 TJ/day existing capacity at Mereenie and 22 TJ/day existing capacity at Palm Valley hence 50 + 20 = 70 (TJ/Day)…."*

and those in the SOA document, which appears to express a different view.

If a significant part of the scope of the Mereenie Surface facilities upgrade shown in the SOA to Increase production to 50 TJ/Day will be needed to process enough gas to utilise the (Presently) available 60TJ/day to achieve the start-up NGP capacity we could have a problem.

If the full scope shown on P226 of the SOA was needed there may be a significant risk that (Regardless of funding issues) it would not be commission in time leading to be a slow ramp up of processing capability to achieve full 60TJ/Day NGP capacity.

This would manifest itself in reduced profit to CTP with a consequent impact on share value.

Table 4-4: Future Mereenie 2P development scope and capital cost

Development scope	Cost (A$ million)
Facility works to allow 30 TJ/d gas production	17
Re-use existing crestal wells EM43/EM12/EM2	0.1
Re-complete WM19/WM15/WM14/WM16 as gas producers	5.5
Drill and complete two new gas production wells and EM44 top hole	9.5
Other	0.5
Total development capital	**32.6**

Facility scope includes:

- restaging of compressors K-201 and K-202;
- installation of integrated control system;
- upgrade of PLCs, safety shutdown, SCADA and individual control systems to enable better reliability at higher production rates;
- installation of a more effective produced water management system; and
- installation of export metering and plant air.

In view of comments made at the AGM webinar P10 it looks like a major refinancing exercise will be done in say 12 months after the reserve base is known.

"it appears to me that if you are going to even think about refinancing when you've got in the next 6-12 months a totally new reserve base Etc. ….."

This important task is under CTP's ownership so I think shareholders need a very clear explanation the scope and mechanism for funding, of any facilities upgrades that are needed to process the first NGP gas quota.

4.00 What can be done by CTP to Improve Shareholder Sentiment?

Shareholder sentiment needs to be maintained especially during the next 12 months. An unrealistically low share price is an open invitation to corporate predators (I have one particular organisation in mind) and even an unsuccessful attempt has the potential to disrupt execution the NGP first gas strategy.

The question at the AGM webinar about future information flow headings was a really good one. The following preliminary list of information flow headings mentioned at the webinar needs to be refined and expanded.

- Regulatory approval for the drilling
- Drilling Contractor Appointed
- Joint venture approvals,
- Spudding of wells
- Outcome of the AEMC enquiry,
- Outcome of the GMRG enquiry by December
- Outcome of the Pepper Enquiry in December

✓ Early identification of a detailed information flow scope is fundamental maintaining shareholder sentiment through an effective communication plan because it prevents unproductive suspicion and speculation. “If it hasn’t been announced yet then it hasn’t happened”.

✓ A realistic L2 schedule should be designed provide shareholders with a clear insight into the milestones that Central is targeting over the next 12 months.

✓ The present estimated **cost of (Mereenie) production** following the 2P horizontal drilling reserve development should be under $1.50.

This coulds be easily clarified by CTP at the next opportunity such as the AGM.

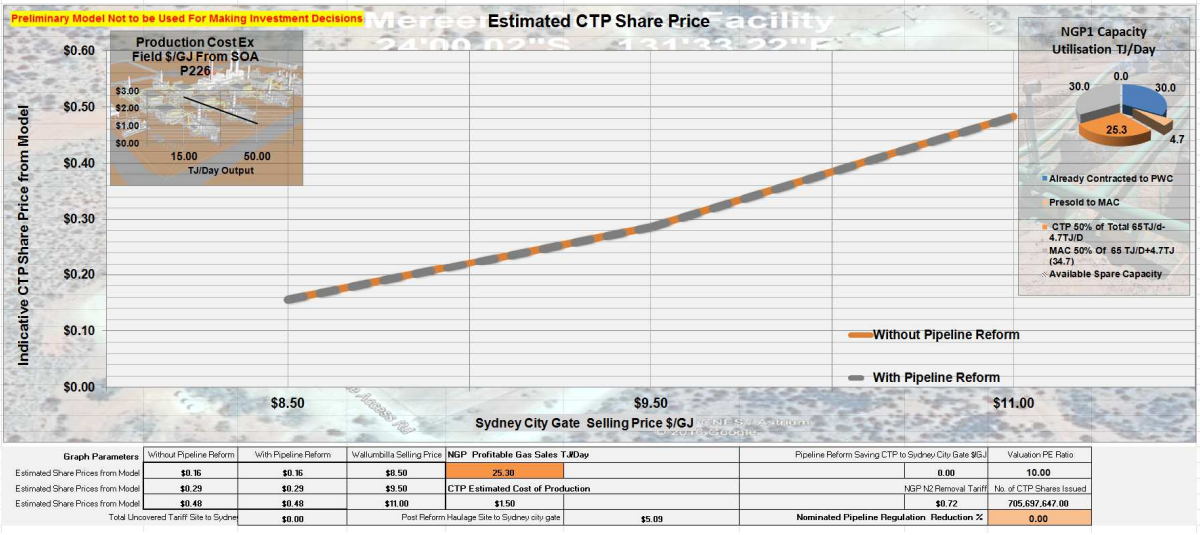
✓ Taking a plausible price of $9.50/GJ point of sale price at Sydney city gate with no pipeline reform:-

Probable Sydney City Gate Sale Price Estimate

CTP Cost of Production Ex Field	**$1.50**	
NGP N2 Removal	**$0.72**	Jemena
NGP Gas Pipeline Tariff	$1.40	Jemena
Amadeus Pipeline To Tennant Creek	0.60	APA
Carpenteria Mount Isa to Ballera	1.62	APA
South West Queensland Ballera to Moomba	0.40	APA
Moomba to Sydney Inc.Throughput Charge $0.05	1.07	APA
Total Haulage to Sydney City Gate Excl. N2 Removal	$ 5.09	
Cost of Production + Haulage	**$7.31**	
Selling Pric	**$9.50**	
Profit/GJ NGP Gas	**$2.19**	

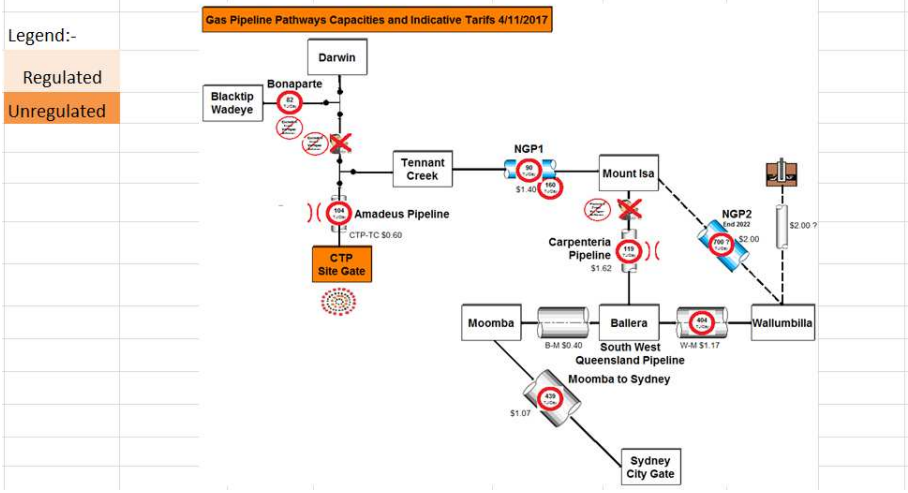
TJ/Day	TJ/PA	$/PA Profit	P/E Ratio	PE X Profit
25.30	9,235	**$20,223,555**	**10.00**	**$ 202,235,550**
			CTP Shares Issued	**705,697,647**
			Estimated Share Price	**$ 0.29**

The sensitivity model base Case **without pipeline tariff reform on uncovered pipes** and the input parameters listed at the bottom of the graph indicates a share price in the vicinity of $29C DYOR.



