Gas Reserves and Resources and Cost Estimates

Eastern Australia, NT

November 2019

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General Definitions

Acronyms

2C	Proved Plus Probable Resource
2P	Proved Plus Probable Reserve
AEMO	Australian Energy Market Operator
AUD	Australian dollars
bbl	Barrel
CORE	Core Energy & Resources Pty Limited
CPI	Consumer Price Index
CSG	Coal Seam Gas
DNRME	Department of Natural Resources, Mines and Energy
EA	Eastern Australia
GBJV	Gippsland Basin Joint Venture
GJ	Gigajoule
GPG	Gas Powered Generation
I	Industrial
LNG	Liquefied Natural Gas
MDQ	Maximum Daily Quantity
NEM	National Electricity Market
NGFR	National Gas Forecasting Report
NSW	New South Wales
OPEX	Operational Expenditure
QGP	Queensland Gas Pipeline
QLD	Queensland
SA	South Australia
SEA Gas	South East Australian Gas Pipeline
PRMS	Petroelum Resource Management System
VIC	Victoria

Report Convention

Author	This Report has been prepared by Core Energy & Resources Pty Limited, referred to as 'CORE'.
Year References	All references to years that appear in the report are to calendar years.
$ value references	All references to $ are to Australian dollars unless otherwise stated, and values are expressed in real July 2019 terms.
Delivery points	Delivered prices are at exit flange/metering point of a transmission pipeline system

Frequently Used Terms

Break-even Price	Indicates the constant real price at which project NPV = 0 given a 10% discount rate applied to all cash flows covering project capex, opex, tax and royalties, and based on estimated production over time.
Delivered Price	The price of gas at the delivery point on a transmission pipeline to a generator or gas distribution offtake point. Note that all prices are quoted in real 2019 terms.
Gas Powered Generation (GPG)	A gas market demand segment that comprises gas-fired power stations. Gas is delivered via transmission pipeline before being combusted to drive a gas turbine to generate electricity.
ICE Brent	An oil price marker widely used, intenationally, to establish the exchange value of oil-linked commodities.
Linepack	The pressurised volume of gas stored in the pipeline system. Essential to enable gas transportation through the pipeline network throughout each day and required as a buffer for within-day supply/demand balancing.
Netback price	An export parity price that a gas supplier can expect to receive for exporting its gas. It is calculated by taking the price that could be received for LNG (on an f.o.b basis) and subtracting or 'netting back' the costs associated with (a) transporting the gas from fields and processing plant/s via dedicated transmission system; (b) liquefaction of the gas via a dedicated LNG plant; and (c) handling the gas for export via a marine terminal (Gladstone).
Forward Cost	Forward costs are those operating and capital costs yet to be incurred at the time that valuation is made. Historical cash flow and 'sunk' costs, such as past expenditures for acquisition, exploration, and development, are not included.
Lifecycle Cost	To incentivise investment over the long term, gas producers must realise a minimum price for production which covers full life cycle costs and a return on capital employed. For the purpose of this engagement this is referred to as the Break-even price.
Prospective Resource	Prospective Resources are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from undiscovered accumulations.
Reserves	Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward.
Contingent Resources	Contingent Resources are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from known accumulations, but which are not currently considered to be commercially recoverable.

Developed Reserve	Developed reserves are expected to be recovered from existing wells including reserves behind pipe. Improved recovery reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor.
Undeveloped Reserve	Undeveloped reserves are expected to be recovered from new wells on undrilled acreage, from deepening existing wells to a different reservoir, or where a relatively large expenditure is required to recomplete an existing well or install production or transportation facilities for primary or improved recovery projects.

1. Introduction

1.1. Scope of Report

The Australian Energy Market Operator ("AEMO") has engaged Core Energy & Resources ("CORE") to provide gas production data, including:

a. Reserve and resource estimates for existing and known basins and fields in all Australian States and Territories located onshore and offshore, excluding Western Australia. Reserve and resource classifications include:

- i. 2P (proved and probable) reserves – developed
- ii. 2P (proved and probable) reserves – undeveloped
- iii. 2C (contingent) resources
- iv. Prospective resources

b. Contracted supply estimates for each basin and field

c. Production costs for each field

1.2. Report Structure

This report includes five main elements:

Approach

Outline of the approach CORE has adopted to arrive at estimates of reserves and resources, contracted supply and costs of production.

