Investor Day
June 4, 2014

Husky Energy

Agenda

Strategy is Delivering		
9:05 - 9:20	Strategy Update	Asim Ghosh
9:20 - 9:30	Financial Plan	Alister Cowan
Foundation Portfolio		
9:30 - 9:35	Portfolio Review	Rob Peabody
9:35 - 9:45	Heavy Oil	Ed Connolly
9:45 – 9:55	Western Canada	Rob Symonds
9:55 - 10:05	Downstream	Bob Baird
10:05 - 10:15	Q & A	Rob Peabody, Ed Connolly, Rob Symonds, Bob Baird, Brad Allison
Break		
Pillars Portfolio		
10:30 - 10:35	Portfolio Review	Rob Peabody
10:35 - 10:45	Asia Pacific	Bob Hinkel
10:45 - 10:55	Oil Sands	John Myer
10:55 - 11:05	Atlantic Region	Malcolm Maclean
11:05 - 11:15	Q & A	Rob Peabody, Bob Hinkel, John Myer, Malcolm Maclean, Brad Allison
11:15 - 11:20	Wrap-up	Asim Ghosh, Rob Peabody, Alister Cowan
11:20 - 11:30	Q & A	All
Lunch		

Investor Day
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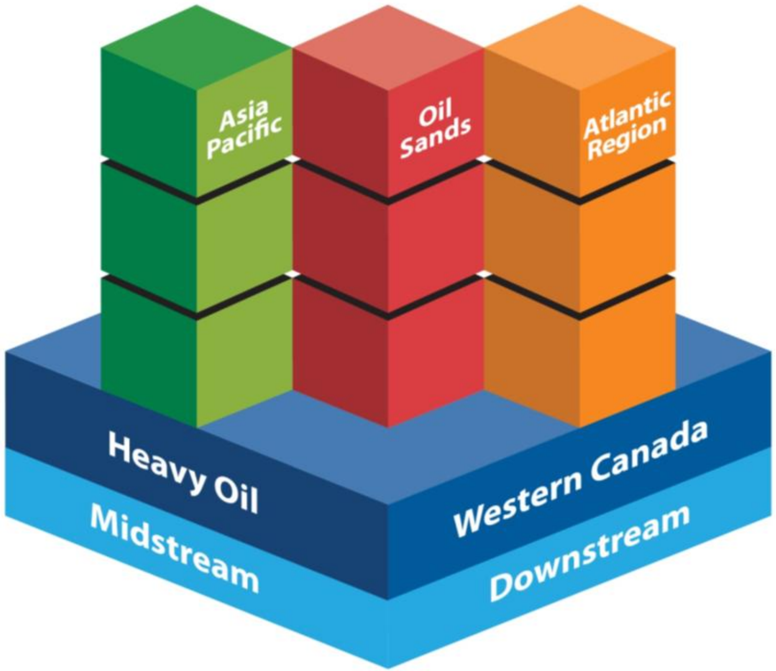
Husky Energy

Strategy Update
Asim Ghosh

Husky Energy

Strategy and Portfolio Development

- Balanced growth strategy delivering
- Transforming the foundation
- Focused integration – achieving world market prices
- Delivering major projects
- Top-quartile dividend
- Reliable and repeatable performance improving returns



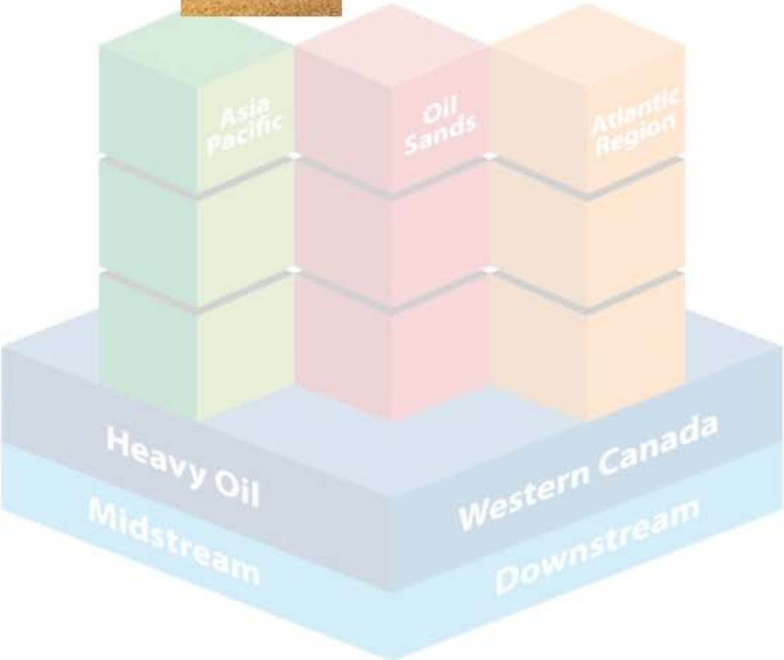
The Way We Were

Near-Term

North Amethyst

Mid-Term

Pikes Peak South



Long-Term

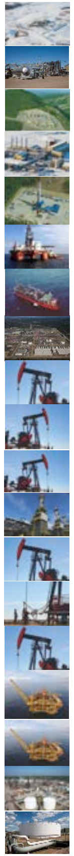
Liwan 3-1

Madura Strait BD

Sunrise Energy Project

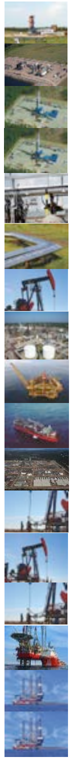
Rich Queue of Projects

Near-Term (2014-2016)



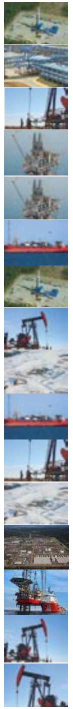
- Sandall Thermal
- Rush Lake Thermal
- Edam West Thermal
- Edam East Thermal
- Vawn Thermal
- South White Rose
- N. Amethyst Hibernia
- Sunrise Energy Project Phase 1
- Wapiti Cardium
- Ansell Cardium
- Ansell Wilrich
- Kaybob Duvernay
- Oungre Bakken
- Viking (various)
- Kakwa Wilrich
- Liwan 3-1
- Liuhua 34-2
- Toledo Recycle Gas Compressor
- Hardisty and Patoka Expansion

Mid-Term (2017-2019)



- Pikes Peak North Thermal
- Rush Lake 2 Thermal
- Lloyd 1 Thermal
- Lloyd 2 Thermal
- McMullen Thermal 1
- Heavy Oil Pipeline Expansion
- S.W. Sask. Multi-zone
- Lima Refinery Heavy Oil Project
- Liuhua 29-1
- West White Rose
- Sunrise Energy Project Phase 2A
- Rainbow Muskwa
- Sinclair Montney
- Kakwa Montney
- Madura BD
- Madura MDA
- Madura MBH

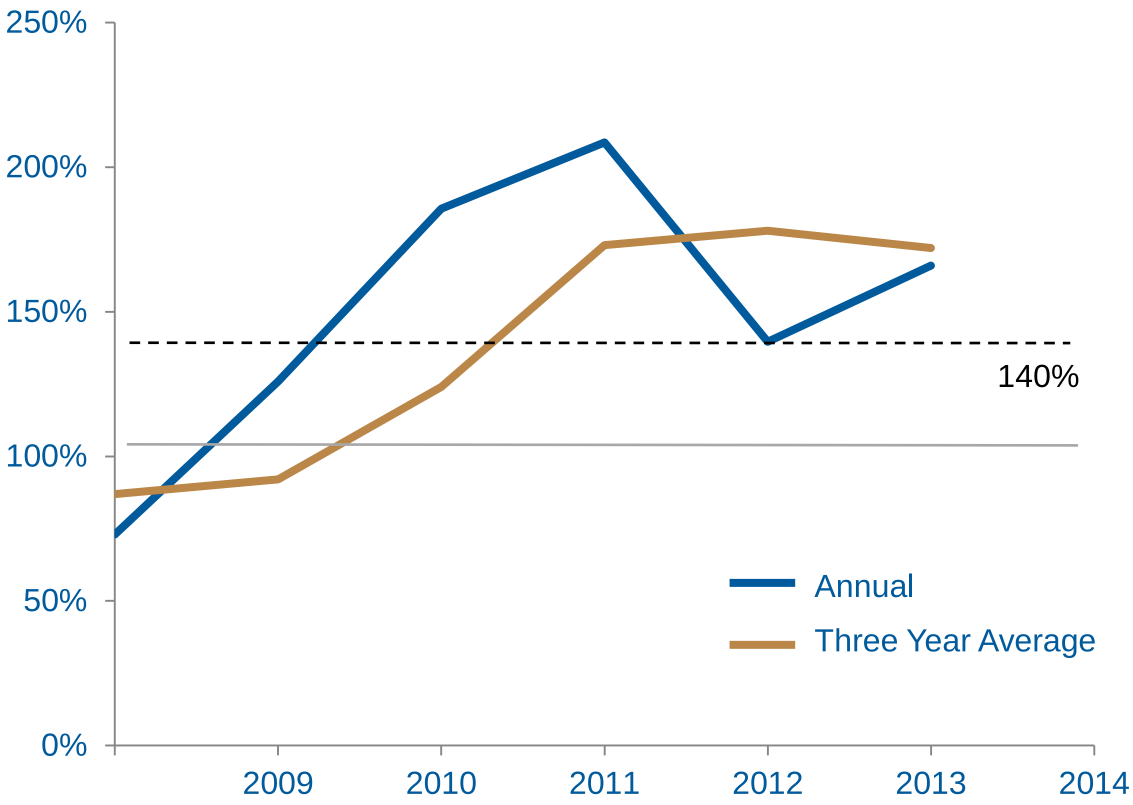
Long-Term (2020+)



- Lloyd 3 Thermal
- McMullen Thermals
- Sunrise Energy Project Phase 2B
- Bay du Nord
- Harpoon
- Mizzen
- Saleski
- Horn River Muskwa
- Wild River Duvernay
- White Rose Gas
- Heavy Oil Cold EOR
- Slater River NWT
- Sunrise Future Phases
- Five Indonesia Discoveries
- Graham Montney
- Cypress Montney

Proved Reserves Replacement Outpacing Production

- On track to exceed 140% annual average through 2017



Values exclude economic revisions

Shaping Risk and Delivering Higher Quality Returns

- Here's what we mean by higher quality returns
  – predictable outputs, less volatility, and sustainable growth
- Here's how we create it:
  - Portfolio flexibility
  - Balancing towards longer-wavelength projects
  - Focused integration
  - Shaping execution risk
  - Oilier pricing

Portfolio Flexibility

- Broad portfolio
- Capital allocation

Near-Term (2014-2016)

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Long-Term (2020+)

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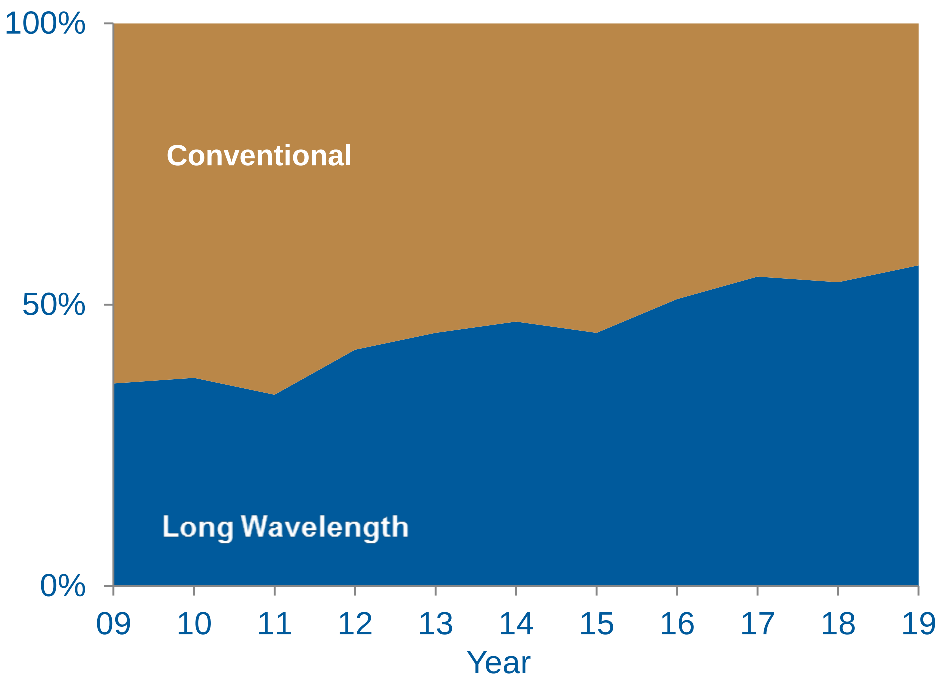
- Cypress Montney

Balancing Towards Longer Wavelength Projects

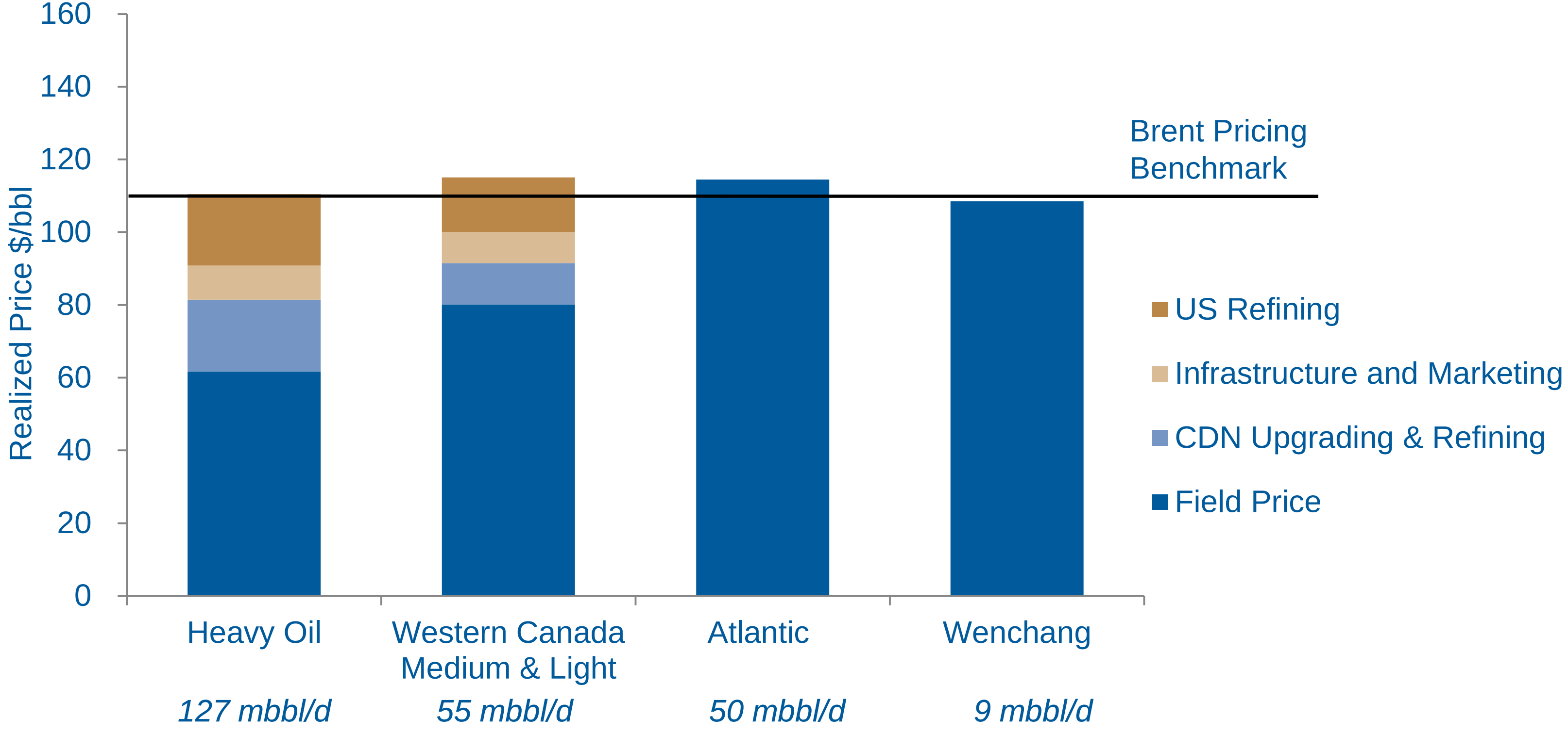
- Long wavelength production includes Heavy Oil thermals, resource plays and Oil Sands
- Conventional production includes Atlantic, Western Canada conventional and Asia Pacific

“Long-Wavelength” Production Forecast as a % of Total



Delivering Pricing Reliability

Realized Pricing on Upstream Production Processed (March 31, 2014)



Additional revenue/bbl $51-$60 **Increased operating netback/bbl $38-$45**

Shaping Execution Risk

Liwan Delivered

SeaRose Reliability

97% Refinery Uptime

Proven Thermal Performance

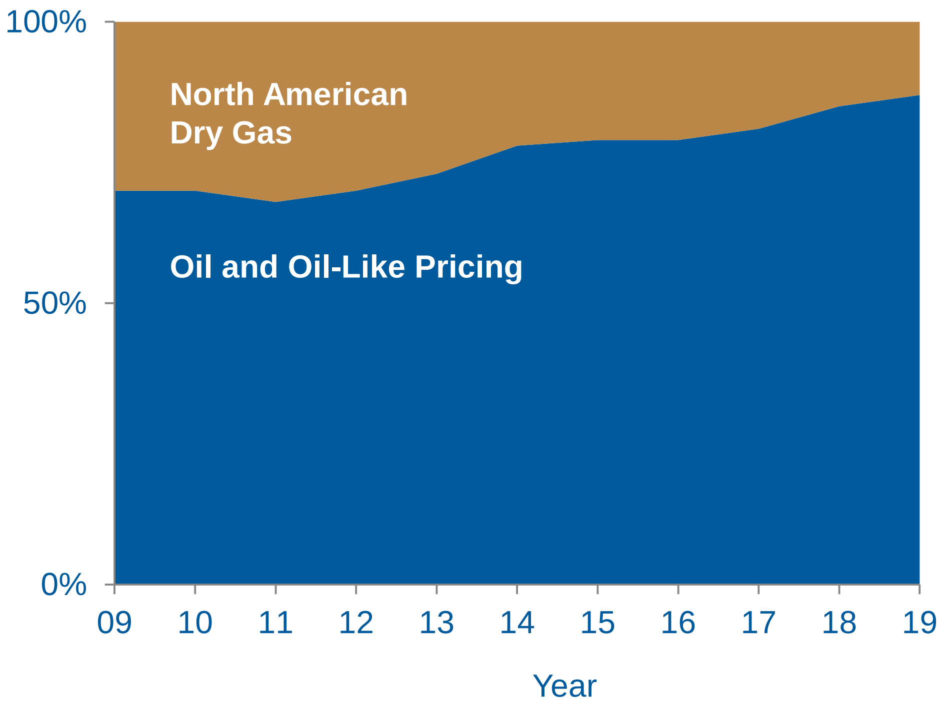
Room to Run at Ansell

Flemish Pass Discoveries

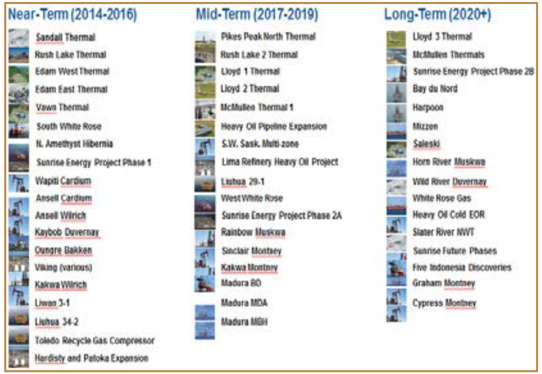
Oilier Pricing

- Commodity value
- Higher netback production

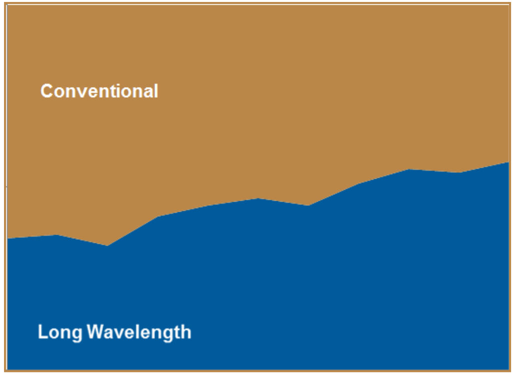
Product Pricing Mix as % of Past/Forecast Production



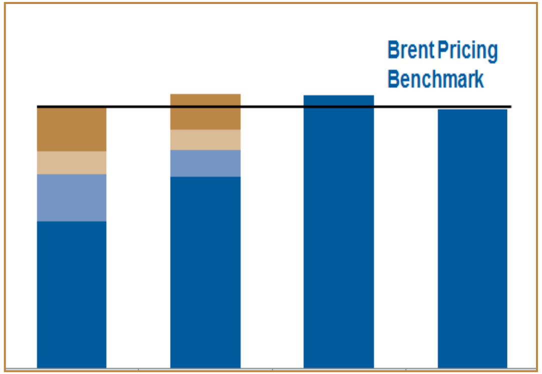
Shaping Risk and Delivering Higher Quality Returns



Portfolio Flexibility →

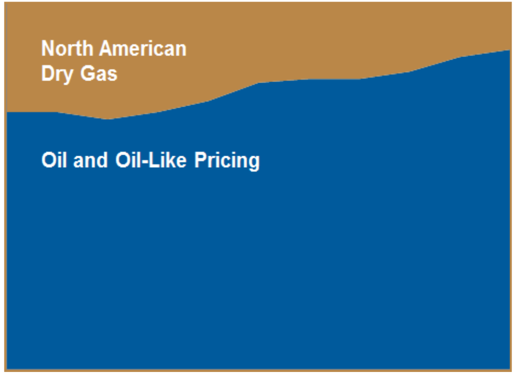


Longer Wavelength →



Focused Integration

Shaping Execution Risk →

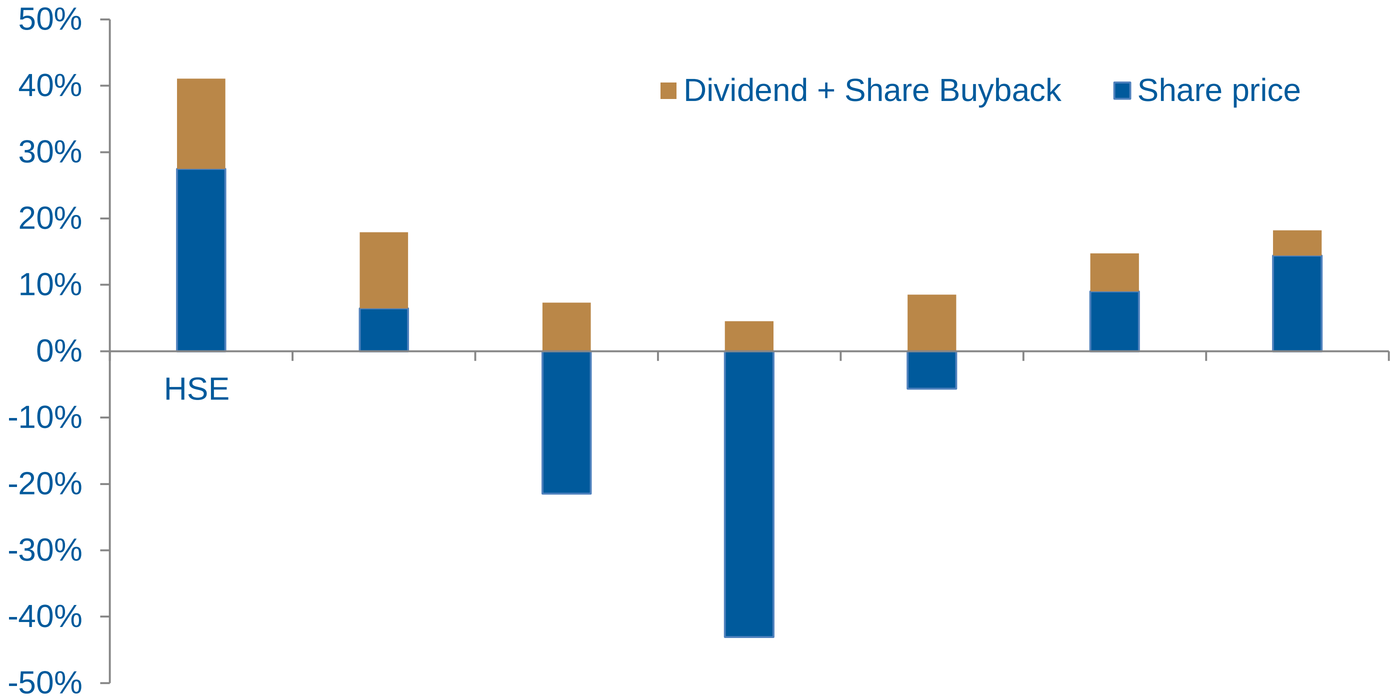


Oilier Pricing

= **Higher Quality Returns + Sustainable Growth**

The Bottom Line – Returns

Total Shareholder Return – June 1, 2011 – June 1, 2014[1, 2]



