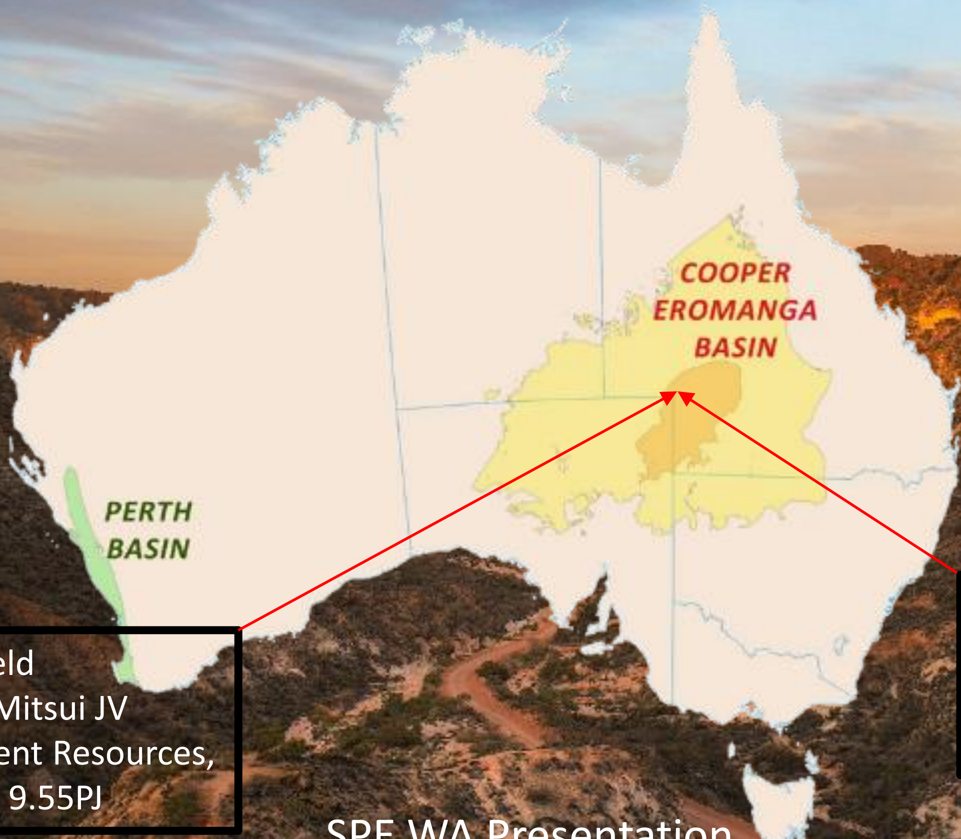
METGASCO

Delivering 'Two' New Gas Sources to the Undersupplied East Coast Energy Market



Odin gas field
GSA with ENGIE/Mitsui JV
39.7 PJ (Gross) Contingent Resources,
Metgasco share 9.55PJ

Vali gas field
GSA with AGL for up to 16 PJ,
101 PJ (Gross) 2P reserves,
Metgasco share 25.2 PJ

SPE WA Presentation
22 August 2023

Agenda - Metgasco Journey from Explorer to Producer

METGASCO

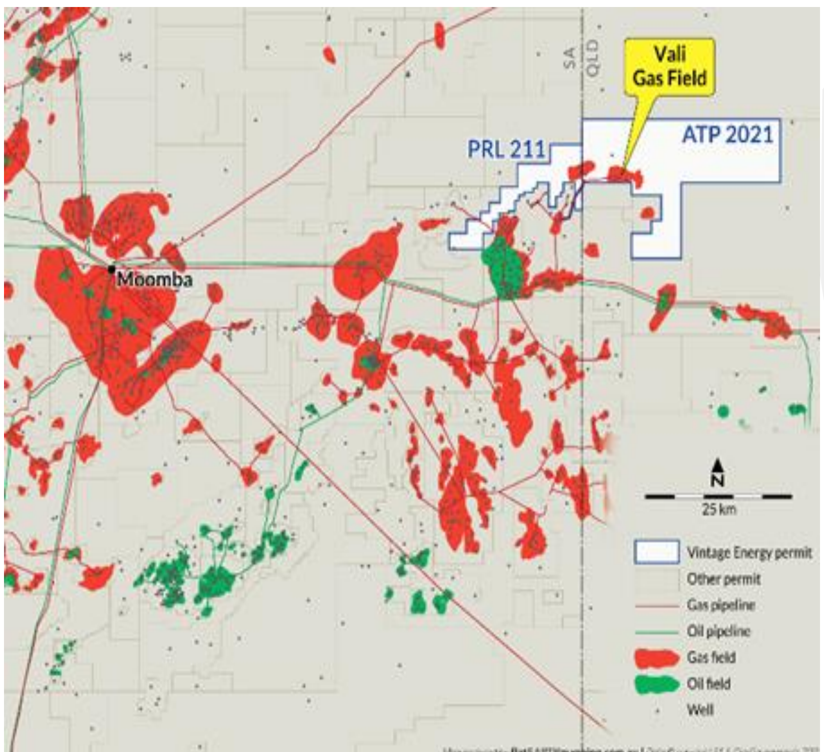
*See Reserve and Resource Notes on page 19 for Further Details

Company Overview and Hub and Spoke Strategy

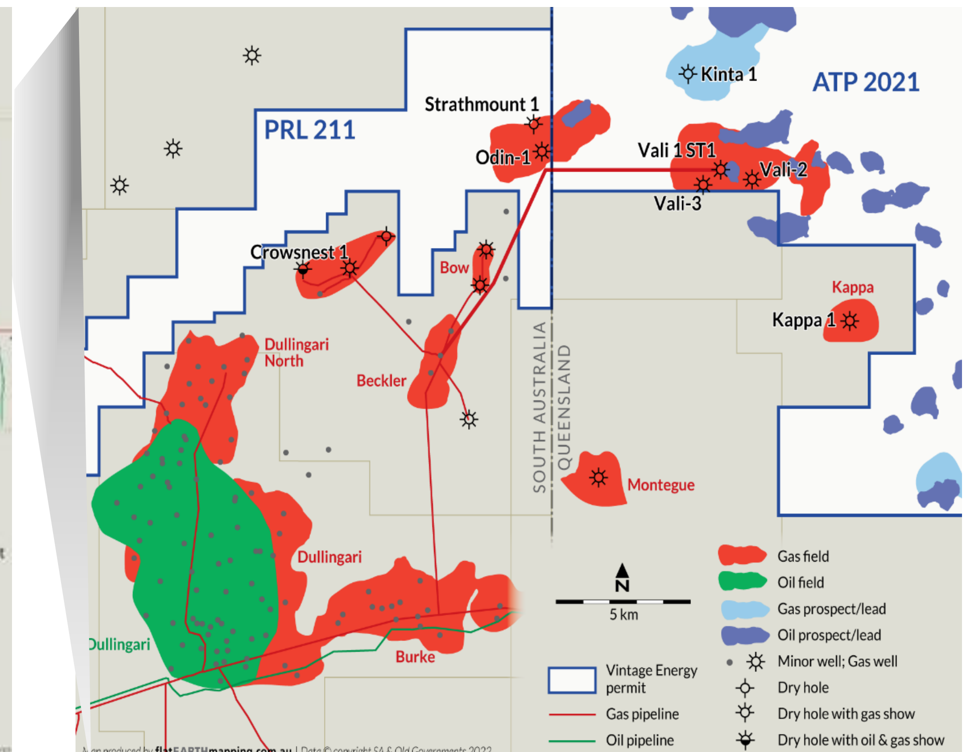
METGASCO

- **Metgasco is an ASX listed (ASX:MEL) small cap oil and gas exploration and production company supplying gas to Eastern Australia domestic customers from the Cooper Basin**
- **Metgasco has a 25% non-operated interest in the ATP2021 and PRL211 Licences**
- **Two gas fields producing by Q3 CY23**
- **Hub and Spoke strategy to build gas production revenue and shareholder value**

