August 27, 2013

Company Announcements Platform
Australian Stock Exchange
Level 4
20 Bridge Street
SYDNEY NSW 2000

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AUGUST CORPORATE PRESENTATION

Please find attached a copy of the Company's most recent corporate presentation that will be used for upcoming investor updates.

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For further information, please contact:

Jonathan Stewart Executive Chairman Aurora Oil & Gas Limited Tel: +61 8 9380 2700	Shaun Duffy F T I Consulting Tel: +61 8 9485 8888 Mob: +61 404 094 384 Shaun.Duffy@fticonsulting.com	Jane Munday F T I Consulting Tel: +61 8 9485 8888 Mob: +61 488 400 248 Jane.Munday@fticonsulting.com

Technical information contained in the presentation in relation to the Sugarkane field was compiled by Aurora from information provided by the project operator and reviewed by Michael Verm, PE, Chief Operating Officer of Aurora who has had more than 33 years experience in the practice of petroleum engineering. Mr Verm consents to the inclusion in this report of the information in the form and context in which it appears.

About Aurora

Aurora is an Australian and Toronto listed oil and gas company active in the over pressured liquids rich region of the Eagle Ford shale in Texas, United States. Aurora is engaged in the development and production of oil, condensate and natural gas in Karnes, Live Oak and Atascosa counties in South Texas. Aurora participates in approximately 79,700 highly contiguous gross acres in the heart of the trend, including approximately 21,800 net acres within the Sugarkane Field in the over-pressured and liquids core of the Eagle Ford.

August 2013
Corporate Presentation

Disclaimers

This document has been prepared by Aurora Oil & Gas Limited ("Aurora") to provide an overview to interested analysts / investors for the sole purpose of providing preliminary background financial and other information to enable recipients to review certain business activities of Aurora. This presentation is thus by its nature limited in scope and is not intended to provide all available information regarding Aurora.

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"Funds from Operations" and "EBITDAX" are commonly used in the oil and gas industry. Funds from Operations represent funds provided by operating activities before changes in non-cash working capital. EBITDAX represents net income (loss) for the period before income tax expense or benefit, gains and losses attributable to the disposal of projects, finance costs, depletion, depreciation and amortization expense, other non-cash charges, expenses or income, one-off or non-recurring fees, expenses and charges and exploration and evaluation expenses. The Company considers Funds from Operations and EBITDAX as key measures as both assist in demonstrating the ability of the business to generate the cash flow necessary to fund future growth through capital investment. Neither should be considered as an alternative to, or more meaningful than net income or cash provided by operating activities (or any other IFRS financial measure) as an indicator of the Company's performance. Because EBITDAX excludes some, but not all, items that affect net income, the EBITDAX presented by the Company may not be comparable to similarly titled measures of other companies.

Management also uses certain industry benchmarks such as net operating income and operating netback to analyse financial and operating performance. "Net Operating Income" represents net oil and gas revenue attributable to Aurora after distribution to royalty holders. "Operating netback", as presented, represents revenue from production less royalties, state taxes, transportation and operating expenses calculated on a boe basis. Management considers operating netback an important measure to evaluate its operational performance as it demonstrates its field level profitability relative to current commodity prices.

Forward-looking Information

Statements in this presentation which reflect management's expectations relating to, among other things, production estimates, changes in reserves, target dates, Aurora's expected drilling program and the ability to fund development are forward-looking statements, and can generally be identified by words such as "will", "expects", "intends", "believes", "estimates", "anticipates” or similar expressions. In addition, any statements that refer to expectations, projections or other characterizations of future events or circumstances are forward-looking statements and may contain forward-looking information and financial outlook information, as defined by Canadian securities laws. Statements relating to “reserves” are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that some or all of the reserves described can be profitably produced in the future. These statements are not historical facts but instead represent management's expectations, estimates and projections regarding future events.

Although management believes the expectations reflected in such forward-looking statements and financial outlook information are reasonable, forward-looking statements and financial outlook are based on the opinions, assumptions and estimates of management at the date the statements are made, and are subject to a variety of risks and uncertainties and other factors that could cause actual events or results to differ materially from those projected in the forward-looking statements and financial outlook information. These factors include risks related to: exploration, development and production; oil and gas prices, markets and marketing; acquisitions and dispositions; our ability to comply with covenants under our debt facilities; competition; additional funding requirements; our ability to raise capital and access debt and equity capital markets; reserve estimates being inherently uncertain; changes in the rate and /or location of future drilling programs on our acreage by our operator(s); incorrect assessments of the value of acquisitions and exploration and development programs; environmental concerns; availability of, and access to, drilling equipment; reliance on key personnel; title to assets; expiration of licences and leases; credit risk; hedging activities; litigation; government policy and legislative changes; unforeseen expenses; negative operating cash flow; contractual risk; and management of growth. In addition, if any of the assumptions or estimates made by management prove to be incorrect, actual results and developments are likely to differ, and may differ materially, from those expressed or implied by the forward-looking statements and financial outlook information contained in this document. Such assumptions include, but are not limited to, general economic, market and business conditions and corporate strategy. Accordingly, readers are cautioned not to place undue reliance on such statements. Further, the financial outlook information regarding future production and future production revenue is included to assist readers in assessing the potential impact of current drilling plans on our performance and may not be appropriate to be relied on for any other purposes.

All of the forward-looking information and financial outlook in this presentation is expressly qualified by these cautionary statements. Forward-looking information and financial outlook contained herein is made as of the date of this document and Aurora disclaims any obligation to update any forward-looking information or financial outlook, whether as a result of new information, future events or results or otherwise, except as required by law. In relation to details of the forward looking drilling program, management advises that this is subject to change as conditions warrant, and we can provide no assurances that this number of rigs will be available or will be utilised or that any targeted well count will be achieved.

Disclosure of Reserves

The reserves shown in this presentation are estimates only and should not be construed as exact quantities. Proved reserves are those reserves which can be estimated with a high degree of certainty to be recoverable; probable reserves are those additional reserves which are less certain to be recovered than proved reserves. Possible reserves are those additional reserves which are less certain to be recovered than probable reserves. There is a 10 percent probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this presentation. Estimates of reserves may increase or decrease as a result of future operations, market conditions, or changes in regulations.

Unless otherwise indicated, all estimates of reserves in this presentation have been prepared or evaluated in accordance with the COGE Handbook effective as of 31 December 2012, and are derived from the January 30, 2013 reserves report as at December 31, 2012 as prepared by Ryder Scott Company, L.P. ("RS") ("RS Report"). RS are qualified independent reserves evaluators under the Canadian Securities Administrators National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities. Price assumptions used in the RS Report are as follows (FY13/14/15/16/17+): Oil US$101.00/bbl, US$100.00/bbl, US$98.00/bbl, US$96.00/bbl, and US$95.00/bbl; and Natural gas US$3.60/mscf, US$4.00/mscf, US$4.20/mscf, US$4.40/mscf, and US$4.60/mscf.

Defined Terms

Defined Reserves and Resource Terms

- "bbl" means barrel.
- "boe" means barrels of oil equivalent, and have been calculated using liquid volumes of oil, condensate and NGLs and treated volumes of gas converted using a ratio of 6 mscf to 1 bbl liquid equivalent, unless otherwise stated.
- "scf" means standard cubic feet.
- "M" or "m" prefix means thousand.
- "MM" or "mm" prefix means million.
- "B" or "b" prefix means billion.
- "pd" or "/d" suffix means per day.
- "NGL" means natural gas liquids.
- "EUR" means Estimated Ultimate Recovery.

Other defined terms

- "AMI" means Area of Mutual Interest.
- "CAGR" means compounded annual growth rate.
- "CQGR" means compounded quarterly growth rate.
- "NPBT" means net profit before tax.
- "NPAT" means net profit after tax.
- "WTI" means West Texas Intermediate crude.
- "LLS" means Louisiana Light Sweet crude.
- "LTM" means last twelve months.
- "Sugarkane" or "Sugarkane Field" means the two contiguous fields designated by the Texas Railroad Commission as the Sugarkane and Eagleville Fields.
- "$" or "US$" means United States (US) dollars, unless otherwise stated.
- "WI" means working interest within leases, AMI or wells.

