BEACH ENERGY

Investor morning – 5 December 2012

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 2012 and represent Beach's share.

Competent Persons Statement

- This presentation contains information on Beach's Reserves and Resources which have been compiled by Mr Gordon Moseby, who is a full time employee of Beach, is qualified in accordance with ASX listing rule 5.11 and has consented to the inclusion of this information in the form and context in which it appears.

Welcome

Chris Jamieson

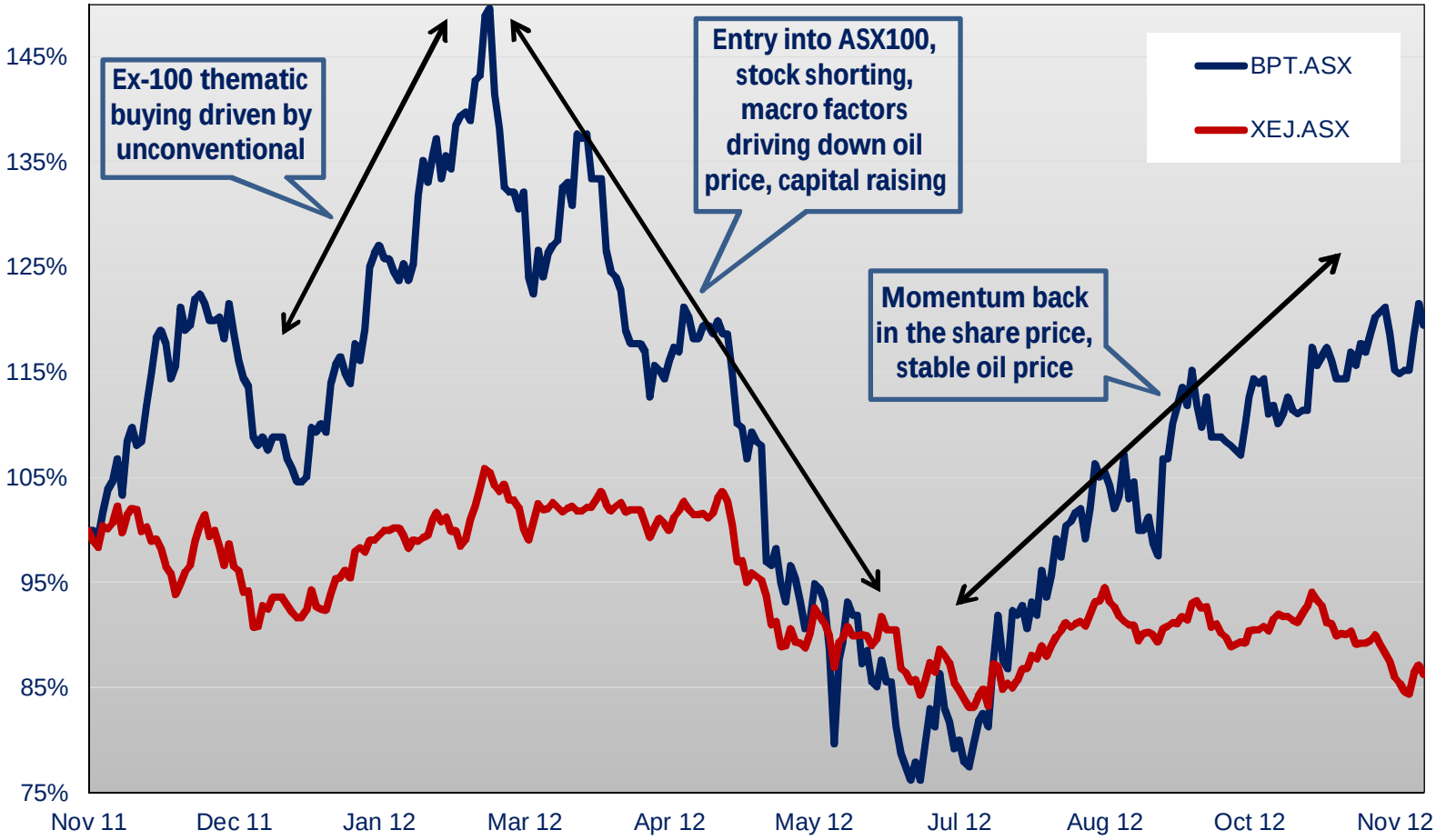
General Manager Investor Relations

Welcome and housekeeping

Time	Topic	Presenter
9:00-9:10am	Welcome	Chris Jamieson
9:10-9:25am	Strategic overview	Reg Nelson
9:25-9:40am	Operational overview	Neil Gibbins
9:40-9:50am	Financial management	Kathryn Presser
9:50-10:10am	Cooper Basin – Western Flank	Mike Dodd
10:10-10:15am	Q&A	All
10:15-10:45am	Morning tea	
10:45-11:05am	International	Simon Brealey
11:05-11:35am	Cooper Basin – Unconventional exploration	Mark Pitkin
11:35-11:50am	Cooper Basin – SACB JV & SWQ JV's and Infrastructure	Gordon Moseby
11:50-12:00pm	Q&A	All
12:00pm	Close	Reg Nelson
12:00-1:30pm	Lunch and open forum	All

Share price performance

Beach share price vs S&P ASX Energy Index (XEJ)



The share price continued to outperform the XEJ over the past year

Strategic overview

Reg Nelson

Managing Director

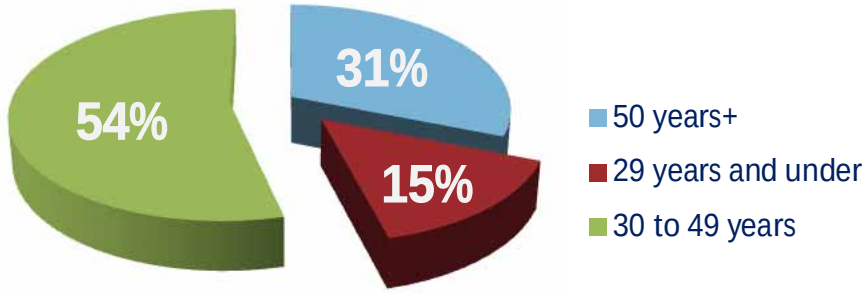
Company overview

Fully funded capex program primarily focused on the Cooper Basin

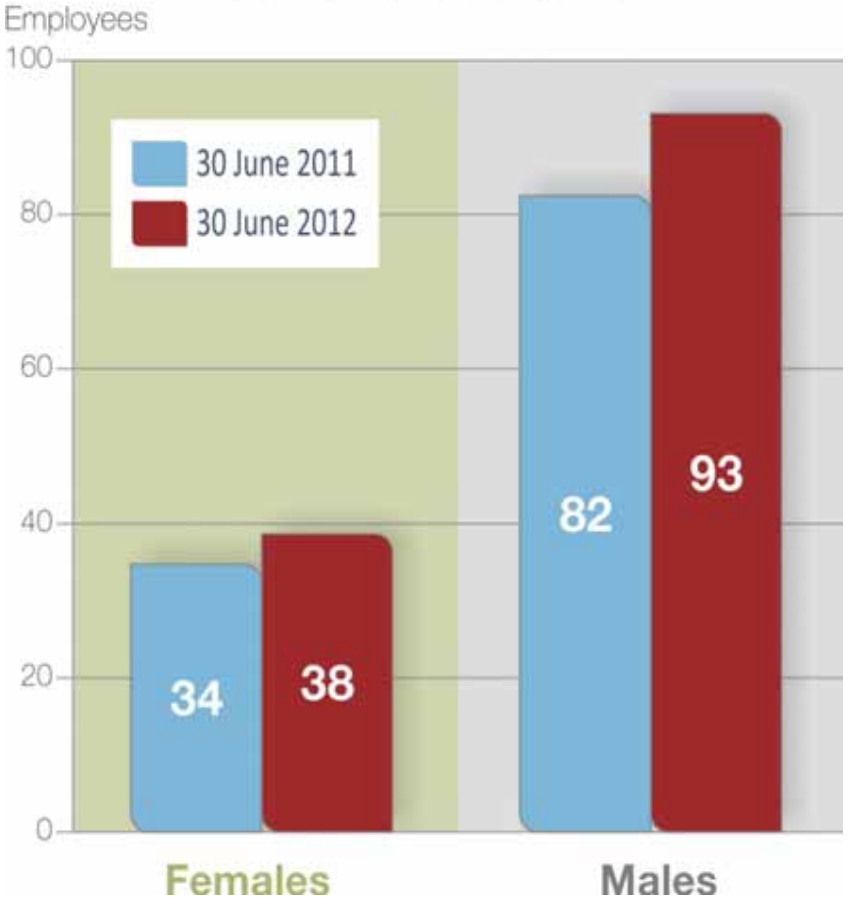
Our people

- Staff numbers up 13% to 131 at end of FY12
- Head count expected to increase by 37% to 180 by end of FY13
- Continued focus on diversity
- Board stability
- Positive staff survey results

Age Demographics



Gender Split Comparison



Engaging well qualified, diverse and motivated people

Stakeholder relations

Working to maintain good stakeholder relations with:

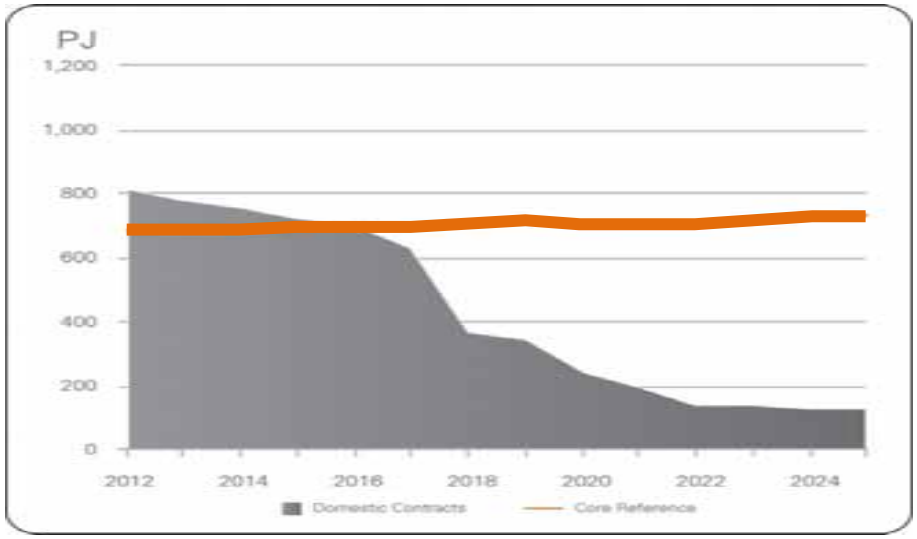
- Traditional owners
- Landholders
- Government

Dieri Consent Determination, Marree Station 1 May 2012

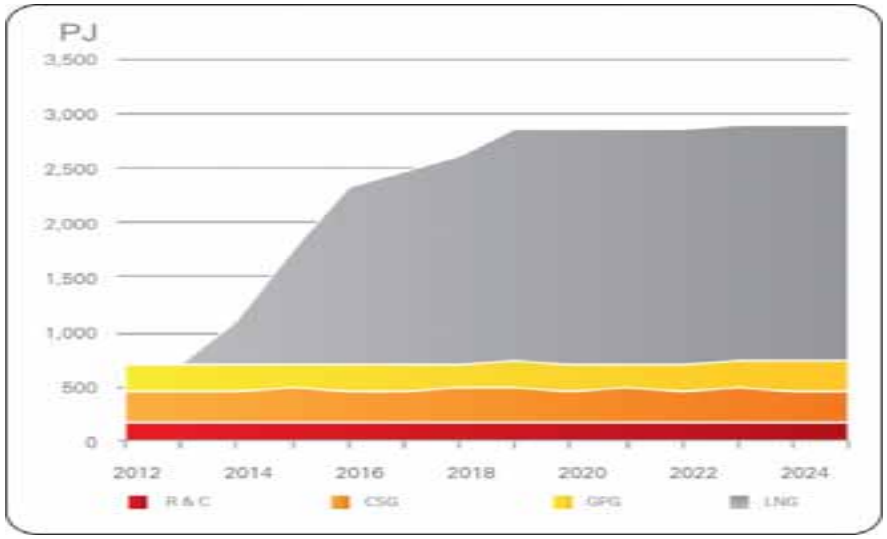
Cattle grazing in Cooper Creek on Mungerannie Station

Eastern Australian gas markets are growing

Existing domestic east coast contracts



Projected east coast total demand

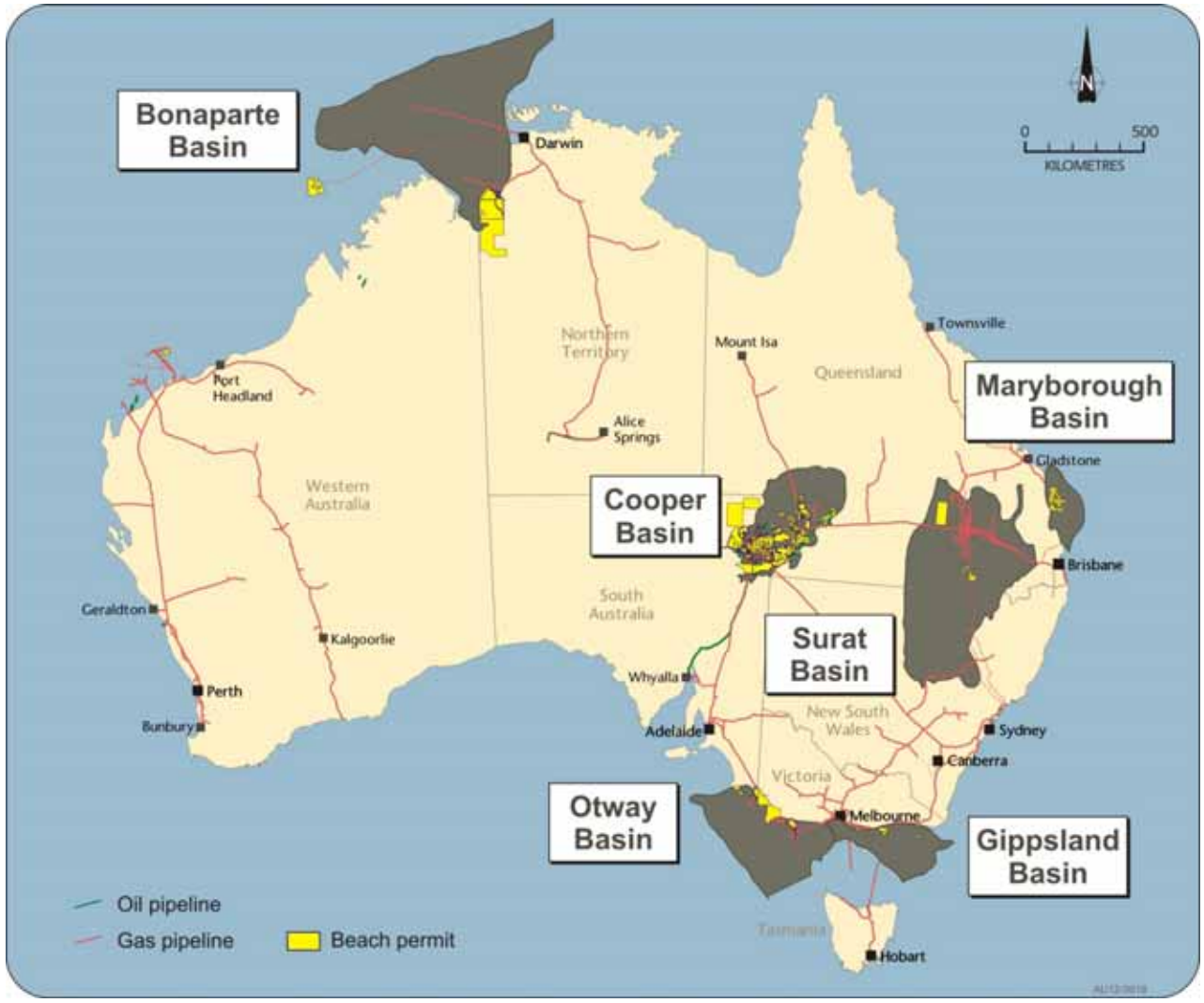


Source: Core Energy Group, July 2012

- The 'clean energy future' is likely to incorporate a larger role for natural gas
- By 2025 gas demand for domestic market and LNG projects expected to be almost 3,000 PJ
- 2015+ opens up various domestic and export linked opportunities

Industry commentators suggesting gas prices trending toward $6-9/GJ

Unconventional basin exposure

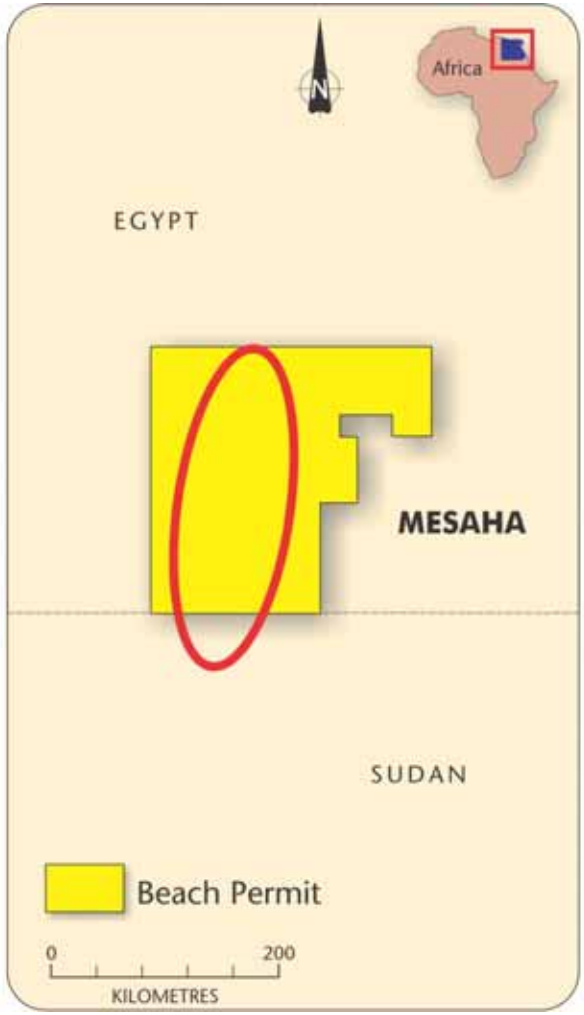


An unconventional but logical thought process

Targeting East African rift plays

Gulf of Suez

Mesaha Concession



Lake Tanganyika

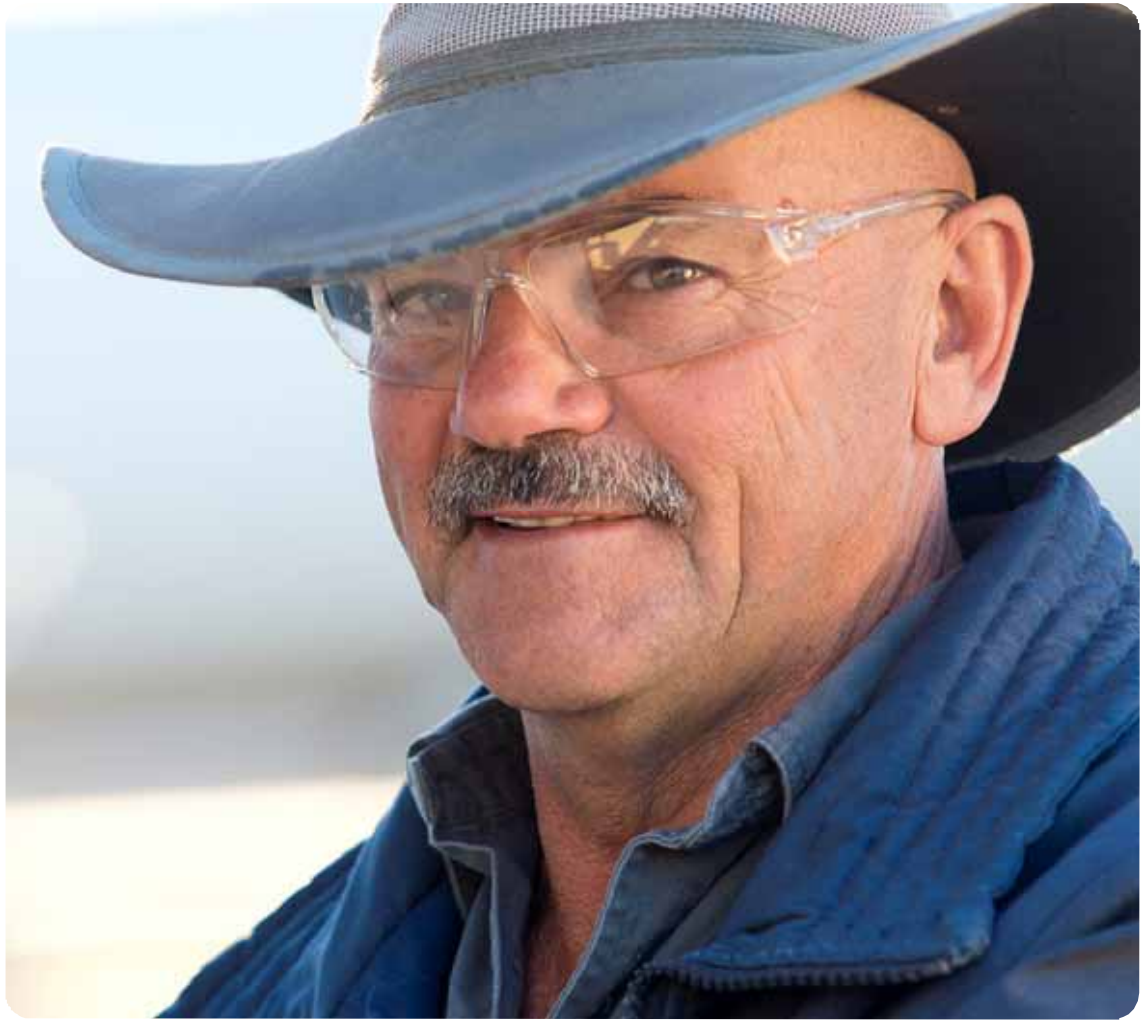
Operational overview

Neil Gibbins

Chief Operating Officer

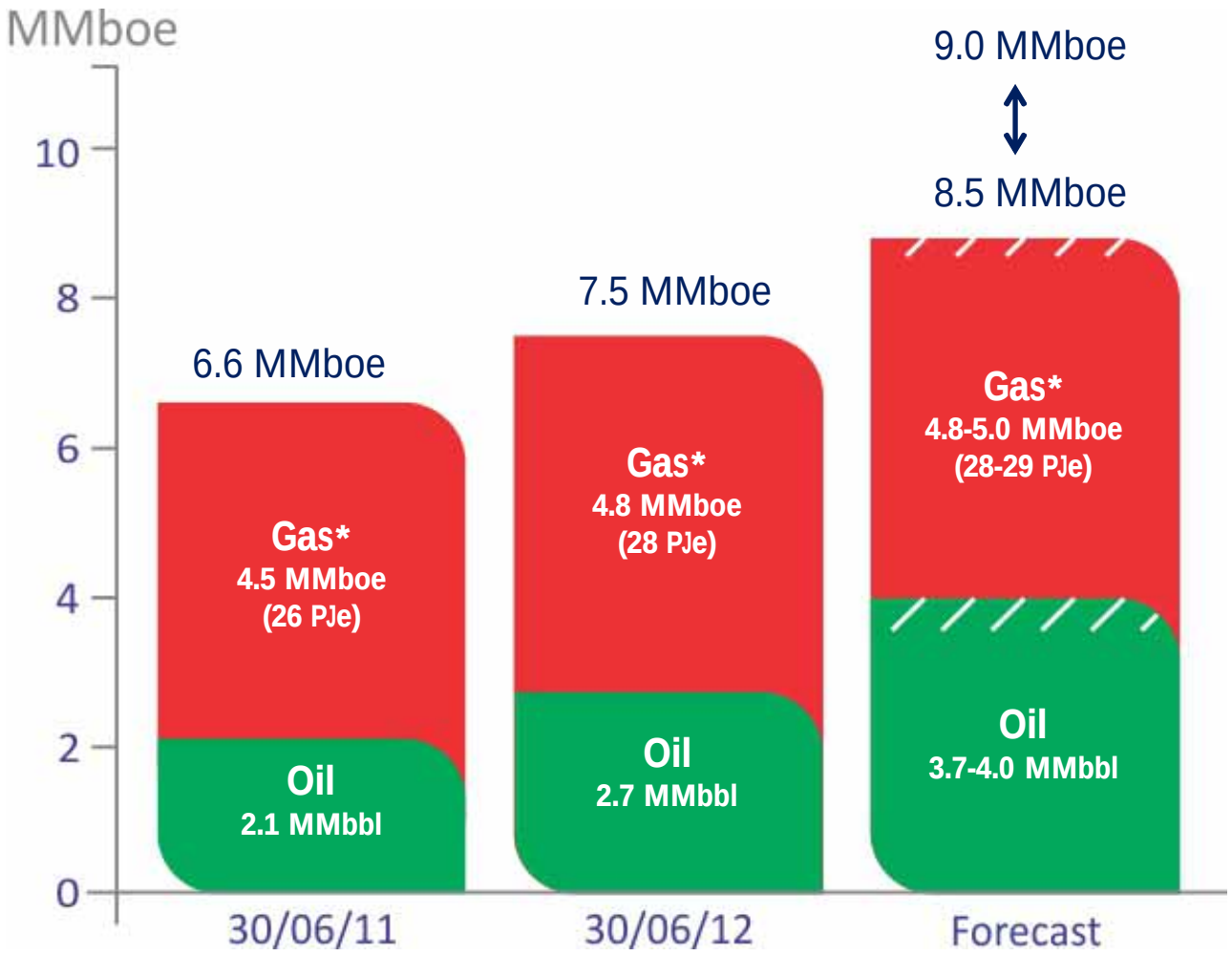
Keeping our people safe

- Low Supervision Classification for Production Operations (SA) by DMITRE
- Continued support for APPEA Stand Together for Safety campaign
- Two recordable injuries among Beach employees across all operated sites for the three years up to end of FY12
- Working to educate increasing numbers of contractors in the Beach safety culture