Graph Parameters	Without Pipeline Reform	With Pipeline Reform	Wallumbilla Selling Price	NGP Profitable Gas Sales TJ/Day		Pipeline Reform Saving CTP to Sydney City Gate $/GJ	Valuation PE Ratio
Estimated Share Prices from Model	$0.16	$0.16	$8.50	25.30		0.00	10.00
Estimated Share Prices from Model	$0.29	$0.29	$9.50	CTP Estimated Cost of Production		NGP N2 Removal Tariff	No. of CTP Shares Issued
Estimated Share Prices from Model	$0.48	$0.48	$11.00	$1.50		$0.72	705,697,647.00
Total Uncovered Tariff Site to Sydne	$0.00		Post Reform Haulage Site to Sydney city gate		$5.09	Nominated Pipeline Regulation Reduction %	0.00

CTP/CSG Cost at Sydney City Comparison



✓ From the AGM webinar, "The ACCC report says the marginal cost of **CSG** will be around about **$5.70** ex-field and then they have to transport it **which would make CTP one of the lowest cost producers".**

I have been conservative and used $4.70 to cover the worst case of competing with CSG producers at the lower end of the range.

Unregulated CTP Break Even Delivered to Sydney city gate

Cost Of Production at Sitegate	$ 1.50	
NGP N2 Removal	$ 0.72	
nregulated Haulage Tariffs CTP Site to Sydney Citygate (Incl. NGP1)	$ 5.09	
CTP Unregulated Cost Delivered to Sydney Citygate	$ 7.31	$ 1.58

Unegulated CSG-CTP Cost Difference

Regulated CTP Break Even Delivered to Sydney city gate

Cost Of Production at Sitegate	$ 1.50	Uncovered % Discount	
NGP N2 Removal	$ 0.72	15	
Regulated Haulage CTP Site to Sydney Citygate (Incl. NGP1)	$5.09		
Potential Regulated Tariff CTP Site to Sydney City Gate	$4.87		
Calculated Pipeline Reform Saving Sydney to Citygate	$0.22		
Regulated Haulage Site to Sydney Incl. NGP no N2 Removal	$4.87	Regulated CSG-CTP Cost Difference	
CTP Regulated Cost Delivered to Sydney	$ 7.09	$ 1.46	

Unregulated CSG Break Even Delivered to Sydney city gate

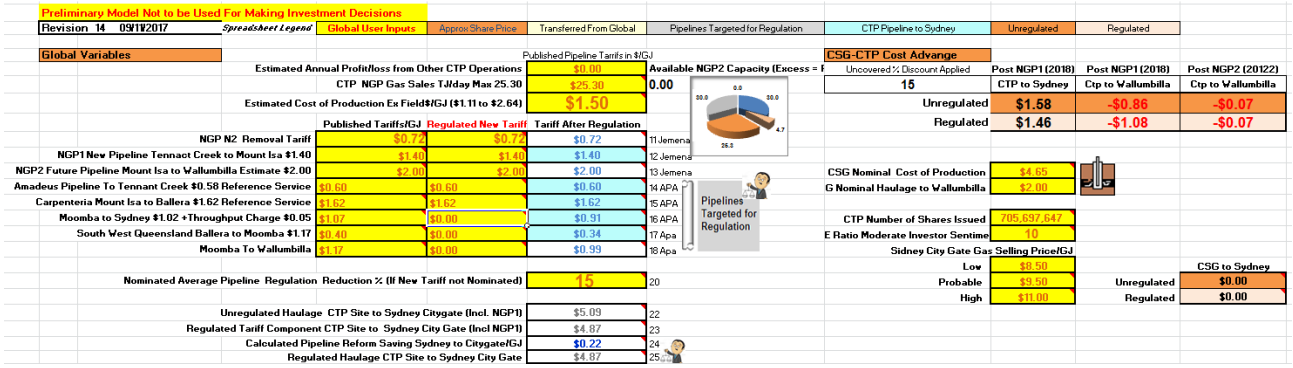
CSG Cost Of Production Ex Site	$4.70
Wallumbilla to Moomba	$1.17
Moomba to Sydney Inc. Throughput Charge $0.05	$1.07
Nominal Haulage CSG Gasfiels to Wallumbilla	$2.00
CSG Haulage to Sydney Citygate	$ 4.24
CSG Unregulated Cost Delivered to Sydney	$ 8.94

Regulated CSG Break Even Delivered to Sydney city gate

CSG Cost Of Production Ex Site	$4.70	Uncovered % Discount
Wallumbilla to Moomba	$0.99	15
Moomba to Sydney Inc. Throughput Charge $0.05	$0.91	
Nominal Haulage CSG Gasfiels to Wallumbilla	$2.00	
CSG Regulated Haulage Wallumbilla to Sydney Citygate	$3.90	
Pipeline Reform Saving Glenaris to Sydney City Gate	$ 0.34	
CSG Regulated Cost Delivered to Sydney	$ 8.60	

Revision 7 09/11/17 Issued as a Preliminary Draft

In this case CSG gas seems to end up costing about $1.50 more than CTP gas delivered to Sydney city gate with no regulation on the Amadeus or Carpentaria Pipelines.



Preliminary Model Not to be Used For Making Investment Decisions

Revision 14 09/11/2017	Spreadsheet Legend	Global User Inputs	Approx Share Price	Transferred From Global	Pipelines Targeted for Regulation
Global Variables				Published Pipeline Tariffs in $/GJ	
Estimated Annual Profit/loss from Other CTP Operations				$0.00	Available NGP2 Capacity (Excess = F
CTP NGP Gas Sales TJ/day Max 25.30				$25.30	0.00
Estimated Cost of Production Ex Field$/GJ ($1.11 to $2.64)				$1.50	
	Published Tariffs/GJ	Regulated New Tariff	Tariff After Regulation		
NGP N2 Removal Tariff	$0.72	$0.72	$0.72	11 Jemena	
NGP1 New Pipeline Tennact Creek to Mount Isa $1.40	$1.40	$1.40	$1.40	12 Jemena	
NGP2 Future Pipeline Mount Isa to Wallumbilla Estimate $2.00	$2.00	$2.00	$2.00	13 Jemena	
Amadeus Pipeline To Tennant Creek $0.58 Reference Service	$0.60	$0.60	$0.60	14 APA	
Carpenteria Mount Isa to Ballera $1.62 Reference Service	$1.62	$1.62	$1.62	15 APA	
Moomba to Sydney $1.02 +Throughput Charge $0.05	$1.07	$0.00	$0.91	16 APA	
South West Queensland Ballera to Moomba $1.17	$0.40	$0.00	$0.34	17 Apa	
Moomba To Wallumbilla	$1.17	$0.00	$0.99	18 Apa	
Nominated Average Pipeline Regulation Reduction % (If New Tariff not Nominated)			15	20	
Unregulated Haulage CTP Site to Sydney Citygate (Incl. NGP1)			$5.09	22	
Regulated Tariff Component CTP Site to Sydney City Gate (Incl NGP1)			$4.87	23	
Calculated Pipeline Reform Saving Sydney to Citygate/GJ			$0.22	24	
Regulated Haulage CTP Site to Sydney City Gate			$4.87	25	

