Citi Australian Investment Conference

15 October 2014

Compliance statements

Disclaimer

This presentation contains forward looking statements that are subject to risk factors associated with oil, gas, geothermal and related businesses. It is believed that the expectations reflected in these statements are reasonable but they may be affected by a variety of variables and changes in underlying assumptions which could cause actual results or trends to differ materially, including, but not limited to: price fluctuations, actual demand, currency fluctuations, drilling and production results, reserve estimates, loss of market, industry competition, environmental risks, physical risks, legislative, fiscal and regulatory developments, economic and financial market conditions in various countries and regions, political risks, project delays or advancements, approvals and cost estimates.

All references to dollars, cents or $ in this presentation are to Australian currency, unless otherwise stated. References to “Beach” may be references to Beach Energy Limited or its applicable subsidiaries.

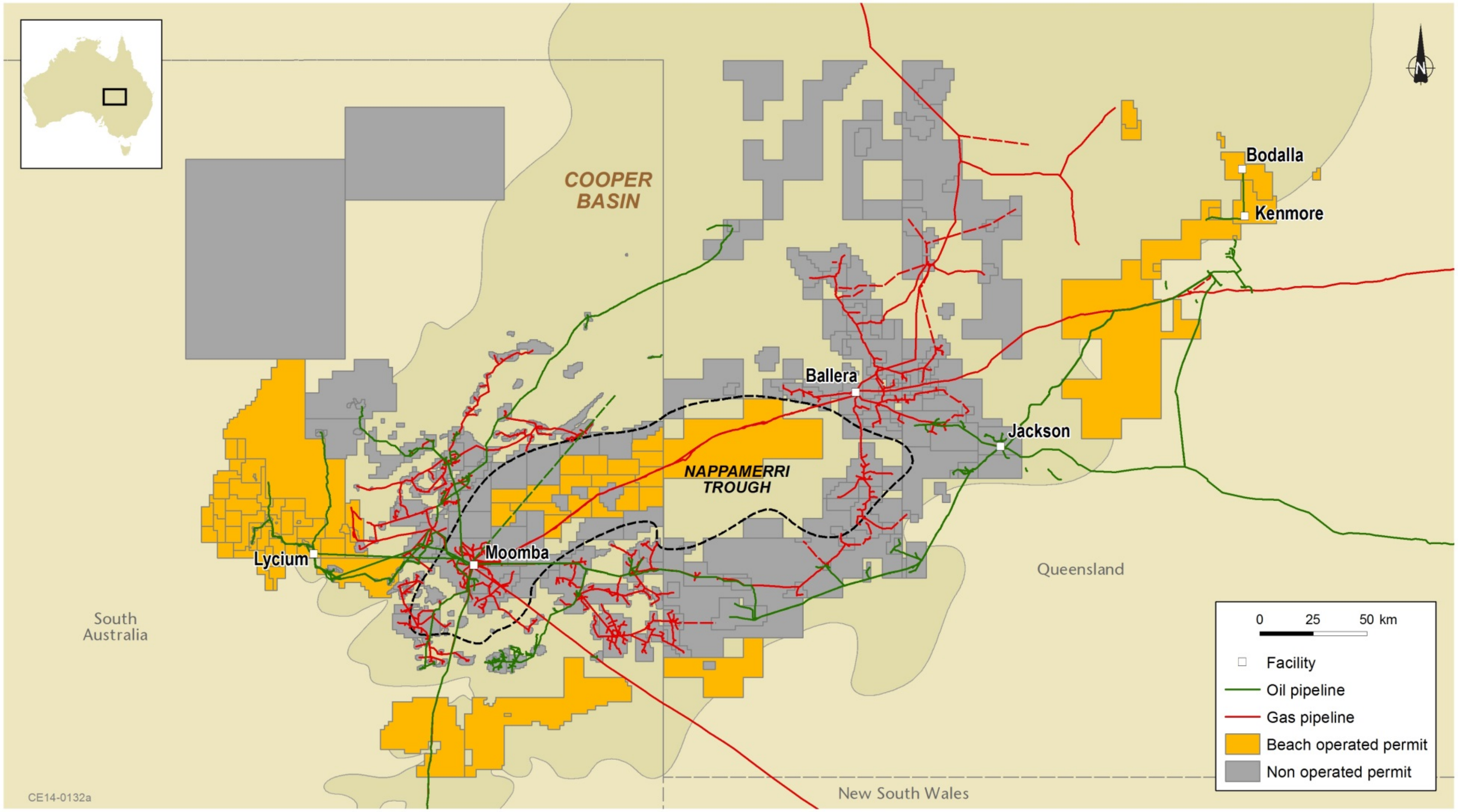
Unless otherwise noted, all references to reserves and resources figures are as at 30 June 2014 and represent Beach’s share.

Competent Persons Statement

The reserves and resources information in this presentation is based on, and fairly represents, information and supporting documentation prepared by, or under the supervision of, Mr Tony Lake (Reservoir Engineering Manager). Mr Lake is an employee of Beach Energy Limited and has a BE (Mech) degree from the University of Adelaide and is a member of the Society of Petroleum Engineers (SPE). The reserves and resources information in this presentation has been issued with the prior written consent of Mr Lake in the form and context in which it appears.

General overview

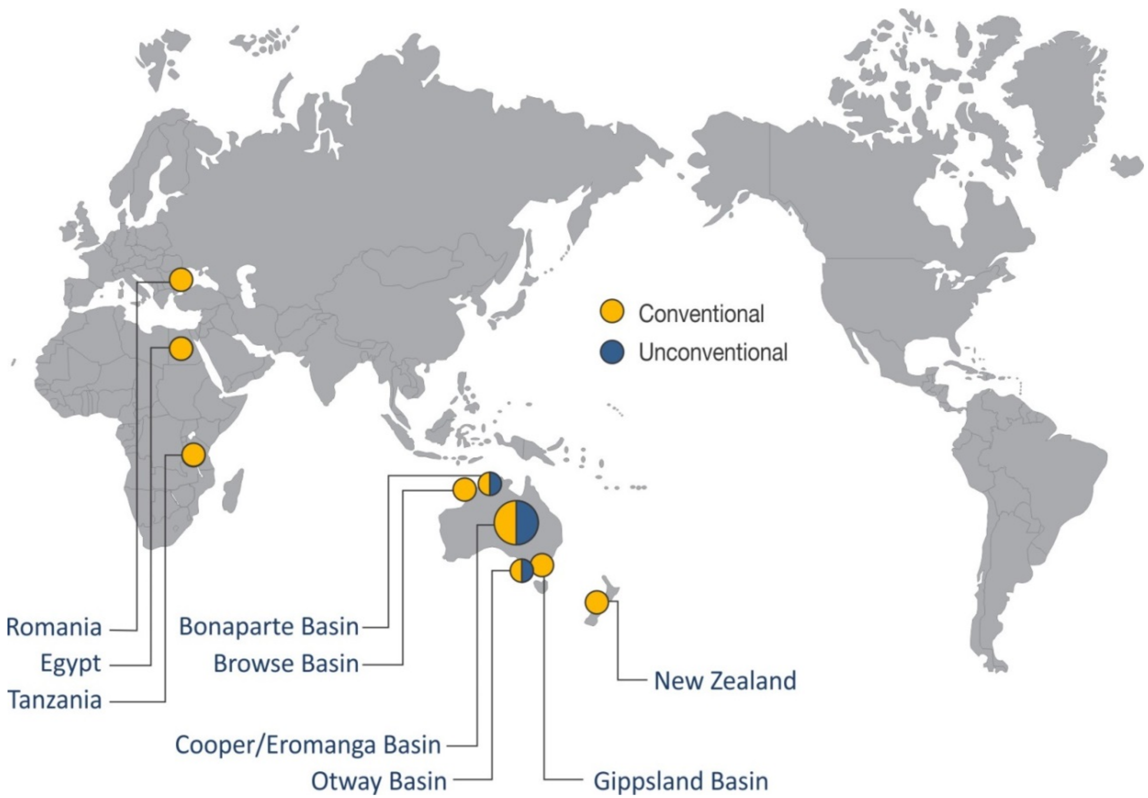
Cooper Basin acreage



Prolific gross acreage of over 56,000 km², generating 99% of production

Key facts about Beach

- ASX 100 company with a market capitalisation of ~A$1.7 billion[1]
- Largest Australian onshore oil producer
- Strong balance sheet with cash of $411 million[2]
- Undrawn secured debt facility of $300 million
- FY14 sales revenue of $1.05 billion
- FY14 underlying NPAT of $259 million



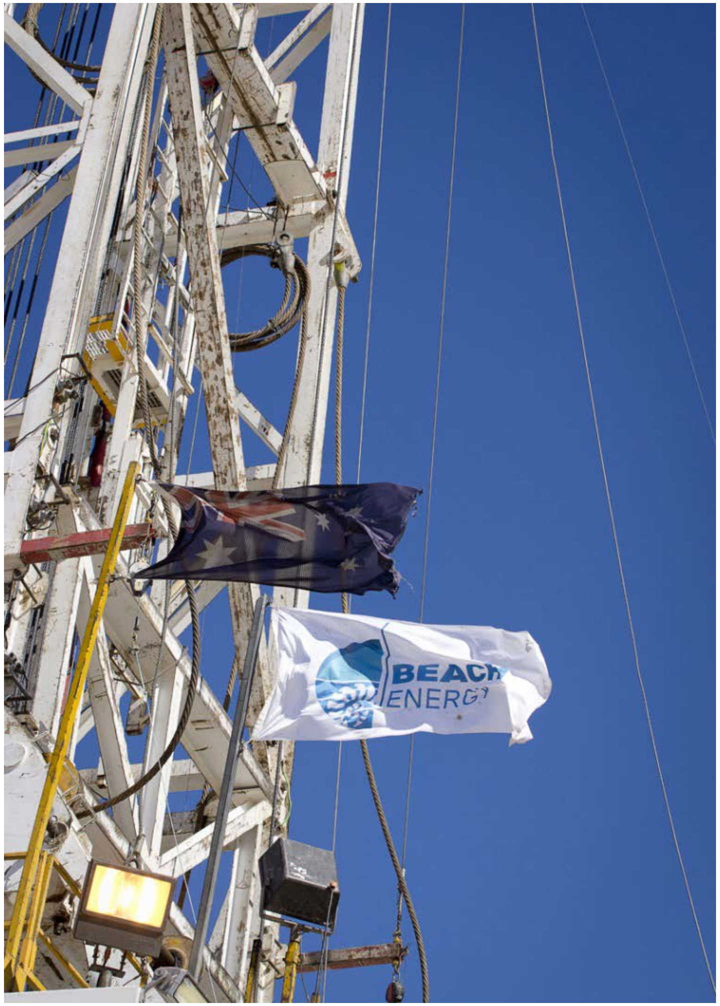
1. As at 13 October 2014 2. As at 30 June 2014

Fully funded capex program primarily focused on the Cooper Basin

Current snapshot

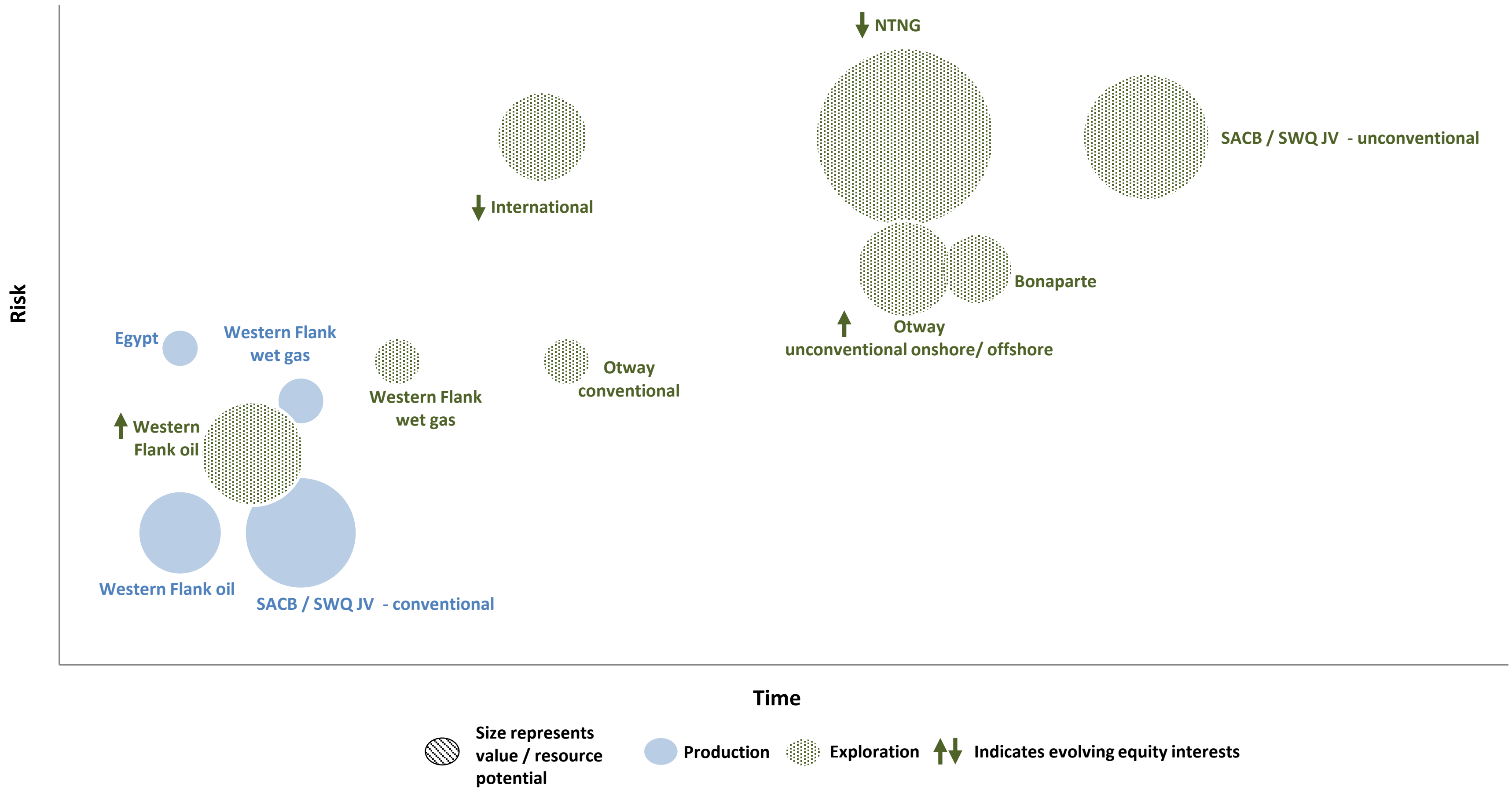
Re-aligning strategic focus and moving key projects toward commercialisation

