3 October 2011

Company Announcements Platform
Australian Stock Exchange
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COMPANY PRESENTATION MATERIAL

Please find attached to this document a copy of the presentation slides to be used by Aurora Oil & Gas Limited at investor presentations being conducted this week in North America.

For Aurora Oil & Gas Limited

Julie Foster
Company Secretary

(Data referencing activities in adjacent acreage has been sourced from publically available information)

Technical information contained in this report in relation to the Sugarloaf project and Sugarkane field was compiled by Aurora from information provided by the project operator and reviewed by I L Lusted, BSc (Hons), SPE, a Director of Aurora who has had more than 19 years experience in the practice of petroleum engineering. Mr Lusted consents to the inclusion in this report of the information in the form and context in which it appears.

Aurora Oil and Gas Limited

Update

October 2011

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This document has been prepared by Aurora Oil & Gas Limited ("**Aurora**") in connection with providing an overview to interested analysts / investors and is being provided for the sole purpose of providing preliminary background financial and other information to enable recipients to review the 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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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; 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.

Regarding 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 August 2011, and are derived from the reserves report of Netherland Sewell & Associates, Inc ("NSAI") dated September 29, 2011 ("NSAI Report"). NSAI is a qualified independent reserves evaluator under the Canadian Securities Administrators National Instrument 51-101 – standards of Disclosure for Oil and Gas Activities ("N1 51-101").

Defined Reserves and Resource Terms

- "2P reserves" means proved plus probable reserves.
- "3P reserves" means proved plus probable plus possible reserves.
- "bbl" means barrel.
- "boe" means barrels of oil equivalent, determined using a ratio of 6 Mcf of raw natural gas to 1 bbl of condensate or crude oil, unless otherwise stated. There are now allowances for NGLs within quoted boe figures in this presentation.
- "scf" means standard cubic feet.
- "btu" means British thermal units
- "m" prefix means thousand.
- "mm" prefix means million.
- "b" prefix means billion.
- "pd" suffix means per day.
- 'NGL" – Natural Gas Liquids – these products are stripped from the gas stream at 3rd party facilities remote to the field.

Boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mscf: 1bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Management uses certain industry benchmarks such as operating netback to analyse financial and operating performance.

Operating netback, as presented, represents revenue from production less royalties, state taxes, transportation and field 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.

Overview

- High growth oil and gas producer with significant onshore acreage in the core of the Eagle Ford Shale, Texas – one of the world's premier shale regions.
- Aurora (ASX:AUT) is part of the S&P/ASX200 Index and listed in Canada (TSX: AEF).
- Strong balance sheet with cash reserves and undrawn, credit approved, $300m reserves based syndicated revolving facility with signed term sheet, initial drawdown capacity of $85m growing with increases in proved reserves.
- 79% of current production and over 90% of forecast revenue is from liquids.
- 2011 – 69 new gross wells spudded for total of 89 (16 net) – funded.
- 2012 – 123 new gross wells to be spudded (33 net) – funding arranged.
- Conversion of majority 3P to 2P reserves anticipated to occur within the current year.
- Current net production approx. 3,140 boepd post royalties[1].
- Estimated exit production 2012 approx. 14,000 boepd post royalties (18,900 boepd pre royalties).
- Sugarkane field offers scalable, low risk, profitable growth.

[1] as at 27 September 2011

Corporate Summary

Key Facts	
Fully Paid Ordinary Shares	411,155,343
Options on issue (varied prices)	6,000,000
Executive Performance Shares	2,400,000
Fully diluted Capital	419,555,343
Cash at 30 June 2011	US$50m
Debt	Nil

Board of Directors			Shareholding
Jon Stewart	Chairman & CEO	Australian	18.5 m
Graham Dowland	Finance Director	Australian	2.2 m
Ian Lusted	Technical Director	Australian	1.3 m
Fiona Harris	Non Executive	Australian	0.1 m
Gren Schoch	Non Executive	Canadian	5.2 m
William Molson	Non Executive	Canadian	1.3 m
Alan Watson	Non Executive	British	1.0 m

History

Exploration Discovery

- Partnered Texas company with regional approach to exploration.
- 2006 Sugarkane Eagle Ford discovery followed by initial 2 year land acquisition program.

Successful farm-out

- Successful 2009 farm-out to Hilcorp Energy delivered a portfolio of producing wells with outstanding results.
- Exciting exploration/appraisal project was transitioned to a large low risk development project during 2010.
- Installation of larger efficient operator reduced project execution risk.

Reserves expanded

- 48% increase in December 2010 3P reserves following acquisition of additional Sugarkane working interest.
- Active 2011 development drilling program converting majority of 3P reserves to 2P category by year end 2011.