Pipelines Targeted for Regulation

CTP Pipeline to Sydney	Unregulated	Regulated	
CSG-CTP Cost Advange			
Uncovered % Discount Applied	Post NGP1 (2018)	Post NGP1 (2018)	Post NGP2 (20122)
15	CTP to Sydney	Ctp to Wallumbilla	Ctp to Wallumbilla
Unregulated	$1.58	-$0.86	-$0.07
Regulated	$1.46	-$1.08	-$0.07
CSG Nominal Cost of Production	$4.65		
G Nominal Haulage to Wallumbilla	$2.00		
CTP Number of Shares Issued	705,697,647		
E Ratio Moderate Investor Sentime	10		
Sidney City Gate Gas Selling Price/GJ			
Low	$8.50		CSG to Sydney
Probable	$9.50	Unregulated	$0.00
High	$11.00	Regulated	$0.00

- ✓ The CSG production cost will probably increase as the CSG fields mature and they have to drill step out wells in less productive areas, deal with pump maintenance and the dreaded P&A budget which usually goes only one way.

- ✓ In comparison, our relatively constant "Horizontal Drilling" extraction will hopefully work increasingly in our favour. In any case CSG producers have to pay for dewatering infrastructure as well.

- ✓ The more expensive CSG producers are likely to have a significant upward influence on the market price.

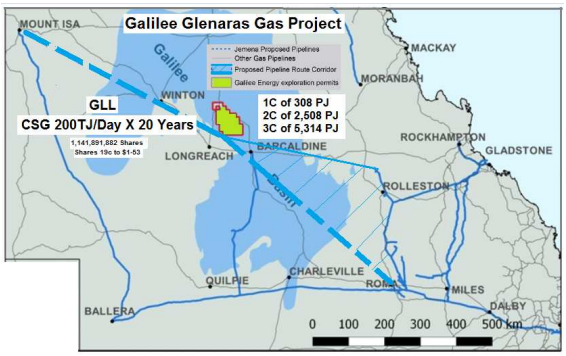
  - Richard made a direct comment to me at a Sydney presentation words to the effect that "Selling the gas is not a problem", and my research comes up with the same conclusion.

    With this in mind I can understand why CTP not in a rush to enter into East Coast GSA's, and is holding out for the best possible deal for shareholders.

    - **Taking a balanced view**, the Second Supplementary Booklet however, paints a more pessimistic picture on P11 and it is only fair to take it into account "The GMRG design recommendations reduce the likelihood that any potential future reductions in pipeline tariffs will be as significant as the reductions advocated by Central." It is worth reading this section carefully as a background when taking into account the current state of gas haulage regulation to gain a balanced view.

  - If someone else beats CTP to filling the NGP1 pipe we have a real problem that will not sort itself out until the NGP/Carpentaria pipeline capacity is increased in at about 2022 when the Eastern Extension of the NGP is presently targeted for commissioning.

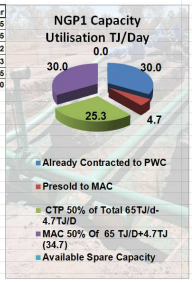
    Snapshot of the Glenaras Gas Project driving the FEED being currently undertaken by Jemena which indicates that just like the NGP was at this stage FID is increasingly probable:-



If CTP are required to supply gas to service the Macquarie $10M prepaid GPSA then until the Amadeus/NGP/Carpentaria delivery chain is upgraded **Central would be restricted to East Coast Gas Sales of 25.3 TJ/day for at least 3** years after the NGP is commissioned unless CTP comes to an alternative arrangement with MAC to in accordance with the Prepaid contract with MAC.

NGP1 Capacity Utilisation Model

NGP "Pipefull" Without Compression at 90 TJ/Day	TJ/Day	PJ/Year
NGP1 Uncompressed Capacity	90.00	32.85
Already Contracted to PWC	30.00	10.95
Presold to MAC	4.7	1.72
CTP 50% of Total 65TJ/d-4.7TJ/D	25.30	9.23
MAC 50% Of 65 TJ/D+4.7TJ (34.7)	30.00	10.95
Available Spare Capacity	0.00	0.00



5.00 Information on the Mereenie Field Development Program contained in the SOA and 2016 Annual Report

http://centralpetroleum.com.au/wp-content/uploads/2015/09/CTP-2016-Annual-Report_FINAL.pdf

2016 Annual Report 21/09/16

Reference P14 2016 Annual Report P4

Mereenie Field Development program was optimised to maximise reserve upgrades and reduce costs. The savings realised through these efficiency gains will be used to further develop the Company's knowledge of the Stairway and P4 formations. The Reserve Upgrade Program comprises three stages:

- Stage 1 – Consisted of reviewing all existing data from Mereenie including nearly 60 wells already drilled and selected wire-line pressure and flow testing at Mereenie and the building and history matching of a static and dynamic model of the gas reservoir at Mereenie. **This was completed at a cost of $4 million.**

- Stage 2 – Subject to joint venture approval consists of refining and optimising of Stage 1, including possible production testing. This should increase further the reserves available for contracting. In addition, production results at Dingo will be incorporated.

- Stage 3 – Subject to joint venture approval will consist of appraisal drilling and production testing on the Stairway Formation generally with a target of doubling the Stage 2 reserves at Mereenie. Successful completion of the Stage 3 reserves plus reserve upgrades at Palm Valley and Dingo would result in future sales to Central (including deliveries under existing contracts) of around 250 PJ.

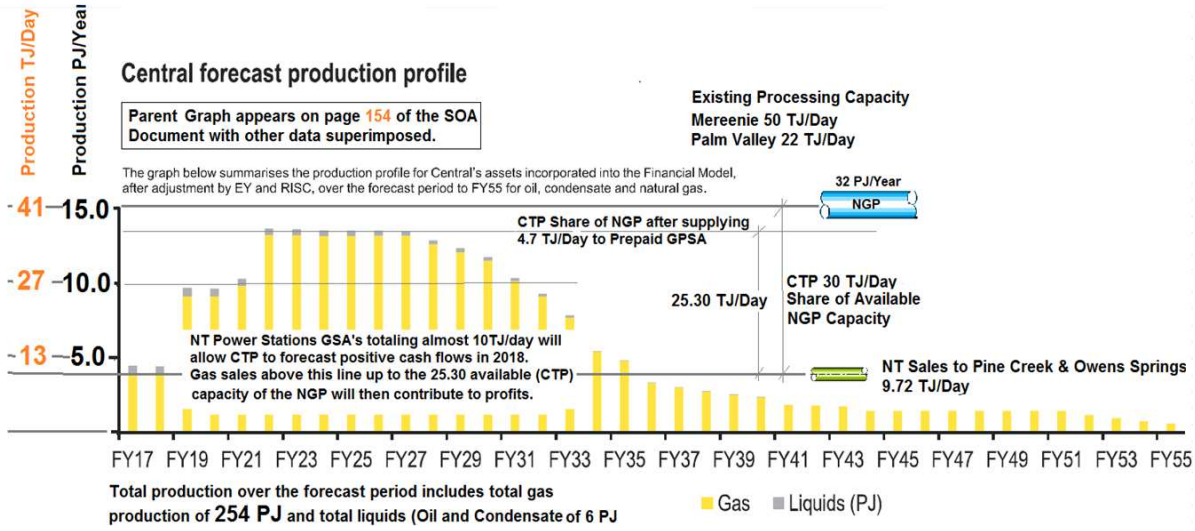
    - By 21/09/16 we had spent 4 million dollars on well engineering in relation to Mereenie exploration.