Cooper Basin - Location of ATP 2021 / PRL 211



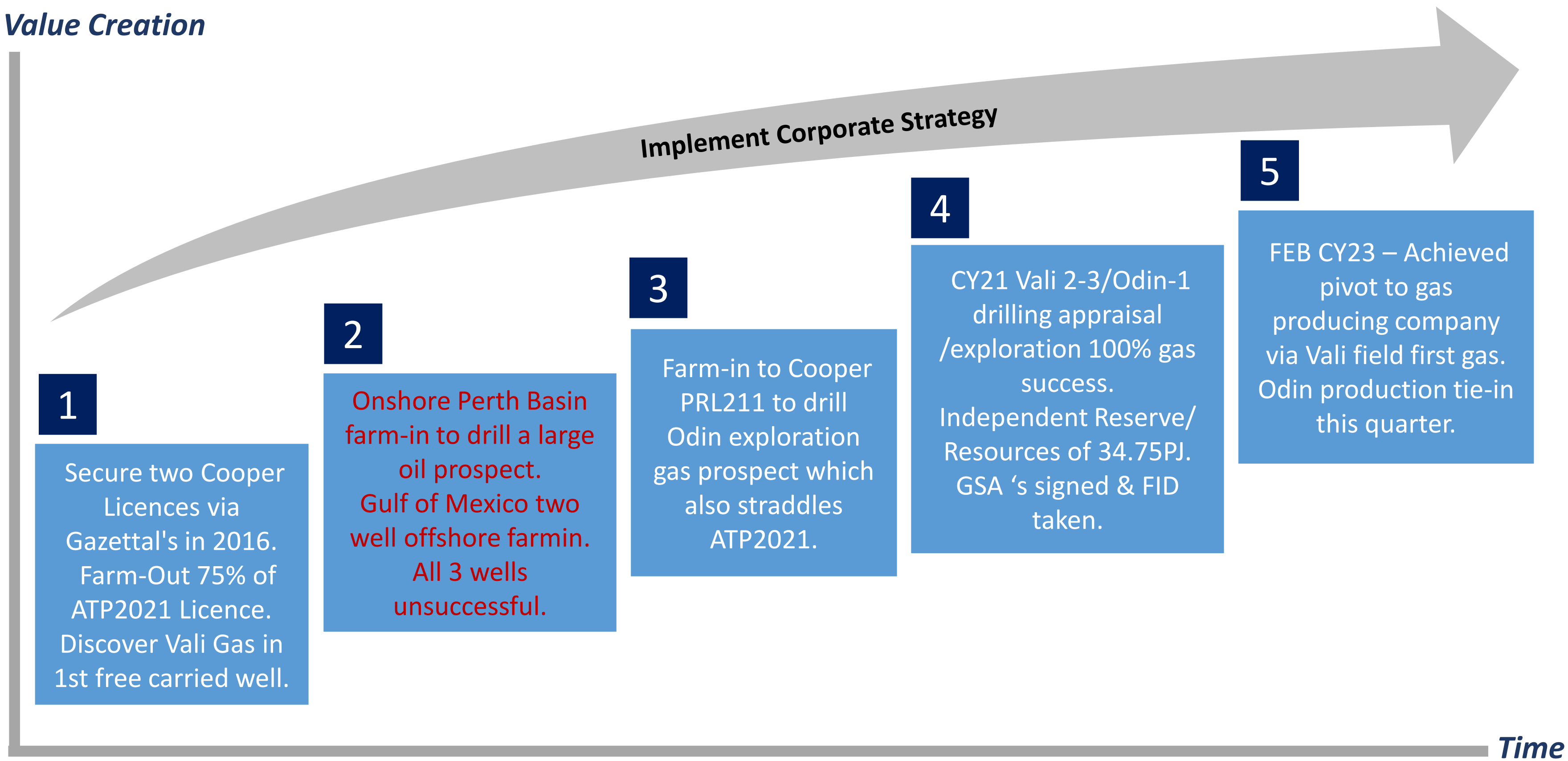
Vali Gas Project and first tie-back (Odin)



Metgasco Business Transformation

METGASCO

Since 2016 the company transformed by building an exploration/appraisal portfolio in onshore Cooper/Perth Basin and offshore GOM. 100% exploration success in 4 Cooper wells building gas hub reserves/resources. First Vali gas production revenue achieved in CY23…Odin next

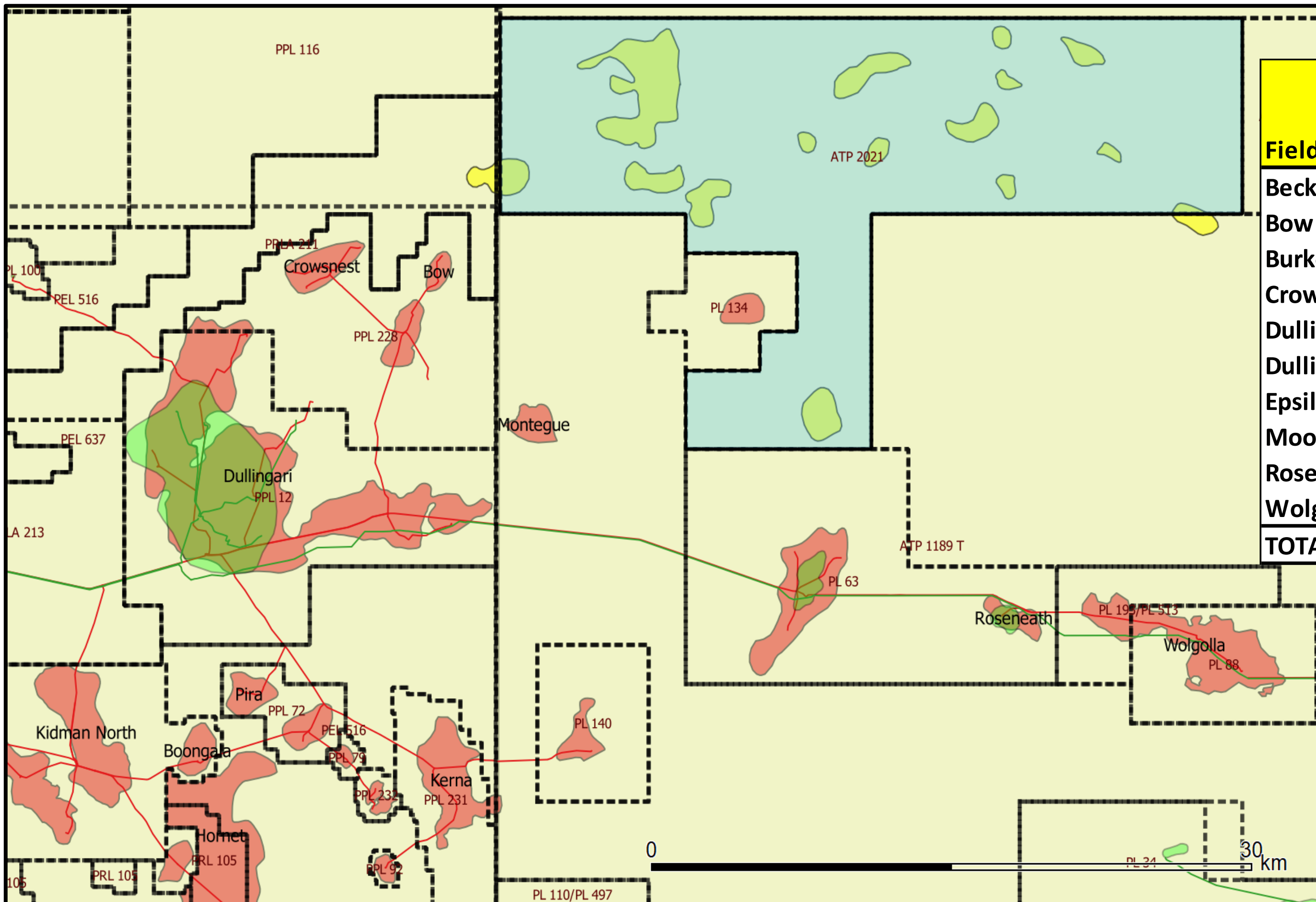


Important to have a diverse portfolio of exploration opportunities due to the inherent risks of exploration