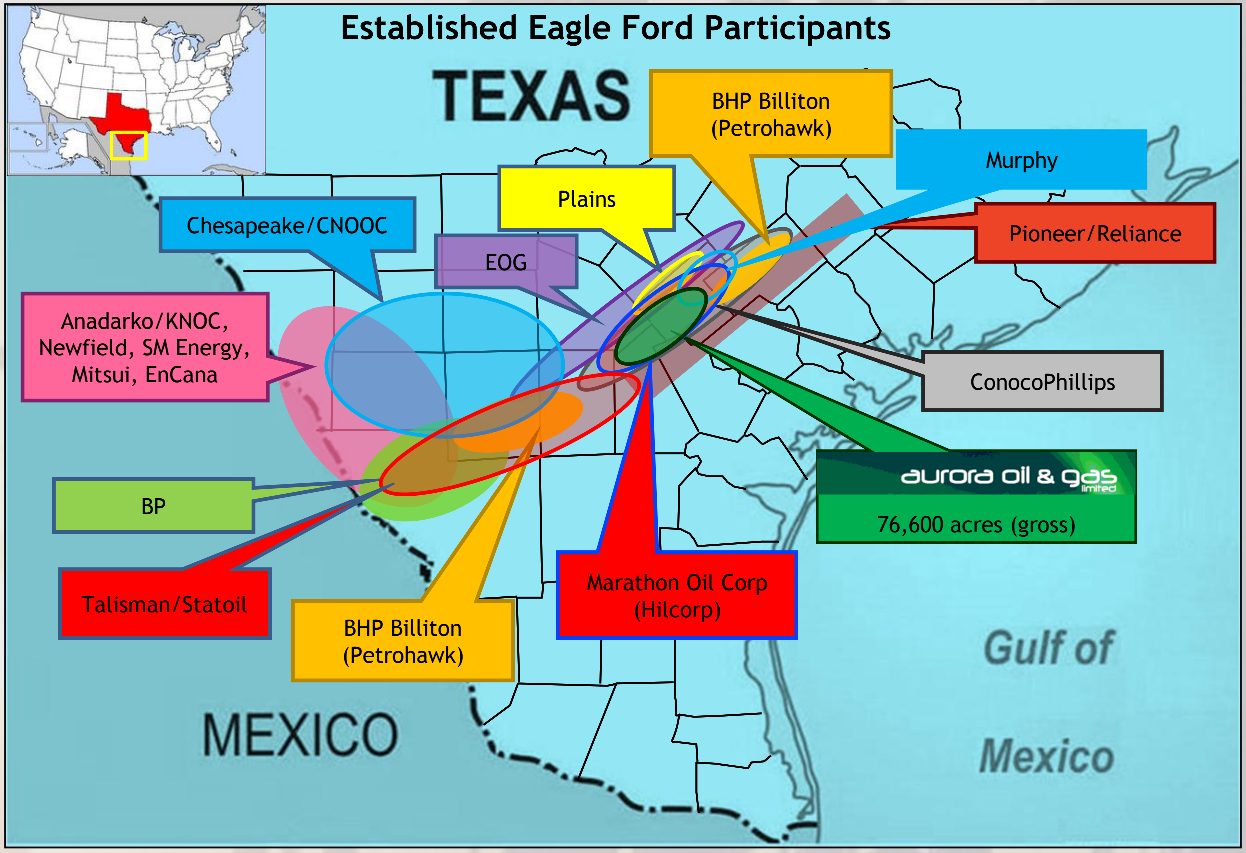
Production ramping up

- Current net production approx. 3,140 boepd after royalties.
- 2011 Hilcorp EF sale to Marathon Oil will accelerate development.

Majors scrambling for Eagle Ford acreage

- The Texas Eagle Ford shale is currently the most active oil and gas A&D market in the USA.
- $13+ billion of deals since June 2010, including:
  - BHP acquisition of Petrohawk Energy
  - Marathon Oil $3.5 billion acquisition of Hilcorp Eagle Ford acreage
  - Royal Dutch Shell
  - Talisman and Statoil
  - CNOCC
  - Reliance Industries
  - KNOC
- Further consolidation expected.
- Over 200 rigs now operating across the trend with continued significant ramp-up of development activities planned for the 2012.
- Aurora established an early foothold and is the "pure play" mid-cap producer in the "sweet spot" providing significant leverage to the upside potential that many are now recognising.

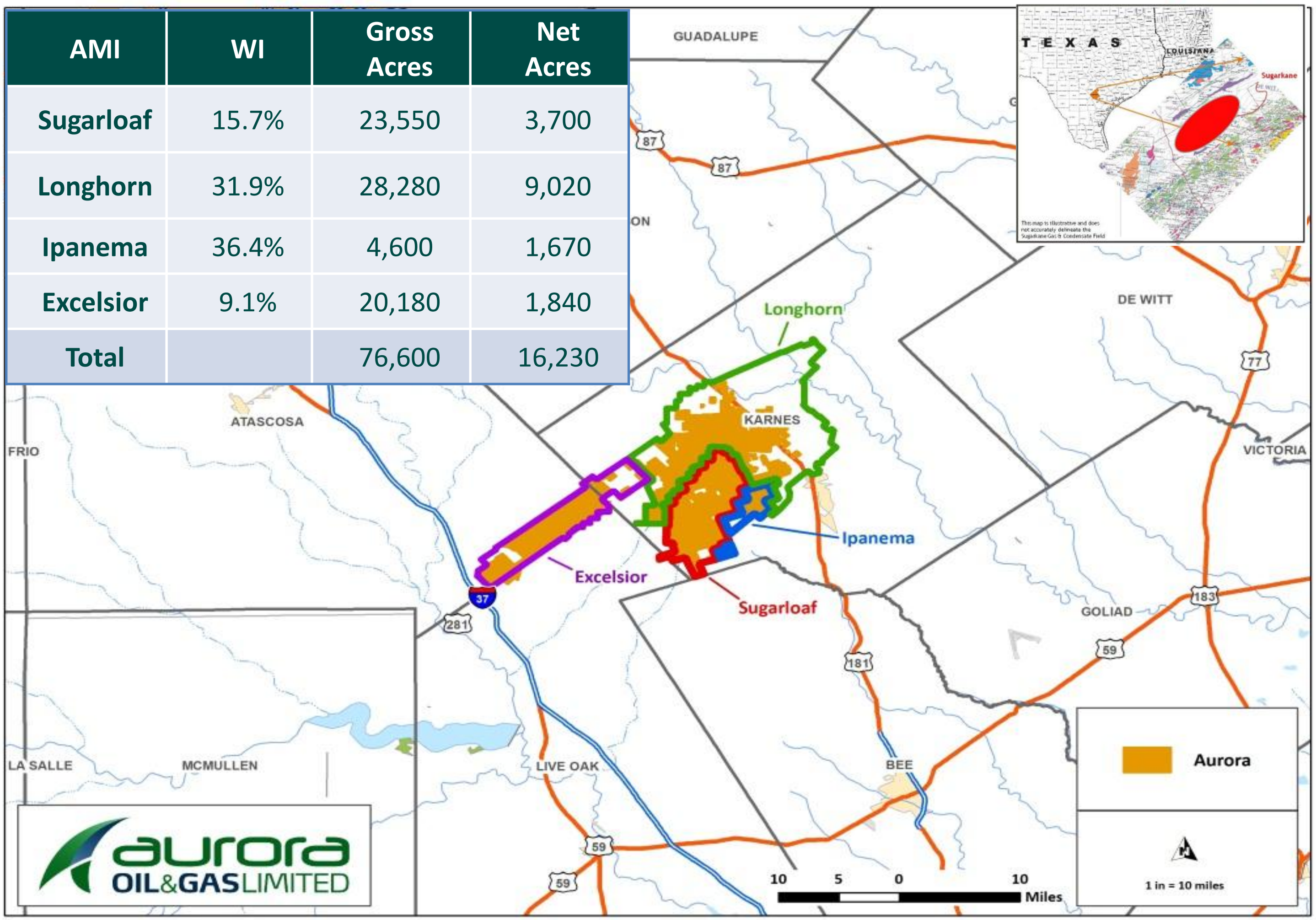
Eagle Ford - the world's premier shale region



- Uniform, continuous and predictable shale across the play.
- Majority of Eagle Ford trend is economic but some is very economic.
- Major US shale players continuing to refocus their portfolios towards liquid rich shales.