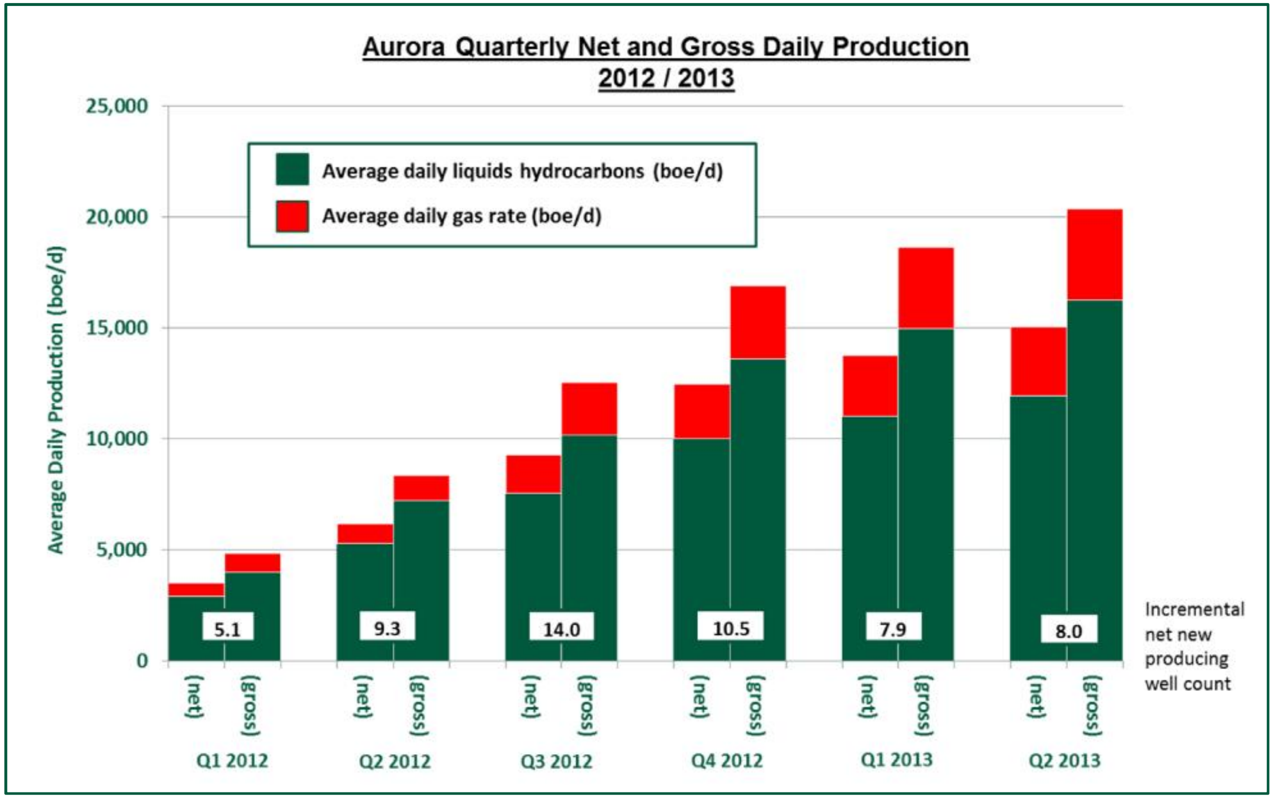
Boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mscf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 mscf:1 bbl, utilising a conversion ratio of 6 mscf:1 bbl may be misleading. Unless stated otherwise, all per boe references are a reference to Aurora's per boe production on a working interest basis before deduction of royalties.

Oil driven production growth from Eagle Ford

- Pure Eagle Ford Shale producer developing highly contiguous ~80,000 gross (22,000 net) acres in the Sugarkane Field on an operated and non-operated basis.
- High margin oil drives rapid production, revenue and profit growth
- Oil and condensate focused growth in reserves
- Strong management team and experienced partner
- Fully funded for continued strong growth profile
- Significant asset value being delivered

Production ramping

- **Production growth over last 6 months of 30% and CQGR of 30% over last 6 quarters**
    - Production 2.61 net mmboe for half year
    - Production grew to over 15,000 boe/d (net of royalties)
- **2013 exit production forecast of 17-19,000 boe/d (net of royalties)**
- **2013 production forecast of 5.5 – 5.9 net mmboe (>90% increase on 2012)**



High margins drive financial growth

Market Cap [1] (US$)	$1,330 mm
Cash (US$)	$165 mm
Total Debt[2] (US$)	$665 mm
Enterprise Value (US$)	$1,830 mm
FY2012 EBITDAX[3] (US$)	$167 mm
1H 2013 EBITDAX[3] (US$)	$156 mm
Q2 2013 EBITDAX[3] (US$)	$80 mm
Last 12 Months EBITDAX[3] (US$)	$270 mm

- **Strong liquidity of US$165mm cash and an undrawn US$200mm credit facility deliver assets to free cash generation after capex[4]**
  - Non-operated assets by approx. end 2013
  - Operated assets by end 2014
- **10 straight quarters of production revenue and EBITDAX growth**

(1) Market Capitalisation based on ASX closing price of A$3.32 per share on August 1, 2013 using an exchange rate A$1=US$0.896.
(2) Unsecured notes - $365mm of 9.875% senior notes due 2017 and $300mm of 7.5% senior notes due 2020.
(3) See “Non-IFRS Financial Measures” above. A reconciliation of net profit after tax to EBITDAX can be found in the appendices.
(4) Assuming similar commodity prices, costs and drilling schedule as experienced in prior 12 months

Why focus on the Eagle Ford?

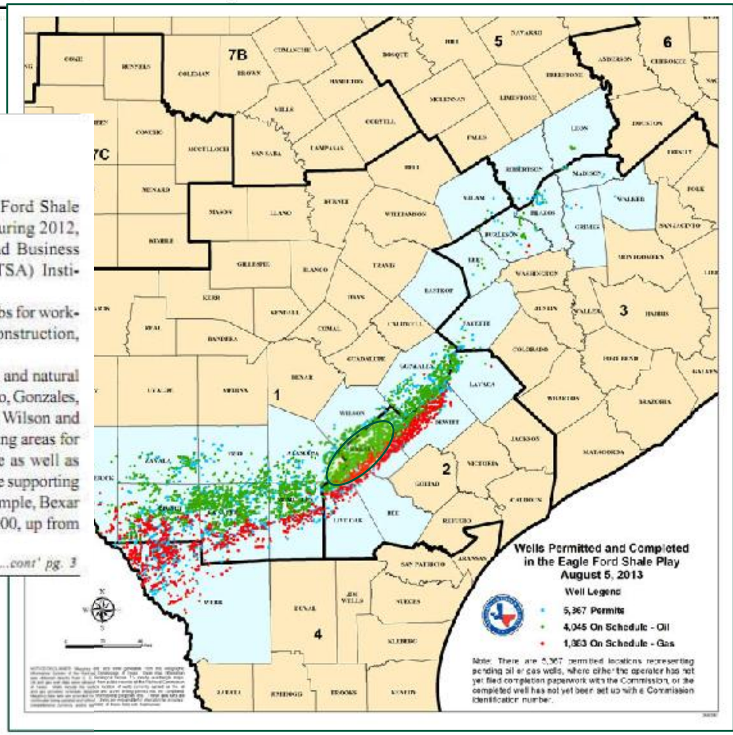
- **First mover advantage**
  - First choice of acreage
  - Low cost entry
- **Economics**
- **Infrastructure**
- **Supportive local community and government**
- **Services available**
- **Pricing**

WEDNESDAY MARCH 27, 2013 NGI's SHALE DAILY™

Annual Eagle Ford Shale Permitting & Production Activity 2008-2012

Year	Drilling Permits Issued	Producing Oil Leases	Producing Gas Wells	Nat Gas Production (MMcf/d)	% of Total	Crude Oil Production (Bbls/d)	% of Total	Condensate Production (Bbls/d)	% of Total	Total Oil & Gas Production (Bbls Equiv/d)
2008	26	N/A	N/A	8	78.8%	358	21.2%	0	0	1691
2009	94	40	67	47	77.6%	844	8.4%	1423	14.1%	10100
2010	1010	72	158	289	65.2%	11986	16.2%	13708	18.6%	73861
2011	1826	368	550	967	44.7%	127965	35.5%	71706	19.9%	360838
2012	4343	1262	875	950	27.2%	352127	60.5%	71748	12.3%	582208

Source: Railroad Commission of Texas data, NGI's Shale Daily calculations



EAGLE FORD SHALE

Eagle Ford Surge: Tens of Thousands Of Jobs, Billions in Revenue

Development of oil and natural gas in the Eagle Ford Shale added more than $61 billion in total economic impact during 2012, according to a study by the Center for Community and Business ... The University of Texas at San Antonio (UTSA) Insti... omic Development.