ATP2021 Gazettal Application 2016 / Awarded 2017

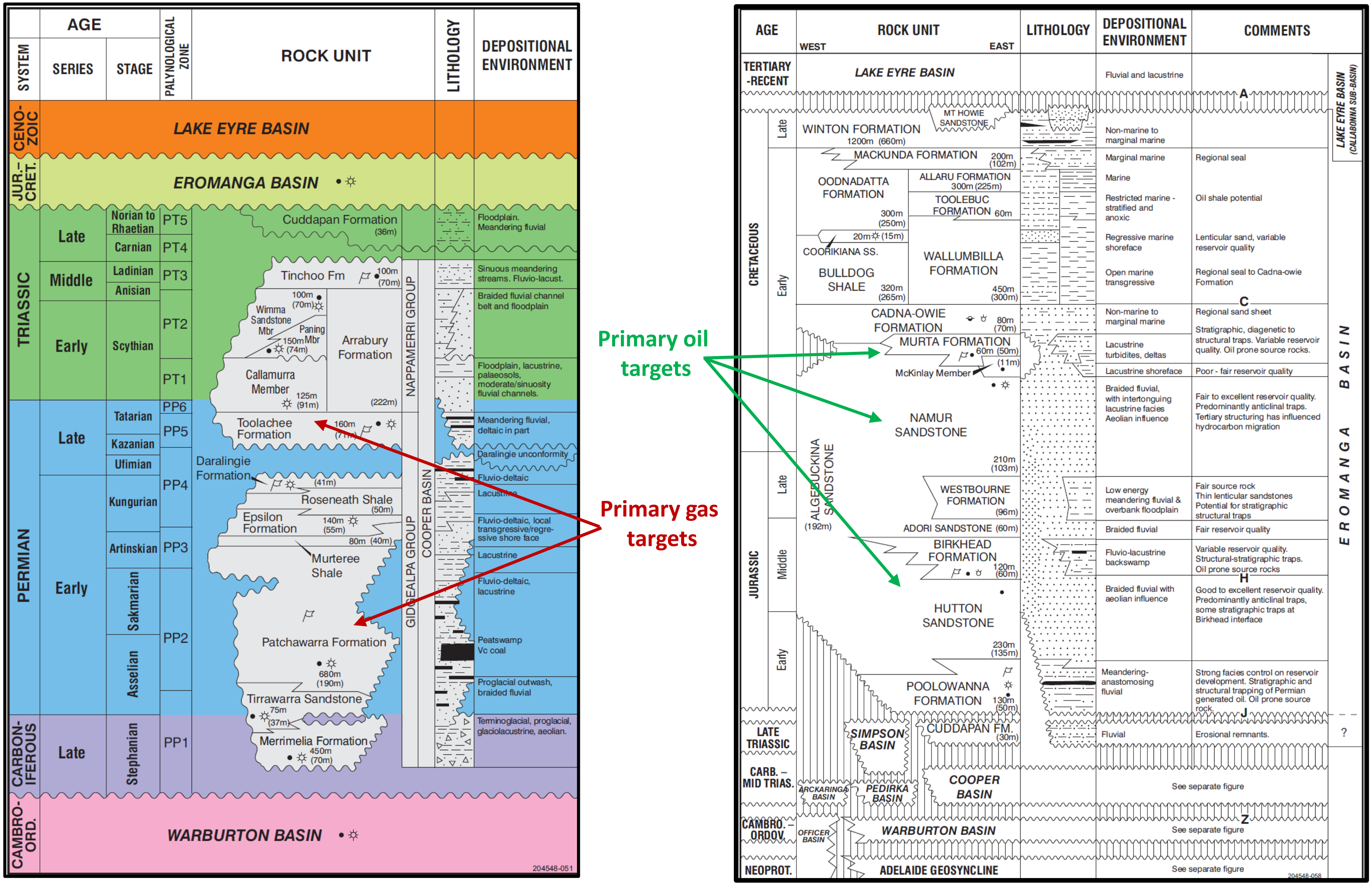
METGASCO

- **Licence Surrounded on 3 sides by oil and gas fields**
- **~ 600Bcf (in 2018) of produced gas within 20km of boundary**
- **Close to producing infrastructure**



Field	Cum. Prod. (Bcf)	Cum Prod (mmbl)
Beckler	32.4	
Bow	4	
Burke	55.6	
Crowsnest	11	
Dullingari	307	11.05
Dullingari North	81	
Epsilon	96.5	
Moon	4.7	
Roseneath	1.51	
Wolgolla	9.3	
TOTAL	**603.01**	**11.05**

