Husky Energy

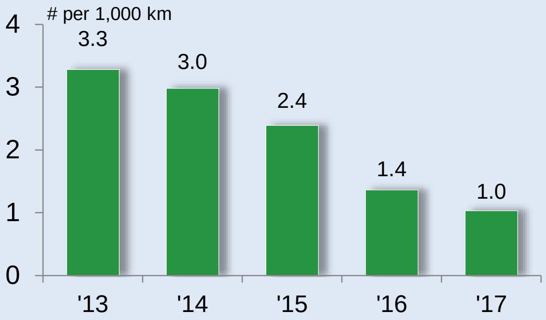
Investor Day

May 29, 2018

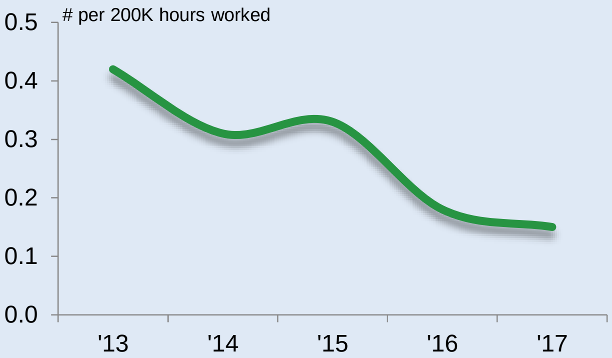
Commitment to Safe and Reliable Operations

Husky Operational Integrity Management System (HOIMS)

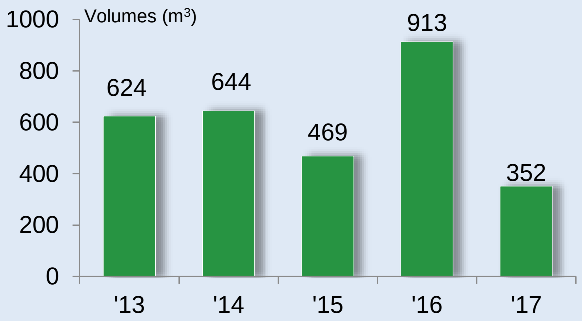
Pipeline Incident Rate



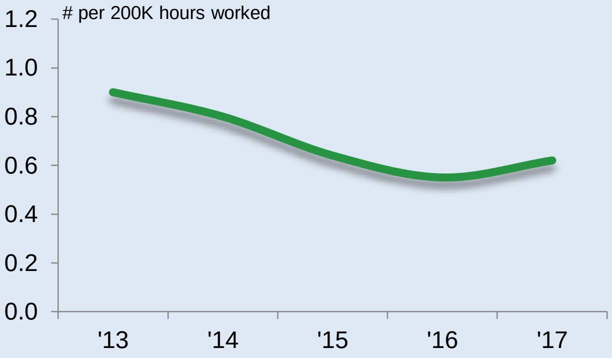
Critical & Serious Incident Rate



Reportable Hydrocarbons Released



Total Recordable Incident Rate



Taking Action on Safety

Board of Directors:

- Management compensation tightly linked to safety performance

Company:

- New Safety SVP to report directly to CEO
- Full assessment of processes and culture – HRG
- Results tracked and reported in transparent manner

Husky Energy

Investor Day

May 29, 2018

Agenda

Delivering Our Plan
Rob Peabody, CEO

ESG Priorities
Janet Annesley, SVP, Corporate Affairs

Financial Framework
Jeff Hart, Acting CFO

Operations
Rob Symonds, COO

Break

Integrated Corridor

Downstream
Jeffrey Rinker, SVP, Downstream

Thermal / Sunrise Update
Andrew Dahlin, SVP, Heavy Oil & Oil Sands
Carmen Lee, VP, Oil Sands

Resource Plays
Gerald Alexander, SVP, Western Canada

Offshore

Atlantic
Trevor Pritchard, SVP, Atlantic

Asia Pacific
Bob Hinkel, COO, Asia Pacific

Summary
Rob Peabody

Q&A

Husky Energy

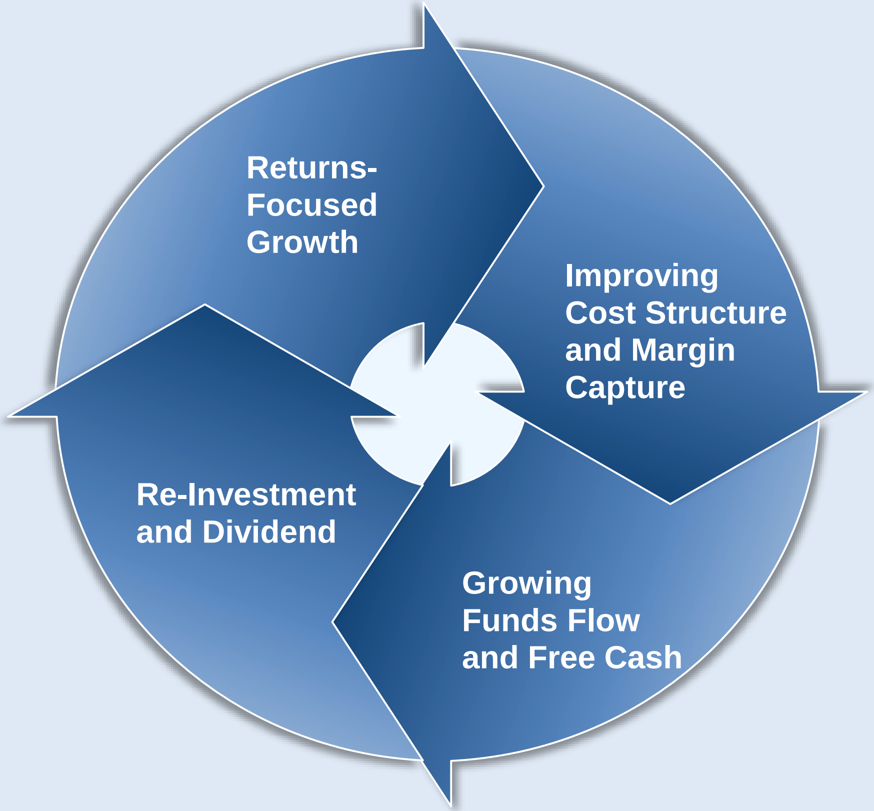
Delivering Our Plan

Rob Peabody
President & Chief Executive Officer

Value Proposition

Resilient and Well Positioned to Capture Upside

- Production and throughput growth from a large inventory of low cost projects = returns-focused growth
- Low and improving earnings and cash break-evens
- Strong growth in funds from operations and free cash flow
- Increasing cash returns to shareholders
- Integration and fixed-price Asia Pacific sales provide resilience to volatile market conditions while preserving upside

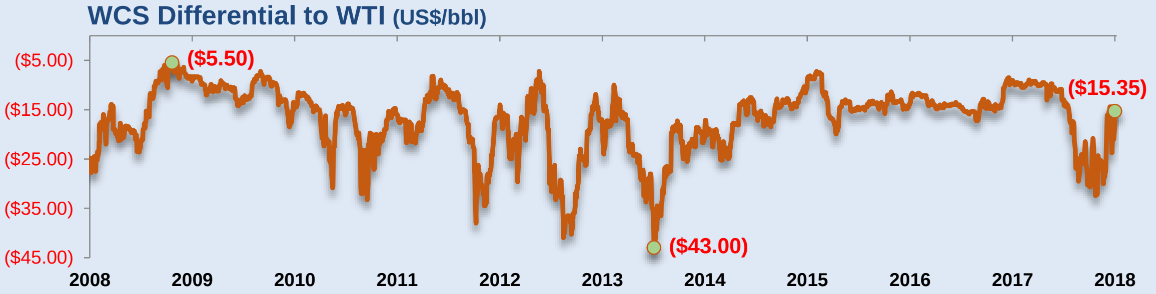


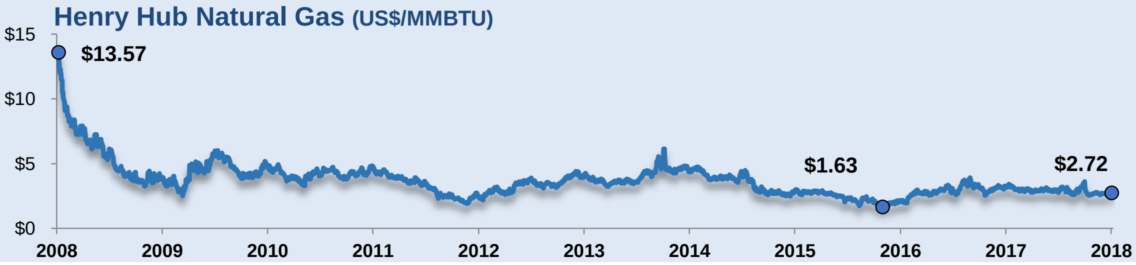
Resilience to Unpredictable Commodity Prices

Setting Husky Apart

Resilience through:

- Strong balance sheet
- Integrated model
- Growing high netback, fixed-price business in Asia
- High weighting of low sustaining capital assets and projects
- Low earnings break-evens





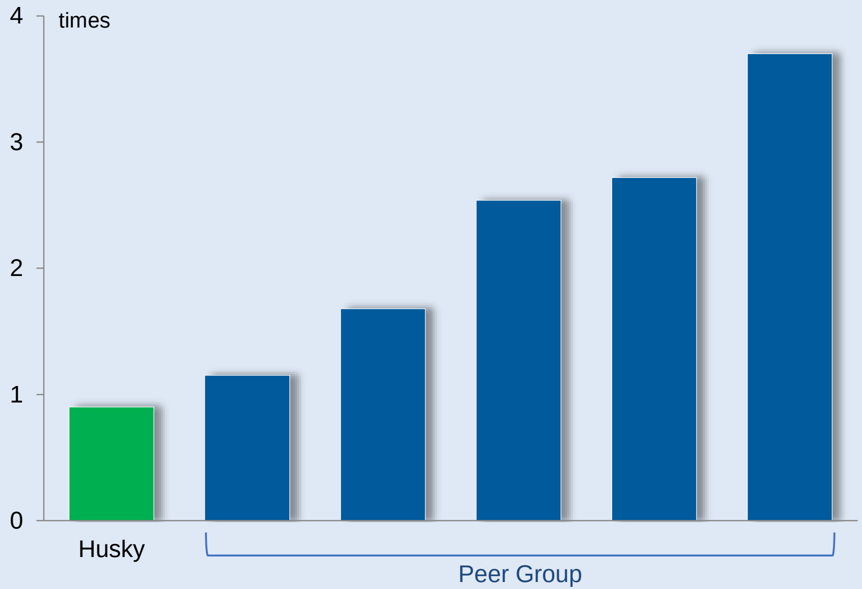
Resilience to Unpredictable Commodity Prices

Setting Husky Apart

Resilience through:

- Strong balance sheet
- Integrated model
- Growing high netback, fixed-price business in Asia
- High weighting of low sustaining capital assets and projects
- Low earnings break-evens

Net Debt to Trailing FFO[1] (Q1 ’18)



Source: Factset, Company Documents
Peer group: CNRL, Cenovus, Encana, Imperial and Suncor

1 See Slide Notes and Advisories

Tight Integration Largely Eliminates Differentials

Setting Husky Apart

Resilience through:

- Strong balance sheet
- Integrated model
- Growing high netback, fixed-price business in Asia
- High weighting of low sustaining capital assets and projects
- Low earnings break-evens

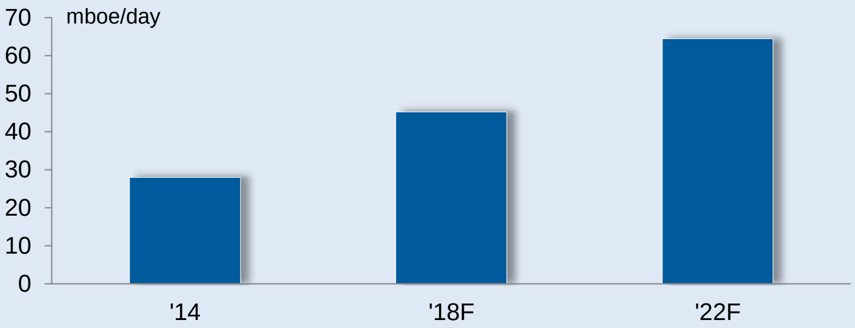
Growing High Netback Business in Asia

Setting Husky Apart

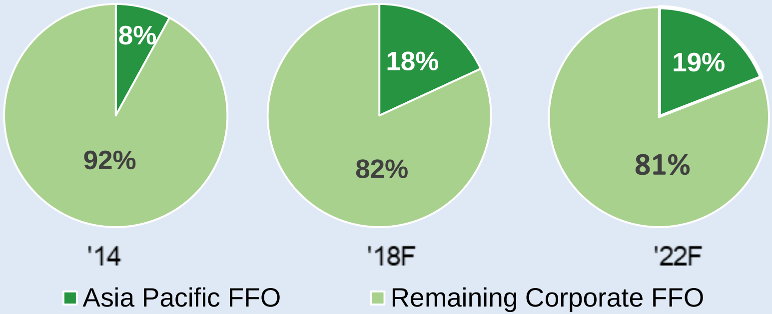
Resilience through:

- Strong balance sheet
- Integrated model
- Growing high netback, fixed-price business in Asia
- High weighting of low sustaining capital assets and projects
- Low earnings break-evens

Asia Pacific Production Growth



Asia Pacific Funds From Operations[1] as Percentage of Total



1 See Slide Notes and Advisories

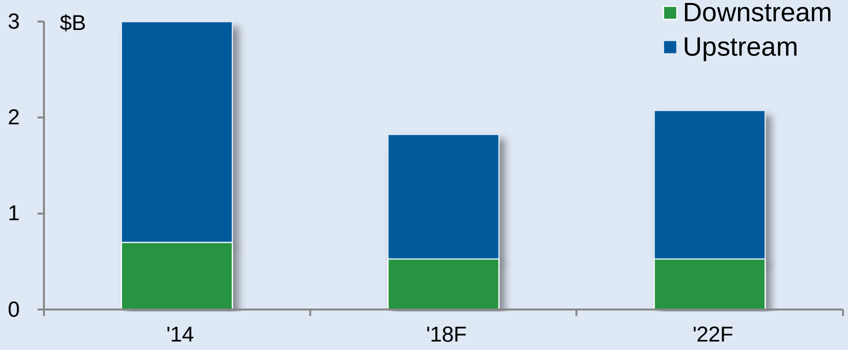
Growing Proportion of Low Sustaining Capital Projects

Setting Husky Apart

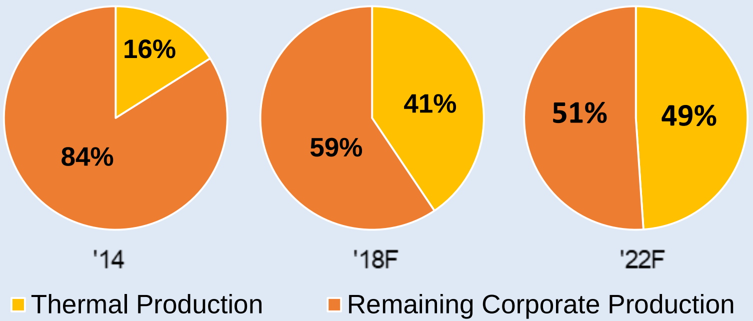
Resilience through:

- Strong balance sheet
- Integrated model
- Growing high netback, fixed-price business in Asia
- High weighting of low sustaining capital assets and projects
- Low earnings break-evens

Total Sustaining Capital[1]



Thermal Bitumen Production as a Percentage of Total



1 See Slide Notes and Advisories

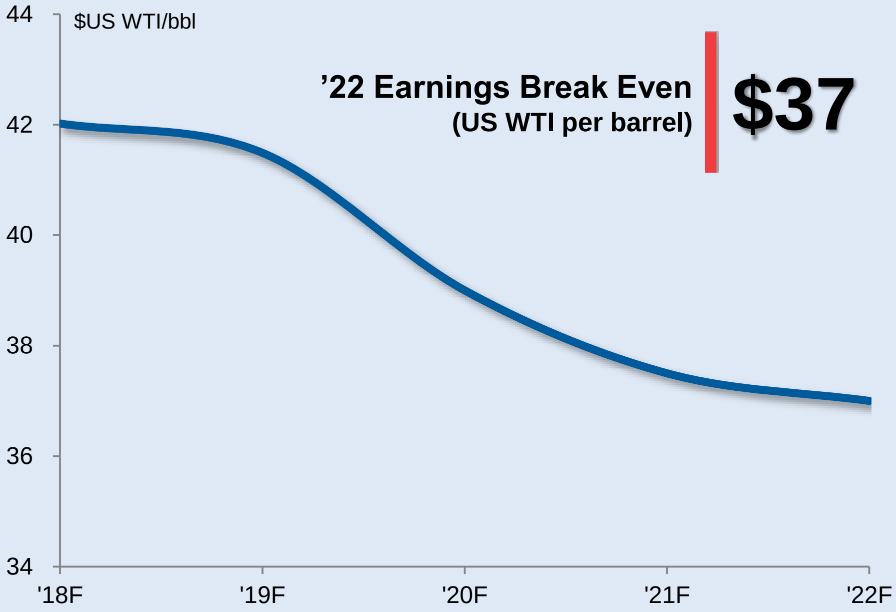
Low Break Evens, And Going Lower

Setting Husky Apart

Resilience through:

- Strong balance sheet
- Integrated model
- Growing high netback, fixed-price business in Asia
- High weighting of low sustaining capital assets and projects
- Low earnings break-evens

Earnings Break-Even Oil Price[1]



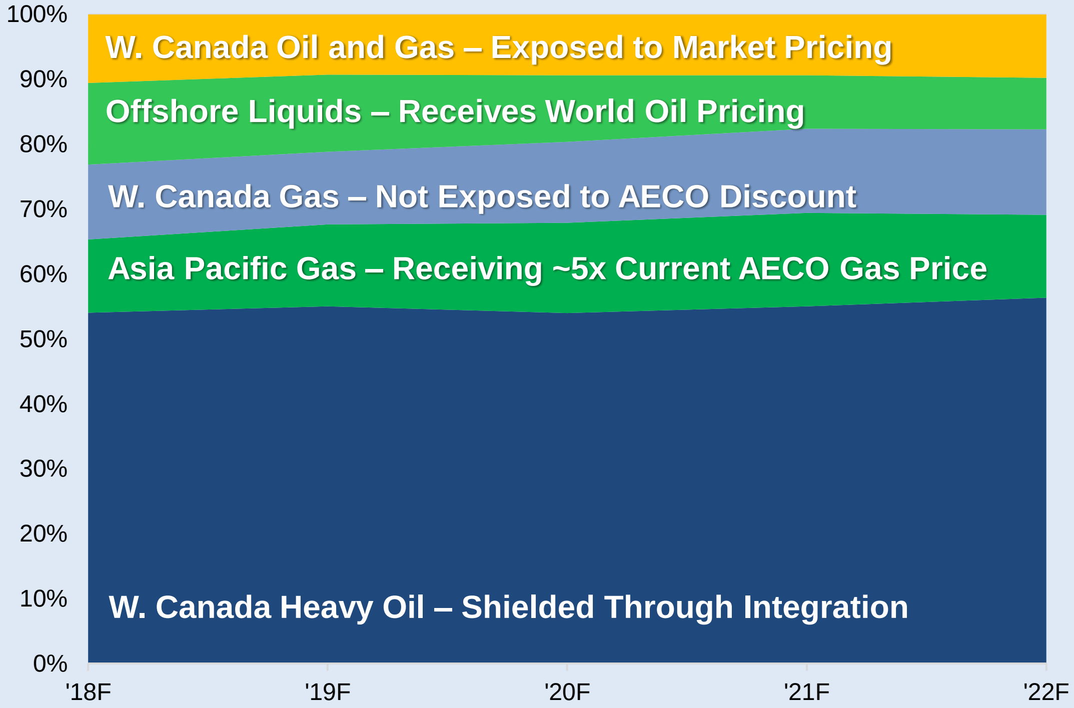
1 See Slide Notes and Advisories

Setting Husky Apart

Resilience through:

- Strong balance sheet
- Integrated model
- Growing high netback, fixed-price business in Asia
- High weighting of low sustaining capital assets and projects
- Low earnings break-evens

Production Mix Commodity Price Exposure



Two Businesses

Built-in Sustainable Competitive Advantages

Integrated Corridor	Offshore

Becoming A Low-Cost Producer

Structural Transformation Has Reduced Complexity, Driven Efficiencies

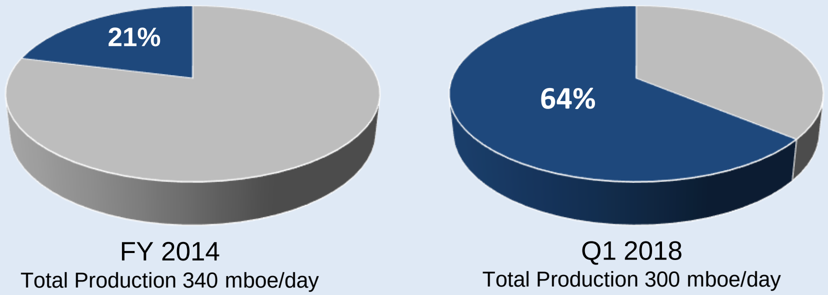
Actions

- Divested of non-core, higher cost assets
- Added lower cost inventory and lower cost production
- Growing proportion of fixed-price income

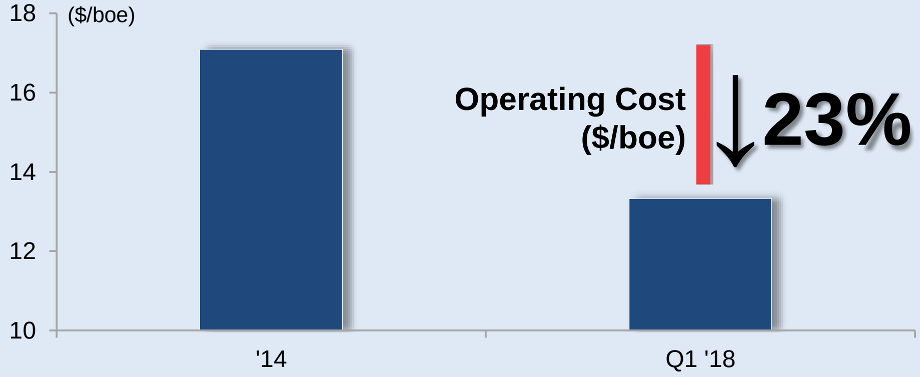
Results

- Lowered average supply cost of portfolio
- Reduced operating costs & increased margins
- Lowered sustaining capital requirements
- Narrower focus driving efficiencies
- More resilience to industry cost inflation

Proportion of Production Below $11/boe Operating Cost



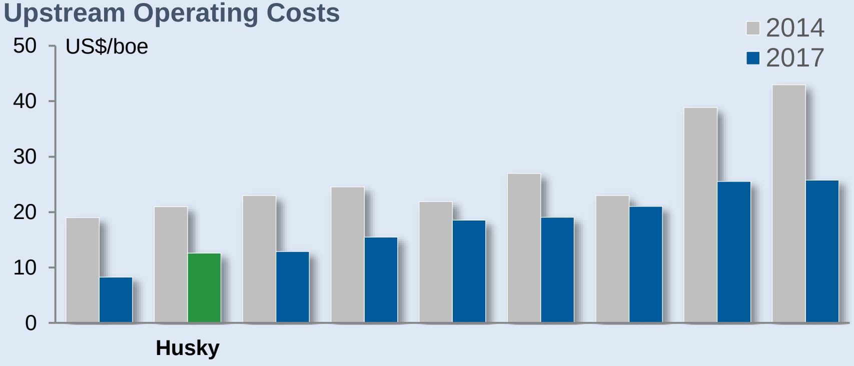
Upstream Operating Cost



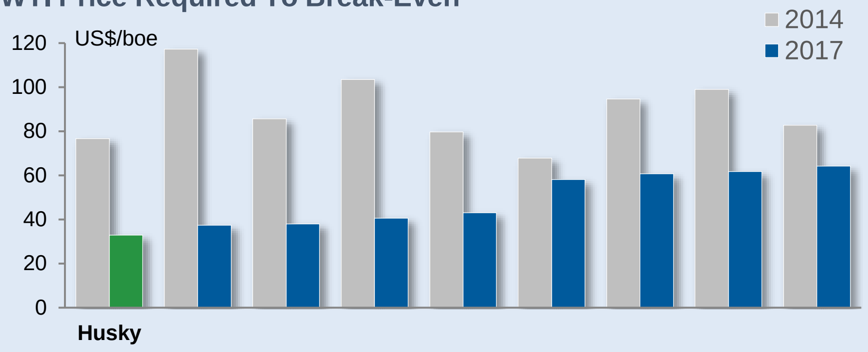
Results of Strategy Execution

Improved Competitive Position vs Global Peer Set (2014-2017)

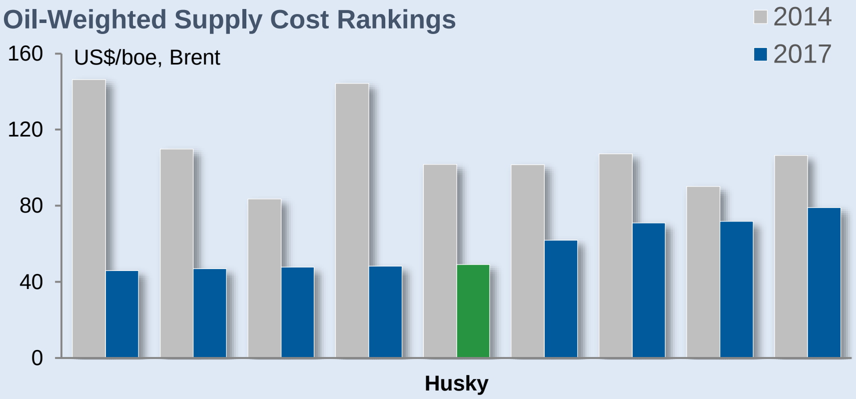
Upstream Operating Costs



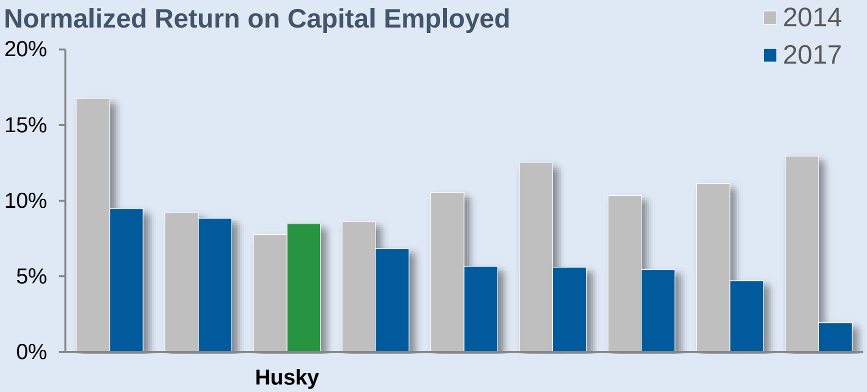
WTI Price Required To Break-Even



Oil-Weighted Supply Cost Rankings



Normalized Return on Capital Employed



Source: BMO Global Cost Study (Aug. 2017) and BMO Capital Markets research

Global Integrated Peers: Cenovus, Chevron, ConocoPhillips, CNRL, Exxon Mobil, Imperial, Occidental, Suncor

Delivered First Year of Five-Year Plan

All 2017 Targets Met or Exceeded

Integrated Corridor

Thermal

- 22% year-over-year production increase
- Sanctioned two new Lloyd thermal projects
- Tucker and Sunrise ramp-up on track

Downstream

- Successful acquisition of Superior Refinery
- 95% overall utilization rate

Resource Plays

- Completed 52,000 boe/day disposition program
- Completed transition, ready to grow

Offshore

Atlantic

- Sanctioned 52,500 bbls/day West White Rose project
- Accelerated two Atlantic infill wells

Asia Pacific

- Record annual Liwan gas volumes of 176mmcf/day (net)
- Sanctioned Liuhua 29-1; first gas in 2020
- First production at BD Project

Key Metrics	I-Day 2017F	2017 Delivery	Status
Production (mboe/day)	**320 – 335**	**323**	✓
Funds from operations (FFO)	**$3.3B**	**$3.3B**	✓
Free cash flow (FCF)[1]	**$750M**	**$1.1B**	✓
Upstream operating cost/bbl	$14.25	$13.93	✓
Downstream realized margins/bbl	$15.00	$15.00	✓
Earnings break-even oil price (US WTI)	~$43.60	$40.56	✓

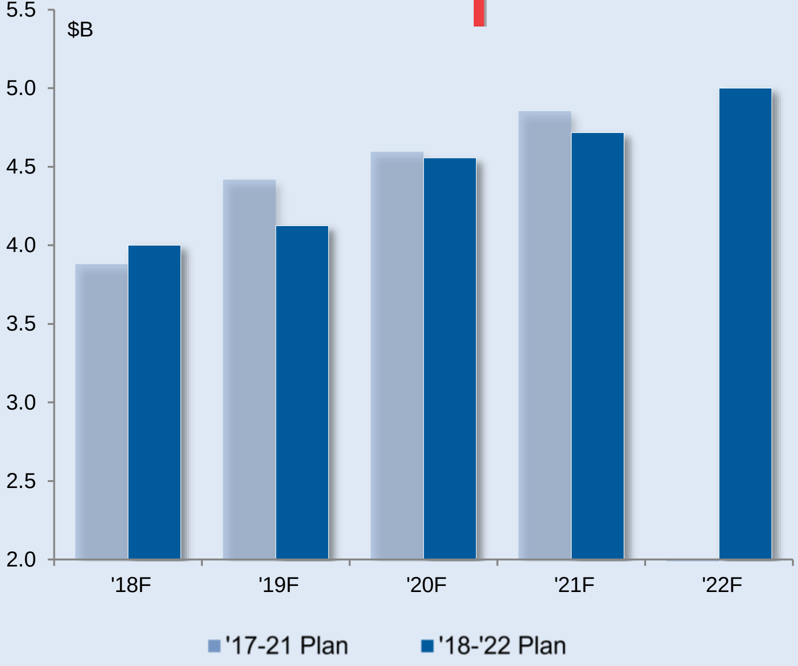
Ranges and Targets			
Sustaining capital	$1.8B	$1.8B	✓
Capital spending[2,3]	$2.5-$2.6B	$2.2B	✓
5-yr avg. proved reserve replacement ratio[4]	>130%	167%	✓
Net debt to FFO[5] at $35 US WTI	< 2x	<1.0x	✓

1,2,3,4,5 See Slide Notes and Advisories

Updated Five-Year Plan (2018-2022)

On Track, Using Flat $60 US WTI Prices

Funds From Operations CAGR '18-'22F **6%**



Key Metrics	'18F	'22F	'18-22F CAGR[1]
Funds from operations (FFO)	**$4B**	**$5B**	**6%**
Free cash flow (FCF)	**$1B**	**$1.4B**	**9%**
Upstream production (mboe/day)	**310-320**	**410-420**	**7%**
Downstream throughputs (mbbls/day)	**360-370**	**360-370**	
Thermal production (mbbls/day)	126-130	200	12%
Heavy processing capacity (mbbls/day)	190	220	
Upstream operating cost/bbl	$13-13.50	$11-12	
Downstream operating costs/bbl (CAD)	$7-8	$7-8	
Earnings break-even oil price (US WTI)	$42	$37	

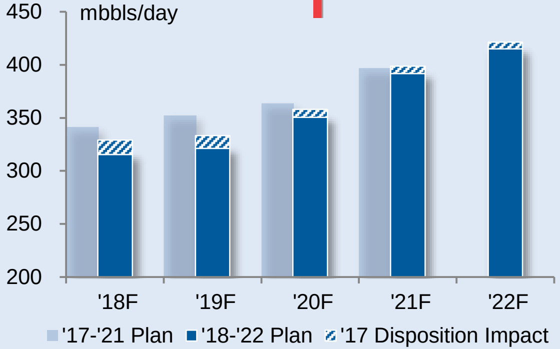
Ranges and Targets	2018F - 2022F
Annual base dividend	$300M with option to grow
Sustaining capital	Avg. $1.9B
Capital spending	Avg. $3.5B
5-yr avg. proved reserves replacement ratio	Target >130%
Net debt to FFO at $35 US WTI	<2x

1 See Slide Notes and Advisories

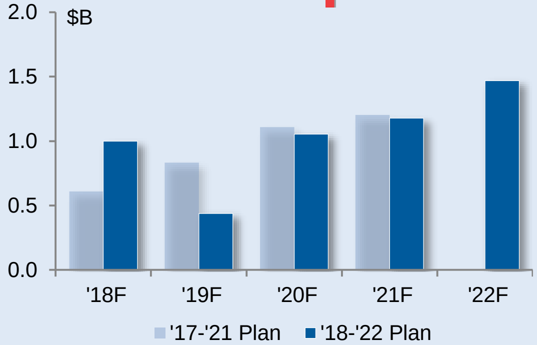
Updated Five-Year Plan

On Track, With Improvements

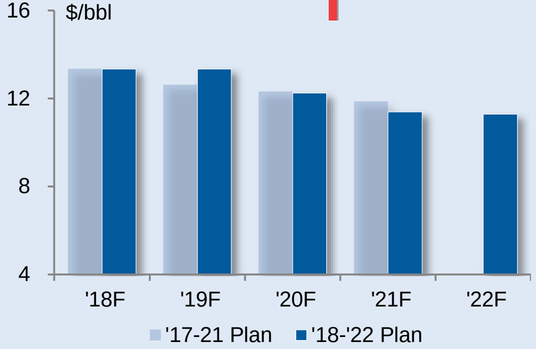
Production Growth CAGR '18-'22F **7%**



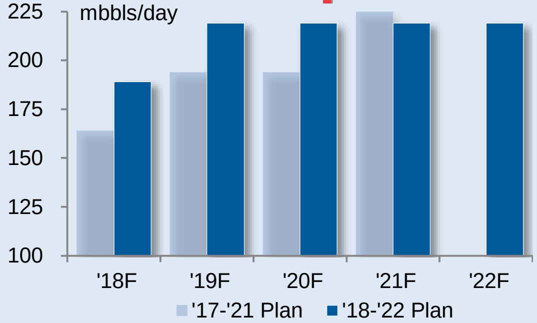
Free Cash Flow CAGR '18-'22F **9%**



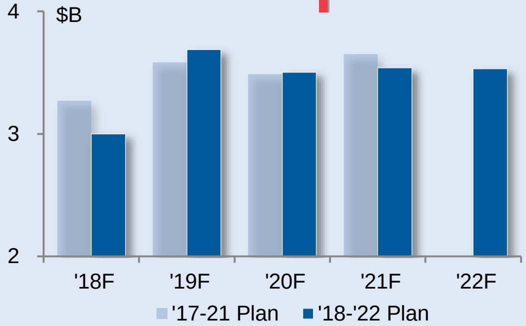
Upstream Operating Costs '18-'22F **↓15%**