- Review of all international assets currently underway to refocus capital allocation over the medium term
- Three new oil discoveries on the Western Flank in Q1 FY15
- Oil linked gas contract with Origin to commence in FY15
- Nappamerri Trough Natural Gas (NTNG) exploration program on track for completion of Stage 1 exploration phase at the end of Q3 FY15
- Strong balance sheet with the potential to fund capex until the end of FY16



Asset portfolio

Deep portfolio of low risk production and exploration assets, with transformational opportunities across diverse Australian basins



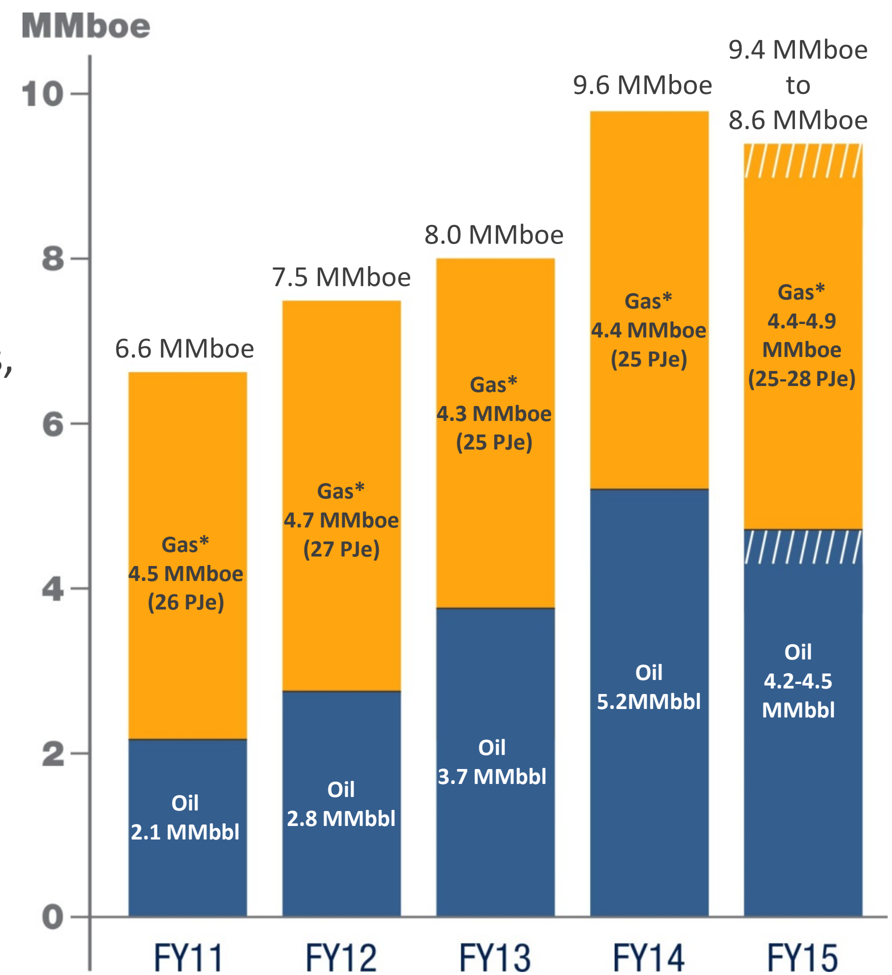
Actual and forecast production

FY14

- Production of 9.6 MMboe
- Production mix: 46% gas and gas liquids, 54% oil
- Cooper Basin oil production driven by:
  - Development of new and existing fields, appraisal and exploration success
  - Flowlines remaining at close to maximum available capacity
- 122 wells drilled, with 85% overall success rate

FY15

- Production guidance range of 8.6 – 9.4 MMboe

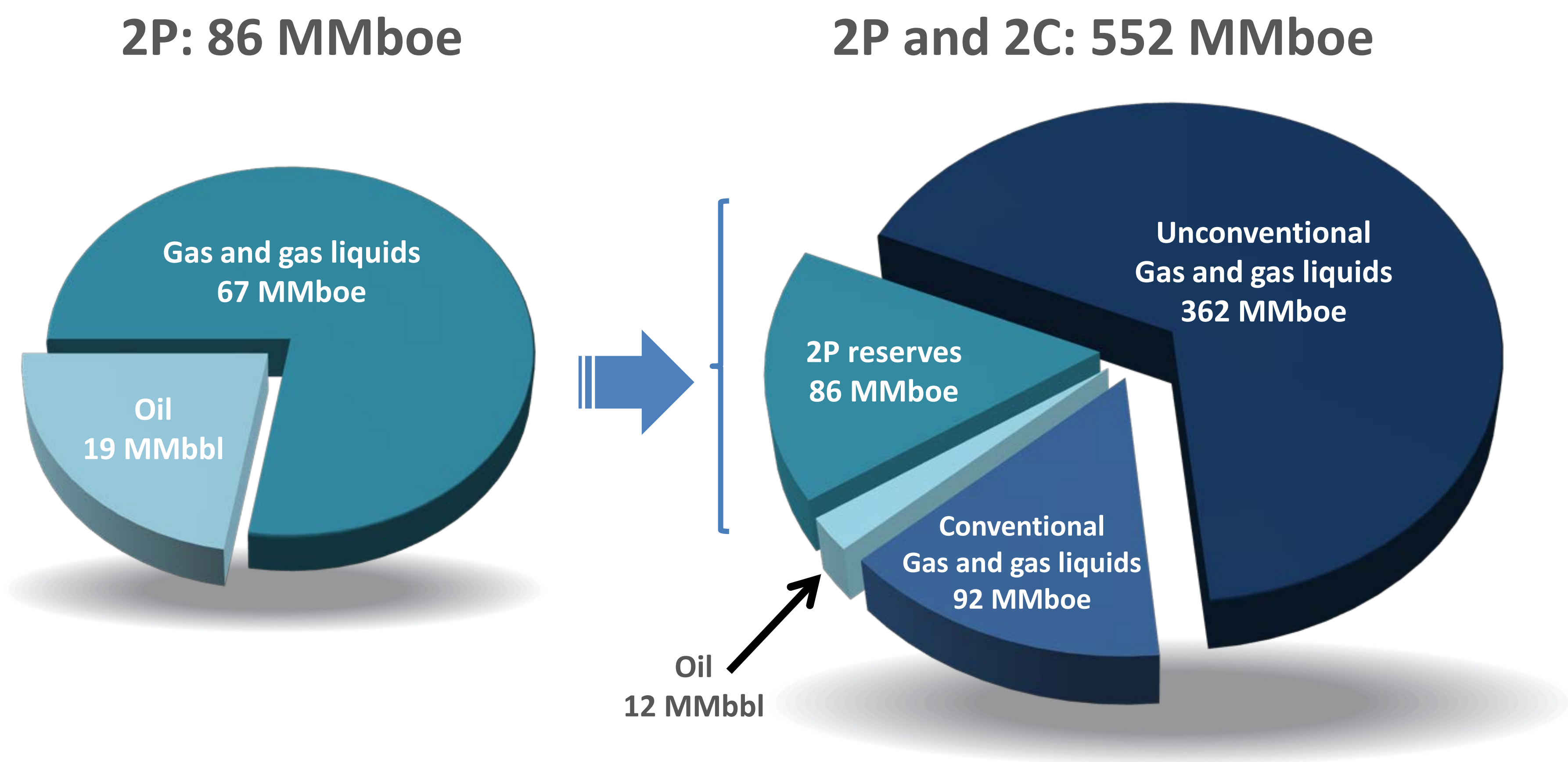


* Gas and gas liquids

FY15 capital expenditure guidance

	Capex ($ million)	Wells	3D Seismic (km^2)
DEVELOPMENT			
Cooper Basin – non-SACB/SWQ JVs	55 – 60	10 – 13	–
Cooper Basin – SACB/SWQ JVs	270 – 300	70-80	–
International	10	3	–
Total Development	**335 – 370**	**Up to 96**	**–**
EXPLORATION			
Cooper Basin – non-SACB/SWQ JVs	40 – 45	23-26	500
Cooper Basin – SACB/SWQ JVs	5	4	–
Unconventional	50-55	4	–
International	20-25	6	450
Total Exploration	**115 – 130**	**Up to 40**	**–**
TOTAL	**450 – 500**	**Up to 136**	**950**

Reserves and contingent resources



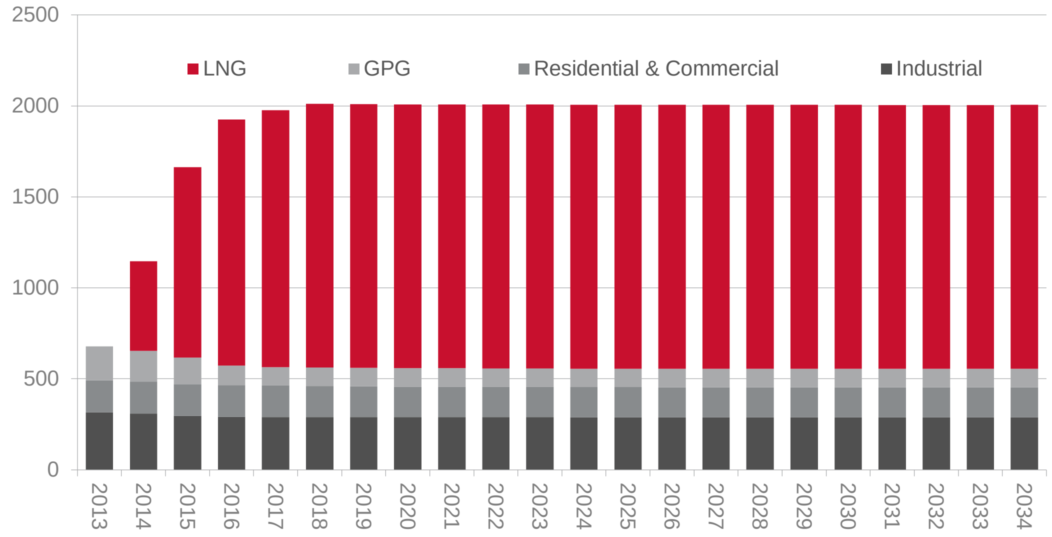
Large reserves and resources base supporting future production

Eastern Australian gas market

Eastern Australian gas markets

- Strong predicted growth in Eastern Australian gas and Asian LNG demand
- Gladstone based export LNG projects have transformed the east coast gas market
- Projected gas supply is 'tight' and demand strong
- The bulk of 'non-LNG' demand is yet to be contracted
- Upward pricing trajectory confirmed by recent contracts and market commentary

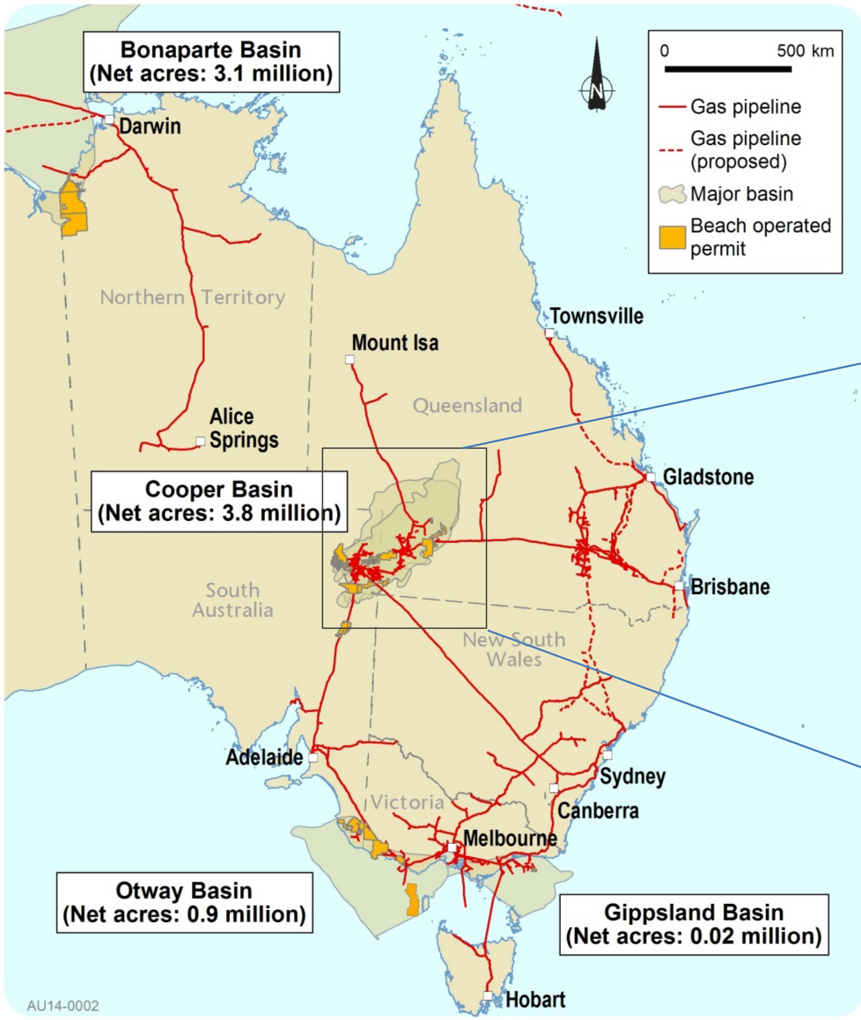
Eastern Australia total gas demand scenarios (PJ)