1. TSR Data Sourced from Bloomberg
2. As of June 1st, 2014. Peers include: Canadian Natural Resources, Cenovus, Encana, Imperial Oil, Suncor and Talisman

Financial Plan

Alister Cowan

Husky Energy

On Pace With Our Targets

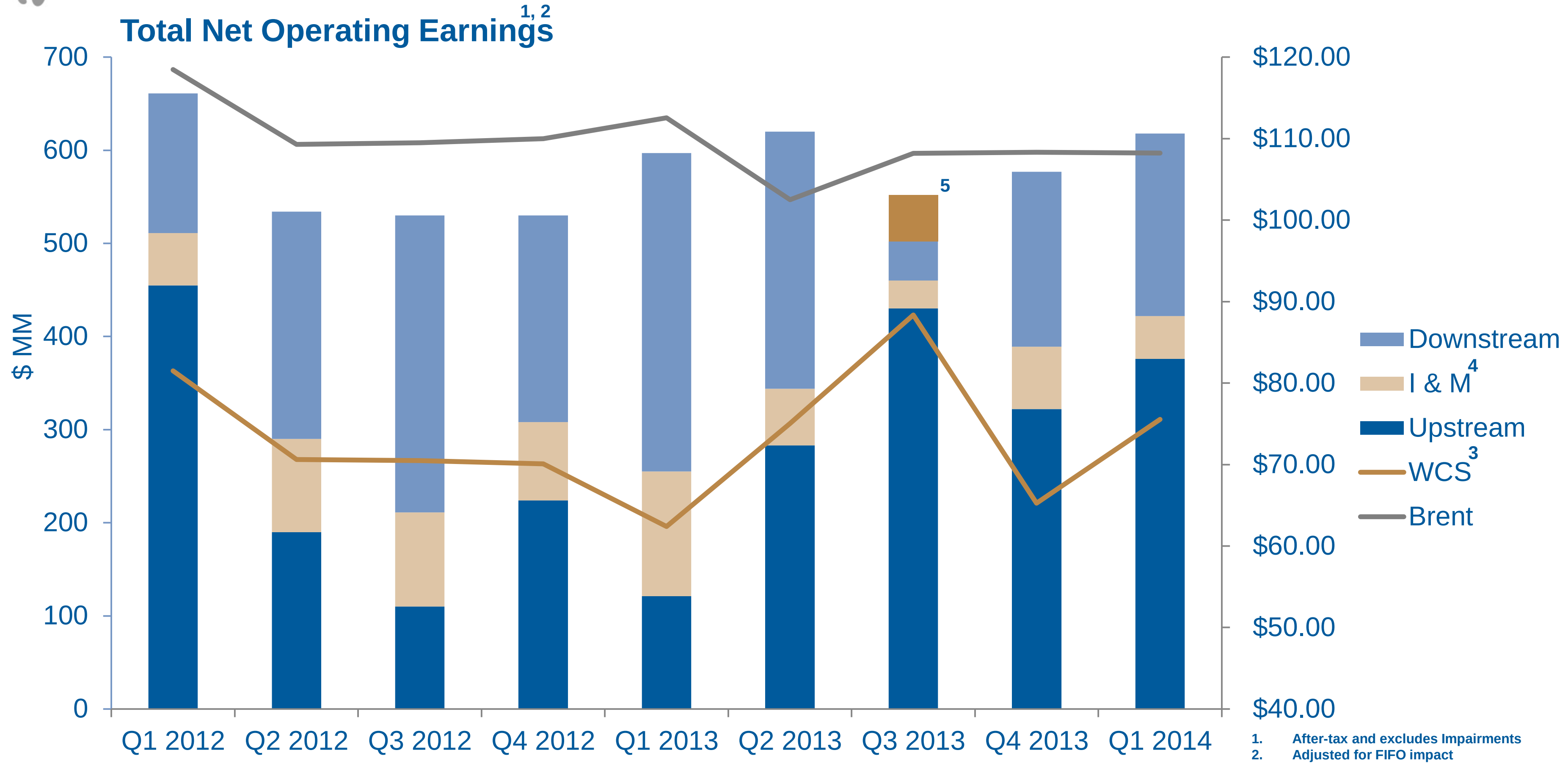
	2010 Actual	2013 Actual	Q1 2014	2012-2017 Targets
Production (mboe/d)	287	312	326	5 - 8% CAGR (3)
Cash Flow from Operations (3)	$3.1 billion	$5.0 billion	$1.5 billion	6 - 8% CAGR (3)
Reserve Replacement Ratio (1)	184%	166%	N/A	> 140% average
Return on Capital in Use (2, 3)	8.4%	12.6%	12.0%	14 - 15%
ROCE 2, 3	6.4%	8.7%	8.0%	11 - 12%

(1) Excluding economic revisions
(2) Adjusted for after-tax impairments on property, plant and equipment of $204 million
(3) Non-GAAP measures
Please see advisory for further detail

Integration Strategy Mitigates Earnings Volatility

1. After Tax and Excludes Impairments
2. Western Canada Select

Integration Strategy Mitigates Earnings Volatility

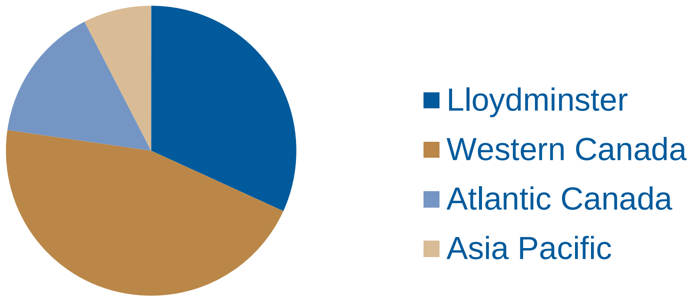


1. After-tax and excludes Impairments
2. Adjusted for FIFO impact
3. Western Canada Select
4. Infrastructure and Marketing
5. Impact of scheduled upgrader turnaround

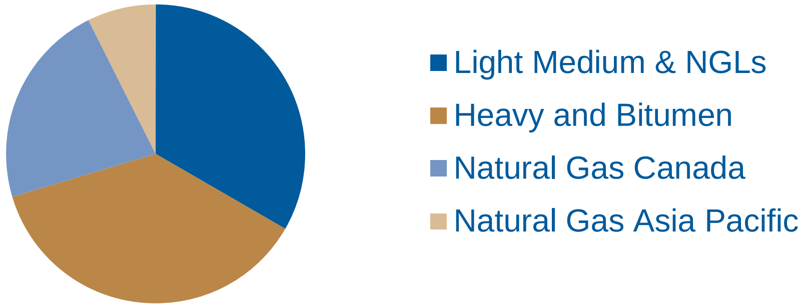
Portfolio Management/Capital Allocation – Shaping Risk

- Product type
- Geography/markets
- Capital requirement/timeline
- Return of Asset/IRR
- Reserve life index
- Technology
- Execution risk

Production by Geography*

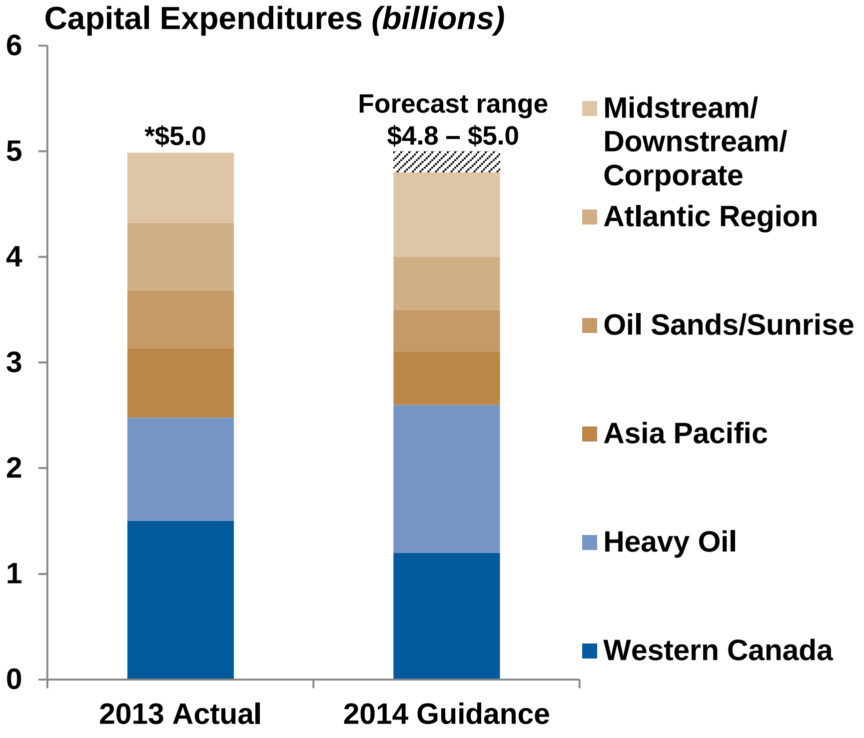


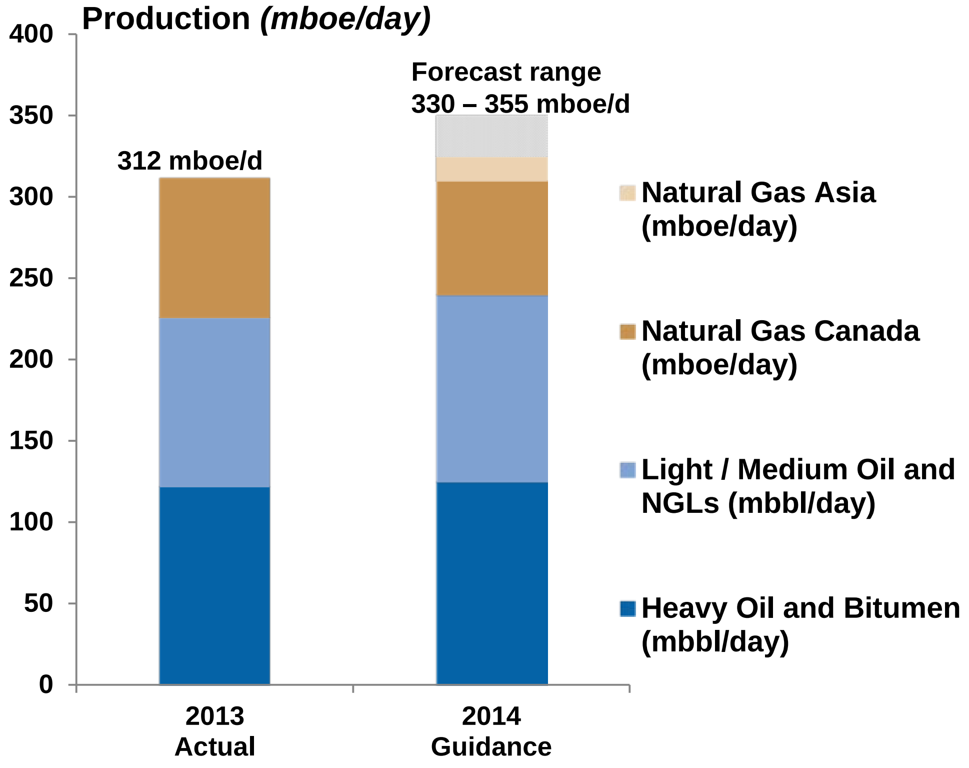
Production by Product Type*



* Per guidance issued Dec 11, 2013

Staying Course on Guidance





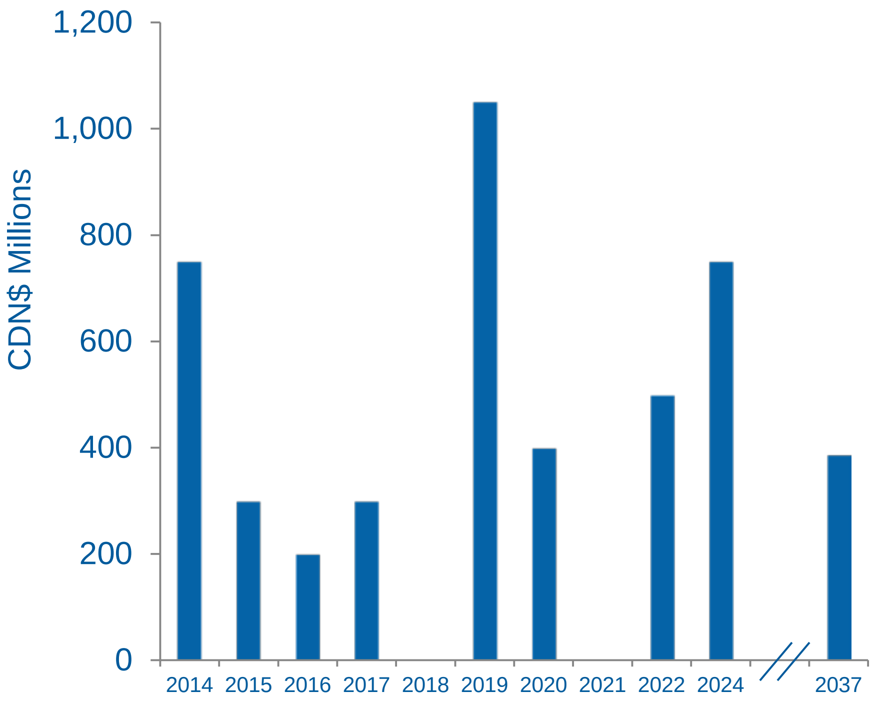
*2013 cash outlay: $4.5 billion

Strong Balance Sheet and Investment Grade Credit Rating

Liquidity		
	Q1 2014 Actual	Debt Targets
Net Debt	$2.7 bln	N/A
Net Debt to Cash Flow*	0.5 X	Below 1.5X
Net Debt to Capital	11%	Below 25%

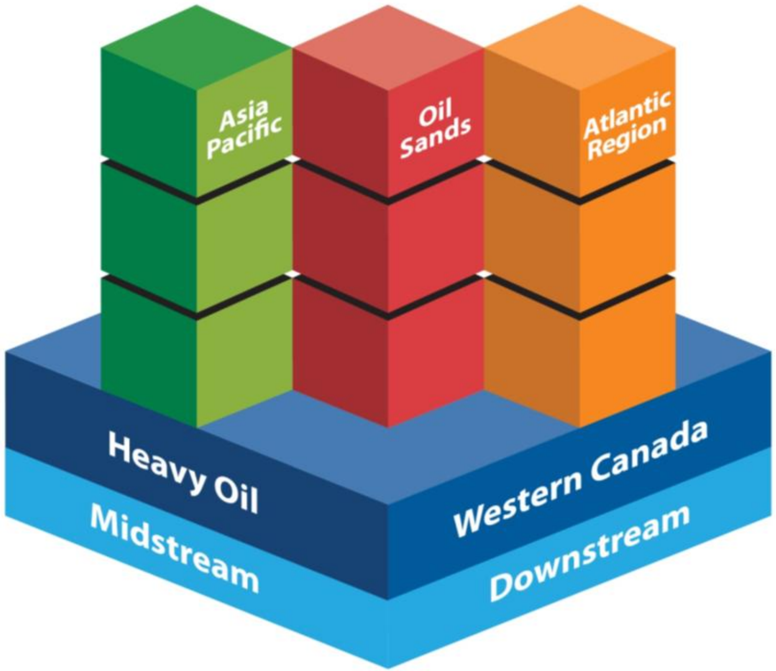
* Using FY2013 Cash Flow

Long-term Debt Maturity Schedule



Focus on Returns

- Strong balance sheet to see long-lead projects through commodity price fluctuations
- Portfolio management
  and flexible capital allocation
- Reliable cash flow growth
- Top-quartile dividend



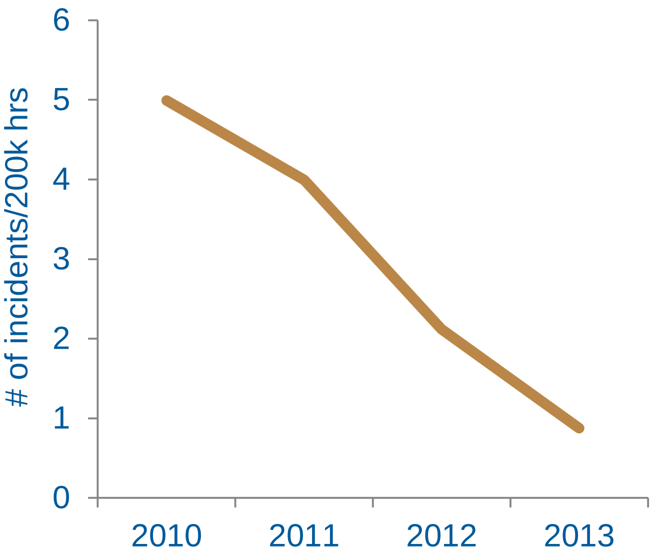
Foundation Portfolio Review

Rob Peabody

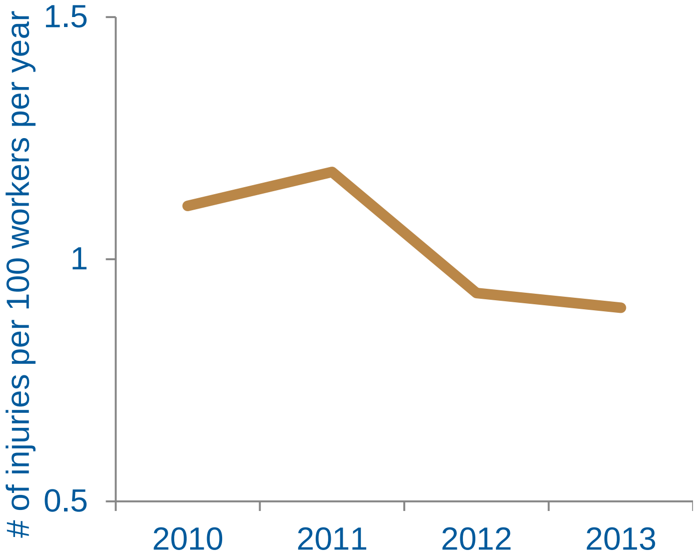
Husky Energy

Shaping Process and Occupational Safety

Critical & Serious Incidents [1]



Total Recordable Incident Rate [2]

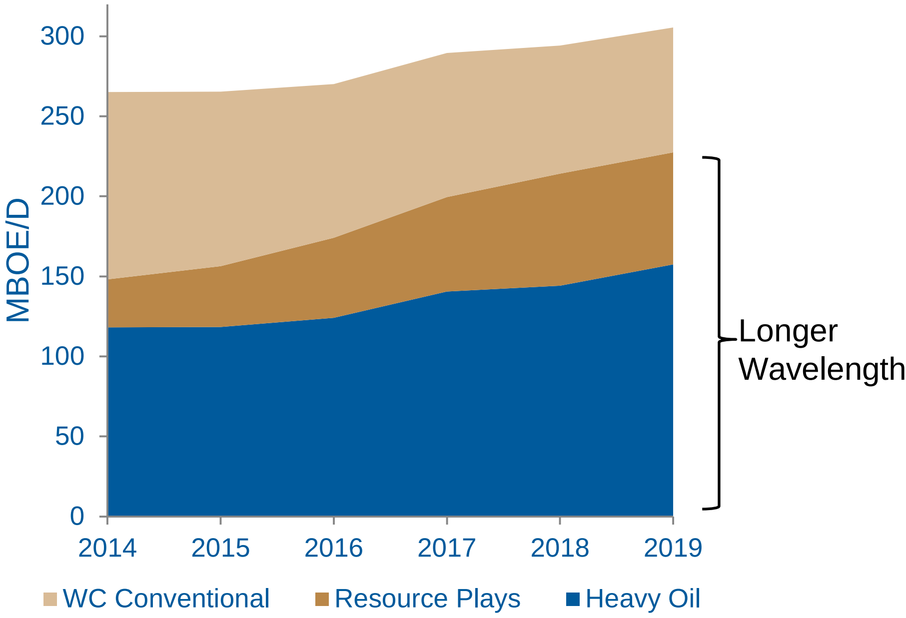


[1] Critical and Serious Incidents includes process and occupational safety
[2] TRIR is a calculated value based on lost-time, restricted work and medical aid incidents

Foundation Facelift

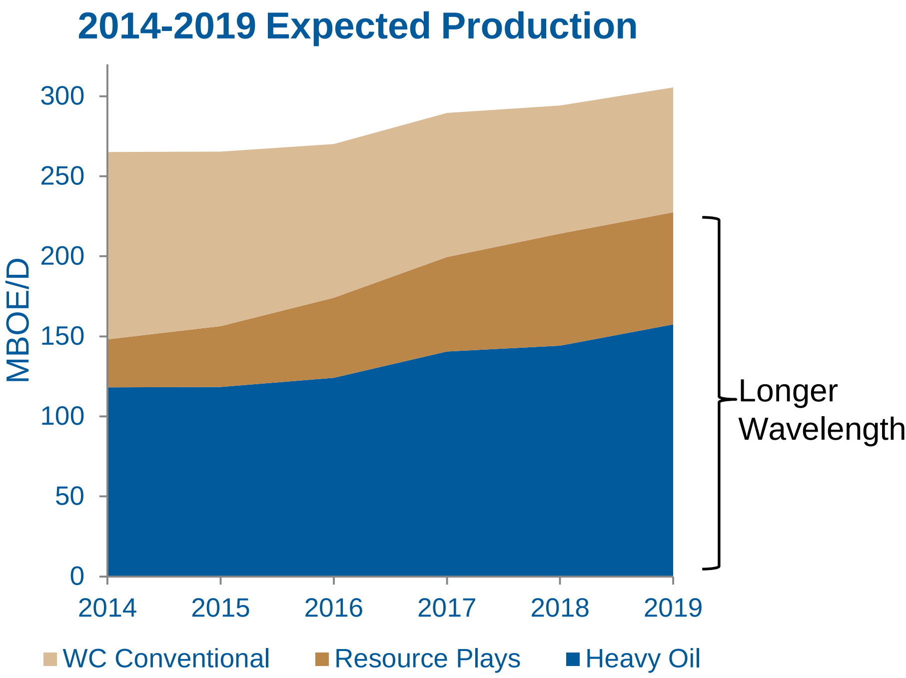
Project	Forecast Net Production Adds (BOE/D)	Forecast Net Capex	Forecast IRR
Near-Term (2014-2016)			
Heavy Oil Thermals			
Four sanctioned projects	**33,500**	**~$1.3 bln**	**>20%**
Western Canada			
Resource plays (various)	**20,000**	**~$1.0 bln**	**>15%**
Downstream			
Toledo Hydrotreater Recycle Gas Compressor Project	**N/A**	**~$20 mm**	**>20%**
Hardisty and Patoka expansion	**N/A**	**~$300 mm**	**>20%**
Mid-Term (2017-2019)			
Heavy Oil Thermals			
Five identified projects	**37,000**	**~$1.0 bln**	**>20%**
Western Canada			
Resource plays (various)	**20,000**	**~1.0 bln**	**>15%**
Downstream			
Heavy Oil pipeline expansion	**N/A**	**~$200 mm**	**>20%**
Lima Refinery crude flexibility project	**N/A**	**~$300 mm**	**>20%**

2014-2019 Expected Production



Lengthening the Stride in our Foundation

- Longer wavelength
- Deep portfolio of high-return projects
- Competitively advantaged