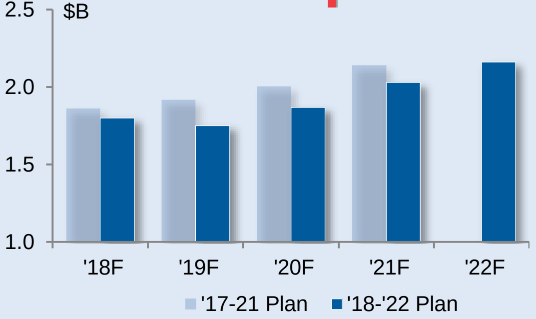
Heavy Oil Processing Capacity '19-22F **220,000**



Average Annual Capital Spending '18-'22F **$3.5B**



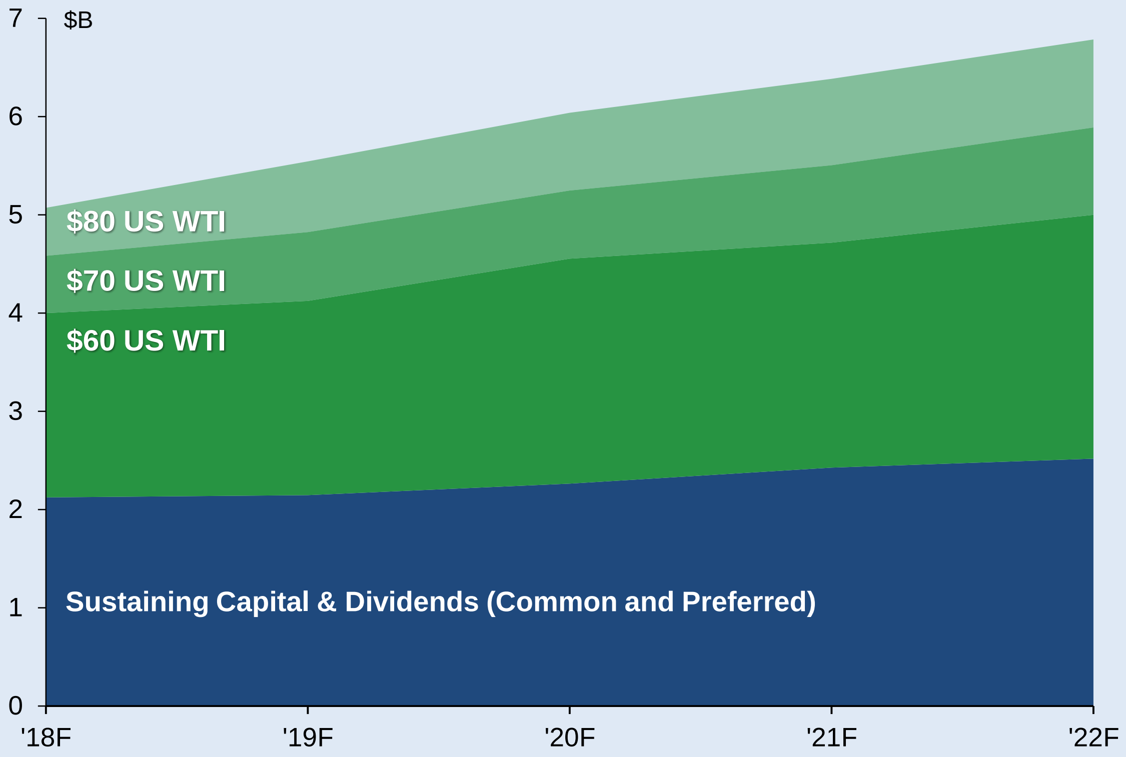
Average Sustaining Capital '18-'22F **$1.9B**



Oil Price Sensitivity

Resilient and Well Positioned to Capture Upside

Funds From Operations In Escalating Price Environment



Value Proposition

Resilient and Well Positioned to Capture Upside

- Production and throughput growth from a large inventory of low cost projects = returns-focused growth
- Low and improving earnings and cash break-evens
- Strong growth in funds from operations and free cash flow
- Increasing cash returns to shareholders
- Integration and fixed-price Asia Pacific sales provide resilience to volatile market conditions while preserving upside

Key Metrics	'18F	'22F	'18-22F CAGR
Funds from operations (FFO)[1]	**$4B**	**$5B**	**6%**
Free cash flow (FCF)[1]	**$1B**	**$1.4B**	**9%**
Upstream production (mboe/day)	**310-320**	**410-420**	**7%**
Downstream throughputs (mbbls/day)	**360-370**	**360-370**	
Thermal production (mbbls/day)	126-130	200	12%
Heavy processing capacity (mbbls/day)	190	220	
Upstream operating cost/bbl	$13-13.50	$11-12	
Downstream operating costs/bbl (CAD)	$7 - $8	$7 - $8	
Earnings break-even oil price (US WTI)	$42	$37	

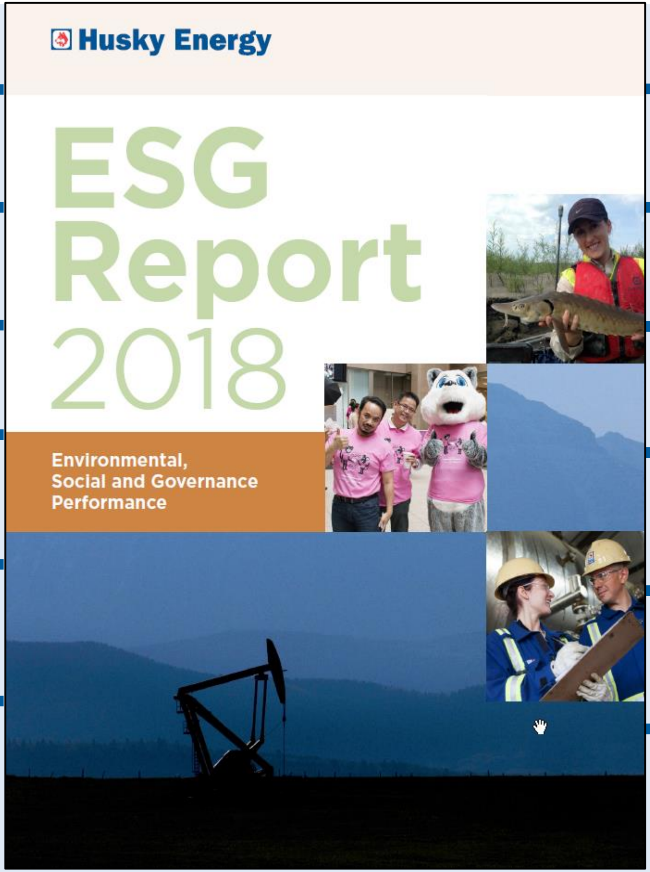
Ranges and Targets	2018F - 2022F
Annual base dividend	$300M with option to grow
Sustaining capital	Avg. $1.9B
Capital spending	Avg. $3.5B
5-yr avg. proved reserves replacement ratio	Target >130%
Net debt to FFO at $35 US WTI	<2x

1 See Slide Notes and Advisories

ESG Performance and Reporting

Measuring Performance and Improving Disclosures

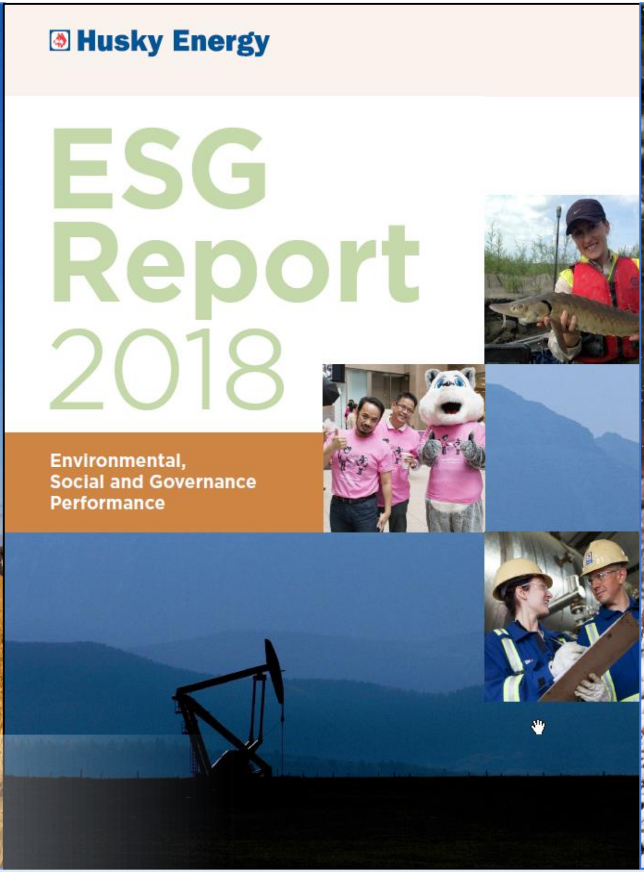
- Business resilience
- Innovation and advanced technology
- Energy use
- Asset integrity and reliability
- Occupational health and safety
- Emergency preparedness and response



- Water use and availability
- Air emissions management, including carbon
- Land use and reclamation
- Talent management and culture of inclusion
- Community & Indigenous People’s Engagement
- Business ethics and transparency

Environmental, Social and Governance

Janet Annesley
SVP, Corporate Affairs



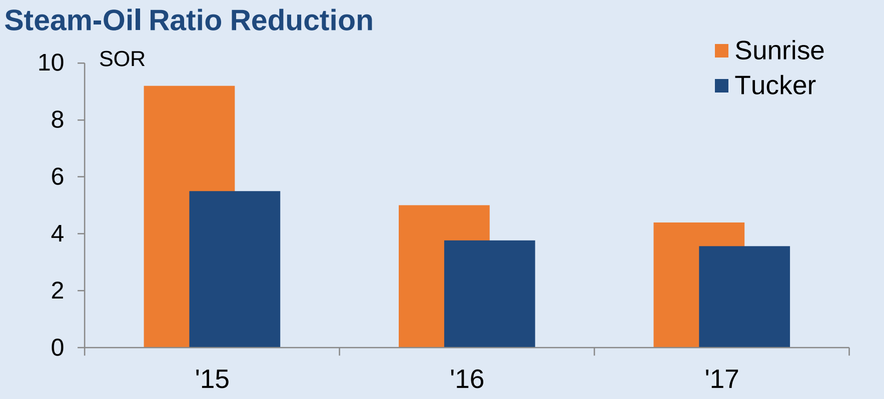
Environmental, Social and Governance

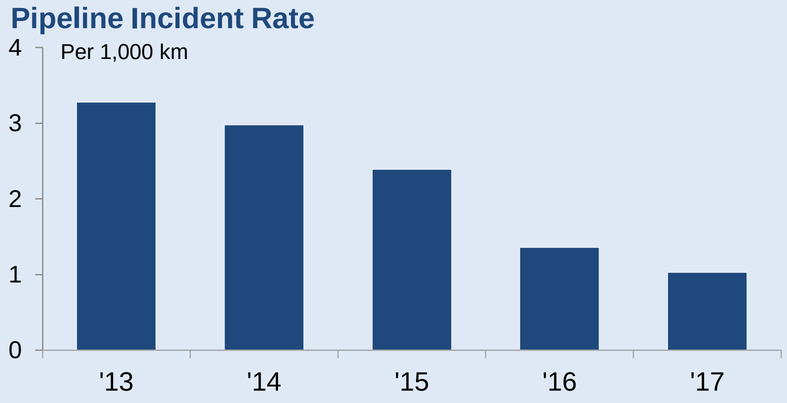
Husky's Top 12 Material Topics

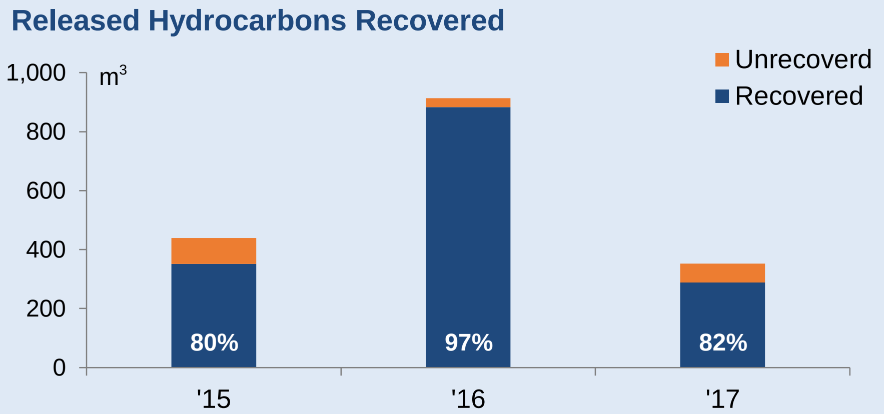
Economic	Safety and Reliability	Environment	Social	Governance
Business Resilience	Asset Integrity & Reliability	Water Use & Availability	Talent Management & Culture of Inclusion	Business Ethics & Transparency
Innovation and Advanced Technology	Occupational Health & Safety	Air emissions management, including carbon	Community & Indigenous Peoples' Engagement	
Energy Use	Emergency Preparedness & Response	Land Use and Reclamation		

Environmental, Social and Governance

- 2017 Carbon Disclosure Project
  - "B" score on Climate and Water Questionnaires, compared to average "C" for energy industry peers
  - "This good result signals that Husky is measuring and managing its impact" – CDP







Environmental, Social and Governance

- Diverse, inclusive workplace
- Husky employee community service grants
- Building Indigenous capacity:
    - Recognizing rights and reconciliation
    - Providing student scholarships, mentoring, summer employment and apprenticeships
    - In 2017, signed contracts worth ~$30 million with Indigenous vendors, including more than $9.8 million with businesses based in Saskatchewan.
        - Contracts awarded on technical and safety criteria, as well as price

Thunderchild First Nation Power Engineering Program

Husky Pink Shirt Day

Financial Framework

Jeff Hart
Acting Chief Financial Officer

Price Planning Assumptions

2017 vs. 2018 Five-Year Plan / Stress Case

Benchmark Prices – 2017 Base Case	2018	2019	2020	2021
WTI (US $bbl)	55.00	60.00	60.00	60.00
Chicago 3:2:1 ($/bbl US)	16.00	16.00	16.00	16.00
Heavy crude differential ($/bbl US)	14.00	14.00	14.00	14.00
AECO ($/mmbtu Cdn)	3.00	3.00	3.00	3.00
US/CAD exchange rate	0.78	0.80	0.80	0.80

Benchmark Prices – 2018 Base Case	2018	2019	2020	2021	2022
WTI (US $bbl)	60.00	60.00	60.00	60.00	60.00
Chicago 3:2:1 ($/bbl US)	16.00	16.00	16.00	16.00	16.00
Heavy crude differential ($/bbl US)	18.00	18.00	18.00	18.00	18.00
AECO ($/mmbtu Cdn)	2.00	2.00	2.00	2.00	2.00
US/CAD exchange rate	0.80	0.80	0.80	0.80	0.80

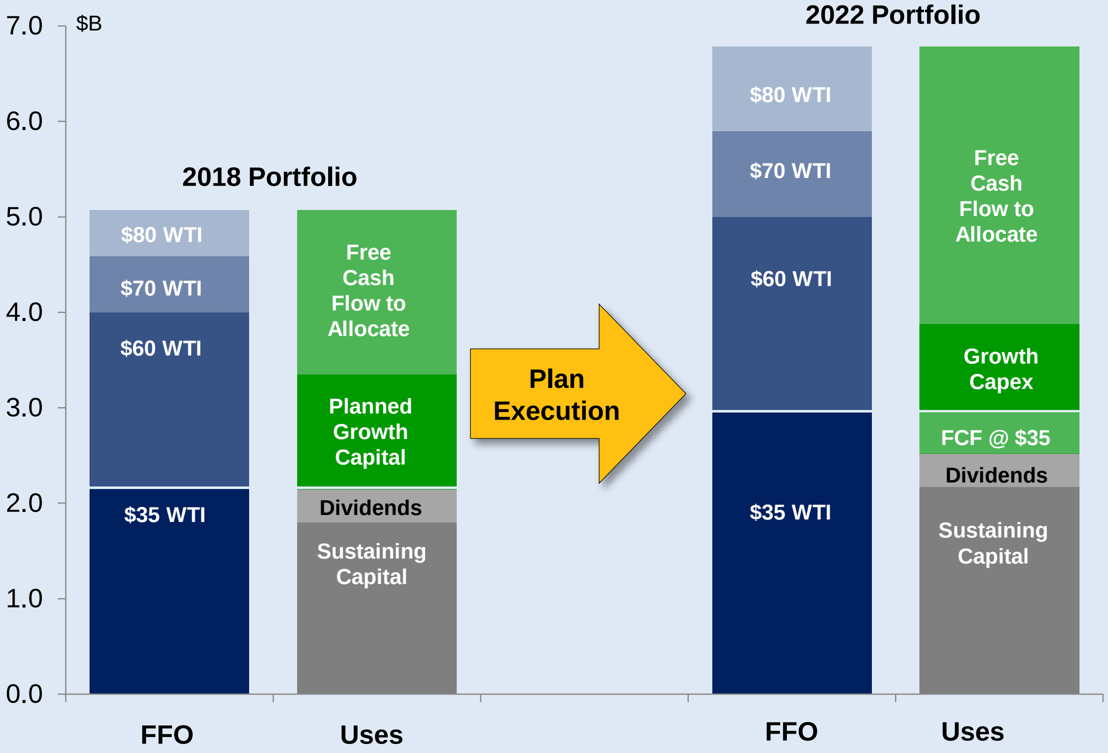
Benchmark Prices – $35 Stress Case	2018	2022
WTI (US $bbl)	35.00	35.00
Chicago 3:2:1 ($/bbl US)	12.00	12.00
Heavy crude differential ($/bbl US)	11.00	11.00
AECO ($/mmbtu Cdn)	2.25	2.25
US/CAD exchange rate	0.71	0.71

Financial Framework

Sustainable Model Through the Cycles With Free Cash Flow Upside

- Maintain balance sheet strength
- Invest in portfolio to:
  - Generate returns
  - Lower cost structure
  - Grow funds from operations and free cash flow
- Return cash to shareholders
- Optimize deployment of discretionary free cash flow

FFO Sources and Uses at Various Oil Prices (US WTI)[1]



1 See Slide Notes and Advisories

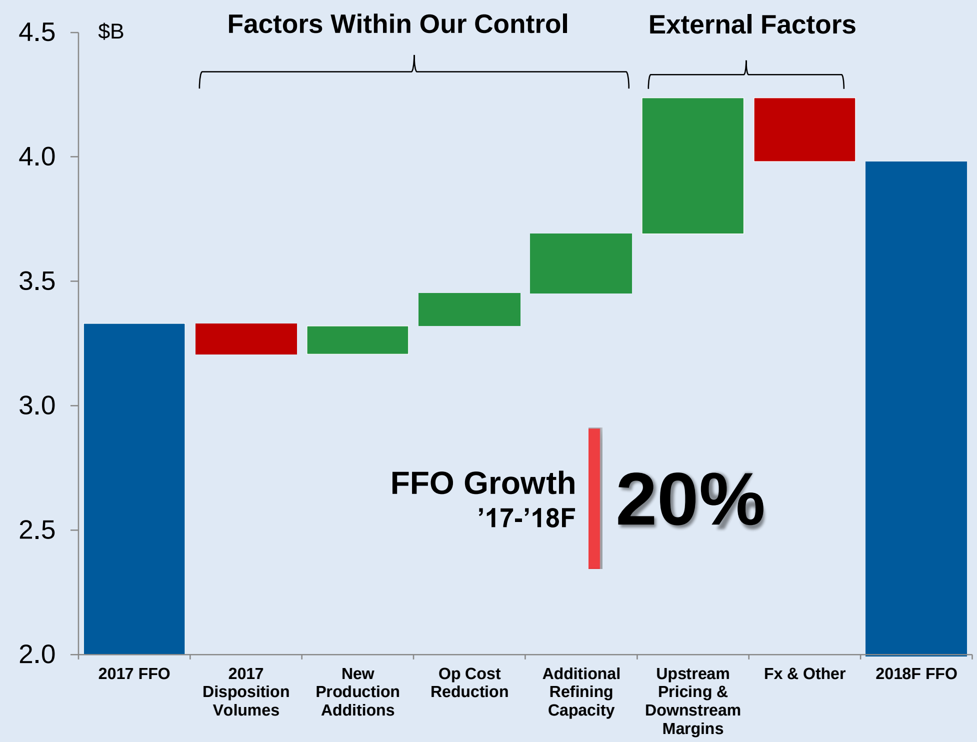
Asset Transformation Driving Gains in FFO ('17-'18)

YoY Increase: 55% Due to Asset Improvement, 45% Due to External Factors

Key Drivers

- Quality of upstream production improving
  - 2017 dispositions of higher cost production
  - Growth in lower cost thermal production
- Additional Downstream margin capture
- Improving macro environment

Bridging 2017 – 2018 Funds From Operations Growth



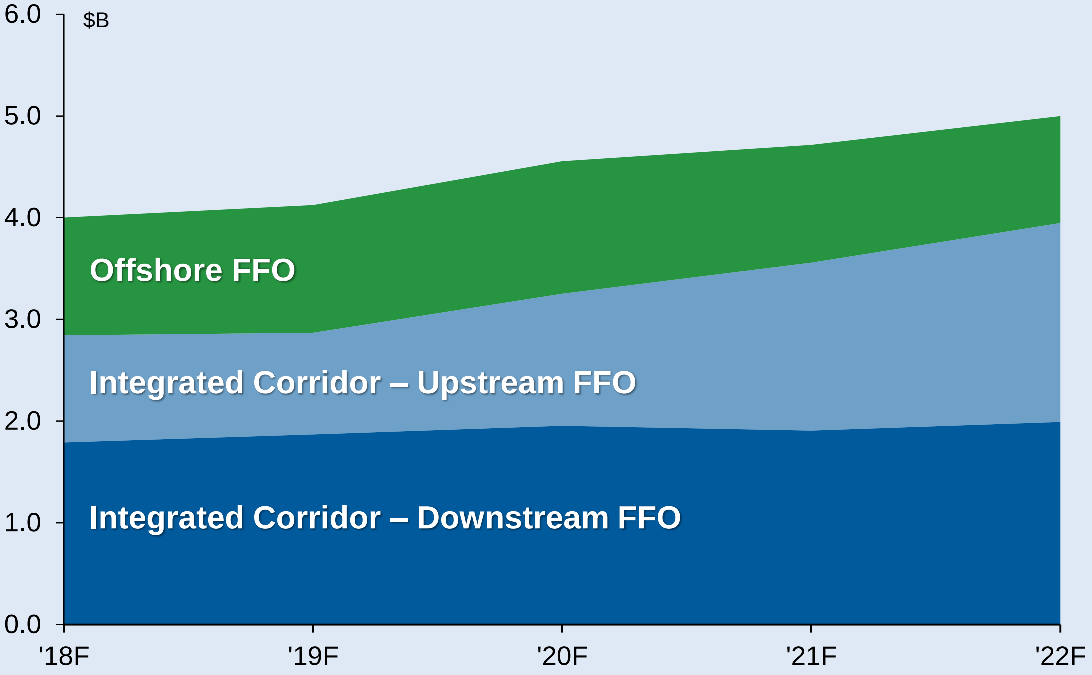
Funds from Operations 2018-2022

Nature of Two Businesses Provides Stable Growth in Funds From Operations

- **Integrated Corridor FFO[1]:**
  - Upstream: $1.1B → $1.9B
  - Downstream: $1.8B → $2.0B
- **Offshore FFO[2]:**
  - Atlantic: $0.4B → $0.2B
  - Asia Pacific: $0.7B → $0.9B

FFO Growth Over Plan
’18-’22F
25%

Funds From Operations at $60 US WTI



1,2 See Slide Notes and Advisories

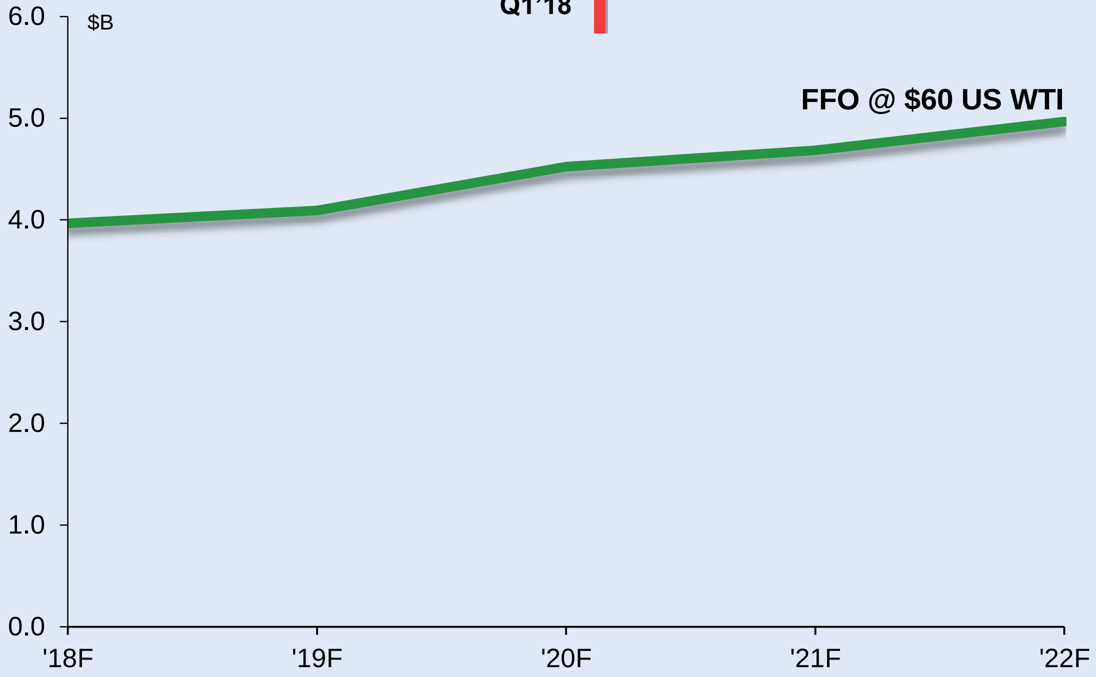
Spending Priorities

Strong Balance Sheet – No Need to Reduce Leverage

1. **Maintain <2X net debt to FFO**

Current Net Debt to Trailing 12 months FFO Ratio Q1'18

~0.9x ✓



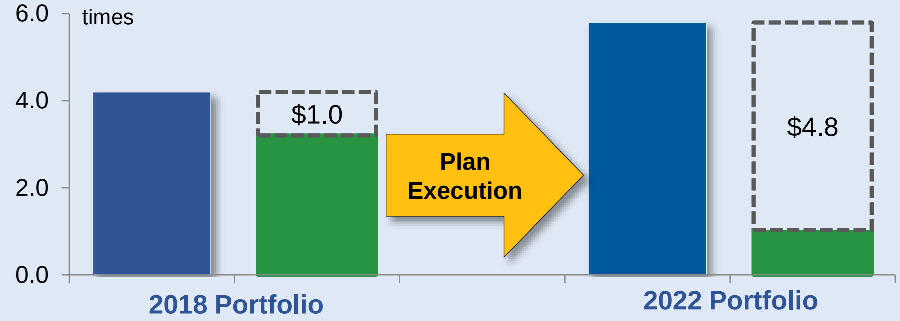
Balance Sheet

Low Leverage, Ample Liquidity

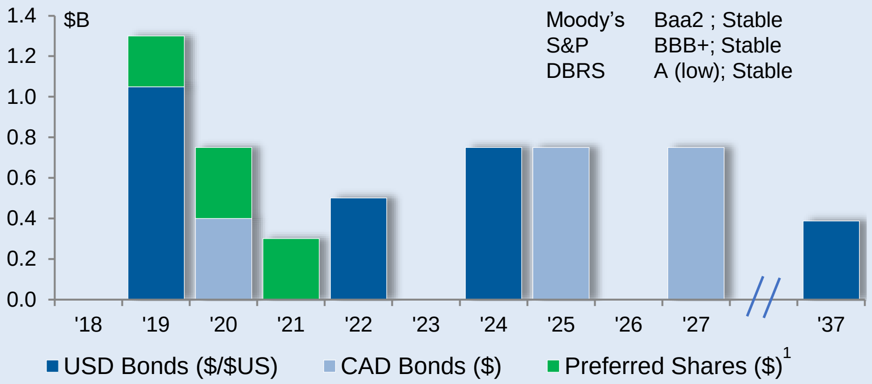
- Net debt $3.2 billion, including $2.3 billion in cash
- $4.2 billion in unused credit facilities
- Total debt to capitalization: 23.2%
- Debt target: <2x net debt to FFO at bottom of cycle
- Investment grade credit rating

All figures as at end Q1 '18

Illustrative 2x Net Debt to FFO Debt Capacity at US$35 WTI



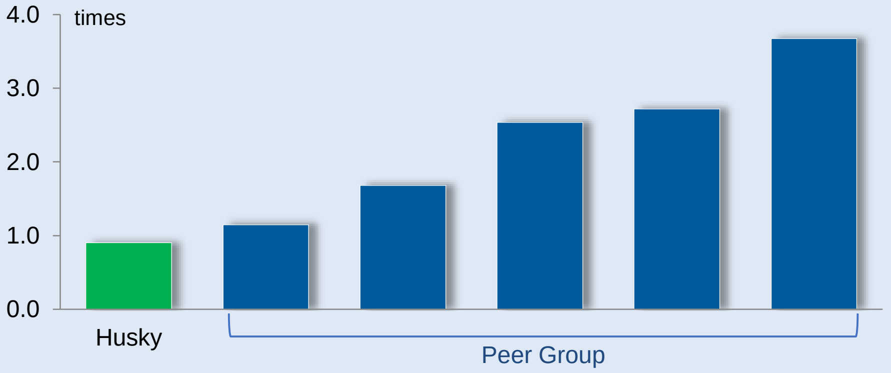
Debt Maturity Schedule



Credit Ratings

Moody's	Baa2 ; Stable
S&P	BBB+; Stable
DBRS	A (low); Stable

Net Debt to Trailing FFO (Q1 '18)



Peer Group: Cenovus, CNRL, Encana, Imperial, Suncor

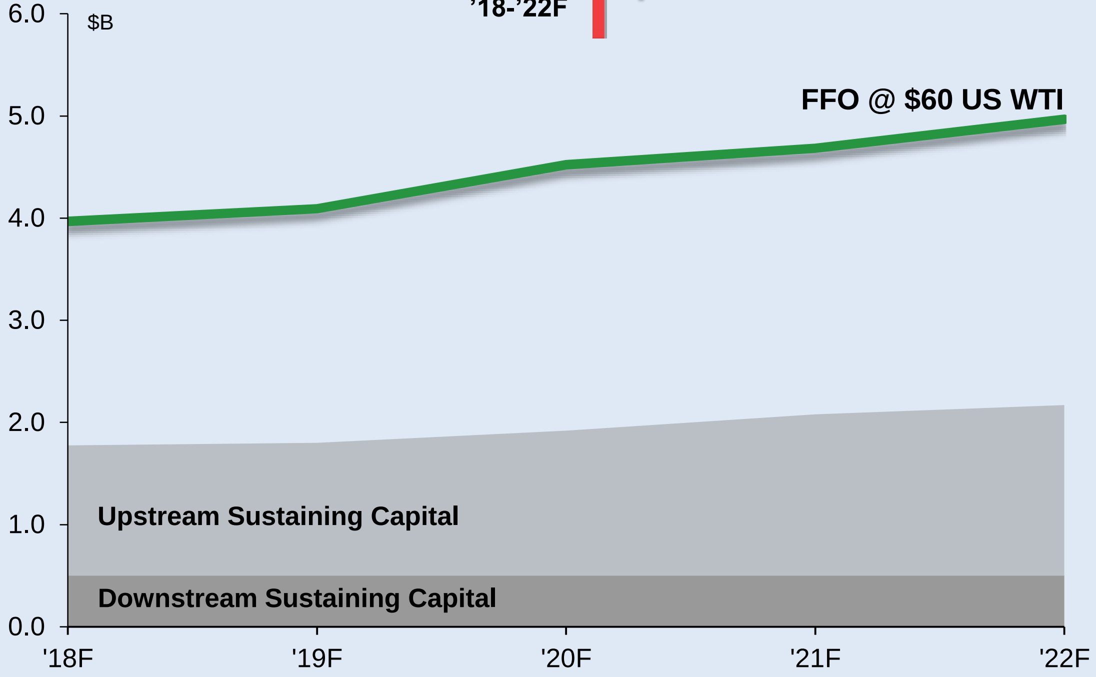
1 see *Slide Notes and Advisories*

Spending Priorities

Sustaining Capital – Keeping Production Flat, Ensuring Assets in Good Working Order

1. Maintain <2X net debt to FFO
2. **Sustaining capital requirements**

Annual Average Total Sustaining Capital ’18-’22F **$1.9B**

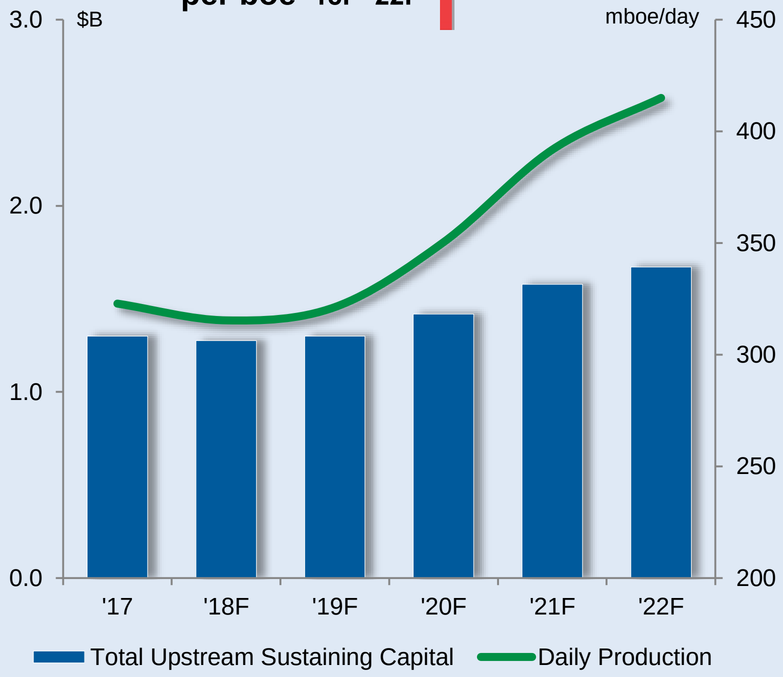


Sustaining Capital Calculation

Sustaining Capital Calculation	’18F	’22F
Upstream production (mboe/day)	**310-320**	**410-420**
Average decline rate	**17%**	**17%**
Replacement production (mboe/day)	53.5	70.5
Average cost of replacement (per flowing boe)	$21,500	$22,000
Cost to replace production	$1.15B	$1.55B
Annual Upstream maintenance capital	$0.15B	$0.15B
Total Upstream sustaining and maintenance capital	**$1.3B**	**$1.7B**
Annual Downstream sustaining capital	$0.5B	$0.5B
Total sustaining and maintenance capital	**$1.8B**	**$2.2B**