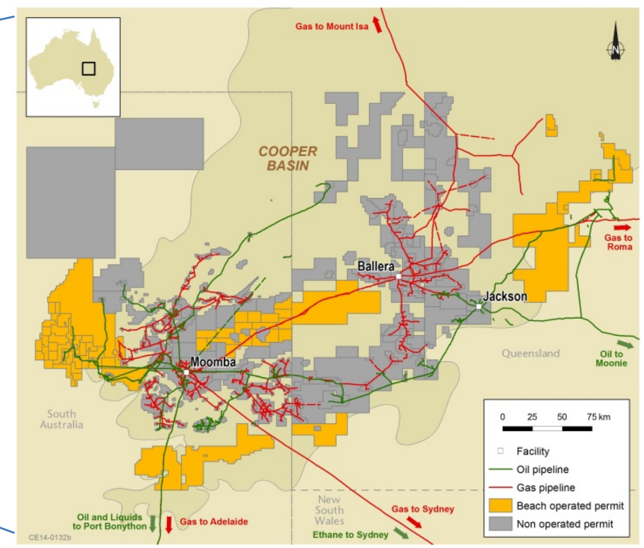
Source: Core Energy, 2014

CBA Energy Research prediction for 2014: "East Coast Gas prices spike above \$13/GJ with Gladstone LNG projects…… hoovering up supply to fill facility LNG capacity shortfall"

Prolific gas acreage strategically located



- Quality acreage footprints accessing multiple markets
- Prime unconventional gas acreage with transformational potential
- Gas liquids potential in most basins



Multi-basin portfolio to feed eastern and northern Australian markets

Upstream and downstream dynamics

- ‘Equity’ molecules to ‘equity’ projects
- Suppliers creating new markets via downstream investments
- Vertical integration driven by both domestic and export opportunities
- Depending on volume and deliverability, supply likely to under-write ‘equity’ projects as a priority
- Strong drivers for LNG participants to fill ramp-up wedge capacity and position for future expansion

Beach well placed as an independent upstream producer with exposure to oil linked gas pricing without LNG capital outlay

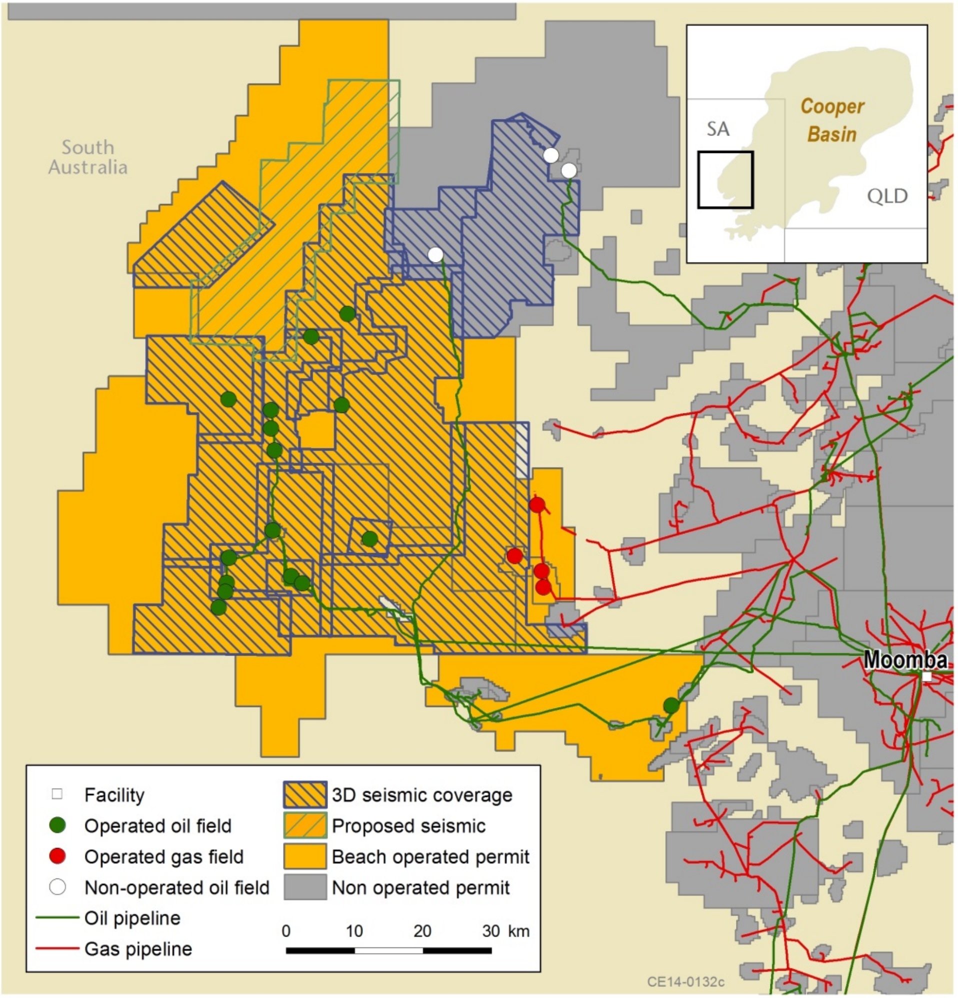
Source: Logos sourced from company websites

Western Flank

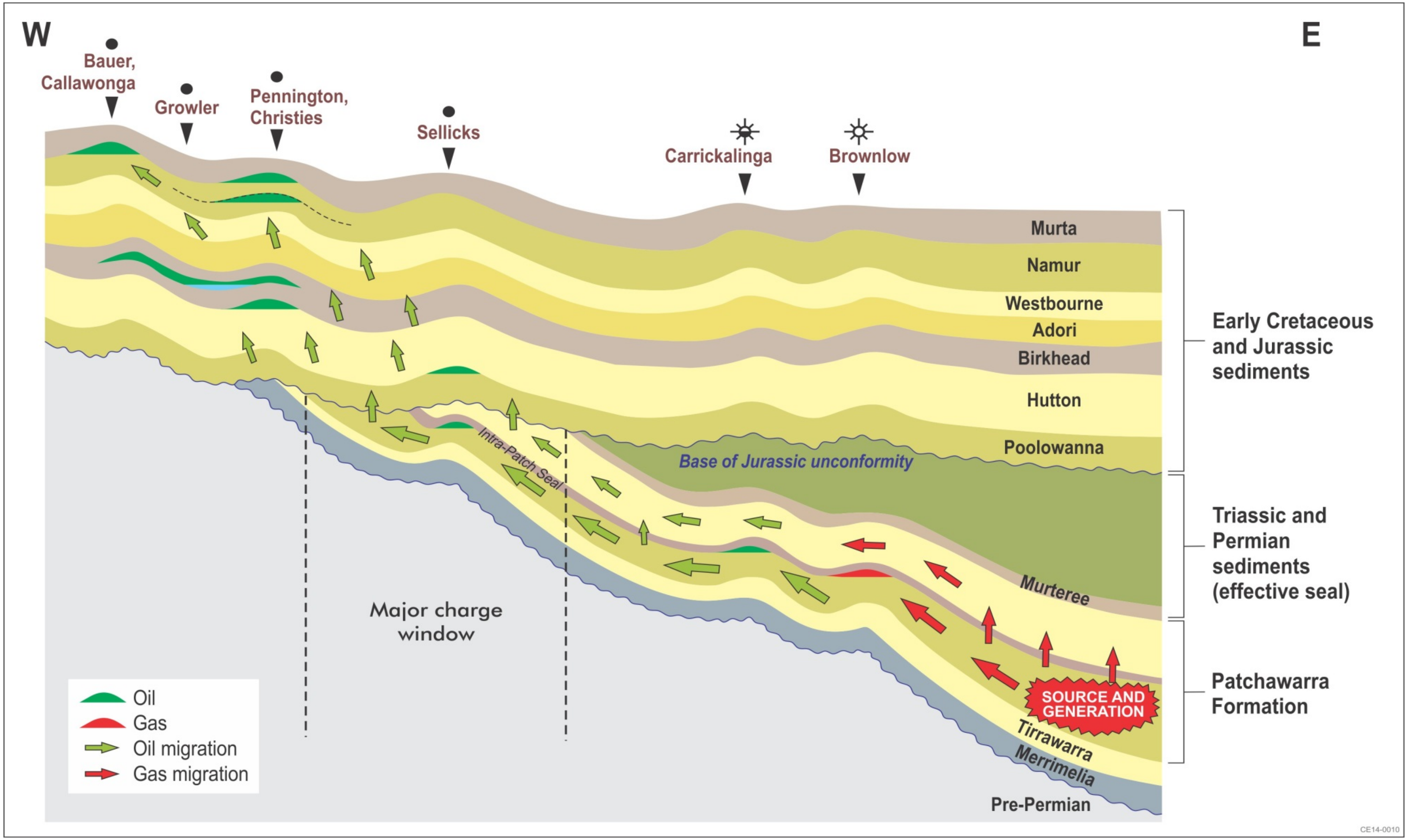
Cooper Basin

Western Flank

- High net back for oil and wet gas
- Quick drilling rate
- High flow rate wells
- Excellent geological understanding
- Established infrastructure
  - 250 kilometres of flowlines
  - 10 facilities and 5 trucking points
  - 40 oil wells on production
- 4,000 km^2 of 3D seismic
- Three new field discoveries at Martlet-1, Balgowan-1 and Burners-1
- New fields to be tied-in FY15
- 32 to 38 wells planned for FY15
- Total FY15 capex of $110 million



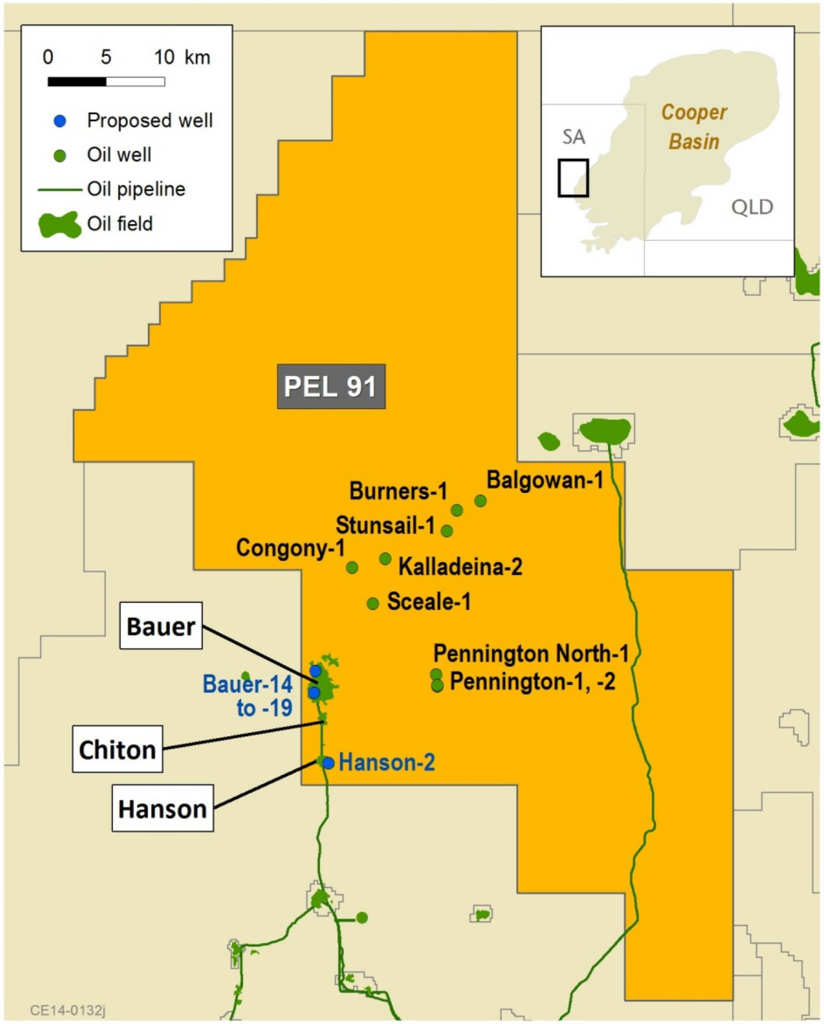
Western Flank oil migration path



PEL 91

- Beach 40% and operator, Drillsearch 60%
- Current gross production ~12,500 bopd
- Bauer facility expansion from 50,000 bpd of fluid to 75,000 bpd in second half FY15
- CKS fields expected on-line in first half and Stunsail, Balgowan and Pennington fields in second half FY15
- 18 wells planned for FY15, 13 remaining
- 500 km^2 Solidus 3D seismic survey
- Net FY15 capital expenditure $36 million

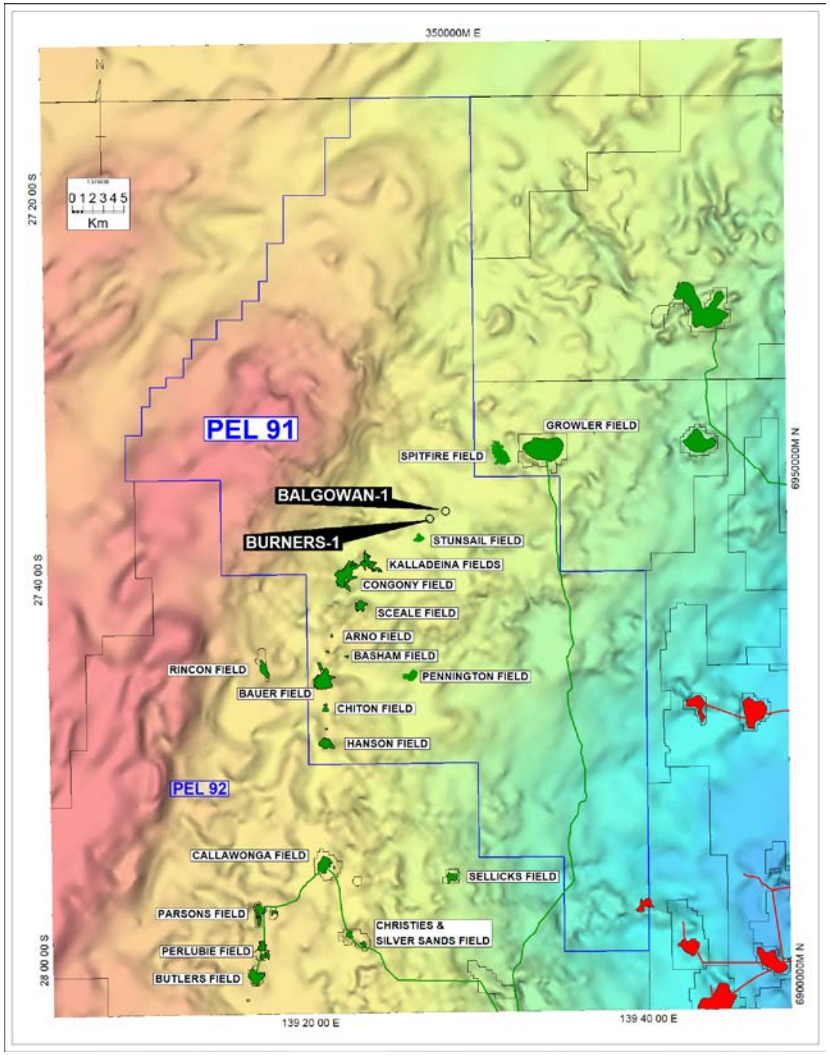
Bauer facility expansion, new fields on-line and drilling expected to sustain pipeline capacity