6.00 SOA's projection of CTP's future production Profile after the NGP1 is commissioned late 2018.

The SOA P226 describes the lower stairway resource development and I am hoping that it was taken into the weighted Central forecast production profile used to produce the montage below.

Clearly this model has inherent inaccuracies and makes a number of broad assumptions.

You can hold down the Ctrl key & use the mouse wheel to zoom in or out



The parent graph used to build the montage appears on page 154 of the SOA documentation on P154 with and vertical scale added for production in TJ/Day.

The line through the lower green Pipeline represents gas sold to NT markets which does not take up capacity in the NGP and the distance between the Green and Blue pipe lines represents CTP's 50% share of the present available capacity of the NGP path to East Coast gas Markets.

CTP's share of available NGP capacity will be reduced by 4.7 TJ/day for 3 years after the NGP is commissioned because it will probably be taken up with supplying gas to MAC to satisfy the prepaid GPSA.

This represents a 15% drop in available capacity.

It is interesting to compare the total gas production in the SOA model (Above) of **254PJ** with the reserve certification target in the Entitlement Offer Information Booklet P17 which, if successful, targets total potential 2P net to Central reserves of **352.9-541.4** reserves so that could explain why the production line 2022-27 on the SOA seems a bit low.

	No. of Wells	Gross Potential	Net to Central
1 Mereenie Stairway	2	110 – 186	55 – 92.5[1]
2 Palm Valley Shallow	1	83 – 165	83 – 165[2]
3 Ooraminna	1	89 – 158	89 – 158[3]
TOTAL 2P	**4**	**282 – 509**	**227 – 415.5[4]**
Existing Total Reserves			125.9[5]
TOTAL POTENTIAL 2P CENTRAL RESERVES			**352.9 – 541.4**

RISC Production Forecast for Mereenie from SOA P221

The RISC model indicates that the 2C Mereenie production through to 2030 is 50 TJ/day. The 2C production ties in with the apparent Mereenie Processing Capacity of 50 TJ/day.

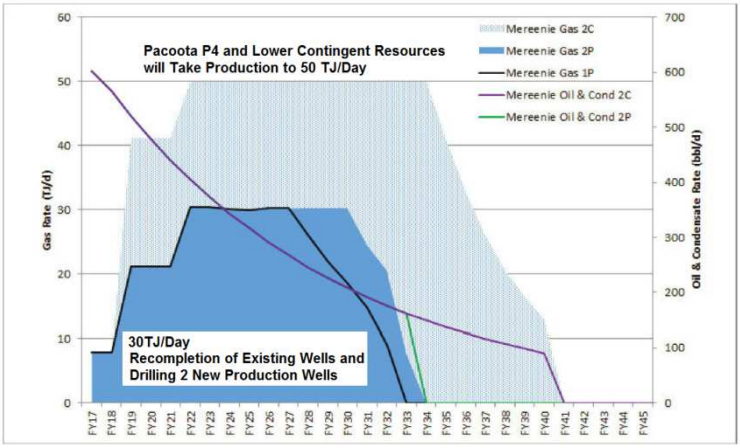


Figure 4-2: Mereenie Gross Gas and Liquids Production Forecasts

What is the Scope of the Lower Stairway Contingent Resource Development documented in the SOA?

SOA P226

I am still not comfortable with the possibility that CTP will need to get their hands on quite a bit of money to bring the Mereenie surface facilities up to enough capacity in time for NGP first gas.

Since as was mentioned at the AGM Webinar CTP will probably wait at least 12 months to refinance I wonder where this money will come from?

Straight out of the SOA at P226

Table 4-5: Lower Stairway contingent resource development scope and capital cost (gross)

Development scope	Cost (A$ million)
Facility works to allow 50 TJ/d gas production	68
48 Lower Stairway development wells	144
Other	0.5
Total development capital for contingent resources	**213**
Three additional development wells targeting 2P resource acceleration	*9.0*

Should the successful development of the lower stairway resources occur, it is also estimated that 3 additional wells are drilled to target the acceleration of 2P gas reserves.

Central's original development concept calls for the Lower Stairway Wells to be slim hole design to enable the utilisation of smaller low cost rigs as the wells are shallow at less than 1000m depth.

However recent work by Central has indicated the potential to drill high angle wells drilled underbalanced and/or with air oriented to maximise the intersection with natural fractures.

In this scenario laterals are anticipated to be in the order of 500-700m requiring a two well proof of concept well program prior to development.

What does the SOA say about how many more wells will be needed and what supportive surface facilities will be needed?

The high angle well option has the potential to significantly reduce the well count to reduce the well count to in the order of **20 albeit more expensive wells**.

If pursued, this option could potentially reduce capital costs by approx. $50 million.

What is the scope of works needed to upgrade the Mereenie Facilities to 50 TJ/Day?

The facility estimate is preliminary in nature and has been prepared with little engineering definition.

The facility scope rewired to increase production to 50 TJ/day is:

- Two new field boost compressors at 2.5 MW each
- Two new Export Compressirs at 1 MW Each.
- Slug Catcher Installation
- Additional Infield pipelines and flowlines.
- Installation of integrated control system
- Upgrade of PLC,s safety shutdown, SCADA, and individual control systems to allow better reliability at higher production rates.
- Installation of a more effective produced water management system.
- Installation of export metering and plant air.

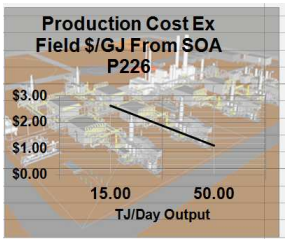
What range of production costs can we expect from the new facility?

SOA P226 It is estimated that operating costs increase from 14.5M in 2017 when production rates are approx 15TJ/Day (Had not signed EDL GSA for 9.85PJ of gas over five years IE. 5.39TJ/Day) to $20.3M/PA as production increases to 50 TJ/D.

Rough calculations on the above:

- **15TJ/day => $14.5M/5.475M GJ = $2.64/GJ operating Cost**
- **50TJ/day => $20.3M/18.25M GJ = $1.11/GJ operating Cost**

The above numbers were used to produce the graph used in the model.

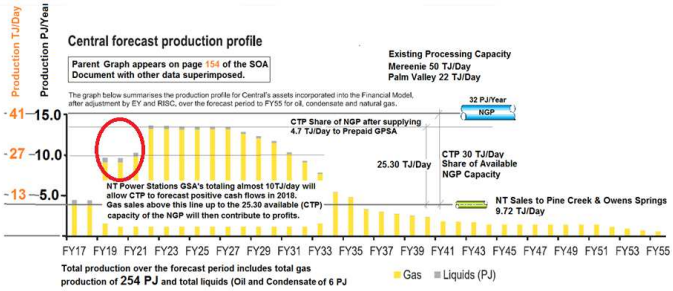


7.0 What Other Risks Does CTP Face?

Sustainable Flow Rates and Impact on Profits and Share Price

CTP would need to explain any variance between the current expected production profile forecast when compared with that shown on P154 of the SOA document which shows gas production peaking at under 40 TJ/day.