Key Risk, Uncertainties and Key Assumptions

Summary of the key risks, and uncertainties relating to estimates addressed in this report.

Reserves and Resources

Summary of estimated reserves and resources at 31 December 2018.

Contracted Supply Estimates

Summary of contracted supply as it relates to domestic customers and sales between LNG producers.

Production Cost Estimates

Summary of the projected cost of producing defined reserves and resources.

2. Approach

The following is a summary of the approach adopted by CORE to develop estimates of:

- Reserves and Resources
- Contracted Supply
- Cost of Production

2.1. Reserves & Resources

CORE has been engaged by AEMO to develop an estimate of reserve and resource for existing and known basins and fields in all Australian States and Territories located onshore and offshore, excluding Western Australia, that are connected to the Eastern Australia gas system.

Estimates of reserves and resources from SA, NSW, VIC and NT regions that flow into the EA gas system were identified via research of public sources, including annual reports and other ASX releases.

Queensland Coal Seam Gas and convetional reserve and resource estimates have been sourced from Queensland Department of Natural Resources, Mines and Energy (DNRME) petroleum and gas production and reserve statistics.

2.2. Contracted Supply

CORE has been engaged by AEMO to develop an estimate of contracted supply at 31 December 2018.

CORE has developed estimates of two contract series, via research and analysis of public releases:

- Domestic Contracts – contracts between a producer and a customer where gas is used for domestic purposes
- LNG Contracts – contracts of gas supply between LNG ventures.

2.3. Production Cost

CORE has been engaged by AEMO to develop an estimate of the cost of production of reserves and contingent resources at at 31 December 2018.

CORE's proprietary Energyview™ energy intelligence platform was utilised to derive production cost estimates. This platform incorporates extensive technical and commercial data, data models and GIS mapping technology to enable focused analysis of each supply region under consideration.

The approach adopted is based on generally accepted best practice within the international oil and gas industry, including the following elements:

- Development of a database of remaining 2P gas reserves disclosed by operators and Government as at 31 December 2018
- Definition of individual supply areas, having regard to geology, permit areas and geographical boundaries
- Development of production scenarios for each supply area
- Identification and quantification of full lifecycle, sunk and go forward/marginal costs
- Derivation of breakeven price, utilising a proprietary model which adopts a net present value methodology

3. Key Risks, Uncertainties and Key Assumptions

As is the case with any projection of future outcomes, there are a range of risks and uncertainties, both to the downside and upside, which relate to reserves and resources, contracts and costs referenced throughout this report. CORE considers that a range of factors, could give rise to a material variance from estimates identified within this report, including:

- Accuracy, consistency and completeness of public disclosures generally, including highly variable quality of disclosure in relation to contingent and prospective resources, future production and cost (marginal and full life-cycle)
- Inherent uncertainty relating to estimation of reserves and resources as defined within the international PRMS guidelines
- Heterogeneity of coal geology which can have a material impact on the productivity of future unconventional coal seam gas wells
- Uncertainty relating to future cost estimation associated with future drilling and completion of wells due to impact of any changes in technology and industry cost structure (including future labour and service costs which can materially impact operating cost), noting also that costs can be correlated with movements in global commodity prices
- The timing of and rate at which operators can introduce cost efficiency programs
- The adequacy of existing processing plant, from capacity and operational integrity perspectives
- Future recovery of reserve per well (EUR per well) over the well life
- Uncertainty relating to initial well flow rates and subsequent rate of decline
- The allocation of cost between gas production and the cost of producing associated gas liquids and related oil (where oil is processed through the same overall complex, such as Moomba and Longford complexes)
- The extent of related costs associated with corporate, general and administration activities
- The cost and timing of abandonment and restoration of well and operational facilities

4. Reserves and Resource Estimates

4.1. Introduction

Reserves and Resource estimates at 31 December 2018[1] are set out in the following tables.