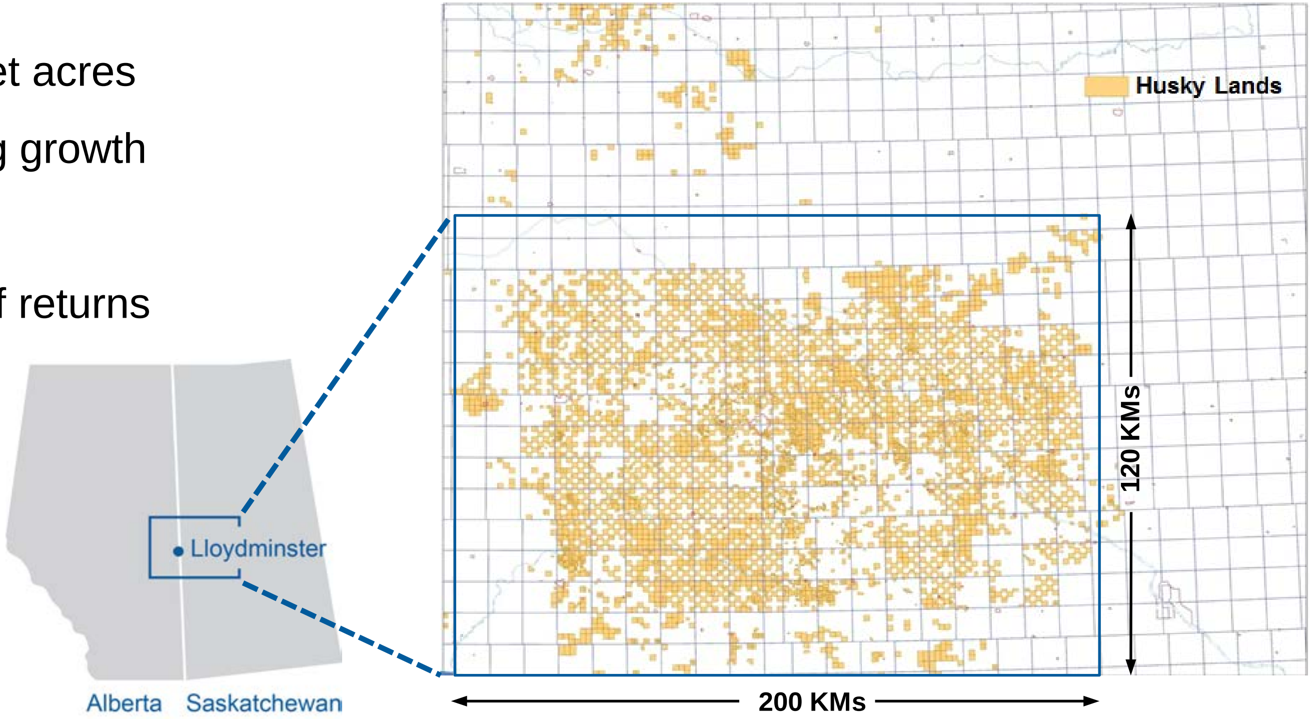
Heavy Oil

Ed Connolly

Husky Energy

Heavy Oil Advantage

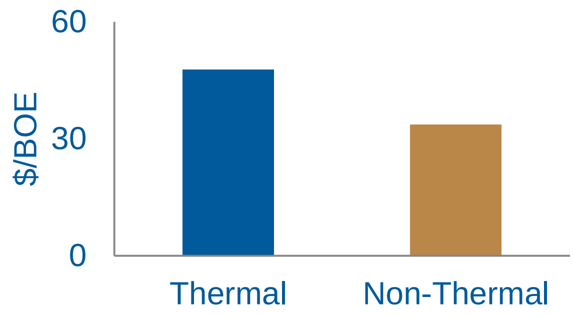
- Second-to-none land and infrastructure position
- Over two million net acres
- Technology fuelling growth
- Fully integrated
- Improved quality of returns



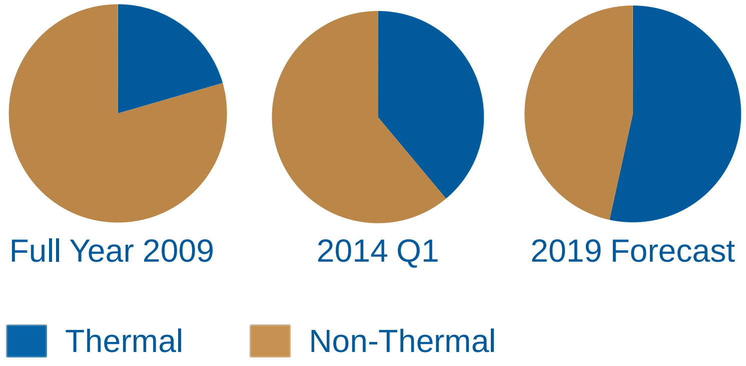
Making Long Wavelengths Longer

- Higher recoveries
- Higher netbacks

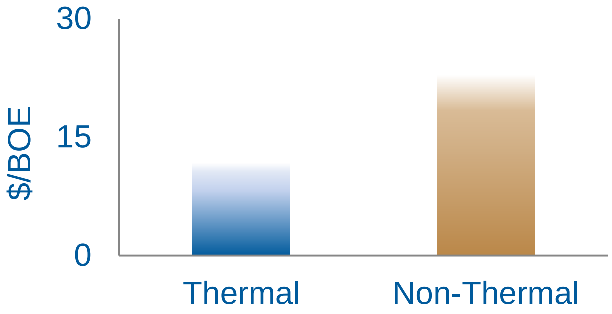
FY2013 Netbacks/bbl*



Proportion of Thermal vs. Non-Thermal Production



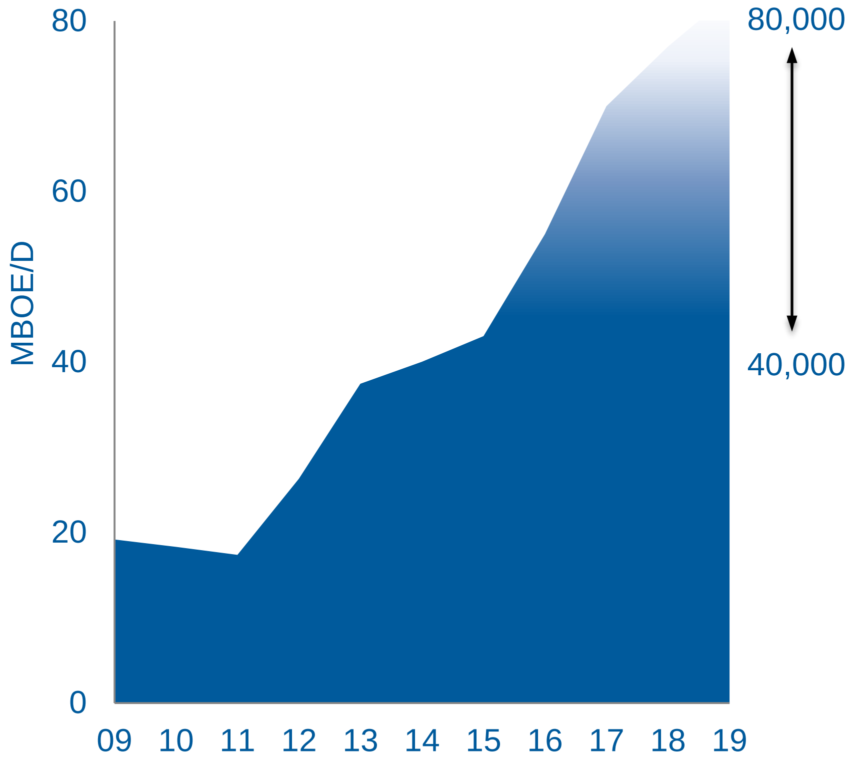
Op Cost/bbl



*Please see advisories for description of Netbacks

Thermal Portfolio Heating Up

Thermal Production Forecast*



* Excludes Tucker

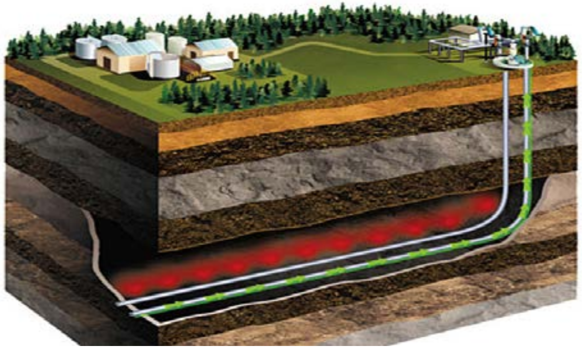
Thermal Project	First Oil Date	Current/ Forecasted Net Production Rate	Status
Pikes Peak	1984	4,100	Producing
Bolney Celtic	1996	19,000	
Paradise Hill	2012	4,500	
Pikes Peak South	2012	12,000	
Rush Lake pilot	2012	1,400	
Sandall	2014	5,200	
Rush Lake Commercial Ph 1	2015	10,000	Near-Term
Edam West	2016	3,500	
Edam East	2016	10,000	
Vawn	2016	10,000	
Pikes Peak North	2017 - 2019	3,500	Mid-Term
Rush Lake Commercial Ph 2		10,000	
Lloyd Thermal 1		10,000	
Lloyd Thermal 2		3,500	
McMullen Thermal 1		10,000	

Typical Thermal Economics

Metric	Target [1]
Construction time	~2 years
Start up to peak production	< 3 months
SOR target	2.0 early years
Sustaining capital/bbl[2]	$5 - $7
Life of project	15 Years +
Recoveries target	>50%
Operating cost per bbl	~$10 for first 2 years
IRR	>20%

1. Based on actual results as of March 31, 2013
2. Non-GAAP measure, please see advisories

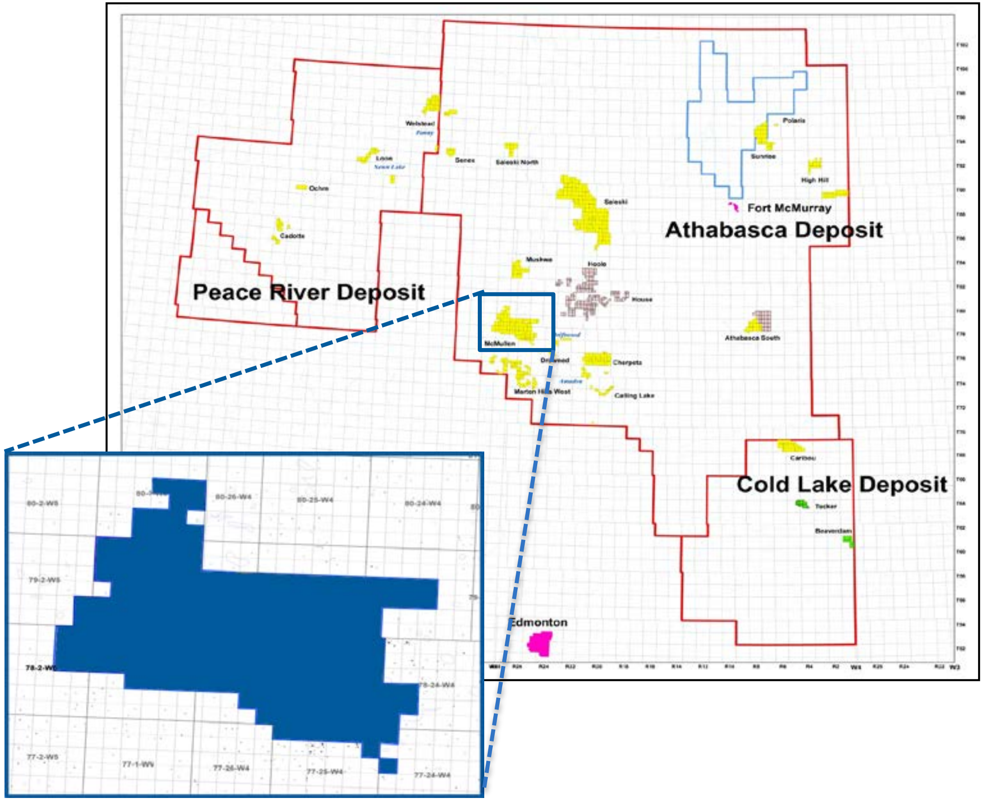
Pikes Peak South



Thermal production

Leveraging Thermal Expertise at McMullen

- Best estimate contingent resources of 644 mmbbls*
- Development
  - Build on Heavy Oil expertise
  - Several 10,000 bpd projects
- Timeline
  - One project in mid-term
  - Several others in long-term



*Please see appendix

Testing Other Technologies

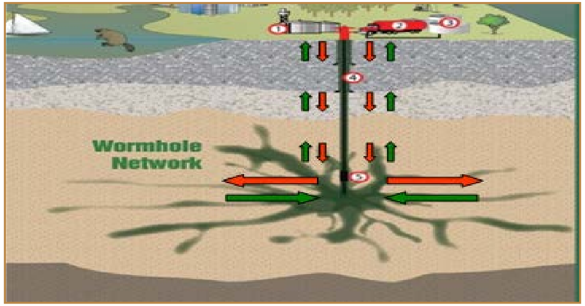
Horizontal wells

- Currently producing 13,000 bpd
- 140 drills per year
- Waterflood targeting 15% recovery

Cold Solvent EOR Process

- Targeting old CHOPS reservoirs
- Uses existing wells and infrastructure
- Early success

Horizontal well

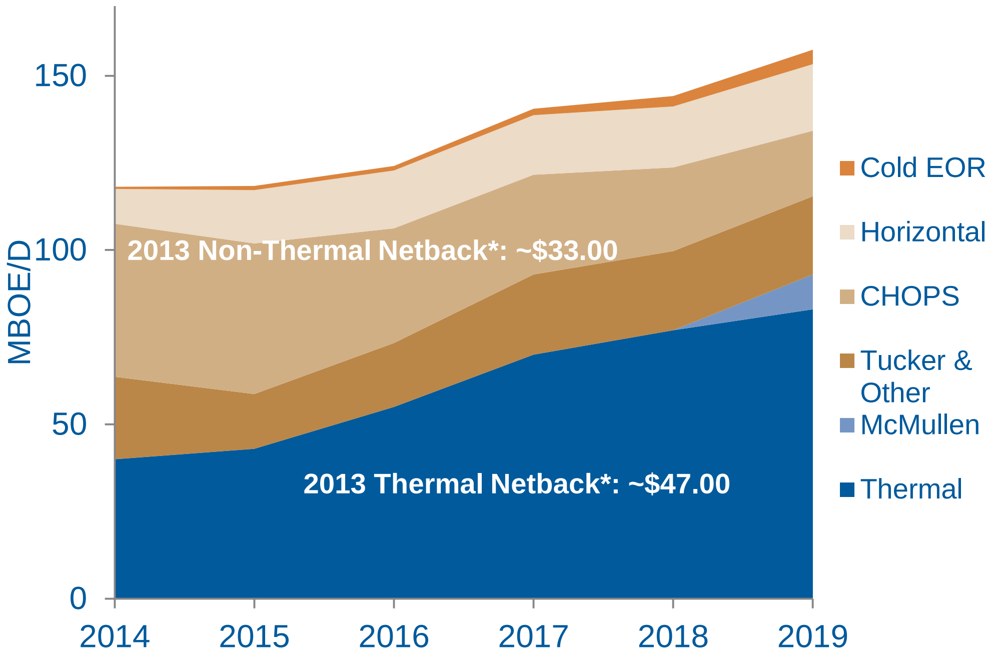


Red: Injection Phase
Green: Production Phase

Delivering Higher Quality Returns

- Second-to-none land and infrastructure
- Technology fuelling growth
- Fully integrated
- Improved quality of returns

Forecast Net Production



*Please see advisory for description of netbacks

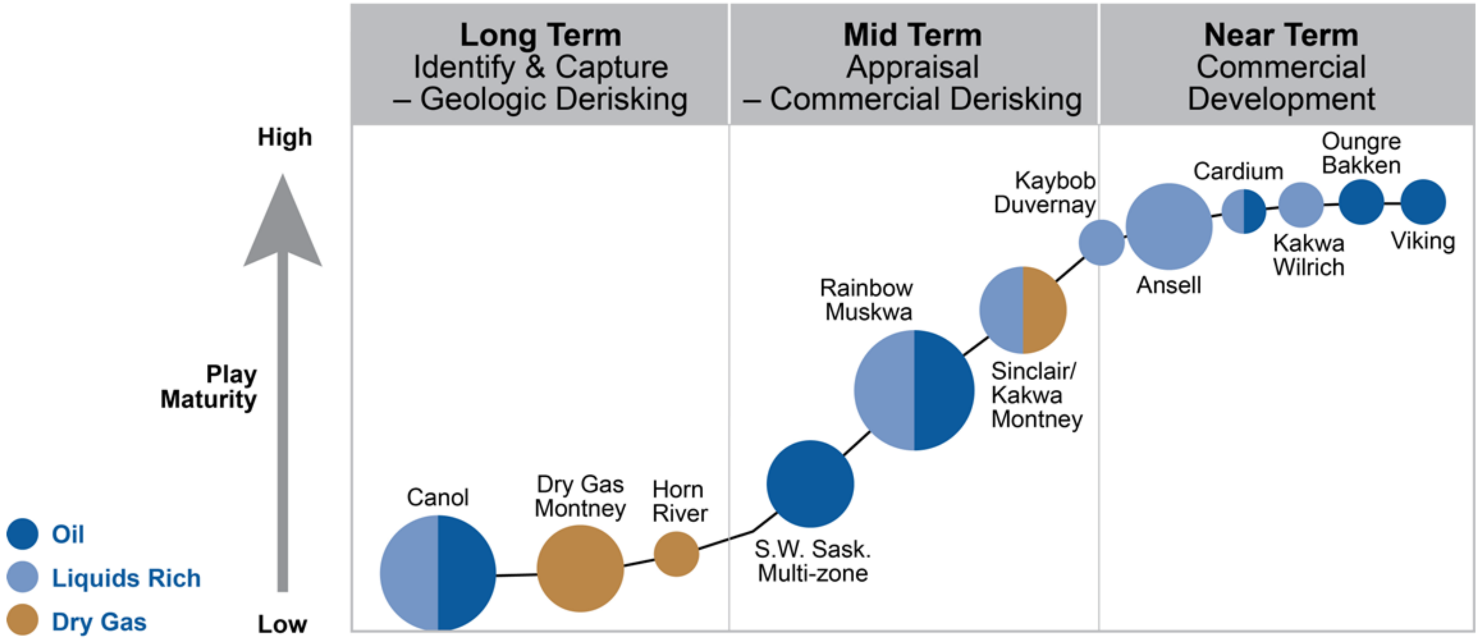
Western Canada

Rob Symonds

Husky Energy

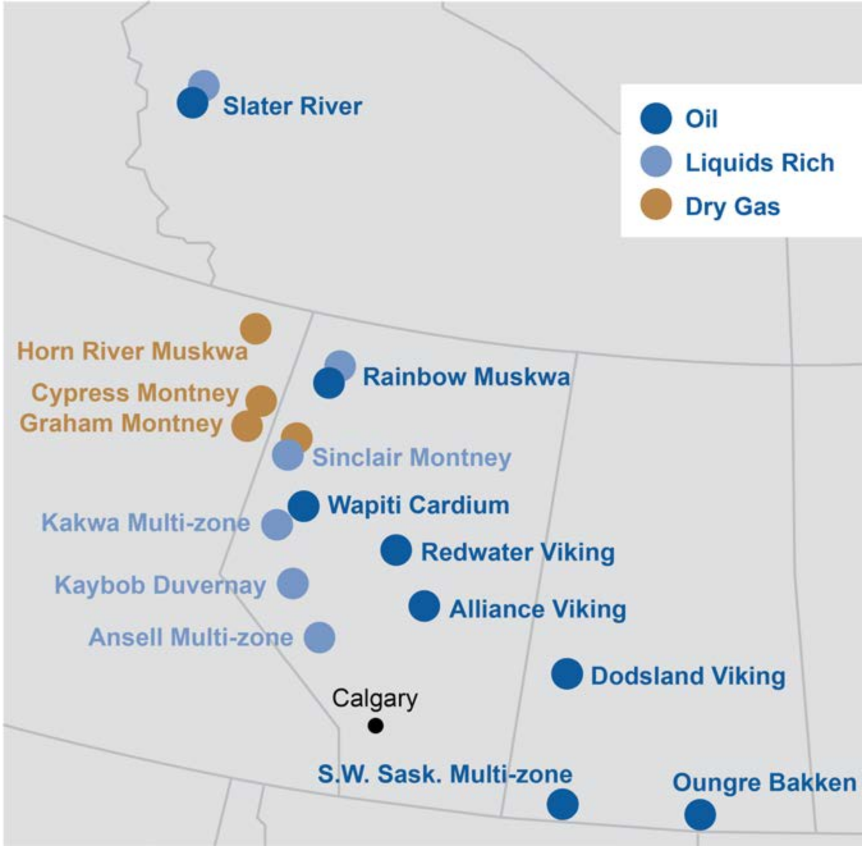
Old Dog, New Tricks

- Extensive resource play portfolio diversified by product, region and scale
- Investing in the right projects
- Breaking down silos to improve efficiencies



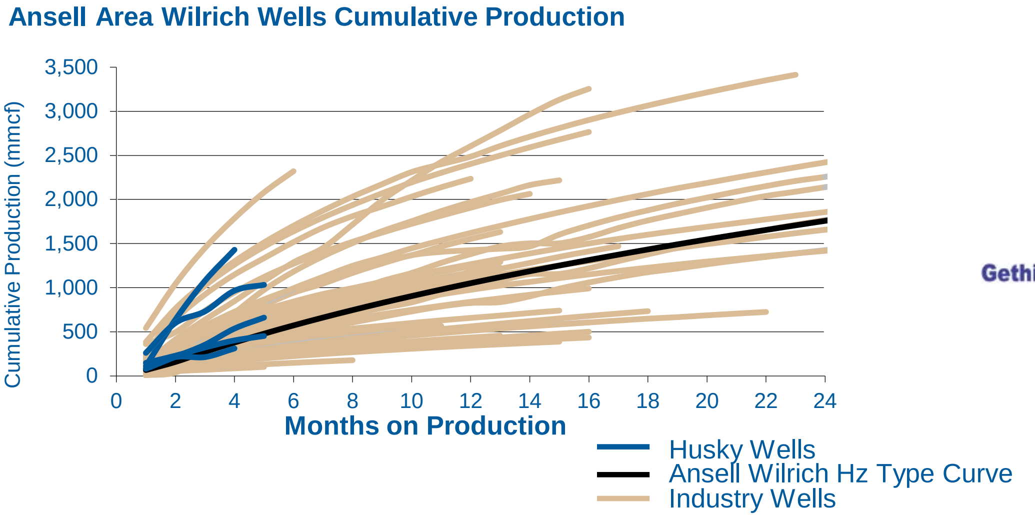
Shaping the Resource Play Portfolio

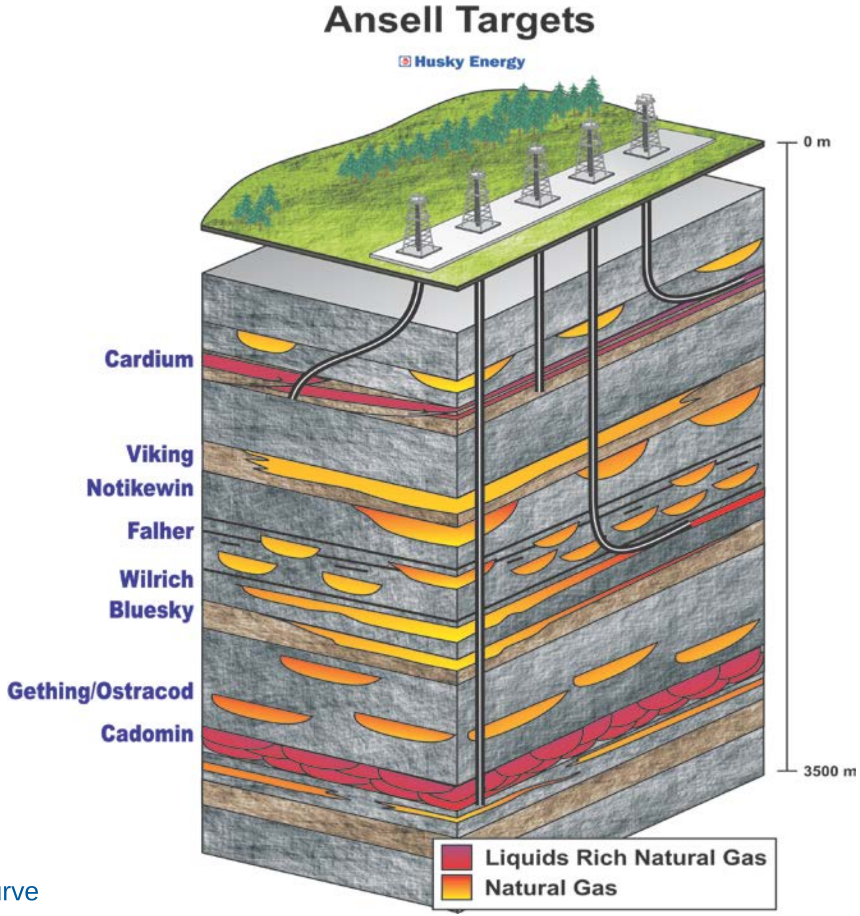
- Disciplined capital allocation
- Average well cost reduction of ~30% over last three years
- Large portfolio allows flexibility
- > 1,500 locations on established resource plays
- Improving cycle time



Ansell – Room to Run

- Large land base
- Multi-zone potential: > 800 locations
- Fully scalable

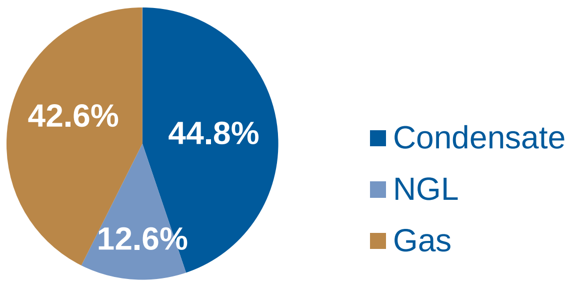




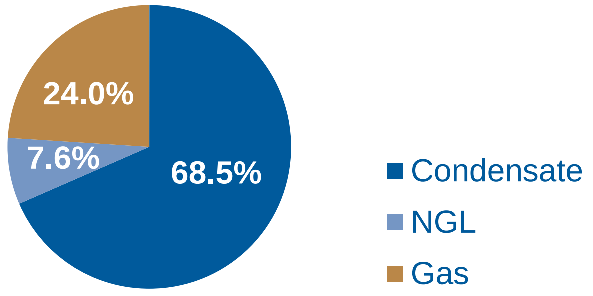
The “Sweet Spot” – Kaybob Duvernay

- Four-well pad and two-well pad onstream
- High condensate yields of > 200 bbls/mmcf
- Early results encouraging
- Reducing costs