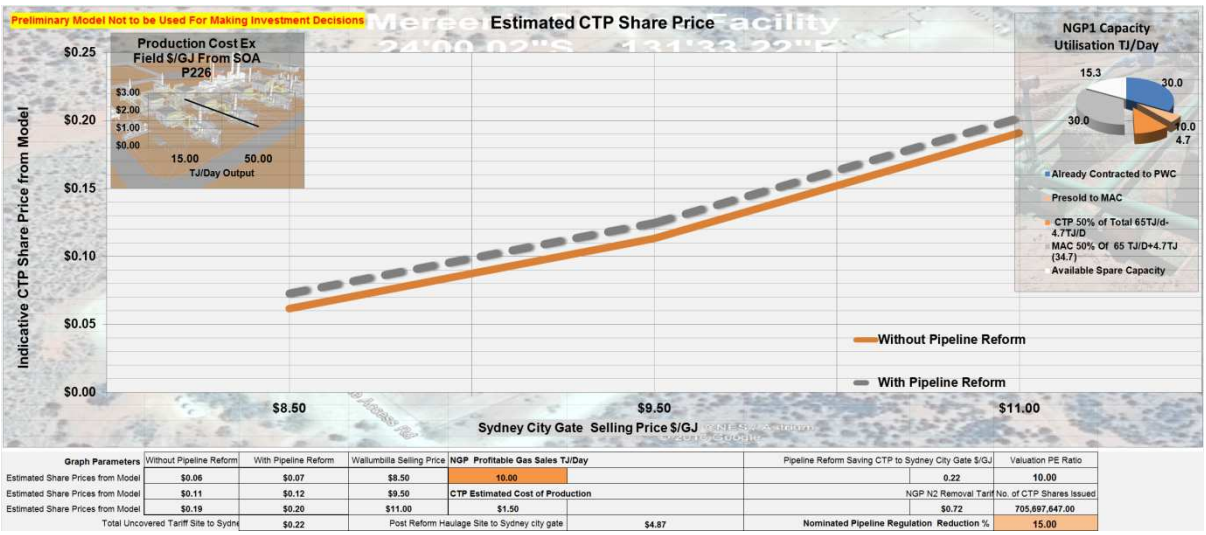
During financial years 19 20 and 21 the graph in the SOA appears to only be showing about 27 TJ/day.



It may be that CTP is relying on horizontal drilling of the stairway to make up the shortfall and there probably is a logical explanation however this needs to be addressed. The palm valley horizontal initiative may be the answer?

Treat the model with great caution because there are no dought a number of mitigating factors and this probably won't happen but with say **10TJ** and a potentoal higher production cost the model is warning us at least that this situation is to be avoided.

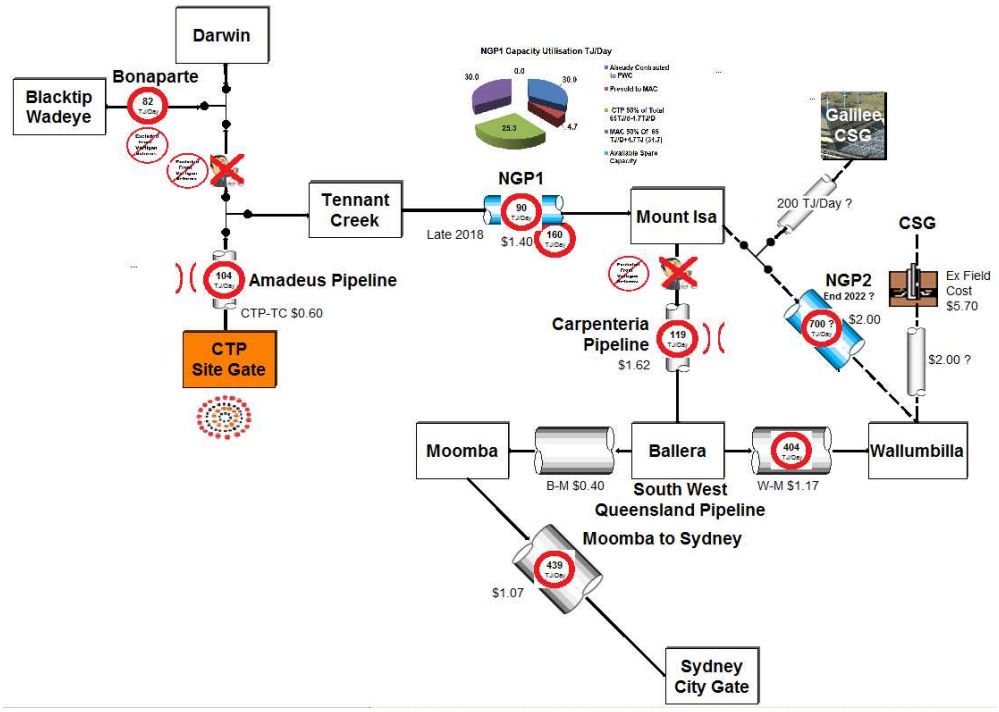
The white sector of the pie graph in the top RH corner shoes unfilled NGP capacity.



Graph Parameters	Without Pipeline Reform	With Pipeline Reform	Wallumbilla Selling Price	NGP Profitable Gas Sales TJ/Day		Pipeline Reform Saving CTP to Sydney City Gate $/GJ	Valuation PE Ratio
Estimated Share Prices from Model	$0.06	$0.07	$8.50	10.00		0.22	10.00
Estimated Share Prices from Model	$0.11	$0.12	$9.50	CTP Estimated Cost of Production		NGP N2 Removal Tariff	No. of CTP Shares Issued
Estimated Share Prices from Model	$0.19	$0.20	$11.00	$1.50		$0.72	705,697,647.00
Total Uncovered Tariff Site to Sydney	$0.22		Post Reform Haulage Site to Sydney city gate		$4.87	Nominated Pipeline Regulation Reduction %	15.00

Failure to produce 40 TJ/day (30NGP +10 NT) in time to take advantage of 60TJ/day initial NGP Capacity late 2018

A ceiling on profitability supported by East Coast gas sales will remain until CTP is able to export theit 30TJ/day share of the 100 TJ/day path to market.



Drilling Approvals covered by NT Schedule of onshore petroleum exploration and production requirements 2016. P25 covers approval application not less than 1 month before drilling.

https://nt.gov.au/__data/assets/pdf_file/0004/295906/schedule-of-petroleum-onshore-requirements-2016.pdf

Already Febuary has been mentioned as the start date for drilling (Mereenie).

From Webinar… Basically you will have an IP (Initial Production) as soon as you drill' and have the 90 day flow rates (90 days later) which will let you know whether your model is grossly accurate or grossly inaccurate and 180 is when you start the reserve certification process.

If reserve certification is a necessary prerequiste to funding of additional wells and infrastructure to produce CTP's share of the 60TJ/day spare NGP startup capacity then the comment in the SOA seems justified.

"Development of the Lower Stairway resources is forecast to start in FY 2019 in order to maximise througput into the NGP. This timeline is however very aggressive and could easily slip by 12 months or more."

To allay concerns shareholders really need to see an assuring L2 Plan.

Impact of Macquarie pre-paid gas sales agreement (GSPA)

It will probably sort itself out but I have assembled some background information.

As announced on 26 April 2017 Central entered into a Gas Sales agreement "GSA" with EDL NGD (NT) Pty Ltd ("EDL") with gas deliveries commencing 1 June 2017.

In May 2016 Central announced it had entered into a 5.2PJ pre-paid gas sales agreement "GSPA" with Macquarie Bank Limited "MBL", repayment of which will commence following commissioning of the Northern Gas Pipeline anticipated in late 2018.