PEL 91 exploration successes

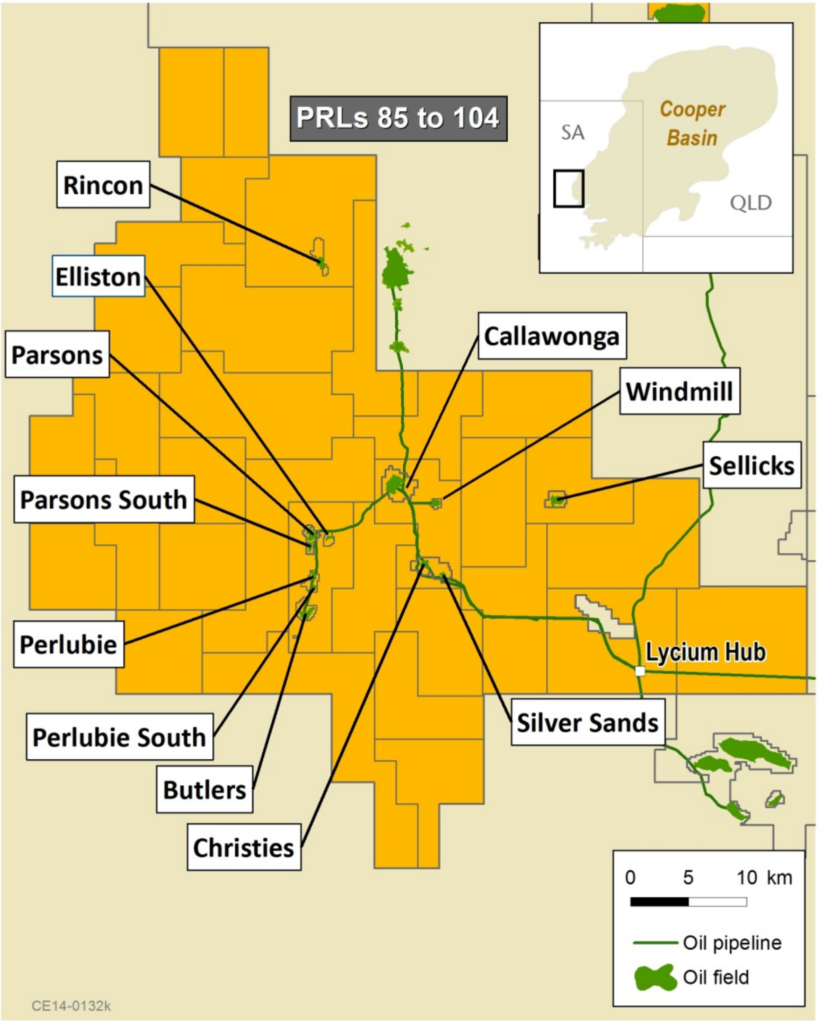
- The 14th and 15th new oil field discoveries at Burners-1 and Balgowan-1
- Continuation of Namur oil play to the north-east of the Bauer, CKS and Stunsail oil fields
- Balgowan-1 intersected a nine metre oil bearing interval, with net oil pay of:
  - 3.5 metres in the Namur Sandstone
  - Two metres in the McKinlay Member
- Burners-1 intersected net oil pay of one metre in the Namur Sandstone
- Both wells cased and suspended

Clear oil fairway trending north-east from the Bauer field



PRLs 85 to 104 (ex PEL 92)

- Beach 75% and operator, Cooper 25%
- Current gross production ~4,500 bopd
- Reprocessing of existing 3D seismic around the Callawonga and Butlers/ Parsons trends
- Nine wells planned for FY15
- Net FY15 capital expenditure $29 million

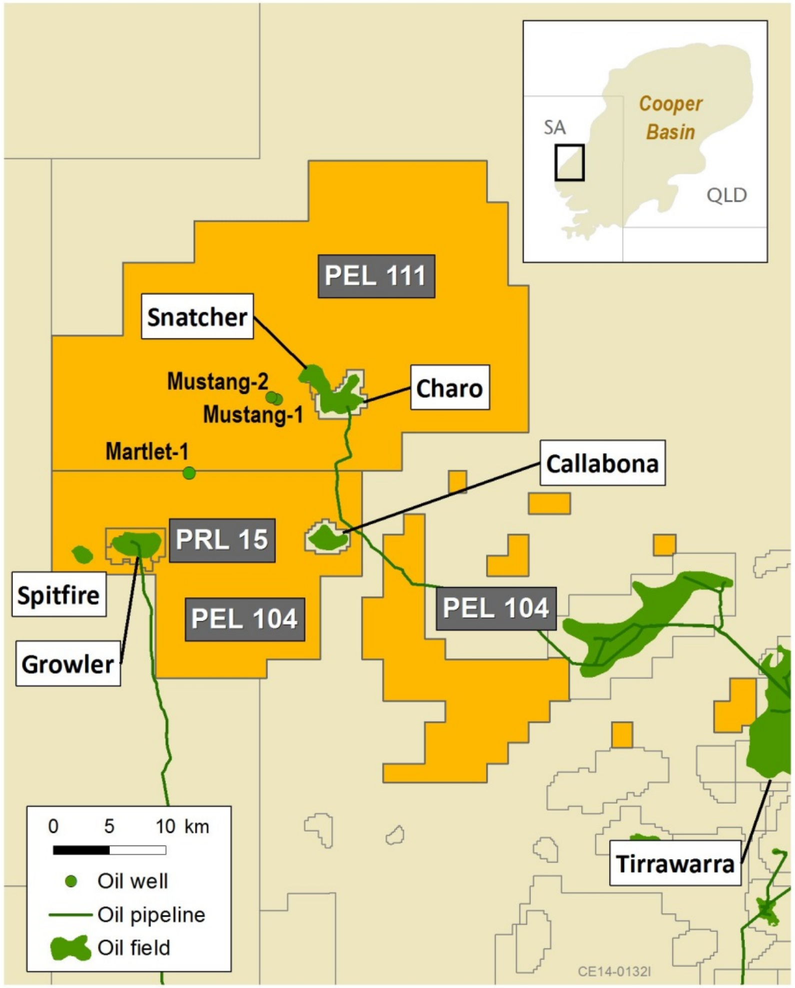


Seismic reprocessing to drive FY15 exploration drilling

PELs 104 and 111

- Beach 40%, Senex 60% and operator
- Current gross production of ~5,000 bopd from Growler/Spitfire and Snatcher/ Mustang fields
- Historical focus on the Birkhead Formation, with the Martlet-1 new field discovery in the Namur Sandstone
- Spitfire field producing strongly
- A number of contingent wells to be agreed by the joint venture
- Production enhancement projects currently being assessed

Strong recent production with options being considered for production rate improvement projects



PELs 104 and 111 exploration success

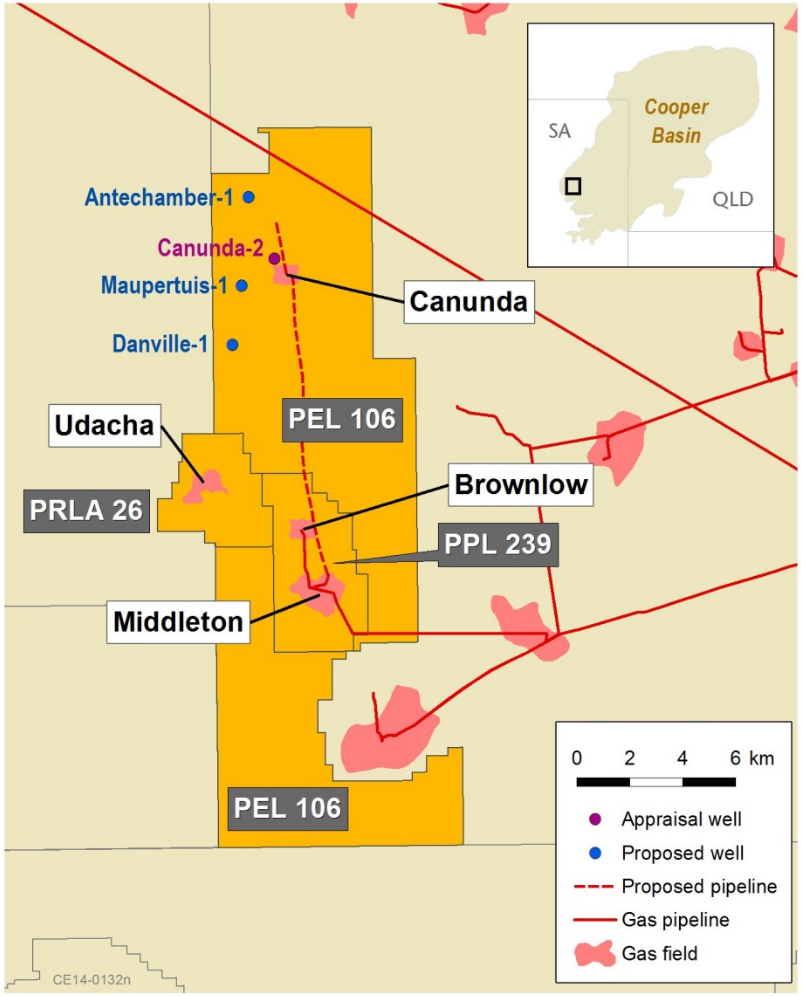
- Martlet-1 exploration well the first Namur Sandstone oil discovery in PELs 104 and 111
- Martlet-1 intersected net oil pay of six metres in the Namur Sandstone
- Commercial oil accumulations previously identified only in the Birkhead Formation in this area
- Potential for further Namur Sandstone oil pools based on prospects identified on 3D seismic
- Operator plans to have the Martlet field on extended production test in Q2 FY15

Further Namur Sandstone prospects to be targeted as a result of the Martlet-1 exploration success

PEL 106

- Beach 50% and operator, Drillsearch 50%
- Liquids rich operated production
- Gas sales agreement with SACB JV to March 2016
- Current gross production of ~12 MMscfd and ~1,000 bbl per day LPG and condensate
- Three exploration wells and one appraisal well
- Compression at Middleton to accelerate production to the market
- Net capital expenditure $11 million

High value and large liquids rich fields



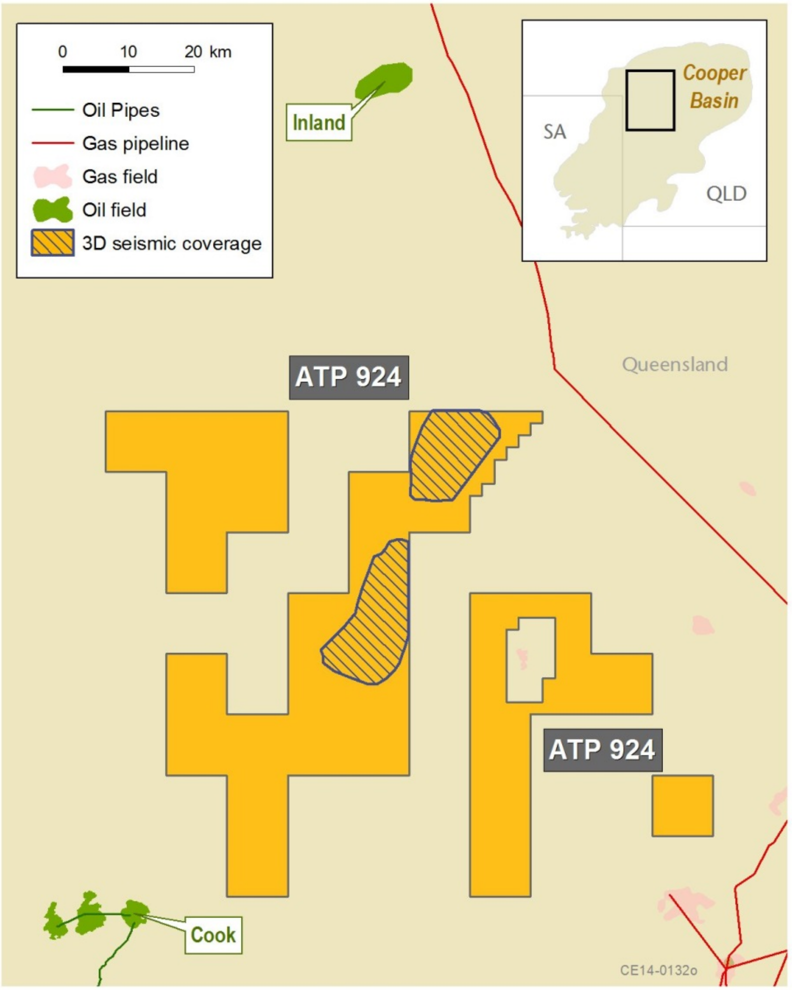
Other

Cooper Basin

ATP 924

- Beach farming-in 45% with Drillsearch
- Permit area ~2,300 km^2 and located between the Inland and Cook oil fields
- Two stage farm-in process
- Beach to fund ~150 km^2 of current 3D seismic and drill initial exploration well
- Upon election to continue, Beach to drill a further exploration well and reimburse Drillsearch for past costs
- Beach to manage operations of activities with its funded exploration wells
- Drillsearch to remain operator
- Three wells drilled in the permit to date