...ion, the region supported 116,000 full-time jobs for work... gas, drilling, support operations, pipeline construction, ...d petrochemicals last year.

...esearchers examined the region's 14 main oil and natural ...g counties (Atascosa, Bee, DeWitt, Dimmit, Frio, Gonzales, ...alle, Live Oak, Maverick, McMullen, Webb, Wilson and ...he six surrounding counties that serve as staging areas for ...as play. The latter include Bexar and Uvalde as well as ...Wells, Nueces and San Patricio counties. These supporting ... seen significant employment growth. For example, Bexar ...upported by the Eagle Ford now exceed 20,000, up from ...000 in 2011, according to the study.

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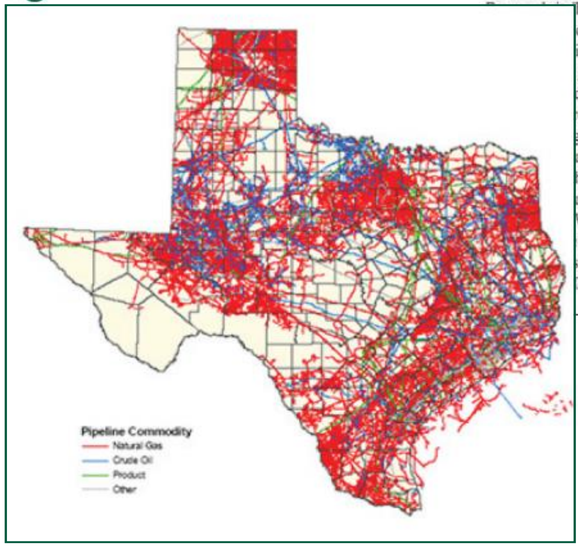


Sources: Harts NGI Shale Daily and Railroad Commission of Texas Eagle Ford Shale Task Force Report

Where are we heading?

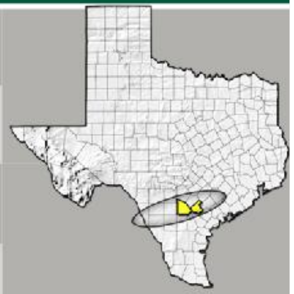
- Strong organic liquids production growth from the Sugarkane Field
- Focus on project execution and improvement of recovery factors in existing holdings
- Reach conclusions on appropriate density of drilling at Sugarkane by end 2013 and deliver development plan to that expanded well inventory and larger reserves base
- Bring Austin Chalk upside in to development plans and reserves
- Sugarkane assets self funding by end 2014
- Apply significant future cash generated to growth, debt maintenance and repayment, shareholder returns and opportunities

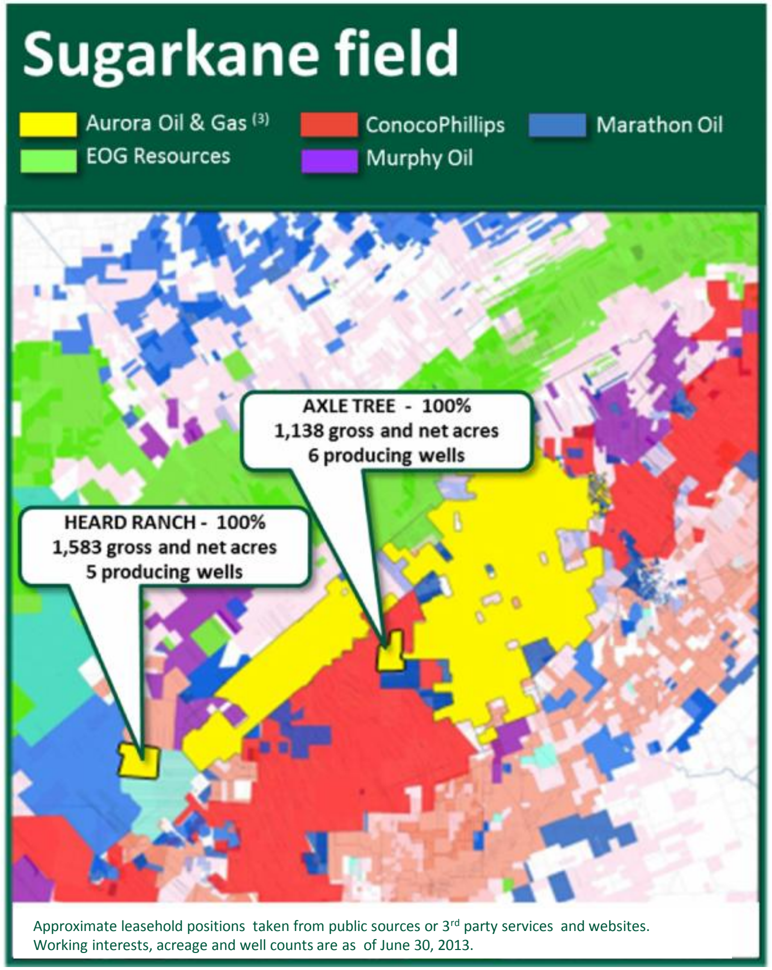
Operated Position

- 100% operated interest in ~2,700 net acres in Karnes and Atascosa counties - all held by production(1)
- Acquired end Q1 2013 with 11 producing wells
- 6.7 mmboe net 1P reserves, 84% liquids(2)
- Q2 2013 average daily gross production of 1,200 boe/d
- 4 wells spudded in 2nd Q 2013
- Upside potential from additional horizons

DRILLING UPDATE

- 1st well spudded end May 2013
- 2 rigs currently drilling
- 14 to 19 net wells planned to spud during 2013
- Development plan on 40 acre spacing
- Utilize knowledge from ~330 combined Operated & Non-Operated wells





(1) Acquired March 2013.
(2) Based on Aurora internal estimates as of March 2013.
(3) Jointly owned with Marathon Oil except for Heard Ranch and Axle Tree properties.