Average Upstream Sustaining Capital per boe ’18F-’22F

$11

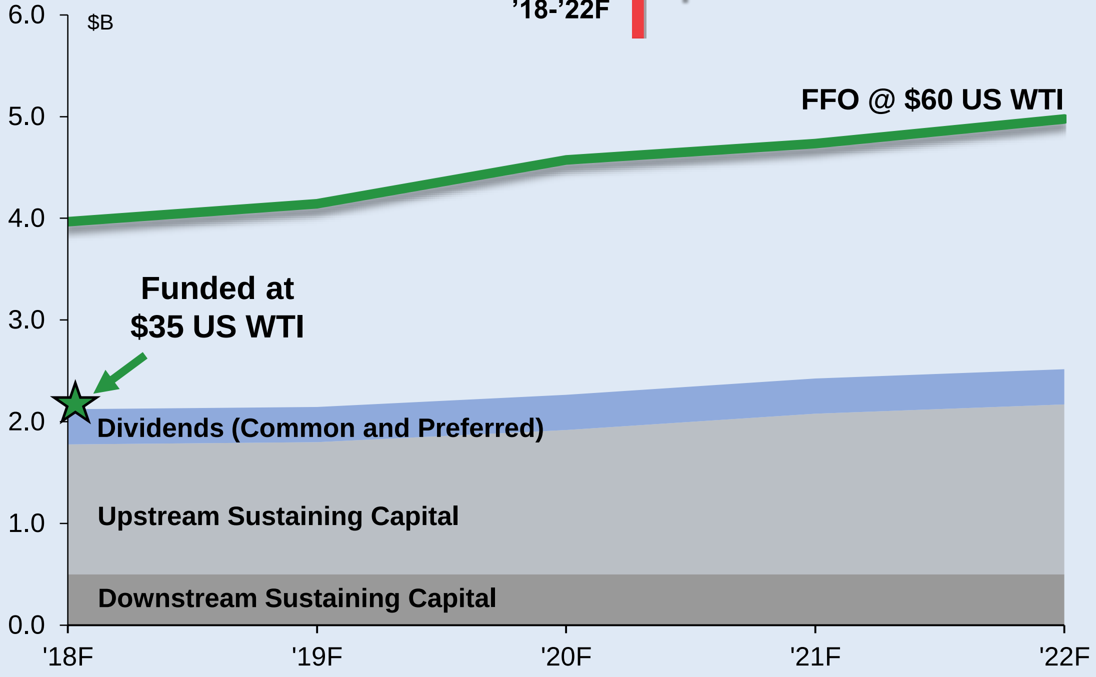


Spending Priorities

Base Dividend and Sustaining Capital Covered at $35 US WTI Today

1. Maintain <2X net debt to FFO
2. Sustaining capital requirements
3. **Maintain base dividend**

Current Annual Common Dividend Base ’18-’22F | **$300M**

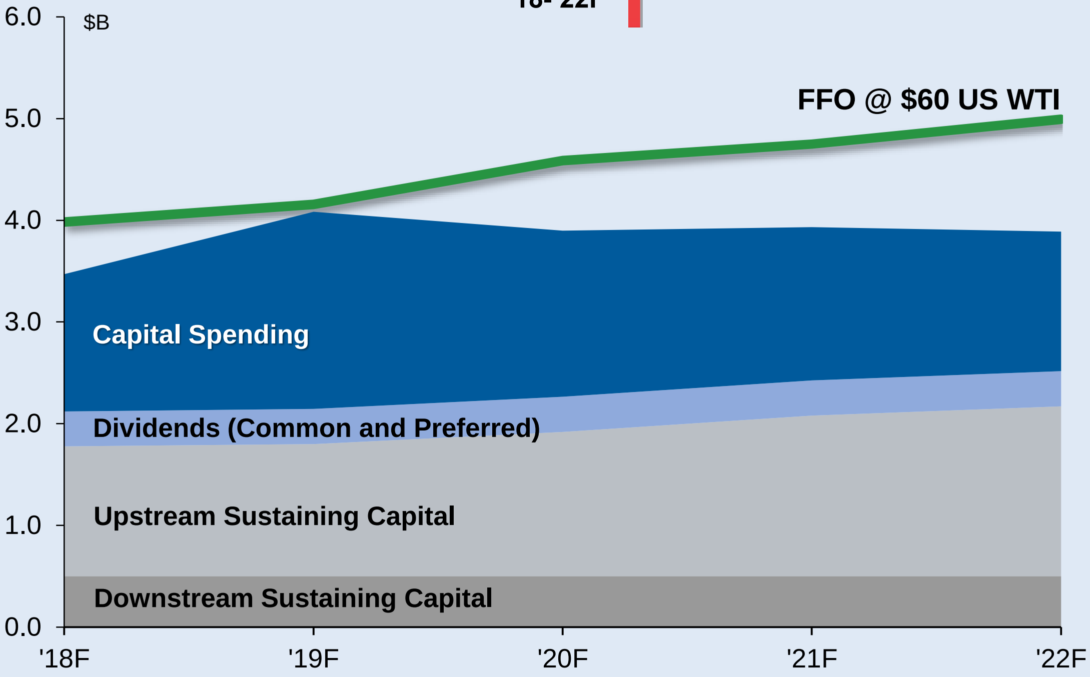


Spending Priorities

Growth Investment Reduces Cost Structure

1. Maintain <2X net debt to FFO
2. Sustaining capital requirements
3. Maintain base dividend
4. **Invest for margin and FFO growth**

Annual Average Growth Capital ’18-’22F | **$1.5B**

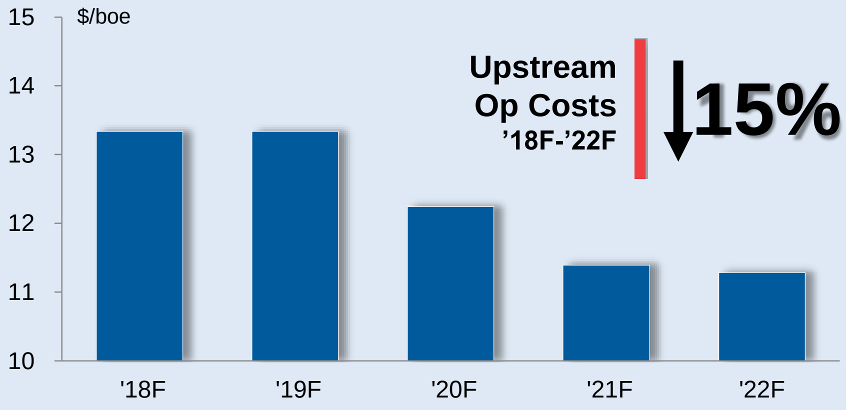


Capex Program Drives Improving Cost Structure

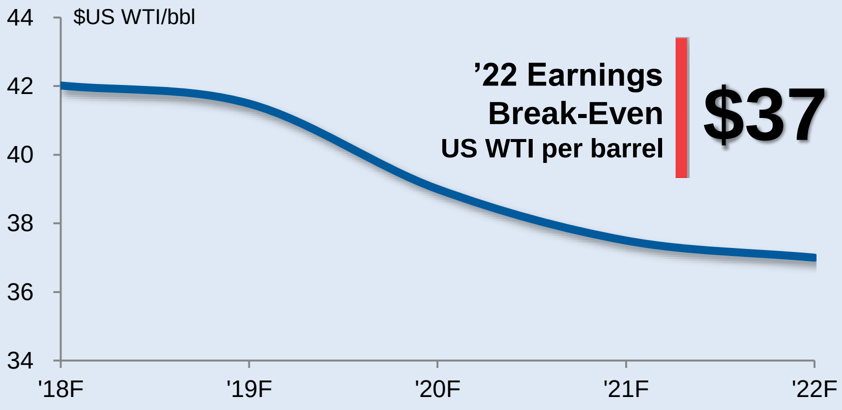
Lowering Operating Costs and Break-Even Oil Price

- New investment hurdle rate of 10% IRR at $45 US WTI and/or $2.00 per mcf AECO
- Investment options in both the Integrated Corridor and Offshore
- Approximately two-thirds of capital plan to be directed to short and mid-cycle projects

Upstream Operating Costs



Earnings Break-Even Oil Price

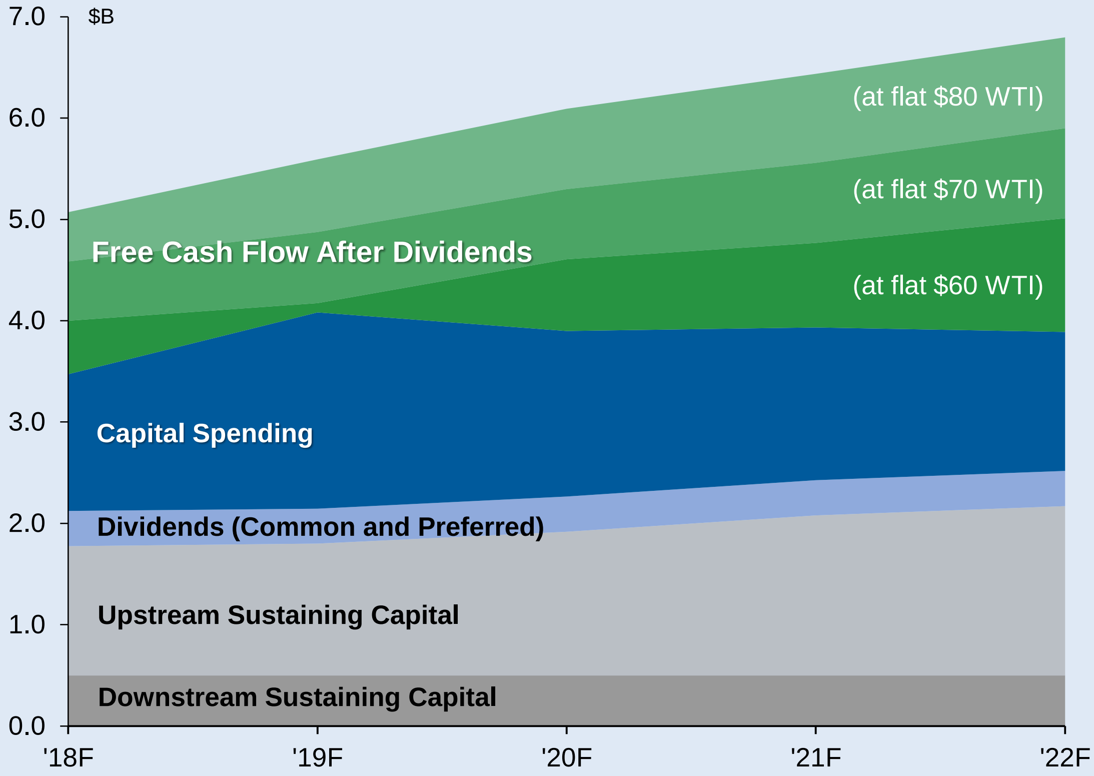


Spending Priorities

$3.3B of Cumulative Free Cash Flow After Dividends Generated at Price Planning Assumptions

1. Maintain <2X net debt to FFO
2. Sustaining capital requirements
3. Maintain base dividend
4. Invest for margin and FFO growth
5. **Allocate discretionary free cash flow**
   - **Return to shareholders**
   - **Organic/inorganic growth**

Cumulative Free Cash Flow After Dividends at $60 US WTI ’18-’22F **$3.3B**



Allocation of Discretionary Free Cash Flow

Various Options

Cumulative Free Cash Flow (after dividends) ’18-’22F

$3.3B

Accelerate Growth

Inorganic Growth

- Needs to be on-strategy
- Need to fit within financial framework
- Have been active on “tuck-ins”

Organic Growth

- Limited acceleration of current portfolio investment without compromising capital efficiency
- Intend to maintain capital discipline

Return to Shareholders

Dividend Growth

- Base dividend can be funded at $35 US WTI
- Option to grow with continued strengthening of asset base

Special Dividends & Share Buybacks

- History of paying special dividends
- Buybacks remain an option

Balance Sheet Strength

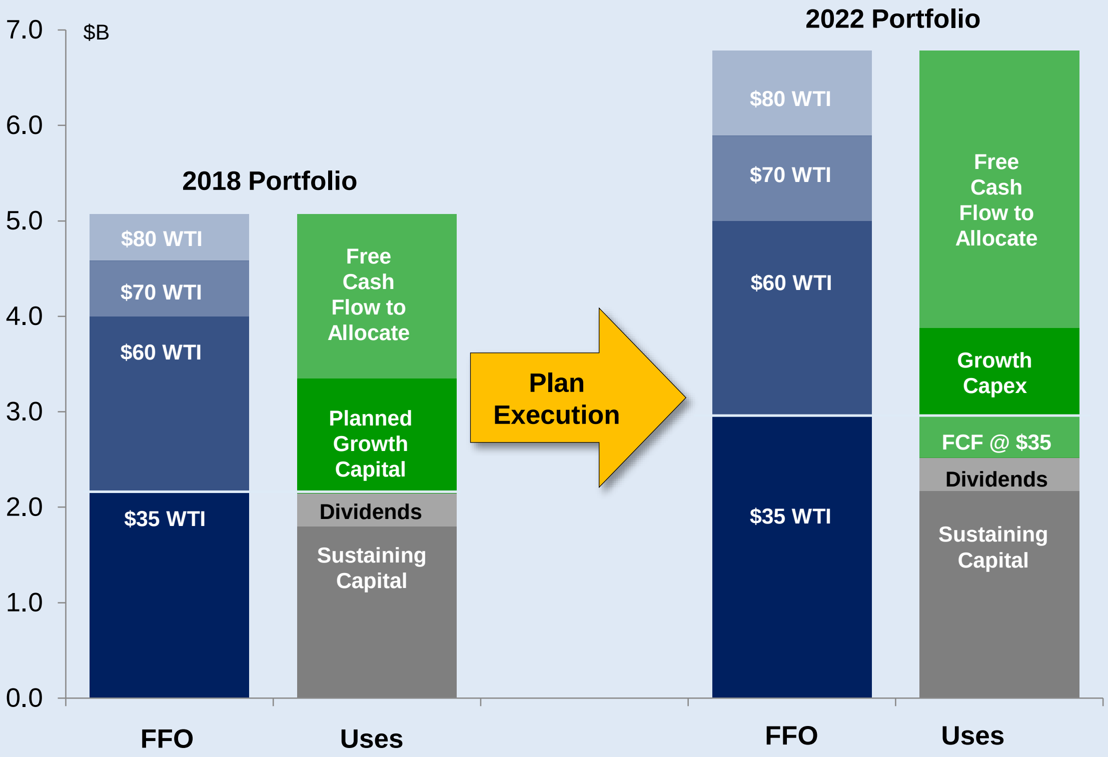
- Already strong, no need to de-lever
- Aim to stay below 2x net debt to FFO at $35 US WTI

Financial Framework

Sustainable Model Through the Cycles With Free Cash Flow Upside

- Maintain balance sheet strength
- Invest in portfolio to:
  - Generate returns
  - Lower cost structure
  - Grow funds from operations and free cash flow
- Return cash to shareholders
- Optimize deployment of discretionary free cash flow

FFO Sources and Uses at Various Oil Prices (US WTI)



Operations

Rob Symonds
Chief Operating Officer

Integrated Corridor

Optimizing the Entire Value Chain

Reserves base (YE ’17)

- 2.0 billion boe of proved & probable reserves

Production of 230 mboe/day (Q1 ’18)

- 123 mbbls/day thermal bitumen
- 60 mbbls/day non-thermal oil and liquids
- 279 mmcf/day gas

Refining and upgrading capacity[1]

- Total processing capacity – 400 mbbls/day
- Heavy processing capacity – 190 mbbls/day

Finished products (Q1 ’18)

- 56 mbbls/day of sweet synthetic oil
- 25 mbbls/day of asphalt
- 104 mbbls/day of diesel / jet fuel
- 145 mbbls/day of gasoline

1 See Slide Notes and Advisories

Husky's Integrated Model Put To The Test

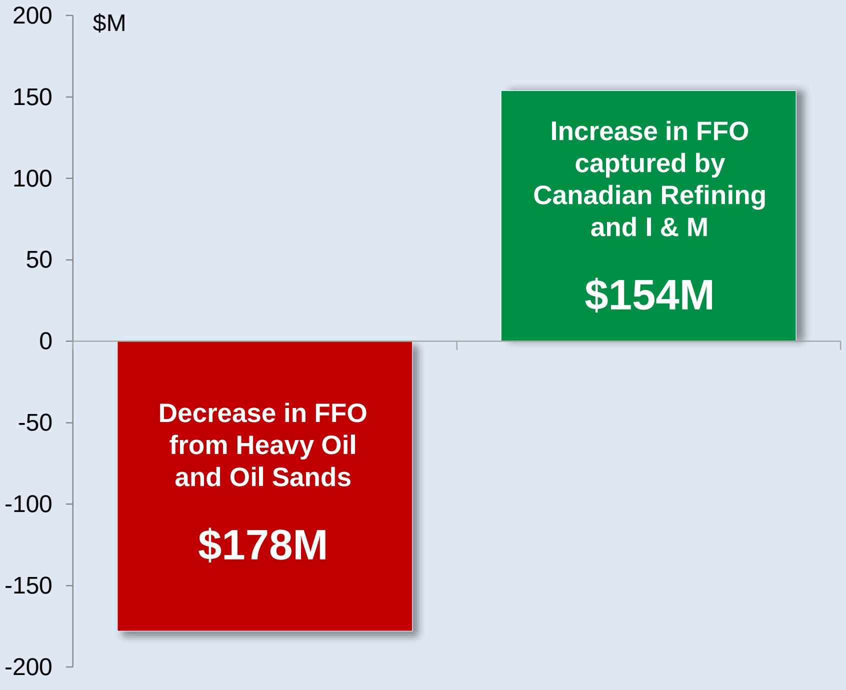
Largely Shielded From Differentials; Stable Free Cash Flow Generator

- Differential widened by almost 100% quarter-over-quarter
- Reduction in Upstream heavy oil mostly offset through Canadian upgrading and refining, and take-away capacity

Light / Heavy Oil Price Differential (US$ per barrel)

	Q4 2017	Q1 2018	Change
WTI	55.40	62.87	7.47
WCS	43.14	38.59	(4.55)
Differential	**-12.26**	**-24.28**	**98%**

Difference in Funds from Operations – Q1 '18 vs. Q4 '17

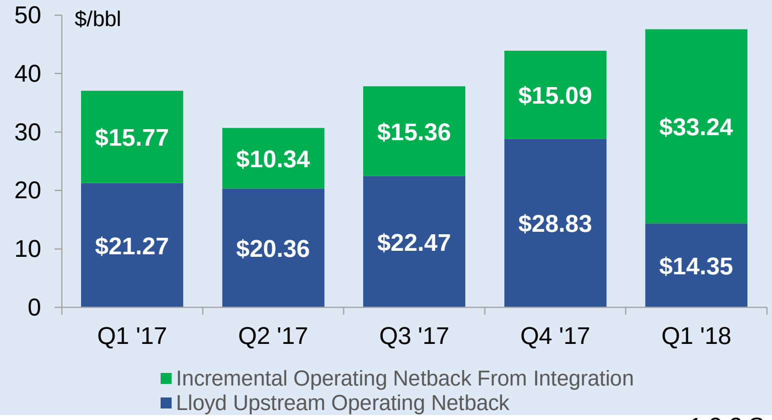


Lloyd Advantage

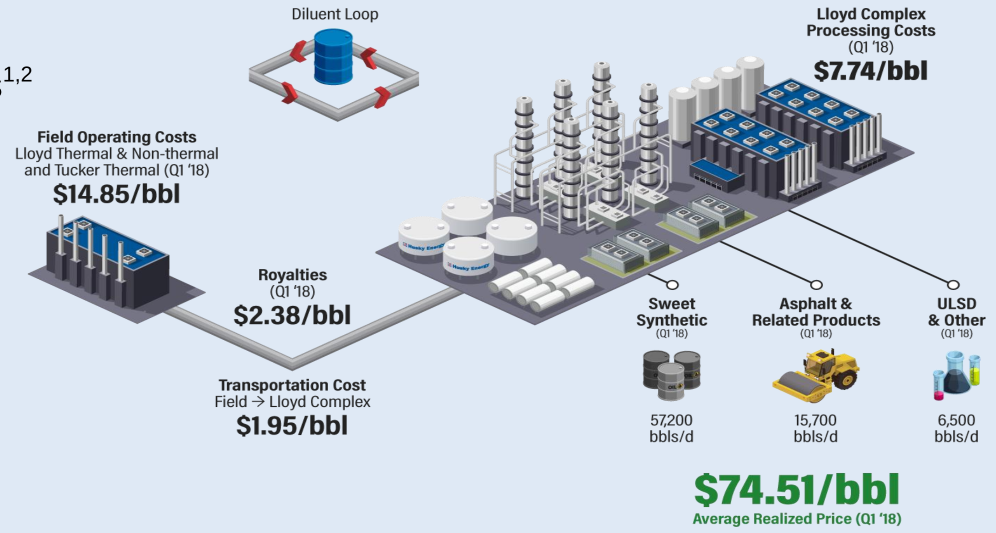
Full Value Chain Netbacks

- Low cost thermal production
- Low cost refining and upgrading
- Higher value, diverse basket of finished products[1,2]
- Higher finished product yield (98%)
- Extensive local market demand

Lloyd Value Chain Operating Netback[3]



Lloyd Value Chain (Q1 '18)



Lloyd Value Chain Operating Netback
($ per barrel, Q1 2018)

$47.59

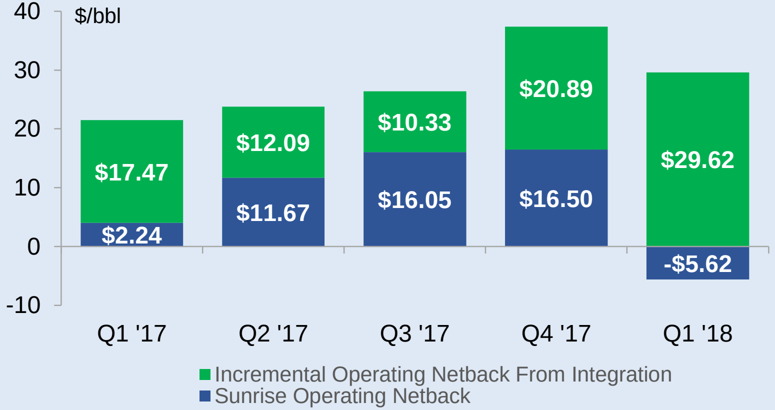
1,2,3 *See Slide Notes and Advisories*

Sunrise to Toledo

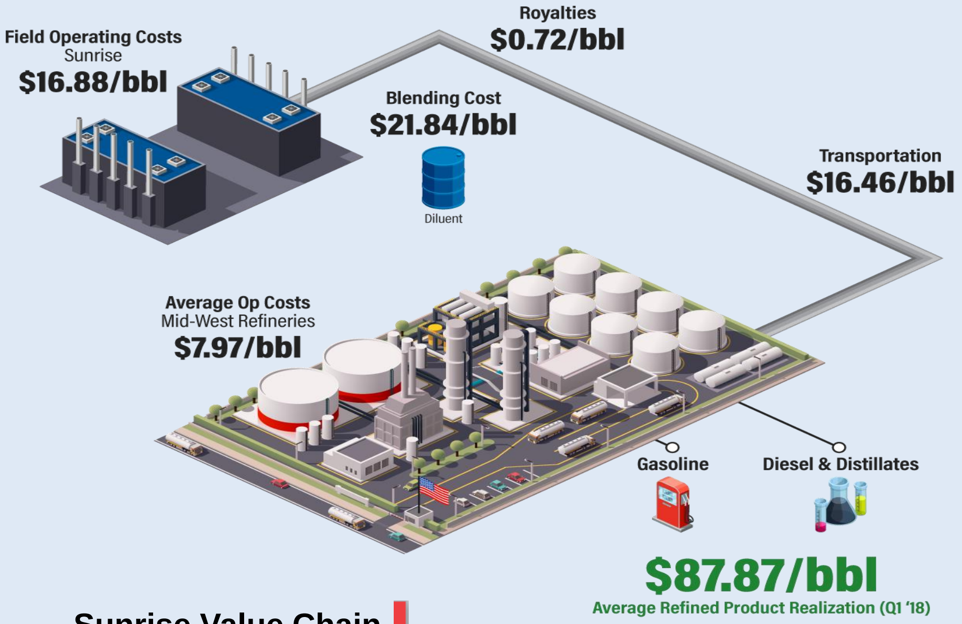
“One-Step” Refining, No Upgrading Required

- Toledo high-TAN project added processing capacity for all Sunrise crude
- Dilbit delivered directly to Toledo
  - No upgrading cost, no volume lost
- High finished product yield[1,2]

Sunrise Value Chain Operating Netback



Sunrise Value Chain (Q1 ‘18)



Sunrise Value Chain Operating Netback ($ per barrel, Q1 2018) **$24**

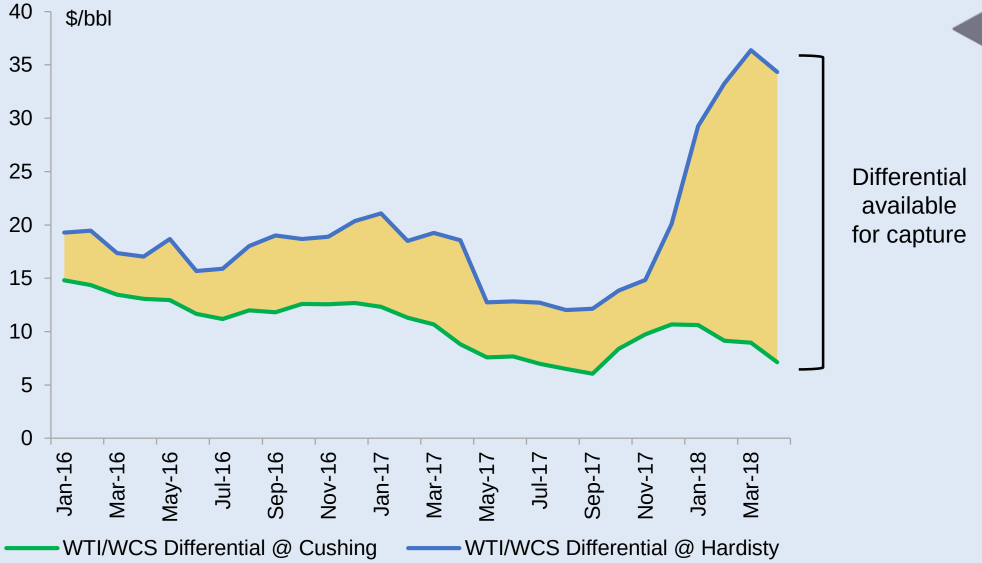
1,2 See Slide Notes and Advisories

Midstream Value Chain

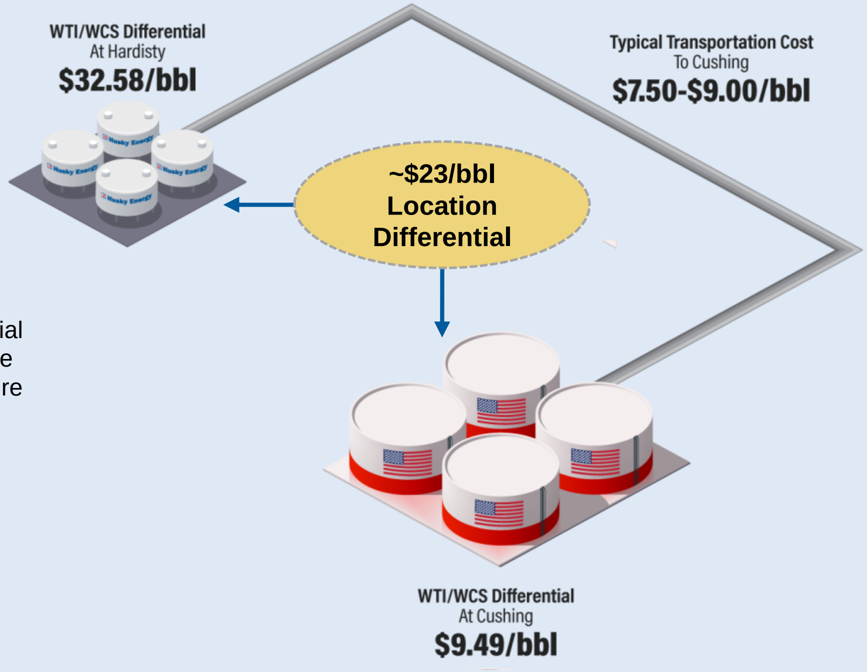
Crude Storage and Export Pipeline Capacity to U.S. Capturing Location Differentials

- 75,000 bbls/day capacity on existing Keystone
- 3.1 million barrels of storage at Hardisty

Heavy Oil Differentials



Midstream Value Chain (Q1 '18)



Integrated Corridor

Growing Higher Quality Production and Increasing Downstream Flexibility

Heavy Oil & Bitumen Production (bbls/day)

	2018F	2022F
Lloyd Thermal	77,000	135,000
Tucker	24,000	30,000
Sunrise	26,000	38,000
Cold & EOR	43,000	40,000
Total	**170,000**	**243,000**
Thermal as % of total	75%	84%

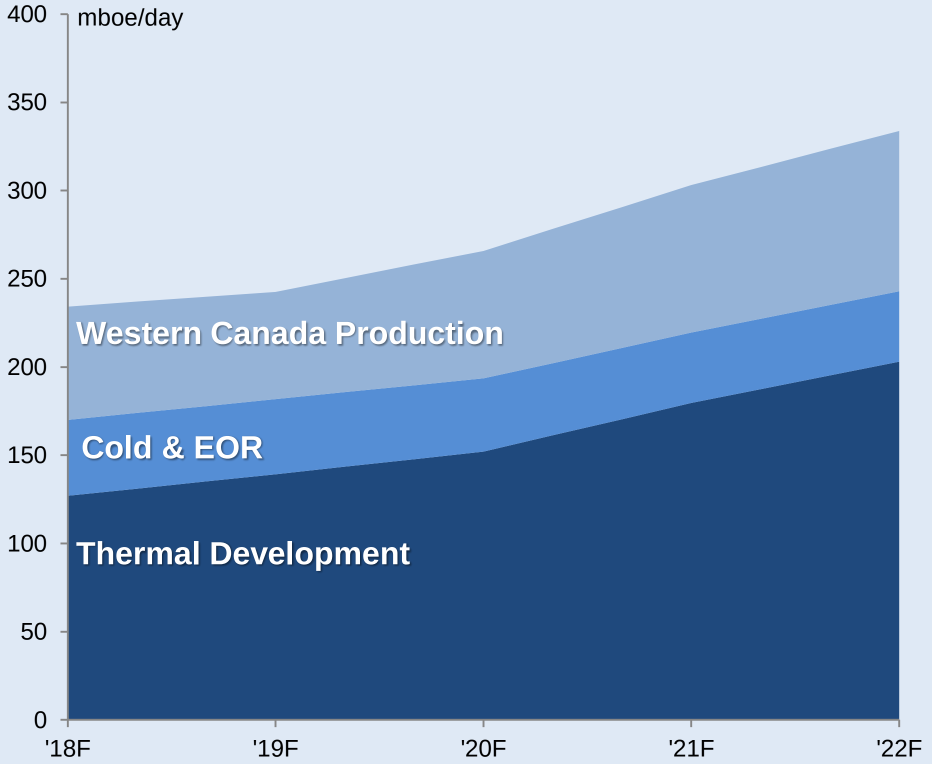
Western Canada Production (boe/day)

	2018F	2022F
Resource plays	30,000	70,000
Other W. Canada production	34,000	20,000
Total	**64,000**	**90,000**
Resource plays as % of total	47%	78%

Downstream Throughputs Capacity (bbls/day)

	2018F	2022F
Heavy oil processing capacity[1]	190,000	220,000
Light oil processing capacity[1]	210,000	180,000
Total refining and upgrading capacity[1]	**400,000**	**400,000**
Heavy oil capacity as % of total	48%	55%

Integrated Corridor Upstream Production Profile



1 See Slide Notes and Advisories

Integrated Corridor

Cost Reduction and Margin Capture Initiatives Leading to Increased Cash Flow

Western Canada

- Three activity hubs share infrastructure
- Operating costs 25% lower since 2014
- Reduced well bore count 80%

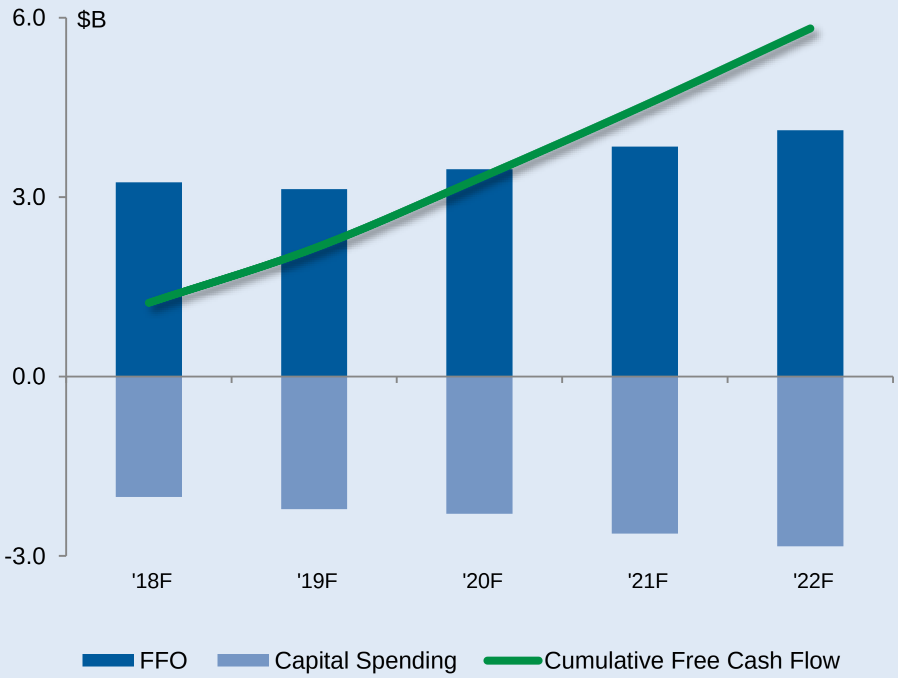
Lloyd Thermals

- Modular, scalable designs
- Shared infrastructure
- Low operating costs and sustaining capital requirements