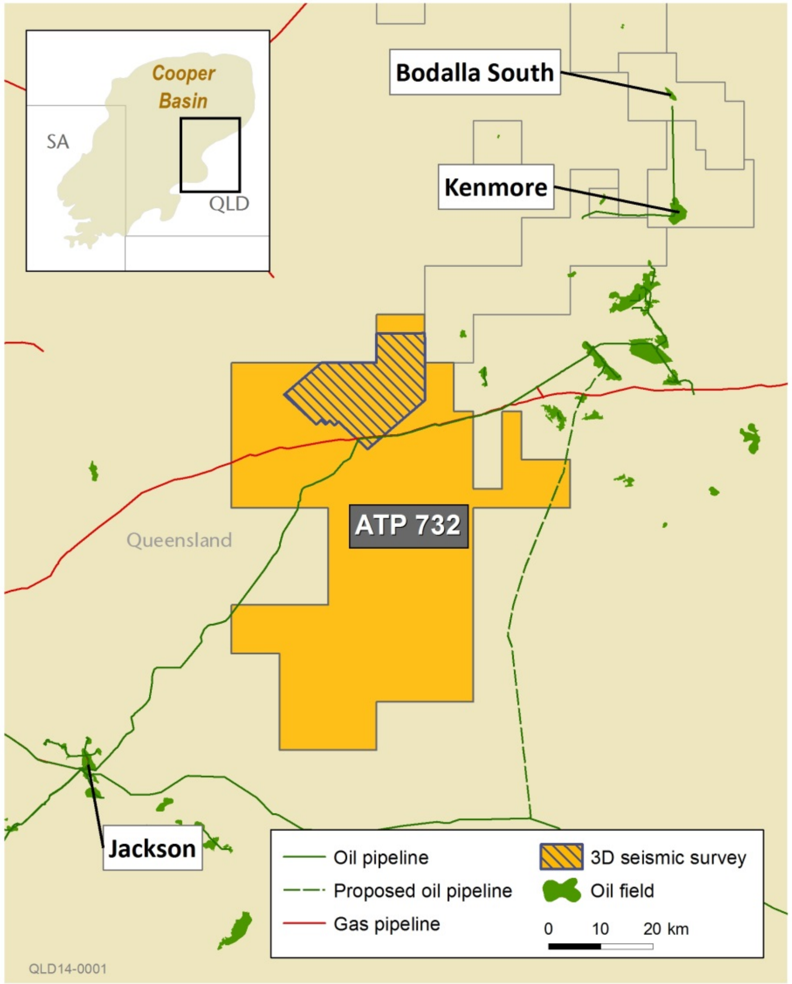
Continuing to focus on prospective oil permits within the Cooper Basin



ATP 732

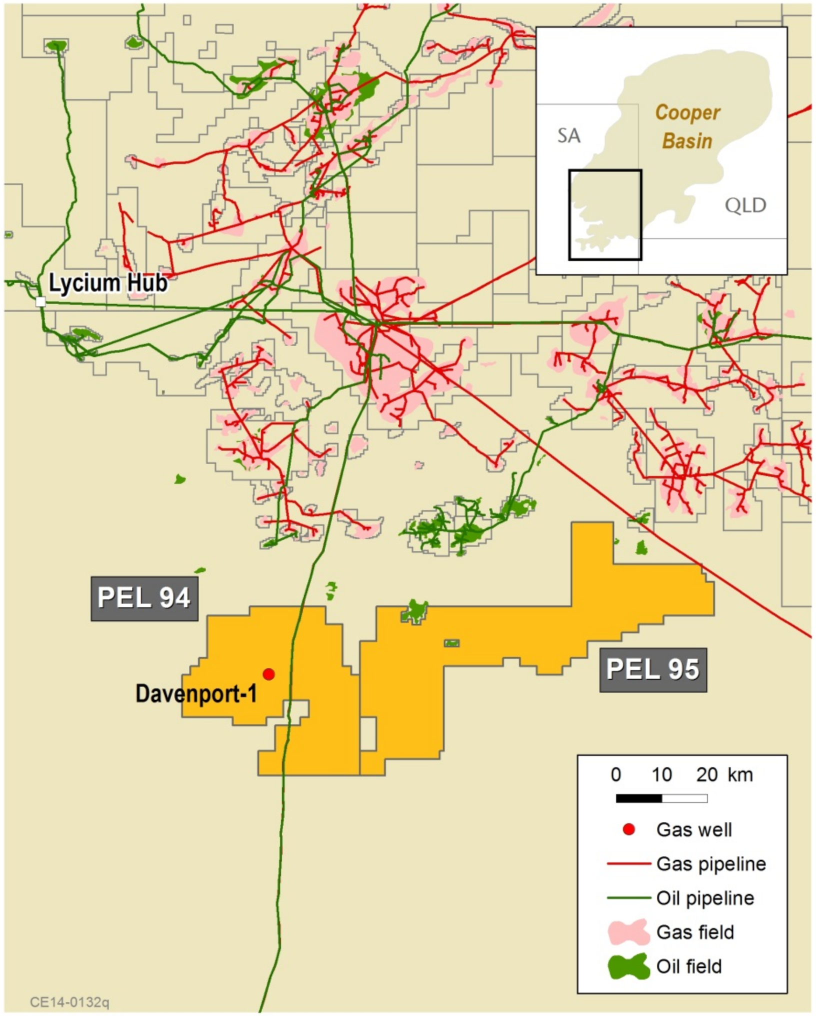
- Beach farming-in 50%, Bengal 50%
- Large underexplored permit
- Located between the Jackson (~50 MMbbl of oil produced) and the Kenmore/Bodalla (~20 MMbbl of oil produced) oil fields
- Targeting conventional oil reservoirs
- Next well to be based on interpretation of ~300 km2 Nassarius 3D seismic data
- Drilling expected in second half FY15
- Hydrocarbon shows in previous wells
- Beach to become operator of the permit

New oil fairway potential in an underexplored area between two prolific oil fields



PEL 94 and PEL 95

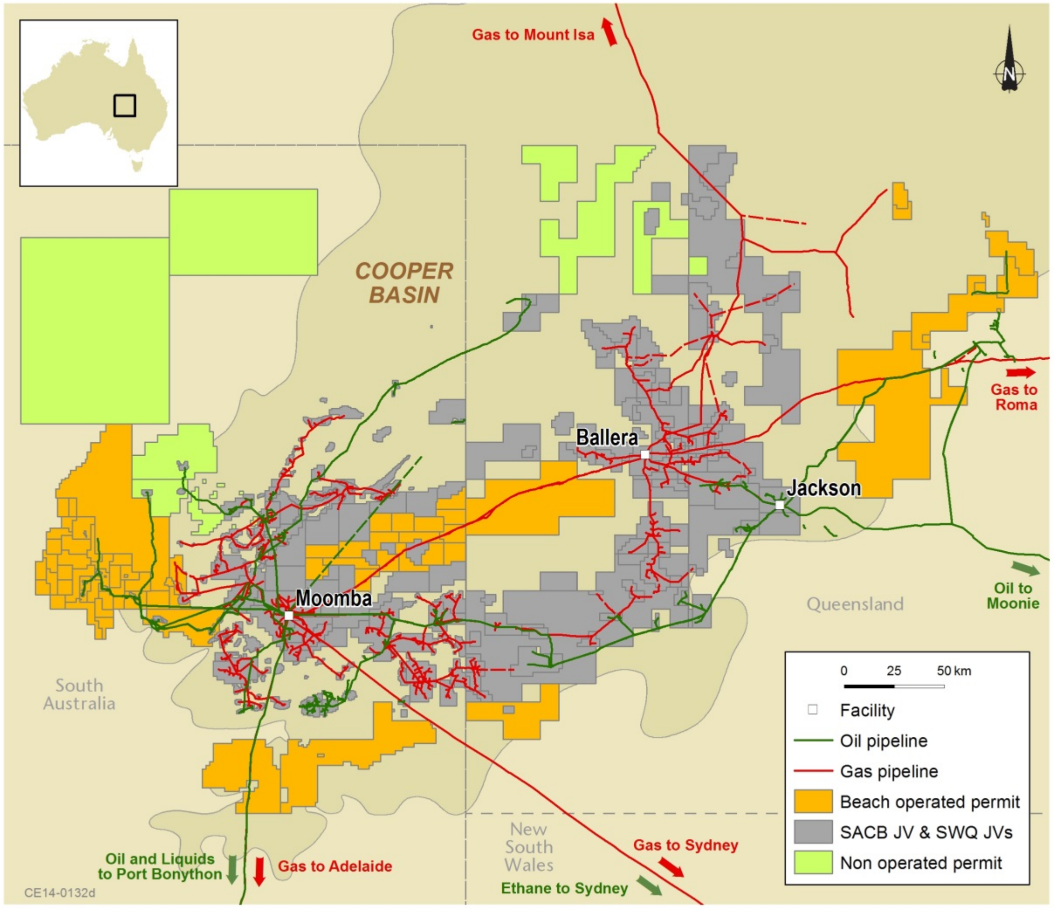
- PEL 94 – Beach 50% and operator, Strike 35%, Senex 15%
- PEL 95 – Beach 50% and operator, Strike 50%
- Targeting deep coals at 1,500 metres – 2,000 metres depth in PEL 94
- Well costs ~$3 million
- Davenport-1 exploration gas well:
  - Fracture stimulated over a lower zone in the VU Patchawarra coal
  - Upper VM3 Patchawarra coal perforated
  - Testing indicated good permeability
  - Hydrocarbon shows during testing
  - Extended flow test to follow



SACB JV and SWQ JVs conventional gas

SACB and SWQ JVs

- Significant acreage with substantial reserves base
- 20.21% in the South Australian Cooper Basin Joint Venture (SACB JV) and 20-40% in the South West Queensland JVs (SWQ JVs)
- Gross area covered by various joint ventures ~26,800 km^2 (~6.6 million acres)
- Joint ventures include:
  - ~6,000 km of flowlines
  - Primary processing and transportation facilities
- Upside from shale and basin centred gas plays



Targeting 30% production capacity increase by 2015

Moomba processing facility

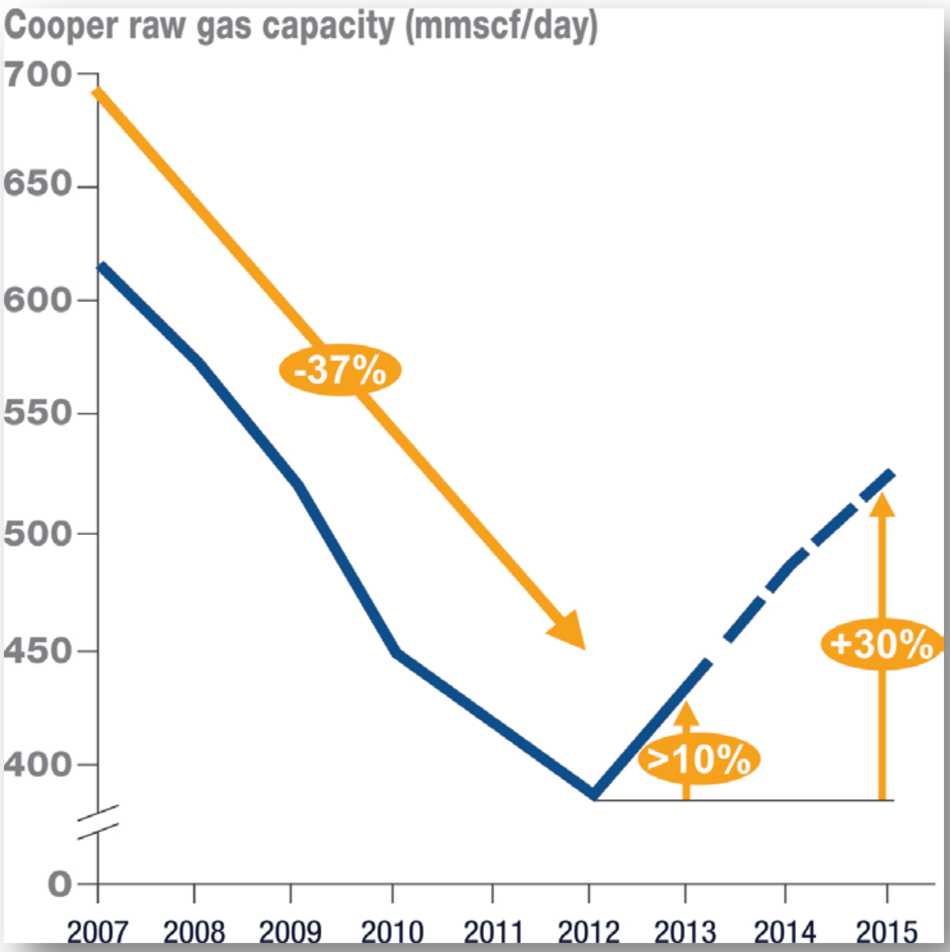
- Strategically located expandable facility
- Current daily capacity approximately:
  - 300 TJ gas
  - 35 kbbl oil/condensate
  - 600 tonnes LPG
- Opportunities to process more third party gas being actively pursued
- Substantial gas storage system with capacity ~70 PJ
- Gas supplied directly into New South Wales, Queensland and South Australian markets
- Further sales gas processing capacity at Ballera of ~80 TJ per day

The key processing point for Cooper Basin and Eromanga Basin oil and raw gas

SACB JV conventional gas

- Five rigs operating
- Focus on cost savings through multi-well pad drilling
- SIMOPS approach to fracture stimulation
- Targeted 30% capacity growth by 2015, leading to a step-change in cost reductions
- Maintenance strategies successfully delivering record low downtime levels leading to production benefits