Non-Operated Position

- **Low risk, fully delineated Eagle Ford position**
  - 19,100 net acres
  - ~800 gross proved well locations based on predominantly 80 acre spacing
- **WI% from 28% to 36% in Karnes, and 9.1% in Atascosa Counties**
- **Q2 2013 average daily production of approx. 13,800 boe/d (net of royalties)**
- **30 to 32 net wells planned to be spudded in 2013**
- **19 net wells spudded first half 2013**

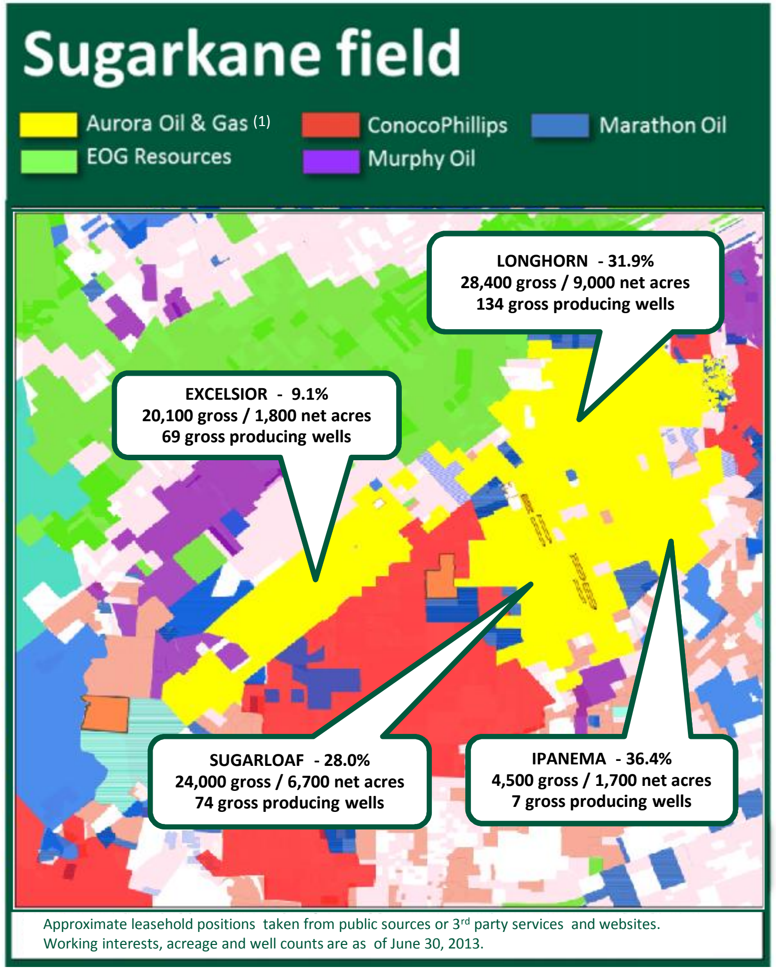
ADDITIONAL EVALUATIONS

Testing 60 and 40 acre Eagle Ford spacing via multiple pilot programs

Austin Chalk pilot programs underway

Pearsall potential being evaluated

Wellbore orientation, fracture stimulation techniques, production optimization

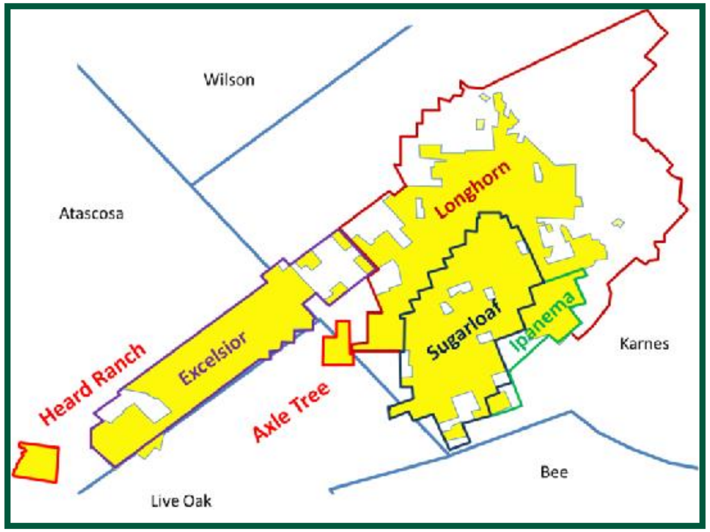


(1) Jointly owned with Marathon Oil and others.

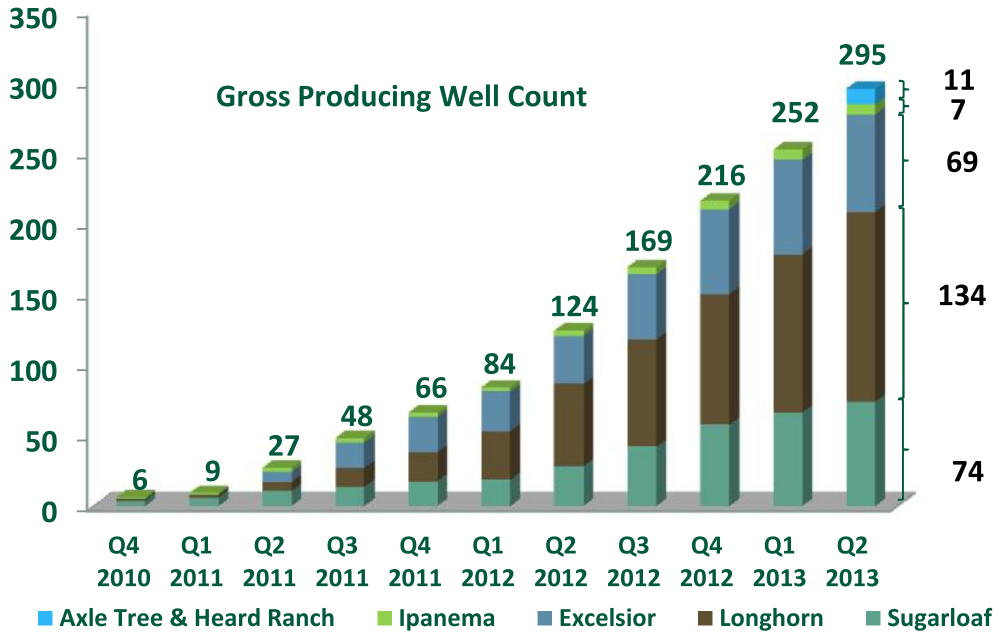
Operational advances

- **New drilling techniques enhancing already strong economics**
  - Longer laterals
  - Pad drilling
  - Down-spaced operated Eagle Ford to 40 acres
- **Expect December 2013 release on non-operated increased density**
- **New completion techniques adopted for "standard" development**
  - Zipper Frac
  - Hi-Way Frac
  - Proppant concentration/type
  - Fluid concentration/type
  - Choke management
  - Optimized artificial lift
- **Continuing to see improving IP rates on non-operated acreage – lessons transferable to adjacent operated acreage**
- **Well costs trending down due to operational efficiencies**