Downstream

- Continual optimization of value chain
- Marketing refined products across North America

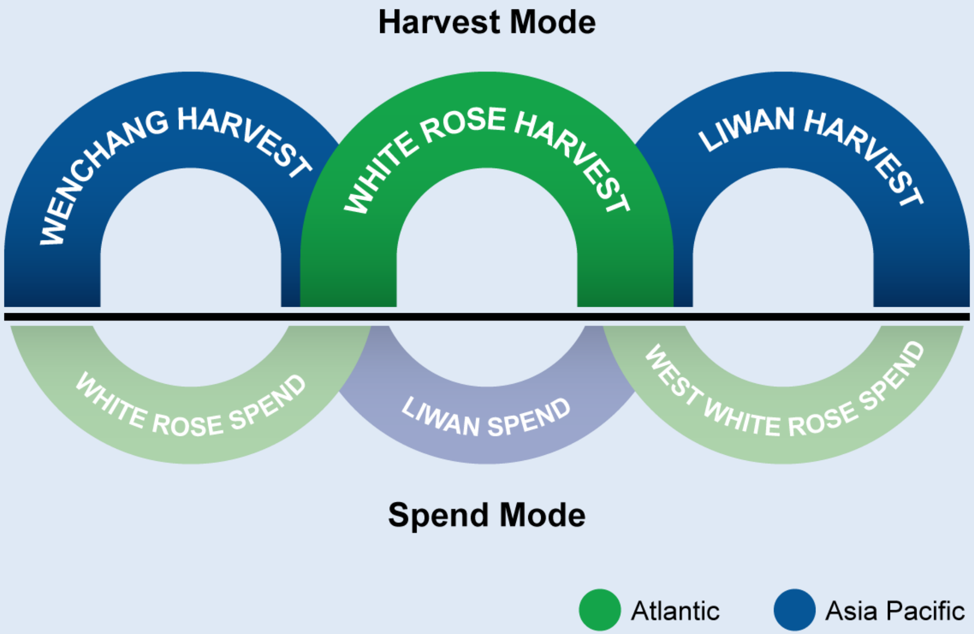
Integrated Corridor Free Cash Flow Growth



Offshore

Self-Funding Business With Synchronized Build-Harvest Cycles

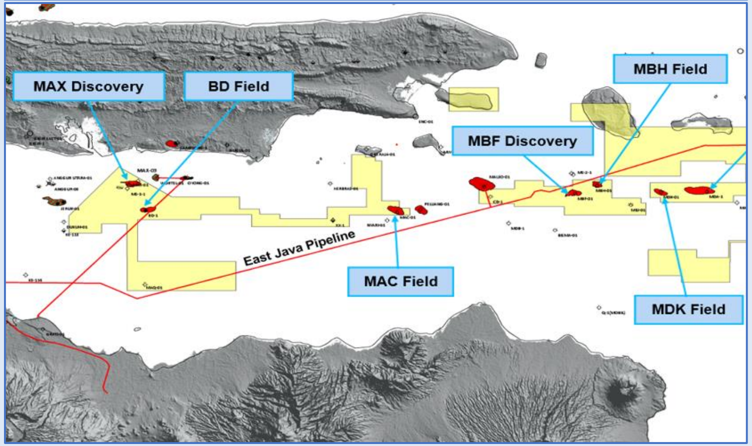
Investment Cycle



Offshore

Leveraging Existing Infrastructure Drives Efficiencies

- West White Rose tieback to *SeaRose* FPSO
- 29-1 tieback to Liwan platform
- Madura Strait fields offshore Indonesia linked by existing East Java pipeline
- Shallow water exploration fields offshore China close to existing infrastructure

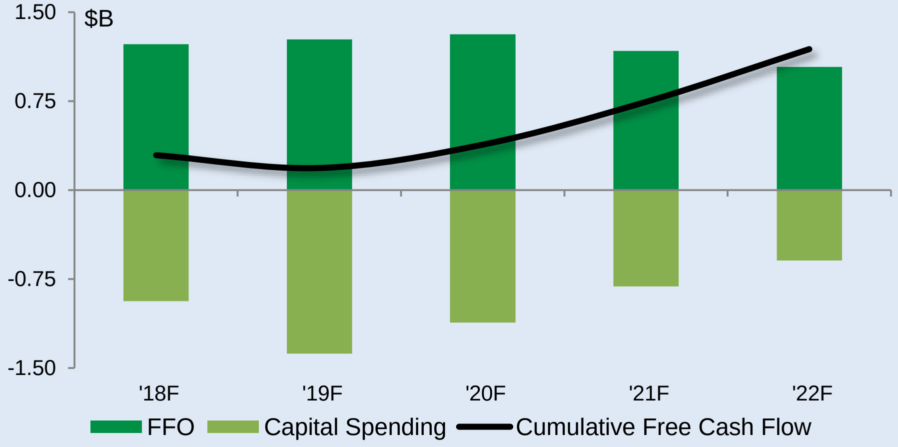


Offshore

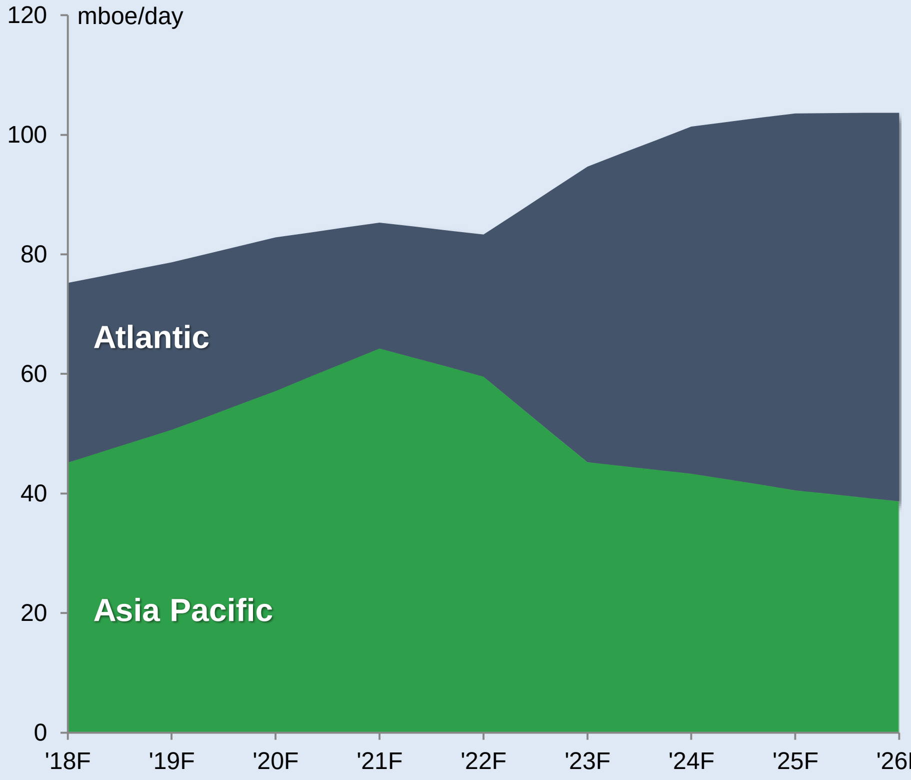
High Netback, Stable Growth

- Gas volumes growing steadily to ~270 mmcf/day (2018-2022)
- Globally-priced liquids volumes rising to ~75,000 bbls/day (2018-2026)

Offshore Free Cash Flow Growth



Offshore Growth



Innovation and Technology

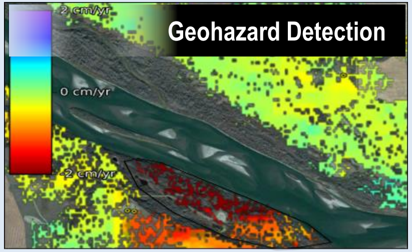
Growing Revenue, Improving Safety, Lowering Costs and Increasing Capital Efficiency

Automation

- Enhanced procurement processes by eliminating repetitive reporting and data movement *(proof of concept complete)*
- 90% reduction in completion time for IT requests *(active)*
- Improved resource planning and safety at plant sites by automated work permitting *(evaluating)*

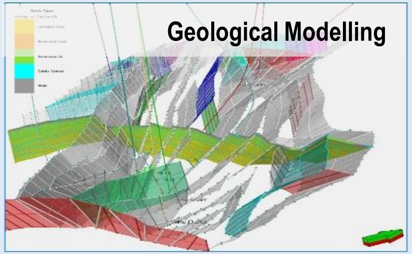
Production Optimization

- Diluent reduction module for lower costs, GHG emissions at Sunrise *(pilot under construction)*
- Improved steam utilization and process safety using Machine Learning for SAGD *(active)*
- Low cost wellsite monitoring devices to reduce WCP site visits / operating costs *(active)*



Remote Analysis

- Drones for visual pipeline right-of-way inspections *(completed pilot)*
- Geohazard identification at pipelines and facilities using satellite image analysis *(proof of concept complete)*
- Safer flare stack and equipment inspections at plant sites using drones *(active)*

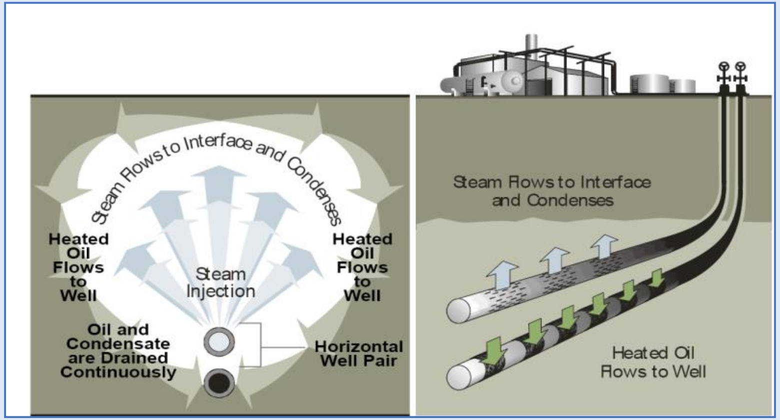


Subsurface

- Reduce geological core description time using AI for pattern recognition *(active proof of concept)*
- Accelerate subsurface interpretation with Cloud computing *(pilot completed)*
- Shorten decision process for Heavy Oil well re-completion with Machine Learning *(active proof of concept)*

Innovation and Technology

Unlocking Further Potential Through Machine Learning



Source: *Applied Energy*, May 2015

Heavy Oil SAGD Optimization AI Pilot

- Using analytics to optimize steam-oil-ratio (SOR) and production for SAGD thermal heavy oil projects
- The results will be used to stabilize and improve production, increase efficiency in steam utilization and loss production prevention

Machine Learning for Sea-state and Ice Drift Predictions

- Initial trials have yielded encouraging results for improved confidence in wave height prediction
- Work is ongoing to advance predictive capability for other metocean conditions, including sea-ice trajectory prediction to provide for more effective intervention

Actively engaged with multiple global technology leaders

Five-Year Plan Milestones

Project Execution in the Integrated Corridor and Offshore

Major Projects	Net Production	2017 – 2022
INTEGRATED CORRIDOR		
Thermal Bitumen		
Tucker	7,000 bbls/d	On Schedule / Ramp Up Period
Rush Lake 2	10,000 bbls/d	Accelerated to Q4 2018 from 1H 2019
Dee Valley	10,000 bbls/d	On Schedule
Spruce Lake Central	10,000 bbls/d	On Schedule
Spruce Lake North	10,000 bbls/d	On Schedule
Edam Central	10,000 bbls/d	Sanctioned Q4/17
Westhazel	10,000 bbls/d	Sanctioned Q4/17
Future Lloyd Thermal Projects (x2)	20,000 bbls/d	
Sunrise - 14 wells	11,500 bbls/d	Completed / Ramp Up Period
Resource Plays		
Spirit River drilling program (Ansell-Kakwa)		17 Net wells planned for 2018
Montney drilling program (Wembley-Karr)		Up to 8 Net wells planned for 2018
Downstream	**Heavy Capacity Increase**	
Lima - Crude Oil Flexibility Project	30,000 bbls/d	On Schedule
Asphalt Capacity Expansion	30,000 bbls/d	Acquired Superior Refinery
OFFSHORE		
Asia Pacific		
China - Liuhua 29-1	45 mmcf/d, 1,800 bbls/d	Sanctioned Q4/17
Indonesia - BD Field	9,000 boe/d	Completed / Ramp Up Period
Indonesia - MDA-MBH, MDK	10,000 boe/d	On Schedule
Atlantic		
White Rose Development / Infill Wells	5-8,000 bbls/d	2 Wells accelerated to Q4 2017
West White Rose	52,500 bbls/d	On Schedule

Husky Energy

Break

Downstream

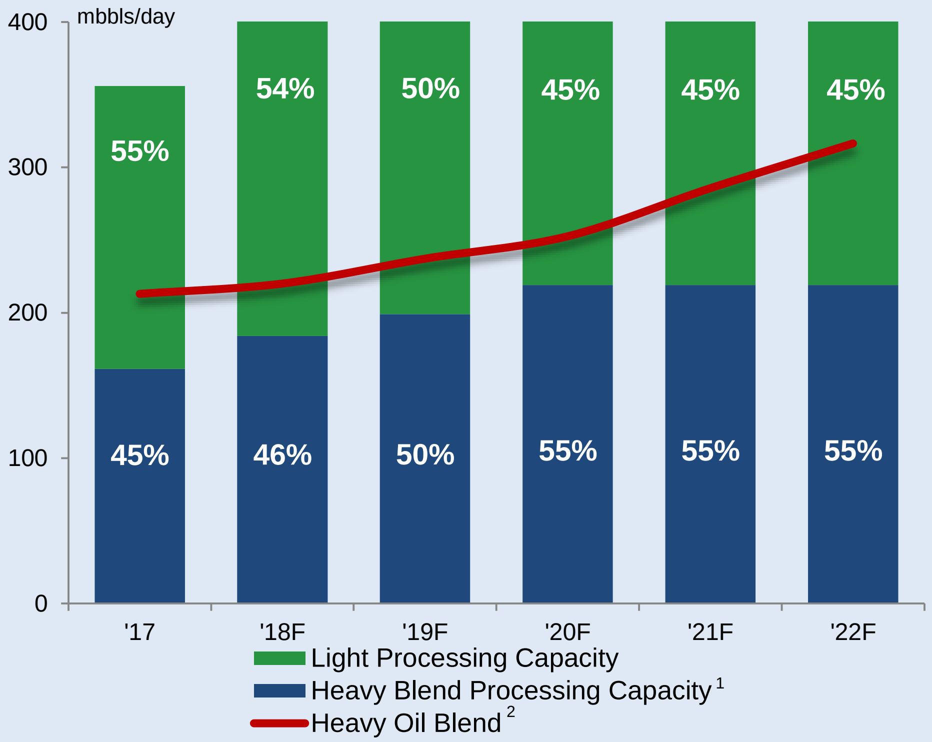
Jeffrey Rinker
SVP, Downstream

Maximizing Value From Every Barrel

Downstream

- Maintain Downstream integration with Upstream production
- Insulation from both location and quality differentials
- Ongoing investments to increase heavy oil processing capacity
- Increasing optionality of feedstocks, products and finished product markets
- Continual optimization of value chain

Downstream Processing Capacity (2017-2022F)



1,2 See Slide Notes and Advisories

Physically Connected Assets Across N. America

Downstream

Lloyd Complex

- 110,000 bbls/day processing capacity
- Physically connected to Lloyd and Tucker


Lloyd Upgrader

Capacity: 80 mbbls/day

- Produces Husky Synthetic Crude (HSB)
- Low operating costs


Asphalt Refinery

Capacity: 30 mbbls/day

- Supplies ~4% of asphalt manufactured in North America
- Transportation by rail

Prince George Refinery


Asphalt Refinery

Capacity: 12 mbbls/day

- Light oil refinery
- Supplies B.C. market

U.S. Refining & Marketing

- ~280,000 bbls/day processing capacity
- Product marketing centered in Ohio


Lima

Capacity: 165 mbbls/day

- Lima, Ohio
- Light oil refinery
- Access to diverse crude supply


Toledo

Capacity: 70 mbbls/day[1]

- Toledo, Ohio
- Configured to process high-TAN Sunrise crude


Superior

Capacity: 45 mbbls/day

- Superior, Wisconsin
- Light / Heavy oil refinery
- Asphalt, diesel, gasoline

Pipelines & Storage

- Five million barrels tank storage
- 75,000+ bbls/day takeaway capacity


Storage Terminals


Gathering System

Crude storage capacity:

- **3.1M bbls at Hardisty**
- **1.0M bbls at Lloyd**
- **1.3M bbls at Patoka**
- **0.9M bbls at Superior**
- Blending business
- Increases flexibility in marketing crude
- 35% interest in Midstream partnership
- Connections to several main pipelines ensure Husky crude can reach market

Retail


Retail Outlets

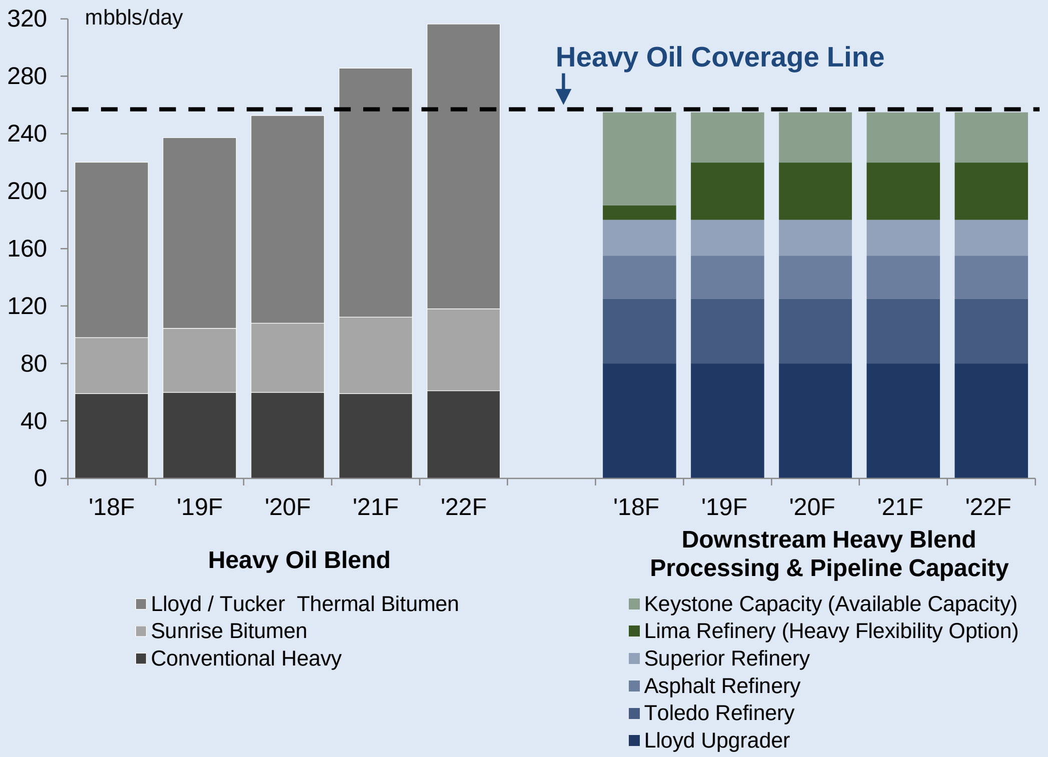
- 550+ retail outlets across Canada
- Branded, dealer-operated
- Cardlock JV with Imperial

1 See Slide Notes and Advisories

Matching Heavy Processing to Upstream Production

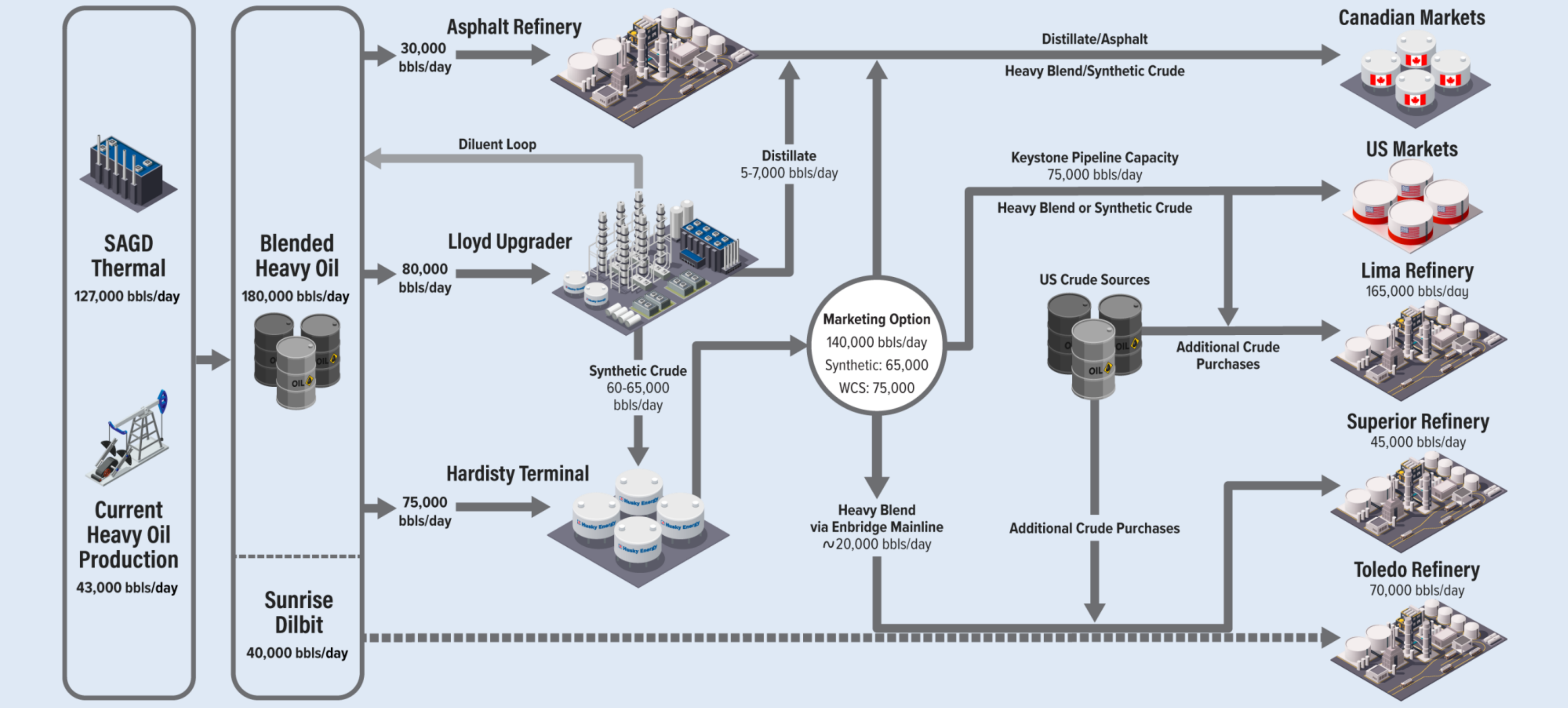
- Heavy oil blend matched to Downstream heavy processing and pipeline takeaway capacity through 2020
- Lima crude oil flexibility project
  - To add 30,000 bbls/day of heavy oil processing capacity in 2019
- Future heavy oil outlet options:
  - Export pipeline access
  - Lloyd asphalt plant expansion
    - Additional 30,000 bbls/day

Heavy Oil Blend vs Downstream Processing & Pipeline Capacity

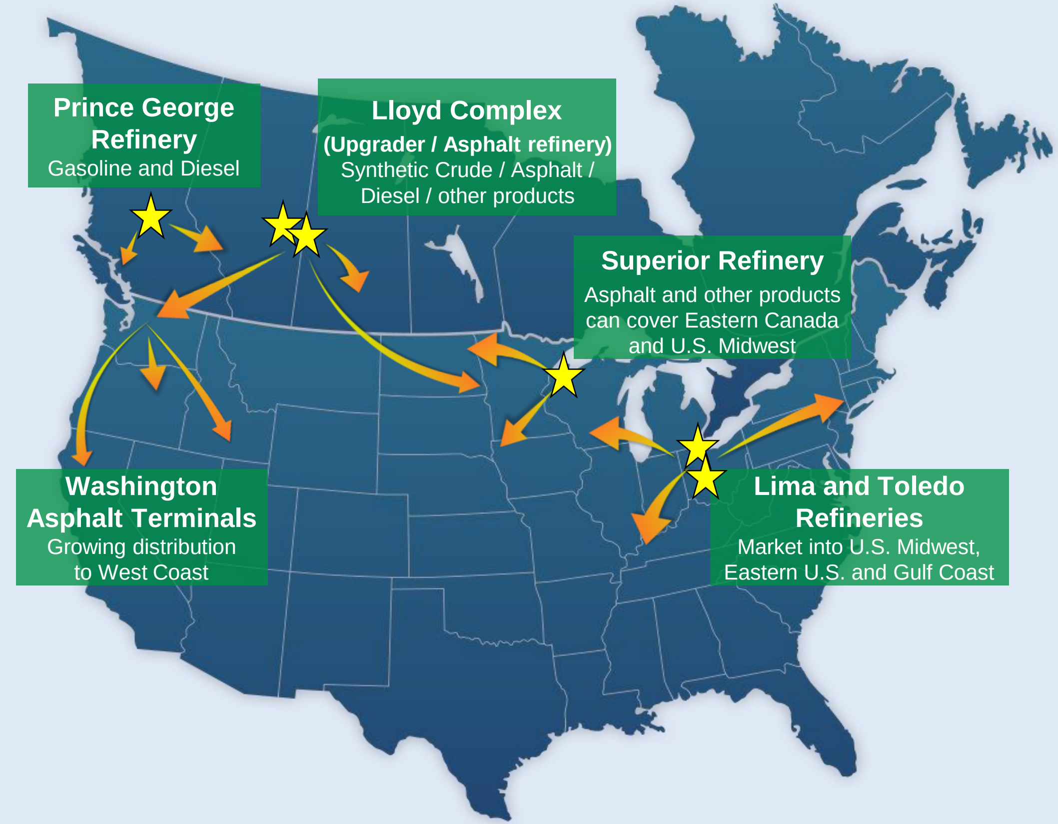


Flexibility of Feedstock, Product Mix and Markets

Downstream Connectivity

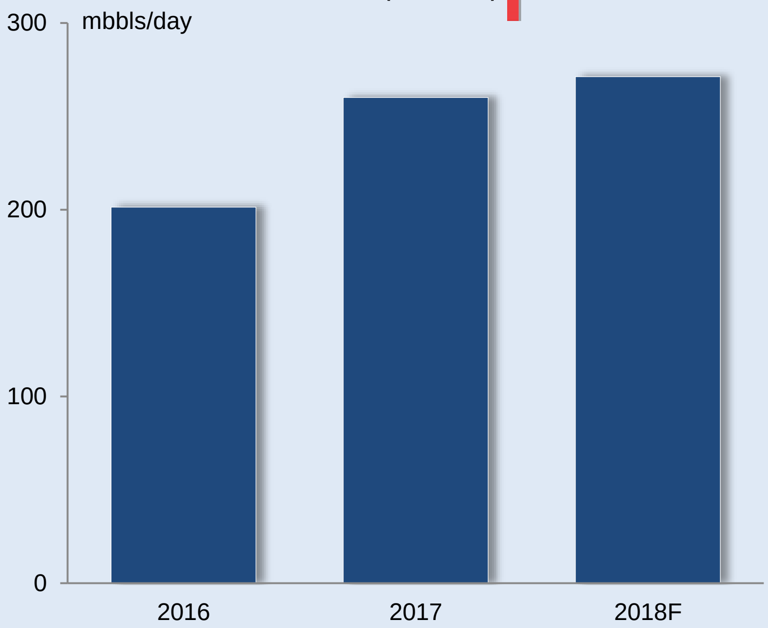


Expanding Finished Product Marketing Options



Volume of Husky Product Marketed to the U.S. ('16-'18F)

+35%



Largely Insulated From Canadian Pipeline Bottlenecks

Flexibility to Adjust to Market Conditions

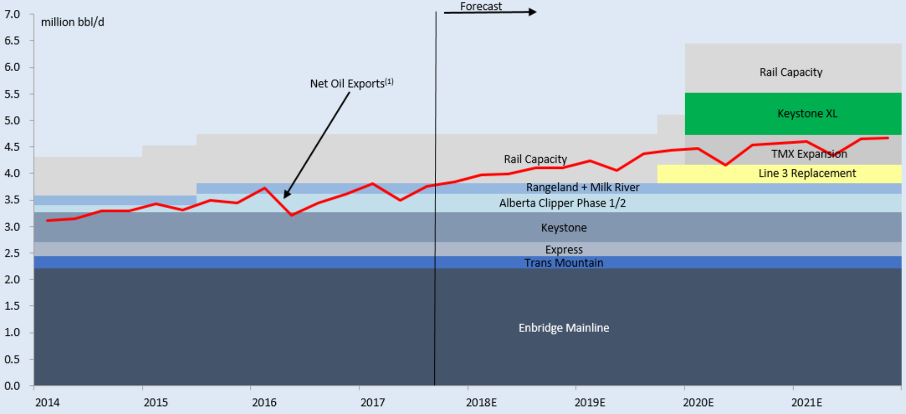
Market Impact

- Continued growth of Canadian heavy production met with lack of additional export capacity causing price discounts
- Timing of new export pipelines remain uncertain

Husky Ability to Respond

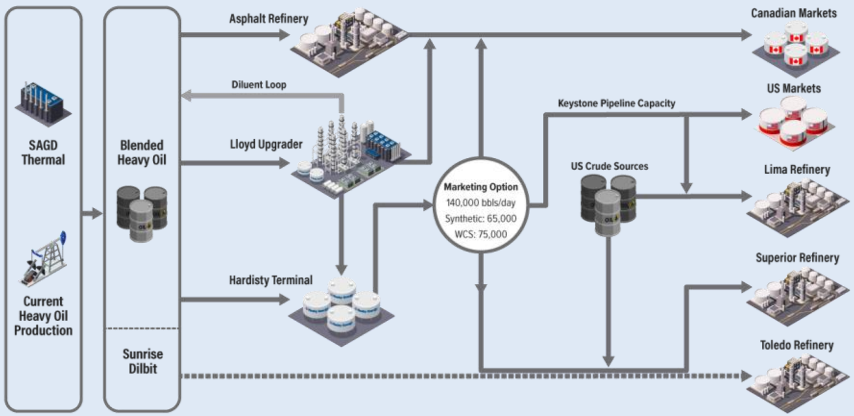
- Ability to export via nominated lines and long-term capacity on existing Keystone
- Ability to grow and maximize Canadian and U.S. throughputs of discounted heavy oil feedstock, capturing WCS/Brent differential

Western Canada Oil Export Pipeline and Rail Capacity



Source: RBC Capital Markets

Husky Downstream System



Configured to Benefit From IMO 2020 Rule

Flexibility to Adjust to Market Conditions

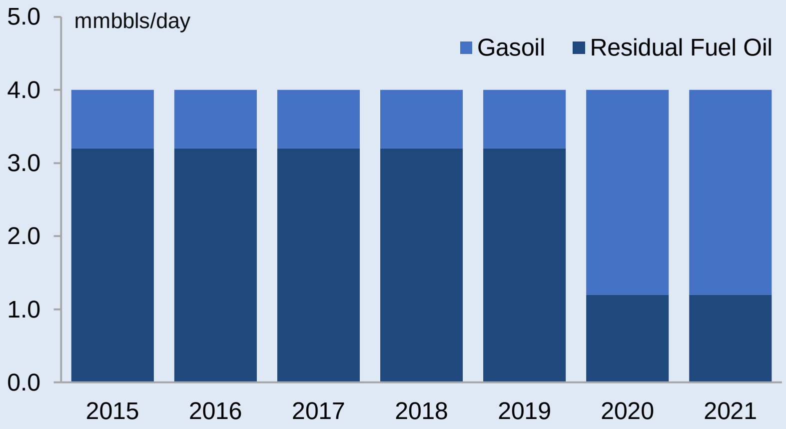
Market Impact

- Decrease in global demand for bunker fuel
- Increase in global demand for diesel and distillates
- Pressure on global heavy oil pricing

Husky Ability to Respond

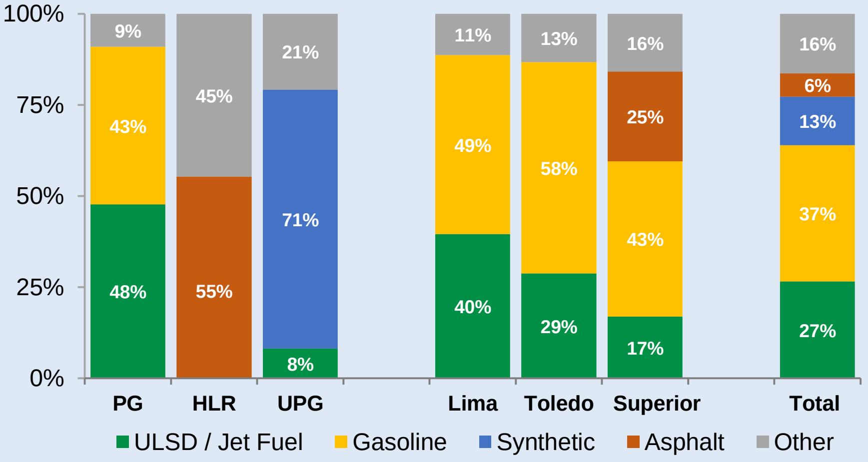
- Refining assets produce a high percentage of diesel and distillate versus other refiners
- Projects underway to grow heavy oil processing capacity to capture potential heavy oil differentials

Oil-Based Marine Fuel Consumption



Source: IEA, Medium-Term Oil Market Report 2016

Refined Products By Facility (Percentage of Throughput)