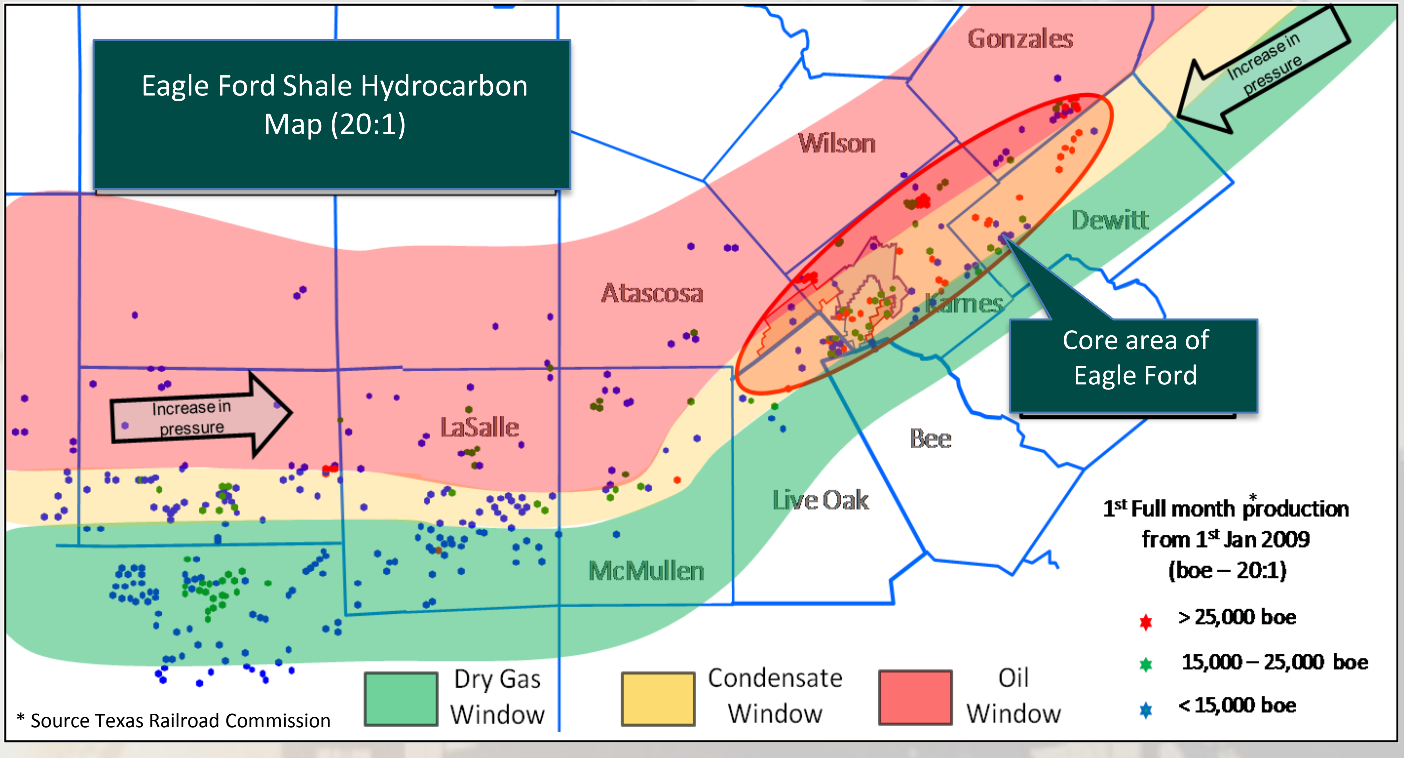
Sugarkane Gas and Condensate Field Holdings

AMI	WI	Gross Acres	Net Acres
Sugarloaf	15.7%	23,550	3,700
Longhorn	31.9%	28,280	9,020
Ipanema	36.4%	4,600	1,670
Excelsior	9.1%	20,180	1,840
Total		76,600	16,230



Source: Aurora

Prime acreage position within Eagle Ford core area



- Sugarkane is entirely within the 'sweet spot' of the Eagle Ford Shale determined by economic well performance.
- Sugarkane is within the gas-condensate and "volatile" (gas rich) oil windows.
- Very high liquids content and significantly over pressured resulting in high productivity and strong economics.

High growth and valuation upside potential

- Fully funded drilling program underway (89 wells spudded by year end – approx. 212 wells to be spudded by end 2012).
- Continued material uplift in 1P & 2P reserves being delivered via 2011 drilling program
- Optimising drilling, completion and production processes.
- Significant upside potential from tighter well spacing.
- Marathon Oil announced plan to ramp up core area development which will drive production and cash flow generation.
- Leverage to oil price.