Safety takes precedence in everything we do

Actual and forecast production



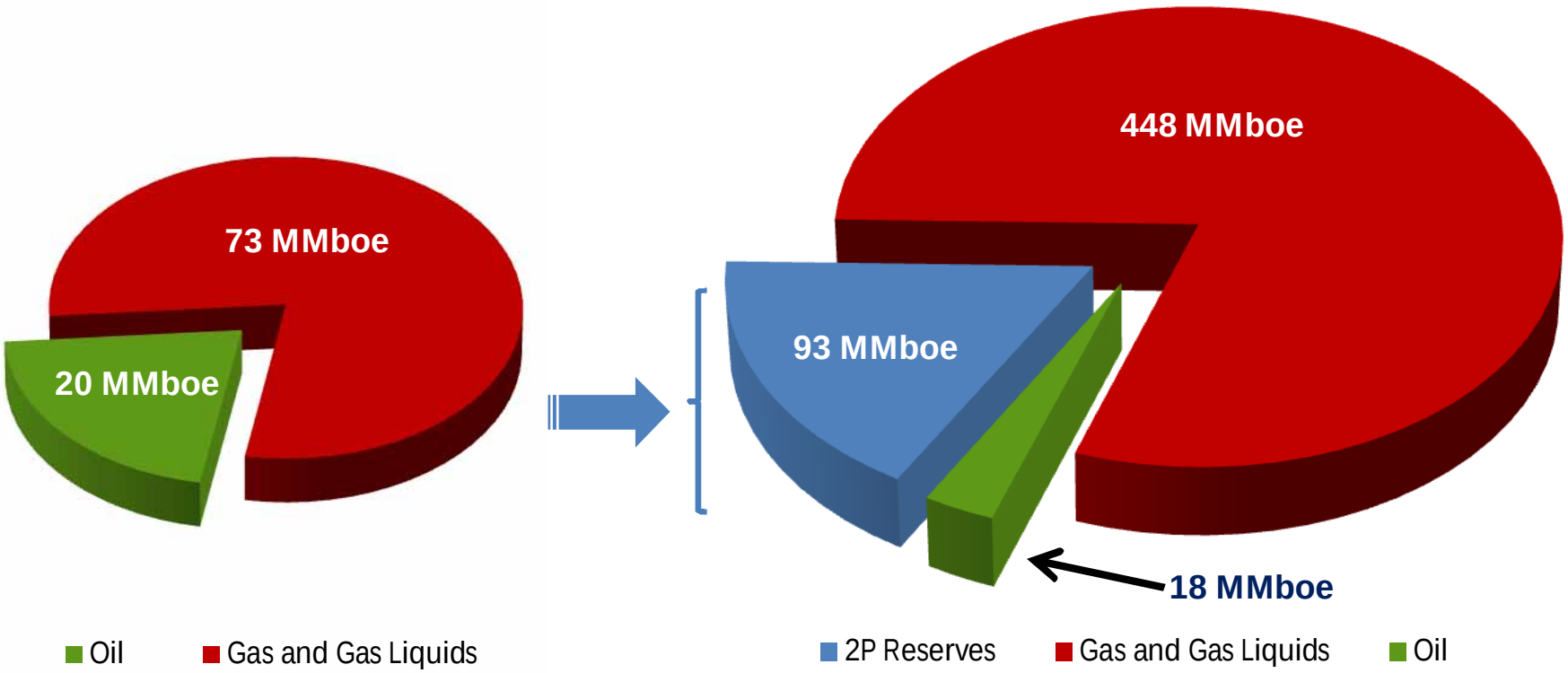
* Gas and gas liquids

FY13 production guidance underpinned by Western Flank oil flowlines

2P reserves and 2C contingent resources

2P: 93 MMboe

2P and 2C: 559 MMboe



Large reserve and resource base driving production growth profile

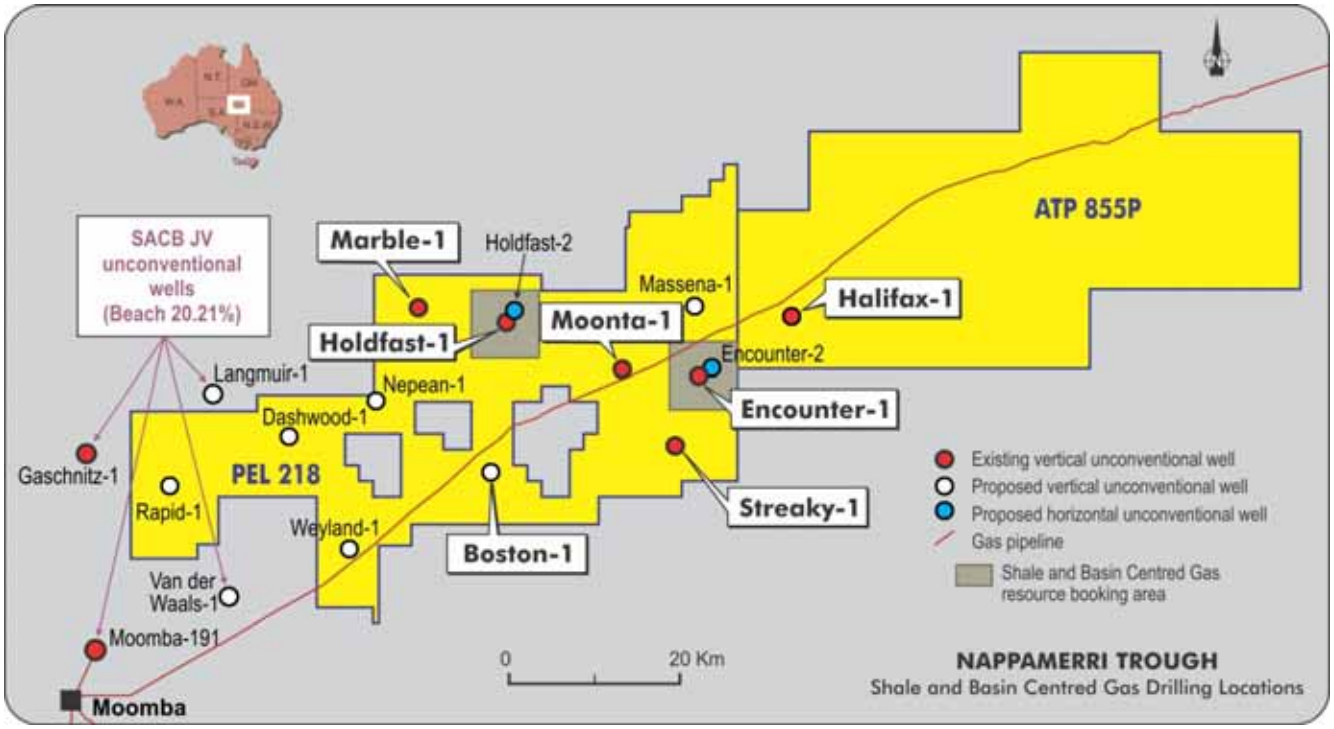
Key FY13 operational activities

Project	Q3 2012	Q4 2012	Q1 2013	Q2 2013	Outcomes
Operated - Cooper Basin unconventional gas	2 vertical wells, mobilise Ensign 965 drill rig ✓	2 vertical wells, 1 horizontal well, stimulate 3 vertical wells	3 vertical and 2 horizontal wells, stimulate 2 horizontal and 4 vertical wells, EFT of vertical wells		Book significant 2C contingent resource
SACB JV	Continued infill drilling to convert 2C contingent resource to 2P reserves				Conversion of approximately 10 MMboe resource to reserves
Operated Western Flank oil flowlines	Tie-in of Growler-Lycium, Lycium-Moomba and Snatcher-Charo flowlines		Tie-in of Bauer-Lycium flowline in Q1 2013. Flowline oil production with minimal trucking		Increased oil production to around 9,000 to 10,000 bpd net to Beach
Operated - Western Flank oil	1 exploration and 7 development wells ✓	11 exploration and 3 development wells			Increased production and 2P reserves
Operated - Western Flank gas and gas liquids	PEL 106B - Four exploration wells and tie-in of Canunda PEL 107 - One exploration well				Increased production and 2P reserves, five new wells and tie-in of two new discoveries
Non-operated - Cooper Basin Western Flank	2 exploration and 3 development wells ✓	5 exploration and 4 development wells			Increased production and 2P reserves
Egypt: Abu Sennan	3 exploration wells and EPT's on existing discoveries			Workover and assessment of discoveries	New and increased oil production, 2P reserve additions
Tanzania: Lake Tanganyika	2D Seismic acquisition ✓	Process and interpret 2D seismic data, identify prospects and leads		Assess farm-down options	Initial prospects and leads, potential farm-down

FY13 Capital expenditure guidance

	FY13 Forecast Capex ($M)	FY13 Forecast Wells	FY13 Forecast Seismic		Forecast reserves additions
			2D – km	3D – km²	MMboe
DEVELOPMENT					
Cooper Basin – non-SACB JV	50 – 60	15 – 20	–	–	–
Cooper Basin – SACB/SWQ JV	100 – 130	35 – 45	–	–	10.0
International	5 – 10	2 – 4	–	–	–
Total Development	**155 – 200**	**Up to 69**	**–**	**–**	**10.0**
EXPLORATION					
Cooper Basin – non-SACB JV	30 – 40	16 – 21	250	1,500	3.3
Cooper Basin – SACB/SWQ JV	15 – 20	5 – 10	–	–	0.4
Other Australasia	5	2 – 3	–	–	1.7
Unconventional	120 – 150	10 – 15	670	–	–
International	20 – 30	3 – 5	2,100	–	1.3
New Ventures and Other	5	–	–	–	–
Total Exploration	**195 – 250**	**Up to 54**	**3,020**	**1,500**	**6.7**
TOTAL	**350 – 450**	**Up to 123**	**3,020**	**1,500**	**16.7**

Unconventional acreage and timeline



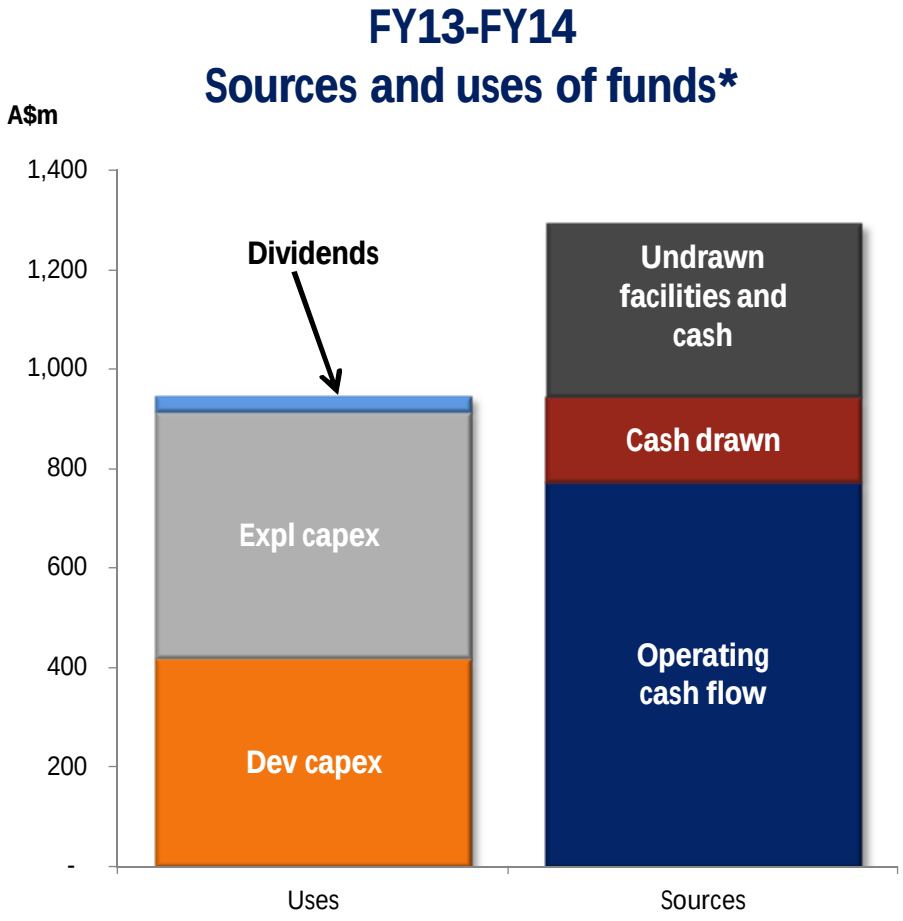
Financial management

Kathryn Presser

Chief Financial Officer

Sources and uses of funds

- ~$330 million cash on hand (as at 30 November 2012)
- FY13 expected to be a peak capex year
- FY14 assumes unconventional exploration success continues and expenditure maintained
- Operating cash flow forecast conservative and assumes:
  - No exploration success other than Western Flank Cooper Basin
- Capex forecast assumes:
  - No facility for unconventional gas processing; and
  - No material divestments/farm-downs



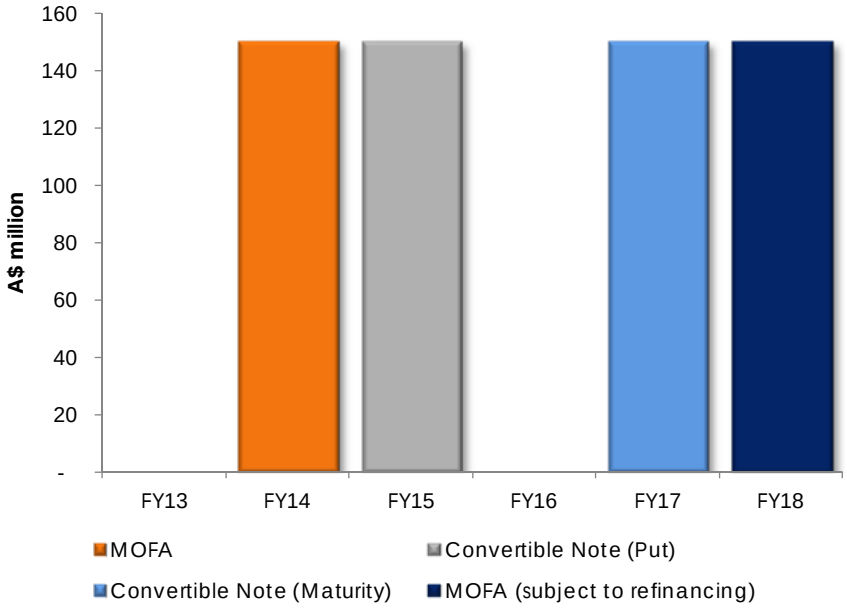
*Assumes oil price of US$110 per barrel

A history of strong and sensible financial management

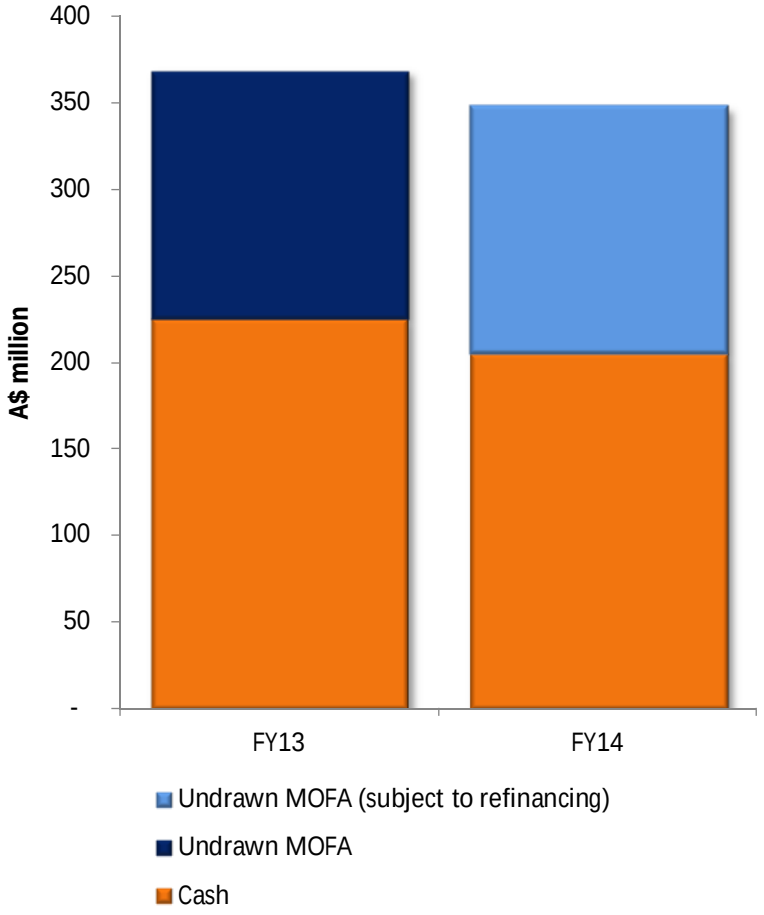
Funding capacity

- Beach well funded over FY13 and FY14 with minimal financing risk
- Unconverted portion of $150 million convertible note only potential debt repayment over next five years

Debt Maturity Profile



Available Liquidity



Over $600 million of funding capacity

Other financial matters

- Internal PRRT assumptions identify the Cooper Basin as a single project
- Single project status would potentially result in no PRRT liability for an extended period
- Carbon tax implications included in internal budget figures
- No changes contemplated to hedging and dividend policies
- ASX updates:
  - Reserves reporting requirements
  - Continuous disclosure changes

Cooper Basin
Western Flank

Mike Dodd

Exploration and Development Manager

Western Flank oil

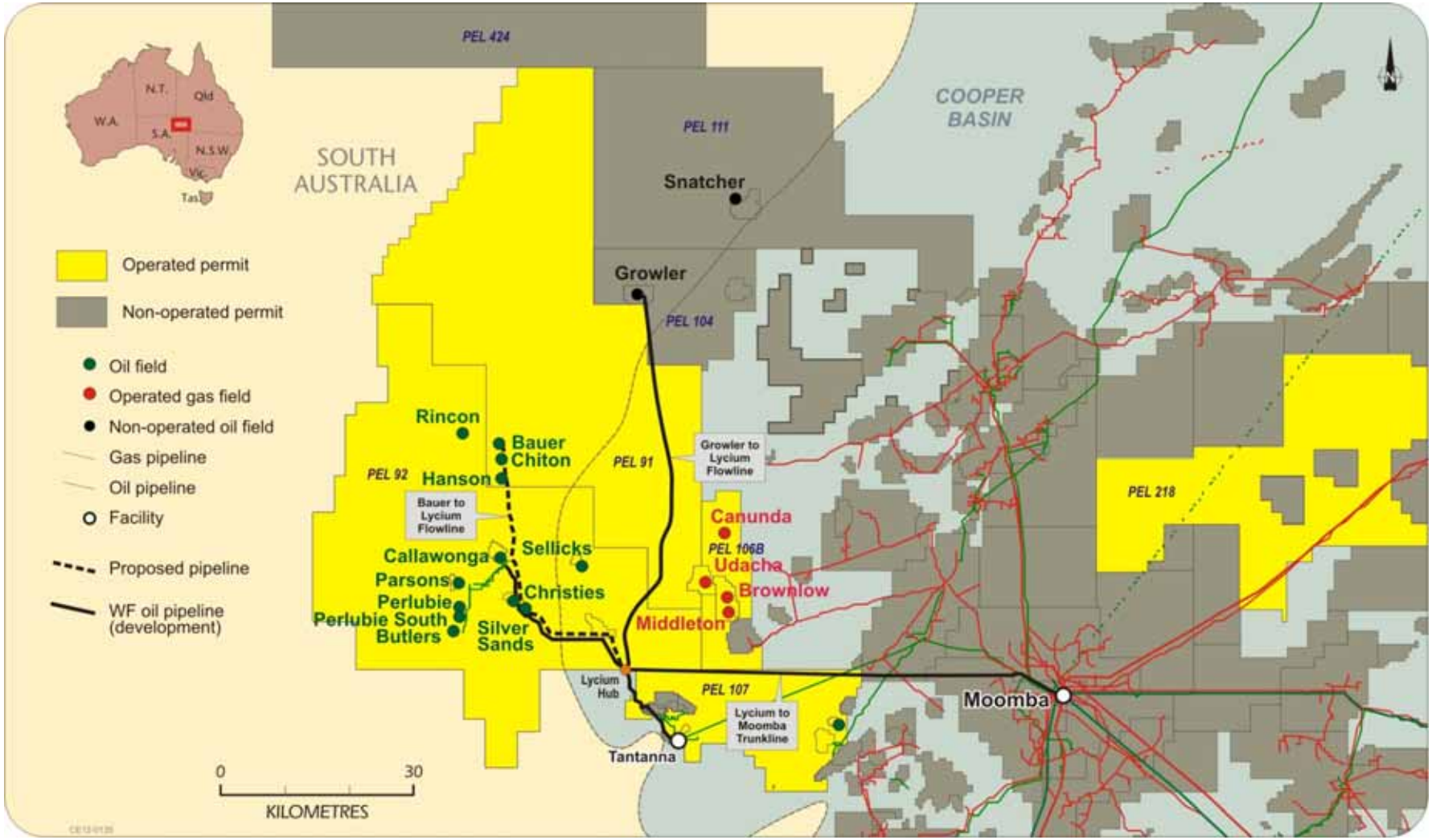
Western Flank oil is a core contributor to Beach due to:

- Sales in Brent
- High net back per barrel of ~ A$80* (including opex, royalties and transportation costs)
- Strong equity positions in significant and prospective acreage
- Quick drill and tie-in periods
- Multiple play types with high flow rates
- Excellent understanding of the geology resulting in high success rates
- 11 operated wells drilled in FY13 to date, 10 successful
- Established and proposed pipeline infrastructure to increase production rates

*Assumes Brent oil price of A$105 per barrel

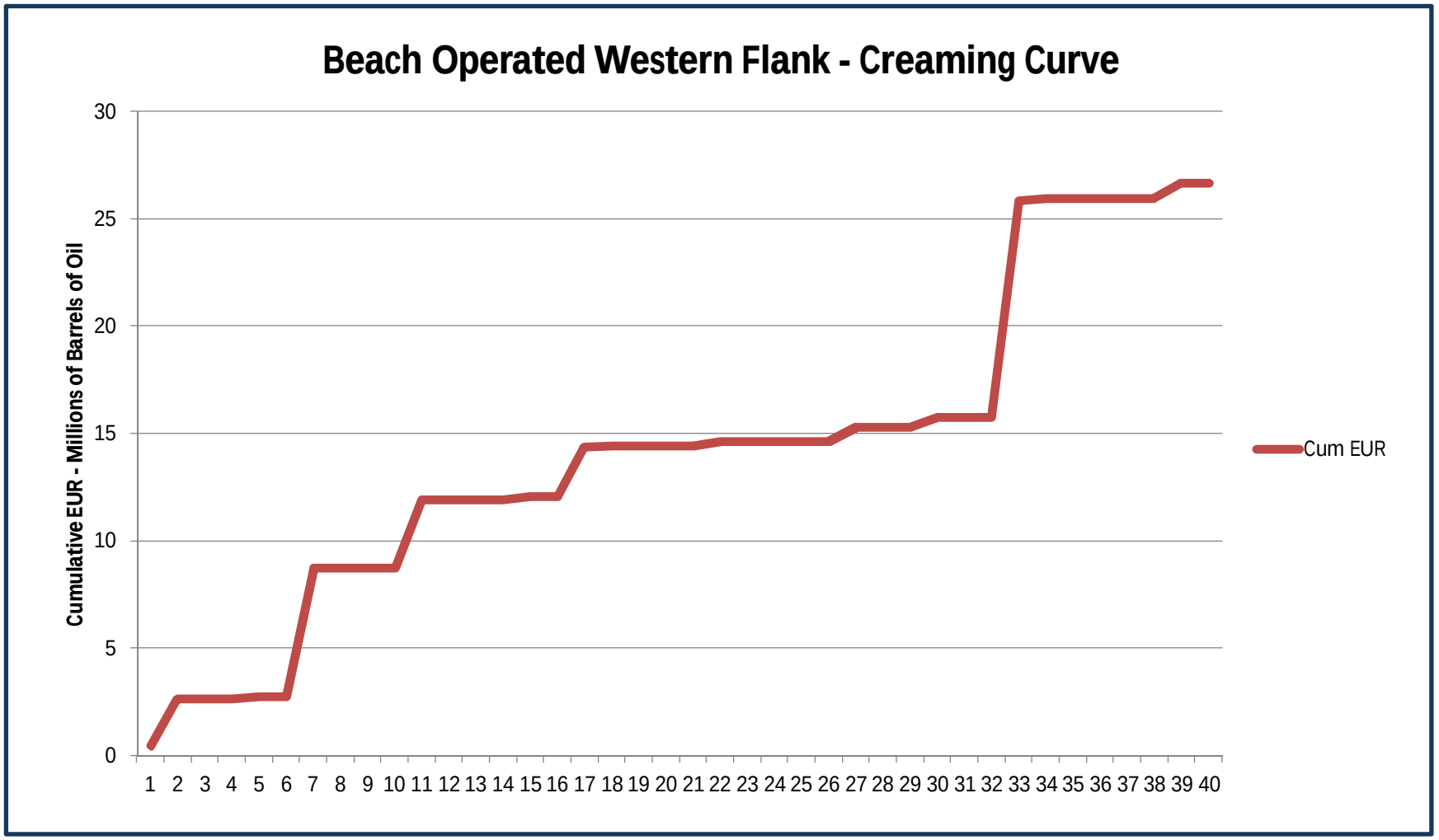
A highly prospective oil province

Investment in infrastructure



2013 net production target of 9,000 to 10,000 bopd from the Western Flank

Western Flank exploration



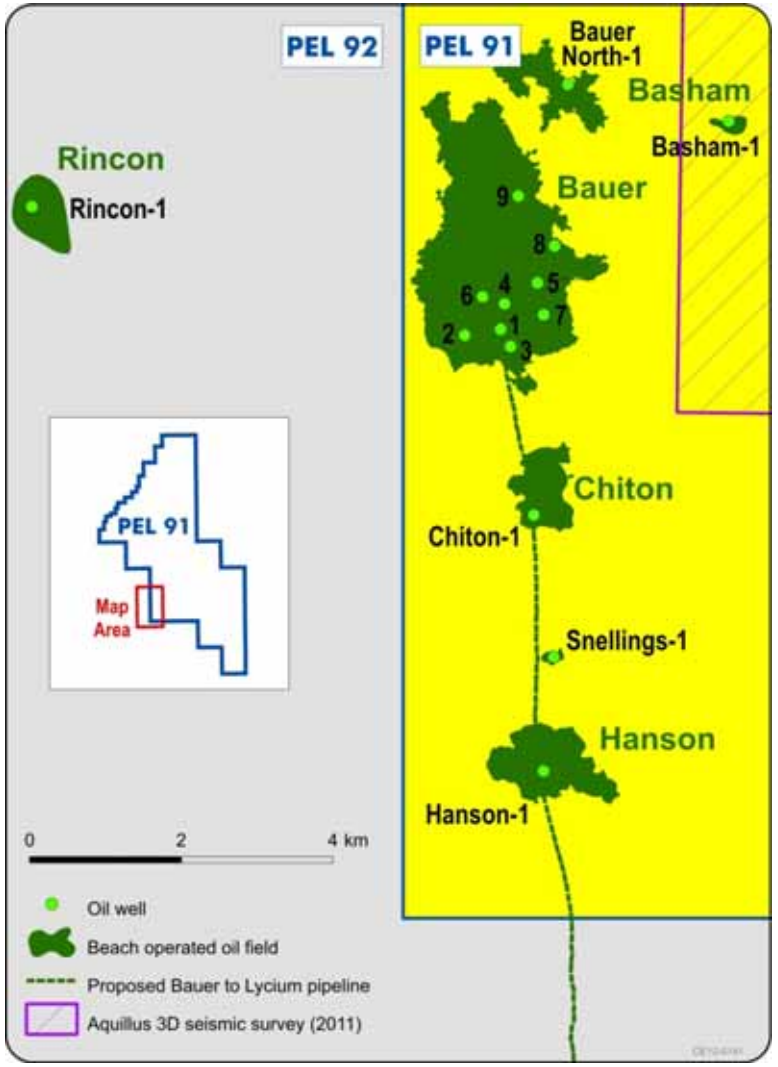
Recent additions largest to date after 10 years of exploration