Instructure Constraints Pressuring Midland Pricing

Flexibility To Adjust to Market Conditions

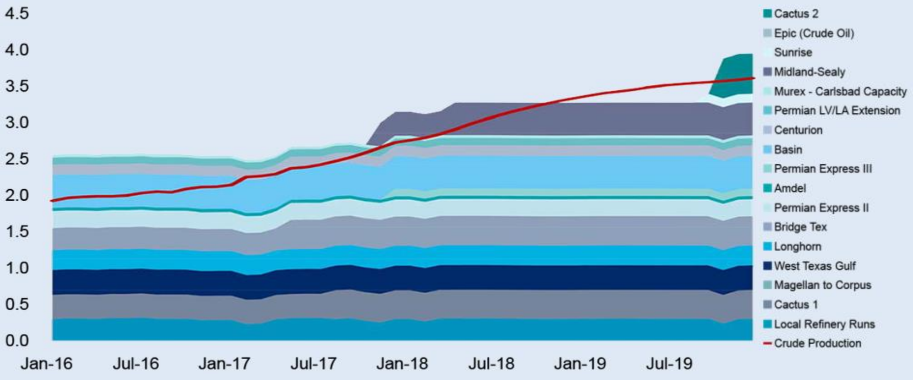
Market Impact

- Fast growing U.S. shale oil production
- Most growth between 45°-50° API gravity
- Infrastructure constraints putting pressure on light oil pricing

Husky Ability to Respond

- Maintain flexibility to process U.S. light barrels at Lima Refinery
- Lima Refinery can operate at a 100% light crude slate; one of shortest routes to refining for Permian production

Permian Oil Production vs. Takeaway Capacity



Source: IEA, Citi Research, Company Reports

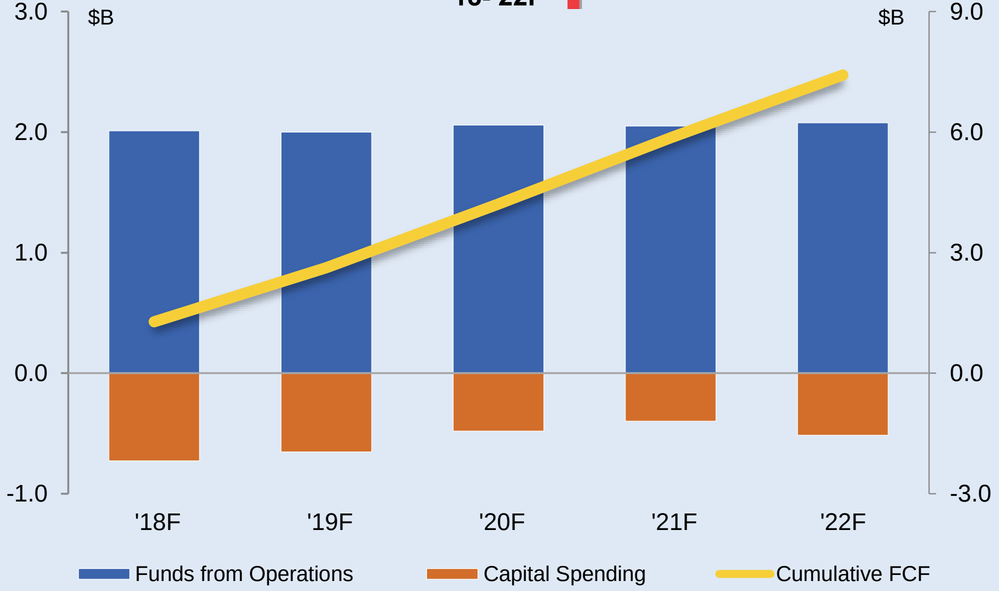
Connectivity from Midland to Lima

Maximizing Value From Every Barrel

Downstream

- Maintain Downstream integration with Upstream production
- Insulation from both location and quality differentials
- Ongoing investments to increase heavy oil processing capacity
- Increasing optionality of feedstocks, products and finished product markets
- Continual optimization of value chain

Downstream Annual Average Free Cash Flow ’18-’22F **~$1.5B**



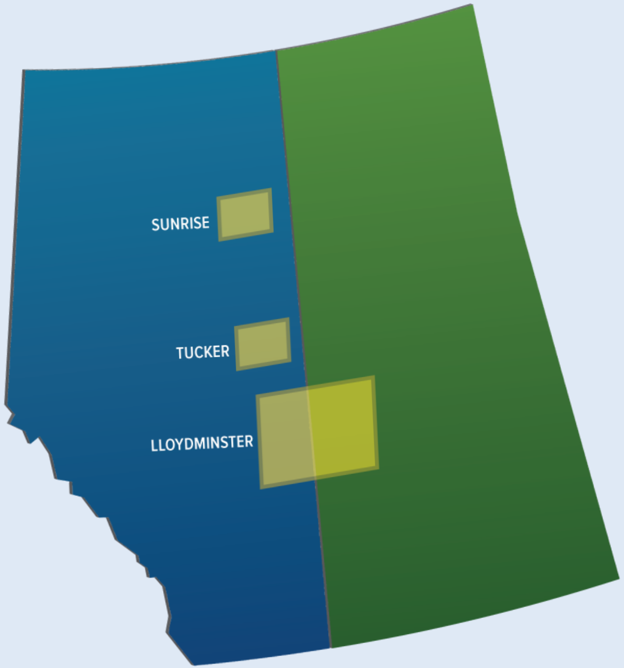
Heavy Oil & Oil Sands

Andrew Dahlin
SVP, Heavy Oil and Oil Sands
Carmen Lee
VP, Oil Sands

Tightly Integrated Growth Engine

Heavy Oil and Oil Sands

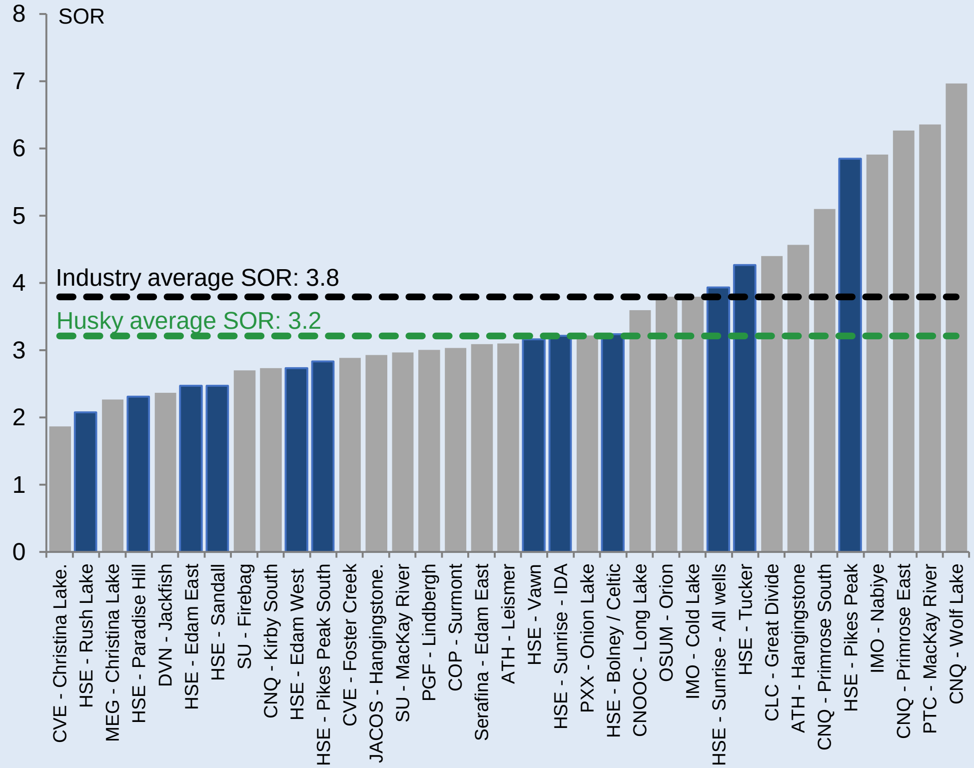
- 170,000 bbls/day today, growing ~40% to ~240,000 bbls/day by 2022
- Modular, scalable designs lowering operating costs and sustaining capital requirements
- Physically integrated with Midstream and Downstream
- **Lloydminster**
  - 10 thermal projects producing ~75,000 bbls/day
  - 60,000 bbls/day of new projects under development
  - Plan to sanction two 10,000 bbls/day projects every year
  - 43,000 bbls/day of CHOPs and EOR oil production
- **Cold Lake**
  - Tucker ramping up to 30,000 bbls/day
- **Fort McMurray**
  - Sunrise ramping to 30,000 bbls/day (net); approved for 100,000 bbls/day (net)



Competitive Steam-Oil Ratios and Netbacks

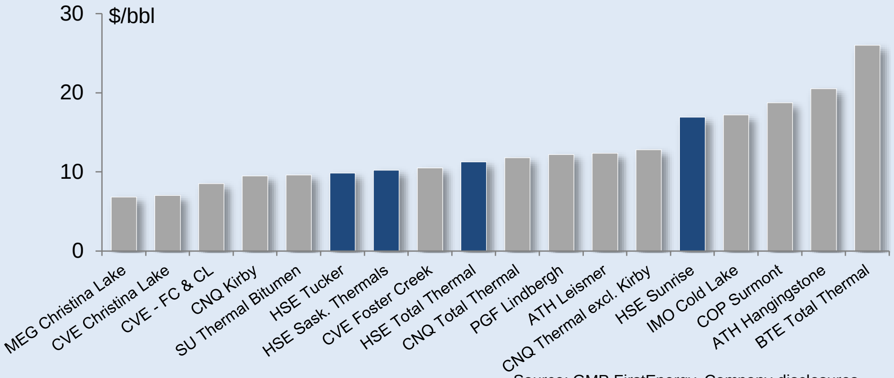
Thermal Business

Thermal SAGD Project SORs (Q1 2018)



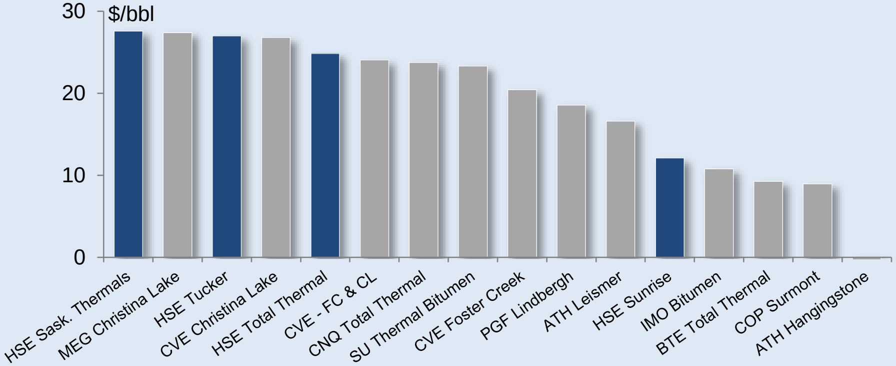
Source: TD Securities, Scotia Capital, GeoScout

Thermal Bitumen Operating Costs – 2017 ($/bbl)



Source: GMP FirstEnergy, Company disclosures

Bitumen Operating Netbacks – 2017 ($/bbl)



Source: GMP FirstEnergy, Company disclosures

Large Inventory of Low Cost Production

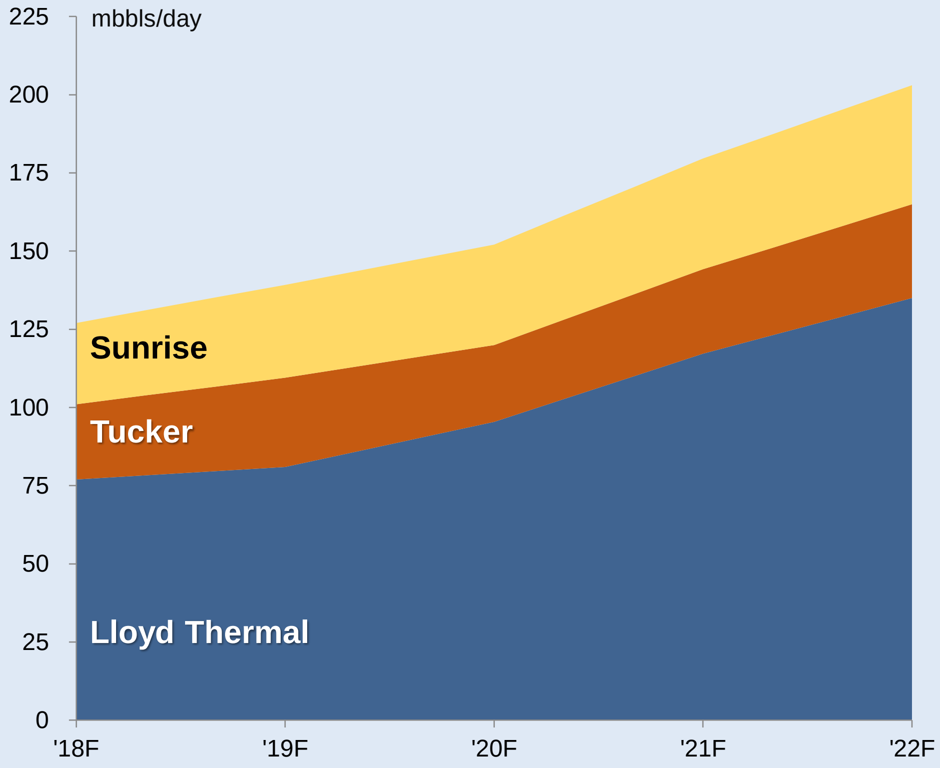
Thermal Business

Project	Production Capacity (boe/day)	Timing of First Oil
Rush Lake 2	10,000	2018
Sunrise Phase 1, de-bottleneck 1	3,000	2019
Dee Valley	10,000	2020
Spruce Lake Central	10,000	2020
Spruce Lake North	10,000	2020
Edam Central	10,000	2021
Westhazel	10,000	2021
Sunrise Phase 1, de-bottleneck 2	6,000	2021+
Future Lloyd Thermals 1-6	60,000	2022-2024
Future Phases of Sunrise	70,000	2024+

Thermal Bitumen Production '18-'22F **50+%**

Thermal Production CAGR '18-'22 **12%**

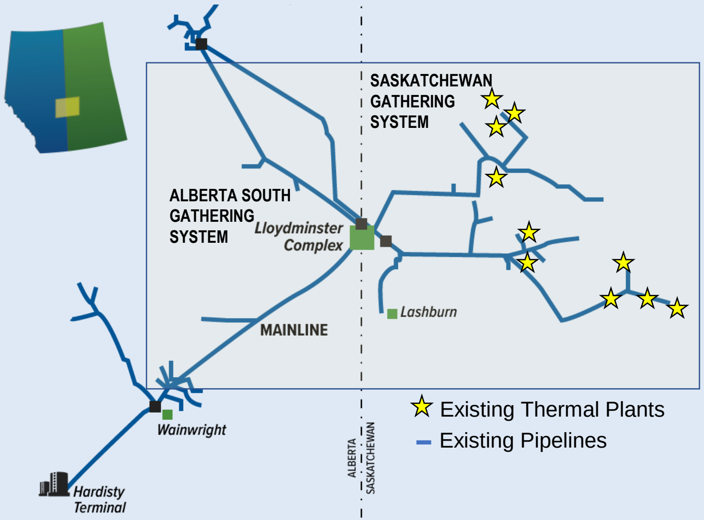
Thermal Bitumen Production Growth (2018F-2022F)



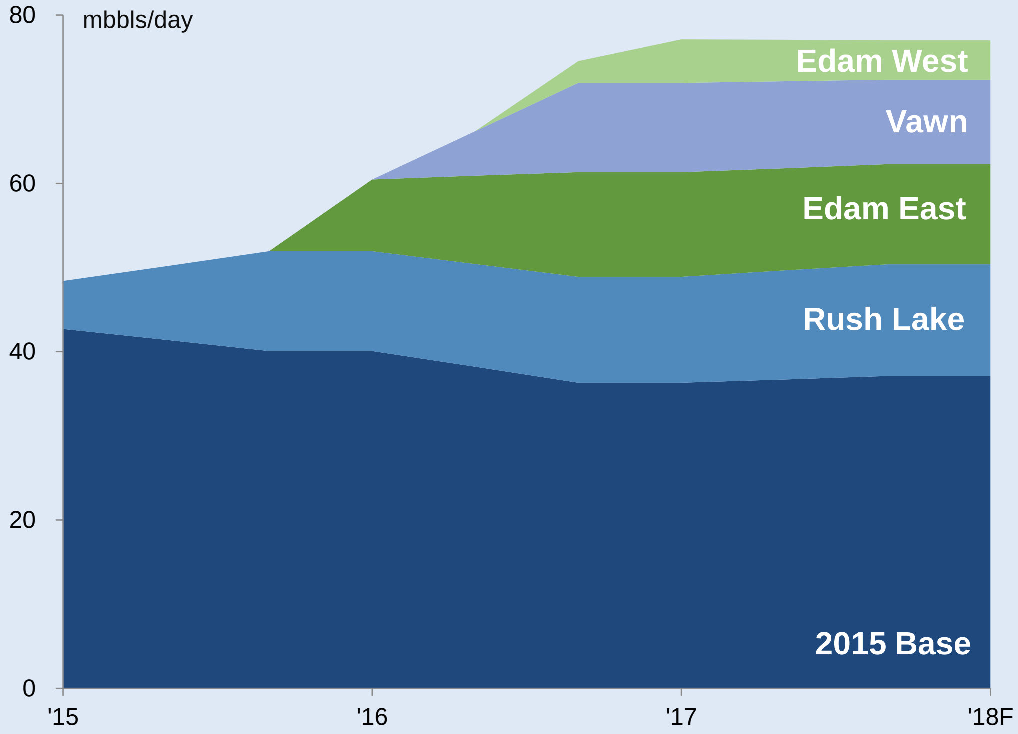
Long Track Record of Successful Execution

Lloyd Thermal Business

- Strong land position
- Replicating engineering design and construction process since 2015
- 10 projects now producing ~75,000 bbls/day



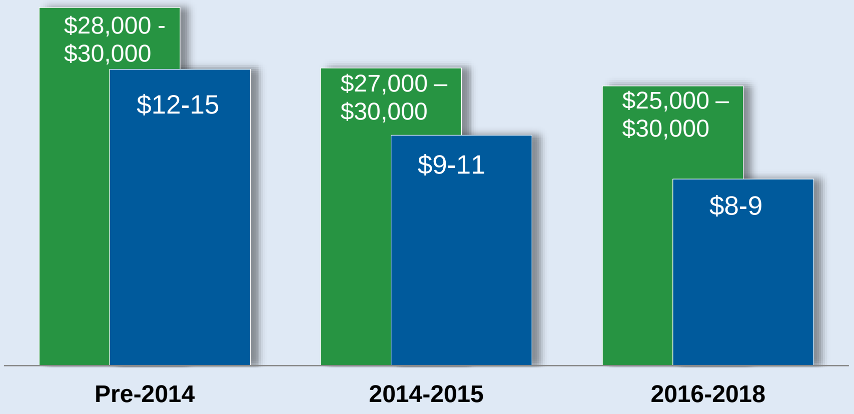
Current Lloyd Thermal Bitumen Production



Improving Capital Efficiency & Operating Costs

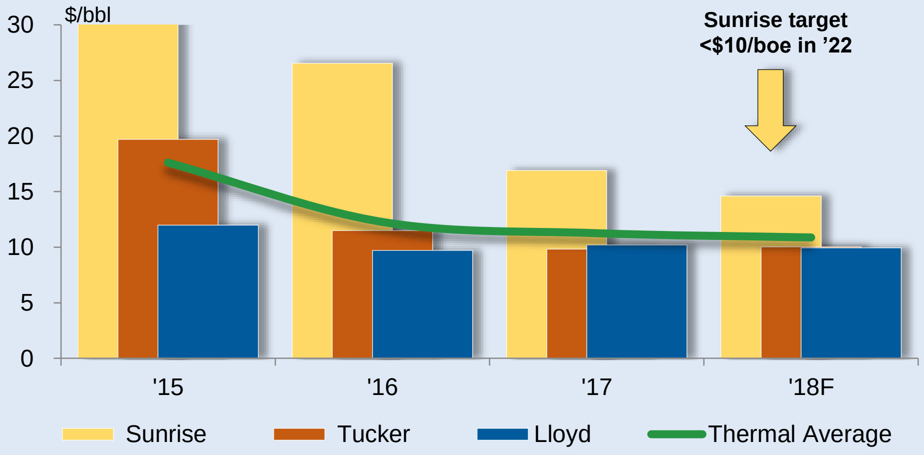
Thermal Business

Lloyd Thermal Project Capital Efficiency Improvements



Capital Efficiencies ’14 –’18 ↑20%

Thermal Production Operating Costs

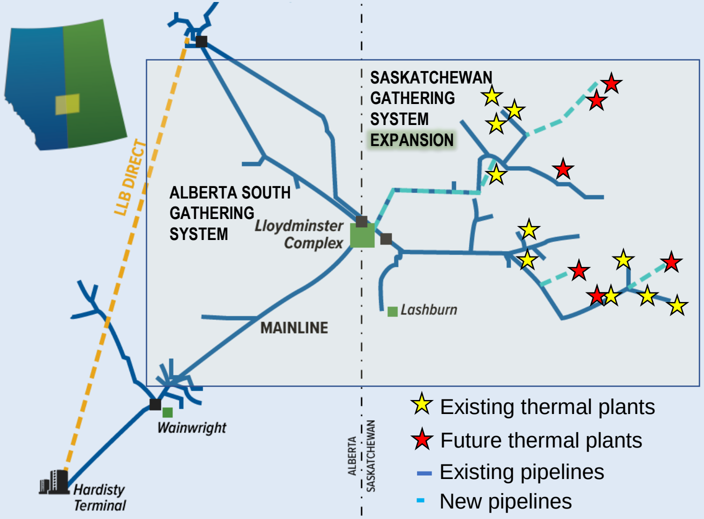


Overall Thermal Operating Costs ’15 –’18 ↓40%

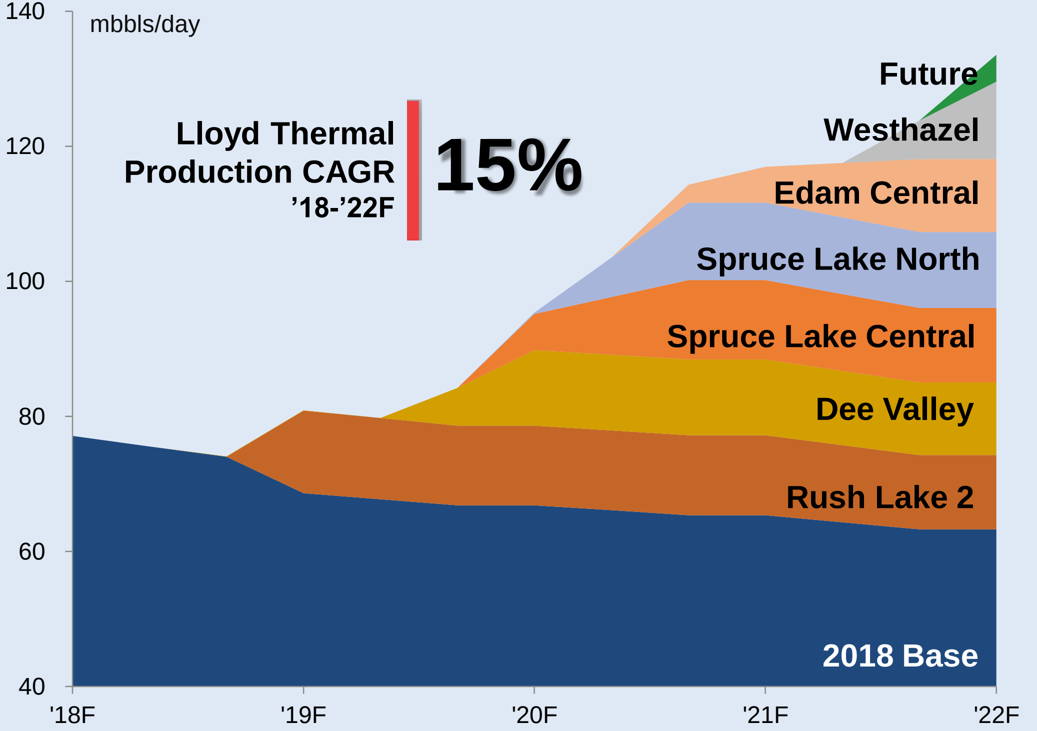
Deep Inventory of Projects

Lloyd Thermal Growth

- Plan to sanction two new projects every year
- Average capital efficiency of $25,000-$30,000 per flowing barrel
- Midstream capacity to match Upstream growth
- Operating costs of $8-$9 per barrel



Future Lloyd Thermal Production



Typical 10,000 Barrel Per Day Project

Growing Inventory Through Land Consolidation

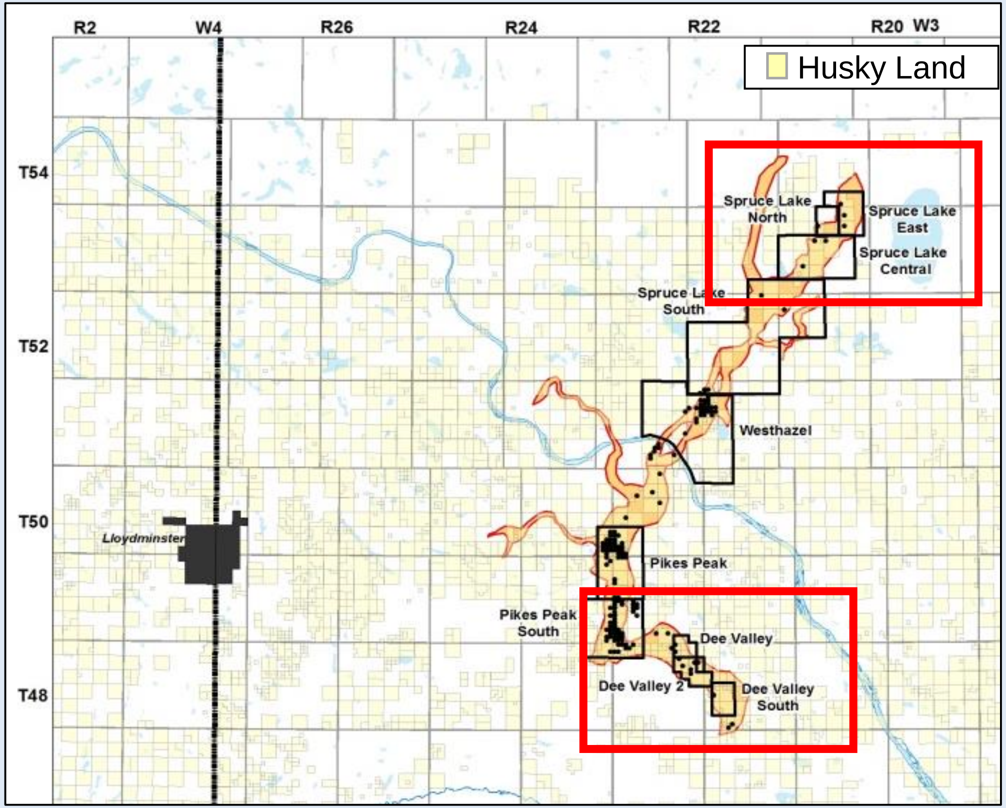
Shared Infrastructure and Services Provide Efficiencies

Spruce Lake area → 35,000 bbls/day

- Initial inventory of three future projects totalling 25,000 bbls/day of capacity
- Recent acquisition allows for an additional 10,000 bbls/day capacity project

Dee Valley area → 40,000 bbls/day

- Initial inventory of two future projects totalling 15,000 bbls/day of capacity
- Recent acquisitions allow for four future projects totalling 40,000 bbls/day of capacity
    - Converted 5,000 bbls/day project to 10,000 bbls/day
    - Added two new 10,000 bbls/day projects

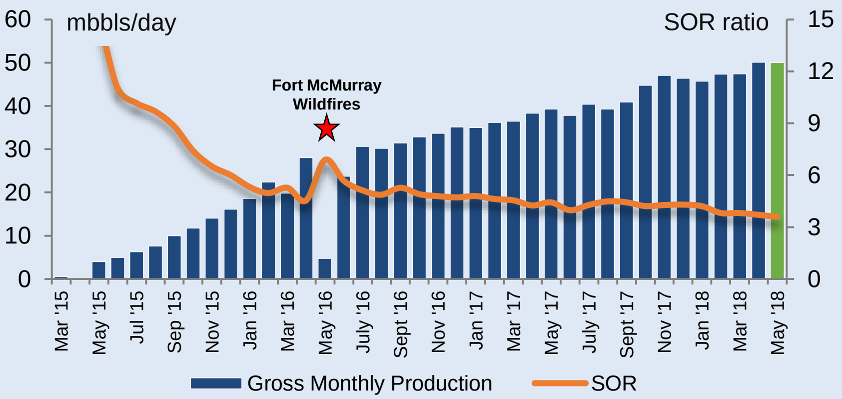


Sunrise

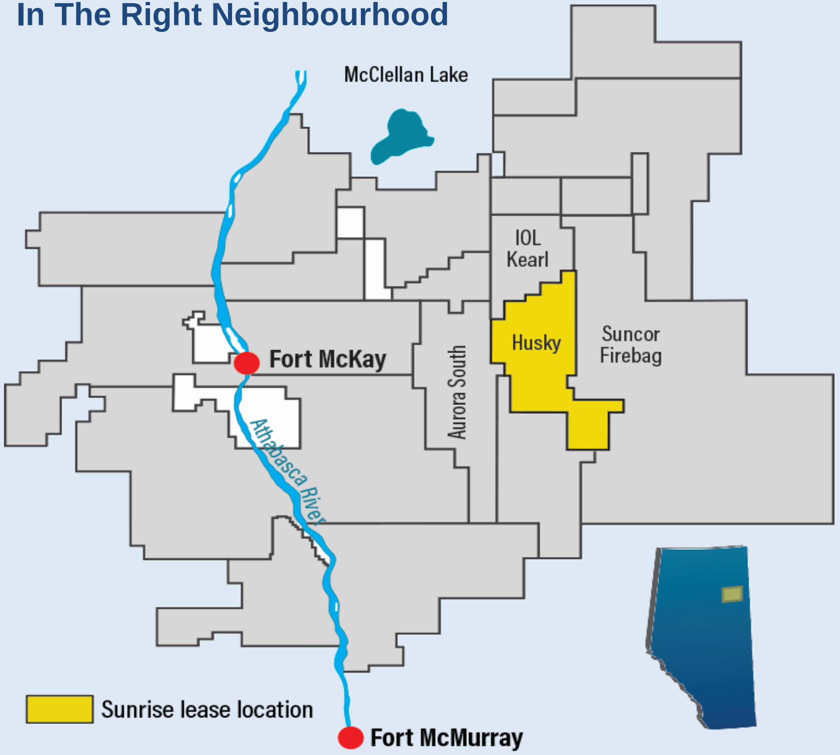
50,000 Barrels Per Day . . . And Growing

Sunrise Energy Project

- Surpassed 50,000 bbls/day (gross) in March 2018
- 2018 year-end target of 60,000 bbls/day (gross)
- Target production per well pair: 800-900 bbls/day
  - 55 well pairs in Initial Development Area now at 815 bbls per well pair
  - 14 new well pairs from Development Area 2 now at 395 bbls/day, expected to ramp to 800-900 bbls/day

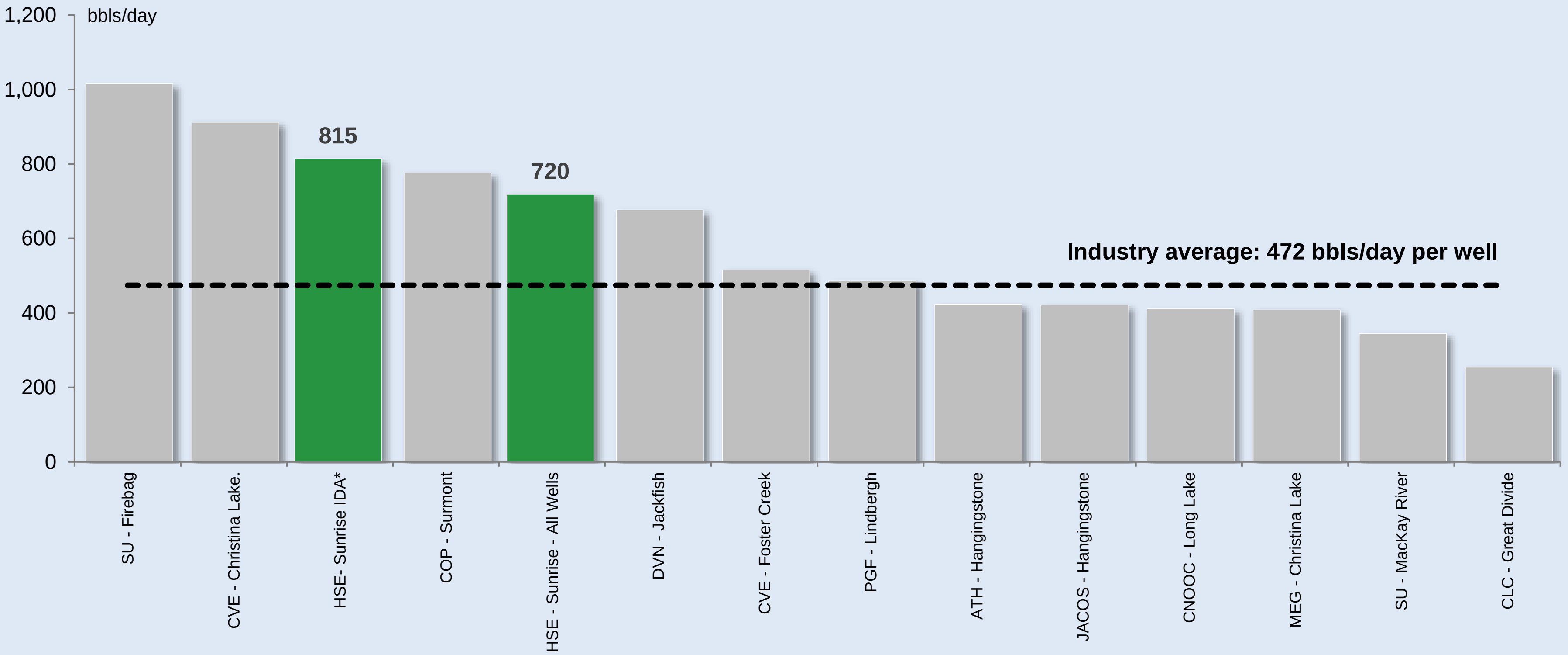


In The Right Neighbourhood



Sunrise Wells Amongst Best in Industry (Mar. ’18)

Oil Sands SAGD Production Per Well Pair (Q1 2018)