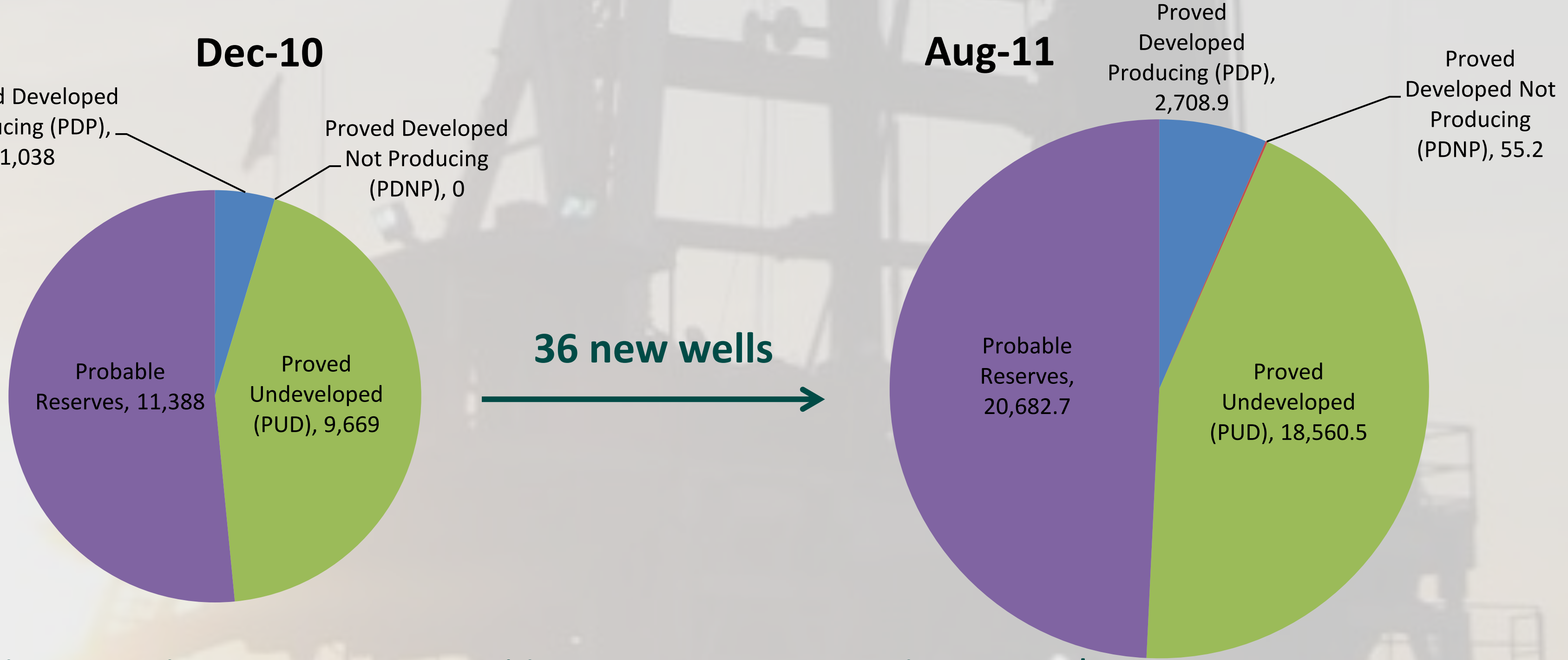
NSAI Reserve Report

Proven and Probable Reserves as at 31 August 2011[1]

Aurora Gross Reserves (before royalty interests)[2,3]	pre royalty interests: Light and Medium Oil (mbbls)	pre royalty interests: NGLs and Condensate (mbbls)	pre royalty interests: Natural Gas (mmcf)	pre royalty interests: BOE[4] (mbbls)	post royalty interests: Light and Medium Oil (mbbls)	post royalty interests: NGLs and Condensate (mbbls)	post royalty interests: Natural Gas (mmcf)	post royalty interests: BOE[4] (mbbls)
Proved Developed Producing	1,332.0	1,418.1	5,479.3	3,663.3	984.1	1,049.2	4,053.8	2,708.9
Proved Developed Not Producing	33.8	17.1	144.2	74.9	24.9	12.6	106.4	55.2
Proved Undeveloped	6,361.3	12,142.9	39,563.4	25,098.1	4,684.9	8,994.3	29,287.9	18,560.5
Total Proved (1P)	7,727.1	13,578.1	45,186.9	28,836.4	5,693.9	10,056.1	33,448.1	21,324.7
Probable	6,759.1	13,645.7	45,249.8	27,946.4	4,977.4	10,117.4	33,527.6	20,682.7
Proved + Probable (2P)	14,486.2	27,223.8	90,436.8	56,782.8	10,671.3	20,173.5	66,975.6	42,007.4

1. The reserves have been prepared in accordance with Canadian National Instrument 51 – 101.
2. Numbers in this table are subject to rounding errors.
3. NGL's currently trade at approximately 50% of West Texas Intermediate ("WTI") crude prices.
4. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: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.

Transformational uplift in 2P reserves under way



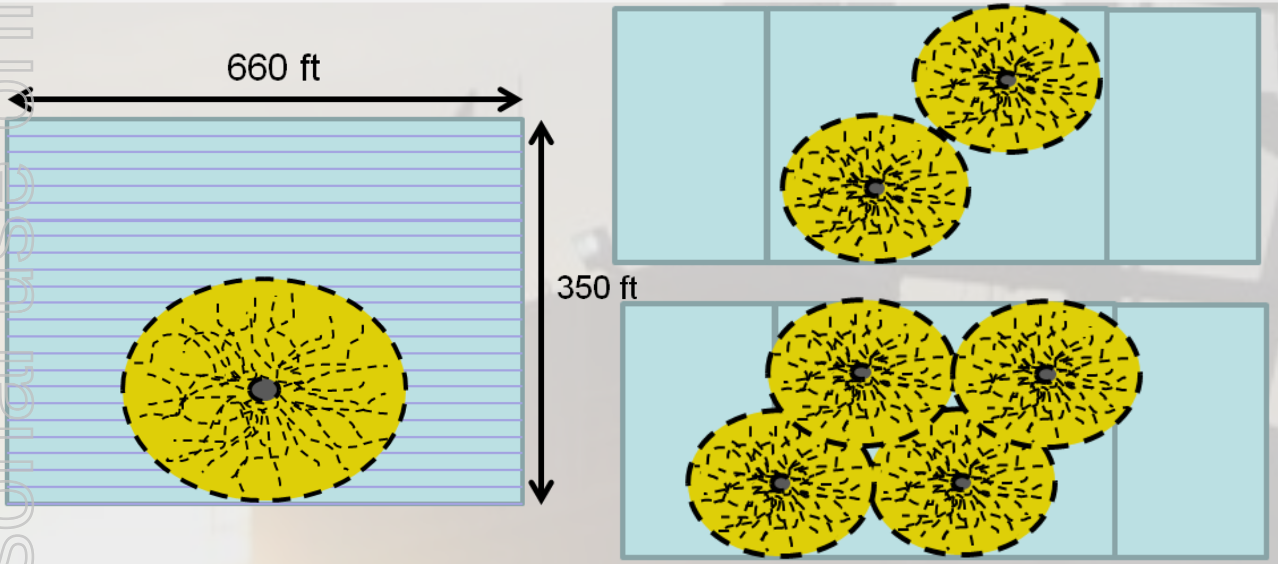
- 90% increase in 2P reserves, 99% increase 1P reserves in 8 months.
- Confident of continued rapid growth in 2P category via balance of 2011 drilling program.
- Further increases in Proved reserves will enable additional borrowing base / drawdown capacity from US$300m debt facility.