Q1 2014 Kaybob Duvernay Products



Q1 2014 Kaybob Duvernay Revenue



Other Mid-Term Potential

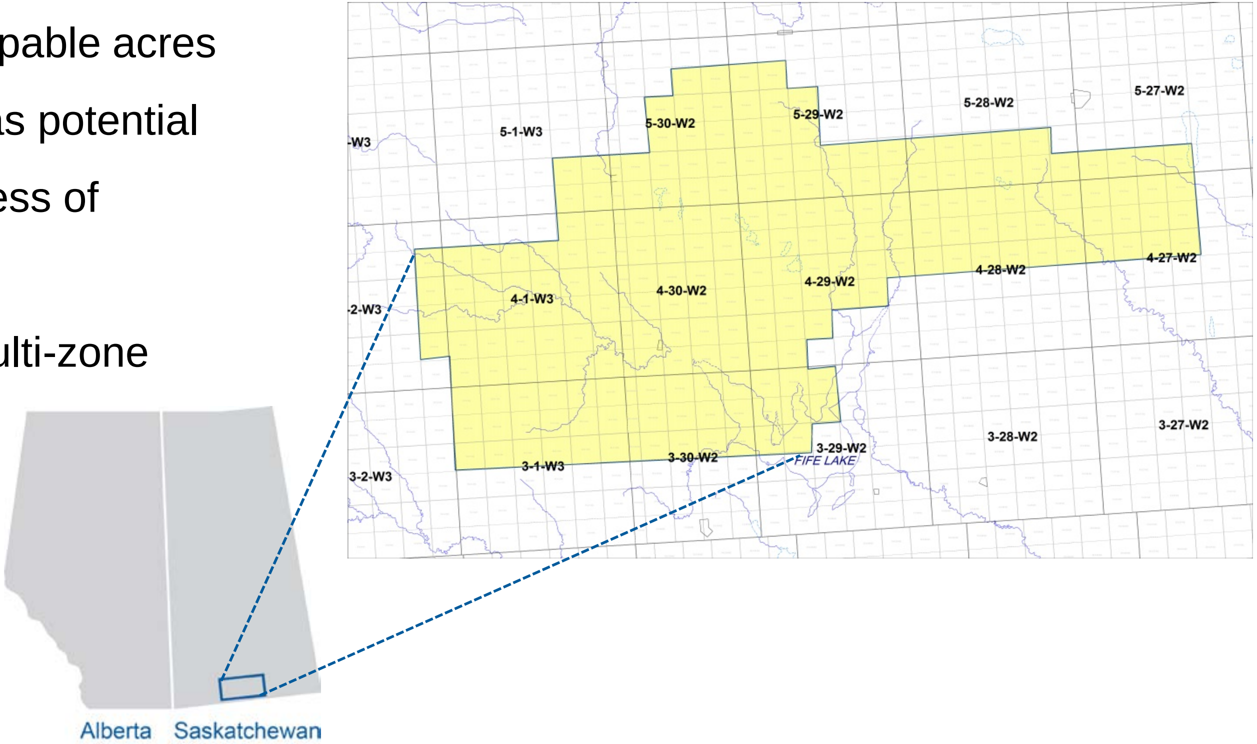
Rainbow Muskwa

- > 300,000 net developable acres
- Oil and liquids rich gas potential
- Assessing effectiveness of different fracs

S.W. Saskatchewan multi-zone

- > 140,000 acres
- Oil potential
- Not yet tested

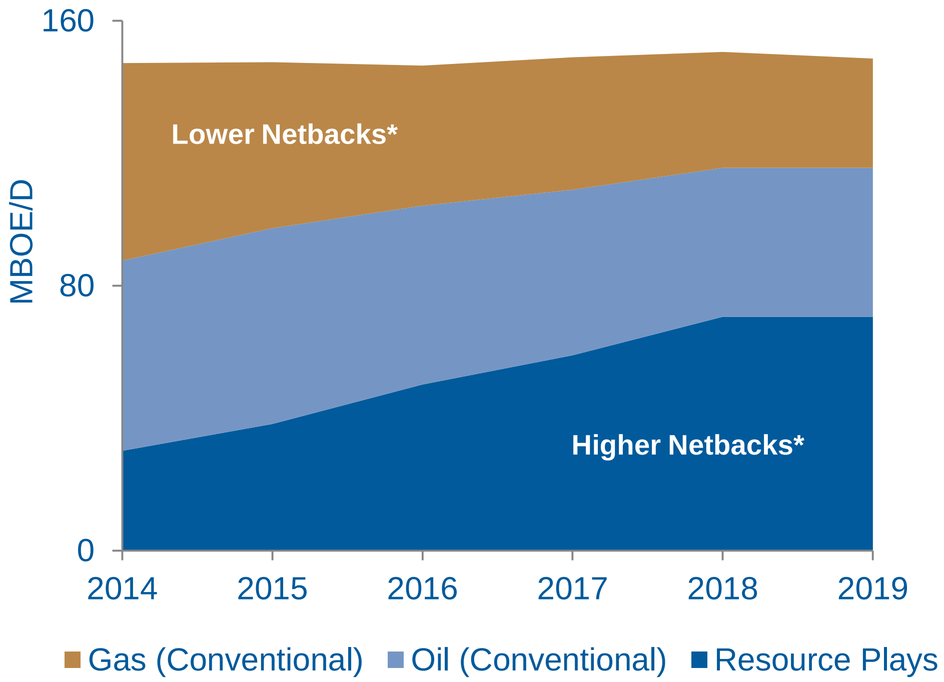
S.W. Saskatchewan Multi-zone



Focus on Higher Quality Returns

- Extensive resource play portfolio diversified by production, region and scale
- Investing in the right projects
- Breaking down silos to improve efficiencies

Forecast Production



*Please see advisories for description of netbacks

Downstream

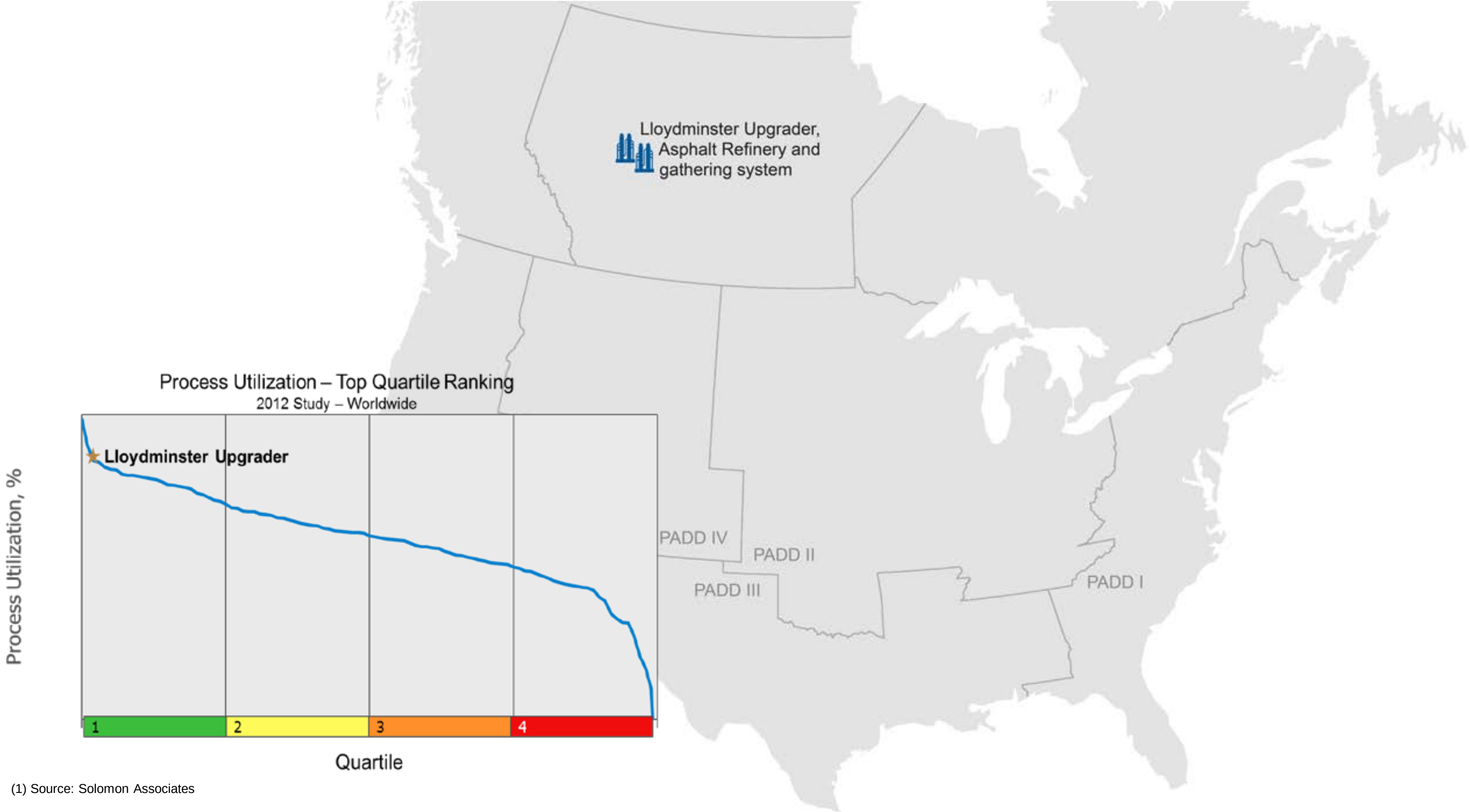
Bob Baird

Husky Energy

Weatherproofing Upstream and Creating Value

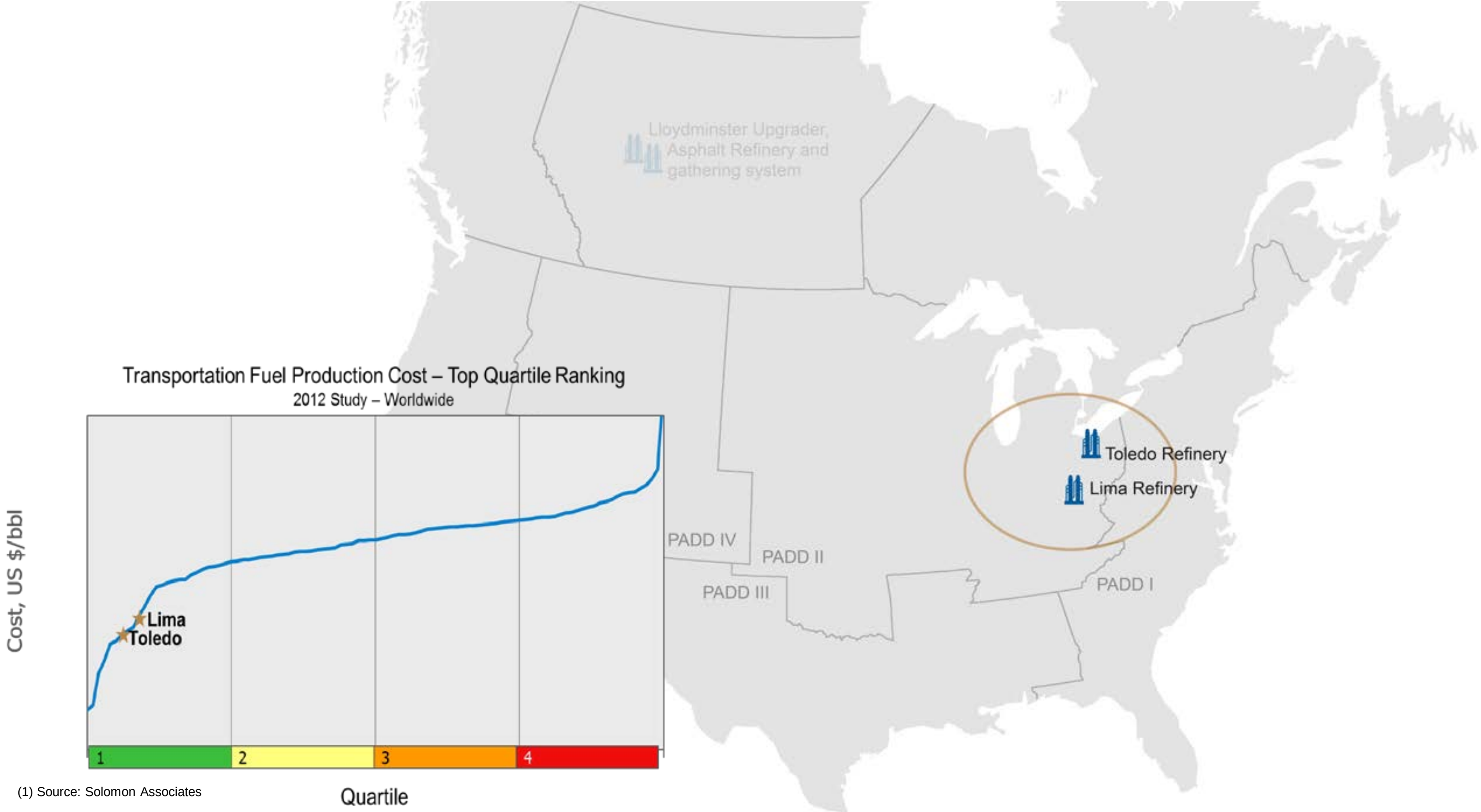
Project	Scope	Forecast Net Capex	Forecast IRR
Near-Term (2014-2016)			
Toledo Hydrotreater Recycle Gas Compressor Project	Improve operational integrity and plant performance	~$20 mm	>20%
Hardisty and Patoka expansion	Expand tankage and blending	~$300 mm	>20%
Mid-Term (2017-2019)			
Lima Crude Flexibility Project	40 mbbls/d of heavy through modification of existing coker	~$300 mm	>20%
Heavy Oil Pipeline System	Grow gathering system to accommodate new Husky thermal and third-party production	~$200 mm	>20%

Strong Downstream Infrastructure Position



(1) Source: Solomon Associates

Strong Downstream Infrastructure Position

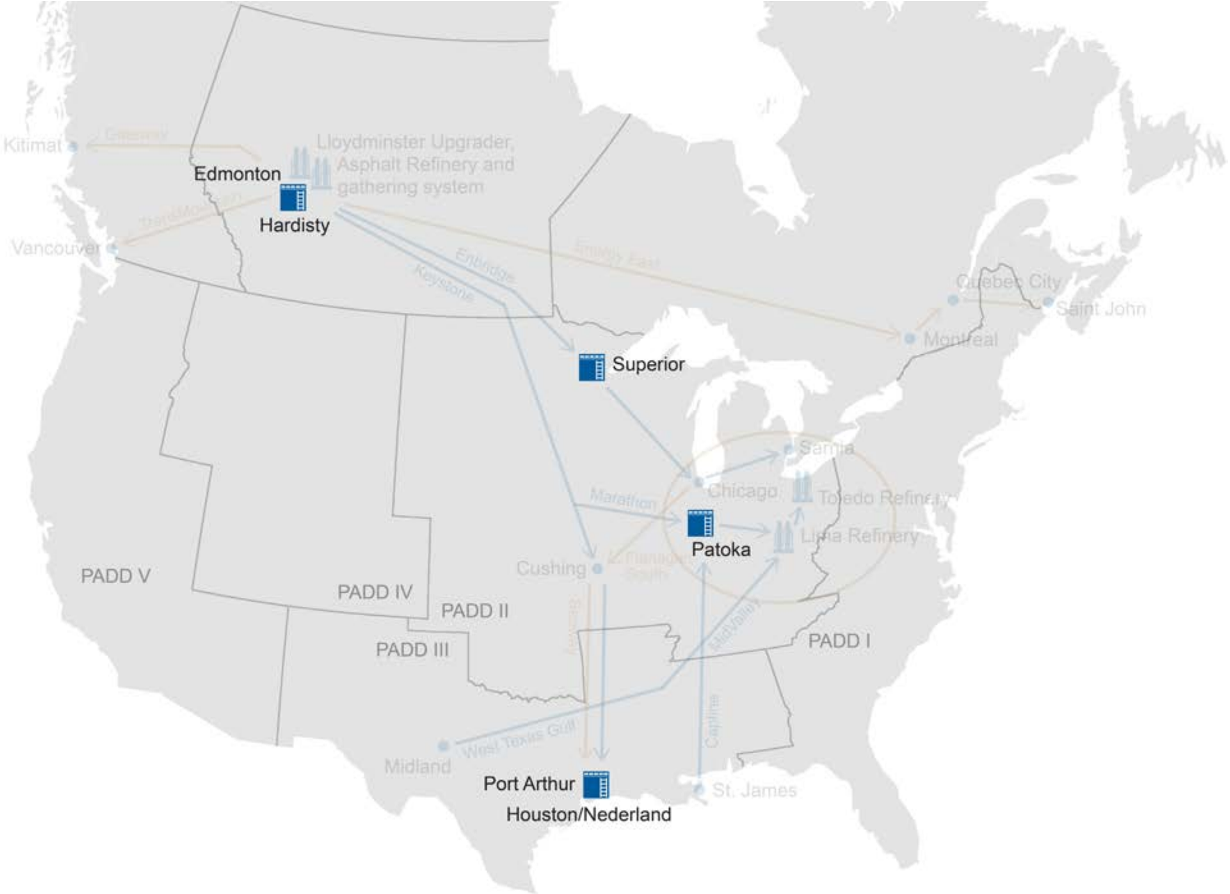


(1) Source: Solomon Associates

Strong Downstream Infrastructure Position

Strong Downstream Infrastructure Position

Strong Downstream Infrastructure Position



Strong Downstream Infrastructure Position

Stabilize Cash Flow and Improve Returns

- Integrated on a barrel for barrel basis
- Reduces cash flow volatility
- Strong returns generated over last three years

1. After-tax and excludes Impairments
2. Adjusted for FIFO impact
3. Western Canada Select
4. Infrastructure and Marketing
5. Impact of scheduled upgrader turnaround

Q & A

Husky Energy

Break

Husky Energy

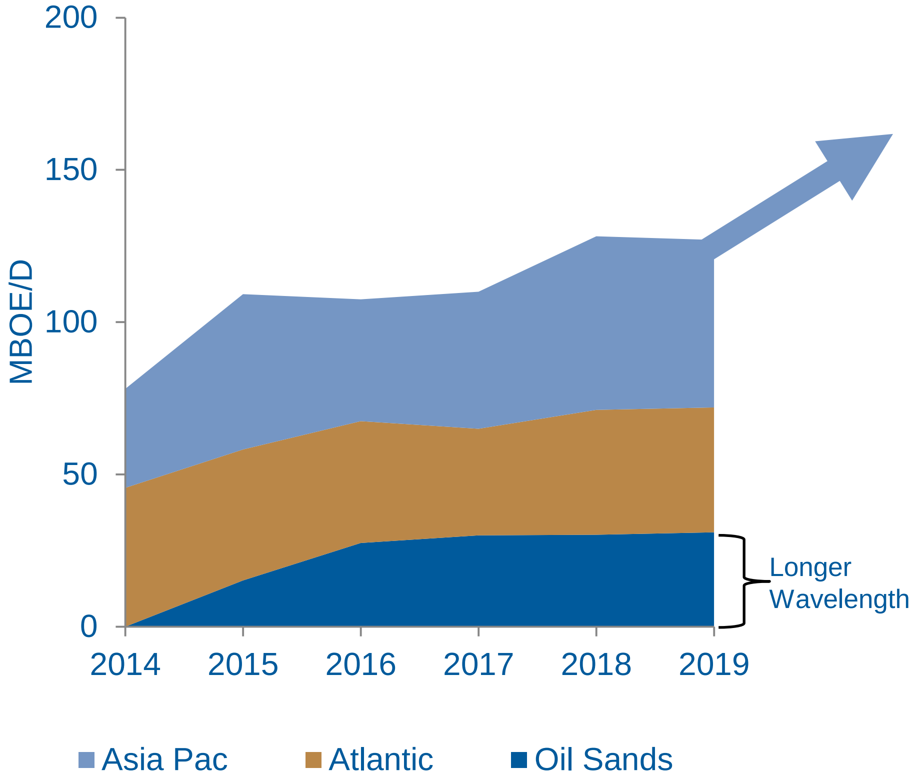
Pillars Review
Rob Peabody

Husky Energy

Pillars Portfolio

Project	Forecast Net Production (boe/d)	Forecast Net Capex	Forecast IRR
Near-Term (2014-2016)			
Asia Pacific			
Liuhua 34-2	3,300	~$100 mm	>15%
Oil Sands			
Sunrise Phase 1	30,000	~$1.4 bln	11-13%
Atlantic Region			
South White Rose	(Peak) 15,000	~$800 mm	>20%
N. Amethyst Hibernia well	(Peak) 5,000	~$100 mm	>20%
Mid-Term (2017-2019)			
Asia Pacific			
Liuhua 29-1	8,000-16,000[1]	~$600 mm	>15%
Madura (MDA, BD, MBH)	17,000	~$500 mm	>20%
Oil Sands			
Sunrise Phase 2A	35,000	~$1.6 bln [2]	12-14%
Atlantic			
West White Rose	(Peak) 25,000	~$2.8 bln	>20%
Long-Term (2020+)			
Asia Pacific			
Five Indonesia discoveries	TBD	TBD	TBD
Oil Sands			
Sunrise Phase 2B	35,000	~$1.6 bln [2]	12-14%
Atlantic Region			
Flemish Pass	TBD	TBD	TBD

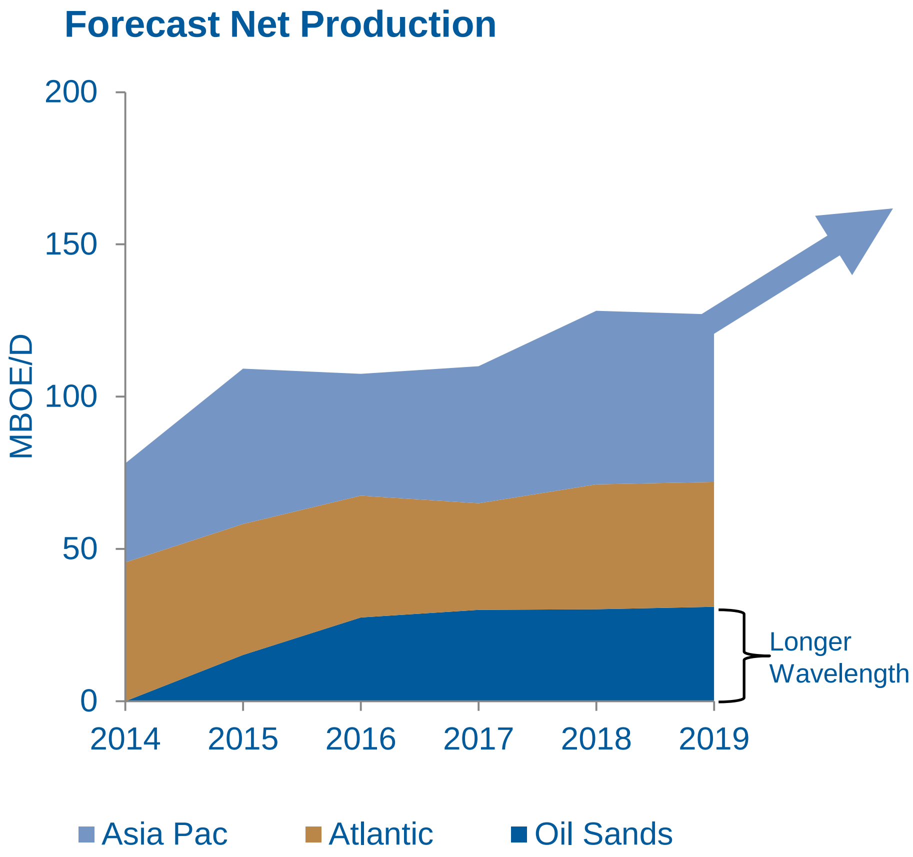
Forecast Net Production



[1] Subject to final gas sales agreement
[2] 2013 dollars

Hitting Our Stride

- Strong pipeline of projects with good returns
- Major identified potential for the future
- Longer wavelength



Asia Pacific
Bob Hinkel

Husky Energy

Crossing the Threshold

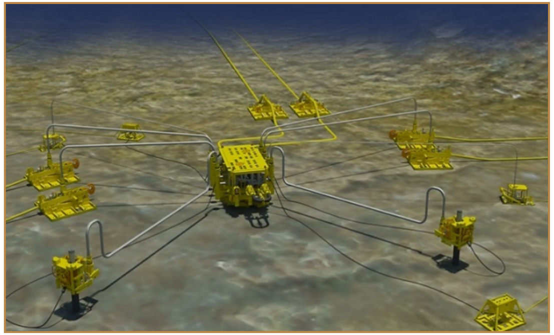
- Material cash flow
- Focused portfolio
- Long track record in region