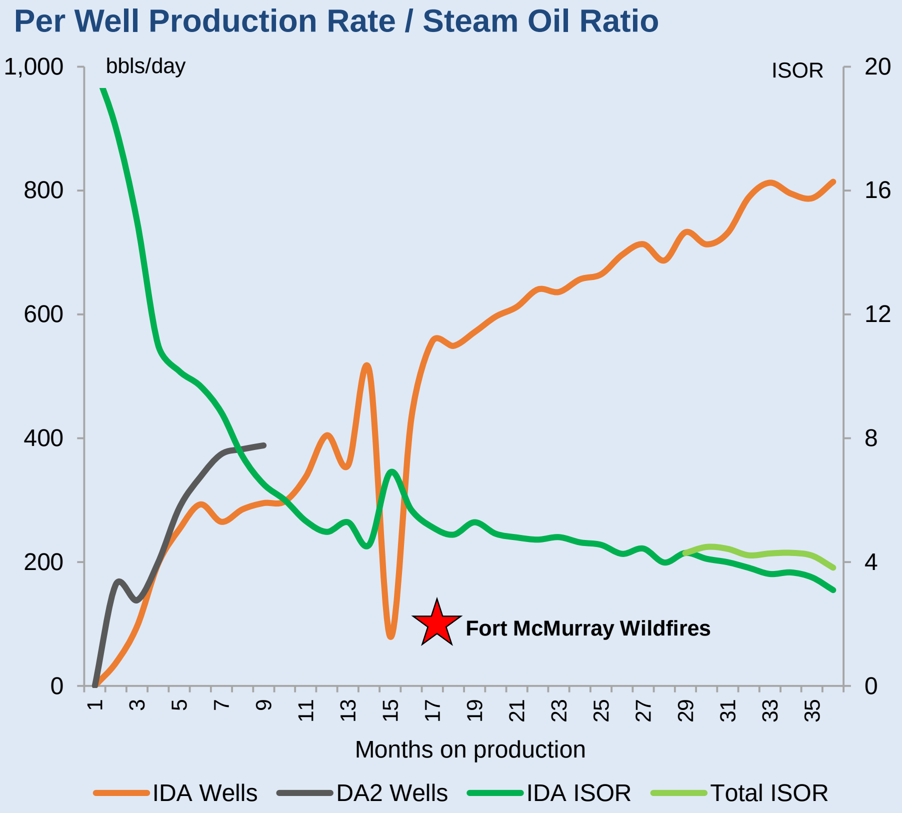
*IDA - Initial Development Area

Source: TD Securities, Scotia Capital, GeoScout

New Wells Driving Towards Full Plant Capacity

Faster Ramp-Ups, Declining SORs

- Improving resource recovery
  - ESP installation on new wells
  - Inflow control devices
  - Infill wells
  - FLIPs
- Plant capacity designed for 3.0x SOR
- 55 Initial Development Area (IDA) wells at 3.1x
- 14 Development Area 2 (DA2) wells ramping up faster than original wells



Unlocking Further Potential At Sunrise

Next Steps

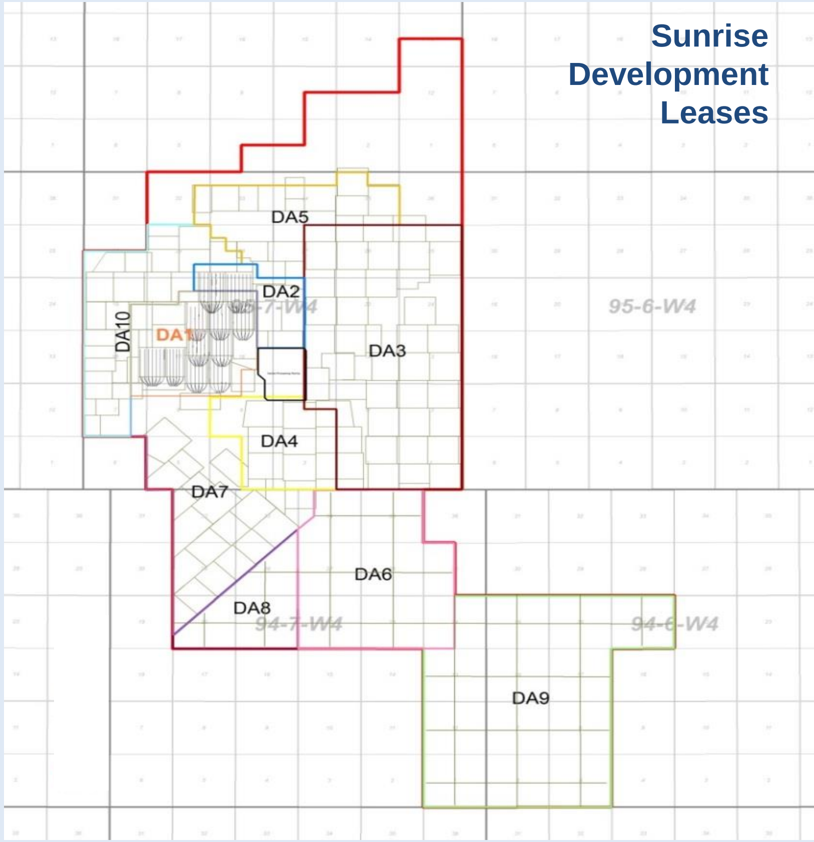
- De-bottlenecking initiatives to create future capacity
- Regulatory approvals in place for 200,000 bbls/day (gross)
- Targeting increased returns with modular approach and cost-effective technologies

Modular Development

- 20,000 bbls/day repeatable, cookie-cutter designs
- Builds on Lloyd thermal expertise and design
- Leverages existing development

Technology Advancements

- Husky Diluent Reduction (HDR) pilot under way
- Potential to reduce condensate diluent requirements by 50%
- Co-generation

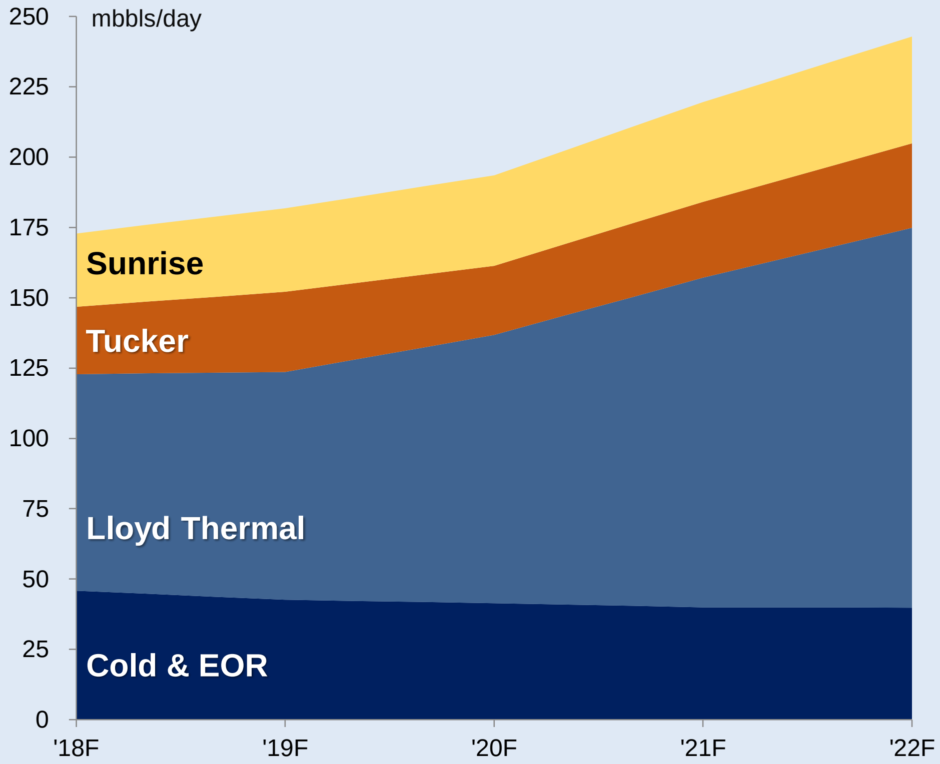


Self-Funded Growth

Lowering Overall Cost Structure and Sustaining Capital Requirements

- Funds from operations growing from $1.2 billion in 2018 to $1.7 billion in 2022
- Adding 80,000 bbls/day of new thermal production over plan period
- Decreasing per-unit operating costs and sustaining capital
- Tightly integrated with Midstream and Downstream

Heavy Oil & Oil Sands Production Growth (2018F-2022F)



Resource Plays

Gerald Alexander
SVP, Western Canada Production

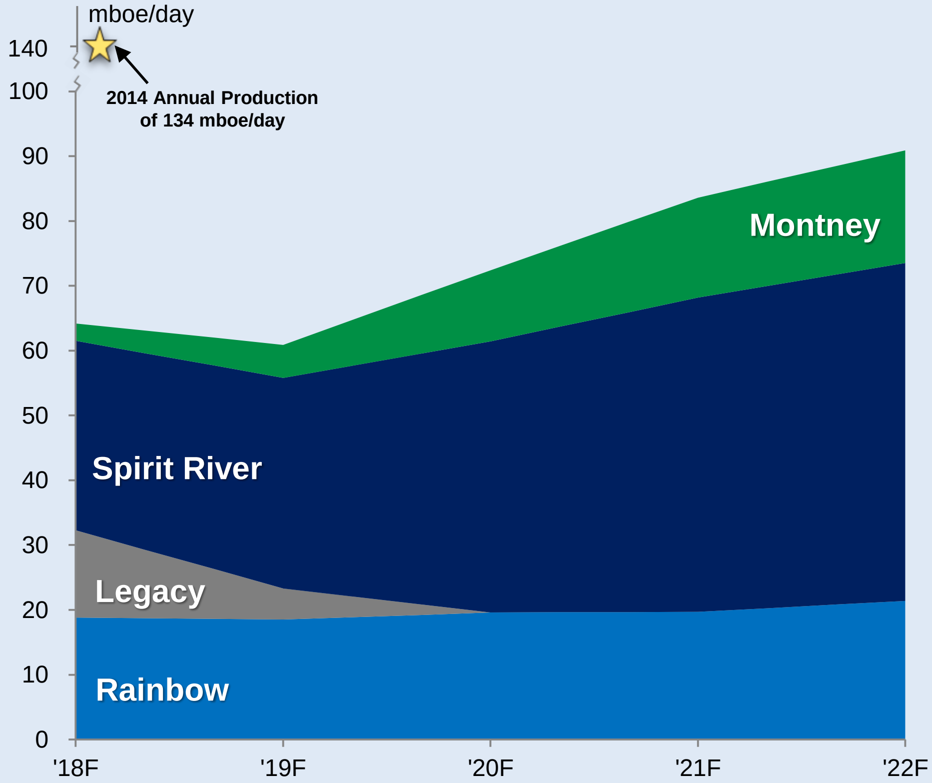
Transformation Complete – Positioned for Growth

- Competitive stand-alone business
- Flexible short-cycle capital spending profile
- Minimal AECO exposure
- Pivoting to liquids
- Multiple egress options enable growth
- Room to run

Western Canada Production '18-'22F | **>40%**

Western Canada Production CAGR '18-'22F | **9%**

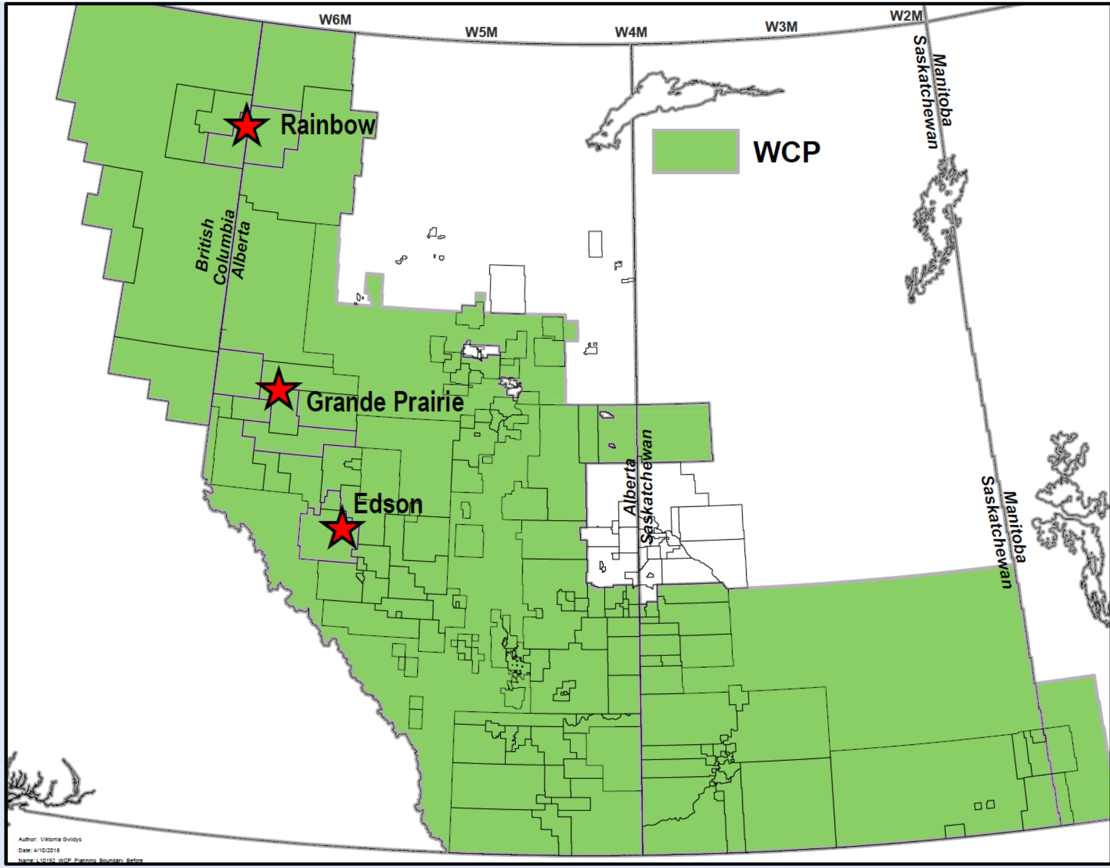
Production Growth Profile



Western Canada Pre-Transformation

Sharpened Focus

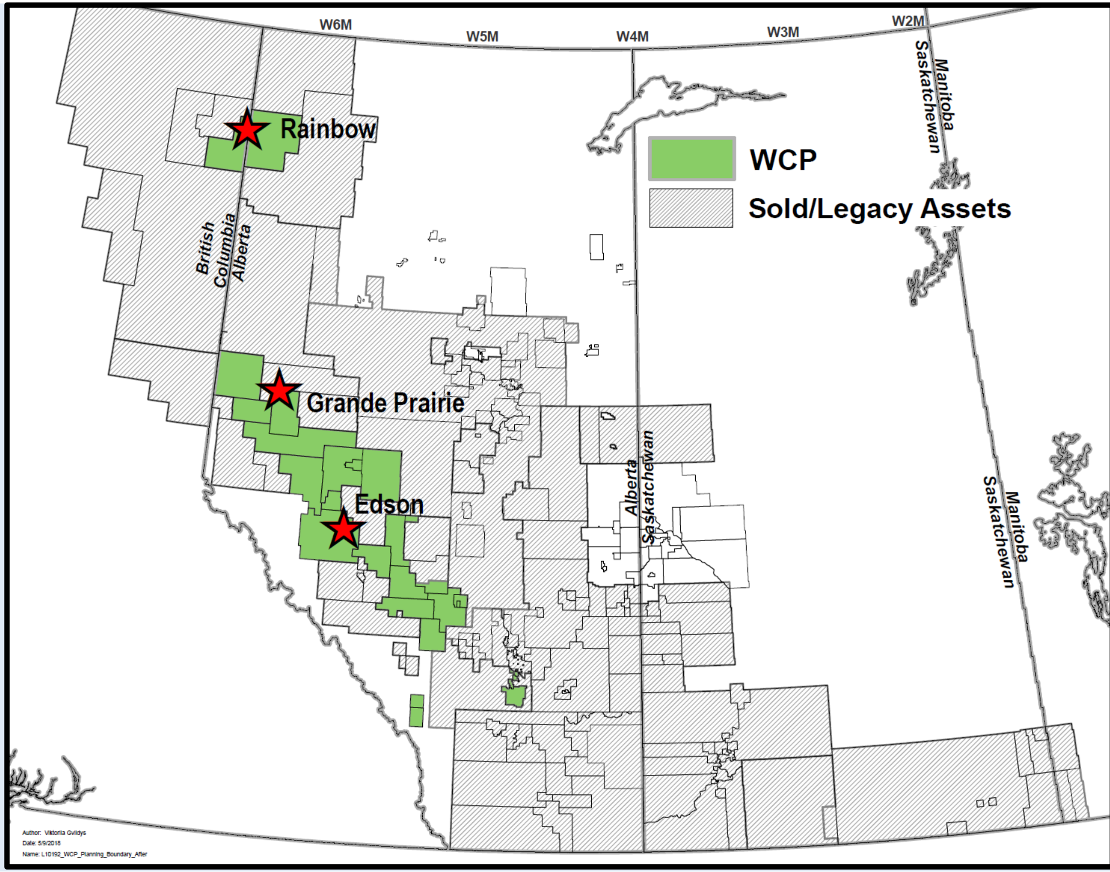
Q4 2015	
Operating region	N.E. BC to S.E. SK
Avg. operating cost	$16.50/boe
Avg. W.I. per well	~60%
Avg. production/well	8.5 boe/day
Gross wellbores	31,000
Annual Sustaining capital	$1.2B



Western Canada Post-2017

Sharpened Focus

	Q4 2015		Q1 2018
Operating region	N.E. BC to S.E. SK	➔	3 hubs
Avg. operating cost	$16.50/boe	➔	$12.20/boe
Avg. W.I. per well	~60%	➔	~80%
Avg. production/well	8.5 boe/day	➔	44 boe/day
Gross wellbores	31,000	➔	6,000
Annual Sustaining capital	$1.2B	➔	$200M



Three Core Hubs

Supporting Operating and Capital Efficiency

Edson – Spirit River and Duvernay

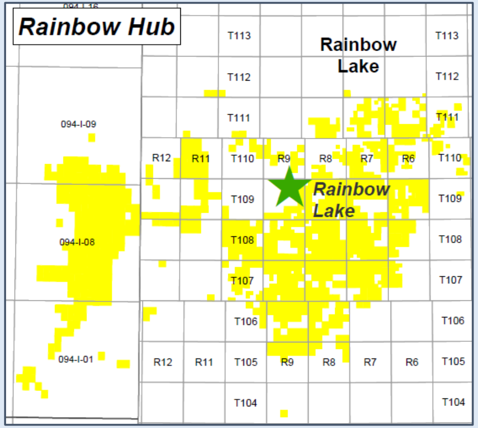
- Ansell: ~170 net sections
- Kaybob: ~30 net sections

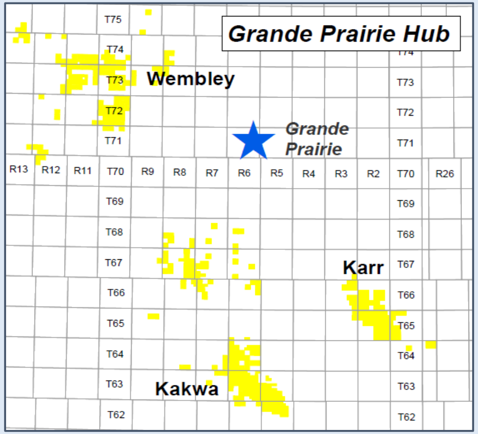
Grande Prairie – Spirit River and Montney

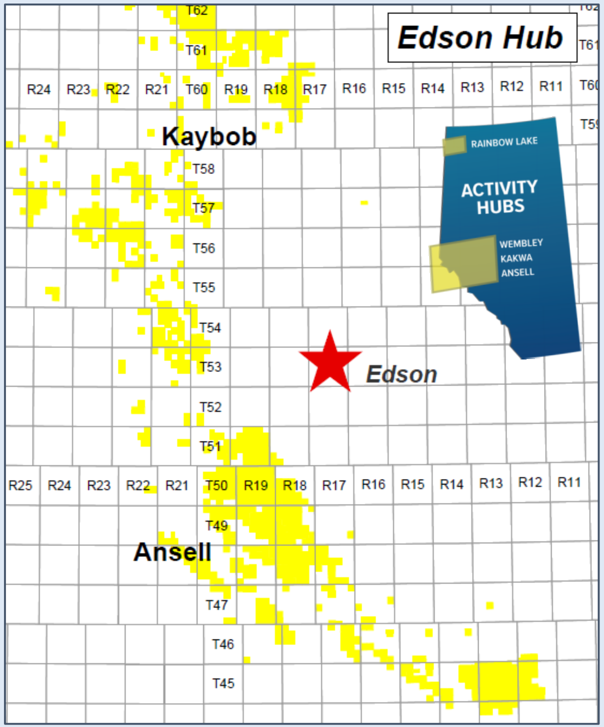
- Kakwa: ~40 net sections
- Wembley-Sinclair: ~100 net sections
- Karr: ~50 net sections

Rainbow Lake – Oil and NGLs

- Harvesting NGLs from the Keg River
- Light oil development opportunities







Wembley-Montney

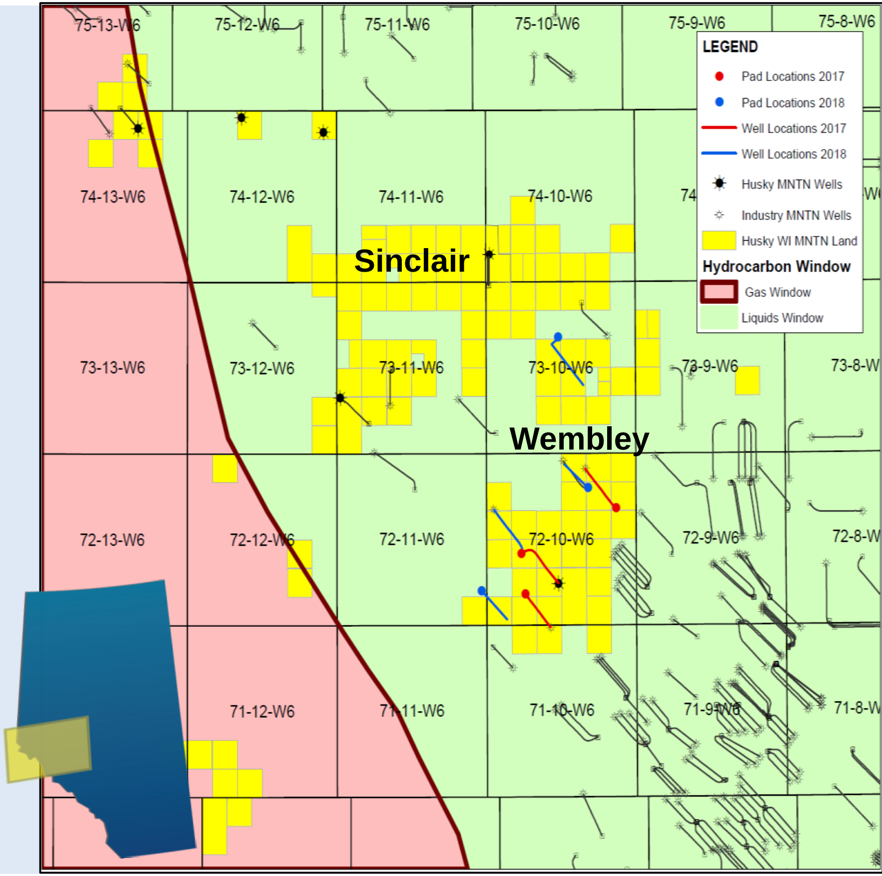
Appraisal Complete, Moving to Development

Wembley position within an established fairway

- 50 net developable sections in liquids-rich gas window
- Multi-layer pad development potential
- First well currently producing at a restricted rate capable of 7 mmcf/day
- Seven wells drilled, completed, and tested by the end of 2018
- Future development opportunities identified

Appraisal activity moving to Sinclair

- 50+ net sections



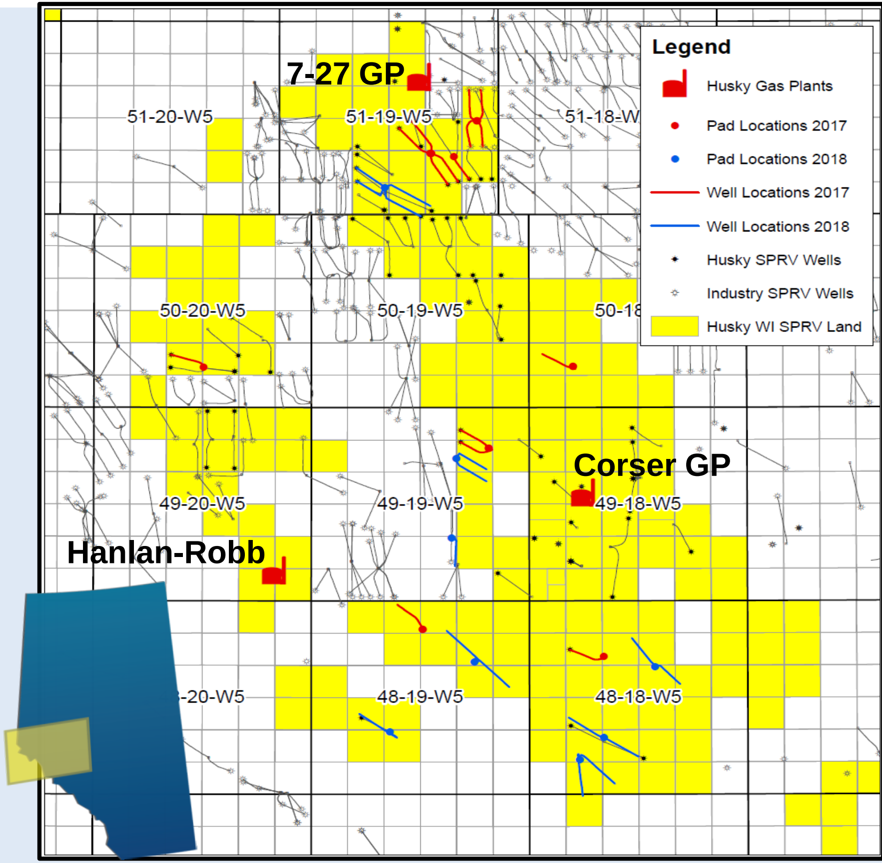
Ansell Spirit River

Building Towards Full Field Development

- Development moving from Wilrich to full Spirit River
- Drilling to keep pace with capacity and egress
- 360 Spirit River potential drilling opportunities[1,2]
- Cardium locations will add liquids to the development
  - Liquids yield of 60 barrels per mmcf

Technology and data integration improving results

- Leveraging 3D seismic in target identification and drills
- Utilizing data analytics to improve rig performance
- Optimizing frac and production facility design



1,2 See Slide Notes and Advisories

Driving Execution and Well Performance

Top-Tier Wells

Industry-competitive drilling efficiencies

- Continuous program decreasing rig drill time and costs
- Last Wilrich well rig released in 14.5 days

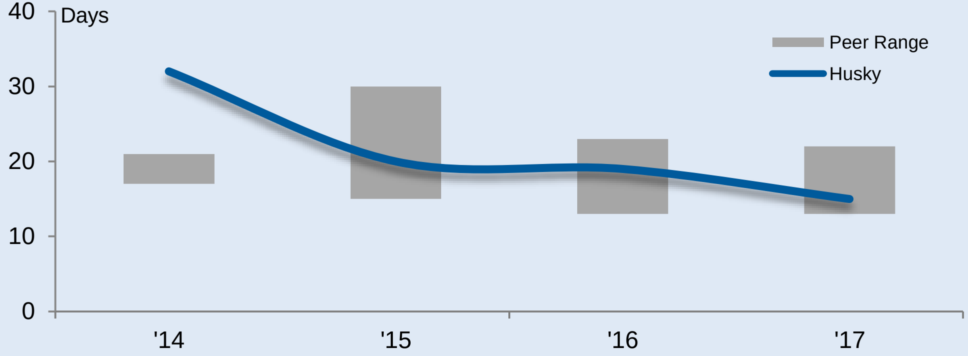
Improving well rates

- Four Top-10 Alberta gas well IP performers in Q1 (Scotia Top Well report)
- Recent IPs best to date; testing higher intensity completions to further increase

Room to Run

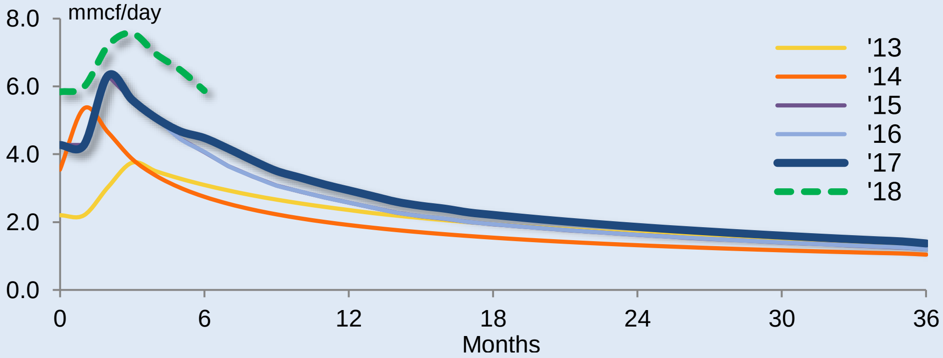
- Spirit River – 360 potential drilling opportunities
- Duvernay – 68 potential drilling opportunities[1,3]
- Montney – 150 net developable sections

Improving Wilrich Drilling Efficiency



Source: RSEG

Wilrich Type Well[2,3] Production Profile



1,2,3 See Slide Notes and Advisories

Ansell Corser Gas Plant

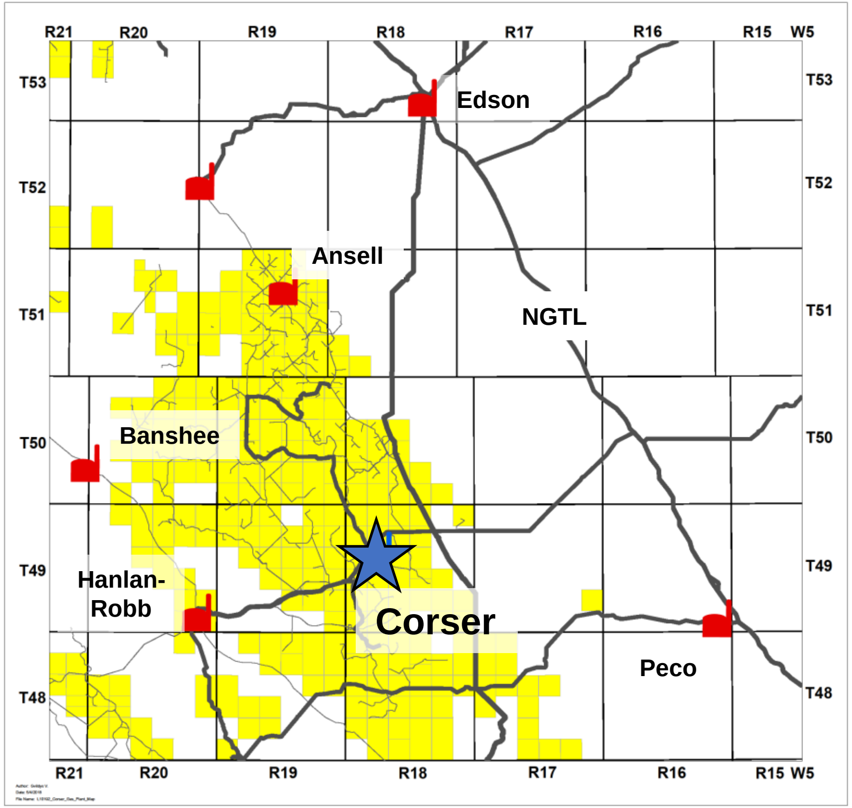
Controlling Infrastructure to Support Growth

How we currently move our gas

- Husky and third-party facilities
- Infrastructure constraints limit pace of growth

Building our own solution – Corser Gas Plant

- 120 mmcf/day processing capacity
- Leveraging Husky Midstream Limited Partnership
- Expected reduction in processing fees by ~30%
- Tied into NGTL system
- Storage facilities for associated LPGs
- Expandable and repeatable model



Minimal Exposure To AECO

Market Optionality

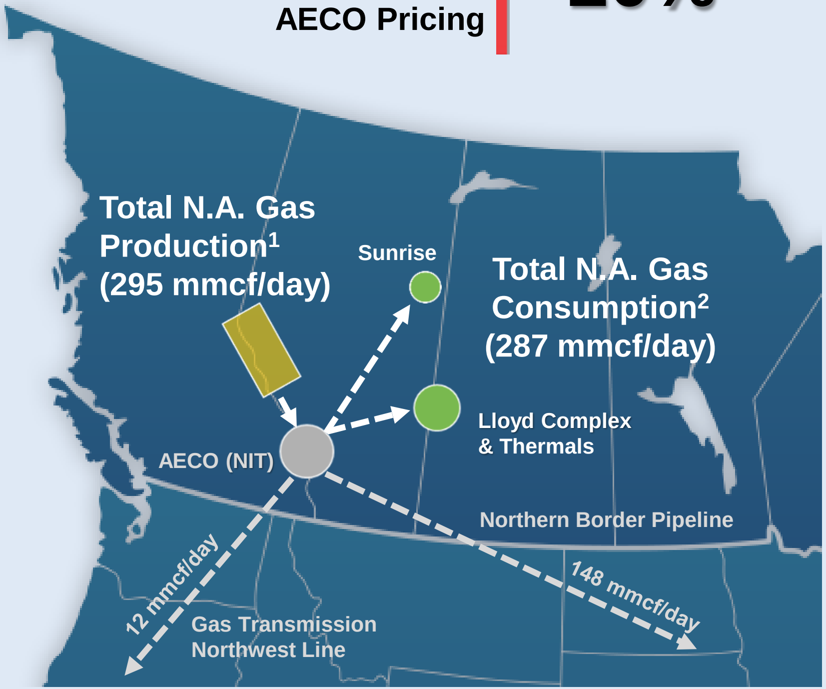
Integration delivers value

- Production offsets gas consumption
- 160 mmcf/day export capacity to U.S. markets
- Forward sales of gas volumes
- Gas storage for seasonal sales

Positioned for growth

- Current gas production growth plan supports thermal projects
- Capacity available to U.S. market can support more aggressive growth plan
- Flexibility for liquids in each core hub