Well Status Summary



Sugarkane Field Project Areas

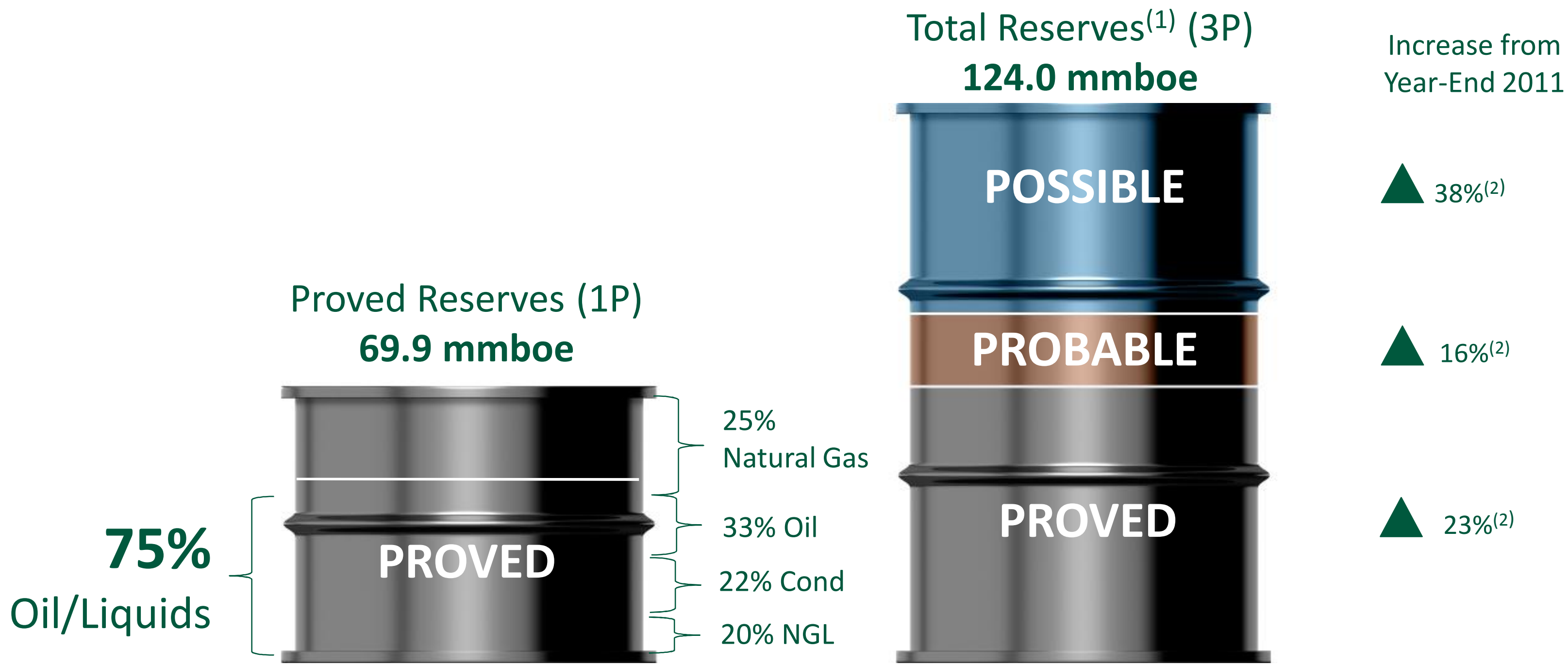


Gross Well Status June 30, 2013	Sugarloaf (28.1%)	Longhorn (31.9%)	Ipanema (36.4%)	Excelsior (9.1%)	Non-Operated Sub – total	Axle Tree & Heard Ranch (100%) (1)	Total
Producing	74	134	7	69	284	11	295
Stimulation Underway	3	3	0	2	8	0	8
Awaiting Stimulation	4	12	0	5	21	0	21
Drilling	6	3	0	0	9	2	11
Total	87	152	7	76	322	13	335

(1) Operated acreage acquired effective date March 1, 2013.

Reserves – Pre-March 2013 Acquisition

Net Proved Reserves at Year-End 2012					
Type	Oil (mmbbl)	Condensate (mmbbl)	NGLs (mmbbl)	Nat Gas (bcf)	Equivalent (mmboe)
Proved Developed	5.7	3.5	3.0	22.3	15.9
Proved Undeveloped	17.4	11.9	10.7	83.3	54.0
Total Proved Reserves	23.1	15.4	13.7	105.6	69.9

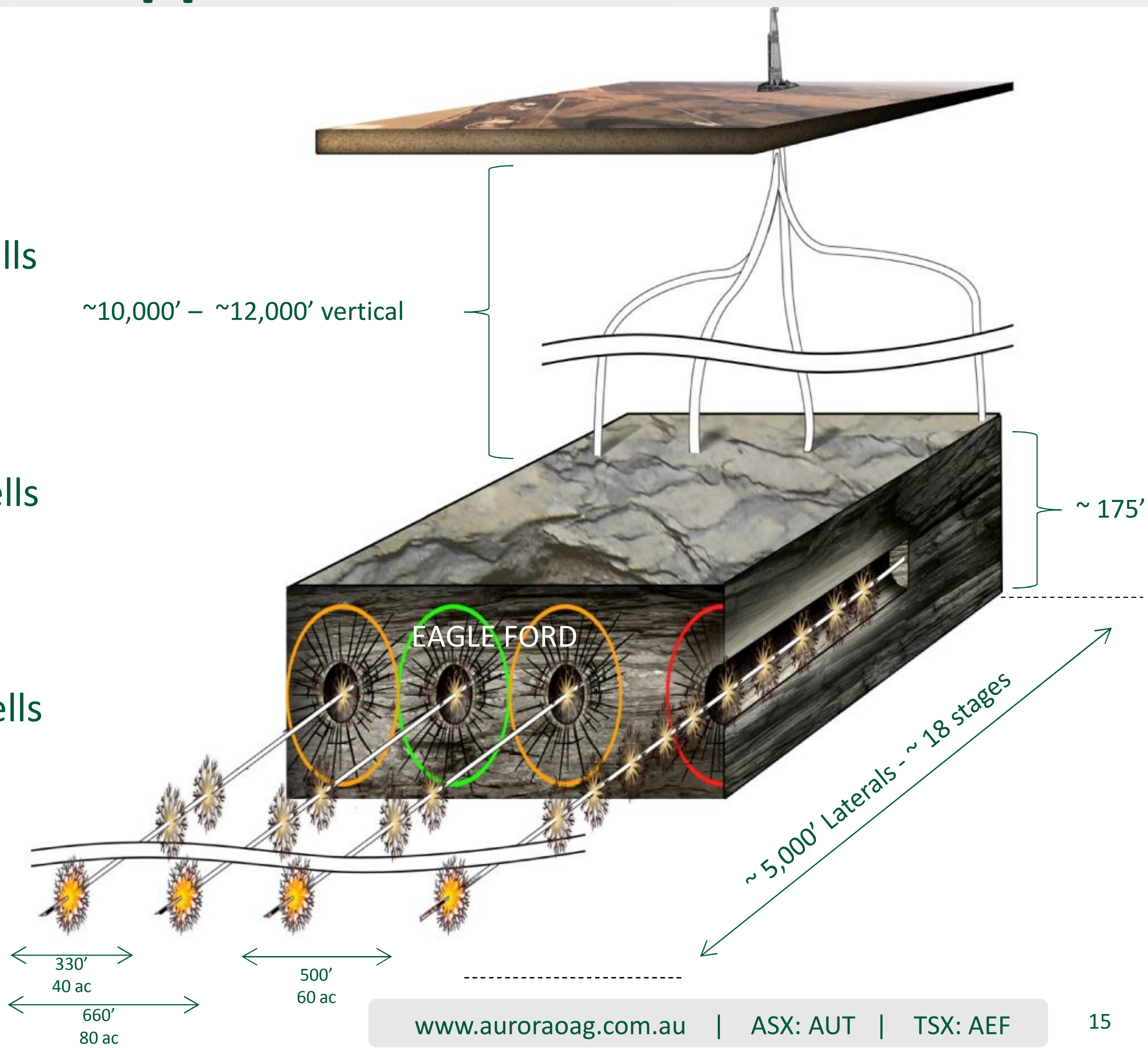


(1) Possible reserves are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will be equal to or exceed the sum of the proved plus probable plus possible reserves.
(2) Adjusted for 2012 production