Project	Current/Forecast Net Production (boe/d)	Forecast Net Capex	Forecast IRR
Expected 2014 Average Production			
Wenchang **Liwan 3-1**	~5,000 ~30,000	- -	>20% ~15%
Near-Term (2014-2016)			
Liuhua 34-2	3,300	~$100 mm	~15%
Mid-Term (2017-2019)			
Liuhua 29-1 **Madura Strait developments (MDA, BD, MBH)**	8,000-16,000 [1] 17,000	~$600 mm ~$550 mm	~15% >20%
Long-Term (2020+)			
Indonesian Discoveries MDK MAC MAX MBJ MBF	 – – – – –	 – – – – –	 – – – – –

[1] Subject to final gas sales agreement

Liwan Gas Project Delivered

- $6.5 billion project for three fields
  - Largest offshore platform in Asia; 1 bcf/d gas terminal
- About seven years from discovery to production
- Producing gas and liquids



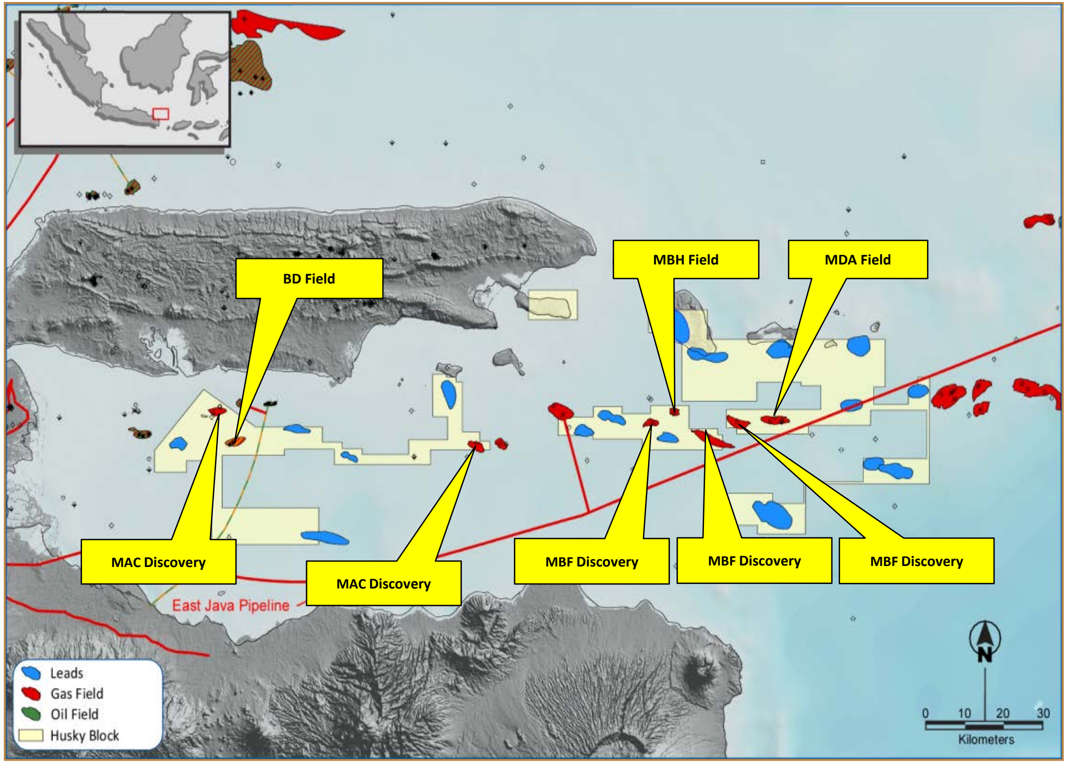
Liwan 3-1 deepwater facilities

Offshore platform

Onshore gas terminal

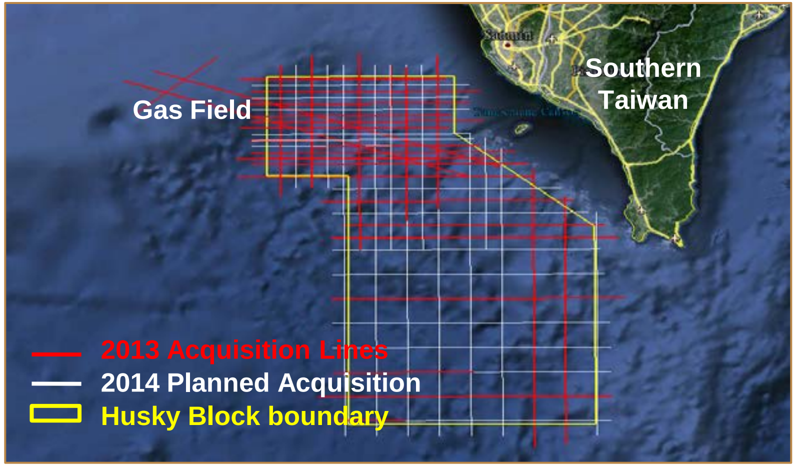
Indonesian Discoveries & Developments

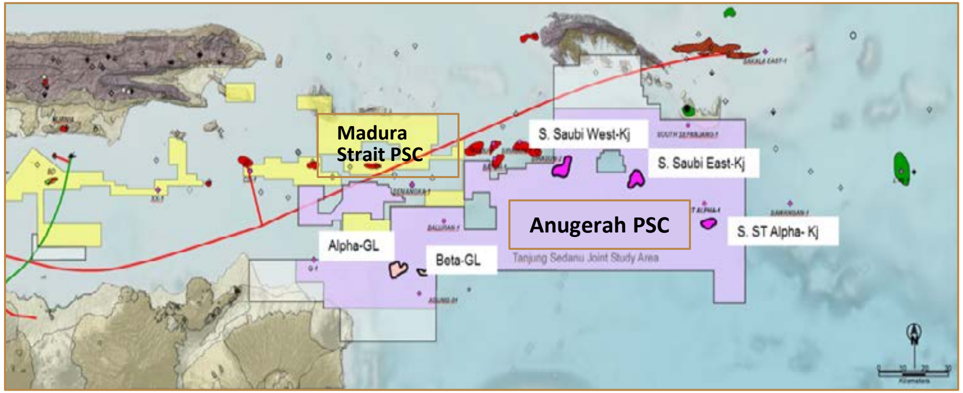
- BD field in construction
  - Net production of 40 mmcf/d gas and 2,400 boe/d liquids (2017F)
- MDA and MBH fields in tender phase
  - Net production of 50 mmcf/d (2017/18F)



The Next Chapter

- Exploration blocks
  - Madura exploration
  - Anugerah PSC
  - Offshore Taiwan
- Leveraging our expertise
- Assessing other opportunities

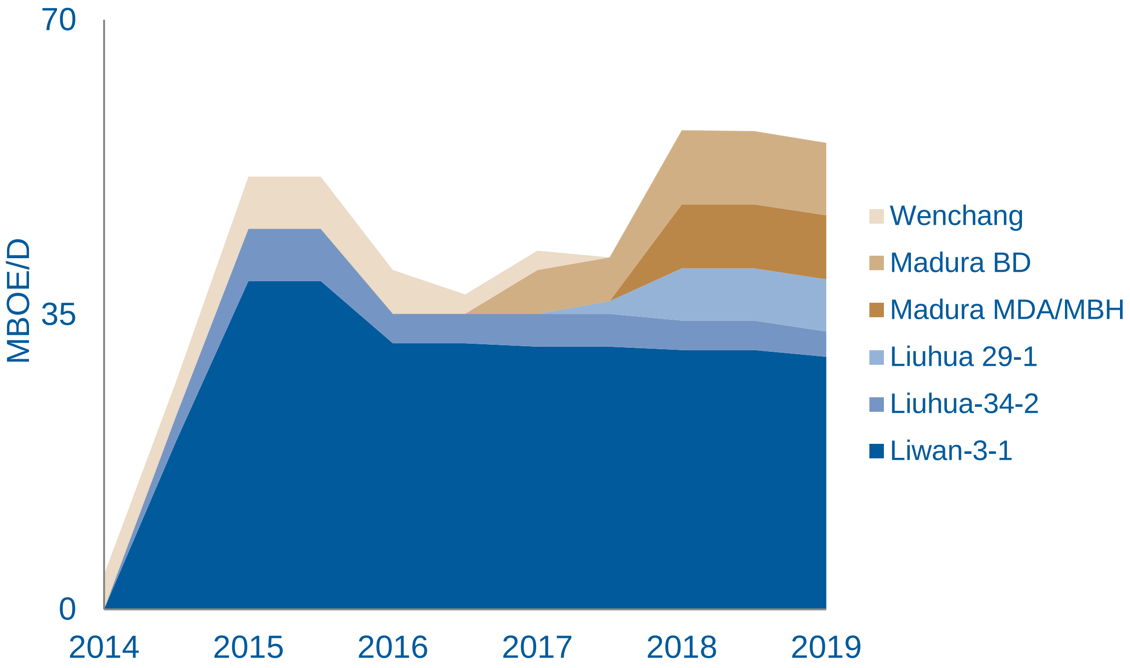




Focused Portfolio

- Material cash flow
- Strong queue of higher return projects
- Established track record

Forecast Net Production (includes cost recovery)



Oil Sands

John Myer

Husky Energy

Predictable Earnings and Cash Flow

- 40-60 year project life
- Paced growth with huge upside
- Technology reducing sustaining capital and operating costs
- Integrated with Downstream

Project	Forecast Net Production (boe/d)	Forecast Net Capex	Forecast IRR
Near-Term (2014-2016)			
Sunrise Phase 1	**30,000**	**~$1.4 bln**	**11-13%**
Mid-Term (2017-2019)			
Sunrise Phase 2A	**35,000**	**~$1.6 bln [1]**	**12-14%**
Long-Term (2020+)			
Sunrise Phase 2B	**35,000**	**~$1.6 bln [1]**	**12-14%**
Saleski	**-**	**-**	**-**
Sunrise Future Development	**-**	**-**	**-**

[1] 2013 dollars

Sunrise Phase 1 By The Numbers

Metric	Target
Production (net)	30,000 bbls/d
Start up to full production	18-24 Months
SOR design rate	3.0
Sustaining capital per bbl [1]	~$8
Life of project	40-60 years
Operating cost per bbl	~$16-18

[1] Non-GAAP measure, please see advisories

Sustaining Capital Protecting Returns

- Two-thirds of the cost of a major oil sands project like Sunrise is sustaining capital
- Evaluating more than 75 technologies to drive down costs, including:
  - Vacuum-insulated tubing
  - Custom rig design
  - Less steel, more modularization

Vacuum-insulated Tubing

Vacuum-insulated Tubing image courtesy of World Heavy Oil Congress, Edmonton Alberta 2011 “An Application of Vacuum Insulated Tubing (VIT) in a SAGD Thermal Completion At Surmont “ WHOC11-621

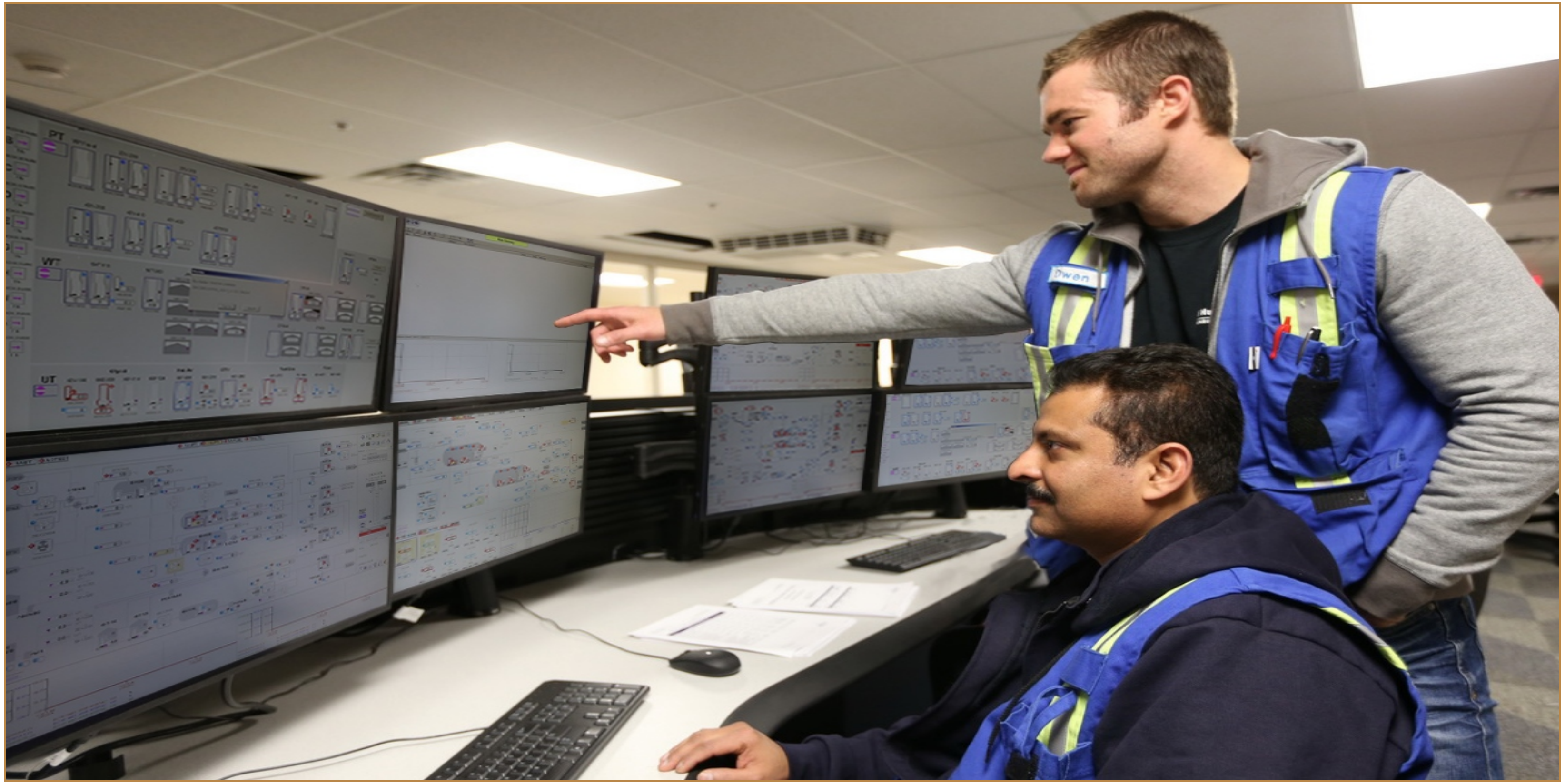
Sunrise Plant 1A

Water Treatment

Motor Control Centre – Plant 1A

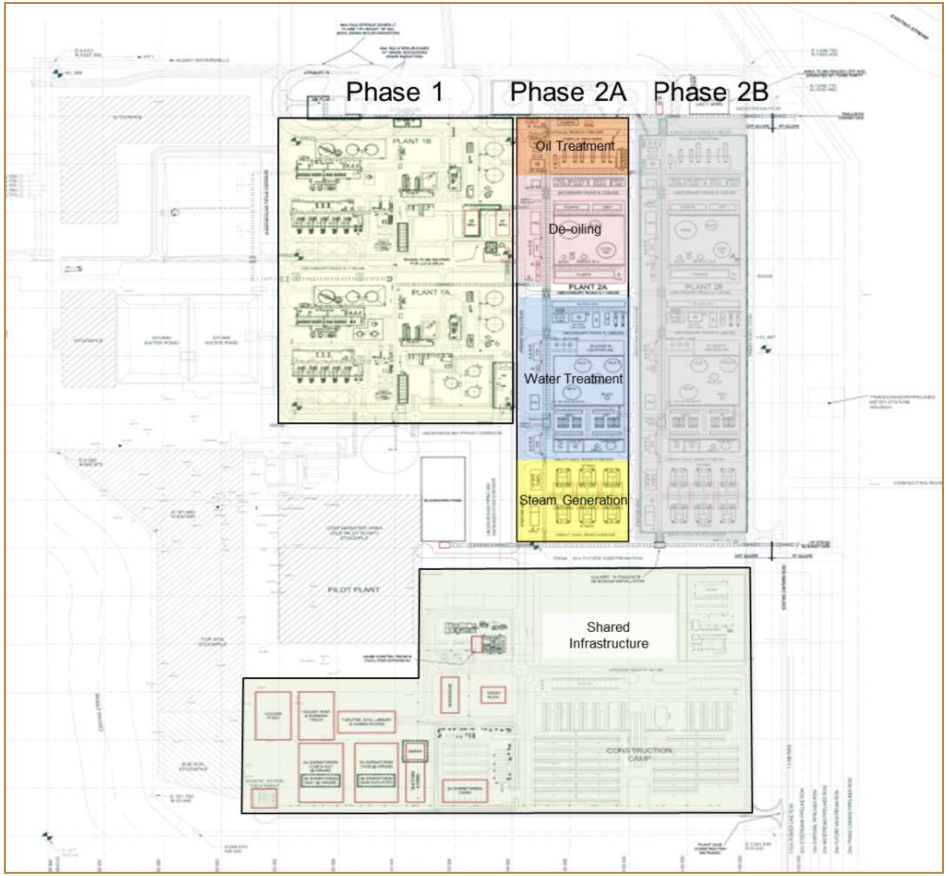
Well Pad

Ready For Operations



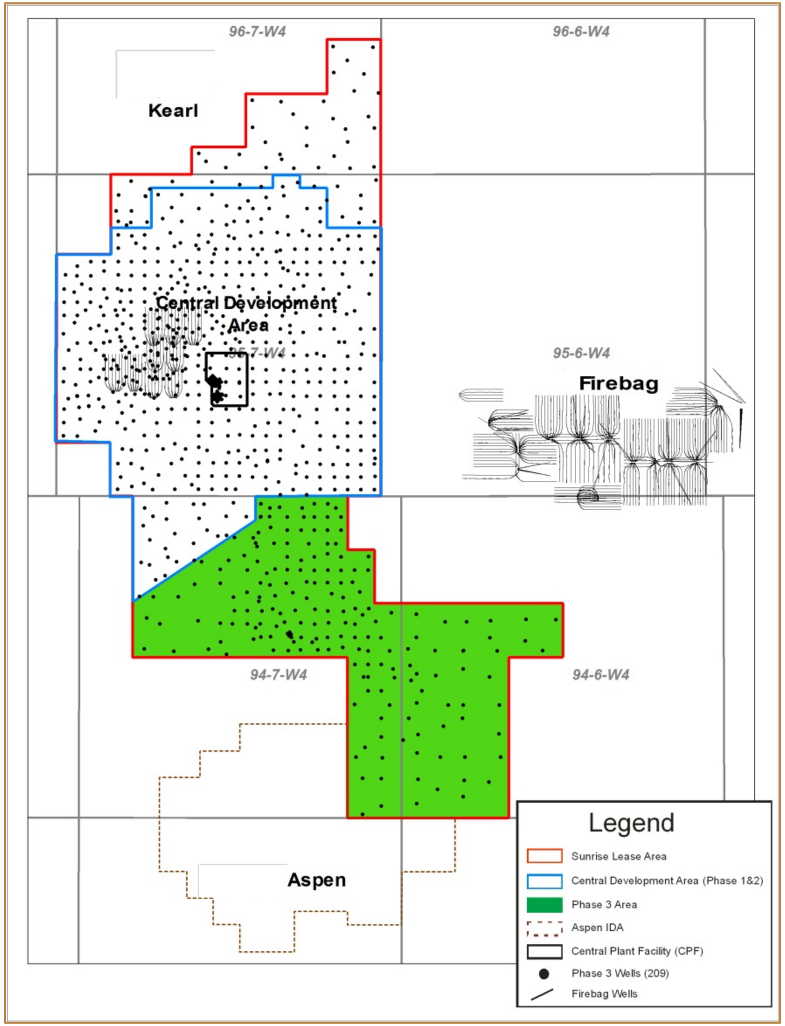
Sunrise Phase 2 – Making Big Projects Smaller

- Phase 2A scheduled for end of decade; Phase 2B about two years later
- Greater modularity
- Reduced plant footprint
- Leveraging existing facilities and equipment
- Greater cost savings



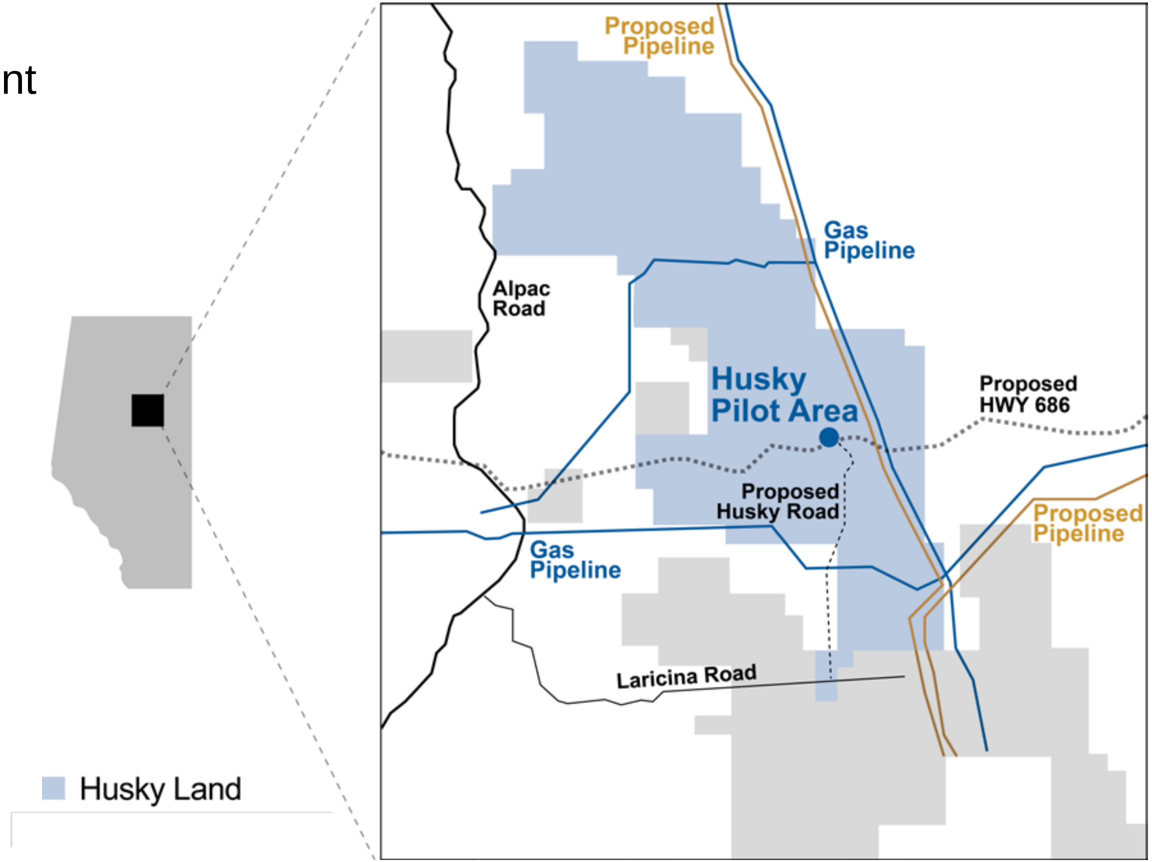
Further Upside at Sunrise

- ~60 square kilometres of 3D seismic program shot
- 209 stratigraphic wells completed
- Thick reservoir
- Potential for further development on lease beyond existing approvals



Growth in the Carbonates – Saleski

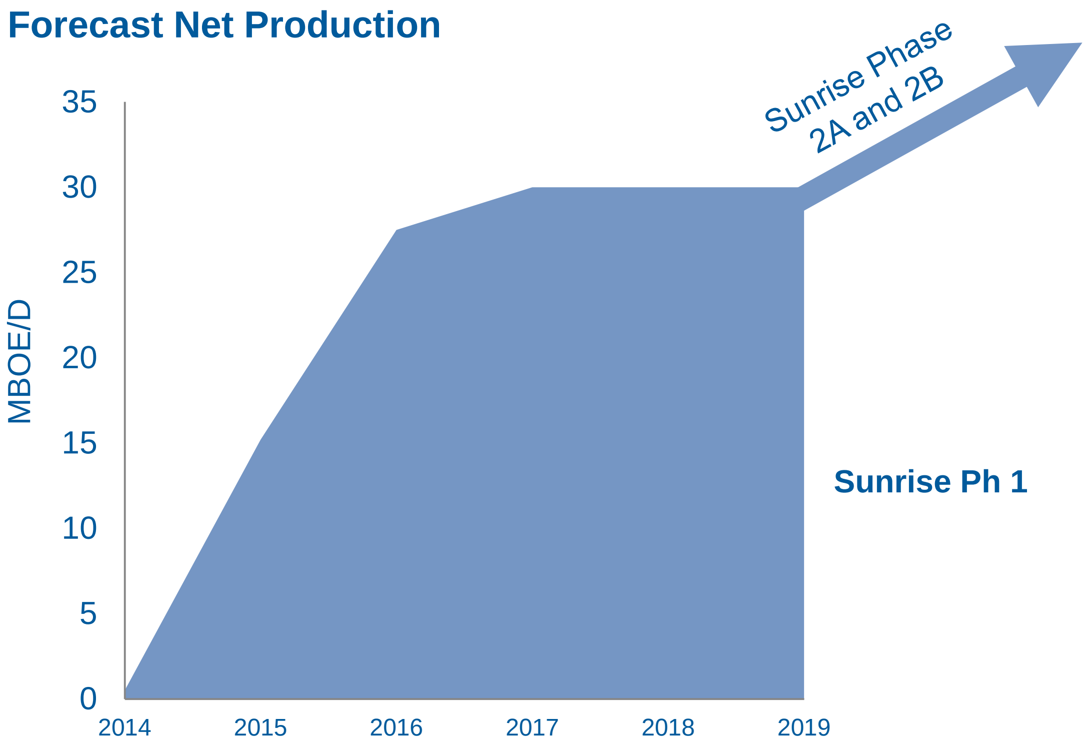
- 10 billion barrels best estimate contingent resources[1]
- Filed regulatory pilot project application
- Infrastructure in place and being developed
- Growth potential for the 2020s