Cooper Eromanga Basin Stratigraphy

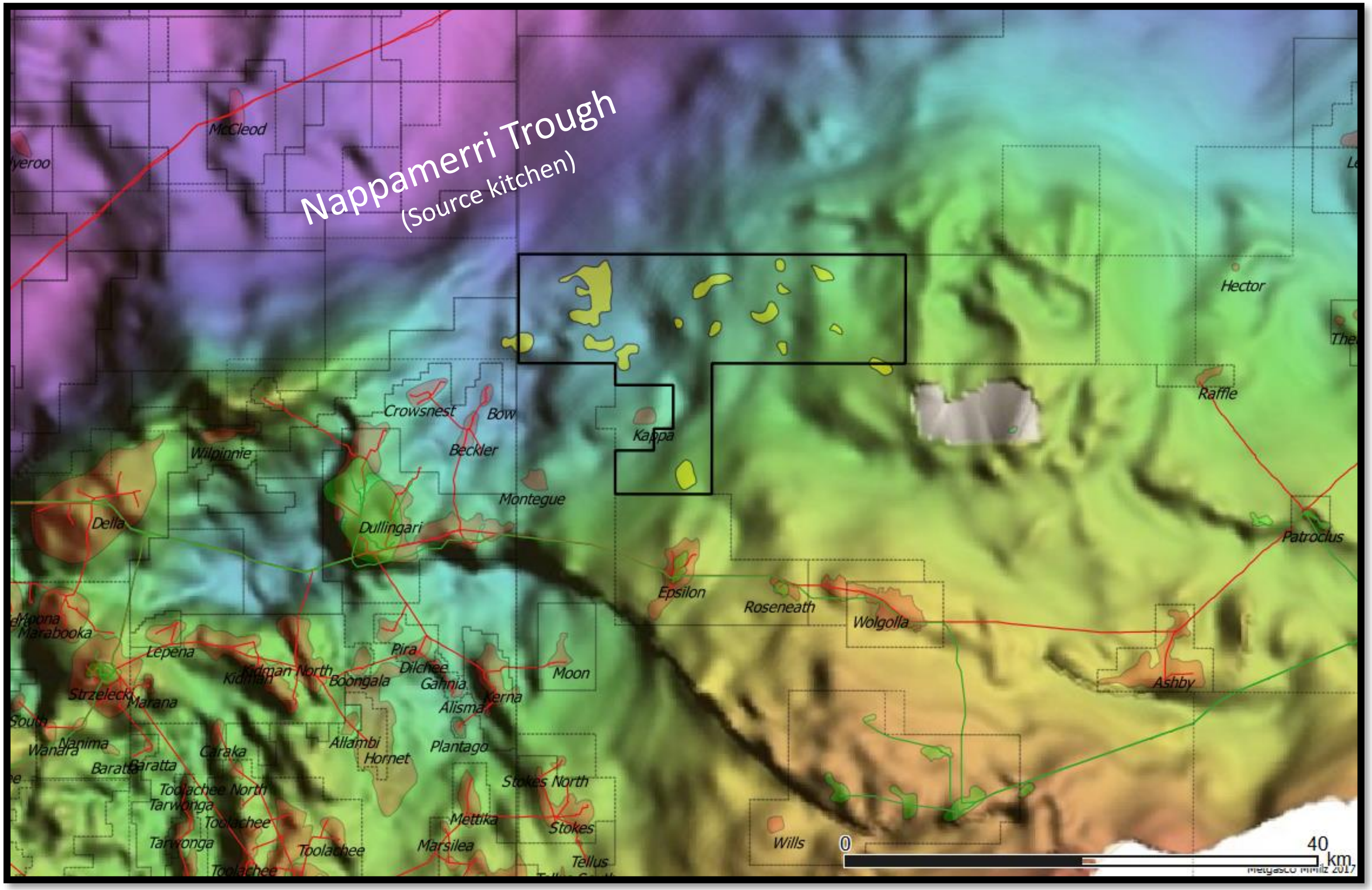


Gazettal Driver - A good Place to Find Hydrocarbons

METGASCO

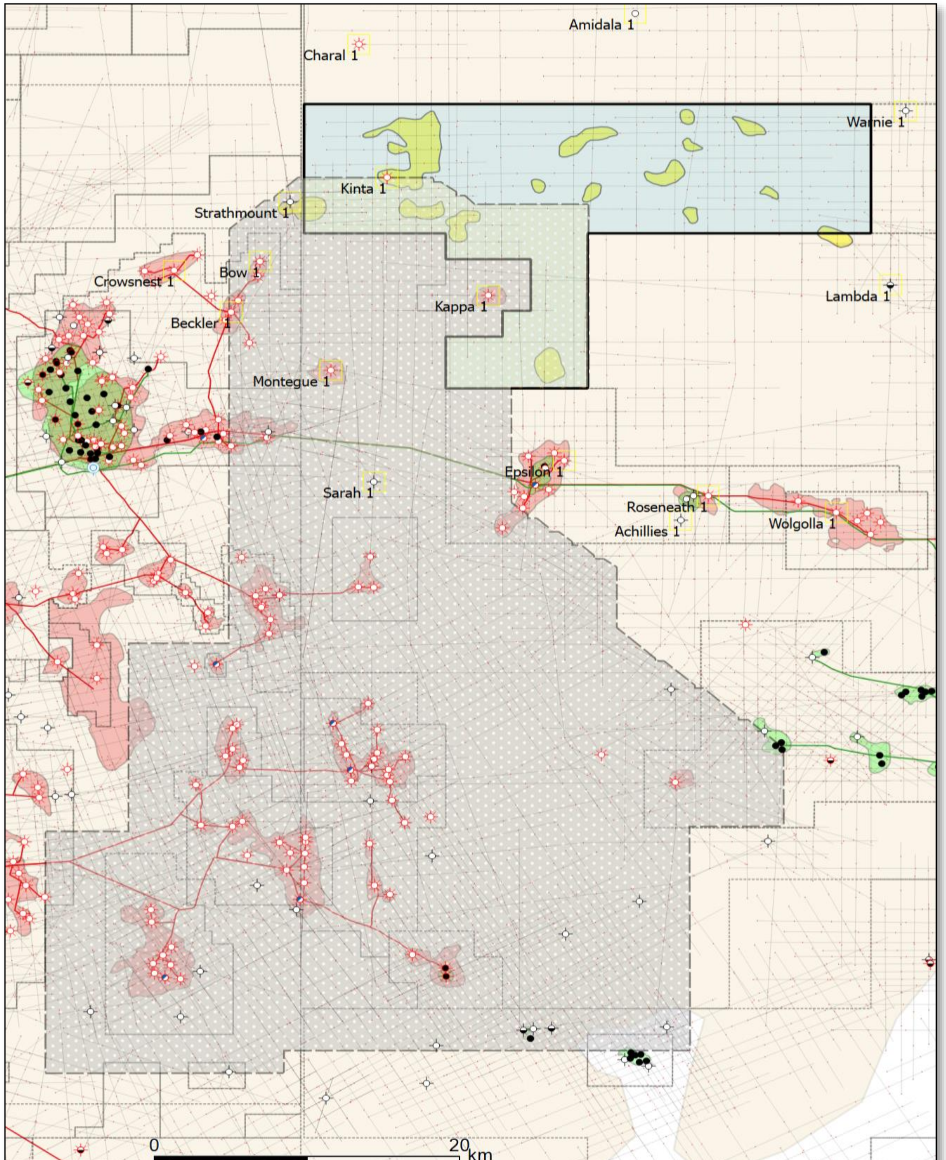
- **ATP2021 Adjacent to the Nappameri Trough source kitchen**

Regional Top Permian Structure Map



Technical Catalyst 1 – Early Access of 3D seismic

METGASCO



- **The Santos Snowball 3D was acquired in 2017 and covers ~115km2 of ATP2021**
  - 3D extends over the primary prospects of Odin and Vali.
  - Altar in the south of the block has partial coverage of 3D.

- **Kinta-1 prospect was drilled in 2003 based on 2D seismic in ATP2021 and had been abandoned at time of gazettal**
  - Two open-hole tests performed (Toolachee and Patchawarra).
  - TD Logging issues due to high bottom-hole temperature.
  - Cased hole test in Patchawarra-no gas flow to surface.
  - Well abandoned as non-commercial.

- **Strathmount-1 was drilled and abandoned in 1987 to the west of ATP2021**
  - Strathmount-1 tested gas in the Patchawarra Formation and Tirrawarra sandstone at RTSTM. Toolachee test failed due to poor mud system.
  - Mapping of the Snowball 3D, indicates Strathmount-1 has no independent closure at either Toolachee or Patchawarra levels.

Technical Catalyst 2 - Kinta & Strathmount Well review

METGASCO

Critical Well Review Checklists

Petrophysical

1. Was the log suite run sufficiently comprehensive, were logging tools properly calibrated, and were hole conditions adequate to allow at least a qualitative assessment to be made of the presence, quality and fluid content of potential reservoirs in the well?
2. Were previous petrophysical interpretations rigorous in particular with respect to any reservoirs encountered in the well that were not regarded as objectives predrill, but which were associated with oil or gas shows during drilling?
3. Have all hydrocarbon shows recorded during drilling been correctly reconciled with the petrophysical evaluation of the logs?
4. Could the adoption of incorrect values for any of the petrophysical parameters m, n, Rw, Vsh or Qv in the quantitative calculation of hydrocarbon saturations have led to underestimation of potential net pay in the well, and/or failure to test zones that in hindsight warranted testing?
5. Were the cut-offs for Ø, Sw, Vsh and/or K adopted for effective reservoir and hydrocarbon pay definition too pessimistic, resulting in potential pay zones having been left untested?
6. Could potential hydrocarbon bearing zones in the well not have been detected and/or fully resolved due to the limited bed thickness of reservoirs?
7. Could potential hydrocarbon bearing zones have been missed ("by-passed pay") in the well due to an anomalously low resistivity response over prospective reservoirs, and/or to a low resistivity contrast between hydrocarbon and water bearing zones?
8. Were any HDT's (hydrocarbon-down-to's) in the well misinterpreted as HWC's (hydrocarbon-water-contact's)?