PEL 91

- Beach 40% (operator), Drillsearch 60%
- Bauer potential recoverable oil of 10+ MMbbls
- Current production of ~1,000 bopd (gross) from two wells targeting 3,000 bopd+ (gross) with increased trucking
- Hanson facility expected to be on-line Q1 2013
- Pennington-1 exploration well encountered a gross oil column of five metres in the McKinlay, a net oil column of eight metres in the Namur and six metres in the mid-Namur

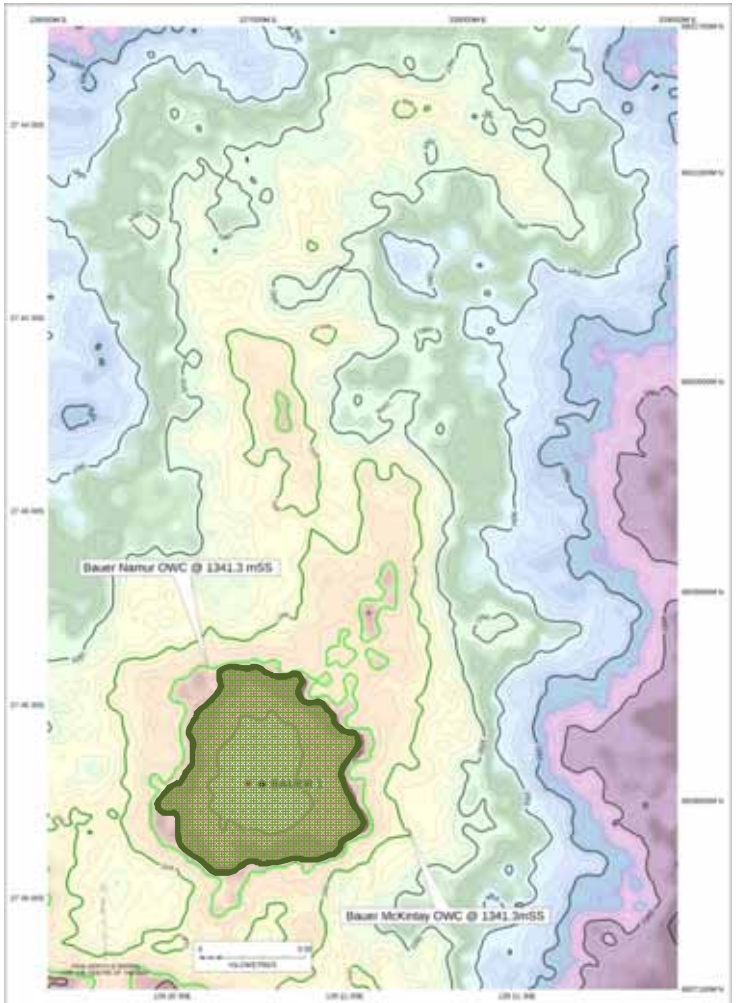
FY13 capital program

- Five exploration and seven development wells, expected net cost $20 million
- Multi-permit Irus 3D recently acquired, 196 km^2 in PEL 91
- New Bauer-Lycium 10,000 bopd flowline, expected Q1 2013 at net cost of $5 million

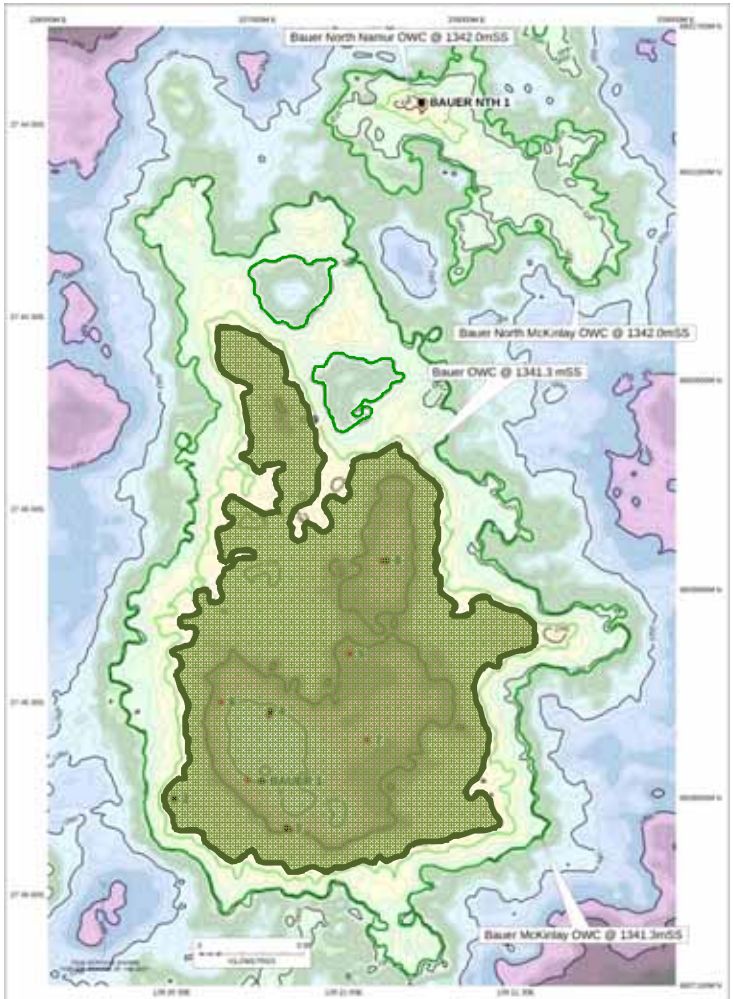


FY13 program to date of ~2 MMbbls reserve increase net to Beach

Bauer oilfield appraisal



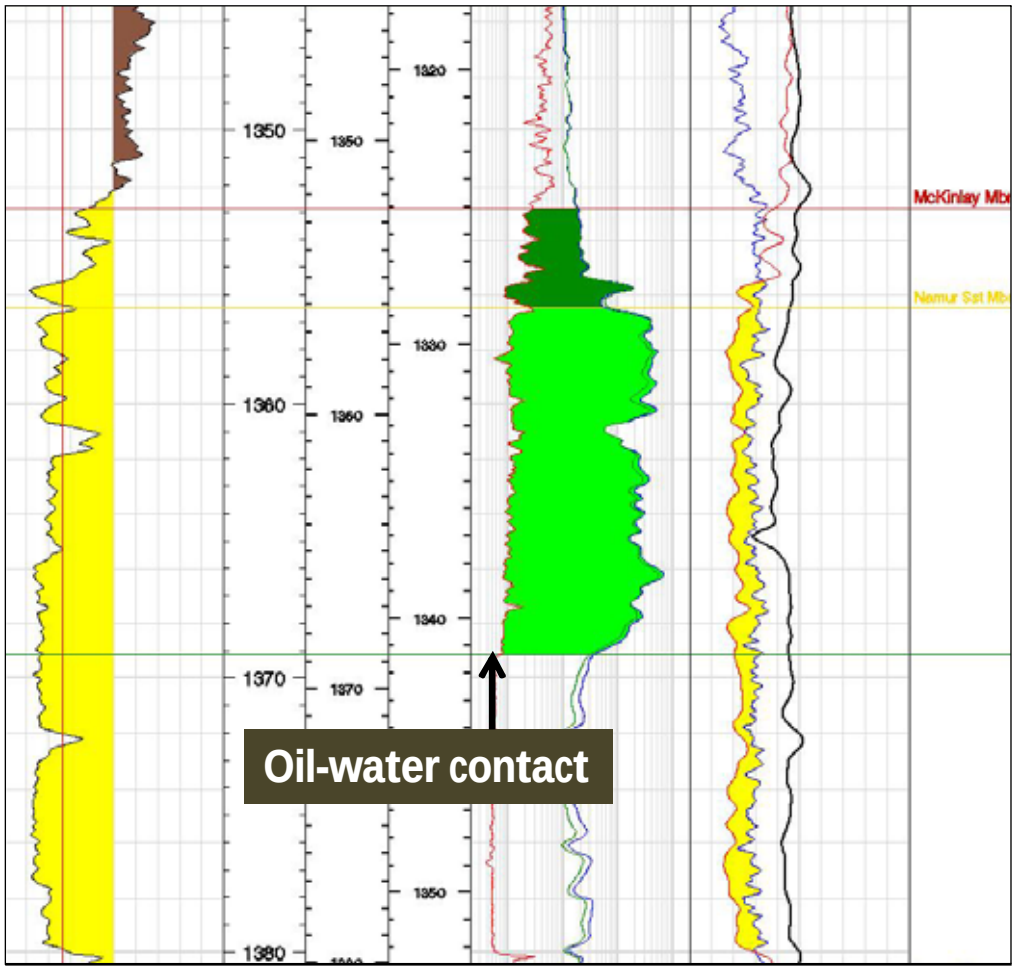
Post Bauer-1



Post Bauer-9

Extremely successful and active appraisal campaign

Bauer oilfield well log



- Average Namur porosity 28%
- Reservoir capable of high production rates
- Bauer-1 free-flow at 15,000 bopd during 80 minute flow test

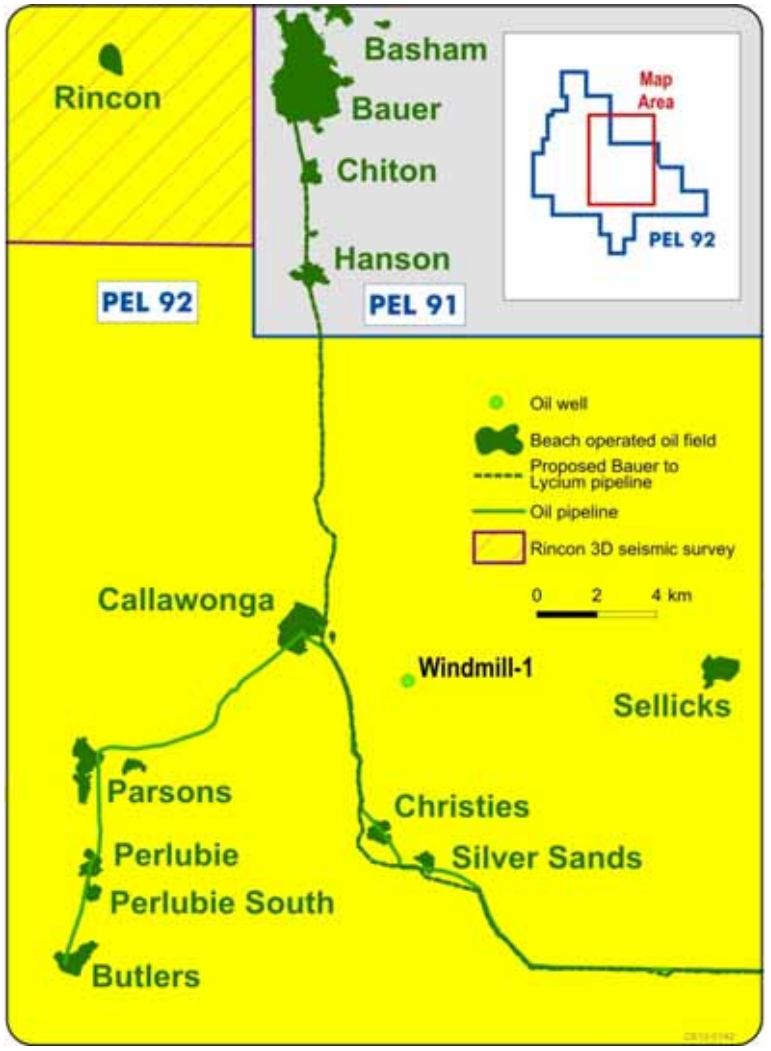
A very high quality reservoir

PEL 92

- Beach 75% (operator), Cooper Energy 25%
- Current gross production of 5,000 bopd
- Gross production expected to recommence at 7,000 bopd with commissioning of Lycium-Moomba trunkline
- Rincon 3D to delineate the Rincon discovery and evaluate additional exploration prospects

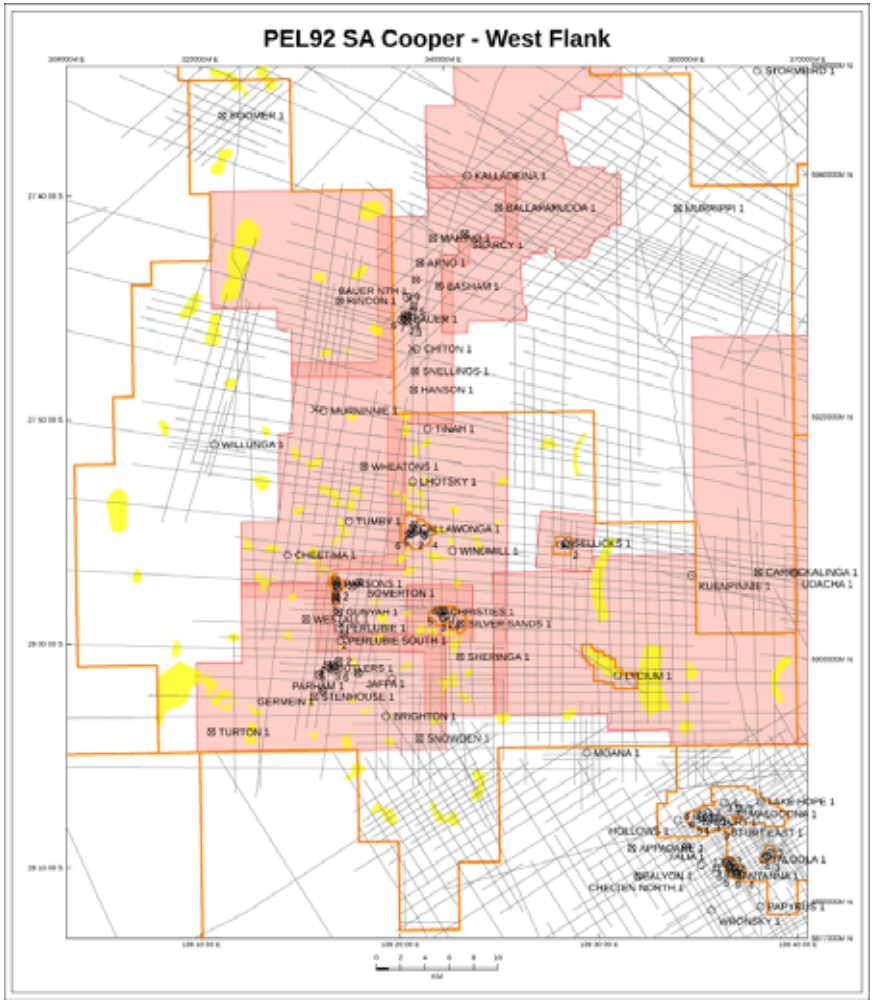
FY13 capital program

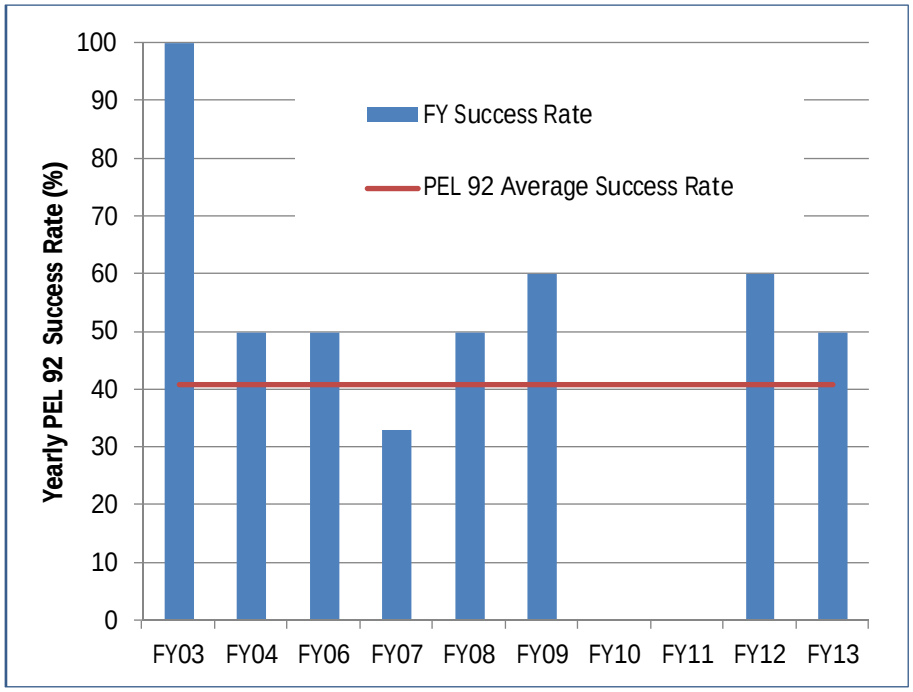
- Seven exploration and three development wells, expected net cost $31 million
- Acquisition of 295 km^2 of the Irus multi-permit 3D completed at a net cost of ~$4.5 million
- Two successful Butlers wells and Windmill new field discovery from four wells drilled to date



FY13 program targeting a gross reserves addition of 1 MMbbl

PEL 92 prospectivity

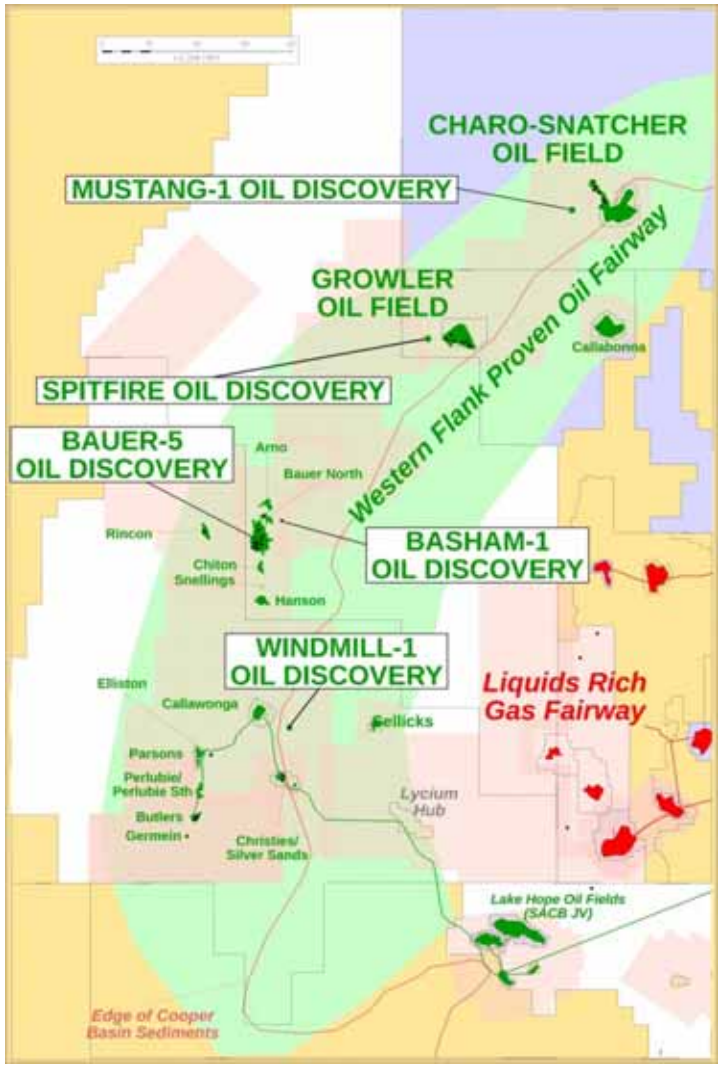


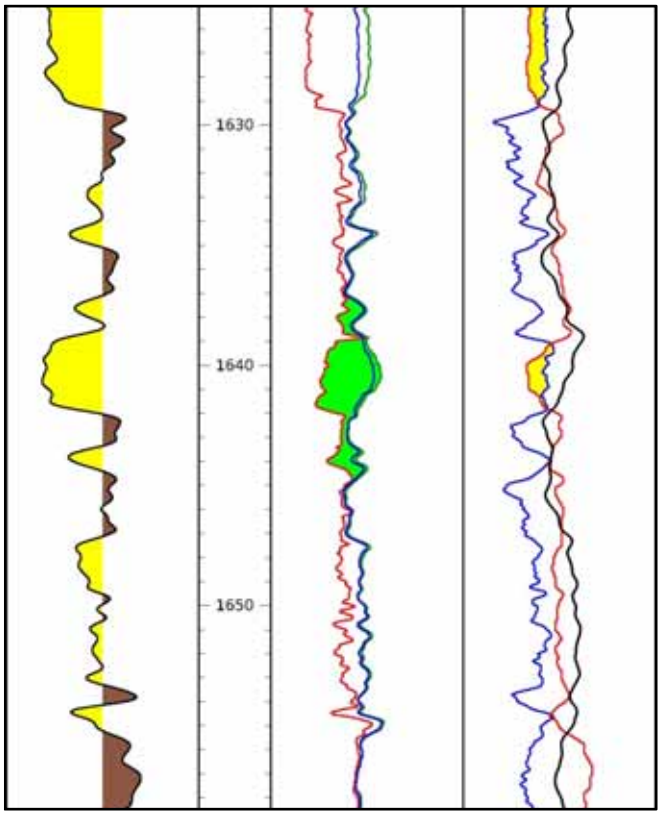


- EUR of oil discoveries to date of ~15 MMbbls
- Approaching 10 MMbbls of oil production
- Exploration success rate over 40%
- Multiple play potential

10 years of exploration and still fertile ground

Windmill-1





- DST recovered 25 barrels of oil
- Discovery has extended Birkhead play fairway 20 kilometres south into PEL 92