4.2. 2P Reserves by Project/Supply Region | December 2018 (PJ)

		2P Reserves	
Project / Supply Region	**Total**	**Developed**	**Undeveloped**
Bass Basin	281	70	210
Camden	28	28	-
Casino, Henry and Netherby	127	50	78
Cooper Eromanga Basin	1,009	757	252
GBJV & Turrum (excludes Kipper Venture)	1,690	536	1,154
Kipper	583	583	-
Halladale/Blackwatch/Speculant	25	25	-
Longtom	79	-	79
Sole	249	-	249
Minerva	8	8	-
Otway Gas Project incl. La Bella	450	121	328
Surat / Bowen / Denison Conventional	122	69	53
NT Gas | Blacktip	804	804	-
NT Gas | Amadeus	185	93	93
Moranbah	257	219	38
QLD CSG - Arrow Energy (excl. Moranbah)	6,461	520	5,941
QLD CSG - BG / QCLNG	8,724	3,963	4,761
QLD CSG - GLNG	5,888	1,397	4,492
QLD CSG - ORG / APLNG	10,266	4,406	5,859
QLD CSG - Other	1,306	176	1,130
Total	**38,542**	**13,824**	**24,718**

[1] Latest date of disclosure of Queensland reserves by DNRME

4.3. 2C Contingent Resource Estimates by Project/Supply Region | December 2018 (PJ)

Project / Supply Region	2C Resources
Bass Basin	70
Casino, Henry and Netherby	36
Cooper Eromanga Basin	5,850
GBJV & Turrum & Kipper	686
Longtom & Sole	130
Moranbah	5,548
Surat / Bowen / Denison Conventional	120
QLD CSG - Arrow Energy (excl. Moranbah)	15,887
QLD CSG - BG / QCLNG	13,700
QLD CSG - GLNG	1,355
QLD CSG - Ironbark / ORG	-
QLD CSG - ORG / APLNG	4,244
QLD CSG - Other	3,832
Gippsland Basin - Other	3,526
Clarence-Moreton Basin - Other	303
Gunnedah Basin - Other	971
Galilee Basin - Other	2,417
Adavale Basin - Other	22
Otway Basin - Other	216
Central Petroleum Amadeus	193
Falcon Oil & Gas (Georgina Basin)	-
Cash Maple	3,712
Beetaloo Basin	6,999
Gloucester Basin	462
Coxco Dolomite	5,196

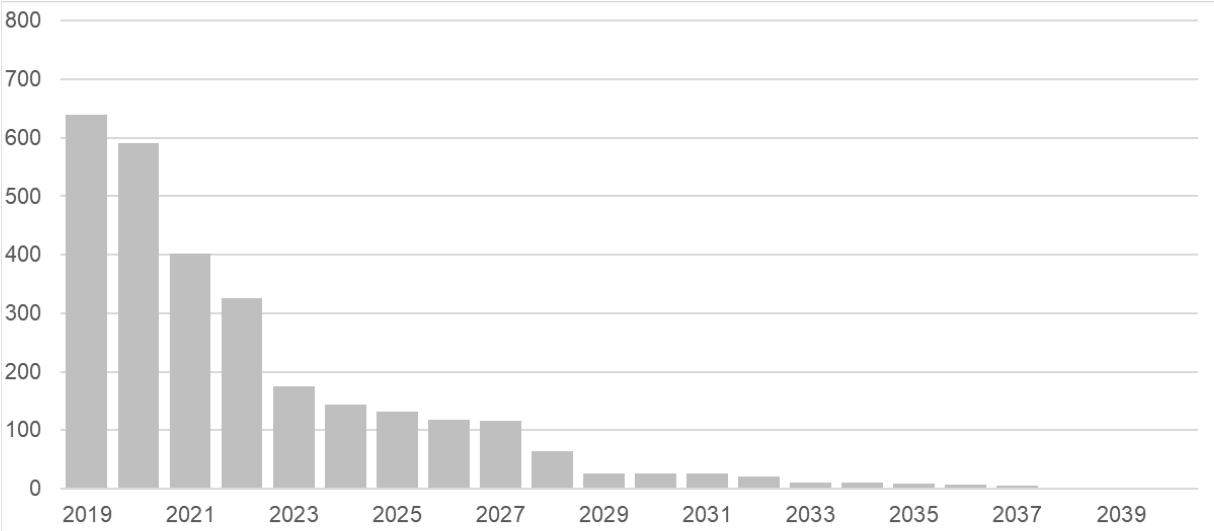
4.4. Prospective Resource Estimates by Project/Supply Region December 2018 (PJ)