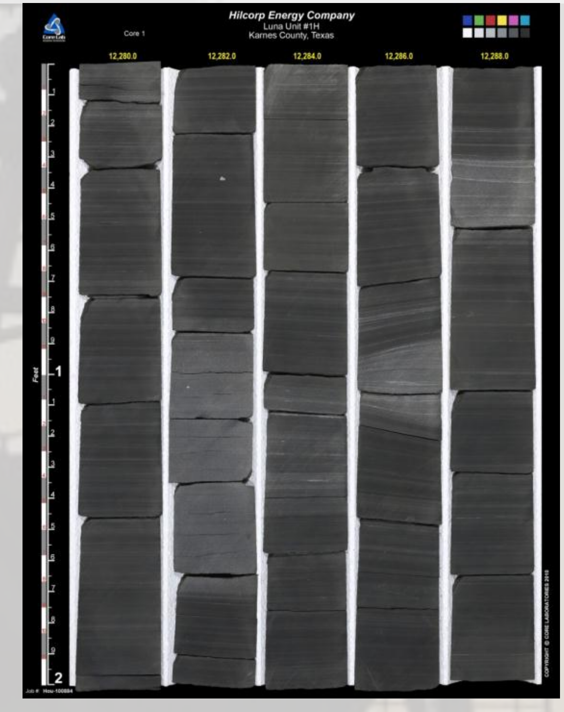
1. The comparison shown is between the NSAI 31 December 2010 and the updated 31 August 2011 reserve report.
2. Figures shown in chart are mbbls BOE. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method. primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Significant upside potential for reserves

- Early production performance is consistent and should deliver higher well EUR's and reserves growth in due course.
- The reserve report effective as at August 31, 2011 and drilling inventory is based on 80 acre spacing. Competitors in the area are now looking at development based on 50 - 60 acre spacing. In other more mature shale plays 40 acre spacing is being used or tested.
- Within Sugarkane field, but not typically within the Eagle Ford, the Austin Chalk is economic with very similar productivity and liquids ratios to the Eagle Ford (the Chalk transitions in to the EF across Aurora's acreage). Numerous wells have and continue to be produced from the Austin Chalk within Sugarkane field. Development on two levels will be tested to efficiently harvest the full productive section.

Improved recoveries - well spacing requires testing





- Current reserve estimates based on 80 acre spacing result in ~5% recoveries of in place volumes in the volatile oil window and 10% in the gas condensate window. With our strong economics this is too low!
- With 5,000 ft horizontals, 80 acre drainage is 660 ft wide and up to 350 ft thick.
- Fracs designed with <200ft radius and stimulation dissipates with distance from well bore.
- Gravity negatively impacts on ability to place propant vertically.
- Horizontal laminations (see core picture) - preferential horizontal propagation of fractures.
- Will adjacent frac interference improve fracture complexity and improve recoveries?
- Two wells in each block? Four wells in each block? ... Spacing is not limited by regulations.

Operations update and outlook

- 5 rigs increasing to 10 - 12 during 2012.
- 2 frac crews increasing to 4 during 2012.
- 57 gross (8.4 net) wells now on production, 65 in total drilled and 4 wells underway.
- Plan to drill 69 wells in 2011, taking total to 89 wells.
- 2012 – 123 wells to be spudded taking total to 212.
- Current net production approx. 3,140 boe per day (after royalties). On a blended average basis this equates to 500 boepd per well.
- Achieving consistently good results – incremental improvements expected via well design, stimulation and flow control.
- Highly contiguous acreage position excellent for development with drilling locations currently dictated by lease expiry schedule which runs through 2014.
- Leases held by production ("HBP") by Q3 2012.
- Centralised processing facilities being installed – 3 completed, 6 by year end across field and 9 planned in total.