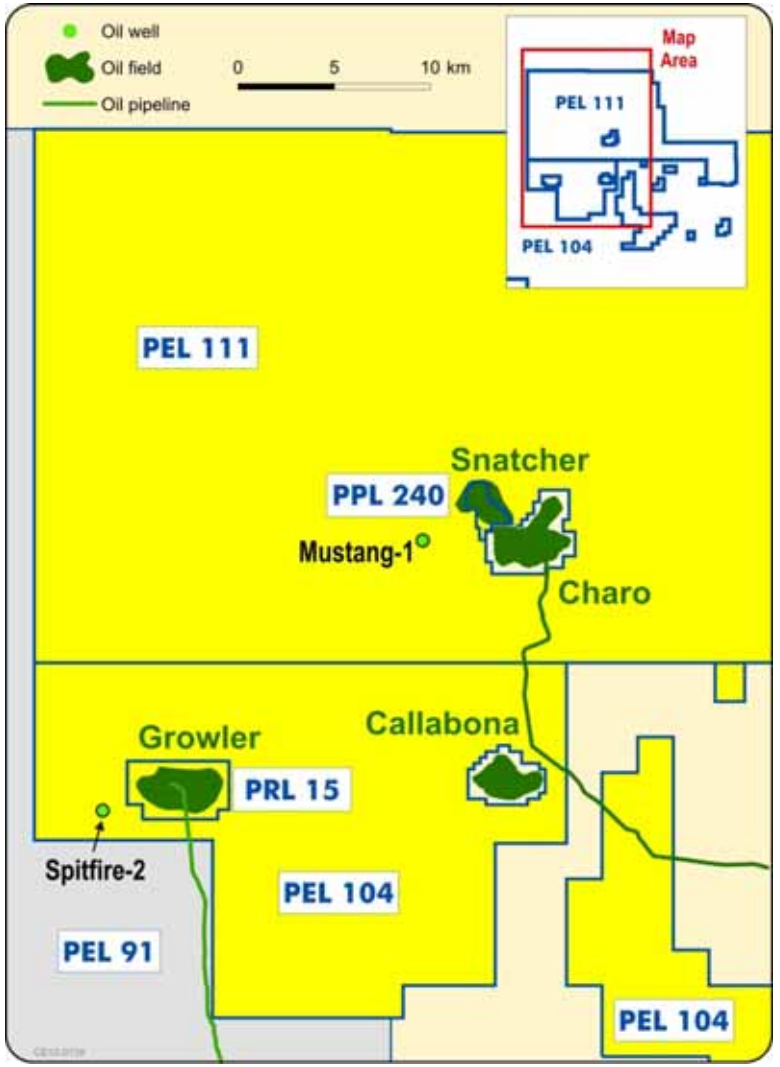
First PEL 92 Birkhead discovery

PRL 15, PEL 104 and PEL 111

- Beach 40%, Senex Energy 60% (operator)
- Focus on the Birkhead formation
- Current gross production of 6,000 bopd from Growler and 250 bopd from Snatcher
- Mustang-1 being prepared for EPT
- Growler-Lycium flowline in final test stage

FY13 capital program

- Seven exploration and seven development wells, expected net cost $29 million
- Snatcher appraisal wells extended field to North
- Spitfire-2 proved oil column updip of Spitfire-1
- Growler-Lycium flowline, capacity 8,000 bopd
- Snatcher-Charo pipeline, capacity 6,000 bopd



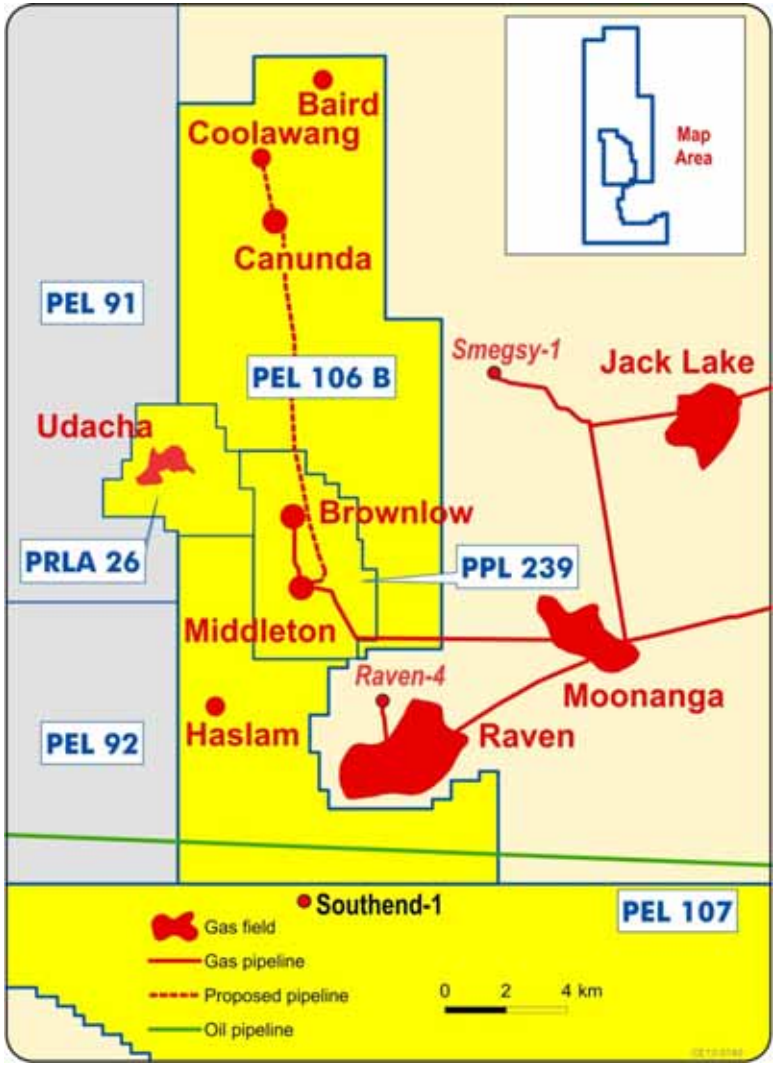
FY13 program targeting a gross reserves addition of 2.5 MMbbl

PEL 106B and PEL 107

- PEL 106B – Beach 50% (operator), Drillsearch 50%
- First production in FY12 from the Middleton / Brownlow production licence
- Initial gross flow rates of 25 MMscfd (15 TJd sales gas and 325 bbld LPG and condensate)
- Production under current contract shut-in in accordance with customer's rights under interruptible GSA
- Commercial discussions underway for extended gas sales beyond April 2013

FY13 capital program

- PEL 106B – Four exploration wells, expected net cost $7 million, net cost of development (incl. Canunda tie-in) expected at $5 million
- PEL 107 – Beach 40% (operator), Drillsearch 60% – one exploration well, expected net cost $1 million



The first Beach operated gas and gas liquids production

International assets

Tanzania

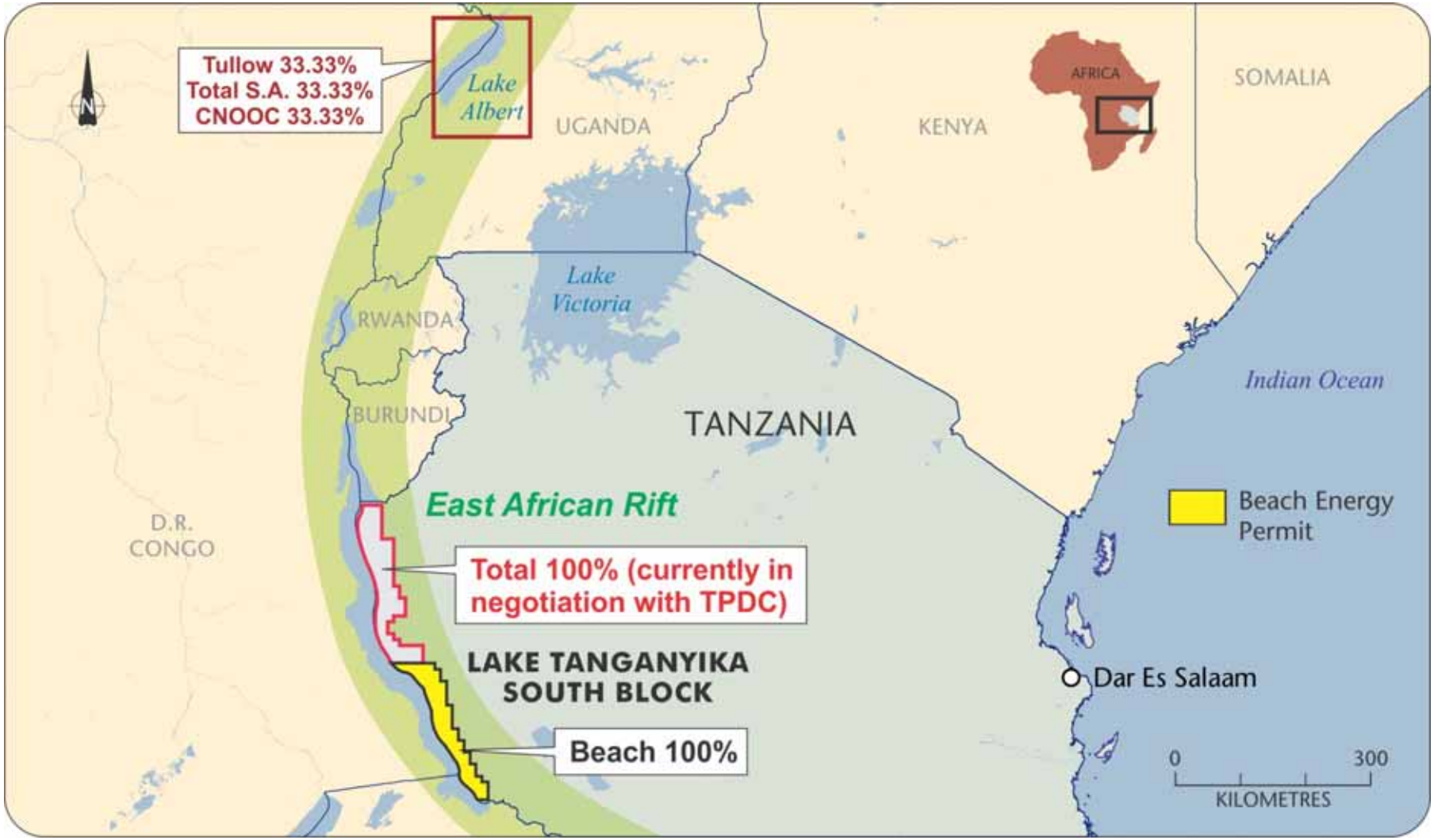
Egypt

Romania

Simon Brealey

New Ventures Country Supervisor

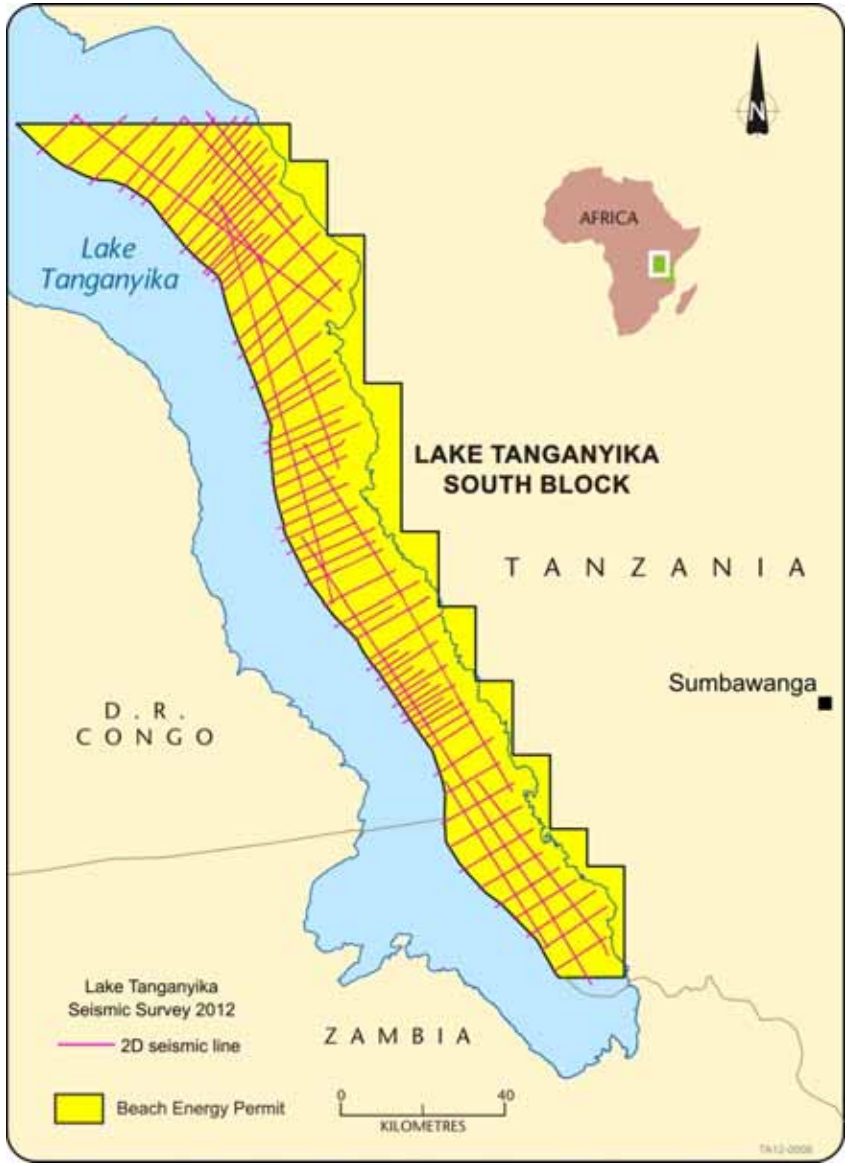
Tanzania – Lake Tanganyika South Block



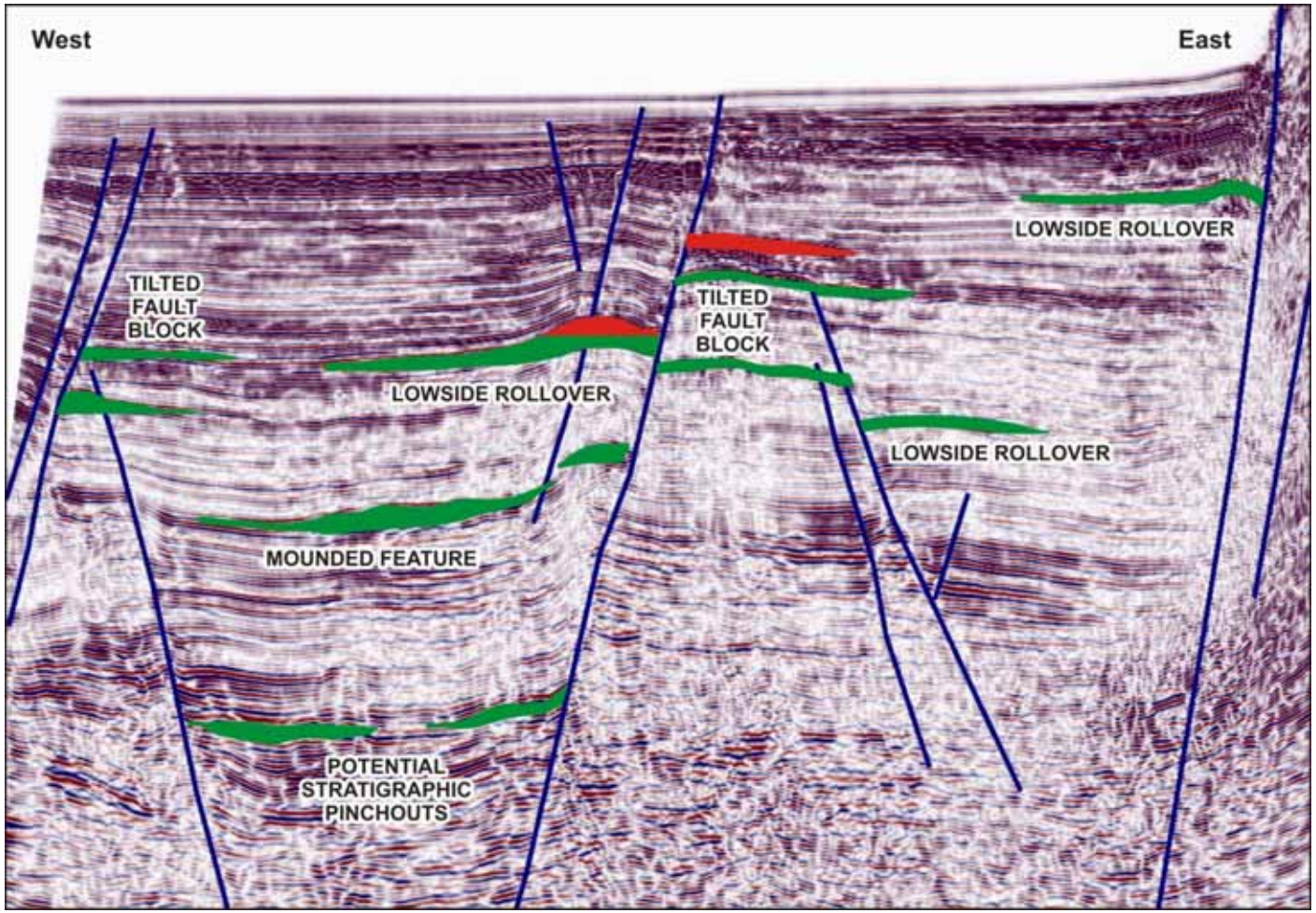
A significant acreage position in the prospective East African Rift

2D seismic survey

- Natural oil seeps in Lake Tanganyika indicate a working petroleum system
- South block area ~7,200 km^2
- Potential for large discoveries (> 200 MMbbl)
- Airborne gravity and hi-resolution aeromag data acquired in 2010
- 2,080 kilometre 2D seismic survey completed in August 2012
- Preliminary results confirm extensive structuring, similar to Lake Albert in Uganda
- Indications of hydrocarbons over tilted fault blocks, low-side rollovers and mounded features



Lake Tanganyika South Block potential play types



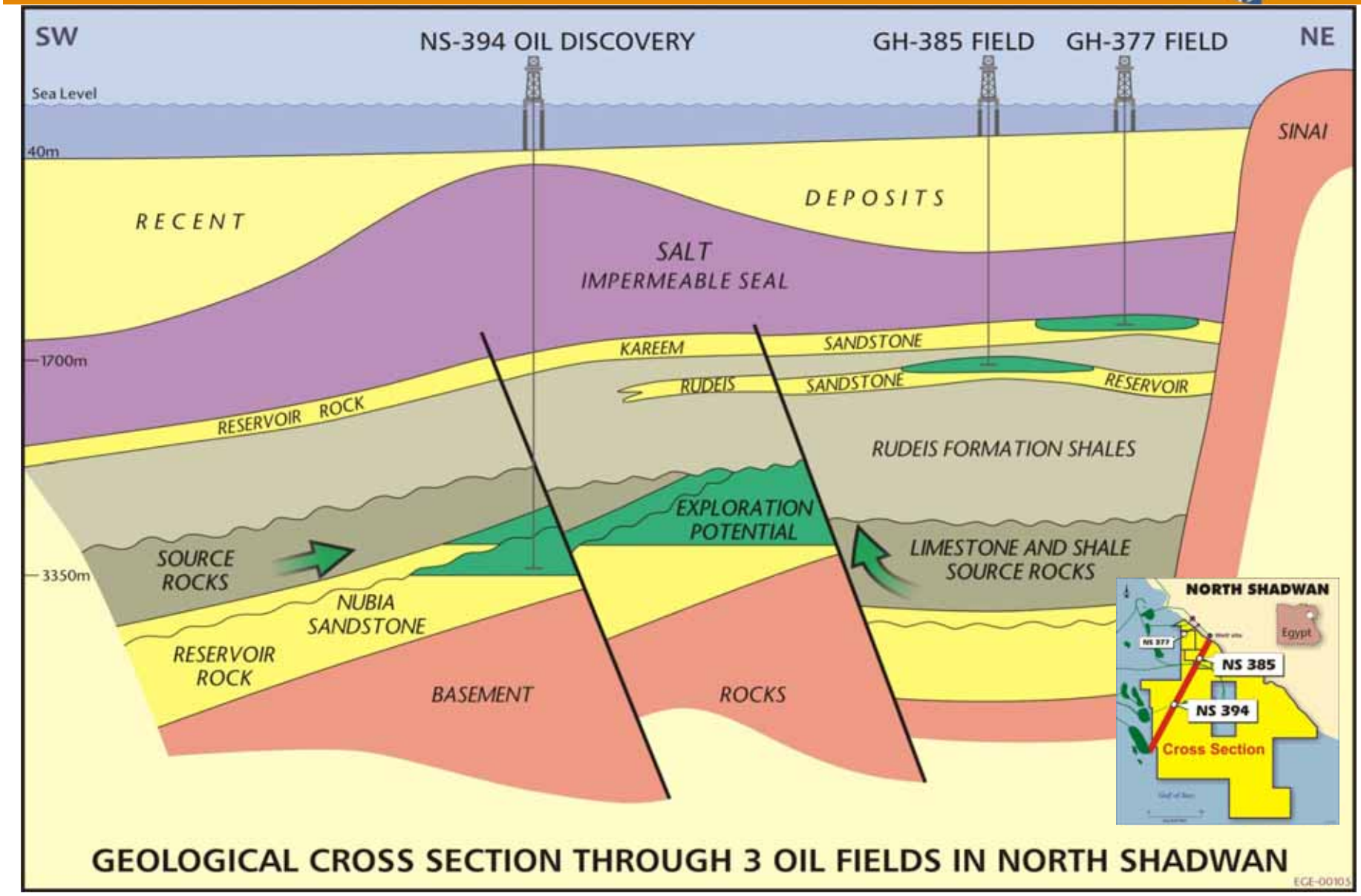
Potential targets from recently acquired 2D seismic, red = gas, green = oil

Direct hydrocarbon indicators consistent with an active petroleum system

Egypt

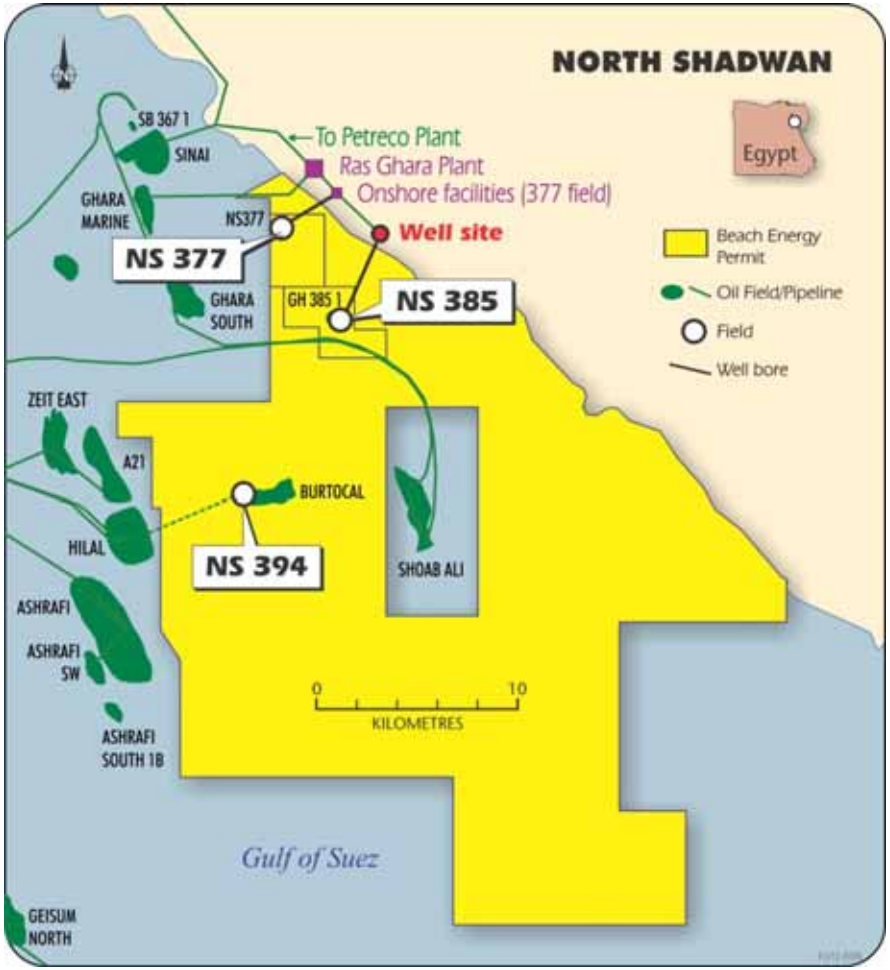
A balanced portfolio of assets with growing oil production

North Shadwan - geological cross section



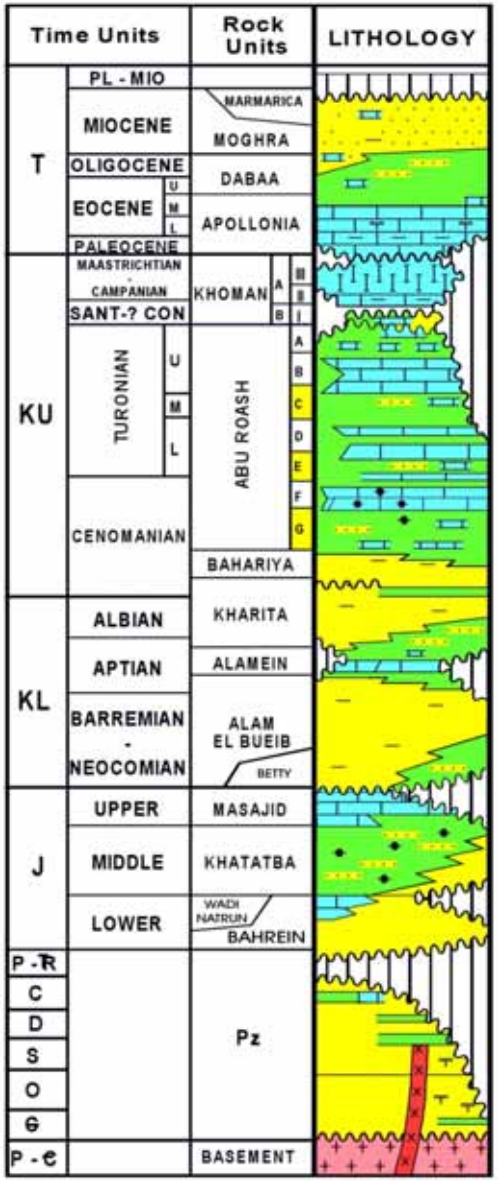
377 and 385 oilfields

- Miocene sands draped over older highs (lacking reservoir)
- On-shore to off-shore developments
- 377-3 intersected 145 metre oil column and cased as first production well for field
- 377-5 intersected 107 metre oil column in better quality reservoir and cased as a production well, artificial lift installed
- Trucking to replace pipeline export during 2012-3 with rate expected to increase to 2,500 bopd from both fields
- NS385-1 field development drilling under way