Supply Project	Basin	Reported Prospective Resource PJe
Barney Creek Shale Wollogorang Shale Tawallah Group McDermott	McArthur Basin	36,924
Arrow Surat Bowen	Surat Bowen Basin	10,807
ATP 855	Cooper Eromanga Basin	30,223
Battunga Shale	Cooper Eromanga Basin	5,027
Battunga Shale Coal	Cooper Eromanga Basin	8,092
Benara	Otway Basin	26
Benara East	Otway Basin	16
CBJV SA UNIT	Cooper Eromanga Basin	53,549
Central Cooper Unconventional	Cooper Eromanga Basin	11,771
Flanagan	Otway Basin	1,421
Galilee Gas Project	Galilee Basin	25
Gangell, Trifon and Barawanath	Gippsland Basin	1,024
GBJV including Turrum	Gippsland Basin	4,062
Gemfish	Gippsland Basin	302
Greater Timmy Area	Bowen Basin	350
Gunn Project Area	Galilee Basin	597
Holdfast	Cooper Basin	1,888
Judith	Gippsland Basin	1,300
Kipling Benchley	Gippsland Basin	1,196
La Bella	Otway Basin	1,107
Lead A	Gippsland Basin	636
Longtom	Gippsland Basin	50
Milpera and Larow Coal	Cooper Eromanga Basin	8,183
Milpera and Larow Shale	Cooper Eromanga Basin	3,627
Nangwarry	Otway Basin	121
PEL 428	Gunnedah Basin	3,502
PEL 456	Clarence-Moreton Basin	13,875
PEL 458	Clarence-Moreton Basin	825
PEP 11	Sydney Basin	4,993
QCLNG	Surat Basin	8,586
Southern Cooper Gas Project	Cooper Eromanga Basin	16,770
VIC P68	Gippsland Basin	238
Weena Shale	Cooper Eromanga Basin	7,322
Mount Kitty	Amadeus Basin	742
Ooraminna	Amadeus Basin	1,802
Waterhouse	Amadeus Basin	1,060
Velkerri	Beetaloo Basin	64,688

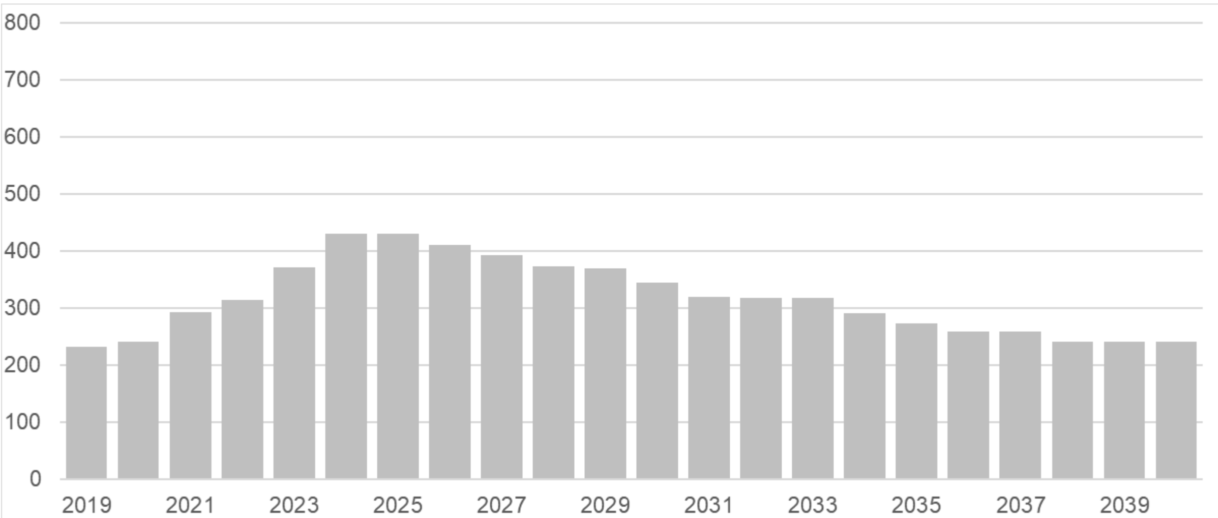
5. Contracted Supply Estimates

As noted in the Approach section above, CORE has undertaken an analysis of contracted supply in eastern Australia and NT as at 31 December 2018 for both domestic supply and gas supplied by an LNG producer to another LNG producer. The results are summarised in the following figures and the underlying data is provided in the related data book.