Gas Production Exposed to AECO Pricing **~20%**



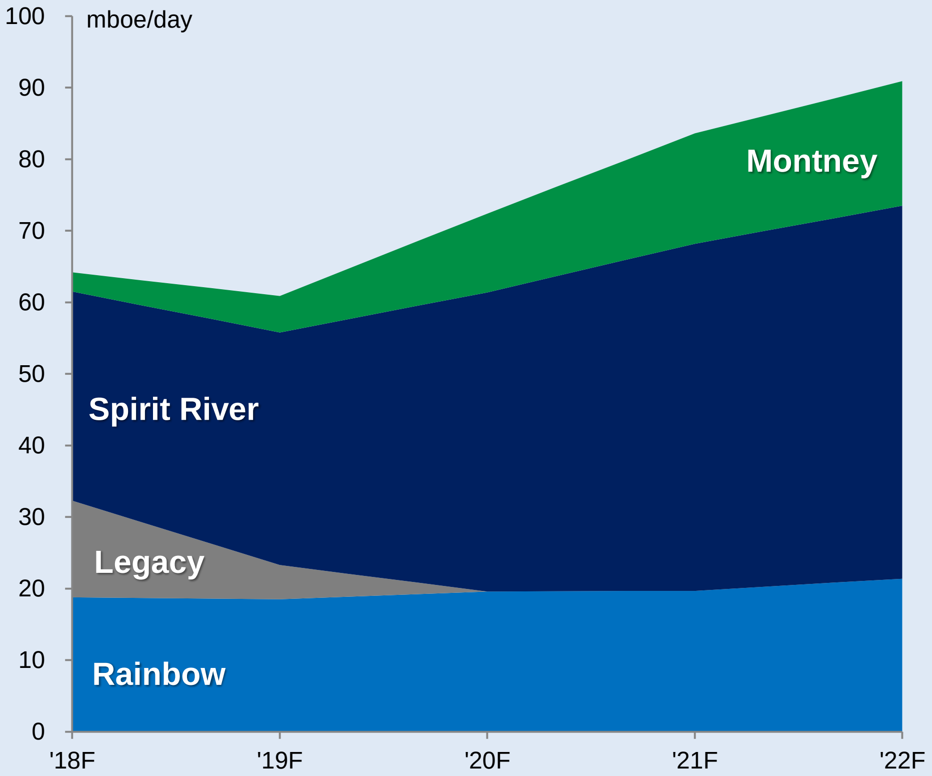
Transformation Complete – Positioned for Growth

- Competitive stand-alone business
- Flexible short-cycle capital spending profile
- Minimal AECO exposure
- Pivoting to liquids
- Multiple egress options enable growth
- Room to run

Western Canada Production ’18-’22F | **>40%**

Western Canada Production CAGR | **9%**

Production Growth Profile



Offshore

Trevor Pritchard
SVP, Atlantic

Bob Hinkel
COO, Asia Pacific

Proven Track Record

High Netback Production With Brent-Like Pricing

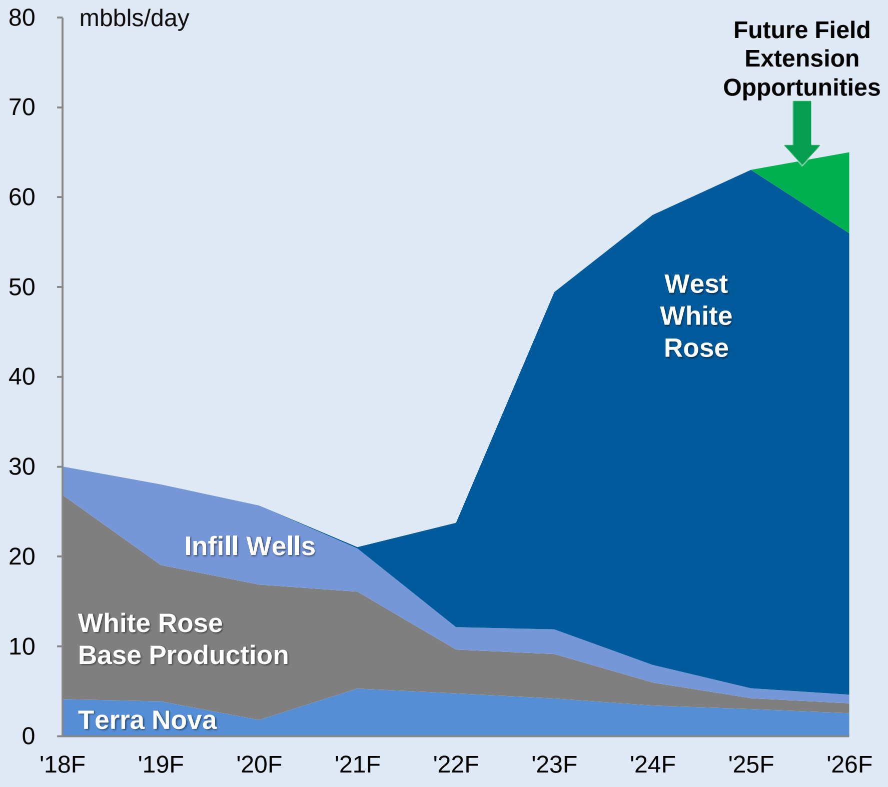
- White Rose producing since 2005
- 280-plus million barrels of oil recovered (as of April 20, 2018)
- High operating netback production receives Brent+ pricing
  - $90.70 per barrel realized price (Q1 ’18)
  - $17.51 per barrel operating costs (Q1 ’18)
  - $65.23 per barrel operating netback[1] (Q1 ’18)
- Investment economics enhanced through tiebacks to existing infrastructure
- Defined growth in next decade
- Exploration upside opportunities

Infill Wells Bridging to West White Rose

Active Development Program

- Progressing additional well interventions and potential infill opportunities:
  - E-18 2 well intervention (completion target: Q4 2018)
  - E-18 6Z well intervention (completion target: Q4 2018)
  - E-18 13 infill production well (online target: Q1 2019)
  - E-18 14 infill production well (online target: Q1 2019)

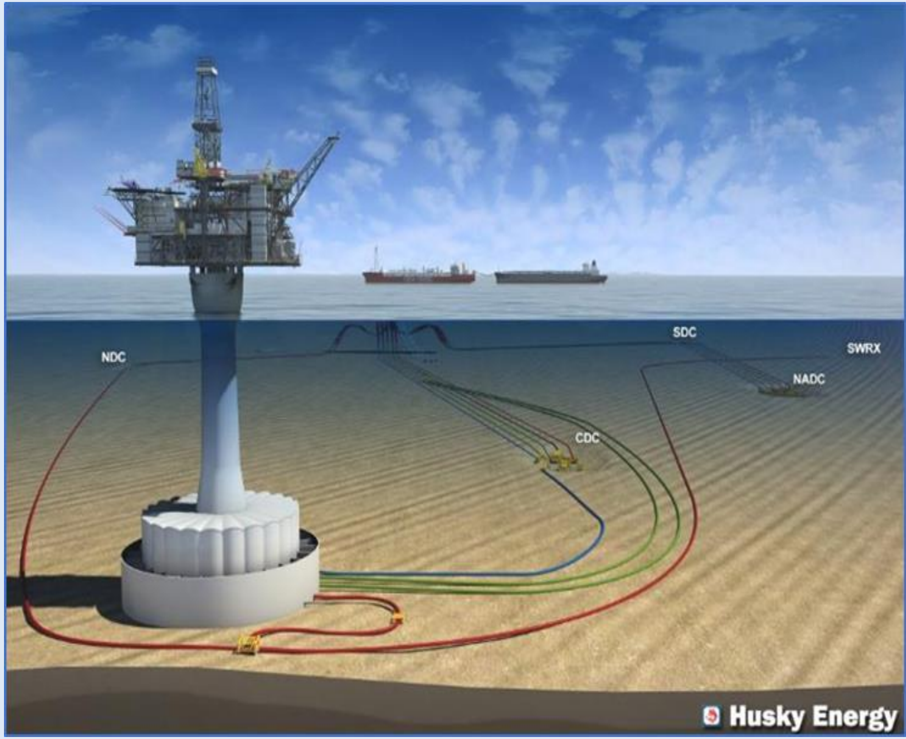
Atlantic Production Profile



West White Rose

Project Update

- ~75,000 bbls/day peak production (52,500 bbls/day net to Husky) in 2025
- Immediately earnings accretive due to royalty regime
- Low incremental operating costs due to existing infrastructure
- Construction of Concrete Gravity Structure and topsides progressing



Exploration

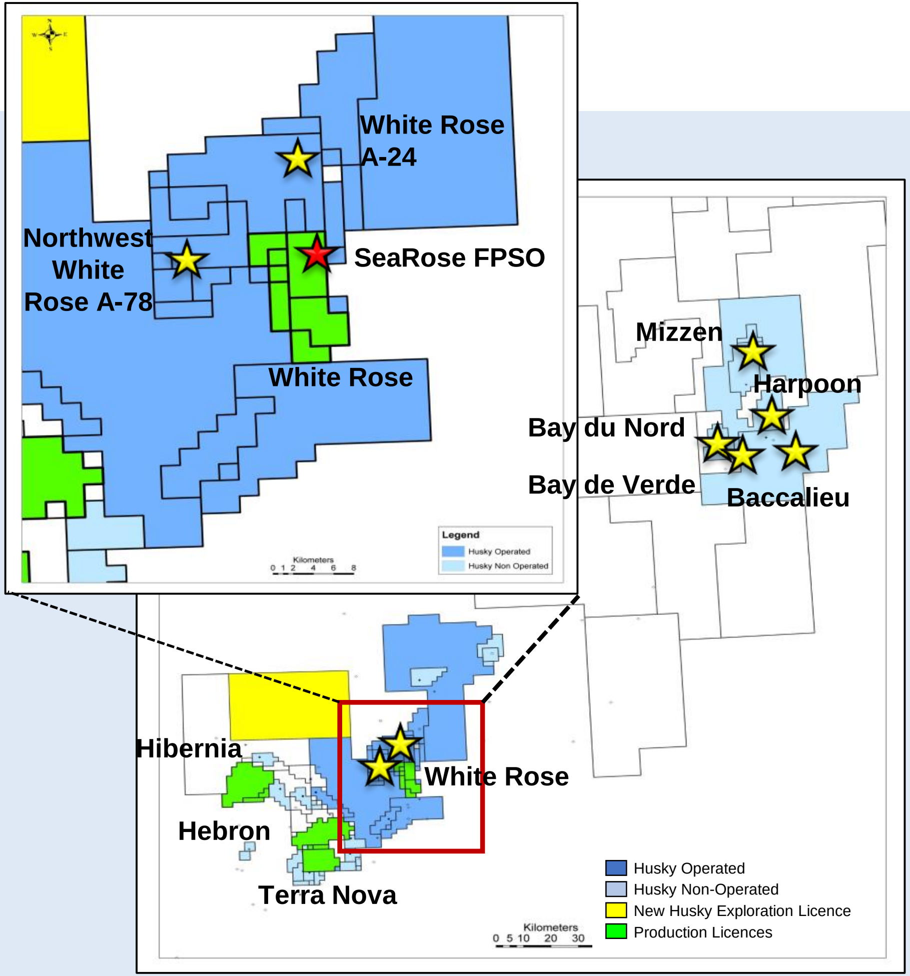
Short, Mid and Long Cycle Projects

Near-term: Near-Field Exploration Success

- White Rose A-24 discovery in 2018
  - Encountered 85+ metre oil-bearing sandstones
- Northwest White Rose A-78 in 2017
  - Encountered 100+ metre light oil column
- Newly acquired exploration acreage

Longer-term: Flemish Pass

- Original Mizzen discovery in 2009
- Light oil discoveries at Bay du Nord and Harpoon in 2013
- Discoveries at Bay de Verde, Baccalieu in 2016
  - Delineation program confirmed large resource potential



Asia Pacific

Established Operator

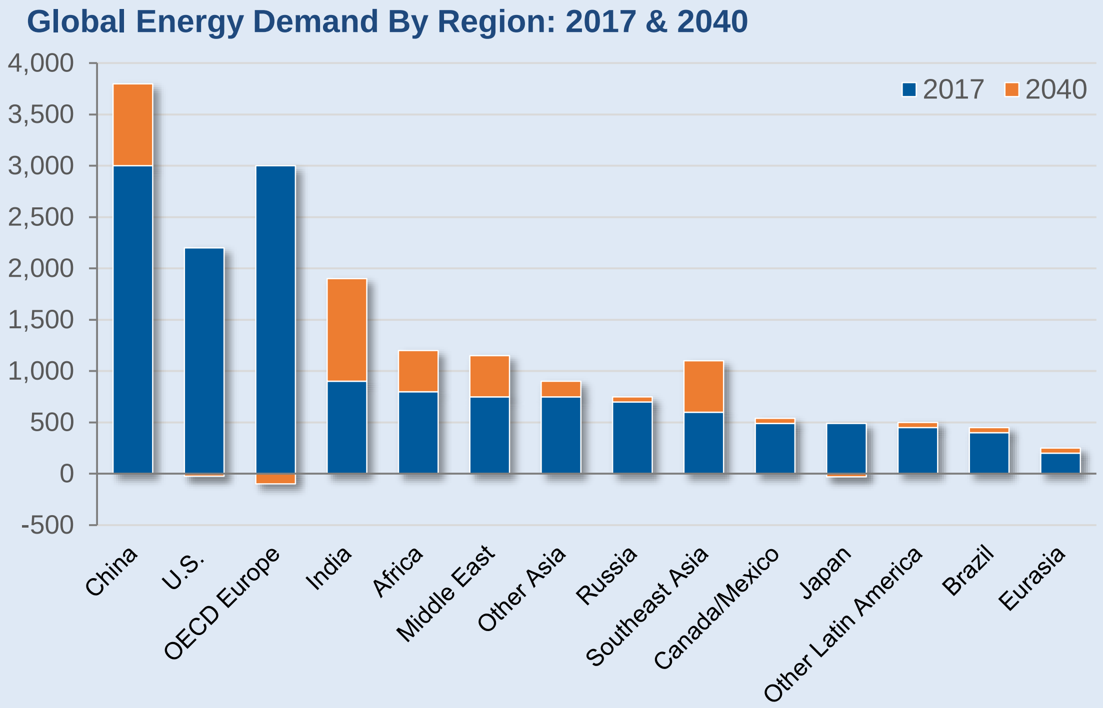
Asia Pacific Region

- Track record for large project delivery
- High operating netback production with gas sales contracts; liquids receive Brent-like prices
- Low level of investment required for growth over the five-year plan
- Defined growth for next five years:
  - Q1 2018 gas production of 198 mmcf/day with 9,200 boe/day of high value liquids
  - Gas production to rise to over 270 mmcf/day with 9,000 boe/day of liquids by 2022
  - Mix of near, mid and long-term development and exploration opportunities

Increasing Production In A Growing Market

Asia Pacific Energy Demand Projected To Rise

- Region provided one-quarter of Husky's funds from operations in 2017
- Strong energy demand in China
  - Third Liwan field in progress
  - New exploration blocks
- Growing economic and industrial development in Indonesia
  - BD Project continuing ramp-up
  - Series of new shallow water gas projects underway in Madura Strait

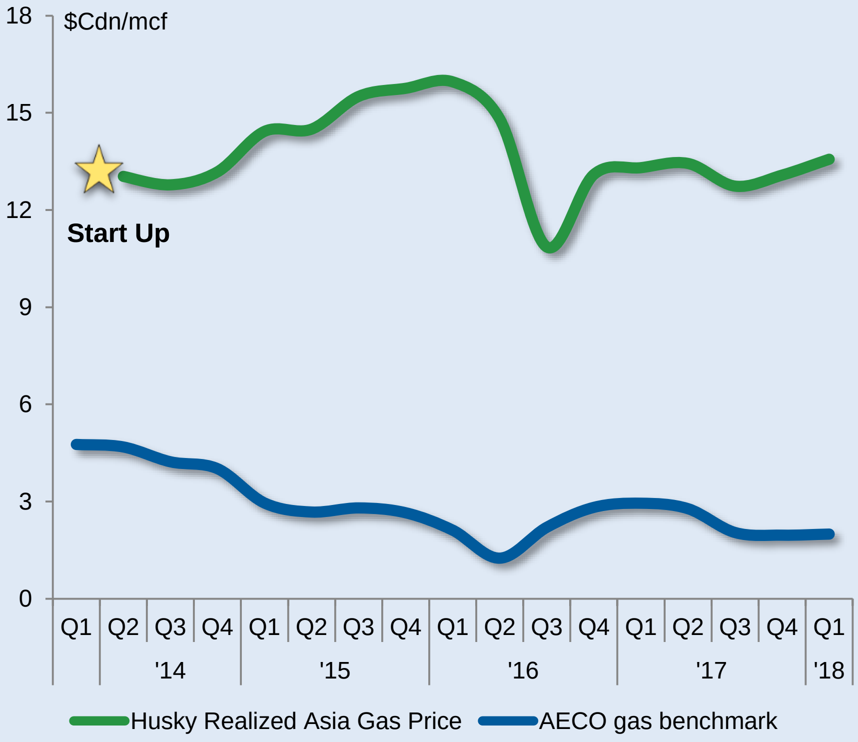


Source: 2017 IEA World Energy Outlook

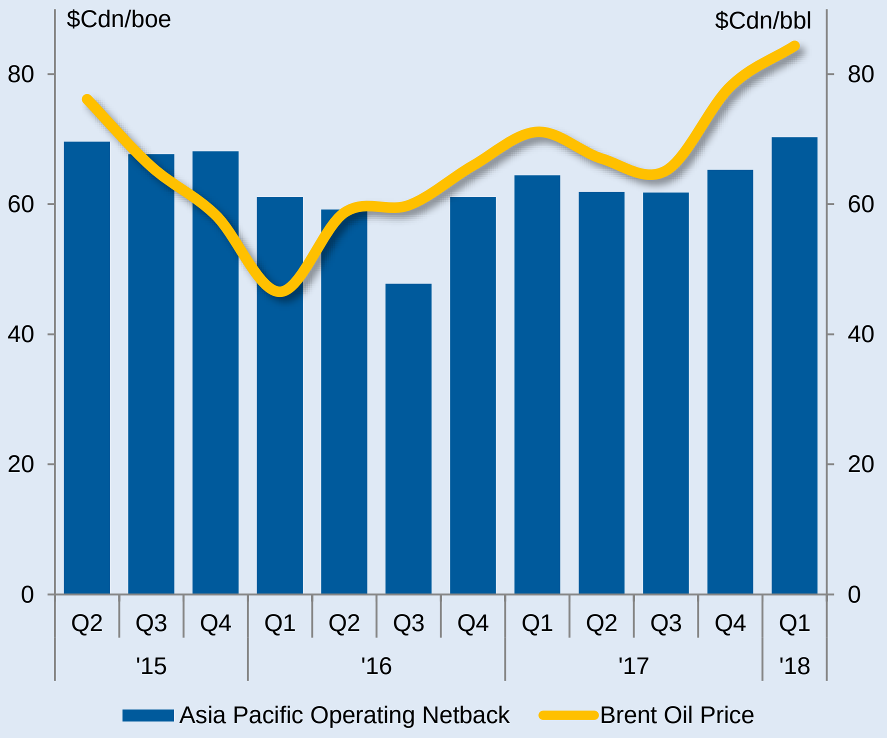
High Netback Production and FFO Stability

Asia Pacific Business Delivering >$60 per boe Operating Netbacks

Asia Pacific Realized Gas Price



High Operating Netback[1]



1 See Slide Notes and Advisories

Production Growth Profile

Capital Efficient Developments

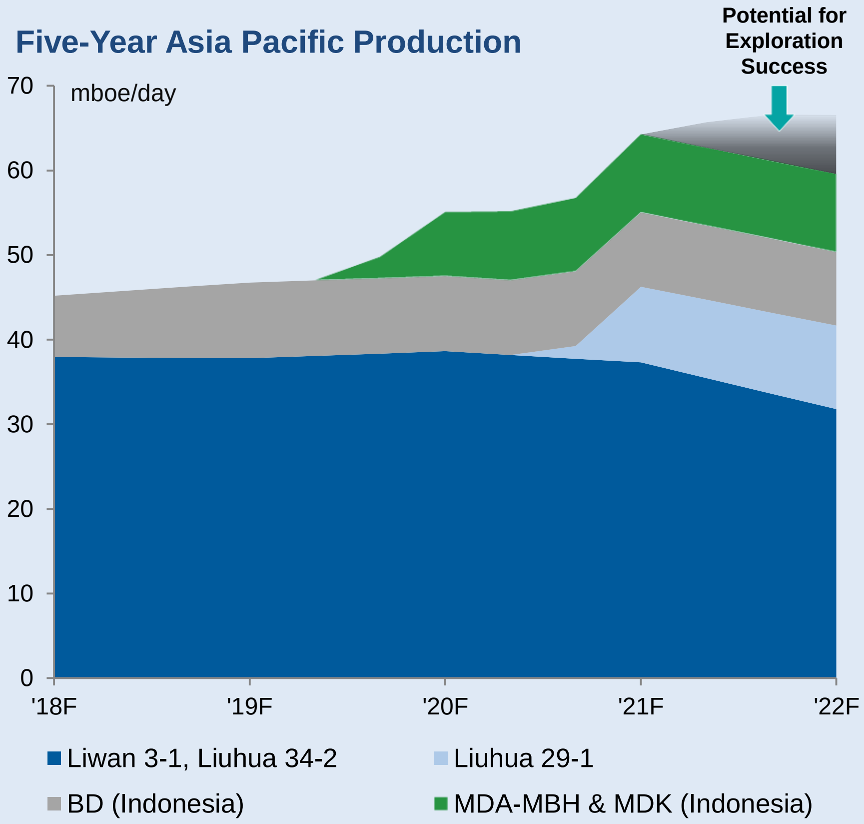
China (Liwan 3-1, Liuhua 34-2 & 29-1)

- Current production of ~170 mmcf/day (3-1 & 34-2)
- Take-or-pay contract 165 mmcf/day (net)
- 29-1 field sanctioned, first gas expected in 2020
  - $250M US in exploration cost recovery

Indonesia (BD Project, MDA-MBH, MDK fields)

- BD Project on production; first gas sales in July 2017
- MDA-MBH, MDK fields in development; first gas anticipated in 2019-2020
  - Seven development wells planned for 2H 2018

Five-Year Asia Pacific Production

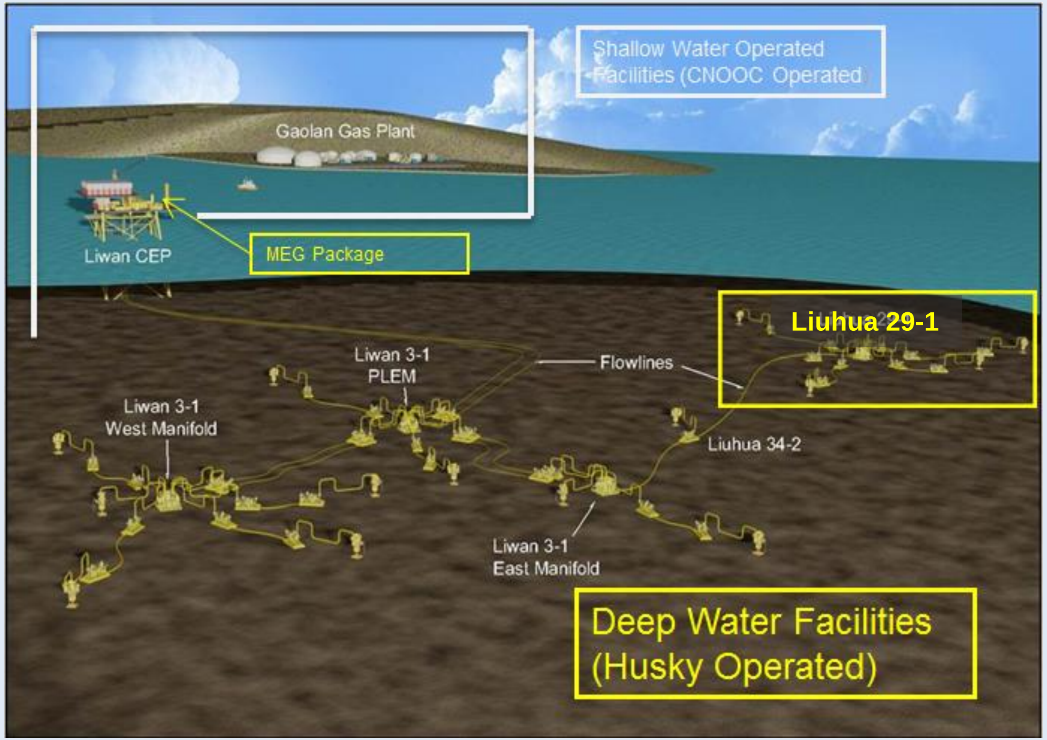


Liuhua 29-1

Third Liwan Development To Extend Field Life

- Uses existing subsea infrastructure
- Pricing agreement:
  - $8.60-9.70 US/mcf floating price mechanism
  - 15+ year contract term
- First gas anticipated in 2020
- Production (net):
  - 45 mmcf/day of gas
  - 1,800 bbls/day of liquids

Full Field Development Schematic

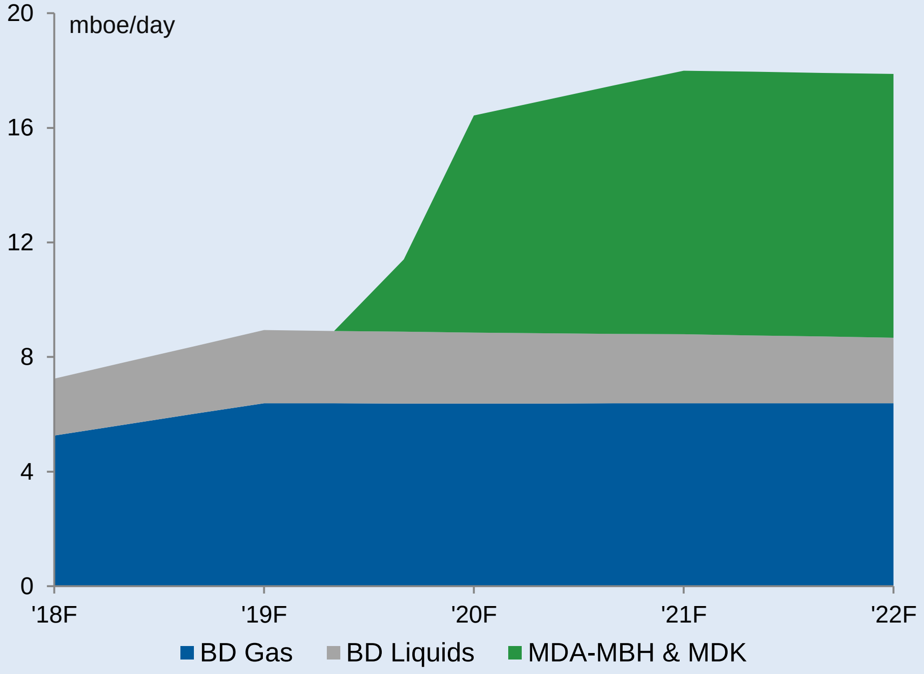


Madura Strait Growth Profile

Stable Production with Contracted Pricing

- BD Project on production (July 2017)
  - US ~$7.00/mmbtu fixed price with 2% escalation per year commencing from the fifth year
- MDA-MBH, MDK fields in progress (2019-2020)
  - US ~$6.50/mmbtu fixed price with 3% escalation per year commencing from the second year
- Combined production target ~20,000 boe/day *(100 mmcf/day of gas plus 2,400 bbls/day of liquids)*
- Regional infrastructure in place for easy tie-in
- Three additional discoveries for future growth

Indonesia Production Profile



Mid-Term Appraisal / Exploration Projects

Ongoing Exploration Throughout the Region

Blocks 15/33 & 16/25

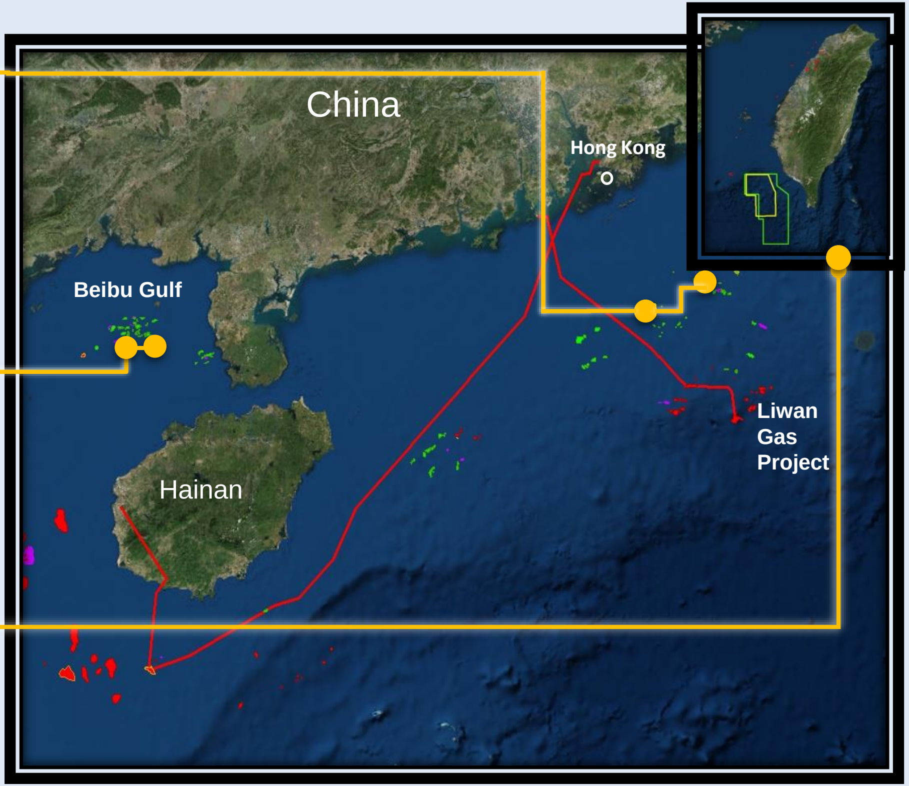
- New discovery on 15/33 (9,000 BOPD test)
- Shallow water blocks
- Close proximity to FPSO
- Exploration and appraisal wells 2H 2018

2 Beibu Blocks

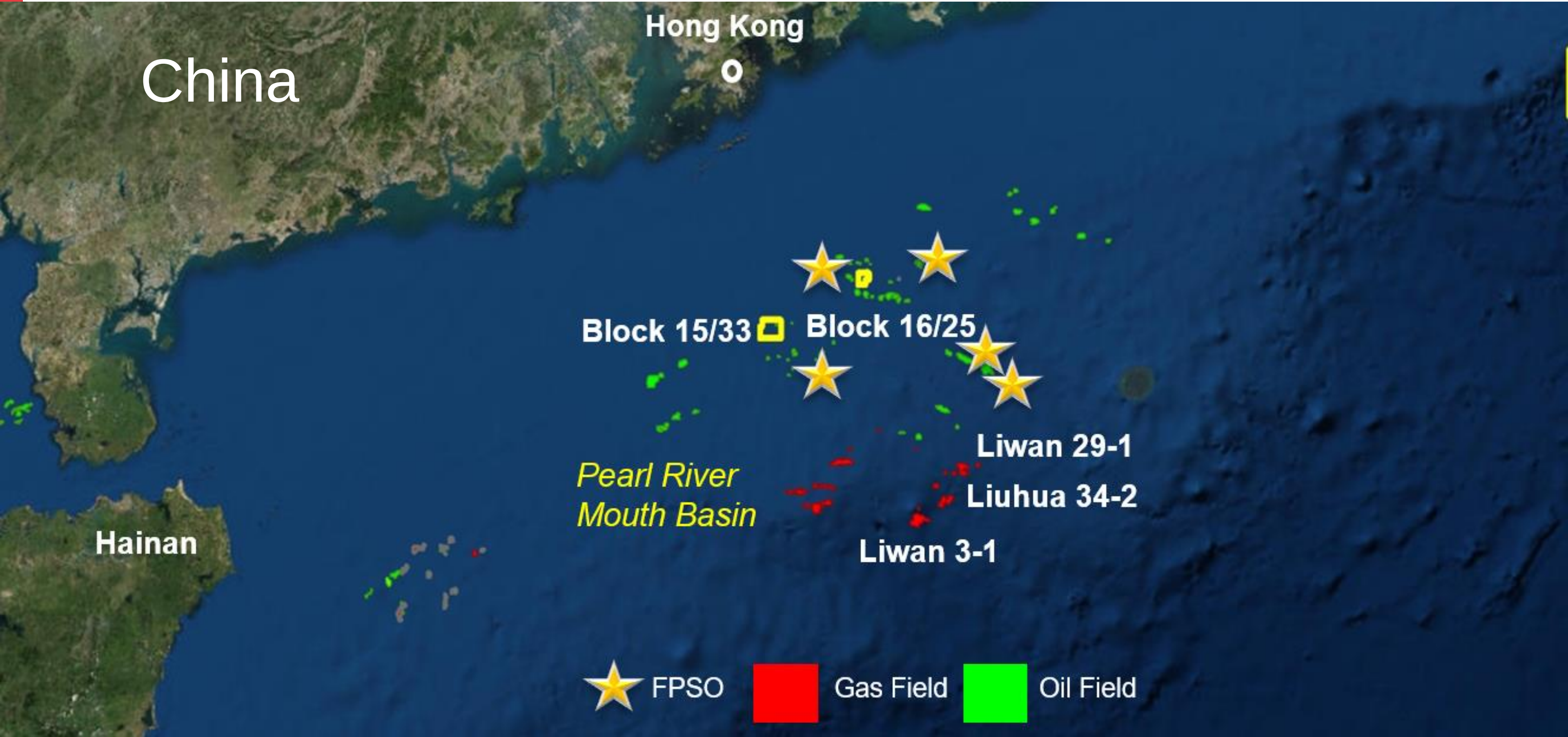
- Shallow water
- Proven basin
- Close to infrastructure

Taiwan Block DW-1

- Gas prone area of 7,700 sq. km.
- 3-D seismic acquisition program completed
- Proximity to large market