Located in the prolific Gulf of Suez with near term development opportunities

Abu Sennan stratigraphic column



ABU ROASH – Classic Abu Gharadiq Basin oil source and ultimate top seal. Very high chance of oil accumulations but with low deliverability ~250 bopd

BAHARIYA - Primary sandstone reservoir in Western Desert – high chance of oil with low deliverability ~600 bopd

KHARITA is better quality sandstone and may deliver at over 2,000 bopd

ALAM EL BUEIB – good sandstone development but paucity of seals both vertically and laterally (Eni)

KHATATBA - Classic Shushan Basin gas, condensate and oil source. Sandstones expected to deliver 1,000-2,000 bopd

BAHREIN/EGHEI - Primary sandstone reservoir in Shushan/Fagur Basin Jurassic/Palaeozoic play (Apache)

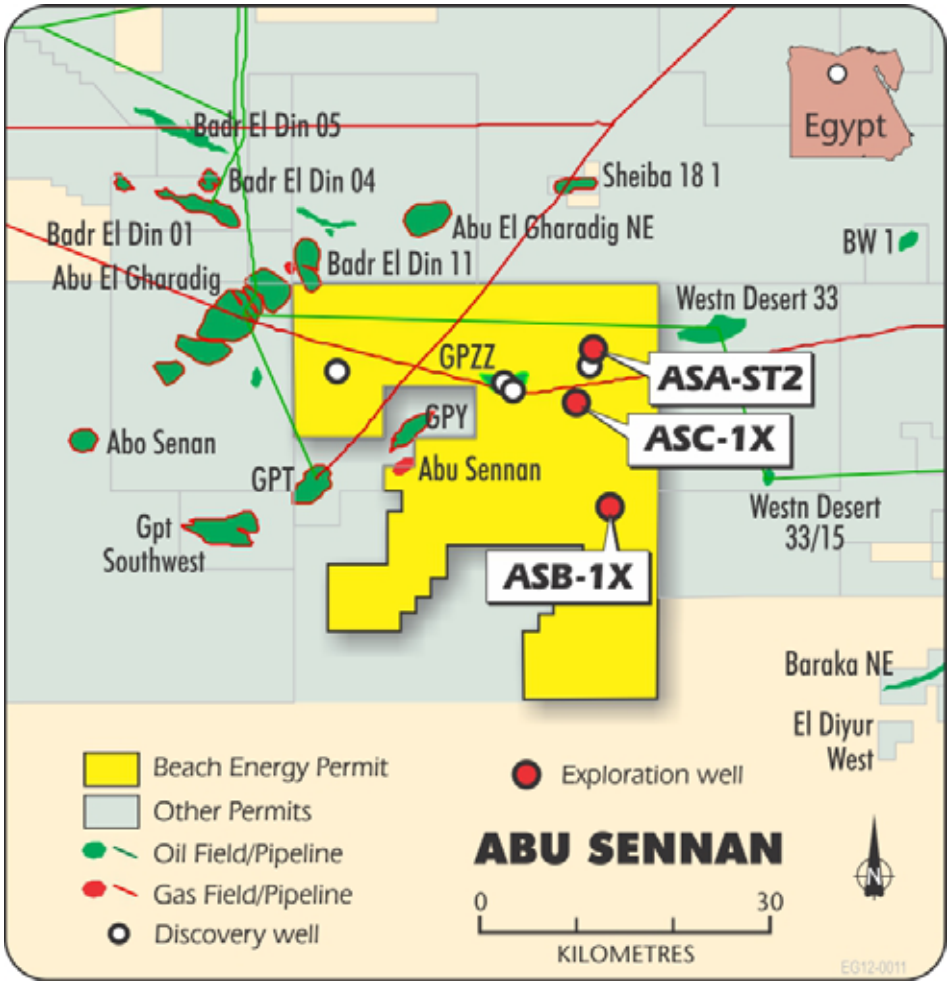
after Holmes

Abu Sennan concession

- Beach 22%, Kuwait Energy 50% (operator), Dover Investments 28%
- Four exploration wells successful, with combined total gross flow rate of ~ 12,000 boepd (gross)
- New three well exploration program approved:
  - First well, ASA-ST2, reached TD of 3,576 metres

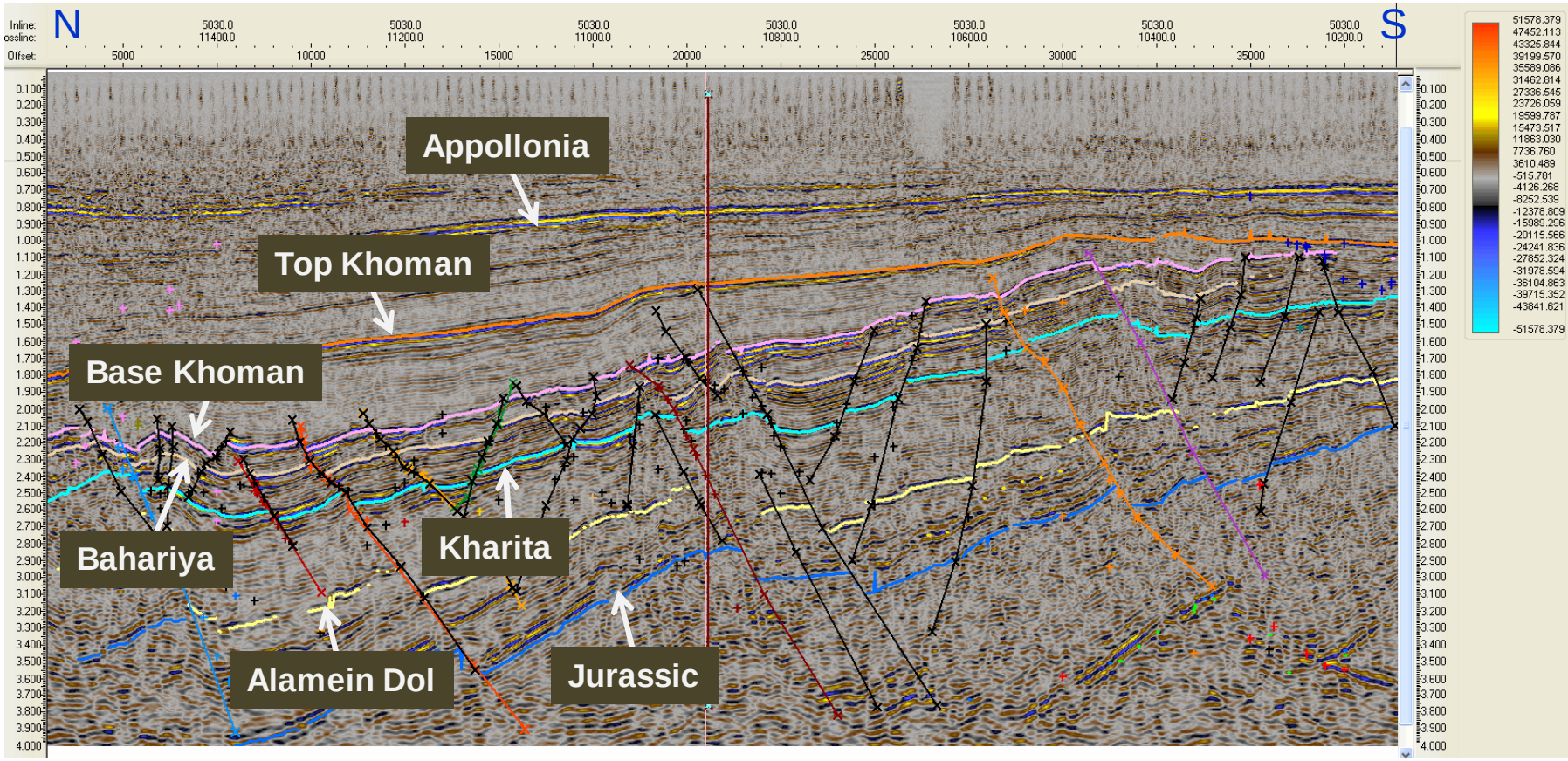
Extended production tests

- EPTs on four discoveries over six months
- Initial test flows up to 2,400 bopd, with associated gas
- EPTs currently choked back and producing 800 bopd, with associated gas



67% exploration success to date in the highly prospective Western Desert

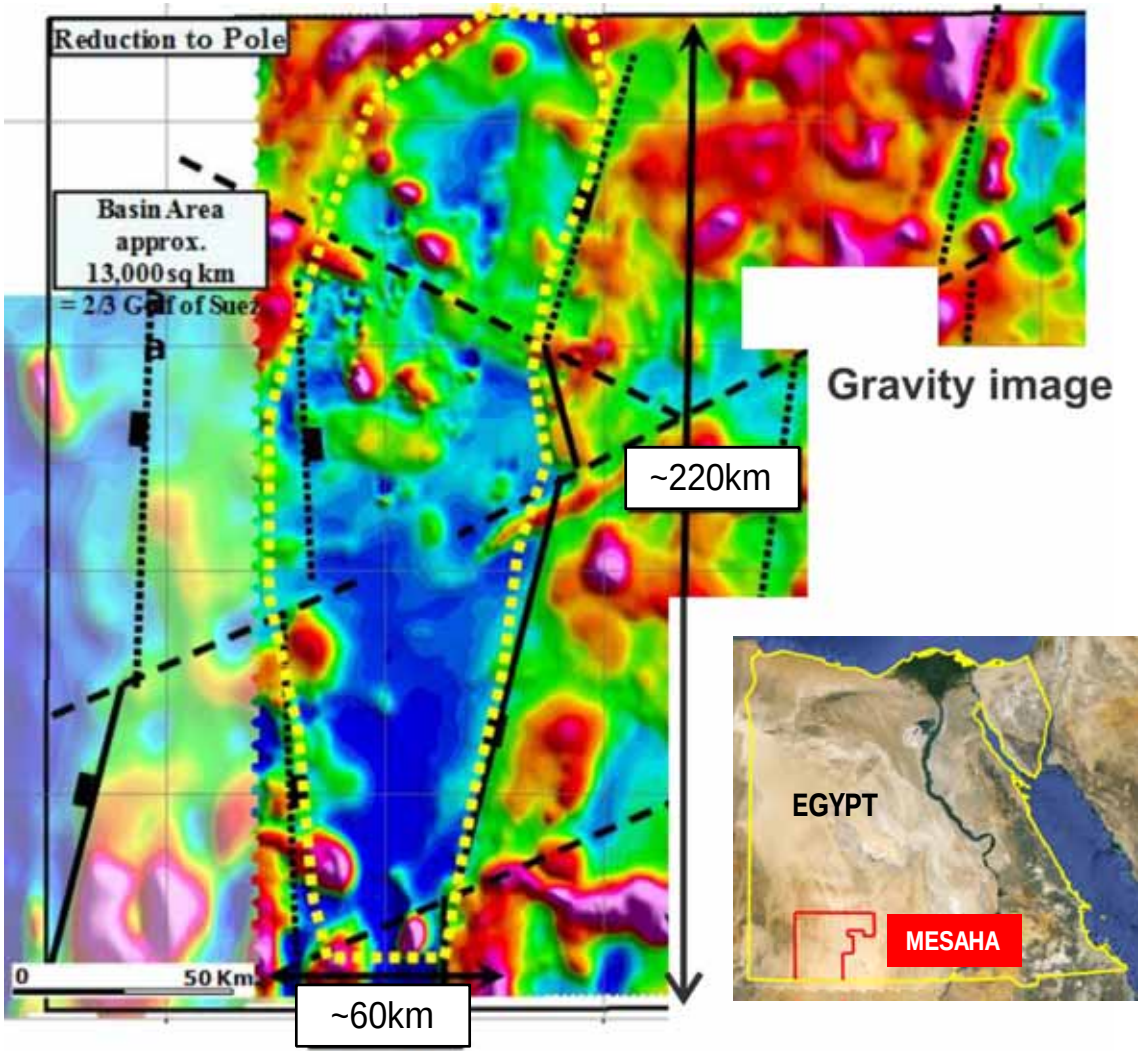
Abu Sennan 3D seismic line (with hypothetical well)



- Initial drilling campaign has encountered shows and/or pay at all named formations except Kharita and Jurassic
- Cross fault juxtaposition of lithologies critical for the Kharita and Jurassic
- Current drilling campaign to target the Kharita and Jurassic in an upthrown 3-way dip closure

The Mesaha graben

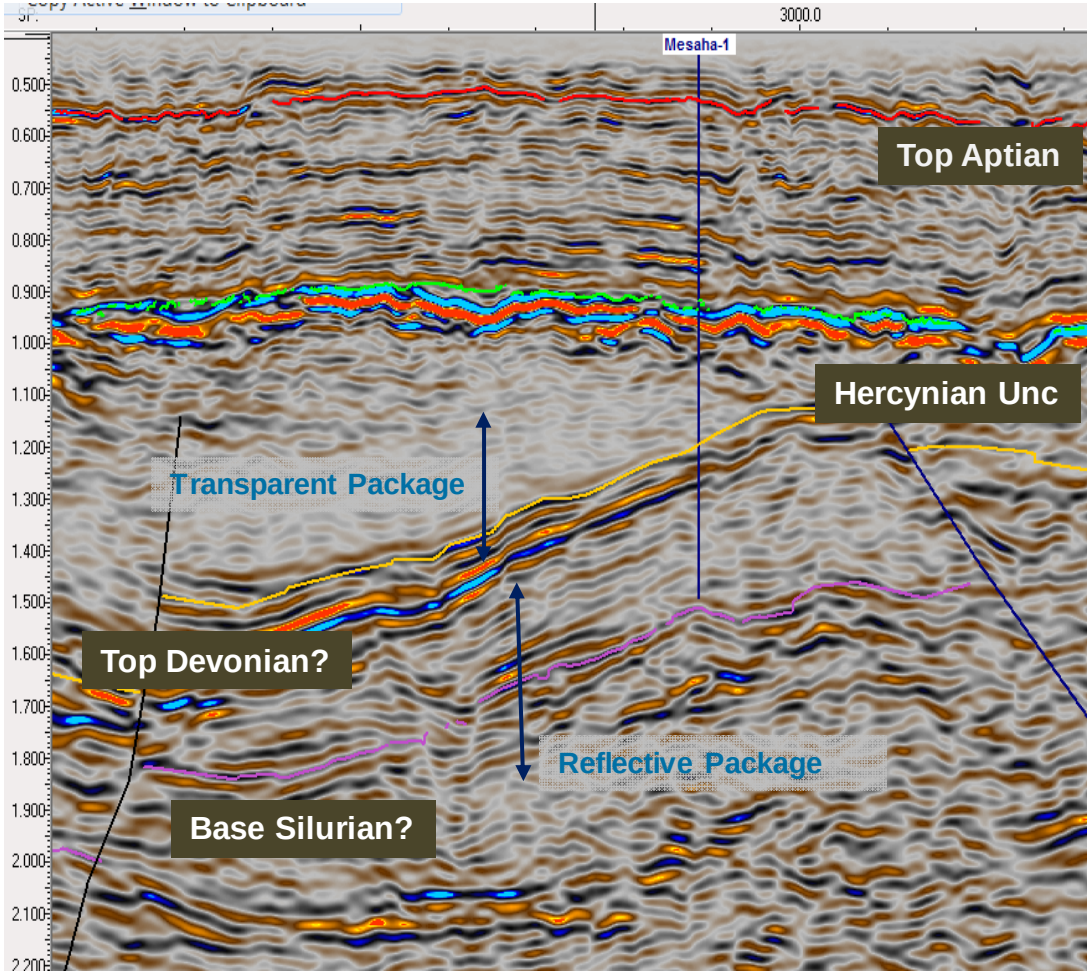
- Mesaha graben initially believed to be a Mesozoic rift graben, two thirds the size of the Gulf of Suez
- No previous exploration drilling
- 2,900 kilometres of 2D seismic with ~5-10 kilometre line acquired
- 2D spacing concentrated over intra-basinal highs
- Interpreted as a Palaeozoic rift basin, analogous to Libyan examples (Ghadames Basin)
- Prospects with the potential for 100+ MMbbls have been mapped



Basin definition on high resolution aero-magnetic data

Mesaha – 1 well location

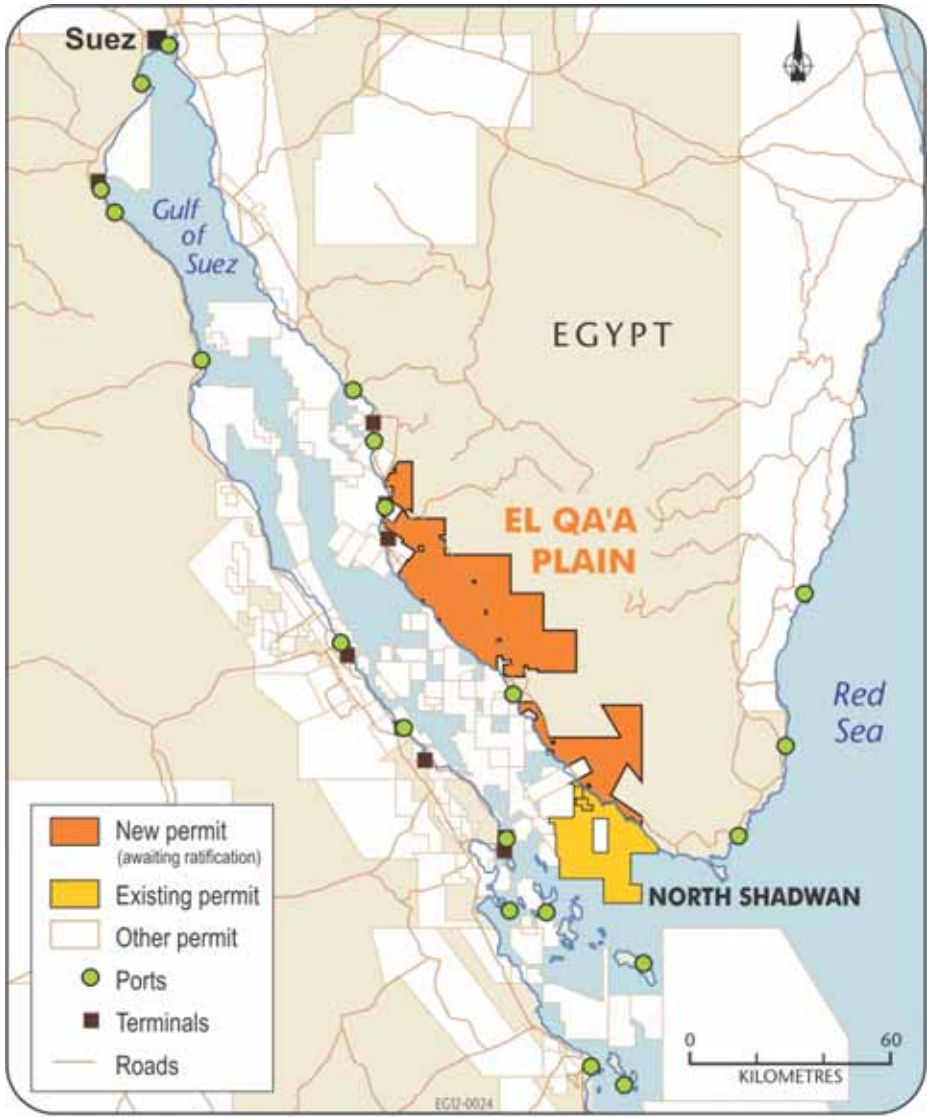
- Pre-Hercynian section can be characterised by two intervals:
  - Transparent package
  - Reflective package
- Mesaha-1 spudded late October
- Designed to test the stratigraphy on flanks of a large structure
- Two pre-Hercynian unconformity markers can be mapped in a limited area
- Prospects up to 25 km^2, average Western Flank prospect size of 1-2 km^2



2 kms

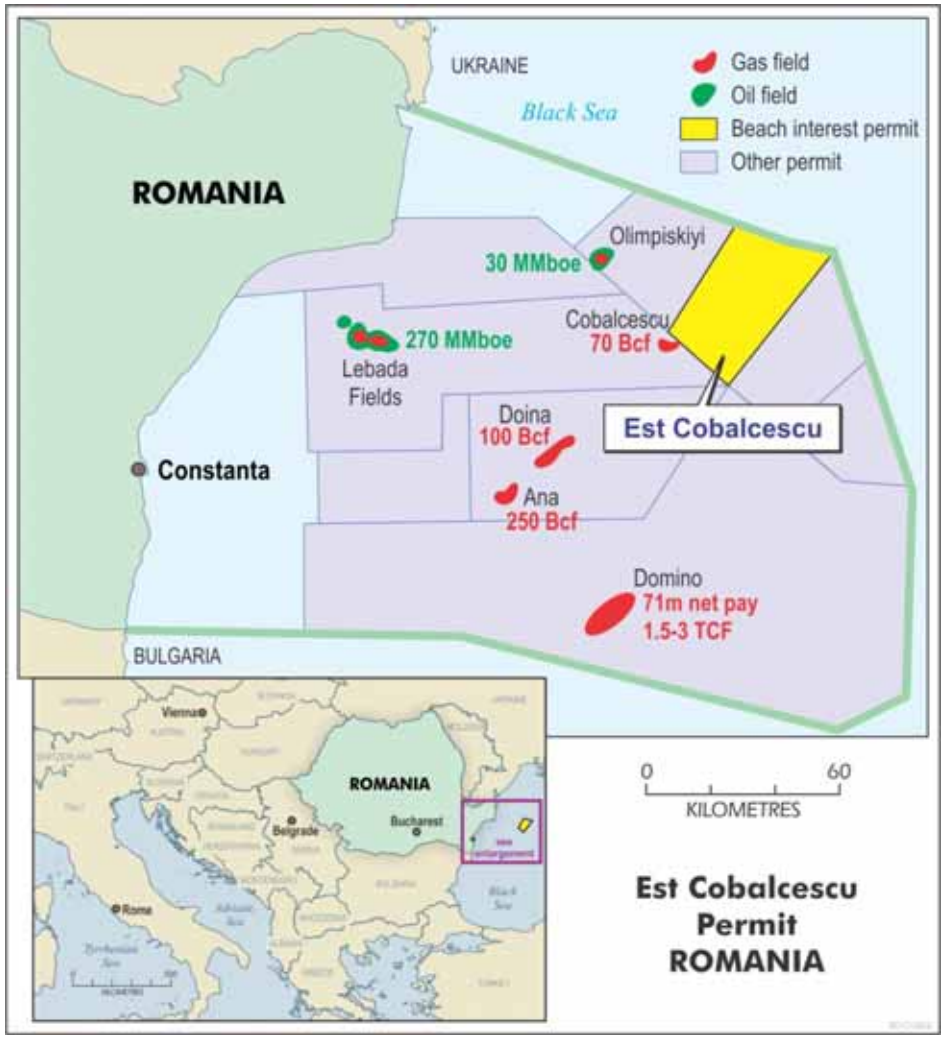
EGPC international bid round 2011

- El Qa'a Plain bidding group: Beach 25%, Dana Petroleum (operator) 37.5% and Petroceltic 37.5%
- Total area of 1,823 km^2
- 1,519 kilometres of 2D seismic by BP and Conoco in early '80s
- 11 wells drilled between 1965 and 1984 (two with oil shows)
- Two prospects and 3 leads at Nubia level mapped on old data, largest up to 18 km^2 with potential for up to 50–100 MMbbls
- Deepest part of El Qa'a sub-basin is ~4,400 metres, mature source rock likely downdip from prospects and leads
- Exploration term four + two years, 3D seismic and one well commitment