Extracting more gas from existing fields with active infill drilling



Source: Derived from Santos

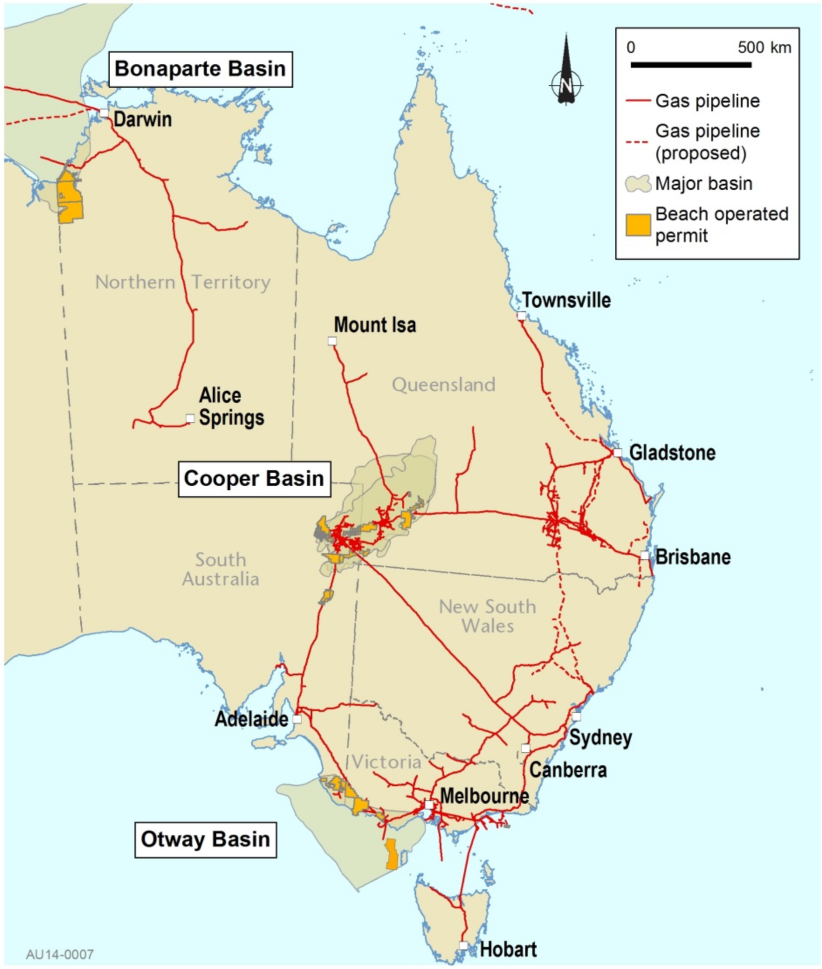
Unconventional gas

Cooper Basin

Unconventional positioning

- Strategically targeted three key basins for unconventional acreage
- Cooper Basin activity:
  - Nappamerri Trough Natural Gas with Chevron and Icon
  - SACB JV unconventional REM and BCG plays
- Otway and Bonaparte Basins targeting gas and gas liquids
- All basins proximal to infrastructure and markets
- Gas demand and pricing trending upward

Positioned to fuel growing northern and eastern gas markets



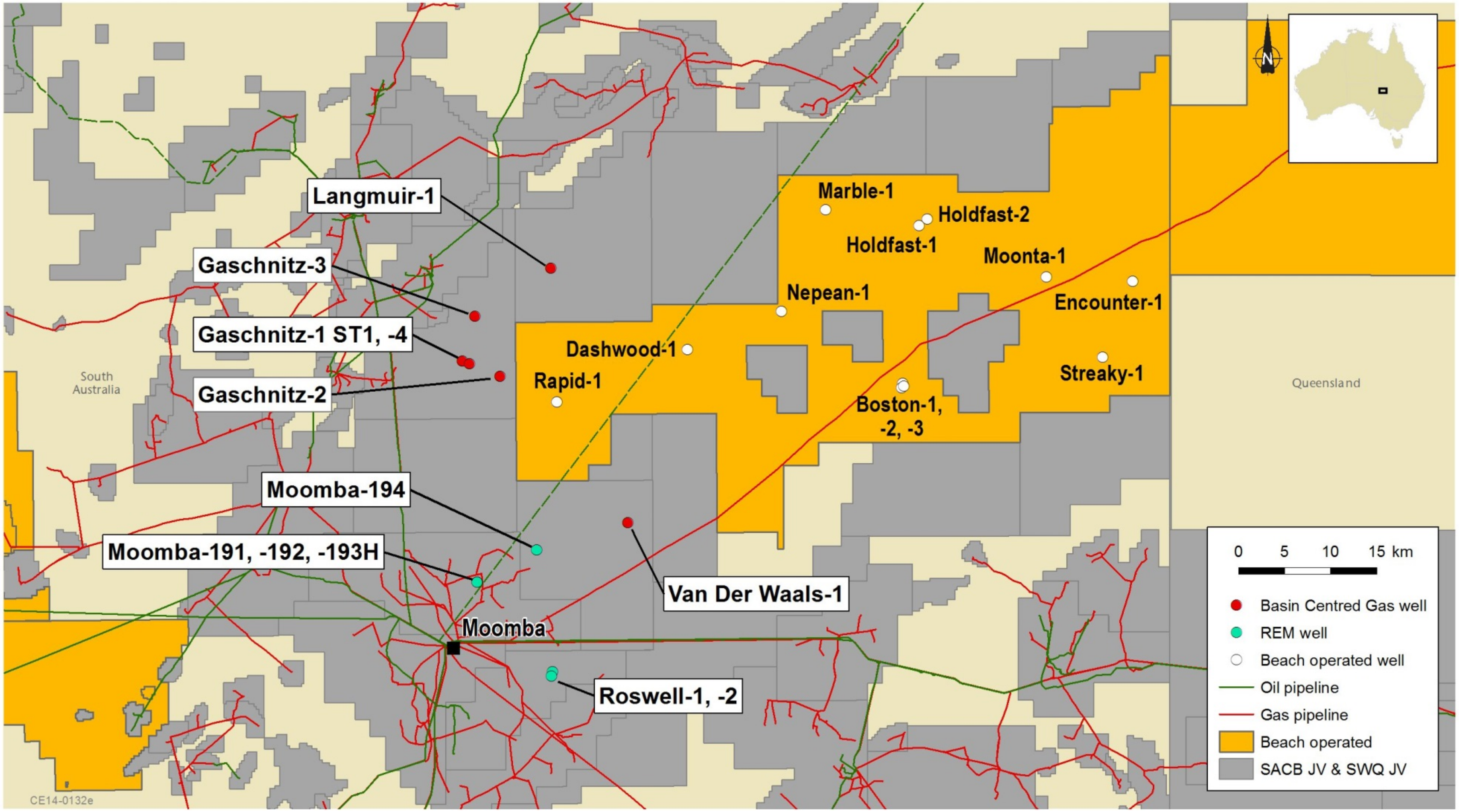
The keys to unconventional success

- Well profiles the key focus on all projects
- Uncovering 'sweet spots' with focused activity around them
- Process improvements and technology to drive efficiencies
- Costs to be driven down by efficiencies and scale
- Gas pricing trending upward
- The right partnerships with the relevant expertise

Estimated ultimate recovery per well the key for commerciality

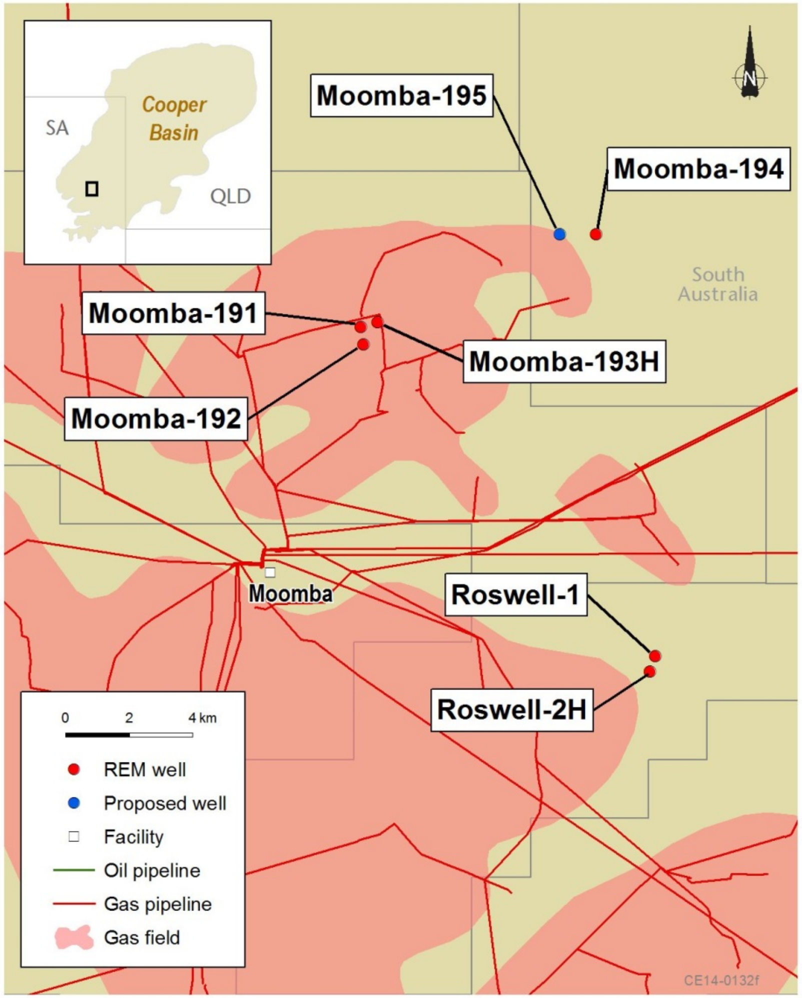
SACB JV unconventional gas

SACB JV unconventional program



REM play

- Targeting the Roseneath Shale, Epsilon Formation, Murteree Shale and Patchawarra Formation
- Moomba-191 and -194 tied-in
- Roswell-1 and Moomba-192 vertical wells fracture stimulated and flow tested
- Moomba-193H:
  - 1,000 metre lateral targeting the Murteree
  - Fracture stimulated over ten stages
  - Flowed at 1.5 MMscfd on test
- Roswell-2H:
  - 500 metre lateral targeting Roseneath
  - Fracture stimulated over five stages
  - Stabilised flow of 0.75 MMscfd on test



BCG play

- Gaschnitz-1 ST1 vertical well:
  - Seven zone stimulation over entire Permian section
  - Produced at ~1 MMscfd
  - Completed and shut-in
- Remaining Gashnitz vertical wells for 2014:
  - Two deep, targeting full Permian section
  - One shallow, targeting Toolachee (coring point)/Daralingie
- Langmuir-1 vertical well:
  - Ten zone fracture stimulation, produced at ~1.5 MMscfd, completed and shut-in
- Van der Waals-1 vertical well:
  - Operational issues resolved
  - Fracture stimulation targets under review

Strong similarities to Beach operated NTNG wells in Nappamerri Trough

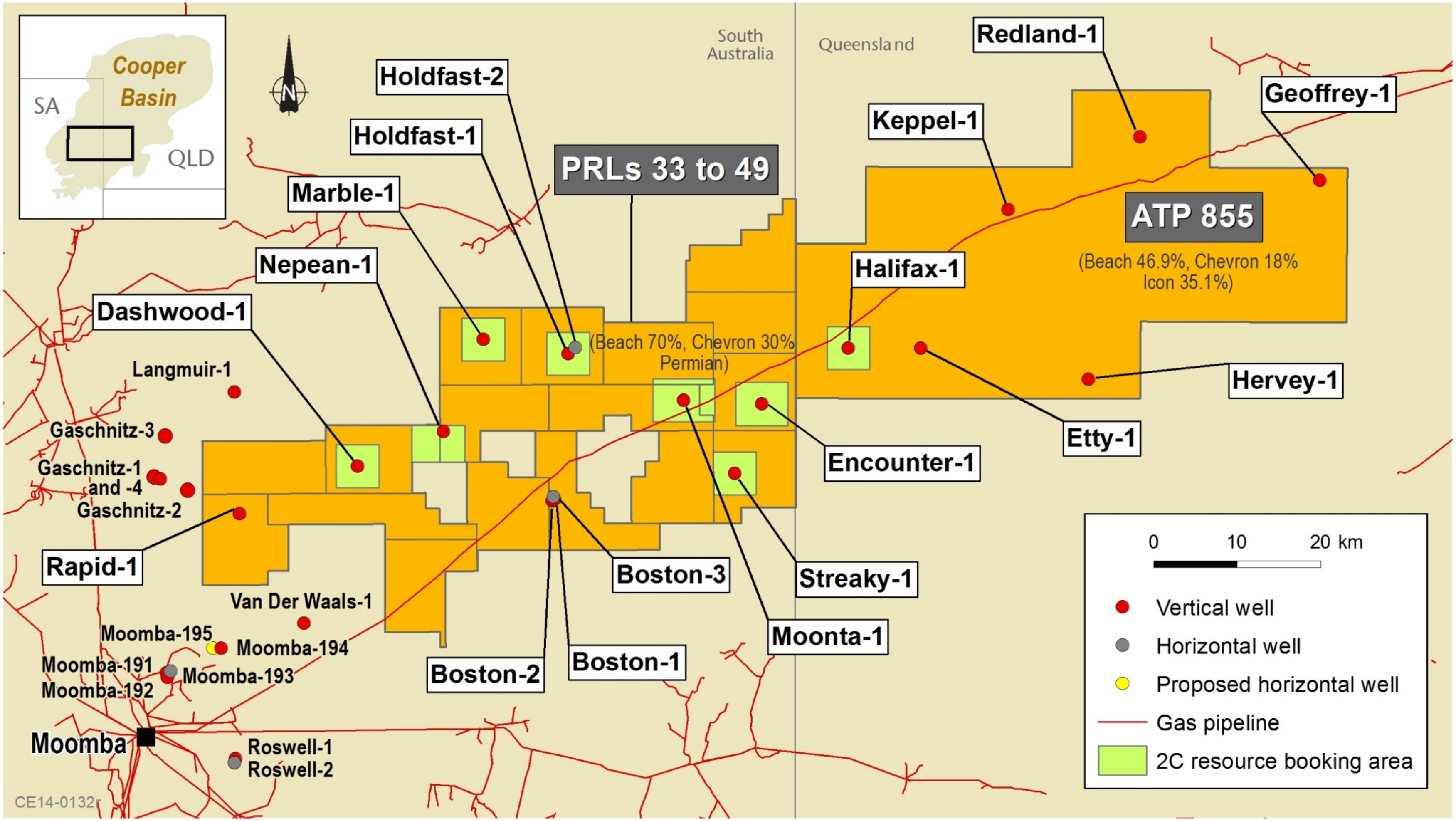
Nappamerri Trough Natural Gas

Nappamerri Trough Natural Gas

- Permian section equity interests:
  - PRLs 33 to 49 (Beach 70% and operator, Chevron 30%)
  - ATP 855 (Beach 46.9% and operator, Chevron 18%, Icon Energy 35.1%)
- Aerially extensive with permits covering more than 800,000 acres
- In excess of 1,000 metres of gas saturated section
- Fracture stimulation campaign in ATP 855 underway
- Retention licenses granted over PEL 218, now PRLs 33 to 49