5.1. Domestic Contract Estimates at 31 December 2018 (PJ)



5.2. LNG Party Supply Contract Estimates at 31 December 2018 (PJ)



6. Production Cost Estimates

6.1. 2P Reserves

Project / Supply Region	Forward Cost | Developed (AUD/GJ)	Forward Cost | Undeveloped (AUD/GJ)	Full Lifecycle Cost | AUD/GJ
Bass Basin	2.90	5.60-6.60 if new well required	4.99
Camden	2.44		5.19
Casino, Henry and Netherby	2.34	5.10-6.10 if new well required	4.07
Cooper Eromanga Basin	2.44	6.36	7.07
GBJV & Turrum (excludes Kipper Venture)	2.34	5.50	3.87
Kipper	2.95		8.40
Halladale/Blackwatch/Speculant	3.87	4.99	5.50
Longtom	3.26		5.70
Sole		5.70	6.62
Minerva	3.16		3.56
Otway Gas Project incl. La Bella	2.70	5.40-6.40 if new well required	4.63
Surat / Bowen / Denison Conventional	2.85	5.95	6.36
NT Gas | Blacktip	2.47-3.78		5.21
NT Gas | Amadeus	2.93-3.16	4.73-5.19	5.04-5.34
Moranbah	3.16	6.78	7.19
QLD CSG - Arrow Energy (excl. Moranbah)	3.16-3.39	5.34-5.92	6.69-6.74
QLD CSG - BG / QCLNG	2.49-2.68	4.48-5.04	6.21-7.60
QLD CSG - GLNG	2.76-3.37	5.80-7.16	6.96-8.25
QLD CSG - ORG / APLNG	1.80-2.81	4.27-5.47	5.30-6.59
QLD CSG - Other	3.81-3.81	6.25-7.10	6.61-7.18

6.2. 2C Contingent and Prospective Resources

<table>
<tr><th>Project / Supply Region</th><th>OPEX, Well Cost & Existing Plant Cost, Royalty & Tax | AUD/GJ</th><th>OPEX, Well Cost & New Plant Cost, Royalty & Tax | AUD/GJ</th><th>Including Appraisal, Acquisition & Exploration Cost | AUD/GJ</th></tr>
<tr><td>Bass Basin</td><td>6.02</td><td></td><td>6.84</td></tr>
<tr><td>Casino, Henry and Netherby</td><td>3.51-4.63</td><td></td><td>0.00</td></tr>
<tr><td>Cooper Eromanga Basin</td><td>7.12</td><td></td><td>7.63</td></tr>
<tr><td>GBJV & Turrum & Kipper</td><td>6.29</td><td></td><td>7.43</td></tr>
<tr><td>Longtom & Sole</td><td>5.80</td><td></td><td>6.51</td></tr>
<tr><td>Moranbah</td><td>5.24</td><td>5.71</td><td>6.91</td></tr>
<tr><td>QLD CSG - Arrow Energy (excl. Moranbah)</td><td>6.61</td><td>7.55</td><td>0.00</td></tr>
<tr><td>QLD CSG - BG / QCLNG</td><td>6.45</td><td>7.39</td><td>0.00</td></tr>
<tr><td>QLD CSG - GLNG</td><td>8.44</td><td>9.44</td><td>0.00</td></tr>
<tr><td>QLD CSG - Ironbark / ORG</td><td>5.18</td><td></td><td></td></tr>
<tr><td>QLD CSG - ORG / APLNG</td><td>6.60</td><td>7.47</td><td>7.93</td></tr>
<tr><td>QLD CSG - Other</td><td>0.00</td><td>8.87</td><td>9.38</td></tr>
<tr><td>Gippsland Basin - Other</td><td rowspan="12">6.77-8.30</td><td rowspan="12">7.28-9.36</td><td rowspan="12">7.28-9.87</td></tr>
<tr><td>Clarence-Moreton Basin - Other</td></tr>
<tr><td>Gunnedah Basin - Other</td></tr>
<tr><td>Galilee Basin - Other</td></tr>
<tr><td>Adavale Basin - Other</td></tr>
<tr><td>Otway Basin - Other</td></tr>
<tr><td>Central Petroleum Amadeus</td></tr>
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<tr><td>Gloucester Basin</td></tr>
<tr><td>Coxco Dolomite</td></tr>
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7. Terms of Use

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