Accelerated drilling to have significant impact

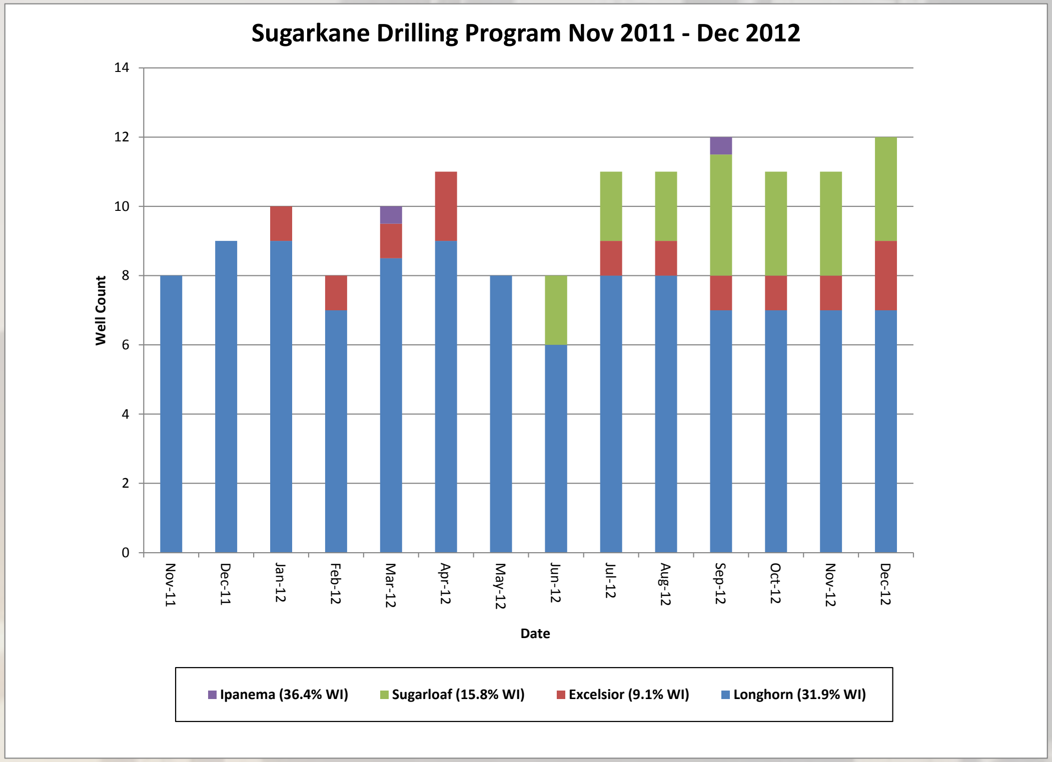
Operating		2011 Estimate	2012 Estimate	2013 Estimate
Number of wells to be drilled	gross	69	123	144
	Net to Aurora	16	33	37
Production run rate y/e – pre royalties	boepd	5,590	18,900	25,600
Annual production - post royalties	boe	870,000	3,200,000	6,100,000
Financial				
Production revenue – post royalties		$60m	$195m	$350m
Run rate revenue y/e – post royalties		$90m	$290m	$400m
Estimated debt facility drawdown each year		$10m	$145m	$10m

- Marathon has advised the planned 2012 drilling program. It includes approx. 90 wells within Longhorn AMI and drilling in Sugarloaf and Ipanema in Q3 and Q4 2012.
- The acceleration of development defers cashflow breakeven to 2013.
- The 2013 estimate does not assume any further build up in rig allocation to Aurora's acreage. Management consider it likely that further rigs would be added in 2013 but do not have Operator confirmation of this.

(1) Based on Management estimates. Revenue calculated on $80/bbl and $3.50/mscf. Drilling program in 2011 & 2012 based on Marathon planned development program. 2013 program assumes 12 gross wells drilled each calendar month.

(2) Debt facility has been credit approved with an initial borrowing base amount of $85m (based on proved reserves as at 31 Aug 2011). This facility has the ability to extend to $300m as proved reserves increase . The facility is currently being finalised and is subject to satisfaction of customary conditions precedent.

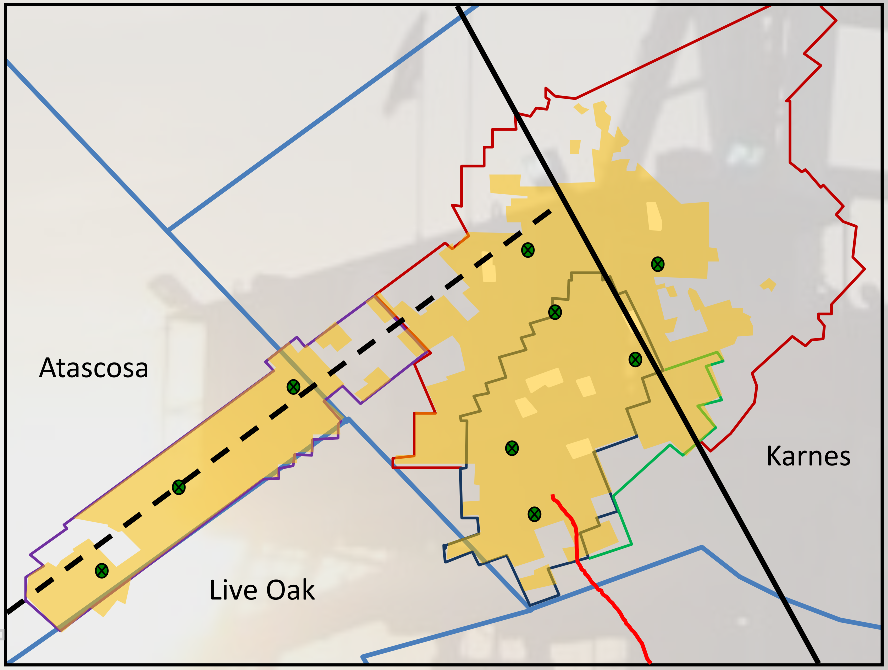
2012 Drilling Schedule



- Plan to spud 123 gross (33 net) wells in 2012.
- Rapid development of acreage with focus from operator.
- Acceleration of production profile – assume a 12 well/month program going forward from 2013 leads to peak net production of 24,000 boepd in 2016.

Accessible routes to market via existing infrastructure

Infrastructure overview



- Existing Oil Pipeline – 20,000 bbls capacity / 6,000 bpd contract
- Planned Oil Pipeline – 40,000 bbls capacity / 20,000 bpd contract
- Existing Wet Gas Pipeline – 57.5 mmscf/d contract (planned 80 mmscf/d)
- Locations of centralised infrastructure
- Sugarkane Leases

Source: Company information.

Map opposite shows Aurora gross acreage, AMI boundaries and local counties.

- Locations of centralised facilities shown (field gathering system not shown).
- Solid black line shows existing oil export pipeline – 20,000 bpd capacity and presently contract 6,000 bpd.
- Dotted black line shows planned 3 Rivers system due 1/1/12 – 40,000 bpd capacity with contract in place for 20,000 bpd.
- Remaining oil presently trucked to refinery.
- Red line shows wet gas export line, connects to two 3rd party lines – presently contract 57.5 mmscf/d negotiations to increase to 80 mmscf/d by approx Nov 2011.

Large 3rd party gas and oil lines presently under construction, considerable additional capacity in area is expected during 2012.