Reservoir Engineering

1. Were the results of tests undertaken in the well interpreted correctly, and were recorded fluid flows or fluid recoveries consistent with log, wireline pressure, core poro/perm data and with hydrocarbon indications recorded during drilling?
2. Could any tests undertaken in the well that failed to recover fluid, recovered an unexpectedly small volume of hydrocarbons, or recovered water instead of hydrocarbons, have been invalid or unrepresentative, due to:
   i. Incorrect interval tested?
   ii. If conducted in cased hole, imperfect perforations?
   iii. Significant filtrate invasion?
   iv. Mechanical faults with tools or plugging of flow lines?
   v. Test duration being too short?
   vi. Interval tested being too large or encompassing separately pressured reservoirs?
   vii. Incomplete isolation of reservoirs tested due to poor cement bond or leaking packers?
   viii. Interference effects due to dual porosity/permeability development?
   ix. Reservoirs having sustained near well bore or deep formation damage?
   x. Excessive water cushions prohibiting or limiting influx from the reservoir?
   xi. "Gas block" or "water block" in low permeability reservoirs causing imbibitions?
3. Could reservoirs that yielded non-commercial hydrocarbon flow rates on test, be drilled underbalanced, drilled with oil-based mud, or otherwise stimulated (e.g. hydraulic fraccing) and flow hydrocarbons at commercial rates?
4. Are reservoir pressure gradients consistent with inferred hydrocarbon column heights?
5. Are there intervals not recognised or considered unworthy of testing at the time of drilling, that would have warranted testing if the well was drilled today?

Geological/Geophysical

1. If reservoir objectives were encountered significantly off prognosis and/or the well synthetic does not tie with seismic through the well location, could the well have been drilled on the wrong location?
2. Could the well have been an invalid test, or drilled significantly downdip of the crest of closure at reservoir level leaving updip potential unevaluated, due to:
   i. Top reservoir not having being accurately mapped?
   ii. Top reservoir having been poorly imaged (eg incorrect statics corrections applied, inappropriate migration algorithm adopted, other processing shortcomings etc)?
   iii. Top reservoir time maps not having been accurately depth converted?
3. Could the reprocessing of existing seismic, or the acquisition of new seismic, in particular 3D, enhance structural and stratigraphic resolution at reservoir level, and identify previously unrecognised potential?
4. If the targeted reservoir in the well was unexpectedly missing or anomalously thin, could this be a function of fault cut-out at the well location subsurface?
5. If reservoirs are poorly developed in the well but hydrocarbons appear to be present, or reservoirs are entirely absent at target level, could reservoir development in fact be better elsewhere within the confines of structural or stratigraphic closure?
6. Could closure persist, or independent closures be developed, below the total depth of the well and so provide potential in deeper reservoirs?
7. If gas was discovered, has the potential for an oil rim in the prospect been evaluated?
8. Could the results of wells drilled nearby, and/or of regional studies completed post-drill, have changed the perception of the attractiveness of the reservoir section targeted in the well, or identified any other plays worthy of pursuing in the prospect drilled by the well?
9. Was the well drilled before the potential of unconventional resources (ie coal seam gas, shale gas, shale oil, tight gas etc) was fully appreciated, and if so could such potential exist in the prospect drilled by the well?

Commercial/Technological

1. Were any recognised zones of interest not fully evaluated for operational and/or financial, as opposed to technical, reasons e.g. budgetary constraints, non availability of testing equipment, feared impact of negative outcome etc.?
2. If the well made a discovery considered uncommercial at the time of drilling, could this accumulation now be economically developed due to:
   i. An increase in estimated trapped volumes resulting from changes in log or test interpretation, or an increase in predicted reservoir bulk rock volume?
   ii. Advances in technology resulting in improved flow rates and/or recovery efficiencies from tight reservoirs e.g. hydraulic fraccing, acidisation, enhanced oil recovery, horizontal drilling etc?
   iii. Advances in technology now allowing the development of smaller fields, accumulations with thin reservoirs or thin hydrocarbon columns, gas accumulations with high levels of impurities such as carbon dioxide or hydrogen sulphide, oil pools with adverse properties such as high viscosity or wax content etc?
   iv. The field now being located closer to accessible processing facilities?
   v. For gas fields, condensate yields being higher than expected?
   vi. An increase in the price of oil, condensate or gas?
   vii. A favourable change in demand for oil or gas?
   viii. A favourable change in fiscal terms?
   ix. A decrease in drilling, completion and/or development costs?
   x. The application of an innovative development solution?
3. If the well encountered a hydrocarbon accumulation considered uneconomic on a stand-alone basis, could this accumulation now be economic to develop in conjunction with nearby discoveries?

Investigative Exploration

Applying the critical checklists to abandoned wells Kinta-1 and Strathmount indicated potential dormant gas discoveries that required modern drilling and production technologies to unlock commerciality

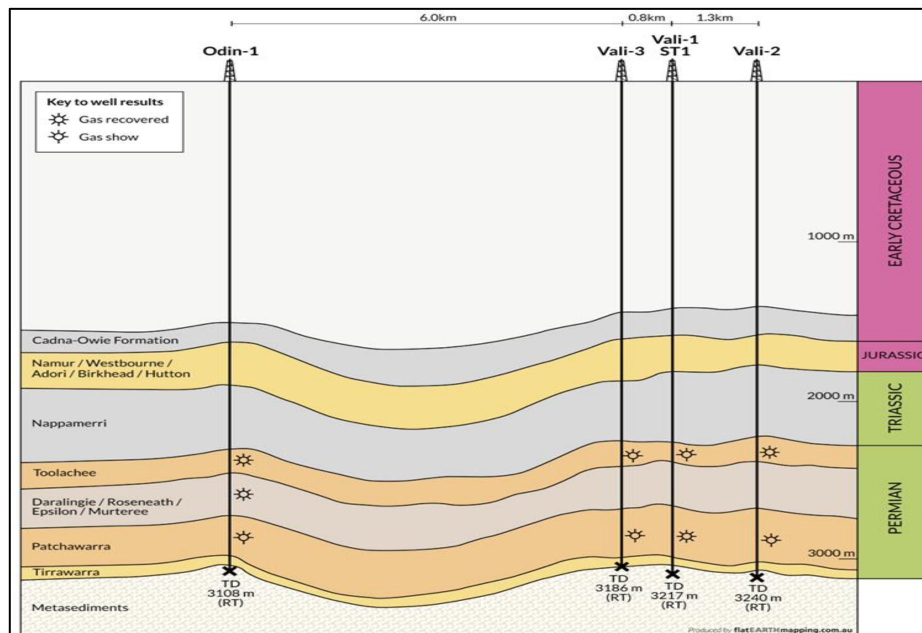
ATP2021 - Farm-out to production in less than 4 years

METGASCO

- **Experienced Management team has delivered 4/4 successful Cooper Basin gas wells**
- **Commercialisation of Vali represents the culmination of a long process of value creation by Metgasco, from initial application for ATP2021, technical appraisal, farm-out and, with our partners, a highly successful exploration drilling program**

Vali	ATP2021 MEL Farm-down	Vali-1ST1 discovery	Appraisal drilling	Stimulate Complete	Construct & Commission	Appraisal Production	Informed field work & further gas marketing	**Ongoing full scale production operation**
	• May 19	• Jan 20	• April–June 21	• Apr to Sept 22	• Oct 22 to Feb 23	• First production on 21 February 2023 • Production to inform full field development	• Development Plan/ wells informed by appraisal production • Marketing uncontracted gas	