Under the GSPA, MBL has a quarterly option to take a financial settlement in lieu of taking the physical delivery of the gas. The amount payable by Central, should MBL opt for a financial settlement, is dependent on the **actual price received under any new GSA's supplied from the agreed production areas.** Where there are no new GSA's or the quantity delivered under new GSA's is less than the GSPA volumes, a floor financial settlement amount would be payable. The economic consequences of the EDL GSTA was disclosed in the First Supplementary Scheme Booklet. As a consequence, Central is required under AASB 139 to adjust the carrying amount of the financial liability in line with the sales price negotiated under the EDL contract, net of any additional gas transportation costs. As the price paid by EDL under the GSA, net of transportation costs, exceeds the floor financial settlement price, the impact of the adjustment will be an expense to current year profit and loss of $9.49 million which reflects the total increase in potential financial liability over the life of the GSPA. It is important to note that the expense to be recorded for the 2016/17 financial year is a non-cash accounting adjustment. Additionally, this accounting treatment will record a liability reflecting the full expected amount to be paid out should MBL opt for a financial settlement in lieu of taking physical delivery of gas which would appear to be the conservative accounting treatment. It is also important to note that Accounting Standards do not allow Central to recognise any future assets associated with the revenue expected to be received under the EDL contract which triggers the increase in value of the GSPA financial liability. In this regard, Central's future accounting periods' profit and loss figures will include recognition of revenue under the EDL contract not currently recognised as an asset in the accounts for the 2016/17 financial year. In addition, where MBL elect for physical delivery of gas under the GSPA, the recorded financial liability will unwind resulting in an increase in accounting revenue for that period.

- **SOA P171 Notes the minimum capital expenditure required to increase production to levels required to meaningfuly access the East Cast gas market is estimated to be approx $40,6M…..**

9.3.1.4 Removal of exposure to near-term capital expenditure requirements

In order for Central to realise the value in its asset portfolio, the company requires further capital expenditure. Based on the Capex profiles reviewed by RISC, the minimum capital expenditure required to increase production to levels required to meaningfully access the East Coast gas market is estimated to be approximately $40.6 million for Mereenie, Palm Valley and Dingo. This does not include any further work on the expansion projects; Palm Valley Deep, Stairway or Ooraminna.

- Ooraminna gas will cost money for basic surface facilities and pipeline to Dingo & **if processed at Brewer estate will be subject to CTP pipeline capacity to the estate of somewhere near 5.36 TJ/Day.**

Ooraminna Commitment Well not drilled by 6 Mar 2018

SOA P242

The geological chance of success in Ooraminna is 100% because two wells have already established a gas resource. The chance of commercial success is dependent on Ooraminna-3 proving that an economic gas flow rate can be achieved on test. RISC estimates the commercial chance of success at 20%.

Comments made at the AGM Webinar which indicated that the wells would be treated as a package implying that this would not be a problem.

- This is important enough to be covered by a separate "Newsflow" announcement.

"Central has a 100% interest in Retention Licences 3 and 4 which has a Commitment Well which must be drilled by 6 March next year (see page 242 of Scheme Booklet for Ooraminna's prospectivity) for which capital will need to be raised. This timeframe has already been deferred from the original deadline. Given the east coast gas shortage and the imminent commissioning of the NGP with spare capacity there is a clear risk that another deferral of this commitment would not be granted again by the NT Government.

To avoid the commitment Central could hand back the licences with adverse consequences to the value of Central"

GRR Contingent Liability

I appreciate that there may be some legal issues here but every effort should be made to keep shareholders up to date.

9.3.1.5 Removal of exposure to contingent liabilities

As set out in section 4.2.4, Central is currently in a legal dispute with GRR. Any payment is contingent on the outcome of this legal dispute, which has been running for some time. There is currently no certainty whether or not Central will ultimately have to pay any of the disputed amount, or any other costs. Further, there is no certainty as to the potential timing of any payment. Central denies liability for the claim and is defending its position. Central has taken the view that there is no basis to record a financial liability in relation to this matter, and therefore no liability has been recorded on Central's audited balance sheet.

Given the uncertainty, and management's expectations with regard to potential payment, we have not included any potential liability in our valuation of Central. However, there is still a risk that Central will be ordered by the court to make some payment in regard to this dispute. If the Proposed Scheme is approved and implemented, Central Shareholders will no longer have any exposure to this potential future liability.

Competition from Imported Gas

Sounds rediculous but at the end of the day it doesen't surprise me that the economy of scale of the large LNG trains will eventualy start to tell and given the relative political inaction in Australia the simplest thing a business could do is to budget on parity with imported gas.

Large users like the Ammonia Reformer at Kooragang island would certainly be keeping an eye on their competitiveness since ammonia is an international commodity.

For a while I have been watching AGL's feasbility study on the AGL Cribb point facility.

http://www.abc.net.au/news/2016-11-24/having-spent-200b-to-export-lng-is-australia-about-to-import/8055164

Extracts:

Macquarie's utility team has also had a look at the numbers and found there is "some attraction" for AGL in importing gas.

"The (FSRU) infrastructure cost over ten years, assuming the facility was used at 75 per cent of capacity, is around $0.20/GJ.

Combined with the cost of rental and conversion, the cost of a re-gas facility is around $0.75/GJ," Macquarie said in a recent research note.

"Such a cost is materially cheaper than the cost of shipping gas from Wallumbilla to Victoria or NSW at around $2/GJ."

Factoring in a US-based Henry Hub price of around $US3.20/GJ and the various liquefaction, shipping and re-gassing charges, Mr Burns said LNG could be landed in New South Wales or Victoria at $10.50/GJ.

- ✓ IMO since gas prices that would trigger market demand destruction, imported CSG and the shipped cost of local coal seam CSG are not that far apart and if CTP can achieve deliverability of their relalitevly low cost product they are in a sound competitive position.

So lets keep an eye on AGL and their import initiative as the canery in the coal mine (Very appropriate). The article on the link below is well worth reading.

Crib point picked as the site:

http://www.smh.com.au/business/energy/victoria-picked-as-agls-preference-for-new-250m-lng-import-hub-20170810-gxtgdo.html

If the import terminal goes ahead it will be interesting to see if a market starts up for imported engine spec. LNG transported by road train or rail.

This was a really good find on the CTP HC site recently about global gas prices.

https://www.bloomberg.com/news/articles/2017-11-02/can-the-u-s-crack-the-90-billion-lng-market

Extract from the article:

The $90 billion global market for liquefied natural gas will be reshaped in 2018 as a number of large, long-term contracts start to expire. Growing supplies from the U.S., higher demand in Europe and Asia, and geopolitical tension surrounding Russia and Qatar, the world's two biggest gas suppliers, promise to shift long-established trading patterns.

For decades the majority of LNG bought and sold around the world has been governed by long-term contracts of up to 20 years. A fifth of those will expire from 2018 to 2020. Over the next decade, contracts governing 80 percent of all global LNG trade will be rewritten. For now, the LNG market is in the midst of an enormous supply glut, in part because of the advent of U.S. exports in the past two years. That glut is likely to persist until at least 2020, keeping prices low.