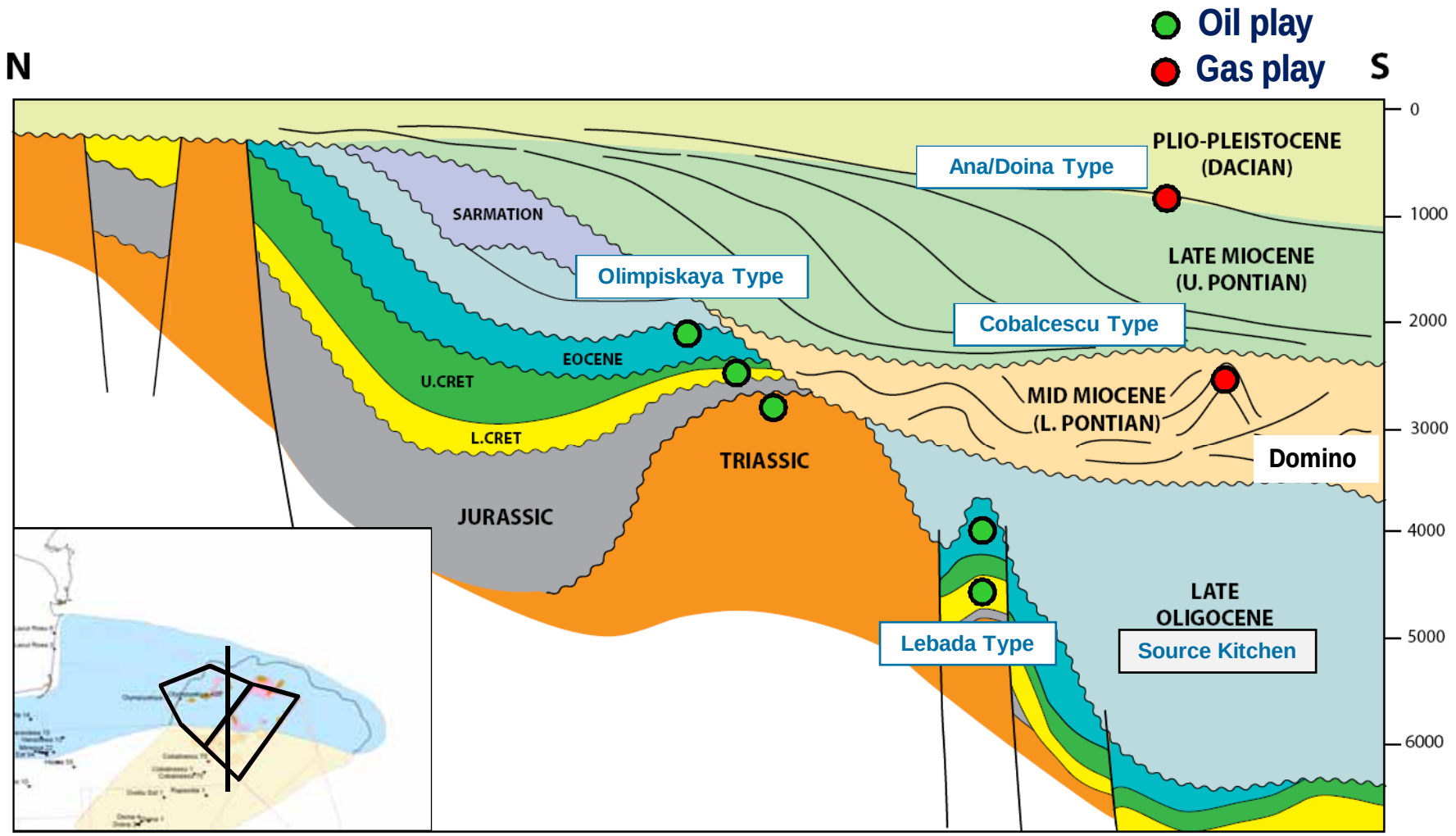
Romania – Est Cobalcesu block

- Post Beach farm-in: Beach 30%, Melrose 40% (operator), Petromar 30%
- Est Cobalcescu block is 1,000 km^2, with 3D seismic over block being processed
- Water depth <100 metres
- Potential for both oil and gas plays
- Significant leads identified on available data
- Adjacent to Exxon-Mobil deepwater block with a 2012 discovery estimated at 3 Tcf
- Strategically aligned with local company Petromar
- Attractive royalty based fiscal regime and farm-in terms



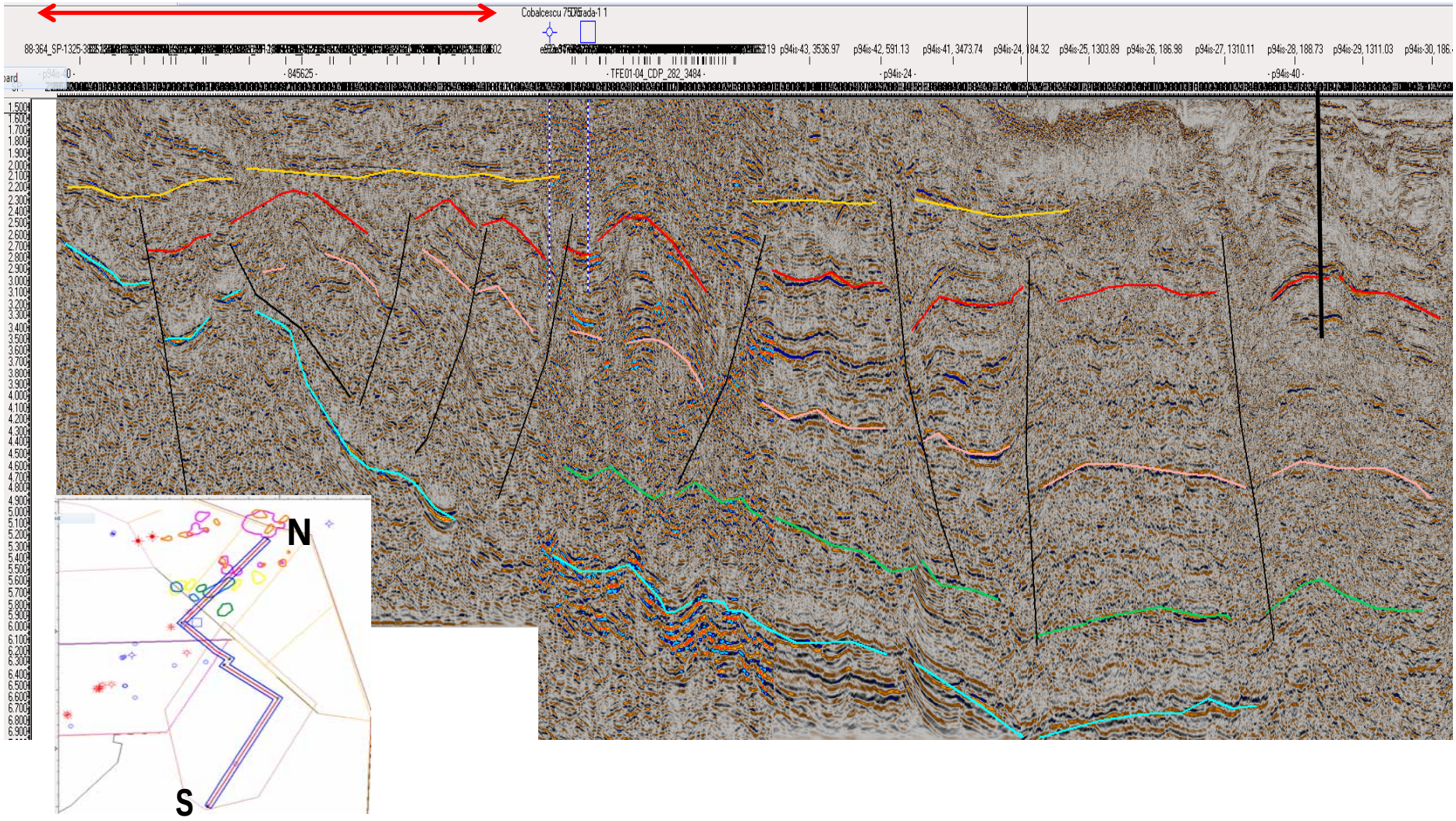
Newly available acreage with proven petroleum systems and multiple targets

Est Cobacescu - Multiple Exploration Play Types



ExxonMobil Domino-1 discovery

N Est Cobalcescu Domino 1 S



Cooper Basin
Unconventional exploration

Mark Pitkin

Team Leader Unconventional Resources

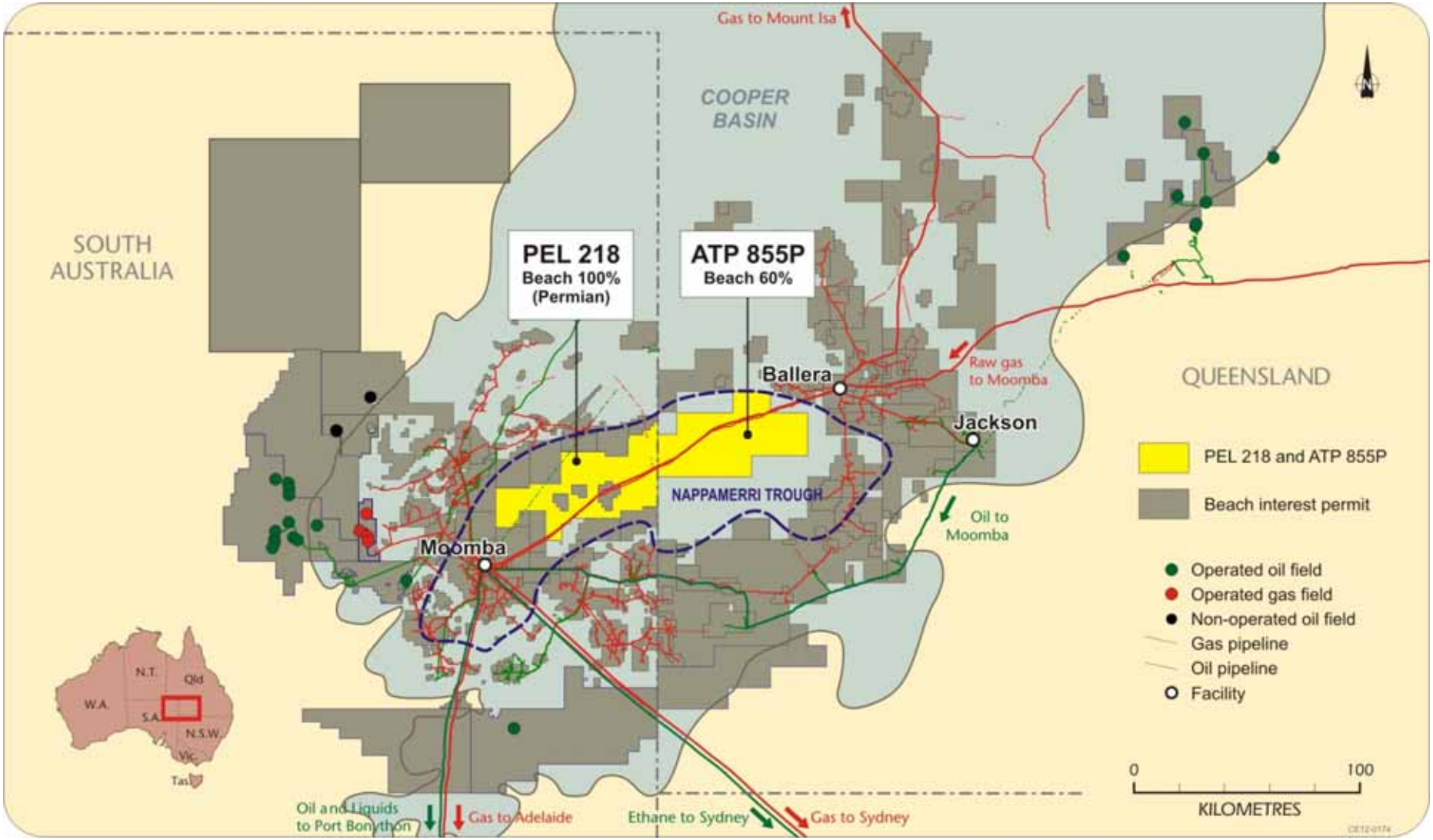
Cooper Basin unconventional exploration

- What was planned for our unconventional exploration well program and stimulation design
- Learnings from Holdfast-1 and Encounter-1
- What we are now doing differently
- Current activity and upcoming unconventional program

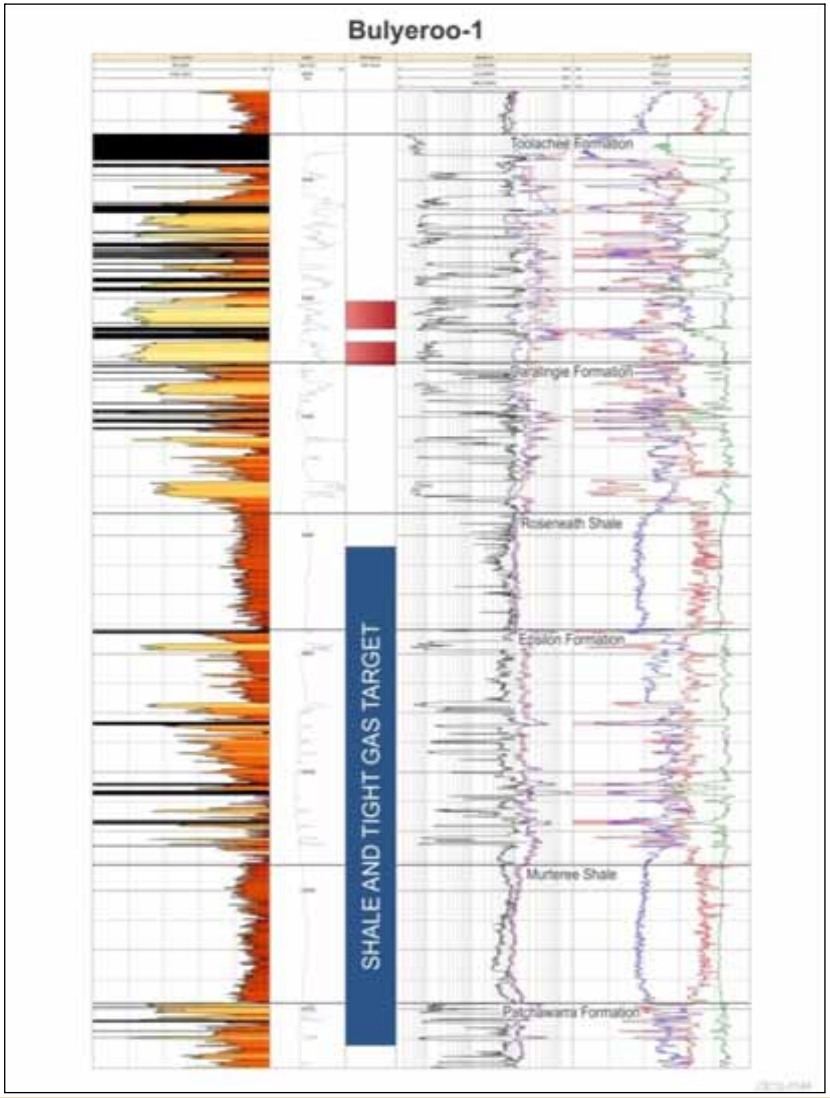
Note: Certain slides in this section of the presentation were extracted from a recent SPE presentation and marked accordingly

Ensign 965 drilling Marble-1 in PEL 218

Cooper Basin (Nappamerri Trough)



Nappamerri Trough historical stimulation results

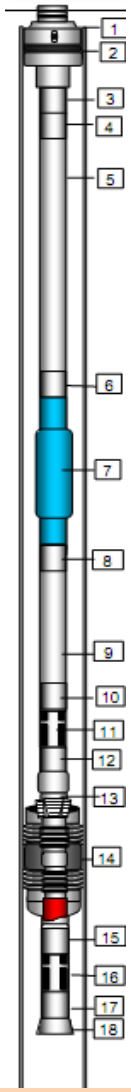


- Fracture stimulation important in accessing and commercialising shale and tight gas
- Bulyeroo-1 (1995) and Kirby-2 (2000) stimulated in the shallower Toolachee
- High treating pressures:
  - Fracture gradient 1.2-1.3 psi/ft
  - NWBPL 1,000 psi at 15-25 bpm
- S_{hmin} similar magnitude to S_v
- Potential for treatments to initiate vertically and twist to horizontal due to stress environment

Reference: SPE 160307

Leveraging off other's experiences to date

Planning for Success

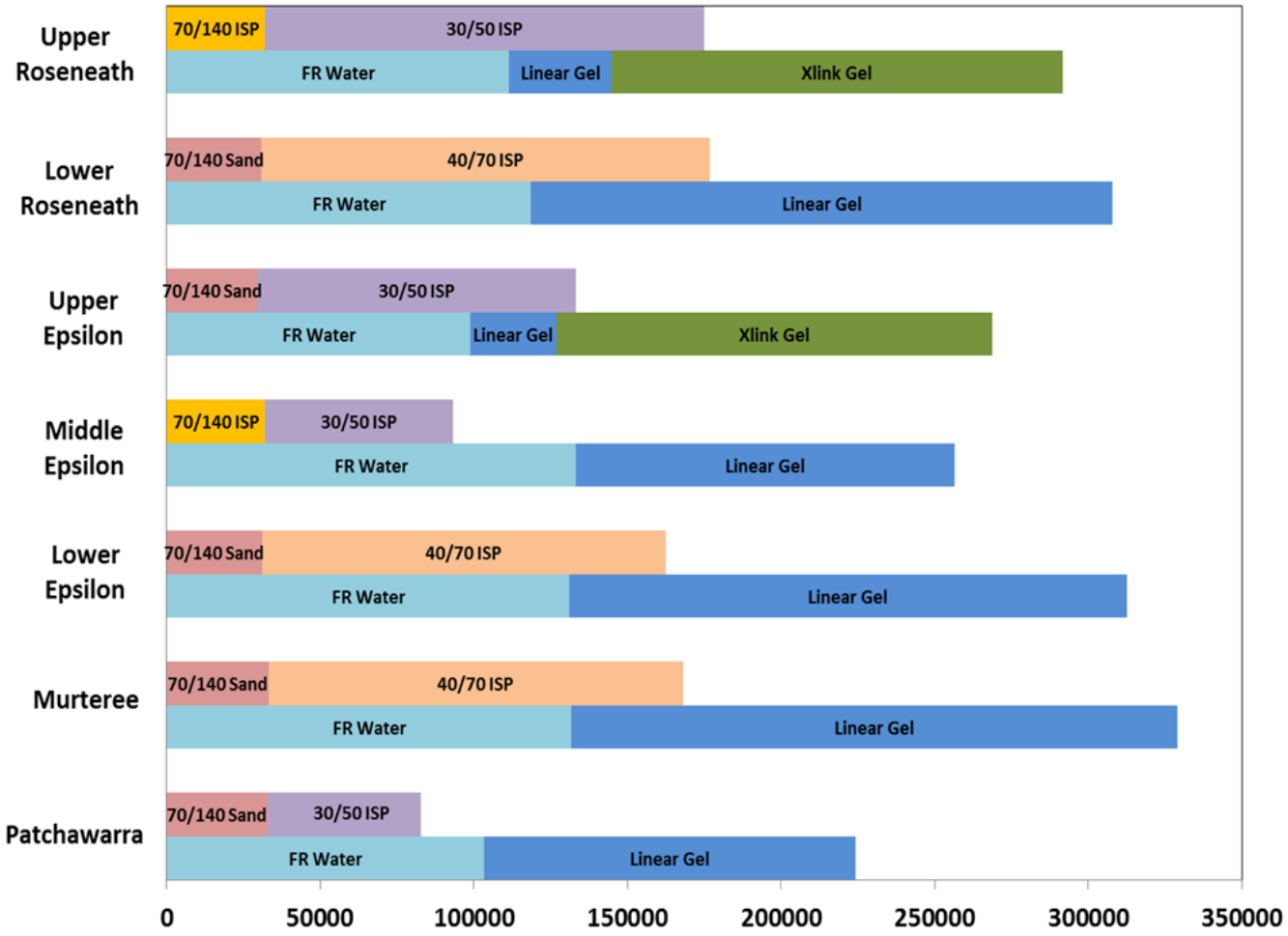


Key considerations	Action/contingency/monitoring
High treating pressures	> 13,000 psi capability
	4 ½" string in 7" casing, 5,000 psi on annulus
High NWBPL	Cement solubility
	Acid spearheads, gel slugs, proppant scours
	Multiple step down tests
	Fibre-optic HP and HT gauge with real time
High stress	Intermediate strength proppant
	Tiltmeters for fracture orientation

Reference: SPE 160307

A well researched program

Treatments placed in Holdfast-1



Typically

- 30,000 lbs 100 mesh
- 140,000 lbs ISP
- > 100,000 gal FR water
- 150,000 gal linear or x-linked gel

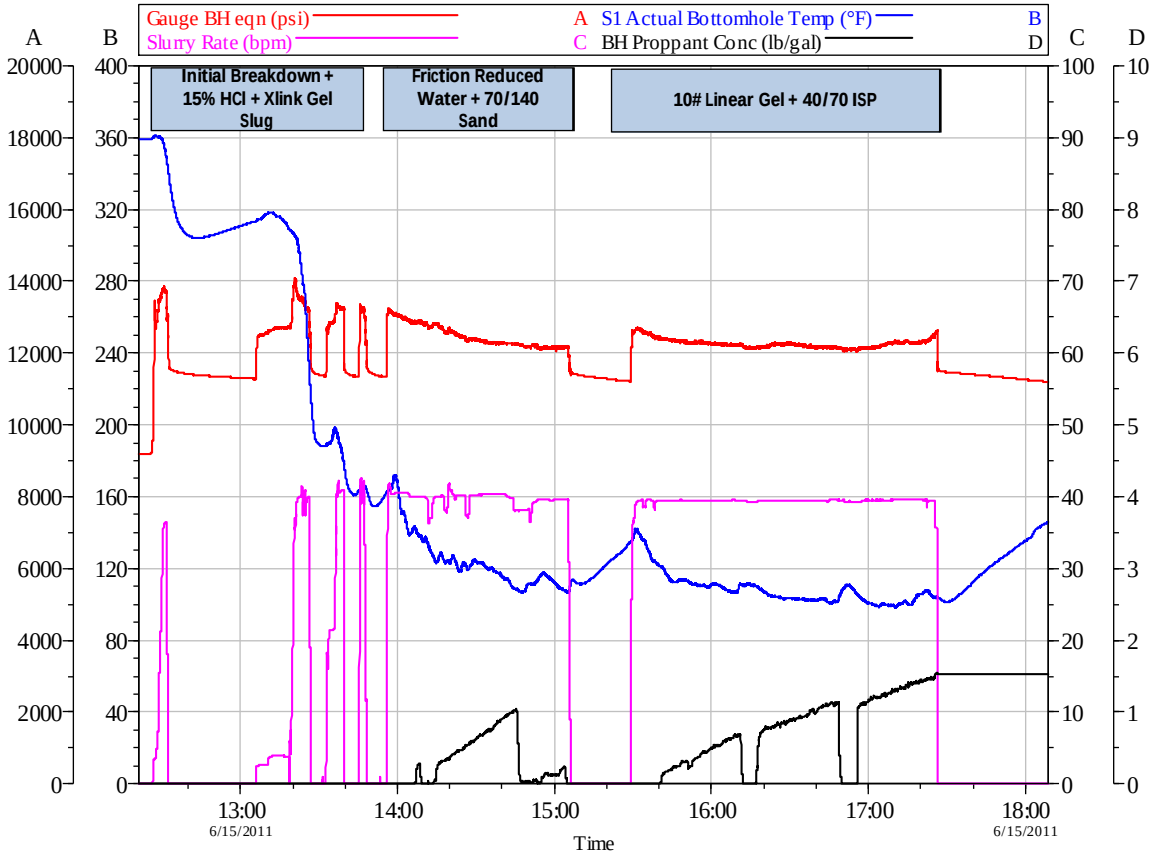
Observations

- 30/50 difficult to place without x-link
- 40/70 placed with little difficulty

Reference: SPE 160307

Contributing to the technical community to facilitate growth of the industry

Treatment overview and diagnostics



Pumping conditions

- Pumping rates between 40 bpm and 55 bpm
- Average surface treating pressures between 9,000 psi and 11,500 psi
- 100 mesh reduced near wellbore pressure loss

Diagnostics

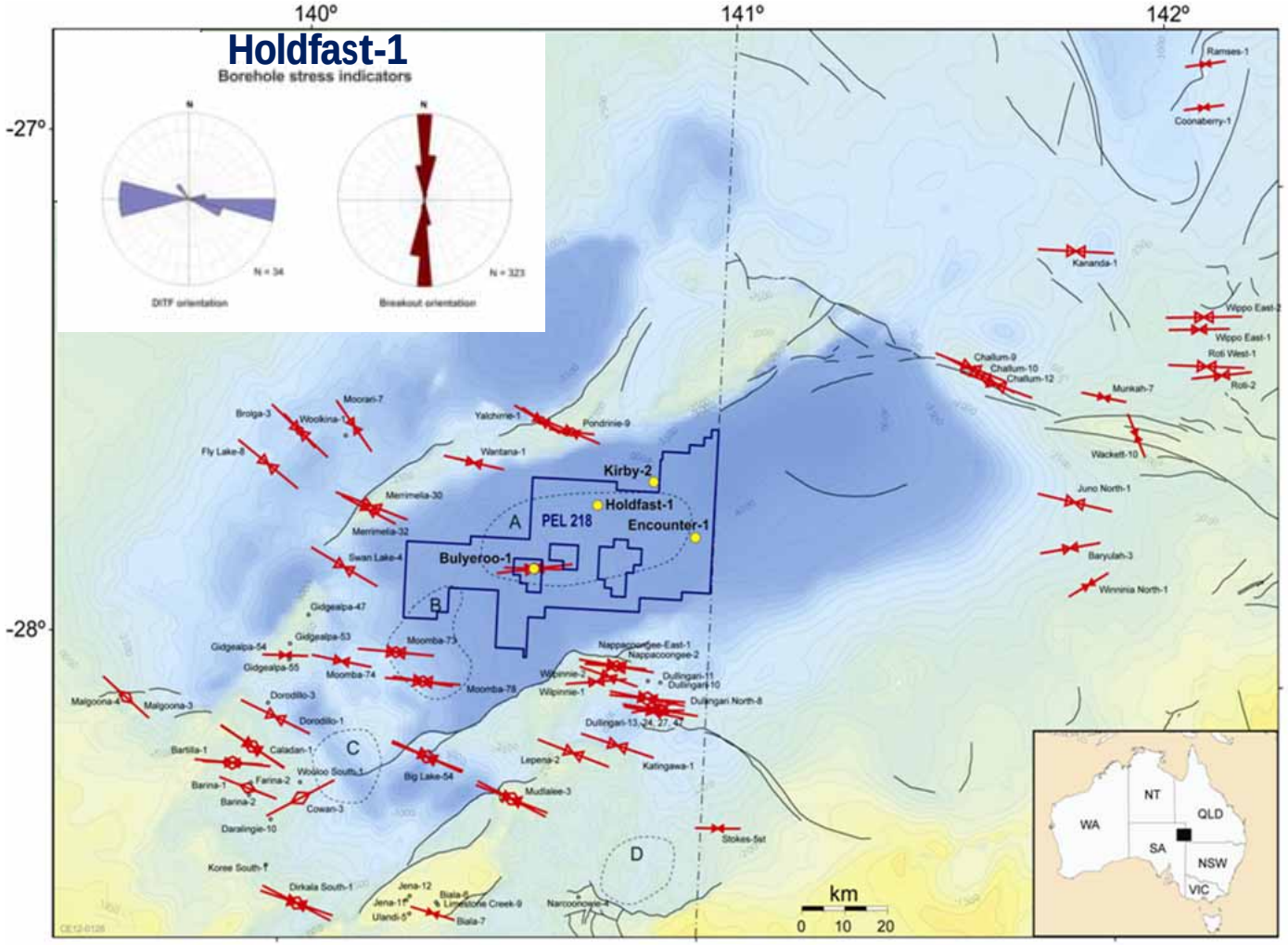
- Step down tests after:
  - Initial breakdown
  - Acid injection
  - Gel slug
  - 100 mesh