[1] Please see appendix

Longer Wavelength Business

- 40 – 60 year project life
- Annuity-type production
- Paced development with upside potential
- Technology reducing sustaining capital and operating costs
- Integrated with Downstream



Atlantic Region

Malcolm Maclean

Husky Energy

White Rose – A Deep Portfolio

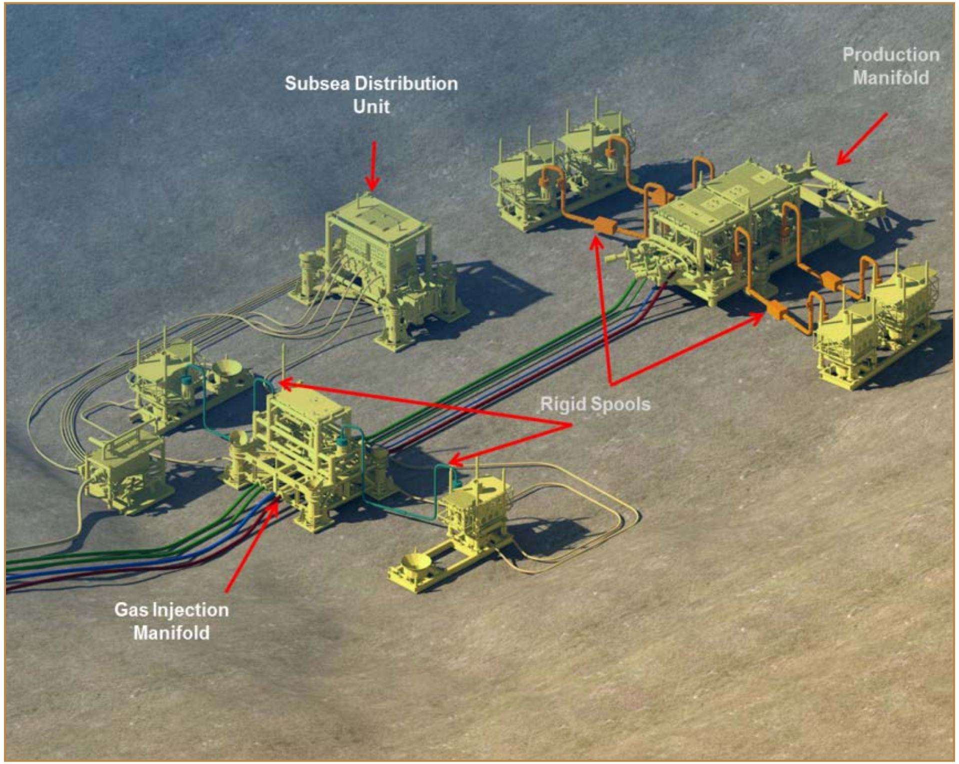
- High netback barrels
- Production and cash flow through the 2020s
- New growth driven by Bay du Nord

Project	Forecast Net Peak Production (boe/d)	Forecast Net Capex	Forecast IRR
Near-Term (2014-2016)			
North Amethyst Hibernia well **South White Rose Extension**	5,000 15,000	~$100 mm ~$800 mm	>20% >20%
Mid-Term (2017-2019)			
West White Rose	25,000	~$2.8 bln	>20%
Long-Term (2020+)			
Flemish Pass **Bay du Nord** **Harpoon** **Mizzen**	 400 million bbls (gross) best estimate contingent resource [1] In delineation 130 million bbls (gross) best estimate contingent resource [1]		

[1] Please see appendix. Husky has a 35% interest in the gross resources.

South White Rose Delivering Higher Quality Returns

- Achieves two objectives:
  - Significant cost savings over standalone gas injection
  - Improves recoverability
- First gas injection Q1 2014, first oil around the end of the year
- Pairing gas injection and oil production improves returns > 20%



Subsea infrastructure

West White Rose Improving Drilling Efficiency

- SeaRose FPSO processing reduces overall project cost
- Wellhead platform designed to facilitate other tie-backs
- Sanction upon development plan approval

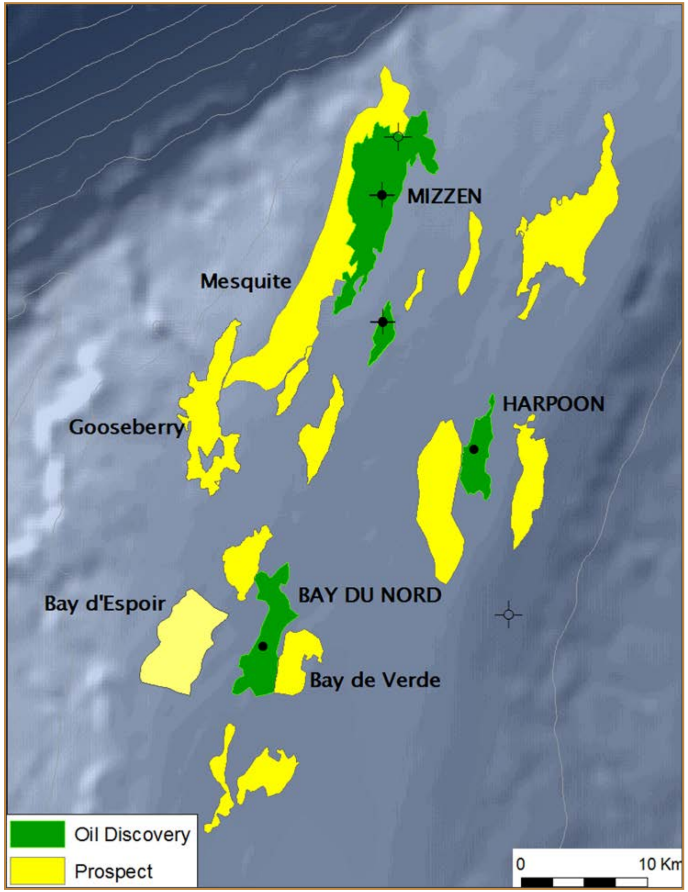
Big Rig, New Technologies

- Employing established technologies in innovative ways to enhance returns
- West Mira custom-built to future needs
- Five-year renewable lease

West Mira under construction

Flemish Pass – Stay Tuned

- Multiple targets identified
- West Hercules drilling rig secured
- 18-month drilling campaign starting in Q3 2014
- Balancing exploration against development

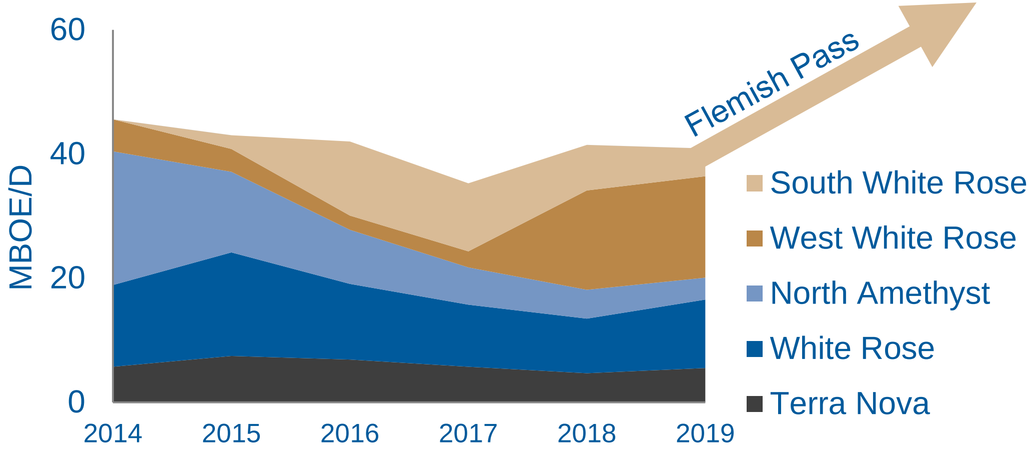


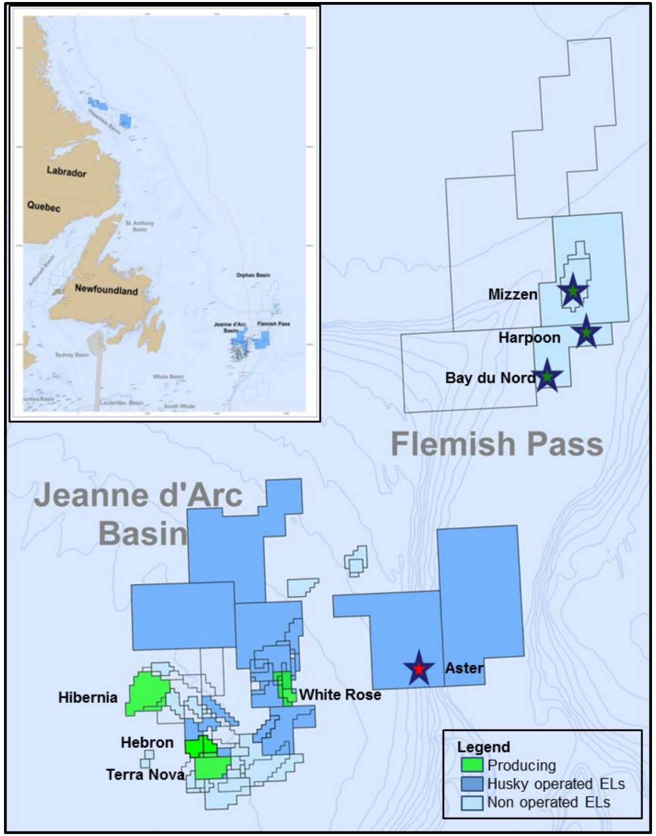
Map courtesy of Statoil

Generating Cash Flow and Growth

- Near and medium-term projects staged to fund future growth and provide dependable cash flow
- Long-term commercial potential in Flemish Pass

Net Production





Pillars Q & A

Husky Energy

Wrap-up
Asim Ghosh

Husky Energy

Balanced Growth Strategy Is Delivering

- Expansive growth portfolio
- Higher quality returns
- Hitting five-year targets
- Top-quartile dividend

Near-Term (2014-2016)

- Sandall Thermal
- Rush Lake Thermal
- Edam West Thermal
- Edam East Thermal
- Vawn Thermal
- South White Rose
- N. Amethyst Hibernia
- Sunrise Energy Project Phase 1
- Wapiti Cardium
- Ansell Cardium
- Ansell Wilrich
- Kaybob Duvernay
- Oungre Bakken
- Viking (various)
- Kakwa Wilrich
- Liwan 3-1
- Liuhua 34-2
- Toledo Recycle Gas Compressor
- Hardisty and Patoka Expansion

Mid-Term (2017-2019)

- Pikes Peak North Thermal
- Rush Lake 2 Thermal
- Lloyd 1 Thermal
- Lloyd 2 Thermal
- McMullen Thermal 1
- Heavy Oil Pipeline Expansion
- S.W. Sask. Multi-zone
- Lima Refinery Heavy Oil Project
- Liuhua 29-1
- West White Rose
- Sunrise Energy Project Phase 2A
- Rainbow Muskwa
- Sinclair Montney
- Kakwa Montney
- Madura BD
- Madura MDA
- Madura MBH

Long-Term (2020+)

- Lloyd 3 Thermal
- McMullen Thermals
- Sunrise Energy Project Phase 2B
- Bay du Nord
- Harpoon
- Mizzen
- Saleski
- Horn River Muskwa
- Wild River Duvernay
- White Rose Gas
- Heavy Oil Cold EOR
- Slater River NWT
- Sunrise Future Phases
- Five Indonesia Discoveries
- Graham Montney
- Cypress Montney

Final Q & A

Husky Energy

Advisories

Forward-Looking Statements and Information

Certain statements in this document are forward-looking statements and information (collectively “forward-looking statements”), within the meaning of the applicable Canadian securities legislation, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. The forward-looking statements contained in this document are forward-looking and not historical facts.

Some of the forward-looking statements may be identified by statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will likely result", "are expected to", "will continue", "is anticipated", “is targeting”, "estimated", "intend", "plan", "projection", "could", “aim”, "vision", "goals", "objective", "target", "schedules" and "outlook"). In particular, forward-looking statements in this document include, but are not limited to, references to:

- with respect to the business, operations and results of the Company generally: the Company’s general strategic plans and growth strategies; the Company’s near, mid and long-term queue of projects; forecast “long-wavelength” and conventional production as percentages of total production by 2019; projected product pricing mix as a percentage of past and forecast production through 2019; anticipated reserve replacement ratio through 2017; 5-year targets for production, cash flow from operations, reserve replacement ratio, return on capital in use, and return on capital employed; proportions of expected production by geographic region and product type for 2014-2019, the Company’s 2014 capital expenditure and production guidance; the Company’s target net debt to cash flow and net debt to capital for 2012 - 2017; forecast near-term and mid-term net production adds, net capital expenditure and IRR from projects in the Company’s Heavy Oil Thermal, Western Canada and Downstream properties; proportions of expected production from conventional, resource plays and heavy oil through 2019; proportions of expected production from conventional oil, conventional gas and resource plays through 2019; forecast near, mid and long-term net production, net capital expenditure and IRR from projects in the Company’s Asia Pacific, Oil Sands and Atlantic regions; and volumes and proportions of expected production from projects in the Company’s Asia Pacific, Oil Sands and Atlantic regions through 2019 and beyond;

- with respect to the Company's Asia Pacific Region: forecast 2014 average, near, mid and long-term net production, net capital expenditure and IRR from projects in the Company’s Asia Pacific Region; anticipated timing and volumes of production from the Company’s Madura BD, MDA and MBH fields ; the Company’s future exploration plans in the Asia Pacific Region; volumes and proportions of expected production from the Company’s Asia Pacific Region projects through 2019; and anticipated time frame for production from the Company’s Liuhua 34-2 and Liuhua 29-1 gas fields and gross production capacity

- with respect to the Company's Atlantic Region: forecast near, mid, and long-term net peak production, net capital expenditure and IRR from the Company’s Atlantic Region projects; expectations for production and cash flow through the 2020s; anticipated timing of first oil from the Company’s South White Rose project; expected improvement in returns resulting from pairing of gas injection and oil production at the South White Rose developments; expectations regarding sanctioning of the West White Rose project; exploration and drilling plans in the Company’s Atlantic Region; anticipated growth and cash flow resulting from the Company’s near and medium-term projects in the region; anticipated long-term commercial potential in the Flemish Pass area; and volumes and proportions of expected production from the Company’s Atlantic Region projects through 2019 and beyond;

- with respect to the Company's Oil Sands properties: anticipated life span of projects in the region; forecast near, mid and long-term net production, net capital expenditure and IRR from the Company’s Oil Sands projects; targets for net production, timing of startup to full production, SOR design rate, sustaining capital per bbl, life of project, , and operating cost per bbl at Phase 1 of the Company’s Sunrise Energy Project; scheduled timing of completion of phase 2A and phase 2B of the Company’s Sunrise Energy Project; anticipated development potential at the Company’s Sunrise Energy Project and other oil sands properties; anticipated long-term growth potential in the Company’s Saleski area; and forecast net production from the Company’s Sunrise Energy Project through 2019 and beyond;

Advisories

- with respect to the Company's Western Canadian oil and gas plays: mid-term exploration and development potential at specified plays; estimated time to drill at specified plays; estimated well costs at specified plays; estimated net resource potential and potential EUR/well at the Company's oil resource and gas resource plays;

- with respect to the Company's Heavy Oil properties: 2019 forecast mix of thermal and non-thermal production; estimated timing and volume of production growth from the Company's thermal projects; estimated timing of first oil and estimated production rates from the Company's slate of thermal projects; estimated thermal production economics; and anticipated proportion of net production from CHOPS, horizontal drilling, Cold EOR, thermal production and the Company's McMullen project through 2019; and

- with respect to the Company's Downstream operating segment: forecast near-term and mid-term scope, net capital expenditure and IRR from projects in the Company's Downstream operating segment.

In addition, statements relating to "reserves" and "resources" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves or resources described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of reserves and resources and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary from reserve, resource and production estimates.

Although the Company believes that the expectations reflected by the forward-looking statements presented in this document are reasonable, the Company's forward-looking statements have been based on assumptions and factors concerning future events that may prove to be inaccurate. Those assumptions and factors are based on information currently available to the Company about itself and the businesses in which it operates. Information used in developing forward-looking statements has been acquired from various sources including third party consultants, suppliers, regulators and other sources.

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements, investors should not place undue reliance on any such forward-looking statements. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, which contribute to the possibility that the predicted outcomes will not occur. Some of these risks, uncertainties and other factors are similar to those faced by other oil and gas companies and some are unique to Husky.

The Company's Annual Information Form for the year ended December 31, 2013 and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe the risks, material assumptions and other factors that could influence actual results and are incorporated herein by reference.

Any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by applicable securities laws, the Company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.

Non-GAAP Measures

This document contains certain terms which do not have any standardized meaning prescribed by IFRS and are therefore unlikely to be comparable to similar measures presented by other issuers. None of these measurements are used to enhance the Company's reported financial performance or position. With the exception of net operating earnings and cash flow from operations, there are no comparable measures to these non-GAAP measures in accordance with IFRS. These non-GAAP measurements are considered to be useful as complementary measurements in assessing Husky's financial performance, efficiency and liquidity, but may not be appropriate for other purposes. These terms include:

Cash Flow from Operations, which should not be considered an alternative to, or more meaningful than “cash flow – operating activities” as determined in accordance with IFRS, as an indicator of financial performance. Cash flow from operations is presented in the Company’s financial reports to assist management and investors in analyzing operating performance by business in the stated period. Husky’s determination of cash flow from operations may not be comparable to that reported by other companies. Cash flow from operations equals net earnings plus items not affecting cash which include accretion, depletion, depreciation, amortization and impairment, exploration and evaluation expense, deferred income taxes, foreign exchange, gain or loss on sale of assets and other non-cash items.

($ millions)	2010	2013	Q1 2014
GAAP cash flow – operating activities	2,222	4,645	1,336
Settlement of asset retirement obligations	60	142	49
Income taxes paid	784	433	96
Interest received	(1)	(19)	(3)
Change in non-cash working capital	7	21	58
Non-GAAP cash flow from operations	3,072	5,222	1,536

Compound Annual Growth Rate ("CAGR") measures the year-over-year growth rate over a specified period of time. CAGR is presented in Husky's financial reports to assist management in analyzing longer-term performance. CAGR is calculated by taking the nth root of the total percentage growth rate, where n is the number of years in the period being considered.

Return on Capital Employed ("ROCE") measures the return earned on long-term capital sources such as long term liabilities and shareholder equity. ROCE is presented in Husky's financial reports to assist management in analyzing shareholder value. ROCE equals net earnings plus after-tax finance expense divided by the two-year average of long term debt including long term debt due within one year plus shareholders' equity. Return on capital employed was adjusted for an after-tax impairment charge on property, plant and equipment of $204 million for the year ended December 31, 2013. Return on capital employed, based on the calculation used in prior periods for the year ended December 31, 2013, was 7.9%.

Return on Capital in Use (“ROCU”) measures the return earned on those portions of long-term capital sources such as long term liabilities and shareholder equity that are currently generating cash flows. ROCU is presented in Husky's financial reports to assist management in analyzing shareholder value and return on capital. ROCU equals net earnings plus after-tax interest expense divided by the two-year average of long term debt including long term debt due within one year plus shareholders' equity less any capital invested in assets that that are not generating cash flows. Return on capital in use was adjusted for an after-tax impairment charge on property, plant and equipment of $204 million for the year ended December 31, 2013. Return on capital in use based on the calculation used in prior periods for the year ended December 31, 2013 was 11.3%.

Return on Equity is used to assist in analyzing shareholder value. Return on equity equals net earnings divided by the two-year average shareholders' equity.

Sustaining capital on a per unit basis is calculated as annual capital expenditures divided by plant design throughput.

Operating netback assists management and investors to evaluate the specific operating performance by product at the oil and gas lease level. The operating netback was determined as realized price less royalties, operating costs and transportation on a per unit basis.

Advisories

Disclosure of Oil and Gas Information

Unless otherwise stated, reserve and resource estimates in this document have an effective date of December 31, 2013 and represent Husky's share. Unless otherwise noted, historical production numbers given represent Husky's share.

The Company uses the terms barrels of oil equivalent ("boe"), which is calculated on an energy equivalence basis whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. Readers are cautioned that the term boe may be misleading, particularly if used in isolation. This measure is primarily applicable at the burner tip and does not represent value equivalence at the wellhead.

Reserve replacement ratios for a given period are determined by taking the Company's incremental proved reserve additions for that period divided by the Company's upstream gross production for the same period. Forecast reserve replacement ratios for a given period are calculated by taking the forecast proved reserve additions for those periods divided by the forecast gross production for the same periods.

The Company has disclosed possible reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of proved plus probable plus possible 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.

The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation. The Company has disclosed its total reserves in Canada in its Annual Information Form for the year ended December 31, 2013, which reserves disclosure is incorporated by reference herein.

The Company has disclosed best-estimate contingent resources in this document. Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters, or a lack of markets. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

Best estimate as it relates to resources is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Estimates of contingent resources have not been adjusted for risk based on the chance of development. There is no certainty as to the timing of such development. For movement of resources to reserves categories, all projects must have an economic depletion plan and may require, among other things: (i) additional delineation drilling for unrisked contingent resources; (ii) regulatory approvals; and (iii) Company and partner approvals to proceed with development.

Specific contingencies preventing the classification of contingent resources at the Company's Atlantic Region discoveries as reserves include additional exploration and delineation drilling, well testing, facility design, preparation of firm development plans, regulatory applications, company and partner approvals. Positive and negative factors relevant to the estimate of Atlantic Region resources include water depth and distance from existing infrastructure.

Advisories

Disclosure of Oil and Gas Information cont'd

Specific contingencies preventing the classification of contingent resources at the Company's oil sands properties as reserves include further reservoir studies, delineation drilling, facility design, preparation of firm development plans, regulatory applications and company approvals Development is also contingent upon successful application of SAGD and/or Cyclic Steam Stimulation (CSS) technology in carbonate reservoirs at Saleski, which is currently under active development. Positive and negative factors relevant to the estimate of oil sands resources include a higher level of uncertainty in the estimates as a result of lower core-hole drilling density. The Company has disclosed best estimate contingent resources in the tables on slide 96. The economic portion of these contingent resources is 10,952.4 mmboe and the uneconomic portion is 1,819.4 mmboe.

Specific contingencies preventing the classification of contingent resources at the Company's McMullen properties as reserves include further geological and reservoir studies, seismic data acquisition and evaluation, exploration and delineation drilling, facility design, reservoir performance, preparation of firm development plans, regulatory applications and company approvals.   Positive and negative factors relevant to the estimate the oil sands resources include a higher level of uncertainty in the estimates as a result of variability in well distribution and depths across the area and regional trends in reservoir quality.

Specific contingencies preventing the classification of contingent resources at the Company's heavy oil properties as reserves include further geological and reservoir studies, seismic data acquisition and evaluation, exploration and delineation drilling, facility design, reservoir performance, preparation of firm development plans, regulatory applications and company approvals. Some development is also contingent upon successful development and application of enhanced oil recovery technologies in post-CHOPS reservoirs, and reservoir response in waterflood projects. Positive and negative factors relevant to the estimate of heavy oil resources include a higher level of uncertainty in the estimates as a result of variability in well distribution and depths across the area and regional trends in reservoir quality.

Specific contingencies preventing the classification of contingent resources in the Company's Western Canada resource plays as reserves include required improvement in gas prices, optimization of drilling and completion design to further reduce costs, preparation of firm developments plans, timing of development and Company approvals. Positive and negative factors relevant to the estimate of Western Canada resource play resources include a higher level of uncertainty in the estimates as a result of a lower number of wells and limited production history. Total reserves estimates for Ansell are provided. This is a total of proved, probable and possible reserves. The 150 million boe of reserves (net) are comprised of Proved: 113 million boe, Probable: 19 million boe and Possible: 18 million boe.