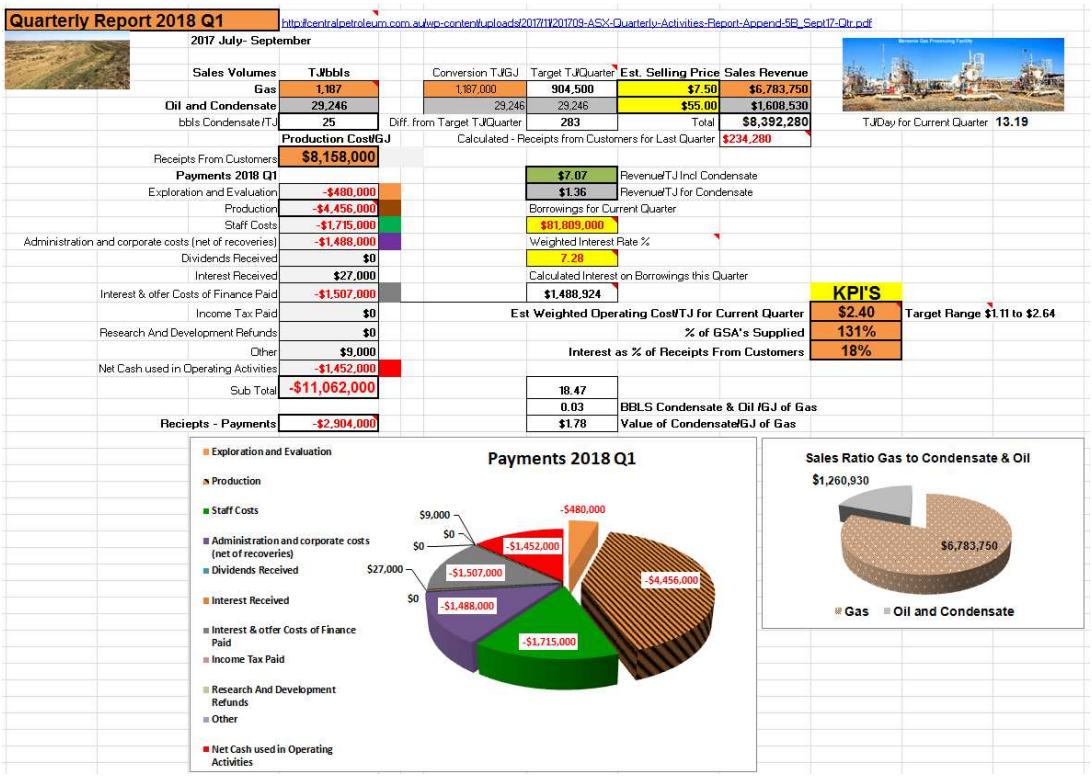
✓ **So as far as I can see we seem to be hovering around the $9-$10 mark which is good for CTP.**

8.00 Ramp up to NGP1 First Gas and Associated Reporting

There are 3 main areas of focus in order to prepare for the ramp up to achieve NGP1 100% of first gas as soon as it is ready.

- A successful appraisal drilling program
- Complete all shortfall works on Surface Facilities
- Fine tune existing 10TJ/Day NT production to reach the target Production Cost of $1.50/GJ

Snapshot from the Monthly Report portion of the Model



Quarterly Report 2018 Q1						
2017 July- September						
Sales Volumes	TJ/bbls	Conversion TJ/GJ	Target TJ/Quarter	Est. Selling Price	Sales Revenue	
Gas	1,187	1,187,000	904,500	$7.50	$6,783,750	
Oil and Condensate	29,246	29,246	29,246	$55.00	$1,608,530	
bbls Condensate/TJ	25	Diff. from Target TJ/Quarter	283	Total	$8,392,280	TJ/Day for Current Quarter 13.19
Production Cost/GJ		Calculated - Receipts from Customers for Last Quarter			$234,280	
Receipts From Customers	$8,158,000					
Payments 2018 Q1			$7.07	Revenue/TJ Incl Condensate		
Exploration and Evaluation	-$480,000		$1.36	Revenue/TJ for Condensate		
Production	-$4,456,000		Borrowings for Current Quarter			
Staff Costs	-$1,715,000		$81,809,000			
Administration and corporate costs (net of recoveries)	-$1,488,000		Weighted Interest Rate %			
Dividends Received	$0		7.28			
Interest Received	$27,000		Calculated Interest on Borrowings this Quarter			
Interest & otfer Costs of Finance Paid	-$1,507,000		$1,488,924		KPI'S	
Income Tax Paid	$0		Est Weighted Operating Cost/TJ for Current Quarter		$2.40	Target Range $1.11 to $2.64
Research And Development Refunds	$0		% of GSA's Supplied		131%	
Other	$9,000		Interest as % of Receipts From Customers		18%	
Net Cash used in Operating Activities	-$1,452,000					
Sub Total	-$11,062,000		18.47			
			0.03	BBLS Condensate & Oil /GJ of Gas		
Reciepts - Payments	-$2,904,000		$1.78	Value of Condensate/GJ of Gas		

Comments on the last Quarterly Report 2018 Q1 July-Sept

http://centralpetroleum.com.au/wp-content/uploads/2017/11/201709-ASX-Quarterly-Activities-Report-Append-5B_Sept17-Qtr.pdf

The 2018 Q1 Monthly Report is producing gas at an average rate of 1,187 TJ for the quarter (About 13.2 TJ/day on average).

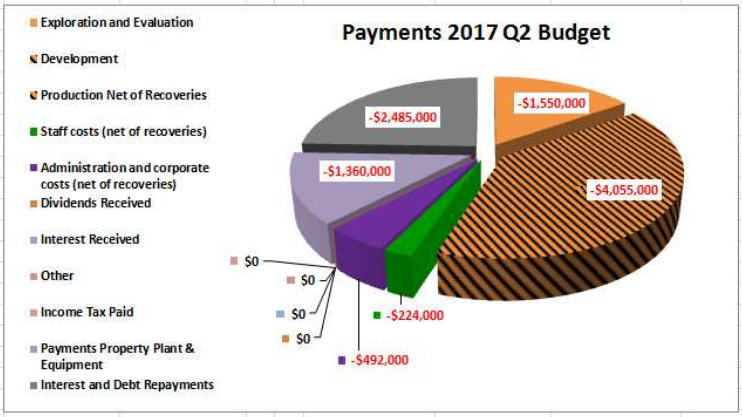
Preliminary list of desired KPI's as of 2018 Q1 :-

- **COP for gas is very difficult to establish with the data in the quarterly report but will need target $1.50.**
- **% of GSA's supplied slightly over target but there is probably a good explanation for this.**
- **Interest and other costs of finance as a % of sales is a % we need to keep in our heads Presently 18%**

The next quarter 2018 Q2 budget shows a significant reduction in staff and admin and whilst this may be due to extraordinary items being included in the last quarter payments $224,000 does not seem much tp pay for staff during this period. I note that the staff costs are net of recoveries and this may mean that CTP are doing a pretty good job in this area.

Next Quarter 2018 Q2 Budget

Payments 2017 Q2 Budget	
Exploration and Evaluation	-$1,550,000
Development	
Production Net of Recoveries	-$4,055,000
Staff costs (net of recoveries)	-$224,000
Administration and corporate costs (net of recoveries)	-$492,000
Dividends Received	$0
Interest Received	$0
Other	$0
Income Tax Paid	$0
Payments Property Plant & Equipment	-$1,360,000
Interest and Debt Repayments	-$2,485,000
Sub Total	-$10,166,000



8.00 NGP1 and NGP2 Extension Update

I left this until last because it is a major component of the jigsaw pussle and it links CTP, Galilee Beetaloo Etc.