Eagle Ford Infill Opportunities

Well Spacing

80 acre	660' between wells
60 acre	500' between wells
40 acre	330' between wells

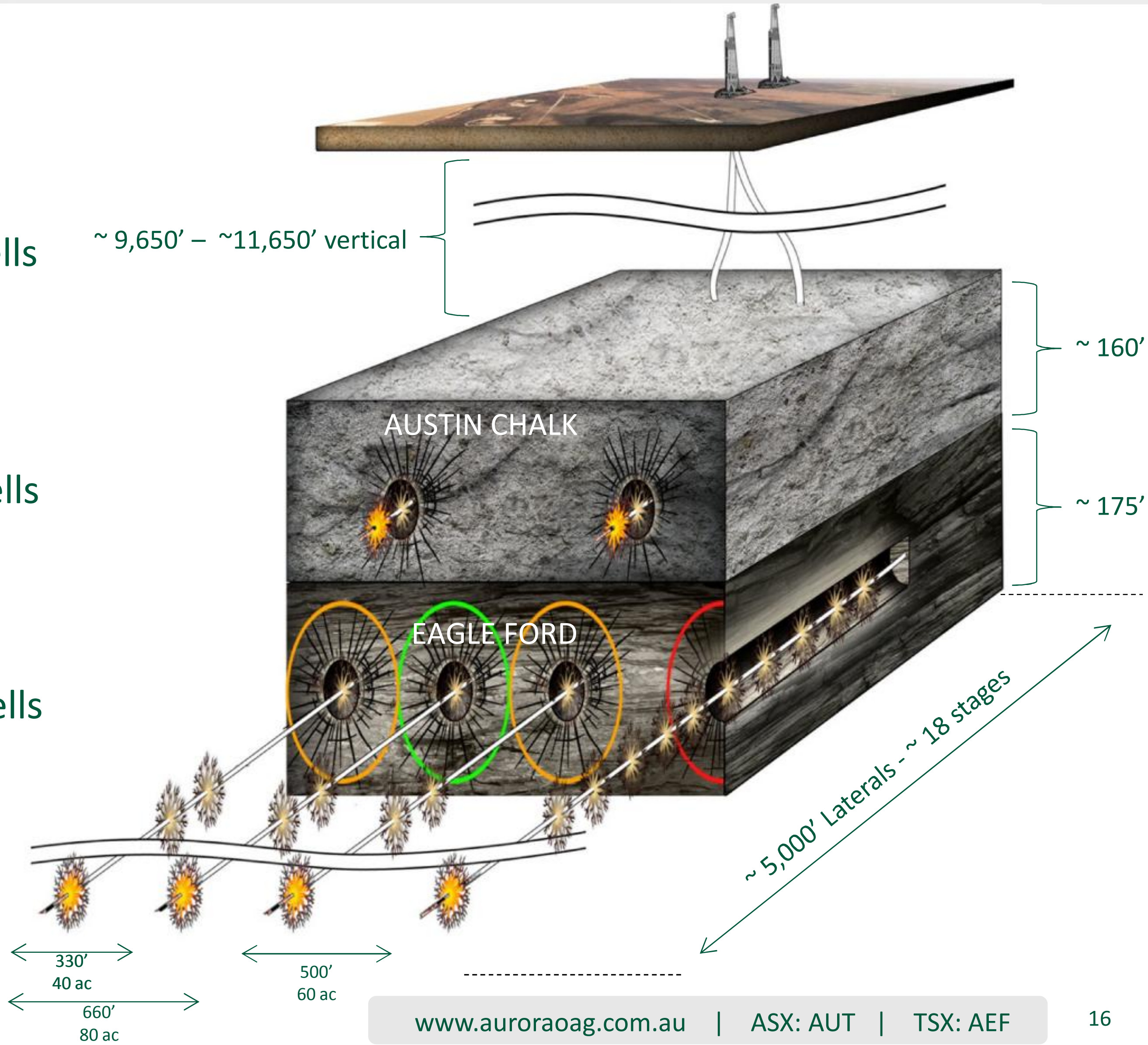


For illustrative purposes only. Not to scale.

Austin Chalk Horizontal Potential

Well Spacing

80 acre	660' between wells
60 acre	500' between wells
40 acre	330' between wells



For illustrative purposes only. Not to scale.

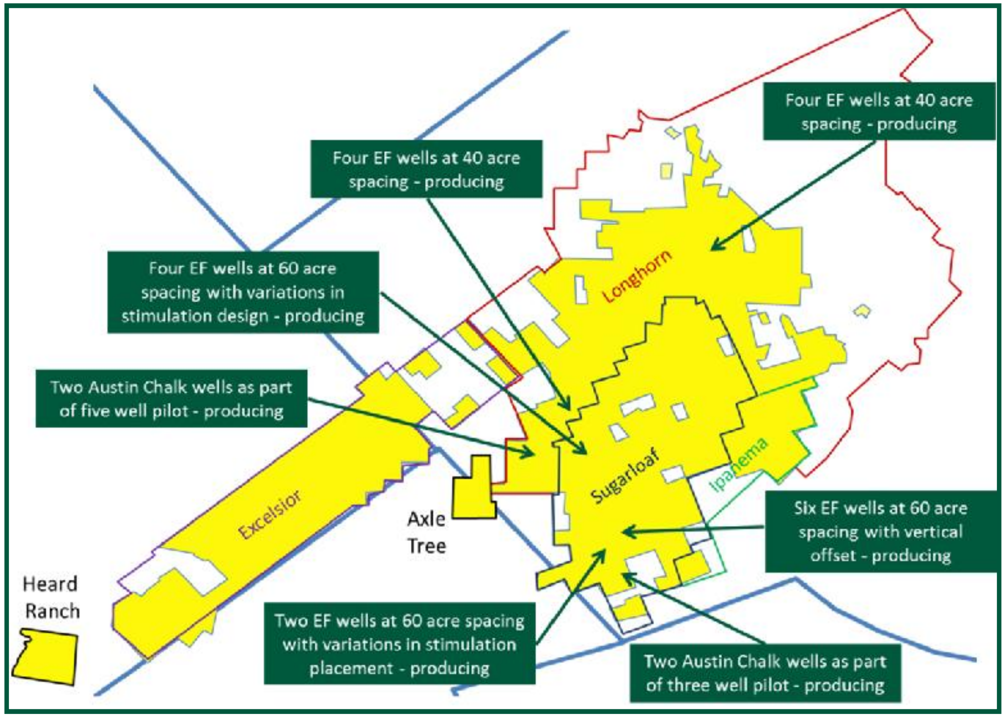
Update on Increased Density and Austin Chalk

Eagle Ford Down Spacing

- Pilot program has 6+ months of production history with results indicating comparable performance to 80 acre type curve
- More than 25% of Eagle Ford wells drilled to date are on less than 80 acre spacing
- 40 acre spacing development planned for recently acquired operated acreage

Austin Chalk Pilot Programs

- Original Feb '10 Austin Chalk well continues to perform
- 3 new wells in Pilot program:
  - 2 new Austin Chalk wells (60 acre spacing)
  - 1 deeper well spaced in between at deeper Eagle Ford horizon



- In separate up-dip pilot (located several miles away), completed 2 Austin Chalk wells and 3 Eagle Ford wells on similar 60x60 acre offset spacing
- Initial data shows variation in liquids content with vertical depth in a consistent manner to the Eagle Ford
- Additional Austin Chalk update planned for Q4 2013

Strong economics & balance sheet

Development Driving Profitability

Quarter by Quarter growth rates

Revenue[1] (US$mm)

EBITDAX[2] (US$mm)

Average Production (boepd)

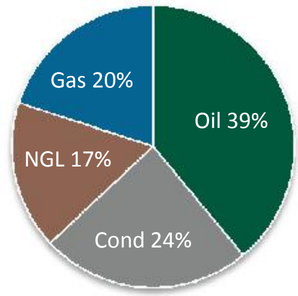
Full Year 2013 average production expected to be:
Pre-royalty: 19,700 – 21,900 boe/d compared to 2012 average of 10,680 boe/d
Post-royalty:14,500 – 16,200 boe/d compared to 2012 average of 7,860 boe/d

(1) Revenue from continuing operations and before royalties
(2) See "Non-IFRS Financial Measures" above. A reconciliation of net profit after tax to EBITDAX can be found in the appendices.