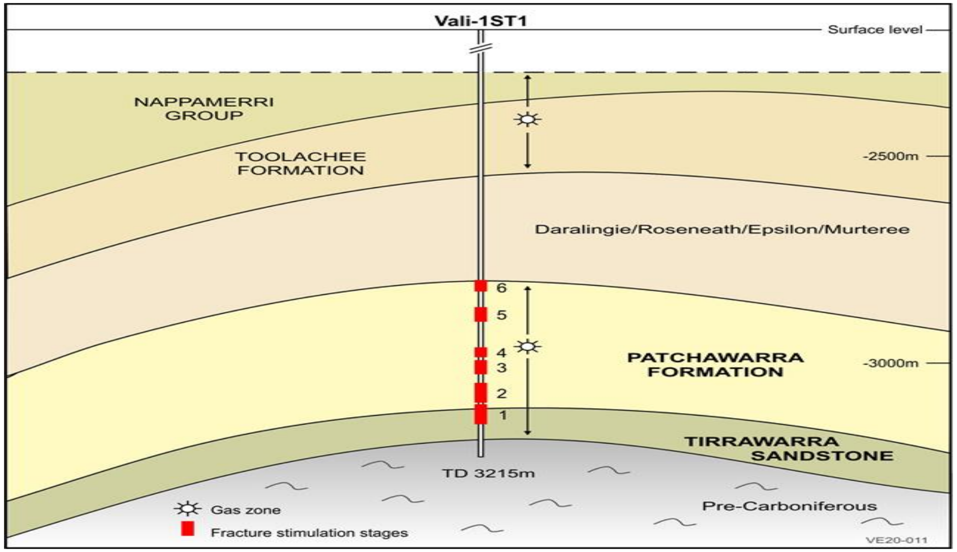
- **2019:** Metgasco farmed out 75% of ATP 2021 to Cooper Basin specialists Vintage/Bridgeport. Provided Metgasco free carry-on Vali-1.
- **2020:** Vali-1 gas discovery and flow test 4.3 MMscf/day.(Patchawarra Sands)
- **2021:** Successful Vali appraisal wells lead to reserves
  - Vali-2 successful - (new gas pool in Toolachee)
  - Vali-3 successful (Toolachee/Patchawarra mainly)
  - Gross 2P reserves of 101 PJ gross net 25.2 PJ
  - Heads of Agreement on supply to AGL
- **2022:** GSA signed with AGL, and Moomba Processing and Tie-in Agreements executed with SACB Joint Venture.
  - Procure deliver and install Vali gas pipeline and field facilities.
- **2023:** Gas production achieved in Feb CY23. Appraisal testing to confirm field full field development plan.



Technical Catalyst 3 – Successful Stimulation of Vali-1

METGASCO

CY2020 Patchawarra stimulation program delivers 4.3 MMscf/d stabilised gas rate



Schematic and pictures provided by Vintage Energy

- 80m of interpreted net gas pay (porosity cut-off 6%) discovered in the Patchawarra (Patch) Formation (primary target).
- Gas pay calculated in the secondary Toolachee target.
- Five Patchawarra zones and one Tirawarra zone stimulated with gel conveyed propped sand fracs to increase Patchawarra gas flow permeability.
- Measured stabilised flow-rate of 4.3MMscf/d through 36/64"choke at 942 psi.
- A production log confirmed all zones flowing.

Vali Commercial Catalysts - Build Reserves & sign GSA

METGASCO

Increase in Gas reserves post V2/3

- An independent evaluation of the Vali field reserves was completed based on the results of the Vali-2 and Vali-3 appraisal wells.
- Independently evaluated Gross 2P reserves of 92 Bscf (101 PJ-25.2 PJ net MEL) versus previous estimate of 30.3 Bscf (33.45-8.4 PJ net MEL).
- Reserves increase for the Patchawarra Formation and addition of the Toolachee Formation.

Vali Reserves and Resources

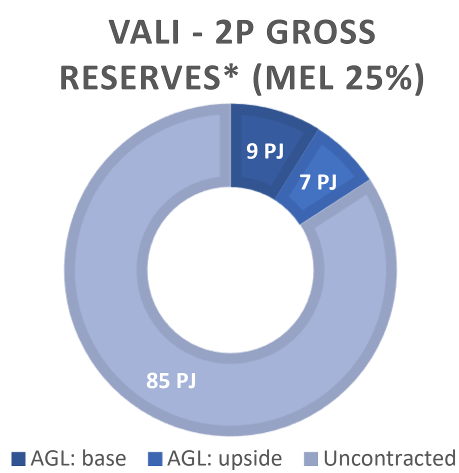
Gross ATP 2021 Vali Gas Field Reserves*			
	1P	2P	3P
Sales Gas (Bscf)	43.3	92.0	191.2
Sales Gas (PJ)	47.5	101.0	209.8

Net Entitlement ATP 2021 Vali Gas Field Reserves*			
	1P	2P	3P
Sales Gas (Bscf)	10.8	23.0	47.8
Sales Gas (PJ)	11.9	25.2	52.4

Vali Gas Supply Contract

agl

- AGL contract provides for sale of estimated 9 PJ – 16 PJ from Vali to end-2026.
- Total contract quantity only represents 9% to 16% of current 2P reserves of 101PJ.*
- JV has received a prepayment of $15million.
- GSA contains multi-tier price structure including upside through escalation and reset mechanisms.
- ➢ **85PJ of uncontracted Gross 2P gas reserves**



Vali GSA with AGL	
Period:	Feb 23 – Dec 26
Volume:	9-16 PJ (gross) 2.25-4 PJ (Metgasco Share)
Features:	Multi tranche price including CPI indexation $15m pre-payment to JV

Refer to MEL announcement on 1 November 2021 and Reserve Notes on Page 19

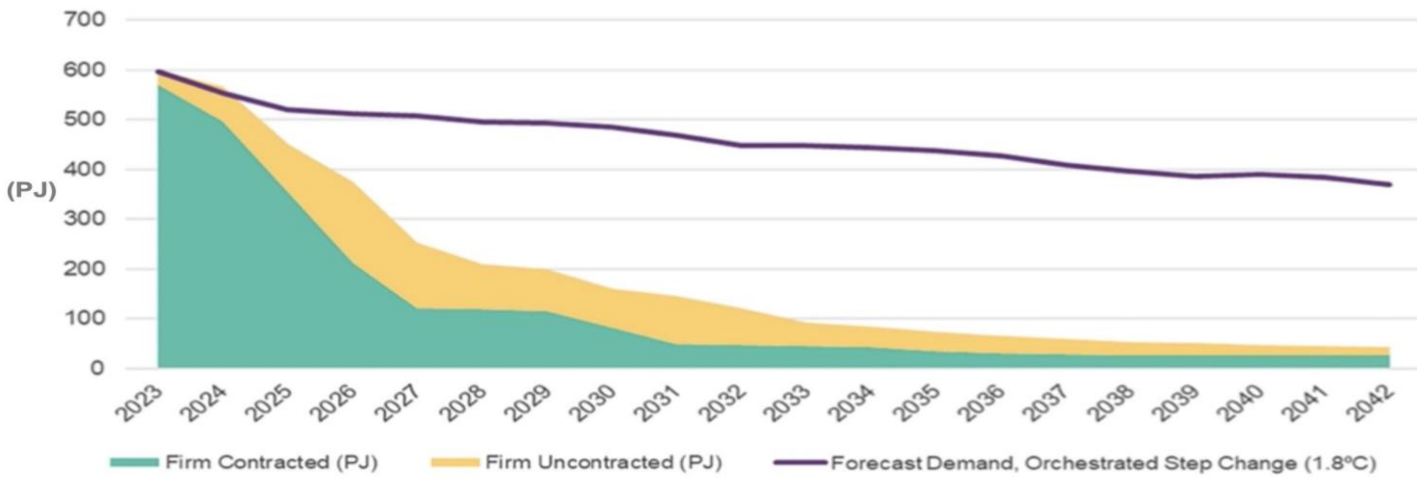
Vali & Odin Catalyst - Undersupplied East Coast Market

METGASCO

Growing Domestic Gas Shortfall

- In January 2023, the Australian Competition & Consumer Commission (ACCC) released its latest interim update as part of the "Gas Inquiry 2017-2030" and it forecasts in the "base case" a potential domestic gas supply shortfall of 30 PJ pa in 2023, before a much greater potential shortfall of ~300 PJ pa in the southern states by 2034.[1]

Firm contracted and firm uncontracted contract quantities for non-LNG producer's vs forecast domestic demand[3]