Net 1.6 Tcf of 2C resource booked at 30 June 2014 in PRLs 33-49 and ATP 855

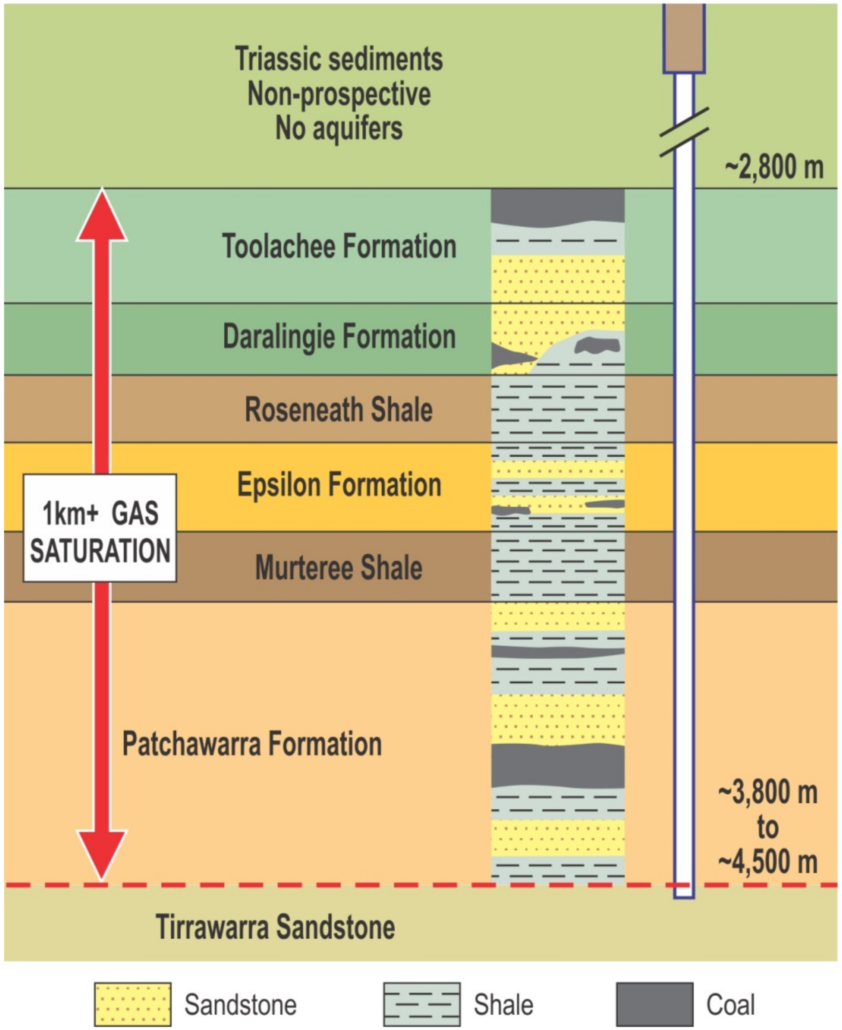
NTNG wells



Cooper Basin
SA
QLD
N
South Australia
Queensland
Holdfast-2
Holdfast-1
PRLs 33 to 49
Marble-1
Nepean-1
Dashwood-1
Langmuir-1
Gaschnitz-3
Gaschnitz-1 and -4
Gaschnitz-2
Rapid-1
Van Der Waals-1
Moomba-195
Moomba-194
Moomba-191
Moomba-192
Moomba-193
Moomba
Roswell-1
Roswell-2
CE14-0132
(Beach 70%, Chevron 30% Permian)
Redland-1
Geoffrey-1
Keppel-1
ATP 855
(Beach 46.9%, Chevron 18% Icon 35.1%)
Halifax-1
Hervey-1
Etty-1
Encounter-1
Streaky-1
Moonta-1
Boston-3
Boston-2
Boston-1
0 10 20 km
Vertical well
Horizontal well
Proposed horizontal well
Gas pipeline
2C resource booking area

ATP 855 stimulation program

- Hervey-1 – Stimulated over five stages, flow testing commencing in coming weeks
- Etty-1 – Up to four stages targeting the Toolachee and Daralingie Formations
- Redland-1 – Up to four stages targeting the Toolachee and Darlingie Formations
- Geoffrey-1 – Injectivity test to influence next step, which may be a free-flow test of lower interval or fracture stimulate Patchawarra and Epsilon and then test
- Proposed stimulation parameters:
  - 40/70 proppant size
  - Max. treating pressure of ~13,300 psi
  - Each stage to use ~8,000 bbl of fluid (~1.3 ML) and ~220,000 lb of proppant
  - Max. pump rate of ~80 bbl per minute



Timing of Stage 1 completion

- Envisaged that the decision point across the two permits will be synchronised
- Terms of the farm-in agreement signed in February 2013 as follows:

South Australia – PRLs 33-49

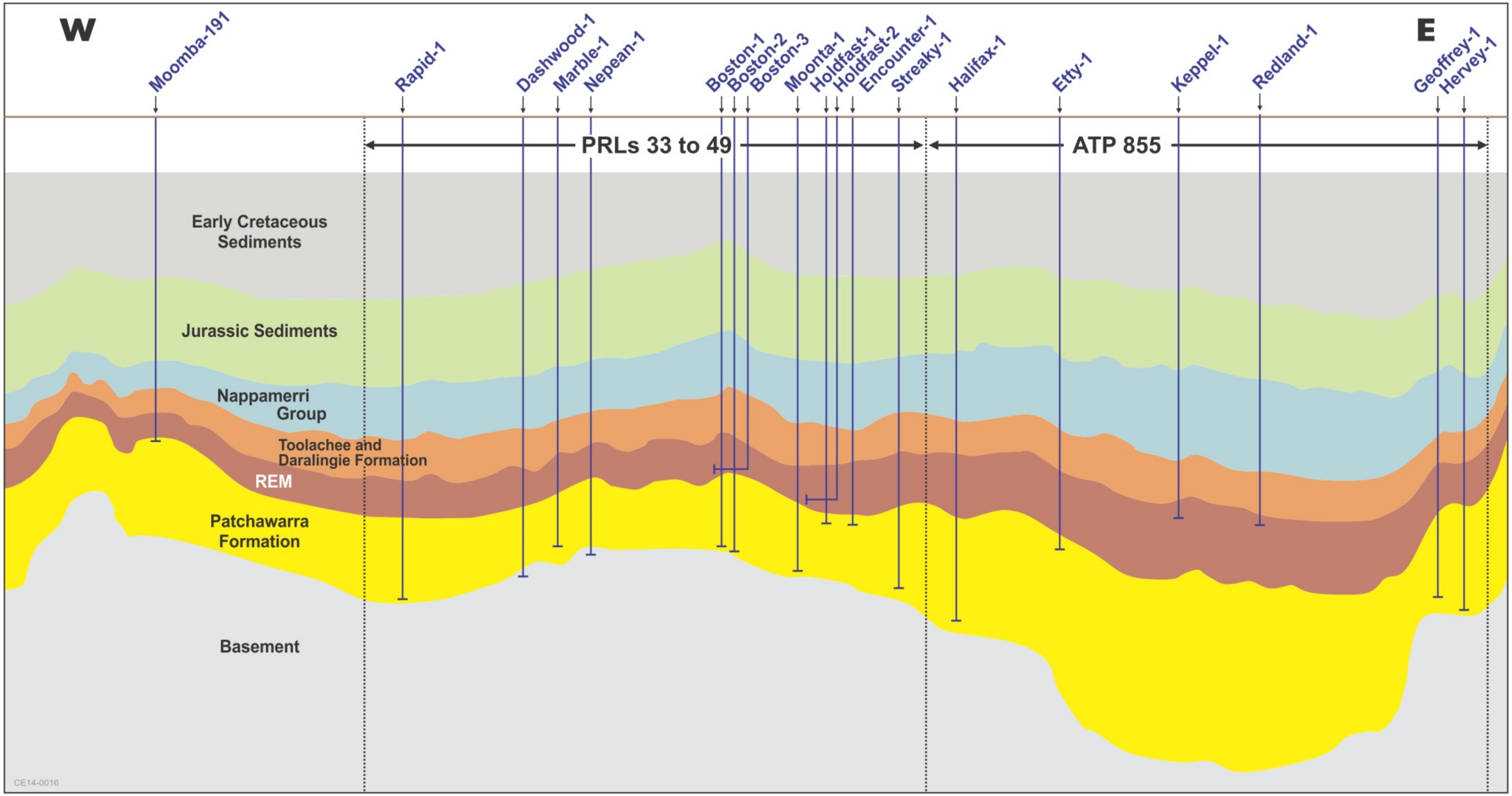
- Beach to notify Chevron following completion of Stage 1 work program
- Once notified, Chevron has 60 days to notify Beach of its decision on whether to proceed to Stage 2

Queensland – ATP 855

- Chevron to decide on whether it moves to Stage 2 by 31 March 2015

Timing of NTNG program in line with original farm-in agreement

Exploration and appraisal cross section



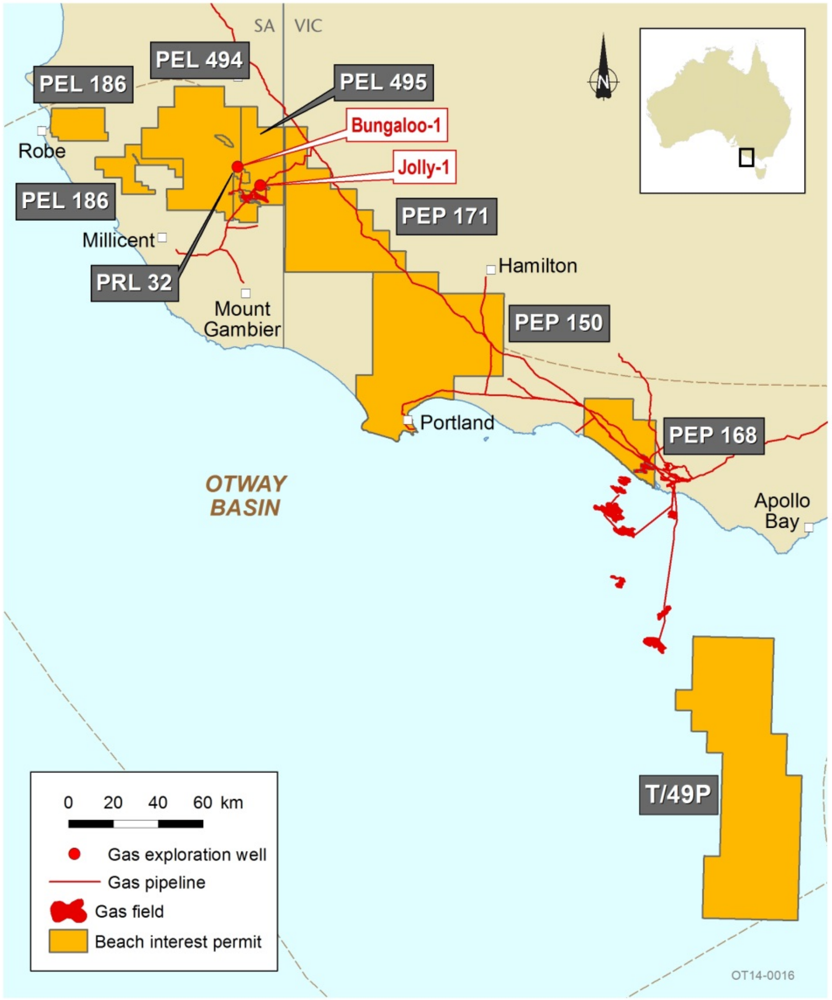
Note: Well locations are approximate only and may have been shifted to show their correct structural position on the cross section

Other Australia

Otway Basin

- Building a portfolio of onshore and offshore gas assets
- The largest growth profile of any Australian basin over the past year
- Onshore processing capability of 500 MMscfd
- Further conventional onshore drilling anticipated
- Acquired a 20% interest in T/49P from 3D Oil for $3 million
- Well positioned near infrastructure and producing fields

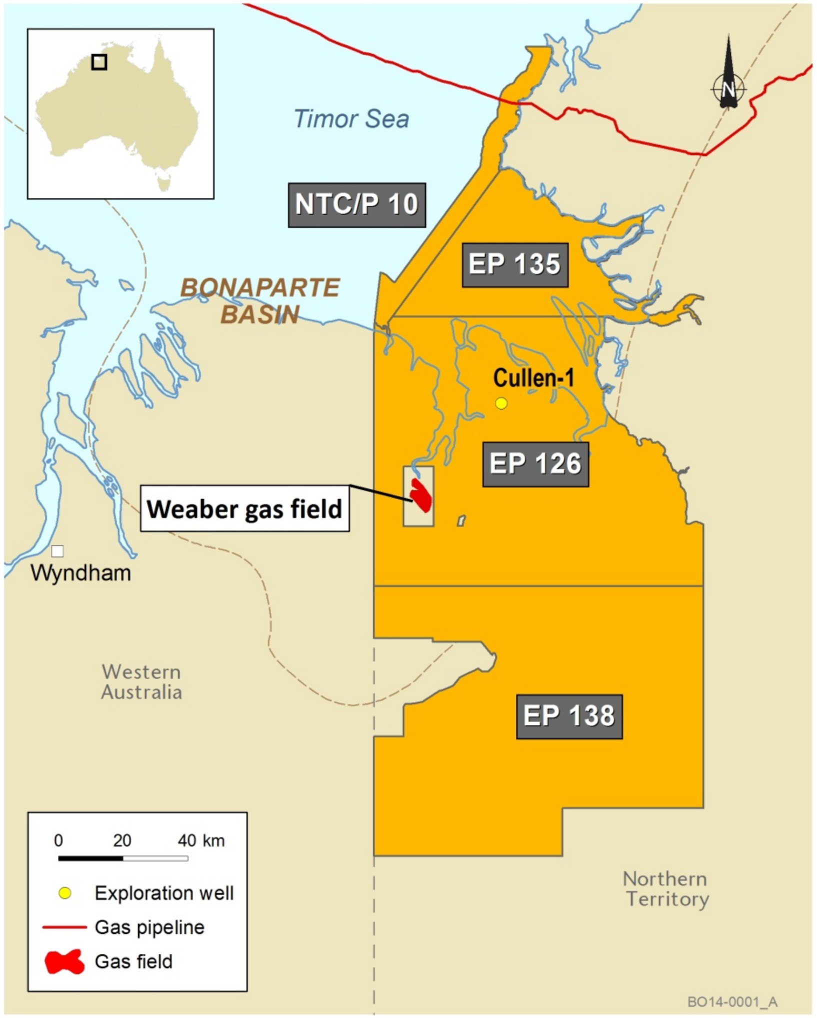
Exploring for conventional and unconventional liquids rich gas near existing infrastructure