Reference: SPE 160307

Contributing to the technical community to facilitate growth of the industry

Maximum horizontal stress orientation

- Derived from break out and drilling induced tensile failure information
- Maximum horizontal stress in Cooper Basin principally EastWest

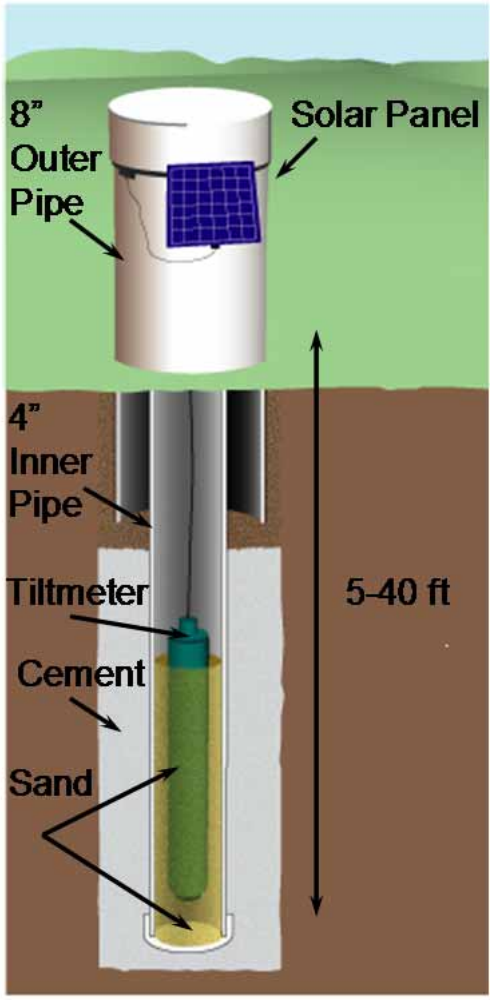


Reference: SPE 160307

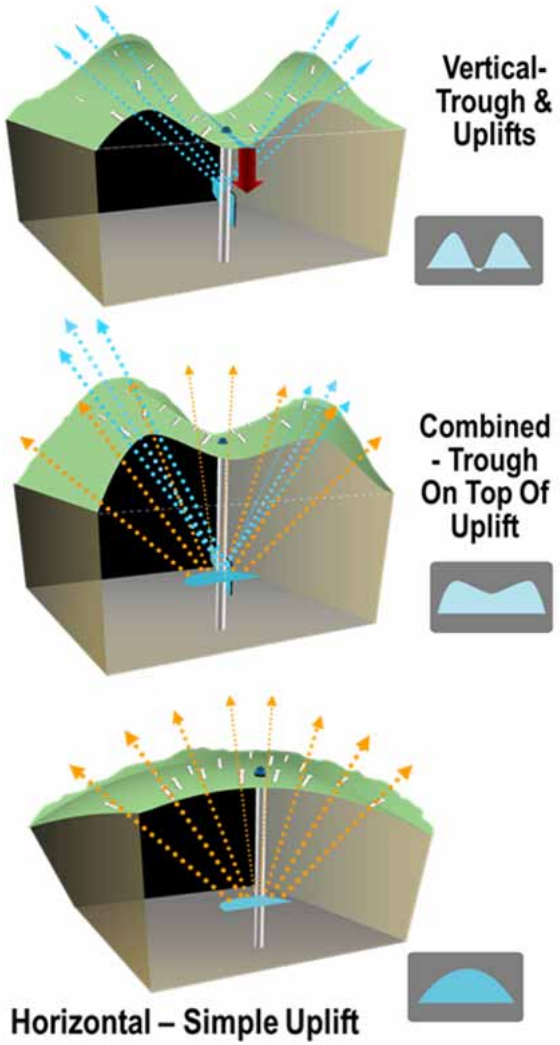
(adapted from Hillis et al. 1998)

Expanding existing knowledge base to drive improved outcomes

Monitoring fracture orientation - tiltmeters



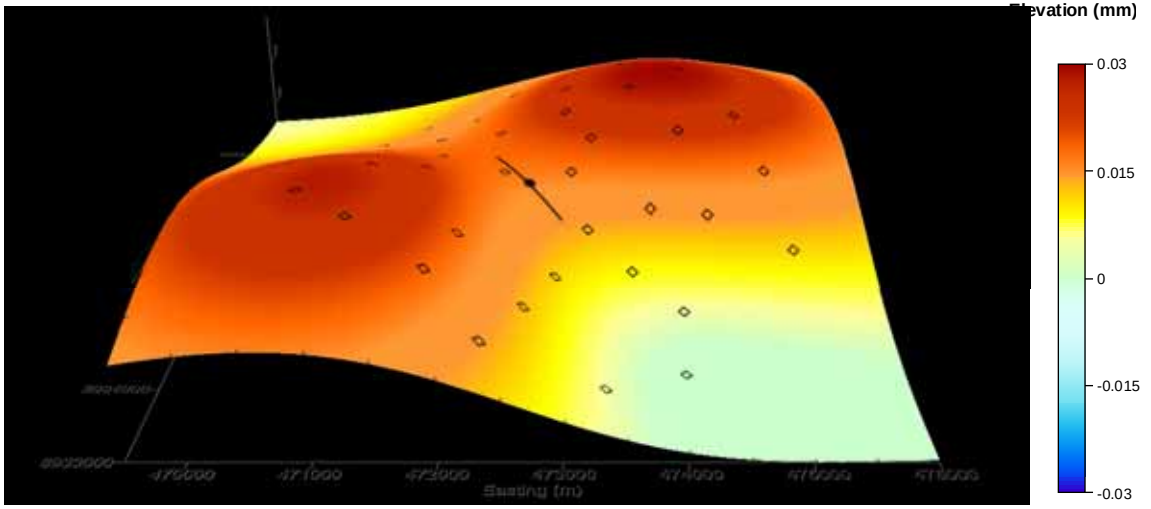
- Stress environment suggests $S_{hmin} \sim S_v$
- Wells spaced 10-20 kilometres apart, down-hole microseismic not possible
- Tiltmeter provided option to resolve horizontal and vertical



Reference: SPE 160307

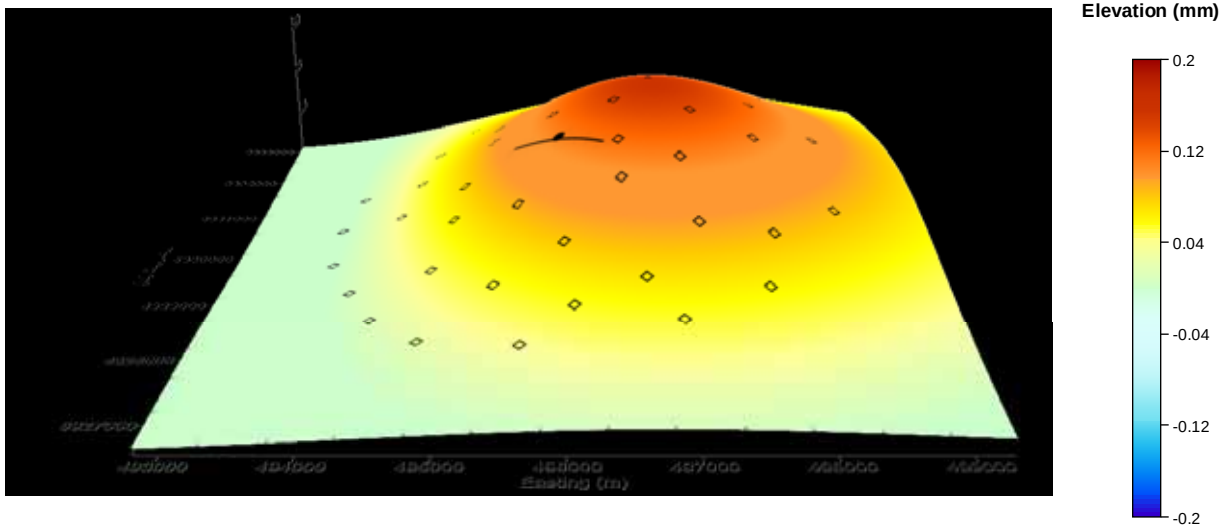
Finding and applying the right technology to overcome challenges

Results from Holdfast-1 and Encounter-1



Holdfast-1

- Effectively vertical
- Horizontal component ~10-25%
- Orientation NW-SE
- Patchawarra shown 20% horizontal



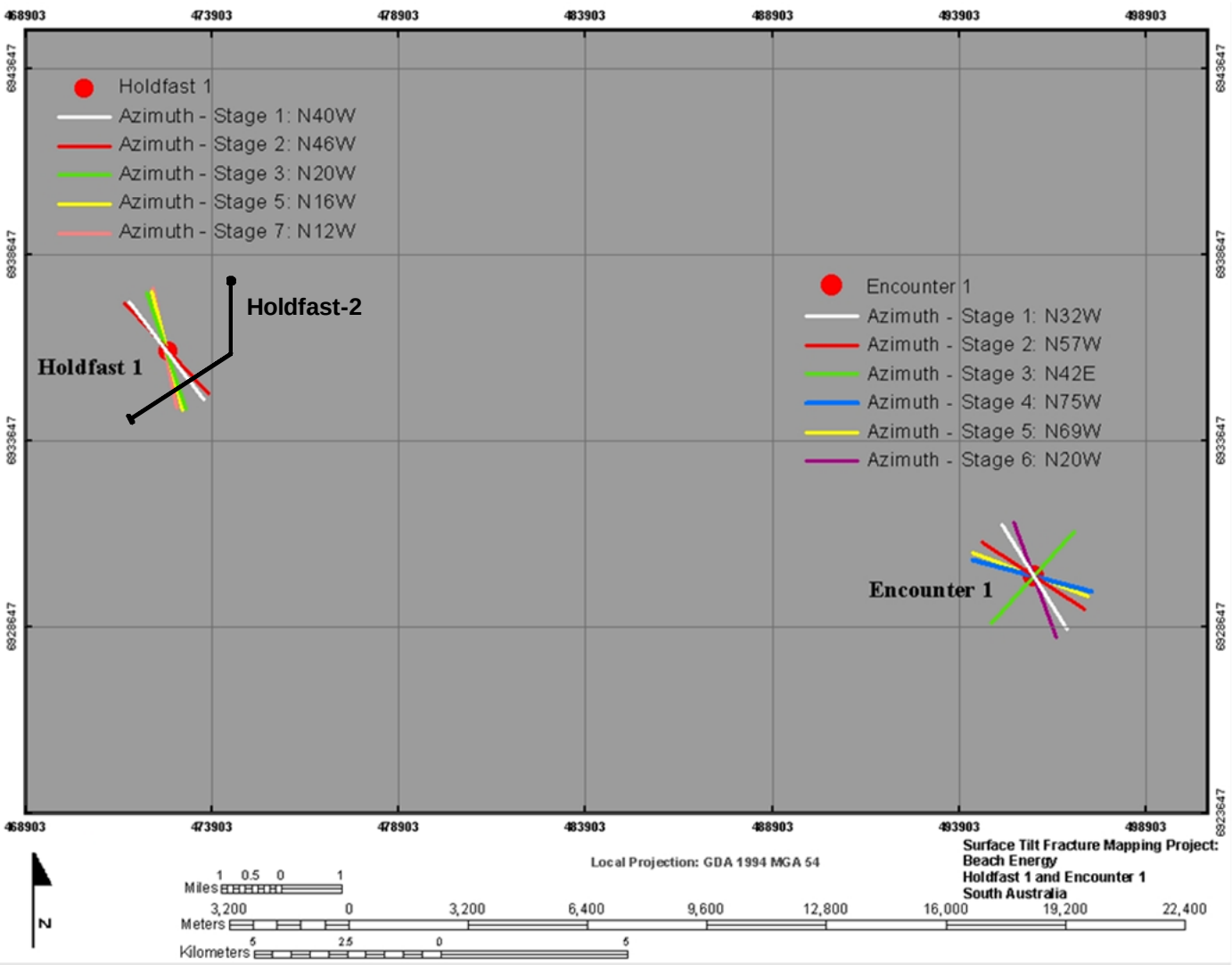
Encounter-1

- Horizontal component ~25-50%
- Vertical component orientation NW-SE
- Murteree stage shown >50% horizontal

Reference: SPE 160307

Subtle deflections delivered significant results and confirmed vertical fractures

Tiltmeters – driving our horizontal orientation

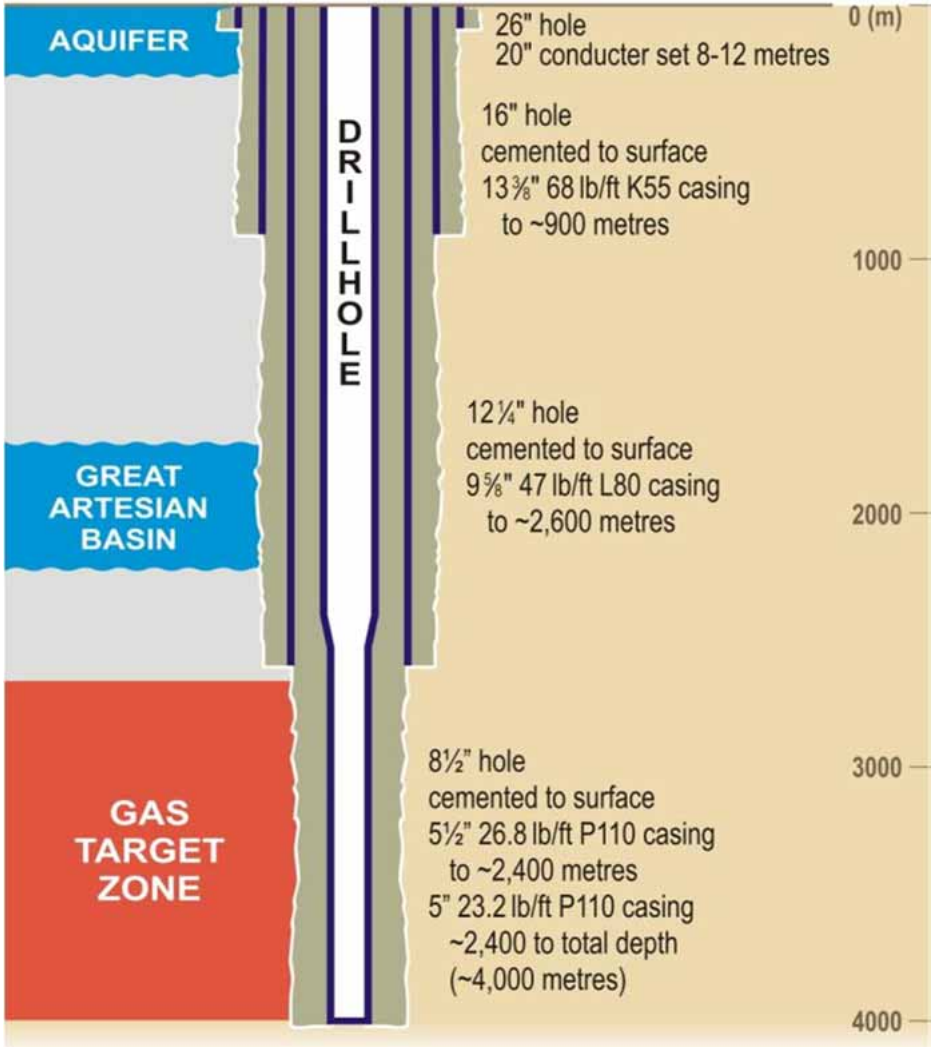


Reference: SPE 160307

First use of new technology in Basin, immediately applicable results

New well design for next generation of wells

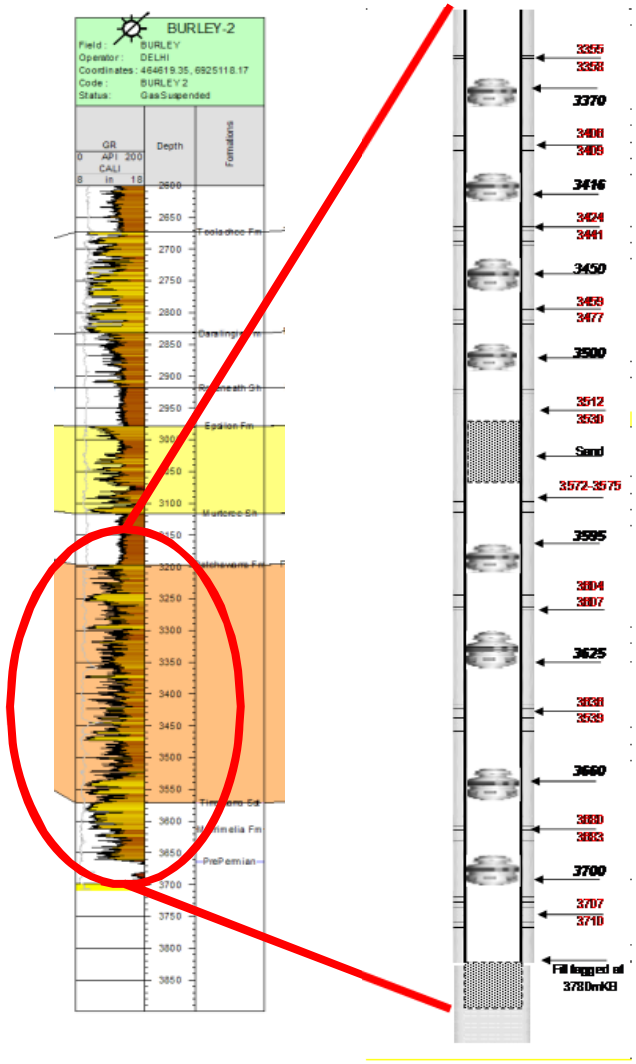
- Tapered mono-bore consistent with North American designs used in Haynesville
- Same design for vertical and horizontal wells
- Enables high rate multi stage stimulation
- Opportunity to assess
  - Stage isolation methods (common plug sizes)
  - Cluster perforation techniques
- All wells in the current campaign utilise this design



Reference: SPE 160307

Building on knowledge from North America to expedite project appraisal

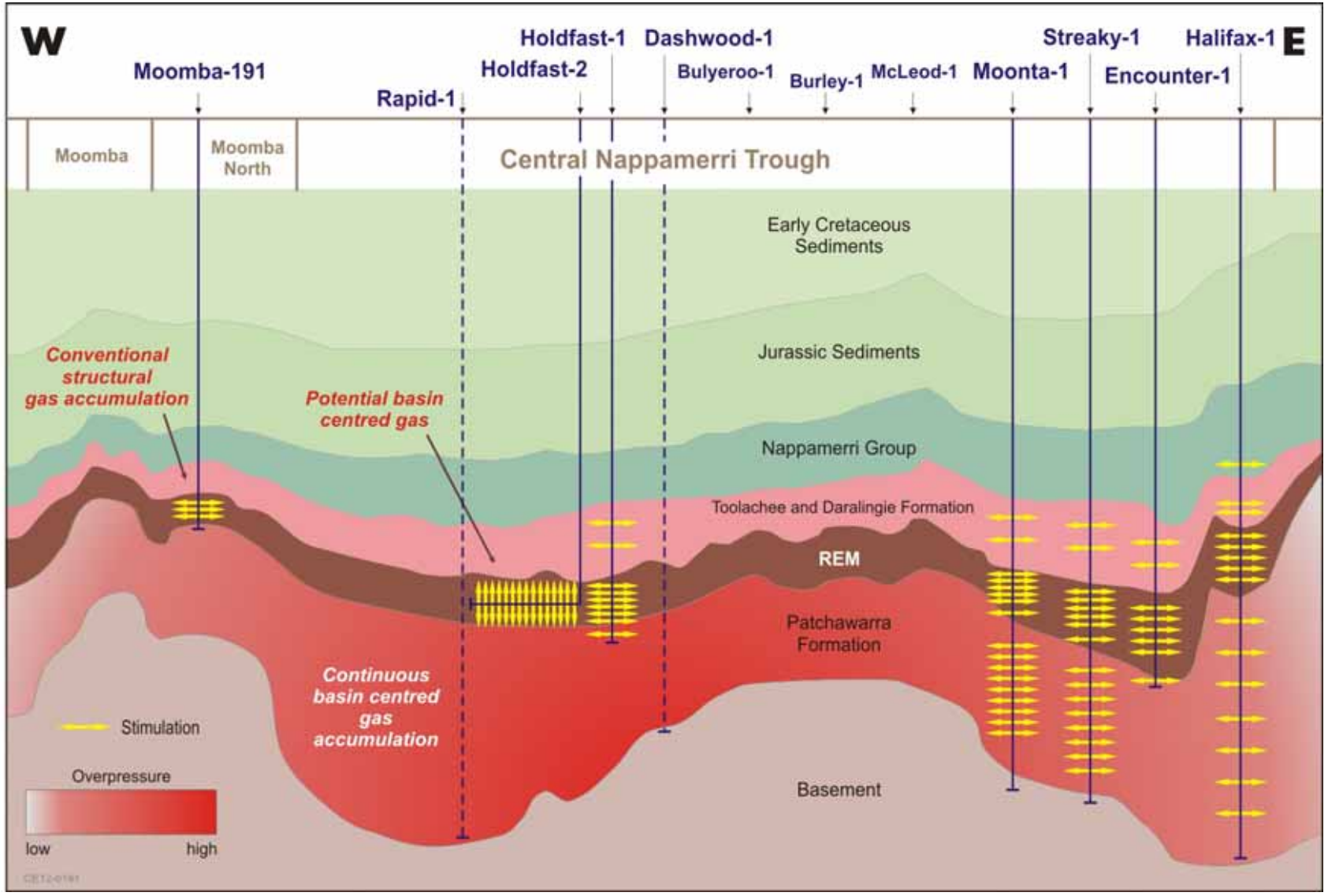
Moonta-1 and Streaky-1 stimulation



- Staged evaluation
- 8-9 zones stimulated in the thick basin-centred tight gas play
- 1-2 zones in the Murteree to assist with horizontal well optimisation
- 80 bpm injection rates achieved, planned fluid and proppant volumes placed
- Composite plug isolation method to separate stages – evaluate for horizontal well application
- Simple milling operation on coiled tubing, quick clean out of wells
- Packer installed on wireline and tubing run by workover rig, ready to flow

Pumping goals being achieved with down-hole tools successfully tried and tested

Fracture stimulation stages



Near-term unconventional deliverables

- Complete fracture stimulation of Streaky-1, estimated to take ~one more week
- Mill out plugs, install tubing and flow test Streaky-1 by mid-December 2012
- Fracture stimulate 15 zones in Halifax-1 across full Permian section
- Commence flow testing Halifax-1 early January 2013
- Drill first horizontal well at Holdfast-2, commencing mid-December 2012
- Flows from first horizontal well expected mid-April 2013