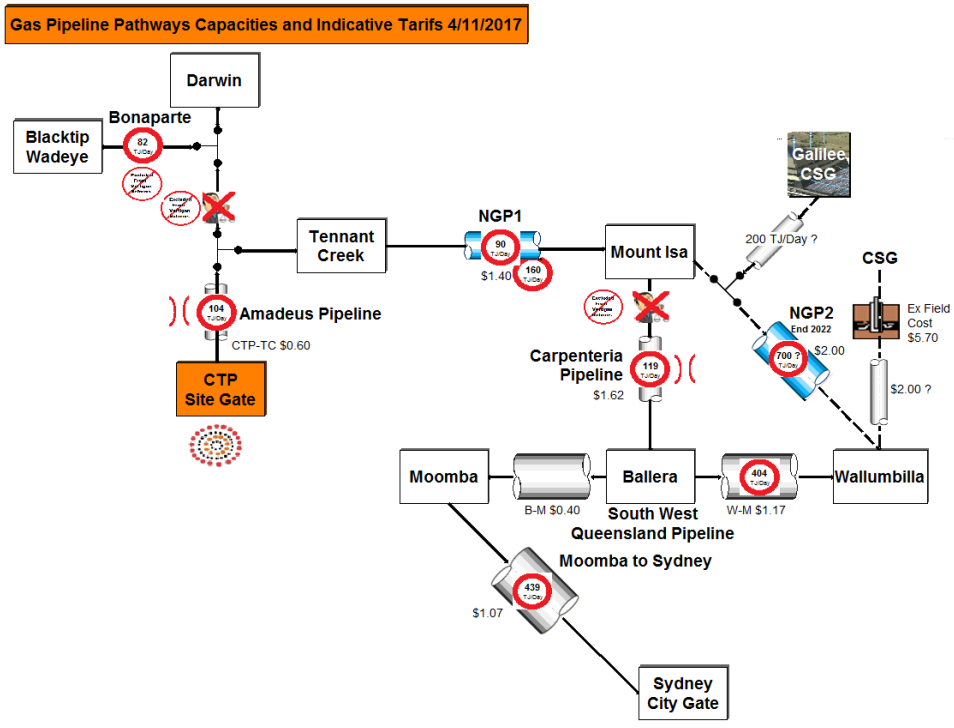
Put simply, my guess is that the NGP1 capacity is likely to remain at 90-100 TJ/Day for at least 3 years after NGP first gas.

The PWC Incitec Pivot 30 TJ/Day supply agreement extends through to 2028 and ties up 30 TJ/Day of NGP and Carpentaria pipeline capacity leaving CTP/MAC with a 60 TJ/Day pathway to East Coast markets until either 2028 of the NGP1 capacity is increased by adding compression.

Apart from oil, condensate revenue and NT gas sales the CTP revenue stream from East Coast Gas sales is limited by the available pipeline capacity to that market.

The risk of the NGP1 not being ready for first gas at end 2018 or very close to that date is very low.

The diagram below has nameplate capacities and published tariffs as of 4/11/17 added.



Debottlenecking CTP's Pathway to Sydney city gate Markets

Whilst the capacity of NGP1 will almost certainly be increased (Hopefully by 2022), coming up with a business cast to justify APA increasing the capacity of the lower portion of the Amadeus pipeline as well as the Carpentaria pipeline may be a much harder task.

It is not much good upgrading the NGP1 capacity without a similar upgrade to the upstream Amadeus and downstream Carpentaria pipelines so CTP needs to focus on a base case of 60 TJ/day of spare NGP1 capacity being available in the medium term future.

http://www.asx.com.au/asxpdf/20151117/pdf/4331qrwkm0n05v.pdf

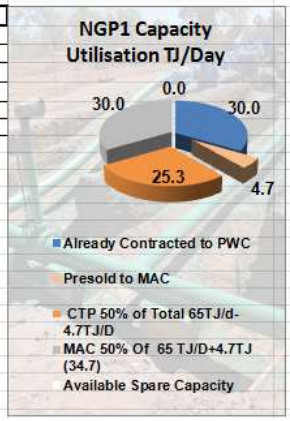
A negotiating strategy needs to be designed to maximise the chances of synchronising CTP/MAC output to East Coast markets in excess of 60 TJ/day.

http://www.abnnewswire.net/press/en/78632/Central-Petroleum-Limited-(ASX-CTP)-Enters-Framework-Agreement-with-Incitec-Pivot-78632.html

NGP1 capacity Utilisation without compression taking into account the supply of 4.7 TJ/day of presold MAC gas.

NGP1 Capacity Utilisation Model

NGP "Pipefull" Without Compression at 90 TJ/Day	TJ/Day	PJ/Year
NGP1 Uncompressed Capacity	90.00	32.85
Already Contracted to PWC	30.00	10.95
Presold to MAC	4.70	1.72
CTP 50% of Total 65TJ/d-4.7TJ/D	25.30	9.23
MAC 50% Of 65 TJ/D+4.7TJ (34.7)	30.00	10.95
Available Spare Capacity	**0.00**	**0.00**



For the record, it was a pity that the CTP announcement that it had entered into a non-binding heads of agreement (HOA) to supply up to 15PJ pa of gas from its conventional reservoirs in the Northern Territory to Incitec Pivot Limited did not result in business to CTP.

http://www.asx.com.au/asxpdf/20141111/pdf/42tmlfbwl49k7r.pdf

I was not impressed at the time that when the PWC stole this one from under CTP's nose that its shareholders were not at least informed. The absurdity of the whole thing is that our EDL GSA molecules will probably go straight round the corner at Tennant Creek down the Carpentaria pipeline and end up at Phosphate hill.
I hope we are able to obtain a discount from Jemena if we feed low N_2 gas into the Amadeus pipeline even if it is headed North.

- Doing a final check but I am pretty sure that to increase capacity from 90TJ/day to 160 TJ/day NGP1 needs to add a midline compressor station which was not in the NGP1 start-up scope. It is my guess that the commissioning of additional NGP capacity will be timed to coincide with the NGP2 extension to be ready late 2022.

The N_2 removal plant should have been sized for the final load or would be easily scalable.

https://jemena.com.au/about/newsroom/media-release/2017/jemena-fast-tracks-plans-to-connect-galilee-basin-

http://www.couriermail.com.au/business/jemena-and-galilee-energy-strike-deal-to-fasttrack-gas-pipeline/news-story/dc93f948abe2b7799733a1332344449d

- Jemena's Mr Boey explained that "by undertaking the early planning works, both Jemena and Galilee Energy will be ready to proceed to front end engineering and design (FEED) on both pipeline and field development in 2019 **with the objective of first gas to market in 2022**."

- IMO the extension of the NGP pipeline will reduce viability of a Carpentaria Pipeline upgrade leaving CTP restricted to 60 TJ/day until the extended Jemena pipeline provides a path for the increased NGP capacity 2022.

    - I noted the comment with interest from Jemena's Mr Boey mentioning 200 TJ/day from Galilee's Glenaras project and the 90-100 TJ/day NGP flow which seems to add weight to the proposition that Jemena won't increase the NGP capacity until there they have firm commitments to fill the pipe and the bottleneck at the Tennant Creek end is solved..

- There has been talk that the NGP extension will probably be able to ultimately handle on the order of 700TJ/day.

 "So until 2022, CTP will have to accept the fact that our gas molecules are being bounced around and penalised by dollar munchers as they drop down the piping pin ball machine on their way to Sydney, whilst our politicians delay the inevitable and much needed pipeline reform indefinitely".

_____The End_____