Production increases generating profit growth

Financial		3 months ended 30 June 2011 US$'000	3 months ended 31 March 2011 US$'000	Increase %
Production revenue		17,416	6,721	159%
Funds from operations		10,006	3,569	180%
Net earnings after tax		12,518	3,683	240%
Net earnings ($/boe)		55.05	38.90	42%
Net Capex		26,005	11,454	127%
Operating				
Production – pre royalties	boepd	2,499	1,052	138%
Prod. Rev (Ave product prices)	$/boe	76.57	70.99	8%
Royalties	$/boe	20.98	18.81	12%
Operating expenses	$/boe	5.59	4.70	19%
Operating netback	$/boe	50.00	47.48	5%

Key data

2011 Funding Arrangements	US$'000
Opening cash	85,760
Cash at 30 June 2010	50,000
Est. cash from operations (excl. Capex) [1]	41,000
Capital program [1]	100,000
Debt Facility – 5 year, $300m, reserves based revolver - initial drawdown availability	85,000

(1) Aurora Management calculation is based on actual results to date and the estimated drilling schedule for the remainder of 2011. The estimated cash flow is based on a number of assumptions for Well cost, Opex and G&A. It is also based on an average oil price of $80/bbl and $3.50/mscf

A pure investment in the core area of the Eagle Ford

- Prime acreage position.
- High profits from liquids rich production.
- Active drilling program underway – 89 gross wells by year end.
- Accelerated development program from 2012.
- Ideal macro environment for US onshore oil development.
- Significant upside potential from:
  - Reserves transition - 3P reserves reclassification to 2P category.
  - Production optimisation.
  - Higher recoveries (tighter well spacing).
- Sharp ramp up in development accelerating production and cash flow generation.

Additional Slides

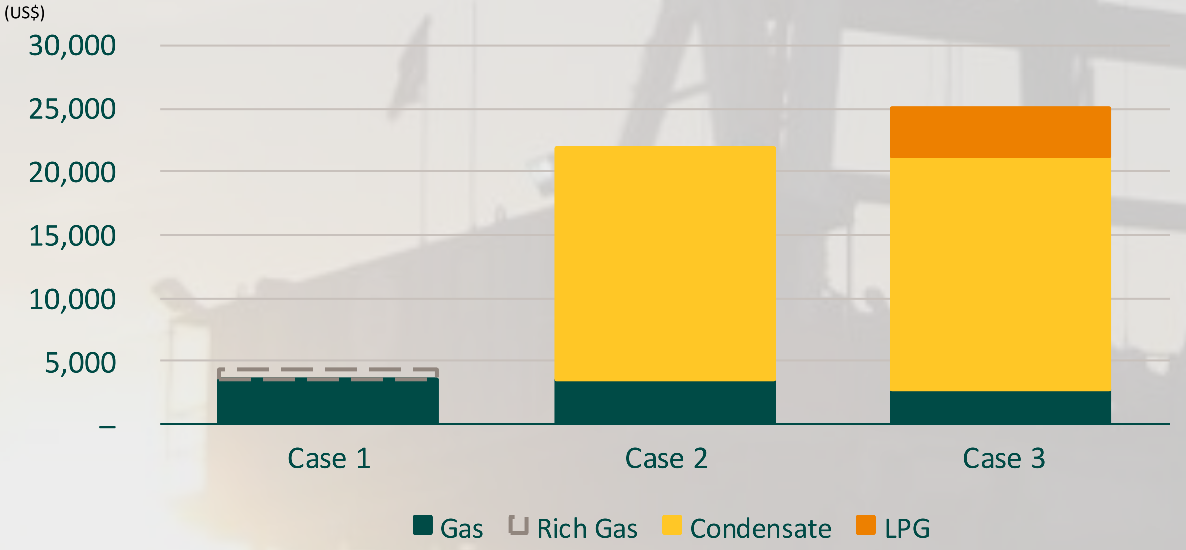
Production late Sept 2011

Production data at 27 Sept 2011	Boepd[1]	Average mmscfpd[2]	Average bopd[2]
Gross Production from acreage in which Aurora participates	25,200	31.48	19,959
Notional gross Aurora production without farmin cost recovery	4,675	6.33	3,619
Gross Aurora production (after farmin cost recovery & pre royalties)	4,254	5.57	3,326
AUT net production (after royalty and cost recovery)	3,139	4.11	2,454
Estimated Y/E Aurora net production (post royalties)	4,140		
NSAI estimated Aurora peak net production 2019 (pre royalties)	29,000		

1. BOEs 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
2. These figures have been estimated from the raw gas and oil produced. A 20% shrinkage is assumed for the gas and a yield of 95 bbls/mmscf for the NGLs. The gas volumes provided are post shrinkage and the bopd values are including NGLs.

High liquids yields drives strong economics

Incremental value of production from Sugarkane rich gas condensate wells



A well produces 1 mmscf of gas, and generates US$3,500 in revenue — if sold as rich gas then + 25% = US$4,375

The gas contains condensate and 230 bbls are recovered. Revenue is now:

- Gas: US$3,500 +
- Condensate: US$18,400

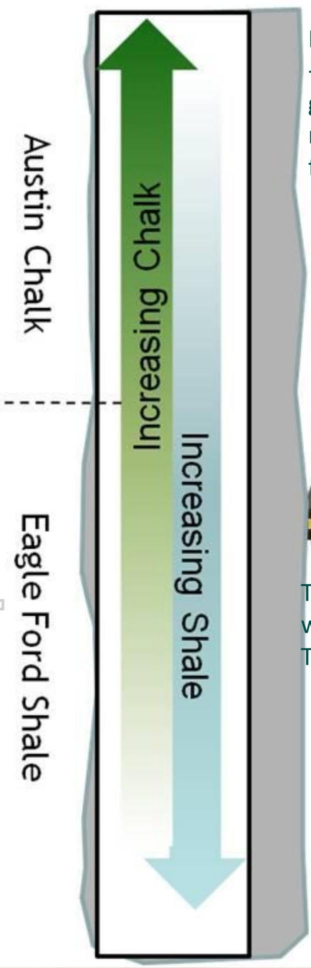
The gas is treated and 95 bbls of NGLs are stripped, this shrinks the gas by 20%. Revenue is now:

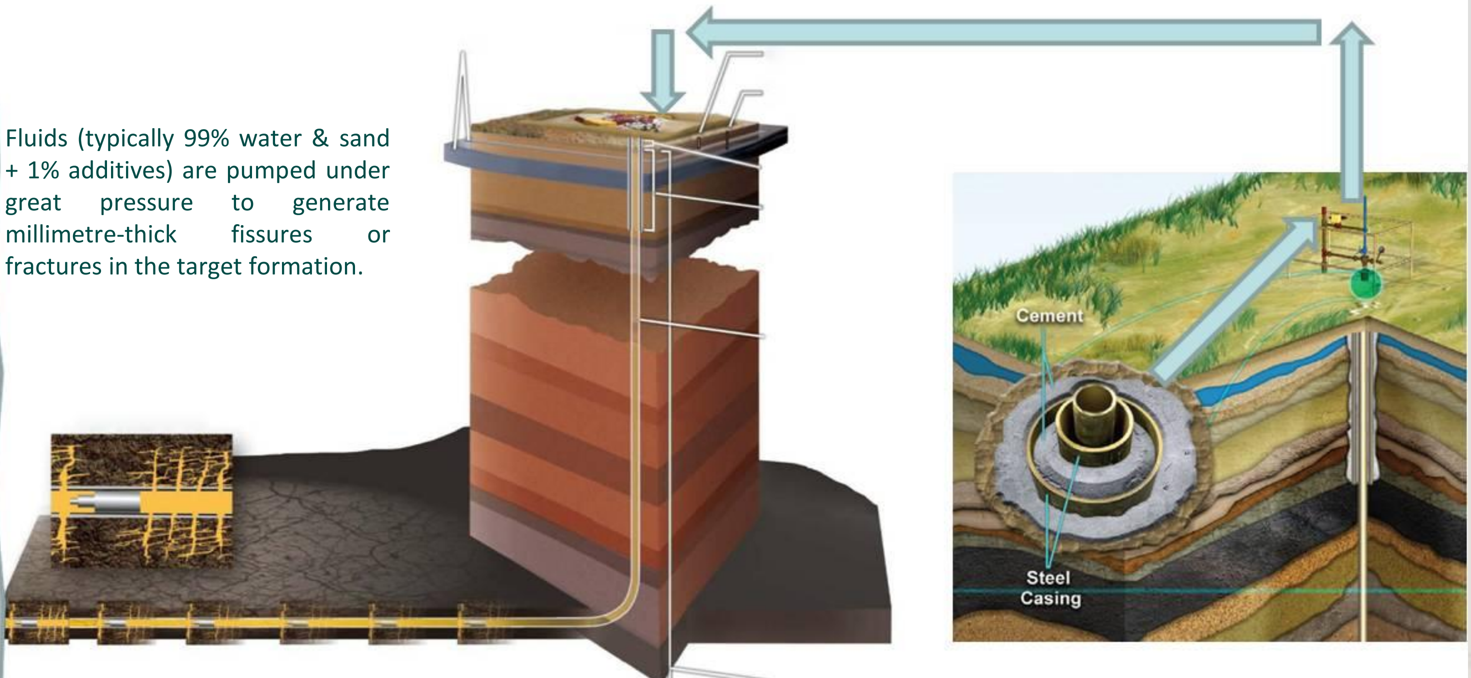
- Gas: US$2,800 +
- Condensate: US$18,400 +
- NGL: US$3,800

- Using Type curve 3 on Page 28 as an example with a condensate yield of 230 bbls/mmscf
- Refinery anticipated NGL yield is c.95 bbls per mmscf with NGL selling at ~50% of the price of condensate
- Recently commissioned wet gas line transports wet gas to Houston facility for NGL stripping

Source: Company information.
(1) Assumes gas price US$3.50/mcf, condensate price US$80.00/bbl and NGL price US$40.00/bbl.

Sugarkane field drilling & stimulation





Fluids (typically 99% water & sand + 1% additives) are pumped under great pressure to generate millimetre-thick fissures or fractures in the target formation.

The additives enable the water-sand mixture to transport the sand deep into the fracture and then change its properties to allow the water to be removed while the sand remains, holding the fracture open. The newly created fissures are propped open by the sand. This allows the hydrocarbons to flow into the wellbore and be collected at the surface.

- Well design has moved towards more stages and significantly larger fracture stimulations with more propant
- Closest potable aquifer is at approximately 3,000' true vertical depth or approximately 8,500 – 9,000 shallower than the well horizontal section
- Aquifers are secured behind casing prior to drilling of horizontal sections

NSAI 31 August Reserves Report – Key Assumptions

NSAI used the following assumptions within their model:-

- Well cost was estimated at $7.8m for a period of 1 year and then reduced to $6.8m. This cost estimate includes drilling, stimulating and producing of each well. There is also an allowance for abandonment liability in NSAI model.
- Operating cost of $15,000/well per month.
- Both the Capex and the Opex costs are escalated by 2% per year
- Forecast Commodity Pricing – NYMEX forward strip price on the effective date of the report has been used and is shown below. The figures are then adjusted for quality, transportation costs, regional price variations and further adjustments are made for the calorific value of the gas.
- All evaluations of future net revenue are after deduction of royalties, development costs, production costs, local taxes and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future revenue values utilized in the disclosed Net Present Values do not necessarily represent fair market value of the Company's reserves.
- The proved and probable well locations are based on 80 acre well spacing and each location has been allocated an EUR and type curve, depending on its location within the overall field. The type curves being applied by NSAI are summarised in the table below.

Year	Oil Price (US$/bbl)	Gas Price (US$/mmbtu)
2011	89.18	4.204
2012	91.01	4.578
2013	92.13	5.055
2014	92.31	5.327
2015	92.78	5.538
Thereafter	93.30	5.735

Type Curve	L/M Oil (mbbls)	NGL/Cond (mbbls)	Gas (mmscf)	BOE (mbbls)
1. < 50 bbls/mmscf	0	393	3,400	960
2. 50 – 100 bbls/mmscf	0	416	2,495	832
3. 100 – 500 bbls/mmscf	0	510	1,580	773
4. 500 – 700 bbls/mmscf	330	54.6	575	480
North Longhorn	340	31.36	330	426
Excelsior	220	24.2	255	287