Aurora Production Mix and Netbacks – Q2 2013

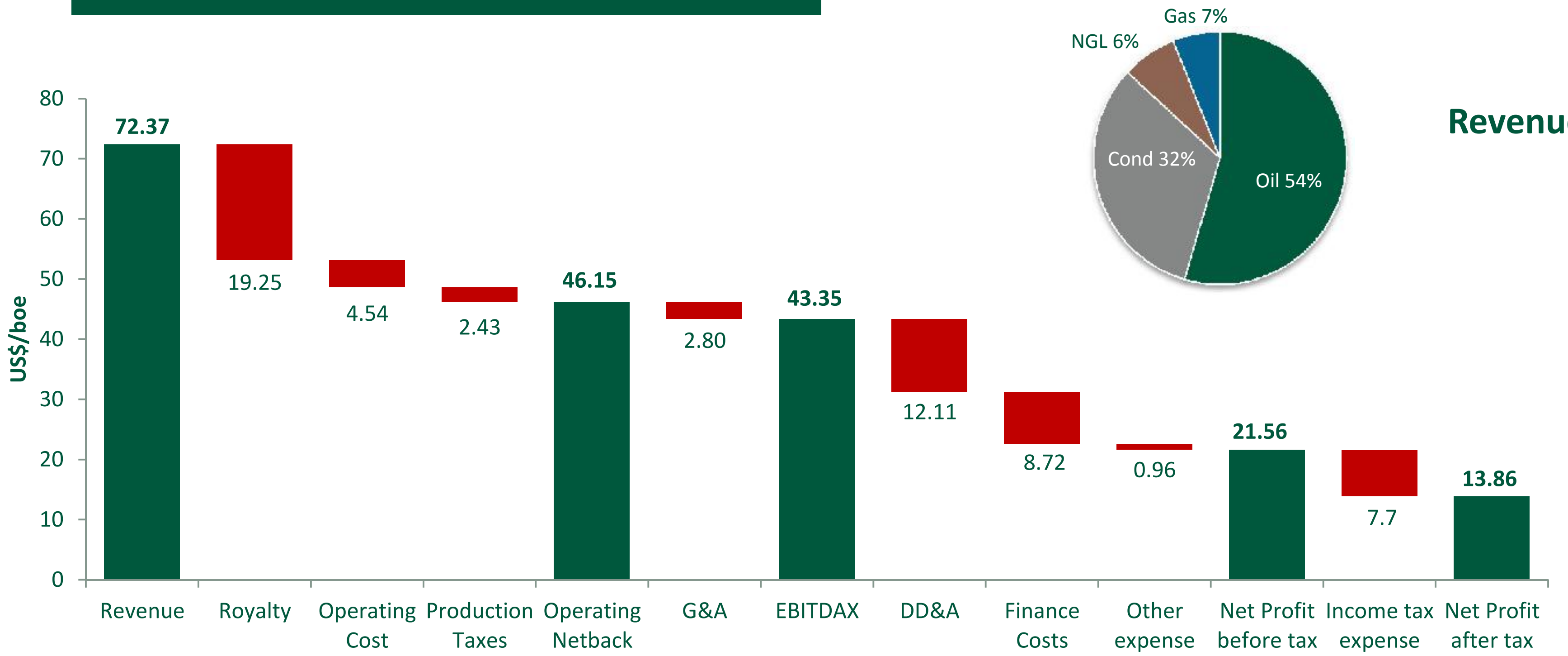
High Valued, Liquids weighted

Based on gross Q2 2013 production of 1.85 mmboe
- **Operating Netback US$46.15/boe**
- **EBITDAX[(1)] US$43.35/boe**
- **NPAT US$13.86/boe**



Production

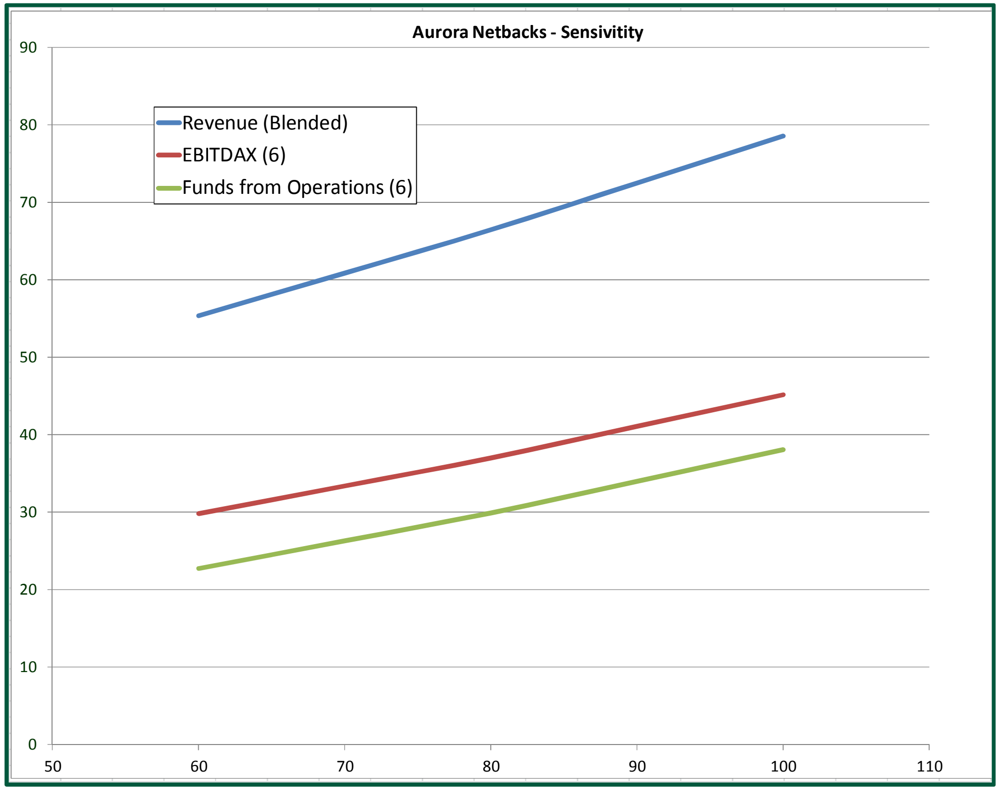
Revenue



(1) See “Non-IFRS Financial Measures” above. A reconciliation of net profit after tax to EBITDAX can be found in the appendices.

Netbacks – Sensitivities 2013

$/BOE



WTI

(1) See “Non-IFRS Financial Measures” above
(2) See the Netback details and assumptions in the appendices

Eagle Ford Economics

- Aurora’s Eagle Ford shale acreage is down the global cost curve
- All Sugarkane acreage is within the trend “sweet spot”
- Economics are less sensitive to commodity price changes
- Liquids generate more than 90% of revenue

Well Capitalised

- Strong liquidity with US$165mm cash and $200mm undrawn credit facility
- No principal maturities until 2017
- Maintain active commodity hedging program

US$ millions	Jun 30 2013
Cash	$ 165
Credit Facility	-
9.875 % Senior Notes due 2017	$ 365
7.50 % Senior Notes due 2020	$ 300
Total Debt	$ 665
Shareholder Equity	$ 511
Equity Market Capitalization(1)	$ 1,330
Total Debt/LTM EBITDAX(2)	2.5x
Total Debt/Annualized Q2 2013 EBITDAX(2)	2.1x
Net Debt/Annualized Q2 2013 EBITDAX(2)	1.6x
Interest Coverage(3)	5.5x
Total Debt/Book Capitalization	57%
Net Debt/Enterprise Value	27%

(1) Market Capitalisation based on ASX closing price of A$3.32 on August 1, 2013 using an exchange rate A$1=US$0.896
(2) See "Non-IFRS Financial Measures" above. A reconciliation of net profit after tax to EBITDAX can be found in the appendices
(3) Interest coverage is Q2 2013 EBITDAX / Q2 2013 Interest

Transaction fundamentals - disciplined execution

Assets

- Attractive underlying assets – including location, acreage quality and technical details
- Fit with existing assets
- Well-positioned properties vs competitors and infrastructure

Financing

- Ability for Aurora to finance the transaction without stressing balance sheet or diluting shareholders
- Ability to finance longer term development

Operational Impact

- Positive impact on overall portfolio
- Impact on scale
- Within management and/or technical expertise
- Positive impact on development/growth plan

Financial Impact

- Reasonable purchase price
- Positive impact on financial metrics such as NAV/share, cash flow/share