Halliburton simulation spread at Moonta-1 in PEL 218

Significant FY13 resource booking expected for all flowing wells

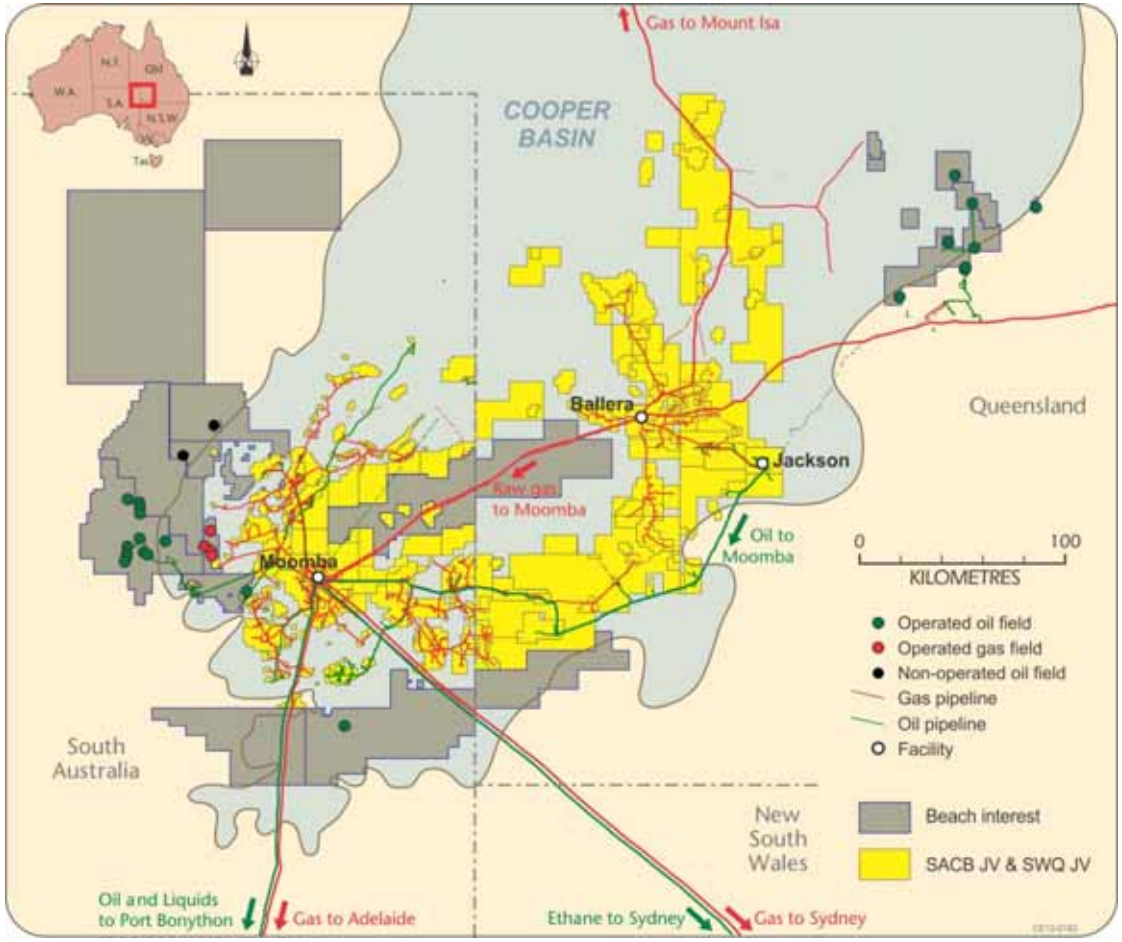
SACB JV & SWQ JV's and Infrastructure

Gordon Moseby

General Manager
Business Review and Planning

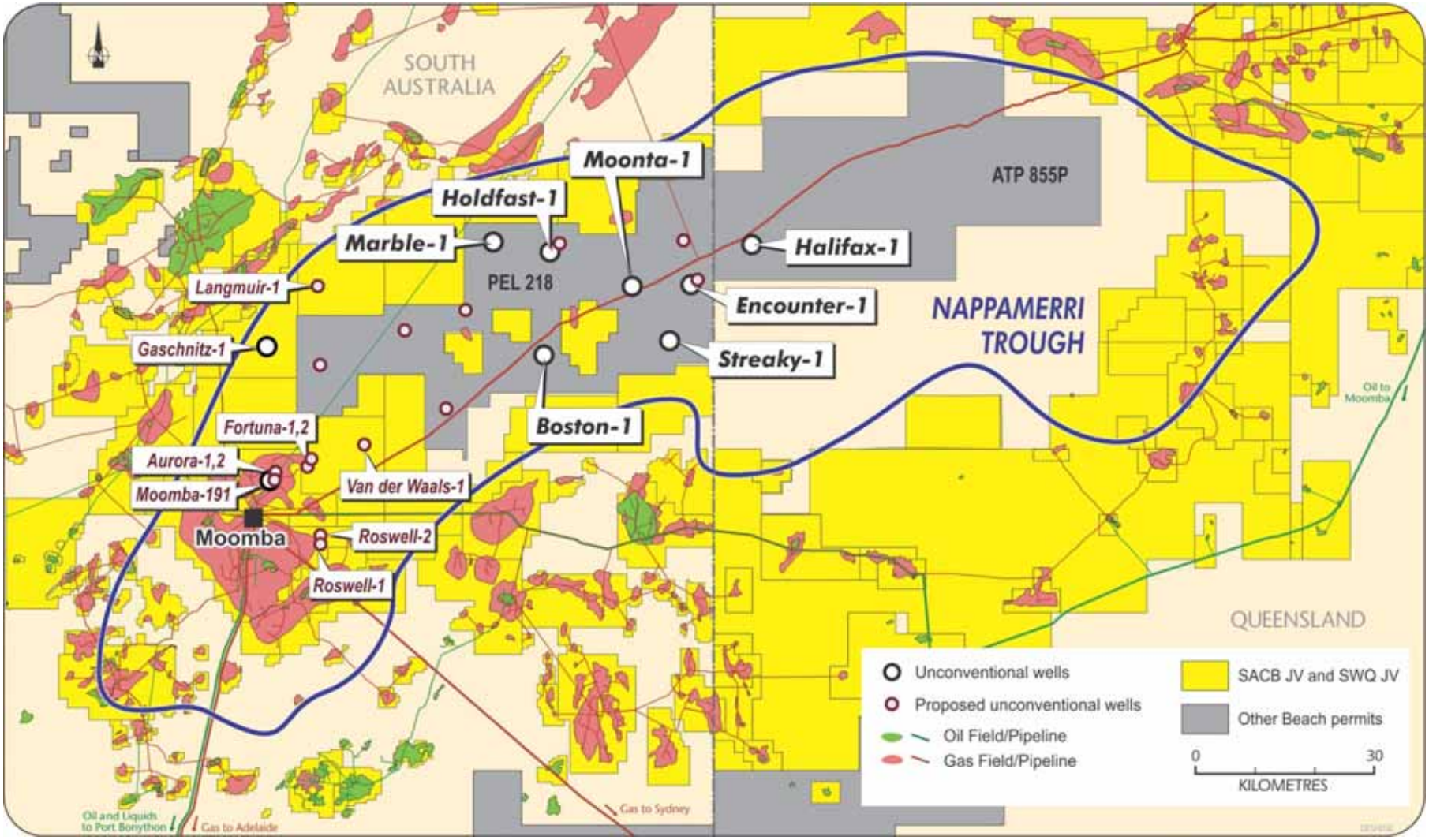
SACB JV and SWQ JV's

- Significant equity interest in the SACB JV (Beach 20.21%) and SWQ JV's (Beach 20-40%)
- Area covered by JV's ~26,800 km^2
- JV's equity interests include:
  - Moomba and Ballera processing facilities
  - All gathering systems within JV acreage
  - Ballera to Moomba raw gas pipeline (~180 kilometres)
  - Moomba to Port Bonython oil pipeline (659 kilometres)
  - Port Bonython oil facility
  - Jackson oil facility



Moomba facility cumulative gross production to date of ~6 Tcf

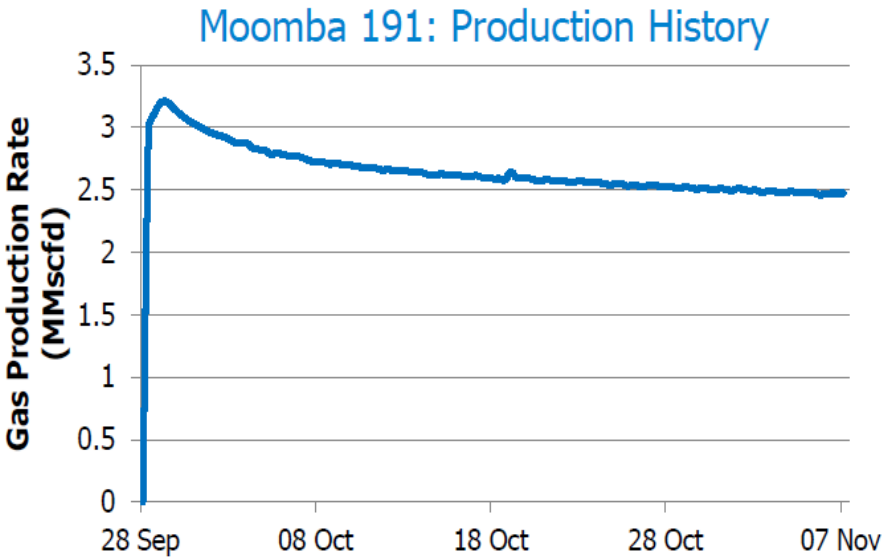
SACB JV unconventional program



Testing the western margins of the Nappamerri Trough

Moomba-191 update

- Initial flow rate > 3 MMscfd
- Average flow rate over first month ~2.7 MMscfd
- Early stage recovery estimates are > 1.5 bcf
- Indicates continuation of unconventional gas trending West of PEL 218 in the Nappamerri Trough



Moomba-191 gas flare

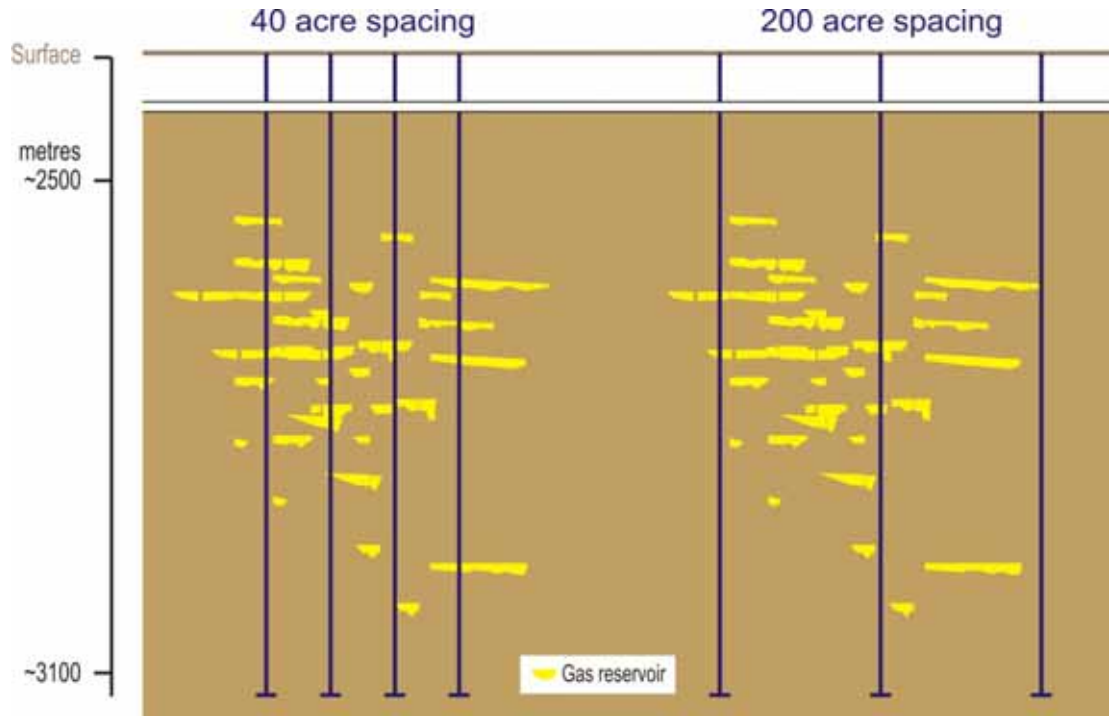
Source: Santos

SACB JV infill drilling program

Resource to reserve conversion drivers:

- Infill drilling with denser well spacing moving towards 40 acres
- More focused fracture stimulation of individual zones
- More efficient wellbore hydraulics, resulting in lower abandonment pressures and improved recovery
- Shale and deep coals accessible via existing wellbores
- Beach anticipates ~10 MMboe (net) resource to reserve conversion per annum for coming years

Infill drilling – 40 vs 200 acre spacing

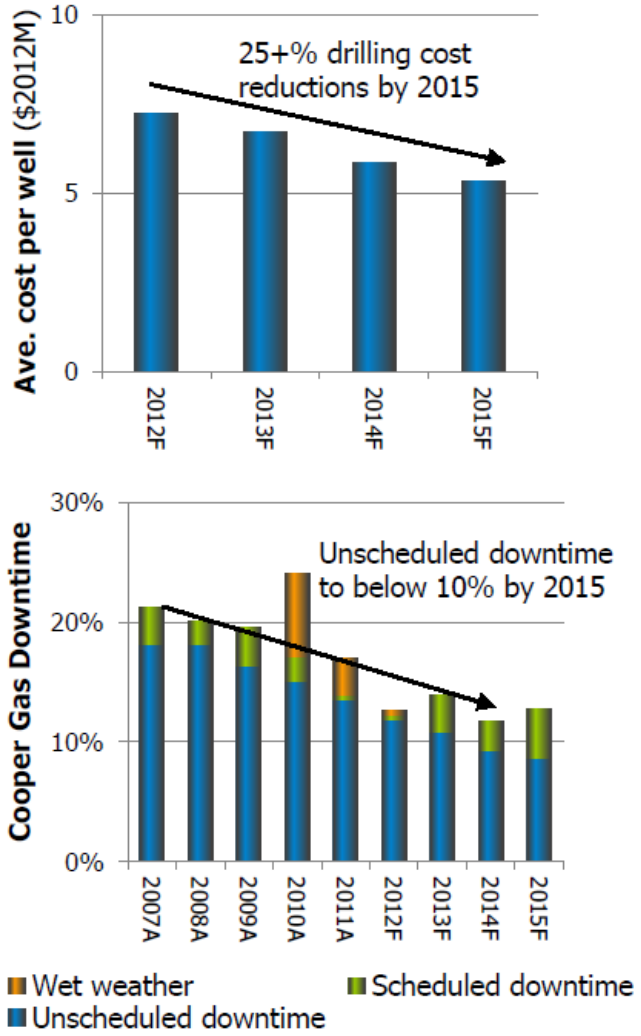


~20 MMboe (net) converted from resource to reserve in 2011

SACB JV gas growth project

Cost reduction initiatives

- Multi-well pad drilling technology – 4 rigs by 2014
- SIMOPS approach to drilling, completions and connections
- 30% production growth to 2015 leads to step-change in cost reductions
- Production costs reducing by 30% to ~$9/boe by 2015
- Maintenance strategies successfully delivering record downtime levels leading to production benefits



Source: Santos

Extracting more gas from existing fields

Cooper Basin unconventional gas infrastructure

SACB JV

- Moomba-191 tied-in within weeks

Beach operated

- Targeted pilot production phase (2013-15)
  - Potential to process through existing SACB JV infrastructure
  - Subject to negotiation with the SACB JV
- Industrialised development program:
  - Scaled up Moomba facility
  - New facility
    - State of the art, fit for purpose, dry gas processing
    - Potentially constructed by 3rd party specialising in infrastructure
    - Tolling rate to be paid for all gas processed

Moomba processing facility

New infrastructure to potentially drive a successful unconventional CB program

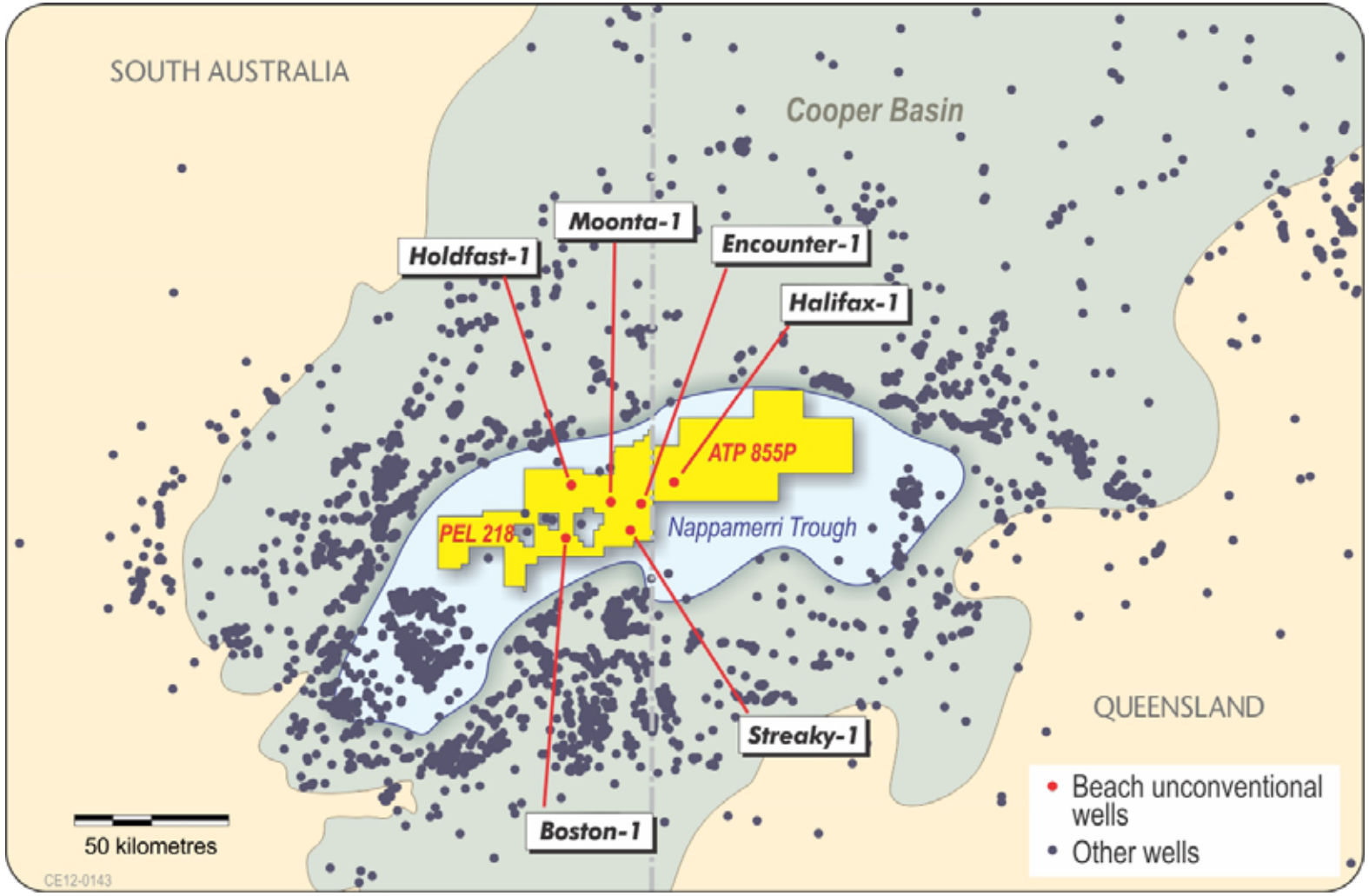
Close

Reg Nelson

Managing Director

Appendices

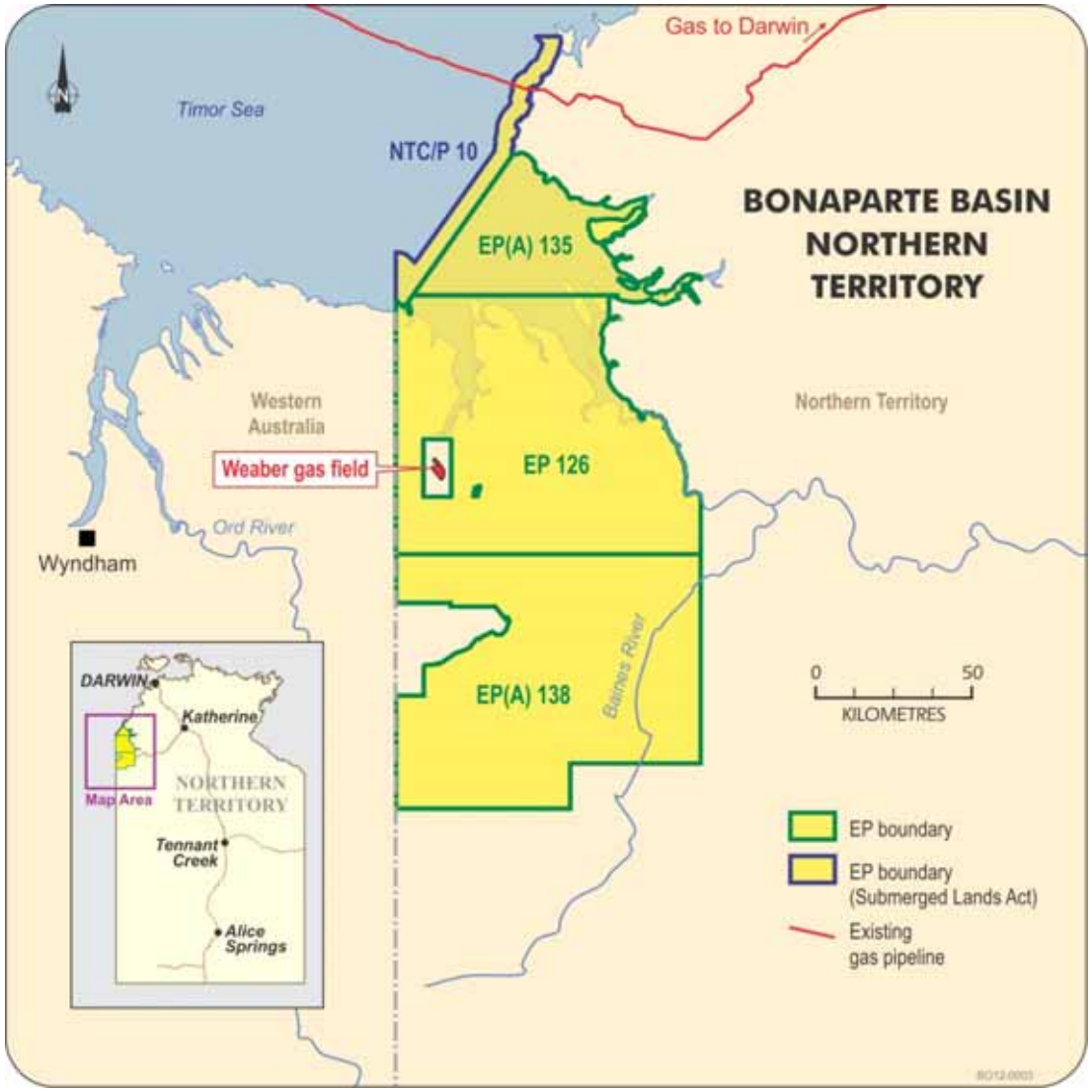
Things you can find in your own backyard...



A relatively under-explored part of the Cooper Basin with enormous potential

Bonaparte Basin

- Beach earning up to 90% of onshore and up to 55% of offshore areas
- Underexplored to date due to lack of quality modern seismic
- Conventional and deep unconventional targets
- Highly prospective as a result of:
  - Working petroleum systems identified in the few wells to date
  - Oil seeps identified at surface
  - Oil staining in mineral cores
  - Weaber gas field adjacent to acreage
- Beach commitment of $5 - $36 million dependent on various options



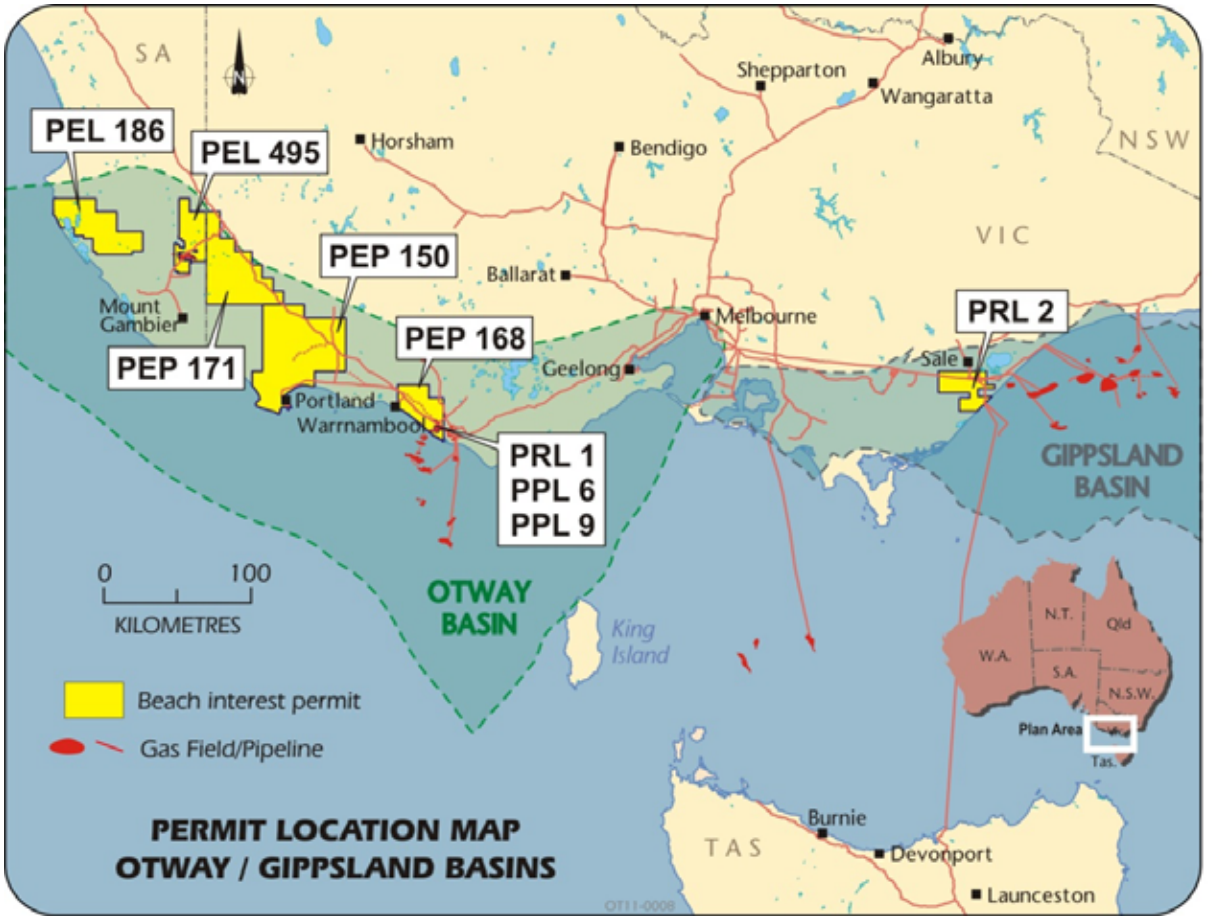
Otway and Gippsland basins

Otway gas and liquids

- Beach 35-67%
- Conventional plays proven – gas, condensate and oil discoveries
- Casterton main source rock, with most attractive unconventional targets
  - Moderate to high TOC's
  - Gas and liquids prone
  - Thick and areally extensive
  - Mature and overpressured

Gippsland gas

- Beach earning up to 33.3%
- Wombat gas project



Note: PEP 150 and PEP 171 are subject to Native Title Agreement

Significant onshore acreage positions well located to access growing markets

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