International and Domestic Gas Prices to remain elevated

- LNG netback prices based on Asian LNG spot prices currently play an important role in influencing East Coast Gas Market (ECGM) gas prices. The spot (Wallumbilla netback) ECGM saw a significant price move in CY2022. LNG netback prices increased significantly, from about $13/GJ in mid-2021 to more than $39/GJ in mid-2022. This was driven by global energy scarcity and increases in gas and LNG prices in international markets. The ACCC expects prices to remain elevated versus pre-2022 levels. [1, 2]

PRL211 gas marketing unaffected by recent Federal Government(Govt) price cap; buyer interest increased. PRL211 exempt from Govt mandatory code of conduct (Gas code)

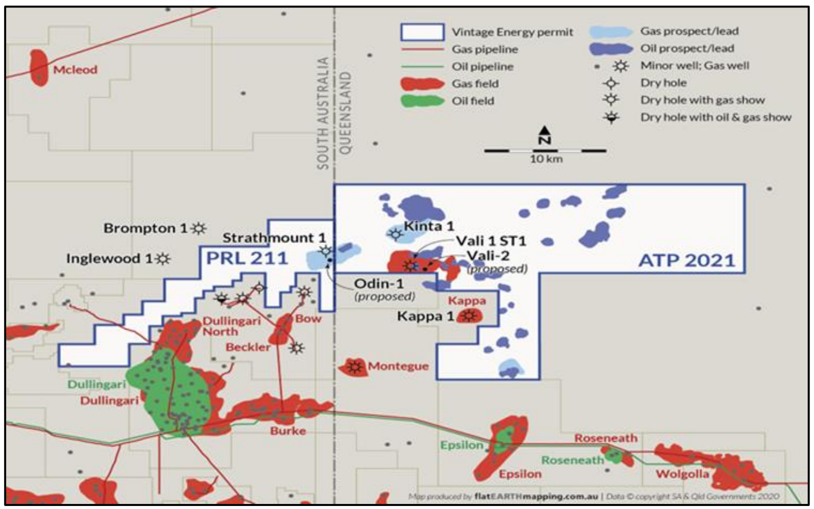
- Producers exempt from $12/gj price cap if producing less than 100PJ per annum exclusively to the domestic market

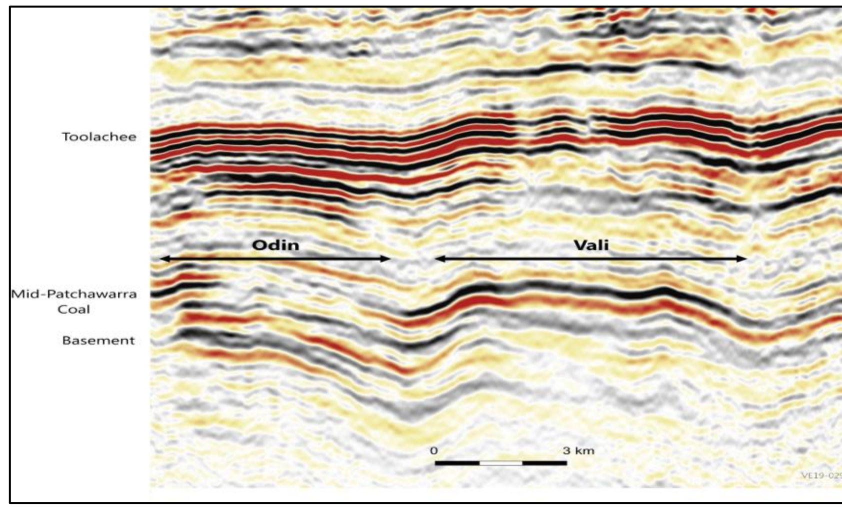
Metgasco can deliver its uncontracted Reserves / Resources into this attractive market

1: https://www.accc.gov.au/system/files/Gas%20Inquiry%20-%20January%202023%20interim%20report%20-%20FINAL_0.pdf
2: https://www.accc.gov.au/inquiries-and-consultations/gas-inquiry-2017-30/lng-netback-price-series 3: https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo

PRL211 Farm-in deal catalyst to drilling Odin-1

- **Strathmount-1 tested gas in the Patchawarra Formation and Tirrawarra sandstone at RTSTM.**
- **Circa 50% of Odin structure was situated in PRL211 leading the ATP2021 JV to farm in, successfully drill and test Odin-1, then purchased a further gross 15% to align with ATP2021 JV to facilitate a low-cost rapid connection via Vali field pipeline facilities.**
- **Odin-1 gas discovery - net gas pay of 172.5m primarily in the Patchawarra/Epsilon/Toolachee**
- **Odin gas field connection being fast tracked to target gas sales in Q3 CY2023.**





Odin

Farm-in to PRL211	Odin-1 discovery & well-test	Well Completion	Conceptual Engineering	FEED/Detailed engineering, procurement & construction	Accelerated Odin-1 production	Odin1- Long Term connection Planning Odin Appraisal program
• Feb20	• Jun–Oct' 21	• July-Aug 22	• Sept to Nov 22	• Q4 CY22- Q2 CY23 • ACCC approval received for joint contracting of Odin gas post 2024.	• Q3 CY23 first gas • Gas supply to December 2024 • Market post 2024 gas • Independent resource to reserve study.	• FY 24+ Appraisal drilling based on Odin production performance.

Odin field Commercial Catalysts – Resources & GSA

METGASCO

Successful test ⇨ Independent Resources ⇨ Gas contract signed

- Metgasco (25%), Vintage (operator with 50%), Bridgeport (25%).
- Odin-1 discovery confirmed gas pay in the Toolachee, Epsilon, and Patchawarra reservoirs.
- Odin-1 conventionally flowed 6.5MMscf/d at 1823 psi FWHP from Epsilon and Toolachee reservoirs.
- Odin-1 completed as conventional producer over the Toolachee and Epsilon reservoirs.

Gross Odin Gas Field Contingent Resources (PJ)			
	1C	**2C**	**3C**
Total	**20.2**	**39.7**	**78.2**

Net Odin Gas Field Contingent Resources (PJ)			
	1C	**2C**	**3C**
PRL 211	2.85	5.55	10.95
ATP 2021	2.00	4.00	7.80
Total	**4.85**	**9.55**	**18.75**

Odin Gas Supply Contract ENGIE

- All of Odin production to Dec 2024 contracted to Pelican Point Power (ENGIE/Mitsui JV) under Master Gas Sales Agreement.
- Odin gas production post 2024 is uncontracted.
- JV received ACCC approval for joint contracting of Odin gas post 2024 allowing marketing to commence.

Odin GSA with ENGIE	
Period:	Field start up to Dec 24
Volume:	As produced

Odin-1 flow test - Toolachee & Epsilon formations

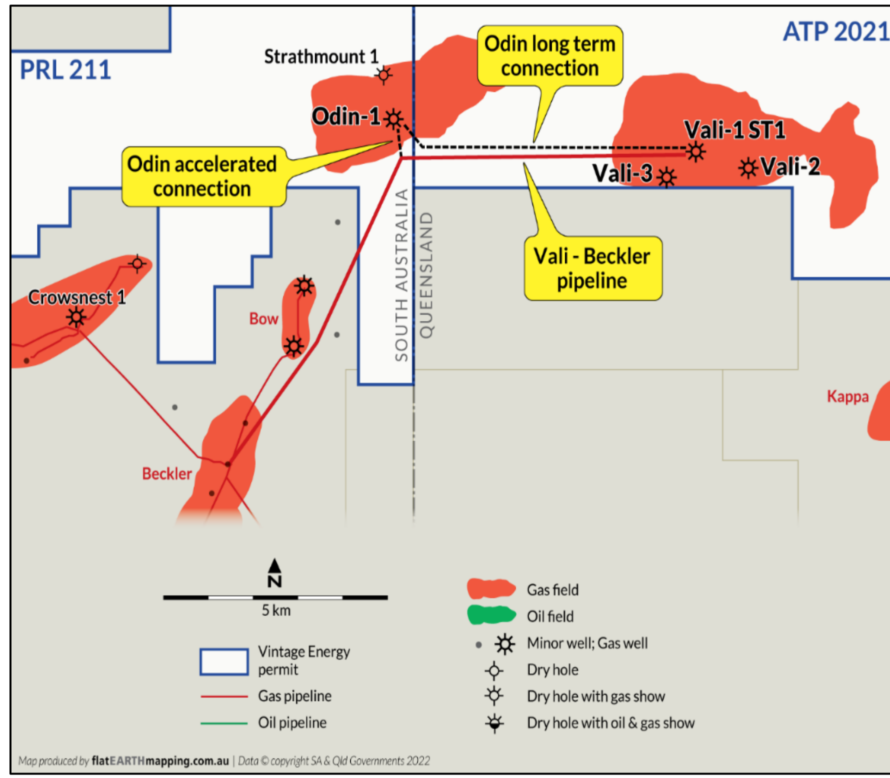
** Refer to MEL announcement on 17 September 2021 and resource notes in slide 19*