Appendices

Hedging Summary – as of August 1, 2013

	Swaps				Collars (no premium)			Total Volume		
	WTI (1)		LLS (1)		WTI (2)			Hedged		% of Estimated Production Jul-Dec 2013(3)
	Oil Hedged (mbbls)	Avg. Hedge Price US$/bbl	Oil Hedged (mbbls)	Avg. Hedge Price US$/bbl	Oil Hedged (mbbls)	Avg. Floor Price (US$/bbl)	Avg. Cap Price (US$/bbl)	Oil Hedged (mbbls)	Average (bbls/d)	
2013 (5 months)	319	95.2	45	95.4	188	79.0	103.4	552	3,608	16.3%
2014 (Full year)	962	91.0	-	-	270	80.0	98.7	1,232	3,375	
Total	**1,281**		**45**		**458**			**1,784**		

(1) Annualised hedge prices are weighted averages for the period
(2) Annualised floor and cap prices are averages for the period
(3) Based on guidance of 7.6mmboe for 2013 less 1st half 2013 actual production

EBITDA/EBITDAX Reconciliation

	Three months ended			LTM
	Jun 30, 2013 US$'000	Mar 31, 2013 US$'000	Dec 31, 2012 US$'000	June 30, 2013 US$'000
Net earnings after tax	25,694	29,611	23,798	95,116
Adjustments:				
Share based payments expense	1,489	1,374	1,102	4,956
Depreciation and depletion expense	22,451	17,915	15,036	69,519
Interest income	(23)	(10)	(23)	(87)
Finance costs	16,169	10,677	10,216	46,118
Foreign exchange (gain) / loss	362	44	14	392
Other income	(47)	(30)	(28)	(105)
Income tax expense	14,285	15,757	13,416	52,368
EBITDA	**80,380**	**75,338**	**63,531**	**268,277**
Exploration and evaluation costs	-	282	1,009	2,178
EBITDAX	**80,380**	**75,620**	**64,540**	**270,455**

See "Non-IFRS Financial Measures" above.

Funds from Operations Reconciliation

	Three months ended			LTM
	Jun 30, 2013 US$'000	Mar 31, 2013 US$'000	Dec 31, 2012 US$'000	Jun 30, 2013 US$'000
Net profit after tax	25,694	29,611	23,798	95,116
Add/(less) non-cash items				
Depletion, Depreciation and Amortisation expense	22,451	17,915	15,036	69,519
Amortisation of borrowing costs and discount /premium on financial instruments	1,333	777	815	4,065
Share based payment expense	1,489	1,374	1,102	4,956
Income tax expense	14,285	15,757	13,416	52,368
Net Foreign exchange loss/(gain)	362	44	14	393
Employee Benefit Provision	(13)	20	(26)	26
Funds from Operations	**65,601**	**65,498**	**54,155**	**226,443**

See "Non-IFRS Financial Measures" above.

Financial Summary – Selected Financial Data

Selected financial data

(US$ in thousands)	Qtr Jun-12	Qtr Sep-12	Qtr Dec-12	Qtr Mar-13	Qtr Jun-13	Qtr US$/boe Jun-13	12 Months to Jun-13
PRODUCTION:							
Total net production (boe) - pre-royalty	761,135	1,152,981	1,555,483	1,678,974	1,854,322		6,241,760
Total net production (boe) - post-royalty	559,438	852,480	1,147,650	1,238,671	1,368,246		4,607,047
Daily production (boe/d) - pre-royalty	8,364	12,532	16,907	18,655	20,377		17,101
Daily production (boe/d) - post-royalty	6,148	9,266	12,474	13,763	15,036		12,622
REVENUES:							
Oil and gas revenues	57,341	85,452	112,496	127,539	134,190	72.37	459,677
Royalties	(15,403)	(22,528)	(29,302)	(34,160)	(35,698)	(19.25)	(121,688)
Net Operating Income	**41,938**	**62,924**	**83,194**	**93,379**	**98,492**	**53.12**	**337,989**
EXPENSES:							
Operating expenses	(4,999)	(7,417)	(8,523)	(9,718)	(8,415)	(4.54)	(34,073)
Production taxes	(1,907)	(2,925)	(3,859)	(4,231)	(4,512)	(2.43)	(15,527)
Operating Netback	**35,032**	**52,582**	**70,812**	**79,430**	**85,565**	**46.14**	**288,389**
Administrative expenses	(3,393)	(2,666)	(6,272)	(3,810)	(5,185)	(2.80)	(17,933)
EBITDAX	**31,639**	**49,916**	**64,540**	**75,620**	**80,380**	**43.35**	**270,456**
Depletion, depreciation and amortisation (non cash)	(7,250)	(14,117)	(15,036)	(17,915)	(22,451)	(12.11)	(69,519)
Other income / expenses	5,063	58	37	(4)	(292)	(0.16)	(201)
Interest expense	(4,910)	(7,637)	(9,119)	(9,708)	(14,580)	(7.86)	(41,044)
Amortisation of borrowing costs and premium/discounts and finance costs	(612)	(1,419)	(1,097)	(969)	(1,589)	(0.86)	(5,074)
Share based payment expense (non cash)	(1,078)	(991)	(1,102)	(1,374)	(1,489)	(0.80)	(4,956)
Exploration and evaluation costs	(2,564)	(887)	(1,009)	(282)	-	0.00	(2,178)
Net profit before tax	**20,288**	**24,923**	**37,214**	**45,368**	**39,979**	**21.56**	**147,484**
Income tax expense – Accrual [(1)]	(9,958)	(8,910)	(13,416)	(15,757)	(14,285)	(7.70)	(52,368)
Net profit after tax	**10,330**	**16,013**	**23,798**	**29,611**	**25,694**	**13.86**	**95,116**

(1) This represents a movement in the deferred tax provision for future taxes payable. No income tax is expected to be due/paid for 2012 or 2013 based on the current forecast plans for 2013.

aurora OIL&GAS LIMITED

Netbacks – Sensitivities 2013

	2012 Actual	*2013 Illustrative* [3]					Q2 2013 Actual
US$/bbl or US$/Mcf							
WTI	94.22	100	90	80	70	60	94.50
LLS	110.66	113	103	93	83	73	111.90
Aurora realised Oil [1] [2]	100.21	105	95	85	75	65	99.33
Aurora realised Condensate [1] [2]	98.43	103	93	83	73	63	98.23
Aurora realised Gas	2.9	3	3	3	3	3	4.04
Aurora realised NGLs	32.71	30	30	30	30	30	31.50
Netbacks	**$/boe**	**$/boe**	**$/boe**	**$/boe**	**$/boe**	**$/boe**	**$/boe**
Revenue (Blended)	75.43	78.53	72.48	66.43	60.85	55.33	72.37
Royalty	(19.86)	(20.57)	(18.81)	(17.04)	(15.27)	(13.50)	(19.25)
Opex	(6.27)	(6.27)	(6.27)	(6.27)	(6.27)	(6.27)	(4.54)
Taxes	(2.58)	(2.69)	(2.48)	(2.27)	(2.08)	(1.89)	(2.43)
G&A Exp [4]	(3.87)	(3.87)	(3.87)	(3.87)	(3.87)	(3.87)	(2.80)
EBITDAX [6]	**42.85**	**45.13**	**41.05**	**36.98**	**33.36**	**29.80**	**43.35**
Interest [5]	(6.28)	(7.09)	(7.09)	(7.09)	(7.09)	(7.09)	(7.86)
Other	(0.68)	-	-	-	-	-	(0.11)
Funds from Operations [6]	**35.8**	**38.03**	**33.96**	**29.88**	**26.26**	**22.70**	**35.38**

[1] 2012 realised average premium to WTI of US$4/bbl for condensate and US$6/bbl for oil

[2] 2013 illustrative assumed conservative premium to WTI of US$3/bbl for condensate and US$5/bbl for oil

[3] 2013 illustrative figures assume production of 7.6 MMboe (before royalty) and a similar product mix to 2012 and includes the effect of 974,100 bbls of crude hedging

[4] 2013 illustrative G&A has been maintained at the 2012 cost per boe for purposes of this illustration

[5] Financing costs for 2013 illustrative includes interest expense for all existing debt and expected drawdowns on RBL debt

[6] See "Non-IFRS Financial Measures" above. A reconciliation of net profit after tax to EBITDAX can be found in the appendices.