Specific contingencies preventing the classification of contingent resources at the Company's Asia Pacific region discoveries as reserves include additional exploration and delineation drilling, well testing, facility design, preparation of firm development plans, regulatory applications, company and partner approvals. Positive and negative factors relevant to the estimate of Asia Pacific resources include water depth and distance from existing infrastructure.

Advisories

Note to U.S. Readers

The Company reports its reserves and resources information in accordance with Canadian practices and specifically in accordance with National Instrument 51-101, "Standards of Disclosure for Oil and Gas Disclosure", adopted by the Canadian securities regulators. Because the Company is permitted to prepare its reserves and resources information in accordance with Canadian disclosure requirements, it uses certain terms in this document, such as “possible reserves” and "best estimate contingent resources" that U.S. oil and gas companies generally do not include or may be prohibited from including in their filings with the SEC.
All currency is expressed in Canadian dollars unless otherwise directed.

Appendix

Husky Energy

Reserves Breakdown: Foundation Portfolio

Project	WI Proved MMBOE	W-I Probable MMBOE	WI- Possible- MMBOE	WI Contingent Resources Best Estimate MMBOE
Heavy Oil				
Non-Thermal (total)	80.1	40.1	24.2	-
Heavy Oil Cold EOR	2.4	0.9	1.8	35.0
Thermal(existing)	65.8	59.6	43.0	-
Rush lake	17.3	46.7	25.8	4.5
Edam West	-	-	-	23.4
Edam East	-	41.2	12.3	-
Vawn	-	49.2	20.0	-
Prince	-	-	-	-
Dee Valley	-	-	-	19.1
Kimino	-	-	-	-
Triangle Thermal	-	-	-	-
Lloyd Thermal	-	-	-	13.7
Beaverdam Thermal	-	-	-	10.9
Tucker	56.2	112.2	117.2	-
Western Canada				
Conventional Oil and Gas	491.4	130.6	10.2	-
Resource Plays				
Oil				
Butte Lower Shaunavon	1.0	0.2	-	-
Oungre Bakken	3.6	1.1	-	-
Rainbow Muskwa	0.5	0.5	-	4.3
Wapiti Cardium	6.5	1.8	-	-
Viking (various)	10.6	2.8	-	-
Kakwa	0.2	0.1	-	0
Gas				
Ansell Multi-zone	112.7	18.6	18.4	396.7
Kaybob South Duvernay	4.9	15.8	-	29.9
Bivouac Jean Marie	5.3	0.4	-	17.1
Kakwa Montney	0.8	1.2	-	-
Kakwa other zones	-	-	-	-
Leland Montney	0.1	0.7	-	3.3
Sinclair Montney (North & South)	-	-	-	11.9
Cypress	-	-	-	48.5
Horn River, Muskwa and Evie	-	-	-	64.8
Wild River Duvernay	-	-	-	-
Slater River Canol	-	-	-	-

All figures as of Dec 31, 2013

Reserves Breakdown: Pillars Portfolio

Project	Working Interest Proved MMBOE	Working Interest Probable MMBOE	Working Interest Possible MMBOE	WI Contingent Resources Best Estimate MMBOE
Atlantic Region				
White Rose				
S. Avalon Oil	23.9	21.2	24.3	-
West White Rose Extensions	9.1	4.4	65.4	-
North Amethyst	11.3	8.4	13.8	-
Terra Nova	19.8	2.8	12.1	-
South White Rose	6.9	9.9	3.1	-
N. Amethyst Hibernia Well	3.4	3.4	3.5	-
North White Rose	-	-	3.5	-
White Rose Gas	-	-	-	215.3
Flemish Pass Oil				
Bay du Nord	-	-	-	141.2
Harpoon	-	-	-	-
Mizzen	-	-	-	46.1
Asia Pacific				
Oil: Wenchang	7.2	1.0	0.8	-
Gas: Liwan 3-1	52.2	47.2	6.0	-
Liuhua 34-2	4.0	2.3	-	-
Madura BD	35.0	8.2	5.3	-
Madura MDA + MBH	-	18.8	3.7	2.3
Liuhua 29-1	-	-	-	29.0
5 Indonesia discoveries (MDK+MAC)	-	-	-	12.5
Indonesia Next Phases	-	-	-	-
Oil Sands				
Sunrise Phase 1 and 2	219.8	1,202.5	431.7	-
McMullen Cold/TCP/Thermal	12.5	8.2	27.7	644.3 (Thermal)
Sunrise Energy Project Phase 3	-	-	-	211.0
Saleski	-	-	-	9,963.3
10 other Oil Sands properties	-	-	-	802.4

All figures as of Dec 31, 2013

Appendix: Liwan Economics

- Operating costs ~10%
- Taxes and royalties ~20%
- Exploration cost recovery ~$800mm

Field	Gross Production Capacity	Price	Time Frame
Liwan 3-1 Gas NGLs	**300 mmcf/d** **10-14 mboe/d**	**~$11-13/mcf** **~$100/boe**	**Current** **Current**
Liuhua 34-2 Gas	**40 mmcf/d**	**~$11-13/mcf**	**H2 2014**
Liuhua 29-1 Gas	**1-200 mmcf/d**	**In Negotiation**	**2017**

Offshore platform

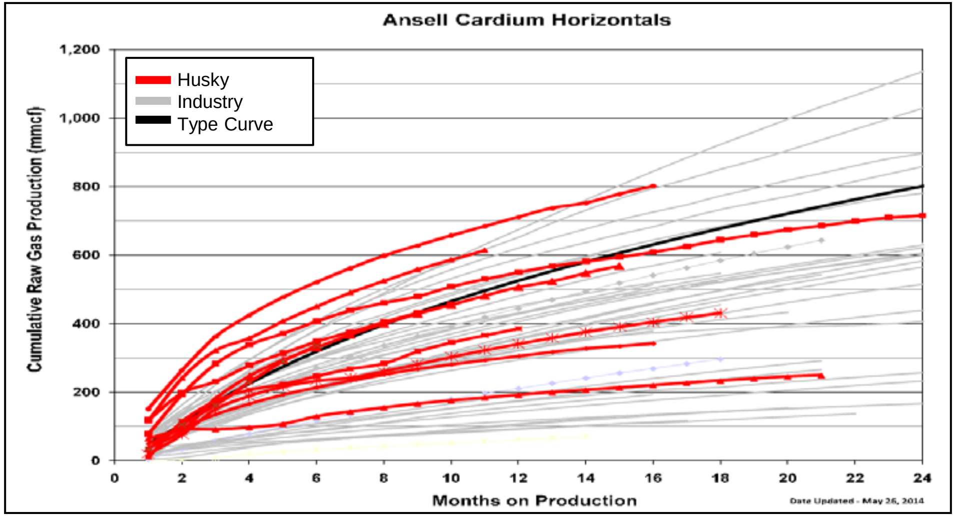
Onshore gas terminal

Gas Resource Play Templates

1. Ansell – Cardium Horizontal Wells
2. Ansell – Wilrich Horizontal Wells
3. Ansell – Falher Notikewin Wells
4. Strachan – Cardium
5. Kakwa – Wilrich
6. Kaybob – Duvernay
7. Kakwa – Montney
8. Sinclair – Montney
9. Horn River – Muskwa / Evie
10. Wild River – Duvernay

1. Ansell – Cardium

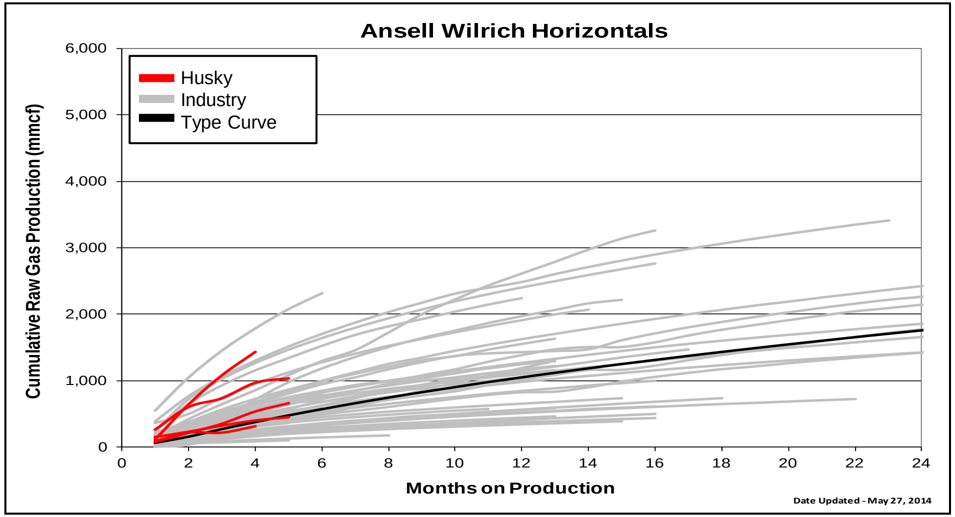
- Total Liquids Content: ~60 bbls/mmcf
- Estimated Ultimate Recovery/Well: ~600 MBOE
- Well Cost (current to steady): ~$9.5 MM to $7.5 MM



Background Facts	Drilling Summary	Completions Summary
• ~120,000 net acres Cardium rights* • ~300 gross vertical wells and 16 Hz drilled to date • 11 HZ wells on production to date: all ball drop system • ~350 net locations **Wilrich & other Spirit River rights sometimes also held	• Vertical depth: 2,400 m • Lateral Length: 1,500 m • Technology: RSS/Conventional directional drilling • Time to drill: 28 days	• Number of stages: 12 - 18 • Length: 1500 m HZ section • Type of frac: ball drop • Tonnes per stage: 25T – 50T • Type of fluid / Amount of fluid: Propane/water • Typical fracs for the area: Slick water, Propane

2. Ansell – Wilrich

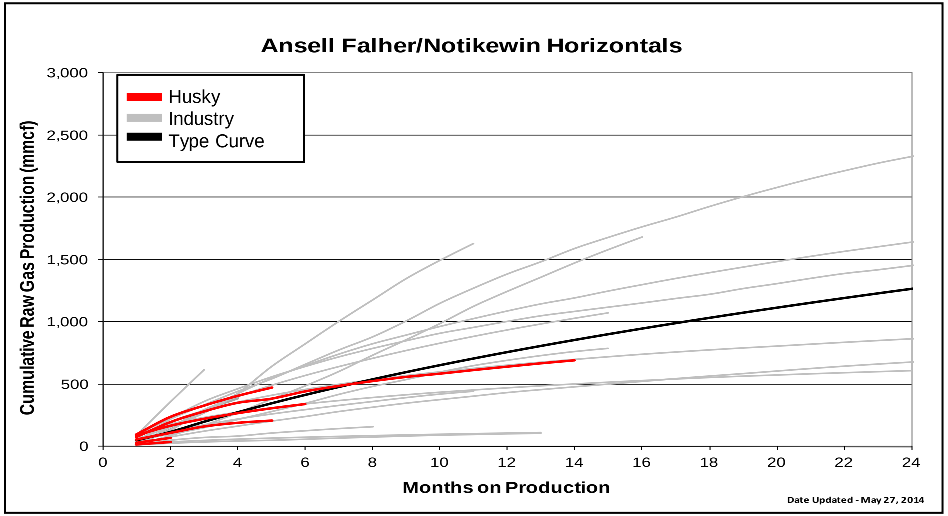
- Total Liquids Content: ~21 bbls/mmcf
- Estimated Ultimate Recovery/Well: ~833 MBOE
- Well Cost (current to steady): ~$9.0 MM to $6.2 MM



Background Facts:	Drilling Summary	Completions Summary
• ~100,000 net acres Wilrich rights* • 10 Hz producers as of Apr. 2014 • ~340 net locations **Cardium & other Spirit River rights sometimes also held	• Vertical Depth: 3,100 m • Lateral Length: 1,500 m • Technology: RSS / Conventional Directional Drilling • Time to Drill: 33 days	• Number of Stages: 10-12 • Length: 1,500 m HZ Section • Type of Frac: Ball Drop • Tonnes per Stage: 80T • Type of Fluid / Amount of Fluid: Slickwater • Typical Fracs for the Area: Slickwater

3. Ansell – Falher/Notikewin Horizontal Wells

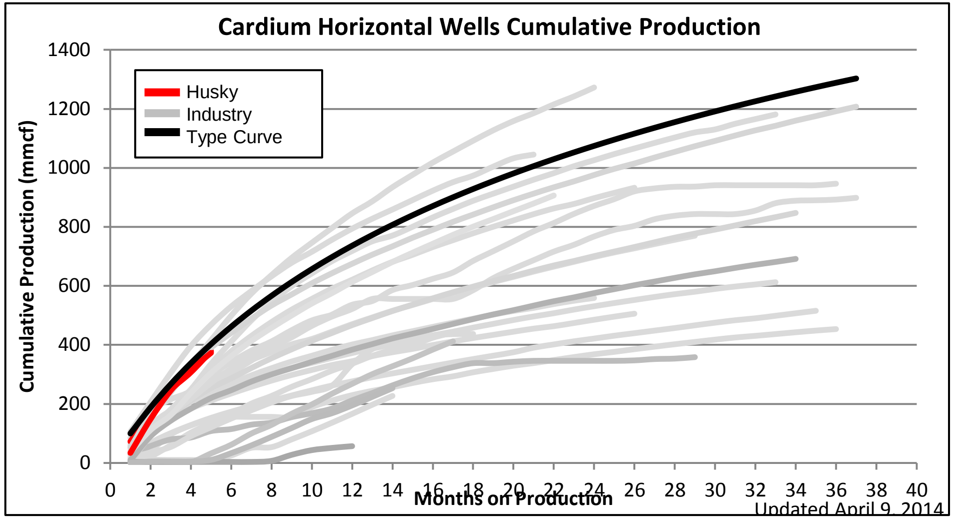
- Total Liquids Content: ~42 bbls/mmcf
- Estimated Ultimate Recovery/Well: ~778 MBOE
- Well Cost (current): ~$9.0 MM



Background Facts	Drilling Summary	Completions Summary
• ~100,000 net acres • 6 Hz producers as of Apr. 2014 • ~90 net locations **Cardium & other Spirit River rights sometimes also held	• Vertical Depth: 2900 m • Lateral Length: 1500 m • Technology: RSS / Conventional Directional Drilling • Time to Drill: 33 days	• Number of Stages: 9 - 19 • Length: 1200-2300 m HZ Section • Type of Frac: Ball Drop • Tonnes per Stage: 80T • Type of Fluid: Slickwater • Typical Fracs for the Area: Slickwater

4. Strachan – Cardium Horizontal Wells

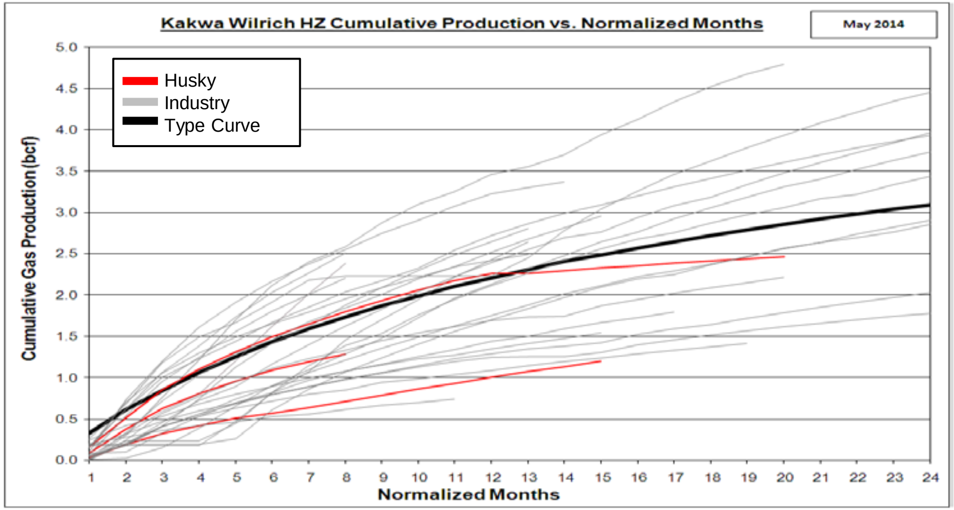
- Total Liquids Content: ~62 bbls/mmcf
- Estimated Ultimate Recovery/Well: ~507 MBOE
- Well Cost (current to steady): ~$5.1 MM to $4.3 MM



Background Facts	Drilling Summary	Completions Summary
• ~11,000 net acres • 2 Hz producers as of March 2014 • ~25 net locations	• Vertical Depth: 3,100 m • Lateral Length: 1,100 m • Technology: Monobore Directional Drilling • Time to Drill: 24 days	• Number of Stages: 15 • Length: 1,100 m HZ Section • Type of Frac: Ball Drop • Tonnes per Stage: 20T • Type of Fluid / Amount of Fluid: Nitrified Gel • Typical Fracs for the Area: Slickwater / Oil

5. Kakwa – Wilrich

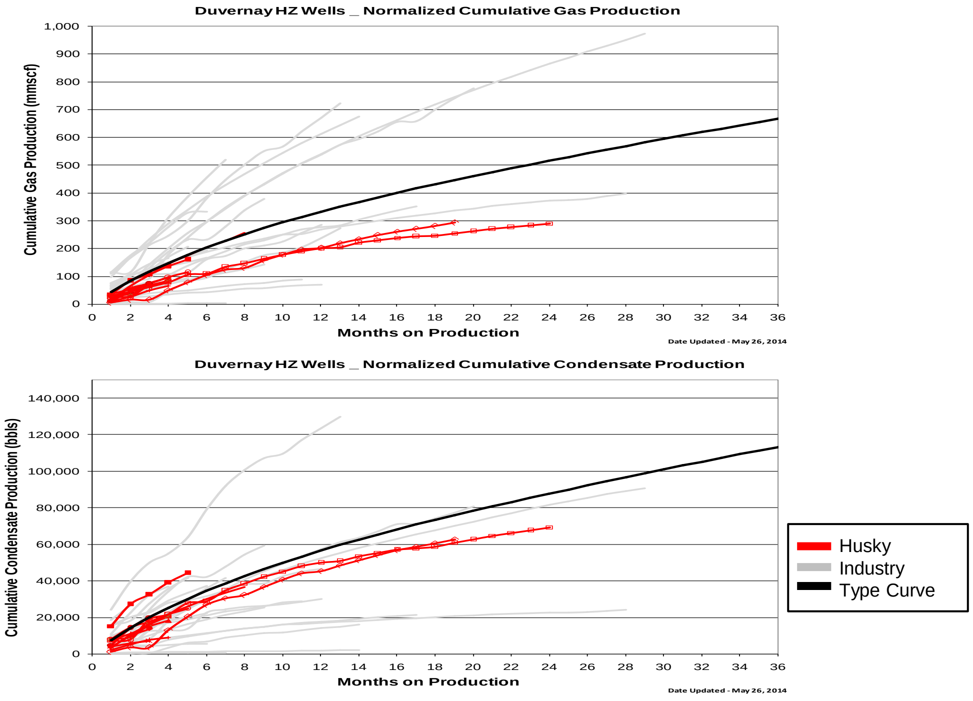
- Total Liquids Content: ~27 bbls/mmcf
- Estimated Ultimate Recovery/Well: ~1,132 MBOE
- Well Cost (current): ~$9.5 MM



Background Facts	Drilling Summary	Completions Summary
• ~24,000 net acres • 3 producing project wells • ~13 net locations	• Vertical depth: ~3,000 m • Lateral Length: ~1,300 m • Technology: Intermediate Casing • Time to drill: ~36 days	• Number of stages: 18 - 25 • Type of frac: Openhole Ball Drop • Tonnes per stage: 50T • Type of fluid / Amount of fluid: Slickwater

6. Kaybob – Duvernay

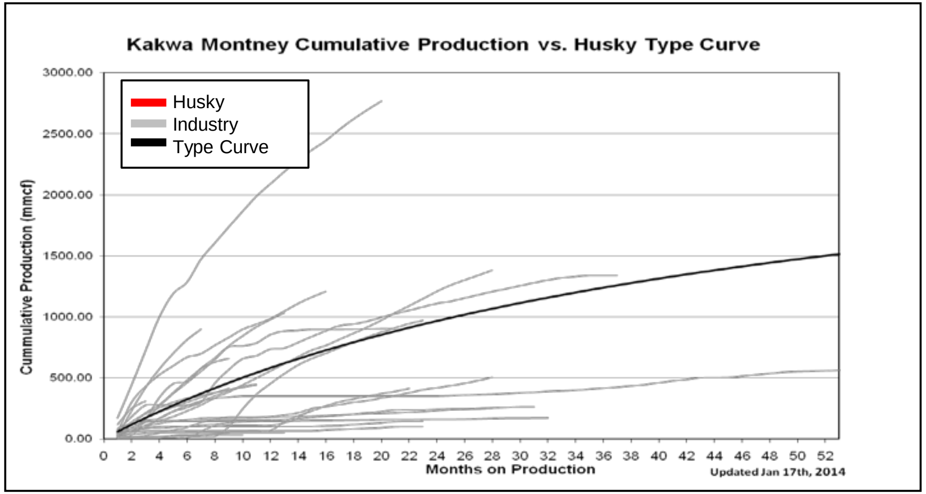
- Total Liquids Content: ~200 bbls/mmcf
- Estimated Ultimate Recovery/Well: ~765 MBOE
- Well Cost (current to steady): ~$14.7 MM to $13.2 MM



Background Facts	Drilling Summary	Completions Summary
• ~20,000 net acres	• Vertical depth: 3,100 m	• Number of stages: 18-20
• 10 producers	• Lateral Length: 1,800 m	• Length (HZ section):1,800 – 2,000m
• 10 wells drilled to date	• Technology: Managed Pressure Drilling	• Type of frac: plug-n-perf & ball-drop
• ~60 net locations	• Time to drill:45 days	• Tonnes per stage: 100 to 150
		• Type of fluid/Amount of fluid: slickwater/20,000m3
		• Typical fracs for the area: perf-n-plug or ball drop with slickwater

7. Kakwa – Montney (Liquids Rich)

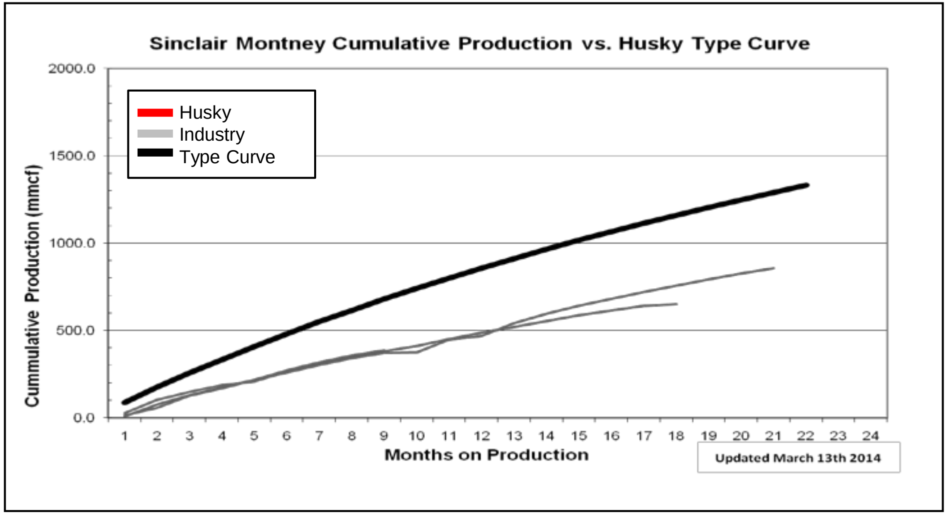
- Total Liquids Content: ~100 bbls/mmcf
- Estimated Ultimate Recovery/Well: ~626 MBOE
- Well Cost (current to steady): ~$11.7 MM to $7.8 MM



Background Facts	Drilling Summary	Completions Summary
• ~14,000 net acres • 1 well drilled to date • ~30 net locations	• Vertical depth: ~3400m • Lateral Length: ~1300m • Invert mud overbalanced • Time to drill: est. 60 drilling days & 70 total	• 17 stages • Plug and Perf or Open Hole Ball Drop • Proppant: ~60 tonnes per stage • Fluid: Slick Water or Gelled Hydrocarbon w/ N2 • Similar completion to other Montney wells in area