Catalyst – Proximity to Vali allowing fast-track tie-in

METGASCO

- Proximity to Vali pipeline enables early gas production to meet the very strong East Coast gas market demand
- **PRL 211 JV agreed to accelerate Odin-1 connection, aiming for first sales Q3 2023.**
  - Accelerated Connection – Install 1.4km fibrespar connection to Vali pipeline – **Completed**
  - Accelerated Connection – Install temporary rental equipment to start production Q3 CY23
  - Odin-1 long term optimal solution: connection of Odin-1 via 6.3km fibrespar line to Vali facilities for dewatering, metering and transport to Beckler.
- ACCC authorisation received allowing longer term joint gas marketing from Jan 2025
- Odin customer gas sales discussions progressing
- JV reviewing future appraisal well options and timing
- Odin field gas tie in, is the first successful example of Metgasco's hub and spoke strategy

Odin-1 connection to Vali infrastructure



Key Enablers in journey from explorer to producer

METGASCO

1. Good technical due diligence on offset wells pre/post gazettal
   - ✓ 3D seismic accelerated farm-out interest
2. Farm-out to basin specialists aligned in priority/sense of urgency
   - ✓ Farm-out to reduce exploration risk
3. Have a portfolio approach to exploration in proven basins. Explore close to production infrastructure
4. Apply new drilling and production technology to unlock commercial gas rates in lower permeability gas reservoirs
5. Highly Supportive East Coast Gas Market – Two GSA’s signed
   - ✓ Customer Gas pre-payment a key commercial catalyst for Vali field
6. Farm-in before drilling if a prospect straddles a licence boundary
7. Hub and Spoke strategy allows lower cost rapid tie in of new fields

Metgasco - Summary Highlights and Catalysts

METGASCO

1 Maiden Gas Production from Vali Gas Field in 2023

- MEL commenced gas supply to Eastern Australia from the Vali field in February CY23, generating maiden revenue.
- ATP 2021 JV contracted to supply an estimated 9 to 16 PJ in period to end-2026, just 9-16% of current Vali 2P reserves.

2 Vali Facilities enables Odin Fast Track Production in Q3 2023

- Odin gas field connection to be fast tracked to enable CY23 sales revenue.
- Odin GSA with ENGIE/Mitsui JV announced 15 May 2023 to supply gas from field start-up until 31 December 2024.
- Vali pipeline facilities enables early gas production to meet the very strong East Coast gas market demand.

3 Material Uncontracted Reserves / Resources*

- Vali (MEL 25%) - 85 PJ of uncontracted Gross 2P gas reserves at Vali field.
- Odin (MEL 25%) - Gross 2C Contingent Resources of 39.7 PJ. Odin gas uncontracted from Jan CY25

**Refer to page 19, MEL announcement on Vali reserves November 2021 and Odin-1 resources on 17th September 2021 & 29 March 2022.*

4 Highly Supportive East Coast Gas Market

- ACCC analysis suggests a significant shortfall in supply from developed 2P reserves from 2023 onwards.
- Metgasco can deliver significant value by leveraging its uncontracted Reserves and Resources connected to, or close to, existing infrastructure, into this market demand.
- **Small producers are exempt from the proposed $12/GJ price cap mechanism.**

5 Focused Strategy, Experienced Management & Funded for Odin

- Strategy is focused on onshore Australian conventional gas (and select high value oil). 4/4 successful Cooper gas wells.
- Experienced management has discovered two new gas fields and additional pipeline of opportunities identified.
- Fully funded for Vali 2/3 remedial work & Odin short and long-term pipeline tie-in projects via March A$5M debt facility.

6 Full Pipeline of News Flow in the next 12 Months

- First Vali production and Odin GSA achieved.
- Odin Reserve Update and first sales (low-cost connection leveraging of existing Vali facilities).
- Follow up exploration targets (hub and spoke model, utilising Vali facilities).
- Currently reviewing new venture exploration and production opportunities.

Disclaimer / Reserves and Resource Notes/Glossary

METGASCO

- This presentation is being provided for the sole purpose of providing the recipients with background information about Metgasco Ltd (Metgasco) which is current only at the date of this presentation. No representation, express or implied, is made as to the fairness, accuracy, completeness or correctness of information contained in this presentation, including the accuracy, likelihood of achievement or reasonableness of any forecasts, prospects, returns or statements in relation to future matters contained in the presentation ("forward-looking statements"). Such forward-looking statements are neither promises or guarantees and involve unknown risks and uncertainties and are by their nature subject to significant uncertainties and contingencies and are based on a number of estimates and assumptions that are subject to change (and in many cases are outside the control of Metgasco, its Directors and Officers) which may cause the actual results or performance of Metgasco to be materially different from any future results or performance expressed or implied by such forward-looking statements.
- This presentation provides information in summary form only and is not intended to be complete. It is not intended to be relied upon as advice to investors or potential investors and does not take into account the investment objectives, financial situation or needs of any particular investor.
- Due care and consideration should be undertaken when considering and analysing Metgasco's financial performance. All references to dollars are to Australian Dollars unless otherwise stated.
- To the maximum extent permitted by law, neither Metgasco nor its related corporations, Directors, employees or agents, nor any other person, accepts any liability, including, without limitation, any liability arising from fault or negligence, for any loss arising from the use of this presentation or its contents or otherwise arising in connection with it.
- This presentation should be read in conjunction with other publicly available material. Further information including historical results and a description of the activities of Metgasco is available on our website, www.metgasco.com.au.
- The contingent resource volumes for the Odin were independently certified by ERCE Equipoise (ERCE) reference Metgasco ASX release 17 September 2021 and updated for increasing interest to 25% on 29 March 2022. The reserves for Vali quoted in this presentation were independently certified by ERCE (ERCE) and were detailed in Metgasco ASX release 14 December 2021. The reserves and resources have been classified and estimated in accordance with the Petroleum Resource Management System (PRMS). Resource estimates are net of shrinkage.
- Competent Person Statement: The reported Vali Gas field reserve estimates are based on information compiled or reviewed by Adam Becis, Principal Reservoir Engineer with ERCE. ERCE is an independent consultancy specialising in petroleum reservoir evaluation. Except for the provision of professional services on a fee basis, ERCE has no commercial arrangement with any other person or company involved in the interests that are the subject of this contingent resource evaluation.

Glossary:

- MMscfd = Million standard cubic feet per day.
- FWHP = Flowing wellhead pressure.
- Bcf= Billion Standard Cubic feet
- PJ= Peta Joules (1PJ = 0.943 Bcf)
- GSA = Gas Sales Agreement.

METGASCO

An East Coast Gas Producer - Contact us for further information

Ken Aitken | Managing Director
Level 2, 30 Richardson Street, West
Perth WA 6005
Main: +61 8 6245 0060