Bonaparte Basin

- EP 126, 138 (Beach earning up to 85%)
- ~6,500 km^2 high resolution airborne gravity and magnetic survey acquired, processed and interpreted
- Cullen-1 reached a total depth of 3,325 metres
- 54 metres of core recovered
- Evidence of natural fractures
- Initial indications of gas and gas liquids, both conventional and unconventional
- Well cased and suspended for further testing

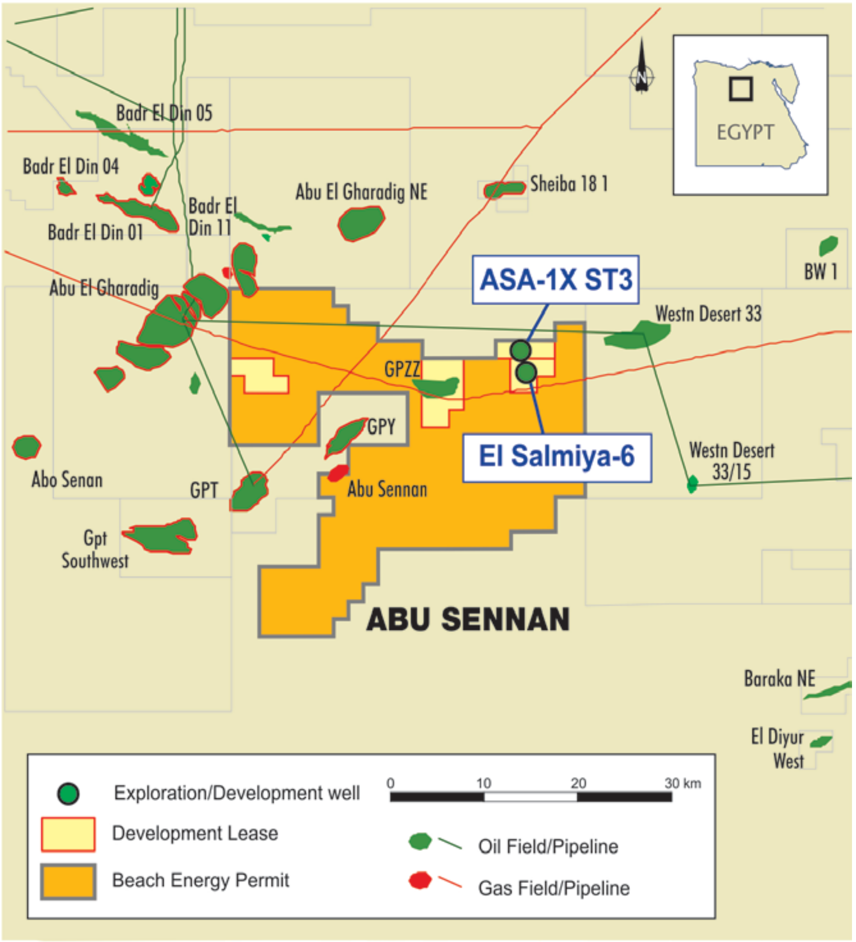
Underexplored with conventional and unconventional oil and gas targets



International

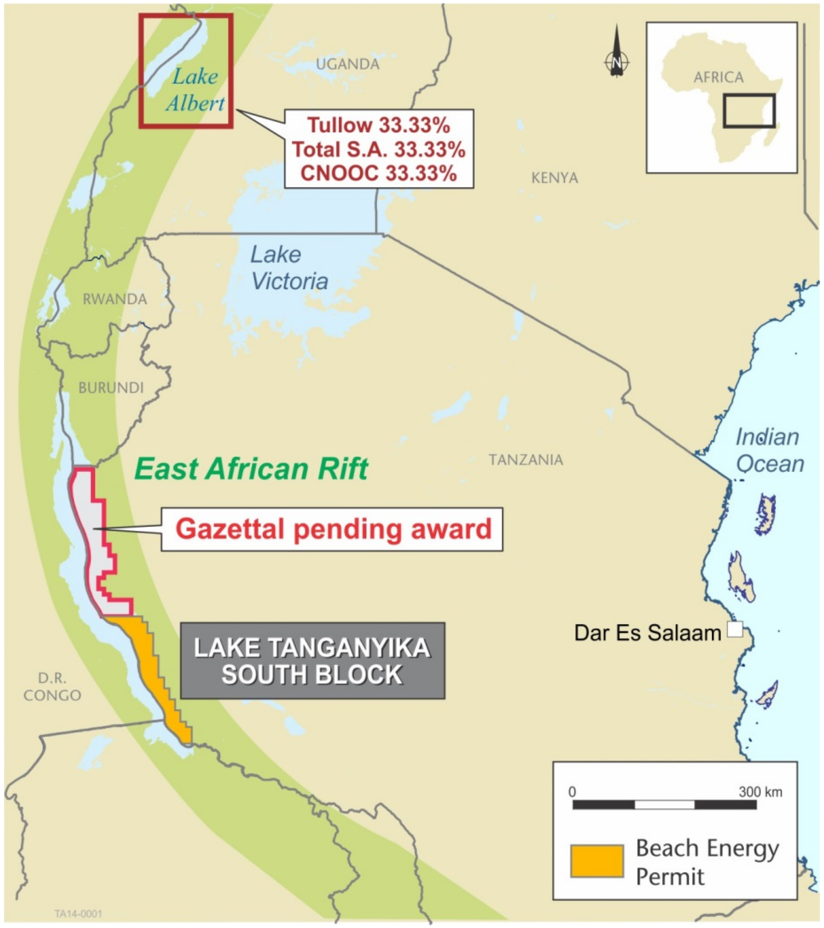
Egypt – Abu Sennan

- El Salmiya-6 – 52 metres of net pay across an 89 metre interval in the primary target Kharita Sandstone
- El Salmiya-6 flow tested at 2,880 bopd and 9.7 MMscfd
- Gas development for El Salmiya to generate gas sales and increase oil production
- ASA-1X ST3 – net pay of 7 metres in the Abu Roash ‘C’ primary target and 6.5 metres in the Abu Roash ‘E’ secondary target
- ASA-1X ST3 flow tested at 2,130 bopd from the ‘C’ and 1,332 bopd from the ‘E’
- Al Jahraa-3 appraisal well and ASH-1X exploration to spud imminently



Farm-out of Tanzanian acreage

- Woodside farming-in to 70% of the Lake Tanganyika South Block
- As part of the farm-in, Woodside will:
  - Reimburse its share of back costs
  - Fund a further round of seismic
  - Contribute to Beach's share of costs for an initial exploration well to an agreed cap, should Woodside elect to proceed beyond seismic operations
- Beach to remain operator during next stage of seismic
- Woodside has option to become operator at a later date
- Transaction conditional on Tanzanian Government consents



Successful farm-out of highly prospective permit to a world class operator

Appendices

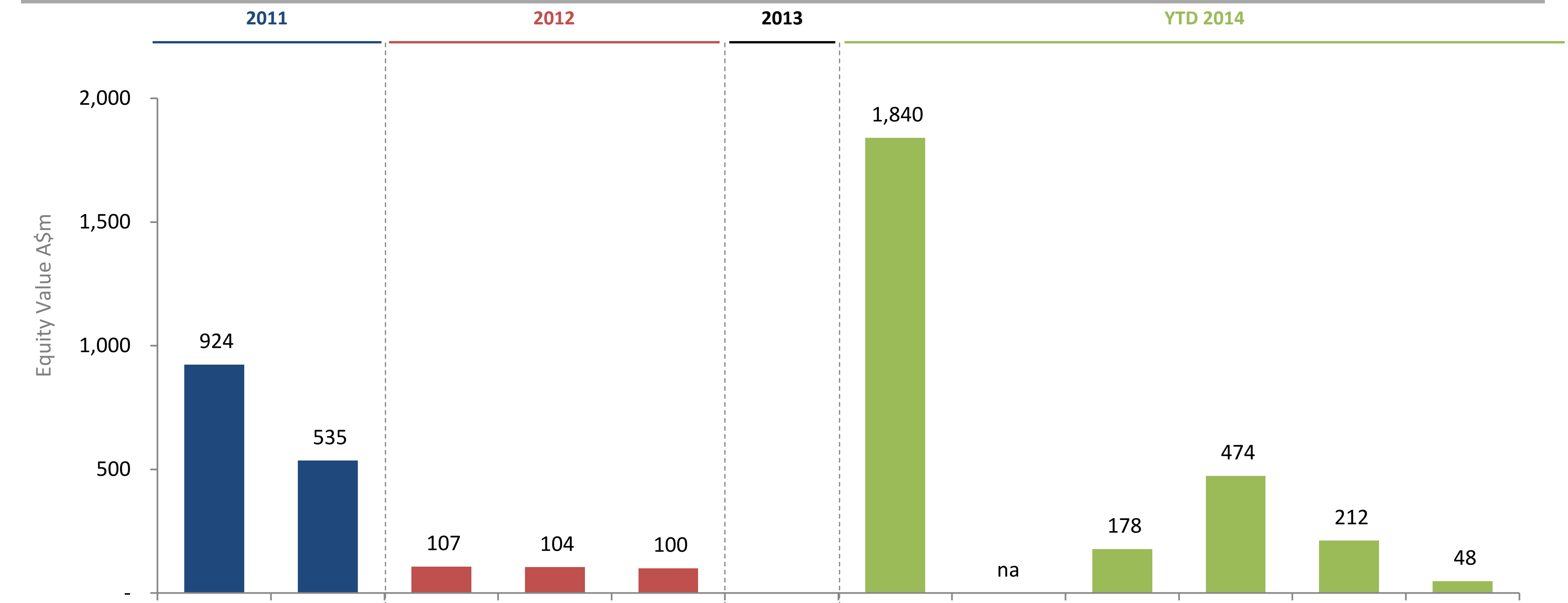
Financial results overview

Outstanding financial results, with records achieved for sales volumes, revenue, operating cash flow and underlying NPAT

	FY14	FY13	Change
Sales volume (MMboe)	10.8	9.0	↑ 20%
Total sales revenue ($ million)	1,052.1	698.2	↑ 51%
Operating cash flow ($ million)	582.6	261.3	↑ 123%
NPAT ($ million)	101.8	153.7	↓ 34%
Underlying NPAT ($ million)	259.2	140.7	↑ 84%
Cash balance ($ million)	411.3	347.6	↑ 18%
Total dividends paid (cps)	4.0	2.25	↑ 78%

Growing corporate activity

2014 YTD – Greatest activity in the listed oil and gas industry over the last four years



Target	EasternStar Gas	Bow Energy Ltd	eureka Energy	Acer Energy	Texon Petroleum Ltd	aurora Oil & Gas Limited	nexus Energy	WestSide	roc	Dart Energy	Ambassador oil and gas
Acquirer	Santos	arrow energy	aurora Oil & Gas Limited	Drillsearch	Sundance Energy	Baytex Energy Corp	SGH	Shandong Landbridge Group Co	FOSUN	IGas Energy	Drillsearch
Announcement Date	Jul-11	Aug-11	Apr-12	Oct-12	Nov-12	Feb-14	Mar-14	Apr-14	Apr-14	May-14	June-14
Completed Date	Nov-11	Dec-11	Aug-12	Jan-13	Mar-13	May-14	Administration[1]	July-14	Pending	Pending	Pending

Note: (1) Entered administration on 12 June 2014 after shareholders voted down the Seven Group Holdings proposal ("SGH"). SGH subsequently acquired Nexus out of administration for ~$181m (enterprise value), with Nexus shareholders receiving zero consideration
Source: Company filings, IRESS, Mergermarket

Chevron transaction summary

- Subject to joint venture approvals, the key work program elements envisaged across the two permits involve an initial exploration program to be followed by pilot production programs

PRLs 33 to 49 – potential payments	ATP 855 – potential payments
Stage 1 (initial 30%) (1) • US$36 million cash • US$95 million carry	**Stage 1 (initial 18%)** • US$59 million cash
Stage 2 (additional 30%) (2) • US$41 million cash • US$47 million carry	**Stage 2 (additional 18%)** (2) • US$36 million cash
• Commitment bonus payment of US$35 million	***US$349 million of potential payments to Beach over several years***

(1) Vertical wells exclude Holdfast-1 and Encounter-1
(2) Permian section equity interests post stage 2 farm-in would be: PRLs 33 to 49 (Beach 40%, Chevron 60%) and ATP 855 (Beach 28.9% , Chevron 36%, Icon Energy 35.1%)
Note: Chevron has option to proceed with stage 2

SACB JV unconventional and infill wells

Moomba wells - nomenclature

Current Well Name	Previous Well Name	Purpose	Status
Roswell 1	Roswell 1	Vc 50 coal, REM, Microseismic	Flowing from Vc 50 post frac
Roswell 2	Roswell 2 Horizontal	Roseneath Shale 1000 -1500'	Spud 12 Oct
Moomba 192	Aurora 1 Vertical	REM, Microseismic	Status being reviewed on Patch gas
Moomba 193	Aurora 2 Horizontal	Murteree Shale	After Roswell 2
Moomba 194	Fortuna 1 Vertical	REM and Patch, Microseismic	C & S 7 Oct REM Frac
Moomba 195	Fortuna 2 Horizontal	Murteree Shale	After Moomba 193
Moomba 196	Moomba North 30 Vertical	Gas Development	Spud 16 Oct
Moomba 197	Moomba North 44 Vertical	Gas Development	After Moomba 196
Moomba 198	Moomba North 46 Pad Well	Gas Development	Spudded 9 Oct
Moomba 199	Moomba North 45 Pad well	Gas Development	After Moomba 198
Moomba 200	Moomba North 47 Pad well	Gas Development	After Moomba 199
Moomba 201	Moomba North 48 Pad well	Gas Development	After Moomba 200
Moomba 202	Moomba South 55 Vertical	Gas Development	After Moomba 197
Moomba 203	Moomba 203	REM and Patch	1Q 2014 Possible replacement for M 192

Contact Information

Head office
25 Conyngham Street
Glenside SA 5065
Tel: +61 8 8338 2833
Email: info@beachenergy.com.au
Website: www.beachenergy.com.au

Chris Jamieson
General Manager Investor Relations
Tel: +61 8 8338 2833
Mob: +61 487 173 244

Derek Piper
Investor Relations Manager
Tel: +61 8 8338 2833
Mob: +61 407 376 748