8. Sinclair – Montney (Liquids Rich)

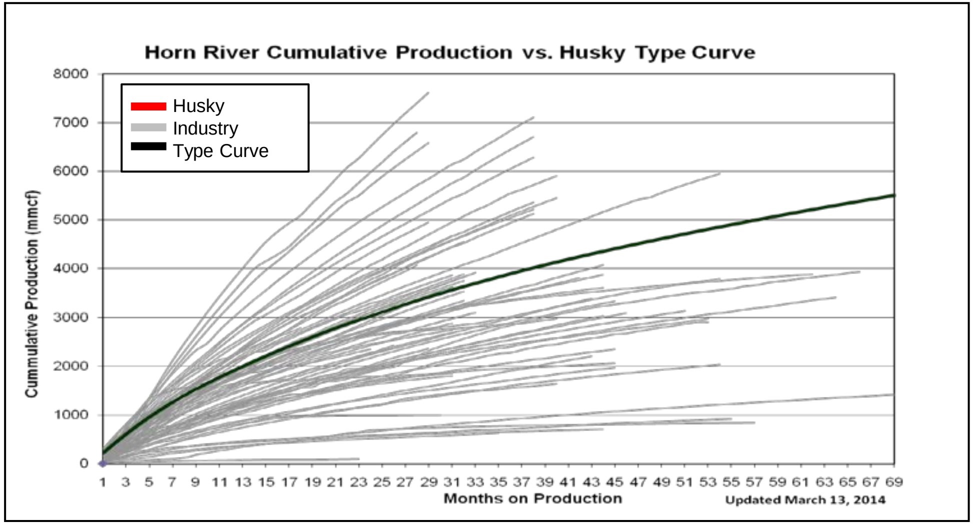
- Total Liquids Content: ~56 bbls/mmcf
- Estimated Ultimate Recovery/Well: ~721 MBOE
- Well Cost (current to steady): ~$11.4 MM to $8 MM



Background Facts	Drilling Summary	Completions Summary
• ~33,000 net acres • 1 net wells drilled to date • ~115 net locations	• Vertical depth:~2700m • Lateral Length:~1200 to 1700m • Invert mud overbalanced • Time to drill: est. 45 days	• 12 to 18 stages • Plug and Perf or Open Hole Ball Drop • Proppant: ~100 tonnes per stage • Fluid: Slick Water / ~1000m3 per stage • Similar completion to other Montney wells in area

9. Horn River – Muskwa

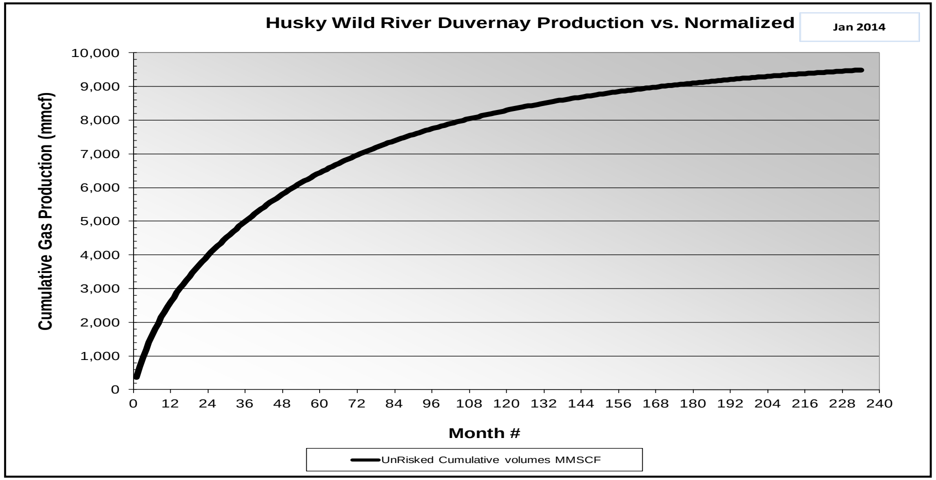
- Total Liquids Content: ~0 bbls/mmcf
- Estimated Ultimate Recovery/Well: ~1,500 MBOE
- Well Cost (current to steady): No drilling activity



Background Facts	Drilling Summary	Completions Summary
• ~30,000 net acres for both zones • 3 (1 Hz, 2 Verts) wells drilled to date • ~150 net locations (~100 Muskwa, ~50 Evie)	• Vertical depth: ~2200m • Lateral Length: ~2400m • Invert mud overbalanced • Time to drill: est. 45 days	• 24 stages • Plug and Perf • Proppant: ~200 tonnes per stage • Fluid: Slick Water • Similar completion to other Muskwa wells in area

10. Wild River – Duvernay

- Total Liquids Content: ~5 bbls/mmcf
- Estimated Ultimate Recovery/Well: ~1,636 MBOE
- Well Cost (current to steady): No Hz drilling activity



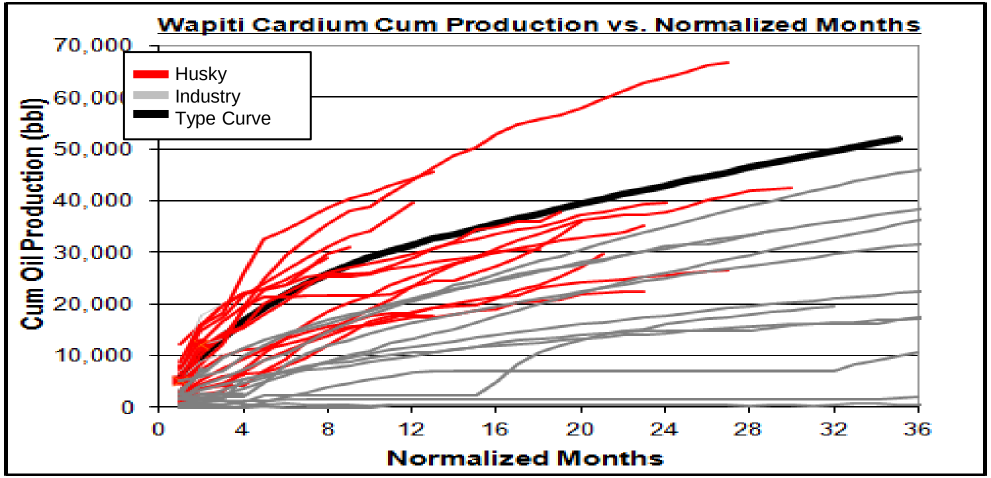
Background Facts	Drilling Summary	Completions Summary
• ~34,000 net acres • 0 net producers • 2 vertical wells drilled but not completed • ~125 net locations • No analog HZ producer	• Vertical depth: 3,940 m • Lateral Length: 1,400 m • Technology: Managed Pressure Drilling • Time to drill:60 days	• Number of stages: 18-20 • Length (HZ section): 1,600 – 1,800 m • Type of frac: plug-n-perf • Tonnes per stage: 100 • Type of fluid/Amount of fluid: slickwater/18,000m3 • Typical fracs for the area: perf-n-plug or ball drop with slickwater

Oil Resource Play Templates

1. Wapiti – Cardium
2. Oungre – Bakken
3. Saskatchewan – Bakken
4. Redwater – Viking
5. Alliance / Sumner – Viking
6. Elrose – Viking
7. Coleville / Hoosier – Viking
8. Dodsland – Viking
9. Rainbow – Muskwa
10. NWT – Canol

1. Wapiti – Cardium

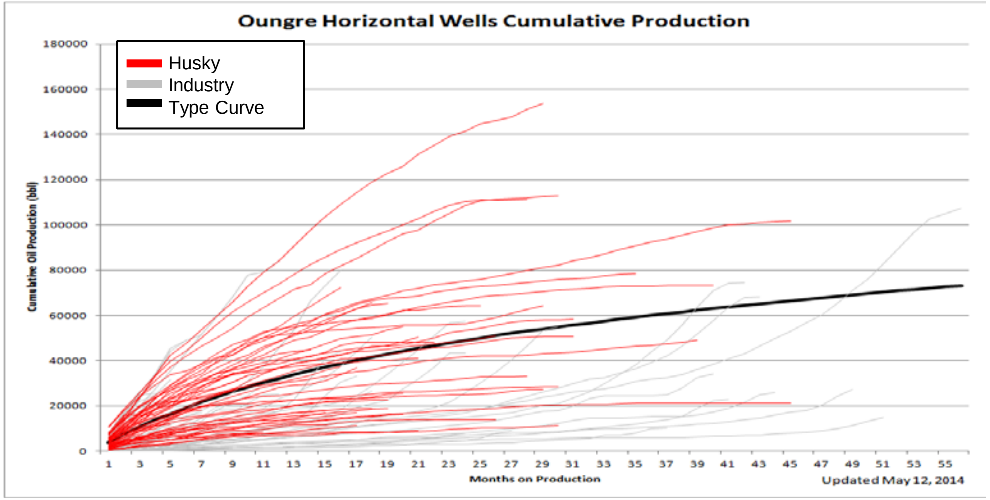
- Estimated Ultimate Recovery/Well: ~380 MBOE
- Well Cost (current): $5.5 MM



Background Fact	Drilling Summary	Completions Summary
• ~12,000 net developable acres • 24 producing project wells • 27 wells drilled to date • ~55 net locations	• Vertical depth: 1,300m • Lateral Length: 1,100m – 1,300m • Technology: Monobore • Time to drill: 17 days	• Number of stages: 15 - 17 • Length: 100m • Type of frac: Open hole ball drop • Tonnes per stage: 25T • Type of fluid / Amount of fluid: Slick Oil, 100m3/stage • Typical fracs for the area: Gelled oil, Slick water, Gas

2. Oungre – Bakken / Torquay

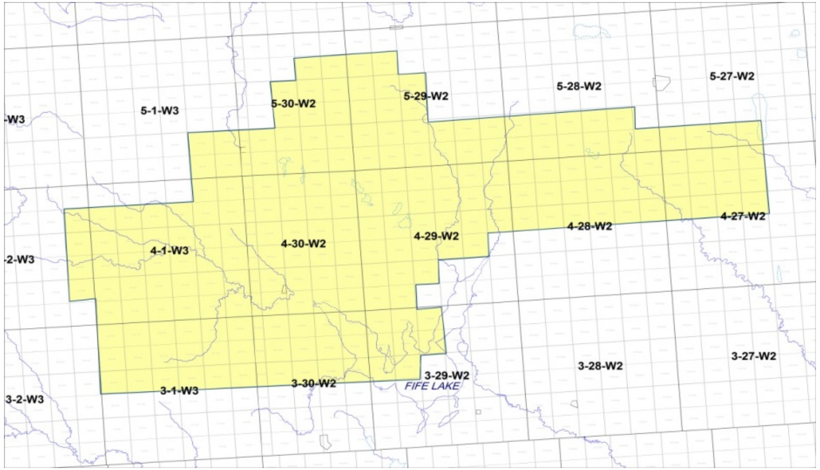
- Estimated Ultimate Recovery/Well : ~125 - 145 MBOE
- Well Cost (current): $2.2 MM



Background Facts	Drilling Summary	Completions Summary
• ~22,000 net acres (27.25 net sections) • 53 Hz producers: 43 Bakken, 10 Torquay • 55 wells drilled to date: 2 Torquay w/o completions • ~110 net locations	• Vertical depth: 2,300 m • Lateral length: 1,400 m • Technology: Casing to ICP (177.8mm) • Time to drill: 15 days	• Type of frac: cemented liner • Number of stages: 25 • Tonnes per stage: 20 • Type of fluid/Amount: x-link gel/3,500 m^3 • Typical fracs for the area: 11-20 T

3. S.W. Saskatchewan – Multi-Zone

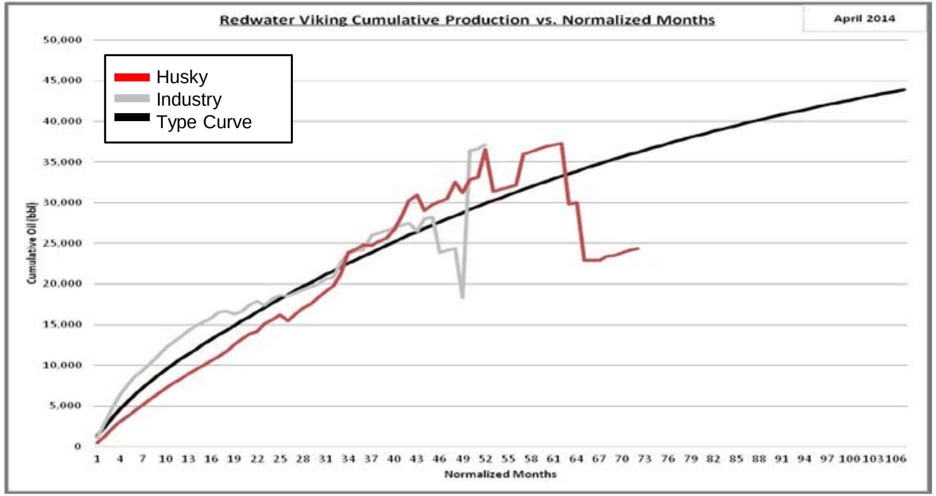
- New position – no wells drilled to date
- Estimated Well Cost: $4 MM



Background Facts	Drilling Summary	Completions Summary
• ~140,000 net acres • No producers • No net wells drilled to date	• Vertical depth: 2,100 m • Lateral length: 1,600 m • Technology: TBD • Time to drill: TBD	• Type of frac: TBD • Number of stages: TBD • Tonnes per stage: TBD • Type of fluid/Amount: TBD • Typical fracs for the area: 11-20 T (Oungre)

4. Redwater – Viking

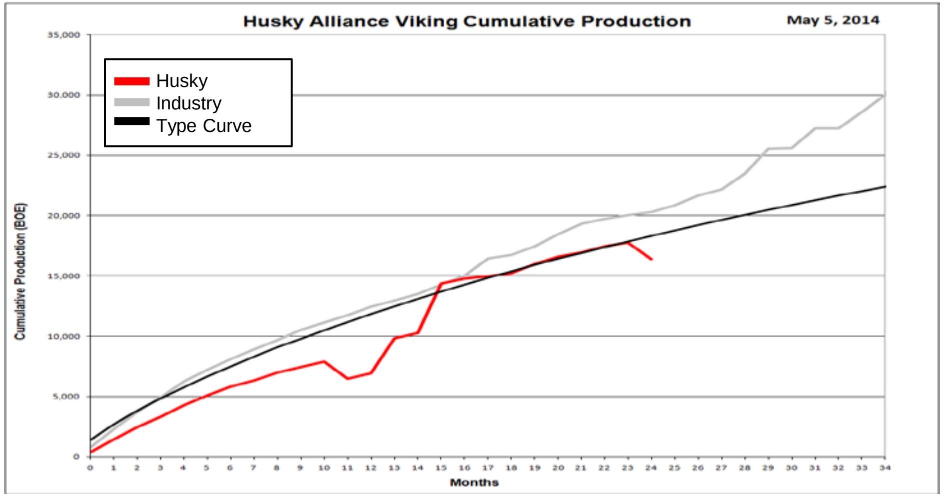
- Potential Estimated Ultimate Recovery/Well: 60 MBBLS
- Estimated Well Cost (current): $1.8 MM



Background Facts	Drilling Summary	Completions Summary
• ~18,000 net acres • 74 net wells drilled to date, • ~90 net locations	• Vertical depth: 650 to 700m • Lateral Length 600 to 700m • Technology – monobore • Time to drill – 4 days with monobore	• Number of stages: 7-8 • Length: 600 to 700m • Type of frac: multiple • Tonnes per stage: 10 to 15 • Type of fluid / Amount of fluid: cross linked gel water/ 500 to 650m3 • Typical fracs for the area: same as industry

5. Alliance/Sumner – Viking

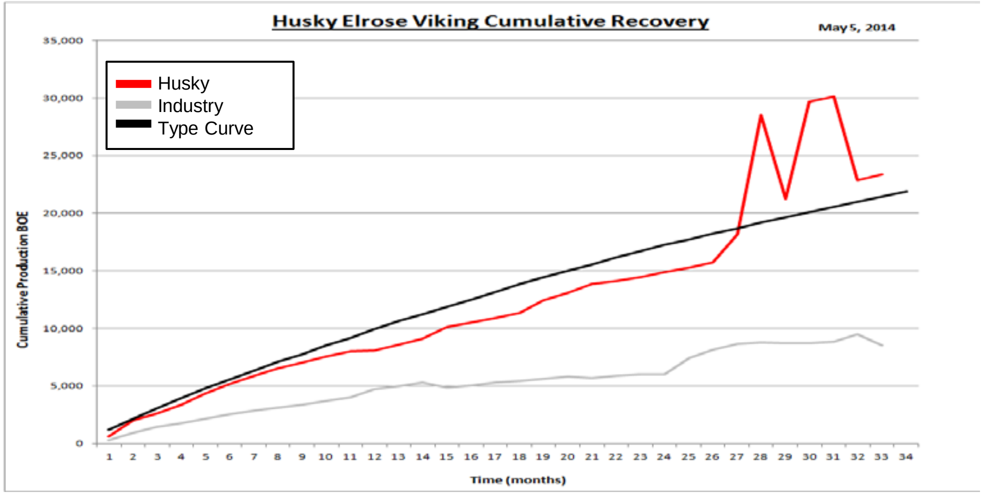
- Potential Estimated Ultimate Recovery/Well: 70-85 MBBLS
- Estimated Well Cost (current): $1-1.6 MM



Background Facts	Drilling Summary	Completions Summary
• ~80,000 net acres • 27 producing project wells • 30 wells drilled to date (24 Alliance, 6 Sumner) • ~280 net locations	• Vertical depth: 835 mKB (Alliance), 900 mKB (Sumner) • Lateral Length: 600m • Technology: 4 ½" Monobore (Alliance), Intermediate casing with slotted liner (Sumner) • Time to drill: 5.0 days	• Number of stages: 10 • Type of frac: Cemented liner, Trican/NCS Port • Tonnes per stage: 15 T • Type of fluid / Amount of fluid: Crosslinked gelled water / 720 m^3 • Typical fracs for the area: Crosslinked gelled water, 15T/stg

6. Elrose – Viking

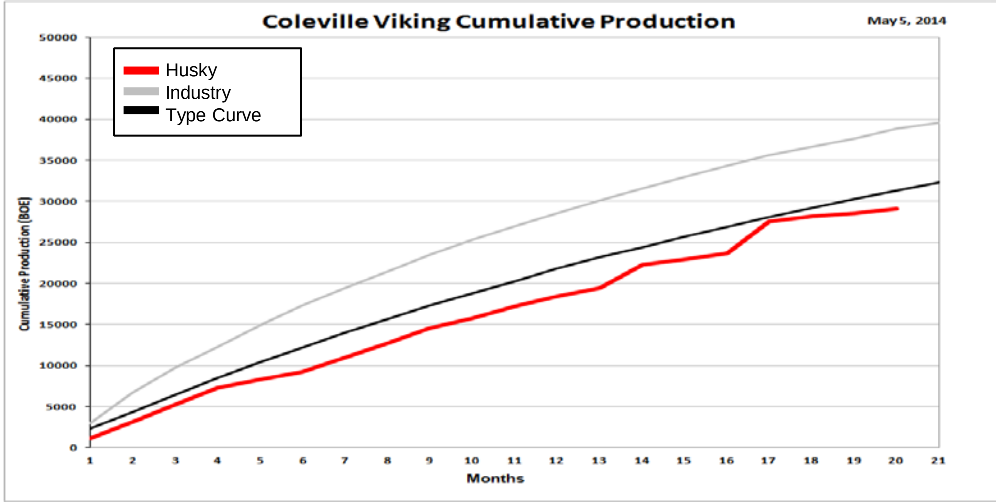
- Potential Estimated Ultimate Recovery/Well: 50 MBBLS
- Estimated Well Cost (current): $1.4 MM



Background Facts	Drilling Summary	Completions Summary
• ~27,000 net acres • 59 producing project wells • 59 wells drilled to date • ~80 net locations	• Vertical depth: 725 mKB • Lateral Length: 600 m • Technology: 4 ½” Monobore • Time to drill: Avg 4.7 days (Best – 3.9 days)	• Number of stages: 10 • Type of frac: Cemented liner, Trican/ NCS Burst port • Tonnes per stage:15 T • Type of fluid / Amount of fluid: Crosslinked gelled water / 630 m3 • Typical fracs for the area:10stg, 15T Gelled water

7. Coleville/Hoosier – Viking

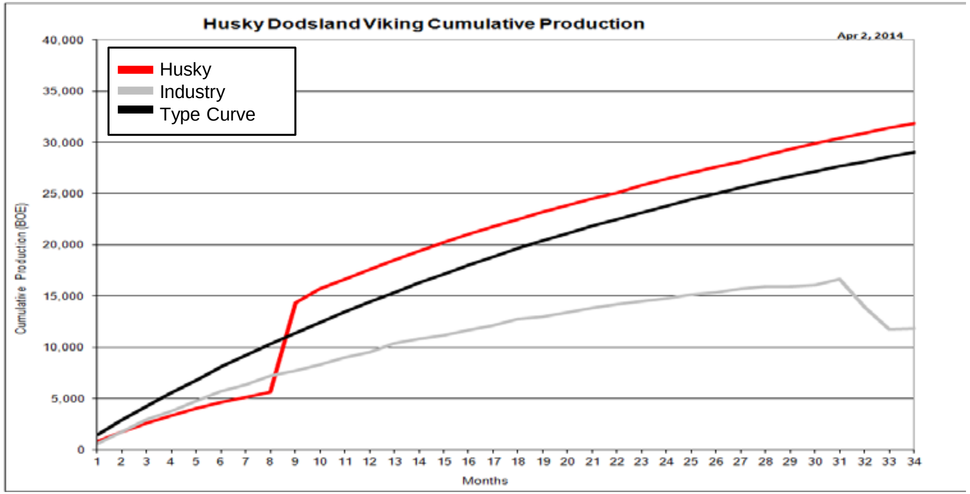
- Potential Estimated Ultimate Recovery/Well: 50 - 70 MBBLS
- Estimated Well Cost (current): $1.5 MM



Background Facts	Drilling Summary	Completions Summary
• ~16,000 net acres • 25 producing project wells • 26 gross wells drilled to date • ~80 net locations	• Vertical depth: 710 mKB • Lateral Length: 600 m • Technology: 4 ½” Monobore • Time to drill: Avg 3.3 days	• Number of stages:11 • Type of frac: Cemented liner, Trican Burst port • Tonnes per stage: 15 T • Type of fluid / Amount of fluid: Crosslinked gelled water / 850 m^3 • Typical fracs for the area: 15T Energized N_2

8. Dodsland – Viking

- Potential Estimated Ultimate Recovery/Well: 55 MBBLS
- Estimated Well Cost (current): $1.5 MM



Background Facts	Drilling Summary	Completions Summary
• ~40,000 net acres • 4 producing project wells • 6 wells drilled to date • ~45 net locations	• Vertical depth: 625 mKB • Lateral Lengt: 600 m • Technology: 4 ½” Monobore • Time to drill: Avg 3.8 days	• Number of stages: 10 • Type of frac: Cemented liner, Trican Burst port • Tonnes per stage: 15 T • Type of fluid / Amount of fluid: Nitrified gelled water / 275 m^3 • Typical fracs for the area: Perf and selective frac tool

9. Rainbow – Muskwa

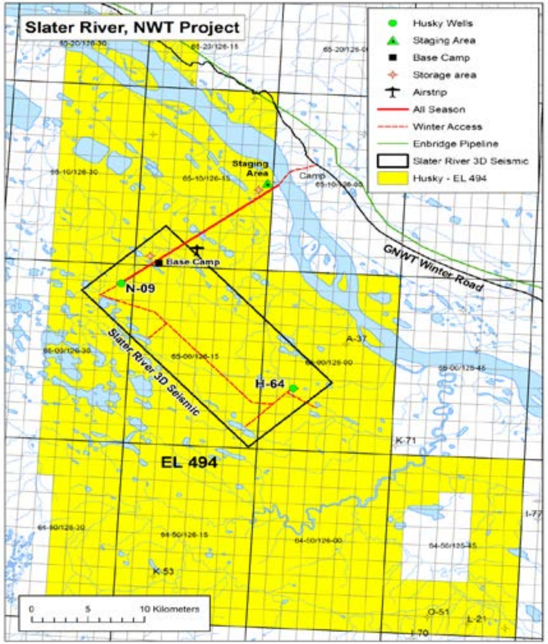
- Still de-risking

	Q1 2014 Production (boe/d)	Potential EUR/Well (mboe)
Oil Resource	90	~140
Gas Resource	94	~820

	Background Facts	Drilling Summary	Completions Summary
Oil Resource	• ~400,000 net acres • 5 producing project wells • 3 pilot wells and 20 Hz drilled to date • 8 wells completed to date	• Vertical depth: 1700m TVD • Lateral Length: Current: 1800m, Future: 1300m • Time to drill Current: 17 days, Future 12 days	• Number of stages: Current: 18, Future 20 • Typical fracs for the area: Evaluating
Gas Resource	• 70,000 net acres • 1 Hz producer • 6 liquids rich wells drilled to date (3 Hz's, 2 Vert & 1 Susp Hz)	• Vertical depth:~1800m • Lateral Length:~1600 to 2000m • Time to drill:est. 21 drilling days & 25 total	• 18 to 22 stages • Similar completion to other Muskwa wells in area

10. Slater River – Canol (Oil/ Liquids rich gas)

- Evaluating



Background Facts	Drilling Summary	Completions Summary
• ~300,000 net acres • 2 vertical strat wells with completions • Initial development model includes oil phase	• Vertical depth: 1000-1700m TVD • Lateral Length: ~1200m	• Number of stages: TBD • Stage Length TBD • Tonnes per stage: TBD