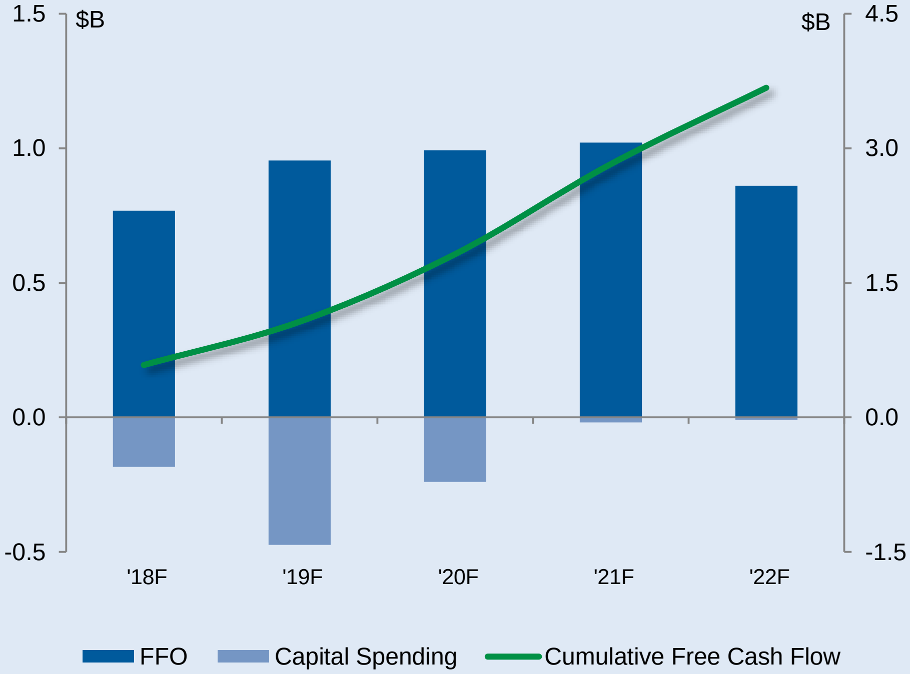
FPSO Locations in South China Sea



Fixed-Price Production & Strong Energy Demand

- High operating netback production with favourable contracts
- Low level of investment required for growth over the five-year plan ($0.9B)
- Defined growth for next five years
  - Q1 2018 gas production of 198 mmcf/day with 9,200 boe/day of high value liquids
  - Gas production to rise to ~270 mmcf/day of gas with 9,000 boe/day of liquids by 2022
  - Mix of near, mid and long-term development and exploration opportunities

Free Cash Flow Growth

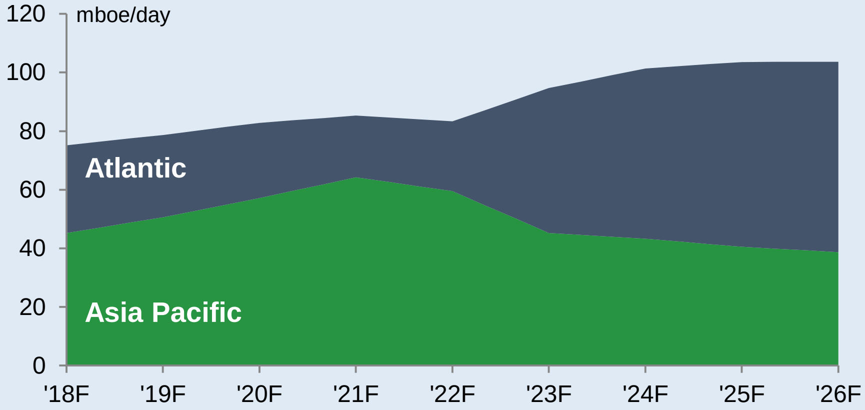


Offshore Business Summary

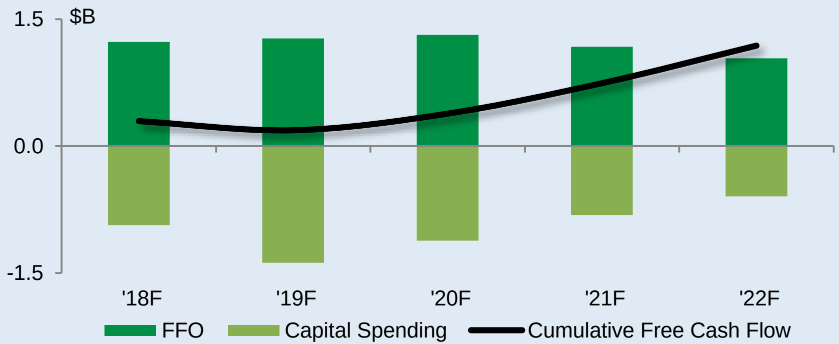
Asia Pacific & Atlantic

- Contracted gas volumes growing steadily to ~270 mmcf/day (2018-2022)
- Globally-priced liquids volumes rising to ~75,000 bbls/day (2018-2026)
- Average operating netbacks of ~$68 per boe (Q1 ’18)
    - ~$70 per boe in Asia Pacific
    - ~$65 per barrel in Atlantic
- Free cash flow of over $1 billion over plan, not including exploration success
- Defined growth into next decade
- Exploration opportunities

Offshore Growth



Offshore Free Cash Flow Growth



Husky Energy

Q&A

Value Proposition

Resilient and Well Positioned to Capture Upside

- Production and throughput growth from a large inventory of low cost projects = returns-focused growth
- Low and improving earnings and cash break-evens
- Strong growth in funds from operations and free cash flow
- Increasing cash returns to shareholders
- Integration and fixed-price Asia Pac sales provide resilience to volatile market conditions while preserving upside

Key Metrics	’18F	’22F	’18-22F CAGR[1]
Funds from operations (FFO)	**$4B**	**$5B**	**6%**
Free cash flow (FCF)	**$1B**	**$1.4B**	**9%**
Upstream production (mboe/day)	**310-320**	**410-420**	**7%**
Downstream throughputs (mbbls/day)	**360-370**	**360-370**	
Thermal production (mbbls/day)	126-130	200	12%
Heavy processing capacity (mbbls/day)	190	220	
Upstream operating cost/bbl	$13-13.50	$11-12	
Downstream operating costs/bbl (CAD)	$7-8	$7-8	
Earnings break-even oil price (US WTI)	$42	$37	

Ranges and Targets	2018F - 2022F
Annual base dividend	$300M with option to grow
Sustaining capital	Avg. $1.9B
Capital spending	Avg. $3.5B
5-yr avg. proved reserves replacement ratio	Target >130%
Net debt to FFO at $35 US WTI	<2x

Husky Energy

Thank You

Husky Energy

Slide Notes & Advisories

Slide Notes

Slide 9

1. Net debt and net debt to trailing funds from operations, as referred to throughout this presentation, are non-GAAP measures. Please see *Advisories* for further detail. All figures are as of March 31, 2018.

Slide 11

1. Funds from operations ("FFO"), as referred to throughout this presentation, is a non-GAAP measure. Please see Advisories for further detail.

Slide 12

1. Sustaining capital, as referred to throughout this presentation, is a non-GAAP measure. Please see Advisories for further detail.

Slide 13

1. Earnings break-even, as referred to throughout this presentation, is a non-GAAP measure. Please see Advisories for further detail.

Slide 17

1. Return on capital employed, as referred to throughout this presentation, is a non-GAAP measure. Please see Advisories for further detail.

Slide 18

1. Free cash flow ("FCF"), as referred to throughout this presentation, is a non-GAAP measure. Please see *Advisories* for further detail.
2. Capital spending, as referred to throughout this presentation does not include capitalized interest unless otherwise indicated.
3. Capital expenditures in Asia Pacific exclude amounts related to the Husky-CNOOC Madura Ltd. joint venture, which is accounted for under the equity method for financial statement purposes.
4. Excludes economic factors; 165 percent including economic factors.
5. Net debt to funds from operations, as referred to throughout this presentation, is a non-GAAP measure. Please see *Advisories* for further detail.

Slide 19

1. Compound annual growth rates (CAGR), as referred to throughout this presentation, are calculated using 2018 forecasted production, FFO and FCF and 2022 forecasted production, FFO and FCF, as applicable.

Slide 22

1. FFO and FCF forecasts for 2018 and 2022 are calculated using the Benchmark Prices – 2018 Base Case Pricing Assumptions on Slide 29.

Slide 30

1. FFO in US$35 WTI Stress Case are calculated using Pricing Assumptions on Slide 29.

Slide 32

1. Integrated Corridor FFO and Offshore FFO (in aggregate and on a project basis, as applicable), as referred to throughout this presentation, reflect FFO from the respective businesses and include an allocation of corporate costs.

Slide 34

1. Husky has a redemption option on Preferred Shares.

Slide 44

1. Includes the acquisition of the Superior Refinery, which closed in Q4 2017.

Slide 46

1. Product variability can be influenced by several factors, including seasonal demand, access to feedstock and distribution system interruptions, among others.
2. Products include Husky Synthetic Blend, asphalt and Ultra Low Sulphur Diesel (ULSD), among others.
3. Value chain operating netback and operating netback, as referred to throughout this presentation, are non-GAAP measures. Please see Advisories for further detail.

Slide 47

1. Product variability can be influenced by several factors, including seasonal demand, access to feedstock and distribution system interruptions, among others.
2. Products include gasoline, distillate, Ultra Low Sulphur Diesel (ULSD), propane, benzene, Sulfur, LPG, LVGO, HVGO, heavy fuels, petro-chemicals and various other by-products.

Slide Notes

Slide 49

1. Includes the acquisition of the Superior Refinery, which closed in Q4 2017.

Slide 59

1. Throughput represents Husky's 100% interest in the heavy oil processing capacity at the Prince George Refinery, Lloydminster Refinery, Lloydminster Upgrader, Lima Refinery and Superior Refinery and 50% interest in the Toledo Refinery.
2. Production volumes represent blended heavy oil volumes (bitumen, heavy oil and diluent).

Slide 60

1. Husky has a 50% working interest in the Toledo Refinery.

Slide 89

1. Prepared by internal qualified reserves evaluators in accordance with COGEH.
2. Drilling opportunities split: Proved Undeveloped (76), Probable (47), Unrisked Economic Best Estimate Development Pending Contingent Resource (242).

Slide 90

1. The potential drilling opportunities (68 net wells) will be drilled over the next 8 to 15 years in accordance with the pre-development study for the resource play. Specific contingencies that prevented the classification of contingent resources in the Duvernay liquids-rich resource play as reserves included the timing of development which is outside the timing allowed for booking as reserves and final Company approvals of capital expenditures
2. Type curves reflect the unrisked, proven plus probable estimate.
3. Prepared by internal qualified reserves evaluators in accordance with COGEH.

Slide 102

1. Q3 2016 Operating Netback reflects the impact of a price adjustment for natural gas from the Liwan 3-1 and Liuhua 34-2 fields, per the Heads of Agreement ("HOA") signed by the Company with CNOOC Limited in Q3 2016. The price adjustment under the HOA is effective as of November 2015 and a retroactive adjustment was recognized in Q3 2016.

Slide 127

1. Capital expenditures include exploration capital in each business unit.
2. Asia Pacific oil & NGLs operating costs and capital expenditures are reflected in Asia Pacific natural gas.

Slide 127 continued

3. Capital expenditures in Asia Pacific exclude amounts related to the Husky-CNOOC Madura Ltd. joint venture, which is accounted for under the equity method for financial statement purposes.
4. Downstream capital expenditures include scheduled turnarounds.
5. Lloyd and Tucker thermal operating costs include energy and non-energy costs.
6. Downstream operating costs exclude the impact of scheduled turnarounds in 2018.

Slide 128

1. This table is indicative of the impact of changes in certain key variables in the first quarter of 2018 on earnings before income taxes and net earnings on an annualized basis. The table reflects what the effect would have been on the financial results had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during the first quarter of 2018. Each separate item in the sensitivity analysis shows the approximate effect of an increase in that variable only; all other variables are held constant. While these sensitivities are indicative for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or upon greater magnitudes of change.
2. Excludes mark to market accounting impacts.
3. Based on 1,005.1 million common shares outstanding as at March 31, 2018.
4. Does not include gains or losses on inventory.
5. Includes impacts related to Brent-based production.
6. Includes impact of natural gas consumption by the Company.
7. Excludes impact on Canadian asphalt operations.
8. Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items, including cash balance

Slide 131

1. Other than as indicated in the Advisories, 10% IRR calculations are based on proved and probable reserves.
2. Gas portfolio break-even prices include assumed associated liquids prices based on a US$40 WTI price scenario.
3. Downstream portfolio IRR is not directly tied to oil or gas price. See Advisories for further detail.
4. Projects Included in Plan Spending Period reflect projects that the Company will allocate capital spending to during the 2018-2021 timeframe.

Advisories

Forward-Looking Statements and Information

Certain statements in this presentation, including “financial outlook”, 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 presentation 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 presentation 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 and the results thereof; the Company’s capital plan for 2018 to 2022; forecast sustaining capital and thermal production (as a percentage of total corporate production) for 2018 and 2022; forecast FFO, FCF, upstream production, downstream throughputs, thermal production, heavy processing capacity, upstream operating costs per barrel, downstream operating costs per barrel and earnings break-even oil price for 2018 and 2022; forecast production (as a percentage of total corporate production) for 2018 to 2022 by region, product type and business segment; ranges and targets for annual base dividend, sustaining capital, capital spending, five-year average proved reserves replacement ratio and net debt to FFO for 2018 to 2022; forecast FFO, production growth and FCF compound annual growth rate for 2018 to 2022; forecast upstream operating costs, heavy oil processing capacity, average annual capital spending and average sustaining capital for 2018 to 2022; forecast FFO sensitivity to oil prices for 2018 to 2022; potential FFO sources and uses at various oil prices in 2022; FFO growth in 2018 as compared to 2017 and factors expected to affect FFO growth in 2018; forecast FFO for 2018 to 2022 (in total and for the Company’s businesses in the Integrated Corridor and Offshore); forecast net debt to FFO for 2018 to 2022; estimated net debt and target net debt to FFO in 2018 and 2022; forecast FFO, total sustaining capital (broken down into Upstream and Downstream), average Upstream sustaining capital, annual base dividend, annual average growth capital, upstream operating costs, earnings break-even oil price and cumulative discretionary FCF for 2018 to 2022; the Company’s potential allocation of discretionary free cash flow for the 2018 to 2022 period, including any return of discretionary free cash flow to shareholders by way of dividend growth or otherwise; forecast FFO, capital spending and cumulative FCF for each of the Integrated Corridor business and the Offshore business for 2018 to 2022; forecast production growth for the Integrated Corridor business for 2018 to 2022 and for the Offshore business for 2018 to 2026; anticipated benefits from the Company’s innovation and technology projects; anticipated timing for execution of the Company’s major projects in each of the Integrated Corridor business and the Offshore business for 2018 to 2022 and forecast production or capacity thereof, as applicable; capital expenditures and production guidance ranges for 2018 broken down by region, product type and business segment; operating costs guidance ranges for 2018 broken down by business segment; and oil prices required to generate targeted IRR for the Company’s listed in-flight and future projects;

Advisories

- with respect to the Company's Downstream operating segment: forecast throughput capacity (total and broken down into heavy oil processing and light oil processing) for 2018 and 2022; forecast light oil processing capacity, heavy oil blend processing capacity, available Keystone capacity and heavy oil blend for 2018 to 2022; plans to add 30,000 bbls/day of heavy oil processing capacity in 2019; potential future heavy oil outlet options; forecast heavy oil blend and downstream processing and pipeline capacity for 2018 to 2022 broken down by product type and project, as applicable; 2018 forecast volume of Husky product marketed to the U.S.; forecast Western Canada oil export pipeline and rail capacity from 2018 to 2021 and the Company’s ability to respond to related market changes; forecast global oil-based marine fuel consumption from 2018 to 2021 and the Company’s ability to respond to related market changes; forecast North American light oil production in 2018 and 2019 and the Company’s ability to respond to related market changes; and forecast Downstream FFO, capital spending and cumulative FCF for 2018 to 2022;

- with respect to the Company's heavy oil and thermal production in the Integrated Corridor: forecast production (in total and broken down by project) for 2018 and 2022; forecast production growth for 2018 to 2022; expected timing to bring Rush Lake 2, Dee Valley, Spruce Lake Central, Spruce Lake North, Edam Central and Westhazel online; anticipated production growth from thermal projects for 2018 to 2022 and associated compound annual growth rate; anticipated timing of first oil from thermal projects; 2018 forecast thermal production operating costs broken down by project and 2018 forecast average thermal operating costs; forecast Lloyd thermal production for 2018 to 2022; strategic plans and growth strategy for the Lloyd thermal projects; expected timing to reach nameplate capacity at Tucker and Sunrise; 2018 year-end gross production target at Sunrise (in total and per well pair); strategic plans and growth strategy for Sunrise; and forecast capital spending, FFO and cumulative FCF for the thermal business for 2018 to 2022;

- with respect to the Company's resource plays and other production in the Integrated Corridor: forecast production from resource plays and other Western Canada assets for 2018 and 2022; forecast production growth from resource plays for 2018 to 2022 and associated compound annual growth rate; drilling plans for 2018 at Ansell-Kakwa and Montney; expected tie-in of seven wells at Wembley by the end of 2018; 2018 forecast Wilrich type well production; expected reduction in processing fees upon completion of the Ansell Corser Gas Plant; and strategic plans and growth strategy for the Company’s resource plays;

- with respect to the Company's Offshore business in the Atlantic: forecast production growth from 2018 to 2026; completion and online target dates for infill wells at West White Rose; expected peak production and payback period at West White Rose; and expected timing of pouring of concrete at the Concrete Gravity Structure at West White Rose; and

- with respect to the Company's Offshore business in Asia Pacific: forecast production growth and FFO (as a percentage of total corporate FFO) for 2018 and 2022; forecast production growth from 2018 to 2026; forecast level of investment required for growth from 2018 to 2022; forecast gas and liquids production by 2022; forecast global energy demand by region in 2040; forecast gas production growth for 2018 to 2022 for Liwan 3-1 and Liuhua 34-2, Liuhua 29-1, the BD Project and the MDA-MBH and MDK fields; expected timing of first gas from Liuhua 29-1; expected net peak production at the BD Project broken down into gas and liquids; expected timing of first gas, and expected net peak production, at the MDA-MBH and MDK fields; drilling plans at the MDA-MBH and MDK fields in 2018; drilling plans at Liuhua 29-1 in 2018; forecast production (broken down into gas and liquids), FFO, capital spending and cumulative FCF for Liuhua 29-1 from 2018 to 2026; forecast Indonesia production for 2018 to 2022 and the combined production target (broken down into gas and liquids) at the BD Project and the MDA-MBH and MDK fields; drilling plans at Block 16/25 in 2018; and forecast FFO, capital spending and cumulative FCF for Asia Pacific for 2018 to 2022.

Advisories

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. In addition, with respect to the type curves and test rates, there is no certainty that future wells will generate results to match type curves or test rates presented herein.

Certain of the information in this presentation is “financial outlook” within the meaning of applicable securities laws. The purpose of this financial outlook is to provide readers with disclosure regarding the Company’s reasonable expectations as to the anticipated results of its proposed business activities. Readers are cautioned that this financial outlook may not be appropriate for other purposes.

Although the Company believes that the expectations reflected by the forward-looking statements presented in this presentation 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, 2017 and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe risks, material assumptions and other factors that could influence actual results and are incorporated herein by reference.

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 management’s assessment of the future considering all information available to it at the relevant time. 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.

Advisories

Non-GAAP Measures

This presentation contains certain terms which do not have any standardized meanings prescribed by IFRS and are therefore unlikely to be comparable to similar measures presented by other issuers. None of these measures is used to enhance the Company's reported financial performance or position. With the exception of funds from operations, free cash flow and net debt, there are no comparable measures to these non-GAAP measures in accordance with IFRS. The following non-GAAP measures are considered to be useful as complementary measures in assessing Husky's financial performance, efficiency and liquidity:

- “Funds from operations” or “FFO” is a non-GAAP measure 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. FFO is presented to assist management and investors in analyzing operating performance of the Company in the stated period. FFO equals cash flow – operating activities plus change in non-cash working capital.

- “Free cash flow” or “FCF” is a non-GAAP measure 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. FCF is presented to assist management and investors in analyzing operating performance by the business in the stated period. FCF equals funds from operations less capital expenditures and investment in joint ventures. FCF has been restated in the first quarter of 2018 in order to be more comparable to similar non-GAAP measures presented by other companies. Changes from prior period presentation include the addition of investment in joint ventures. Prior periods have not been restated.

The following table shows the reconciliation of net earnings to FFO and FCF for the periods indicated:

	Three Months Ended	12 Months Ended	
($ millions)	March 31, 2018	March 31, 2018	December 31, 2017
Net earnings (loss)	248	963	786
Items not affecting cash:			
Accretion	24	108	112
Depletion, depreciation, amortization and impairment	618	2,800	2,882
Exploration and evaluation expenses	-	5	6
Deferred income taxes	77	(288)	(359)
Foreign exchange loss (gain)	1	14	(4)
Stock-based compensation	21	65	45
Loss (gain) on sale of assets	(4)	(52)	(46)
Unrealized mark to market loss (gain)	(86)	20	56
Share of equity investment gain	(9)	(45)	(61)
Other	2	22	16
Settlement of asset retirement obligations	(49)	(137)	(136)
Deferred revenue	(20)	(32)	(16)
Distribution from joint ventures	72	97	25
Change in non-cash working capital	(366)	72	398
Cash flow - operating activities	529	3,612	3,704
Change in non-cash working capital	366	(72)	(398)
Funds from operations	895	3,540	3,306
Capital expenditures	(637)	(2,473)	(2,220)
Investment in joint venture	(40)	(121)	0
Free cash flow	218	946	1,086

Advisories

- “Net debt” is a non-GAAP measure that equals total debt less cash and cash equivalents. Total debt is calculated as long-term debt, long-term debt due within one year and short-term debt. Net debt is considered to be a useful measure in assisting management and investors to evaluate the Company's financial strength.

The following table shows the reconciliation of total debt to net debt as at the periods indicated:

($ millions)	**March 31, 2018**	**December 31, 2017**
Short-term debt	200	200
Long-term debt due within one year	-	-
Long-term debt	5343	5,240
Total debt	5,543	5,440
Cash and cash equivalents	(2,301)	(2,513)
Net debt	3,242	2,927

- “Net debt to funds from operations” or “net debt to FFO” or “net debt to FFO ratio” is a non-GAAP measure that equals net debt divided by FFO. Net debt to FFO is considered to be a useful measure in assisting management and investors to evaluate the Company's financial strength.

- “Net debt to trailing funds from operations” or “net debt to trailing FFO” is a non-GAAP measure that equals net debt divided by the 12-month trailing FFO as at March 31, 2018 and December 31, 2017. Net debt to trailing FFO is considered to be a useful measure in assisting management and investors to evaluate the Company's financial strength.

- “Upstream operating netback” or “operating netback” is a common non-GAAP measure used in the oil and gas industry. This measure assists management and investors to evaluate the specific operating performance by product at the oil and gas lease level. Operating netback is calculated as realized price less royalties, operating costs and transportation costs on a per unit basis.

- “Value chain operating netback” is a non-GAAP measure used in the oil and gas industry. This measure assists investors to evaluate the operating performance of the Integrated Corridor. Value chain operating netback is calculated as an average realized price of synthetic crude and other refined products less royalties, operating costs, transportation costs and processing costs on a per unit basis.

Advisories

- “Sustaining capital” is the additional development capital that is required by the business to maintain production and operations at existing levels. Development capital includes the cost to drill, complete, equip and tie-in wells to existing infrastructure. Sustaining capital does not have any standardized meaning and therefore should not be used to make comparisons to similar measures presented by other issuers.

- “Earnings break-even” reflects the estimated WTI oil price per barrel priced in US dollars required in order to generate a net income of Cdn$0 in the 12-month period ending December 31 of the indicated year. This assumption is based on holding several variables constant throughout the applicable 12-month period, including foreign exchange rate, light-heavy oil differentials, realized refining margins, forecast utilization of downstream facilities, estimated production levels and other factors consistent with normal oil and gas company operations. Earnings break-even is used to assess the impact of changes in WTI oil prices on the net earnings of the Company and could impact future investment decisions. Earnings break-even does not have any standardized meaning and therefore should not be used to make comparisons to similar measures presented by other issuers.

- “Return on capital employed” or “ROCE” measures the return earned on long-term capital sources such as long-term liabilities and shareholder equity. ROCE is a non-GAAP measure used 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 and short-term debt plus total shareholders’ equity. The Company’s determination of ROCE does not have any standardized meaning prescribed by IFRS and therefore is unlikely to be comparable to similar measures presented by other issuers.

Disclosure of Oil and Gas Information

Unless otherwise indicated: (i) reserves and resources estimates and potential drilling opportunities in this presentation have been prepared by internal qualified reserves evaluators in accordance with the Canadian Oil and Gas Evaluation Handbook, have an effective date of December 31, 2017 and represent the Company's working interest share; (ii) projected and historical production volumes provided represent the Company’s working interest share before royalties; and (iii) historical production volumes provided are for the year ended December 31, 2017. The Company has disclosed its total reserves in Canada, Indonesia and China in its Annual Information Form for the year ended December 31, 2017, which reserves disclosure is incorporated by reference in this presentation.

The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Husky’s Lloydminster Heavy Oil and Gas thermal bitumen unrisked best estimate contingent resources consist of 186 million barrels of economic development pending, 150 million barrels of economic development unclarified and 589 million barrels of economic status undetermined development unclarified. The figures represent Husky’s working interest volumes. The development pending category consists of 8 steam assisted gravity drainage (SAGD) projects and one combined SAGD and cyclic steam stimulation (CSS) project that have been scheduled for initial production starting in 2021 through to 2040. The first three projects have a total capital cost to first production of $0.9 billion based upon the pre-development studies. The estimated total capital to fully develop these 9 development pending projects is approximately $3 billion.

Advisories

The economic and economic status undetermined development unclarified projects require additional technical and commercial analysis of the conceptual SAGD or CSS studies. Of these, the first project requires $0.4 billion to achieve commercial production in 2022. The remaining projects are to be developed over more than 50 years in accordance with the conceptual studies for this large resource. In total, 288 million barrels of thermal bitumen are based upon pre-development studies while an additional 672 million barrels of thermal bitumen are based upon conceptual plans. This oil is reported as thermal bitumen and has viscosities ranging from 12,800 centipoise (cP) to as high as 600,000 cP with gravities between 9 and 12 degrees API. Specific contingencies preventing the classification of the Company's Lloydminster Heavy Oil thermal contingent resources as reserves include the need for further reservoir studies, delineation drilling, verification of sub-zone continuity and quality that would enable feasible implementation of a thermal scheme, the formulation of concrete development plans and facility designs to pursue development of the large inventory of opportunities, the Company's capital commitment, development over a time frame much greater than the reserve timing window and regulatory applications and approvals. Positive and negative factors relevant to the contingent resource estimates include potential reservoir heterogeneity in sub-zones which may limit the applicability of thermal schemes, a higher level of uncertainty in the estimates as a result of lower drilling density in some projects and current lack of development plans in the unclarified contingent resources. The main risks are the low well density and the associated geological uncertainties in certain projects, the production performance and recovery long term, future commodity prices and the capital costs associated with wells and facilities planned over an extended future period of time.

Sunrise thermal bitumen unrisked best estimate contingent resources consist of 479 million barrels (Husky's working interest) of economic development pending volumes. Husky has a working interest of 50 percent. 401 million barrels are associated with future expansions in which the initial development time frame is not within the reserves timing window. Initial production from the first 20,000 barrel-per-day expansion is estimated in 2028 at a project cost of $0.6 billion. Total capital cost of $3.3 billion (Husky's working interest) will be required to develop all future expansions including the facilities, well pairs and capitalized maintenance over 50 years. 31 million barrels of contingent resources are associated with the production from well pairs booked as undeveloped reserves that go beyond the 50 years reserves time frame. The remaining 47 million barrels of development pending resources are associated with well pairs that are scheduled to be developed beyond the 50-year reserves time frame. The total capital costs to develop these additional well pairs is estimated at $475 million. The oil at Sunrise is reported as thermal bitumen and has viscosities as high as 1,200,000 cP with gravities between 6 and 9 degrees API. Specific contingencies preventing the classification of contingent resources at Sunrise as reserves include the timing of development which is outside the timing allowed for booking as reserves, final Company approvals of capital expenditures, the formulation of concrete development plans and facility designs to pursue development of the large inventory of opportunities, further delineation drilling requirements and regulatory applications and approvals. Positive and negative factors relevant to the contingent resource estimates include a higher level of uncertainty in the estimates as a result of lower drilling density in parts of the project area. The main risks are the future commodity prices and their impact on the development timing.

McMullen contains unrisked best estimate economic development pending contingent resources of 44 million barrels of bitumen for Phase 1 of the development with a further 1.3 billion barrels of bitumen of unrisked best estimate economic status undetermined development unclarified contingent resources. McMullen is a thermal play in the Wabiskaw formation covering over 130 sections southwest of Wabasca. Husky has a working interest of 100 percent. The cost to first production for Phase 1, based upon the pre-development study, is approximately $452 million for the initial commercial demonstration facility and horizontal cyclic steam stimulation (HCSS) wells in 2023. The results of the commercial demonstration will be utilized to refine the subsequent phases that are based upon a conceptual development plan at this time and each has the same capital estimate with initial production scheduled for 2028 for Phase 2. The total commercial facilities and wells will be developed over more than 50 years at an estimated total cost of $40 billion in accordance with the conceptual study for this large resource. The development of these projects depends on the results of the technical analysis, future bitumen prices and the Company's commitment to dedicate capital to this large inventory of projects.

Advisories

Specific contingencies preventing the classification of contingent resources at the McMullen thermal development project as reserves include the need for further reservoir studies, delineation drilling, facility design, preparation of firm development plans, regulatory applications and approvals and Company approvals. Positive and negative factors relevant to the estimates of performance and recovery long term. These resources include a higher level of uncertainty in the estimates as a result of lower core-hole drilling density. The main risks are the low well density and the associated geological uncertainties, the production performance and recovery long term and the capital costs associated with wells and facilities planned over an extended future period of time.

The Ansell Spirit River liquids-rich natural gas resource play is located in the deep basin Cretaceous formations of west-central Alberta, and Husky has an average 92 percent working interest. Husky is actively developing Ansell. This producing property contains unrisked best estimate economic development pending contingent resources of 224 million barrels of oil equivalent, consisting of 1.3 trillion cubic feet (Tcf) of natural gas and 12 million barrels of natural gas liquids (NGL). Ansell also includes unrisked best estimate economic development on hold contingent resources of 174 million barrels of oil equivalent from the Cardium formation, consisting of 0.8 Tcf of natural gas and 35 million barrels of NGL from approximately 300 potential drilling opportunities. The initial contingent resource fracture stimulated horizontal wells are scheduled to be drilled starting in 2025, following the development of the proved and probable reserves. The cost to achieve initial commercial production is the cost of the first well of $3.9 million. The development pending drilling opportunities (242 working interest) will be drilled over the next 8 to 20 years in accordance with the pre-development study for the resource play. Specific contingencies preventing the classification of contingent resources in the Ansell liquids-rich resource play as reserves include the timing of development which is outside the timing allowed for booking as reserves and final Company approvals of capital expenditures. Positive and negative factors relevant to the estimate of Ansell contingent resources include a lower level of uncertainty in the estimates as a result of the large number of producing wells, extensive production history from the property, Husky's large contiguous land base and Husky's ownership of existing infrastructure in the area. Key risks include the performance of future wells when the play is expanded and reducing costs to achieve optimal results in a low gas and NGL price environment.

The Duvernay liquids-rich natural gas resource play is located in west-central Alberta. Husky has 32.5 net sections (30 gross sections with a 100% working interest and five gross sections with a 50 percent working interest). This producing property contains unrisked best estimate economic development on hold contingent resources of 57 million barrels of oil equivalent, consisting of 140 billion cubic feet (Bcf) of natural gas and 34 million barrels of natural gas liquids (NGL). The first of these contingent locations (horizontal multi-stage fractured wells) are scheduled to be drilled starting in 2019. All-in well cost of $11 million per well is estimated for the first PAD of four wells to achieve initial commercial production. The potential drilling opportunities (68 net wells) will be drilled over the next 8 to 15 years in accordance with the pre-development study for the resource play. Specific contingencies that prevented the classification of contingent resources in the Duvernay liquids-rich resource play as reserves included the timing of development which is outside the timing allowed for booking as reserves and final Company approvals of capital expenditures. Positive and negative factors relevant to the estimate of the Duvernay contingent resources include some uncertainty in the estimates as a result of the few number of producing wells (11 gross on Husky working interest land), the limited production history from the property and competitors, and Husky's large contiguous land base. Key risks include the performance of future wells when the play is expanded and reducing costs to achieve optimal results in a low gas and NGL price environment.

Husky's Lloydminster Heavy Oil cold heavy oil production with sand (CHOPs) and Horizontal well opportunity includes 38 million barrels (Husky's working interest) of unrisked economic best estimate contingent resources in the development pending sub-class and a further 737 million barrels (Husky's working interest) of unrisked best estimate contingent resources in the development unclarified sub-class with the economic status undetermined. A typical CHOPS well has a cost estimate to drill, complete and equip of $0.6 million, while a five-well horizontal pad has a cost estimate of $7.0 million with the first developments online in 2030 based on a pre-development study.

Advisories

This is a continuation of the CHOPs and horizontal well development programs which have been proven to be successful in the Lloydminster area. The timing of development and Company approvals are the main contingencies preventing the booking of these volumes as reserves. Positive and negative factors relevant to these contingent resources include a lower level of uncertainty in the estimates as a result of the large number of producing wells, extensive production history from the property, Husky's large contiguous land base and Husky's ownership of existing infrastructure in the area. The key risk is the execution of a multi-year program and reducing capital and operating costs in a low heavy oil price environment.

Heavy Oil Cold EOR, located in the Lloydminster area, contains 311 million barrels (Husky's working interest) of unrisked economic status undetermined best estimate contingent resources in the development unclarified sub-class. Cold EOR Solvent Injection is a cyclic process utilizing CO2 which has been demonstrated to be technically successful in the area. The wells and area have been identified in the conceptual development study, but more detailed development plans are required for each field. The first phase of the projects is planned for 2023 with a capital cost of $207 million to reach first oil production in one of the identified fields. The timing of development, regulatory and Company approvals are the specific contingencies preventing the booking of these volumes as reserves as well as the need for additional assessment for the area where the economic status is undetermined. Positive and negative factors include the extensive land base and infrastructure while the ultimate recovery for this technology is still being evaluated in the field. Key risks include the range of uncertainty in the ultimate recovery and accessing a long term supply of CO2 for the projects.

There is uncertainty that it will be commercially viable to produce any portion of the resources referred to in the above paragraphs.

The Company uses the term "barrels of oil equivalent" (or "boe") and "thousand cubic feet of gas equivalent" (or "mcfe"), which are consistent with other oil and gas companies' disclosures. Boe amounts have been calculated by using the conversion ratio of 6 mcf of natural gas to 1 bbl of oil and mcfe amounts have been calculated by using the conversion ratio of 1 bbl of oil or NGL to 6 mcf of natural gas. A boe conversion ratio of 6 mcf: 1 bbl and an mcfe conversion ratio of 1 bbl: 6 mcf are based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent value equivalency at the wellhead. Readers are cautioned that the terms boe and mcfe may be misleading, particularly if used in isolation.

The Company uses the term "capital efficiency", which is calculated by dividing the development capital per well by the well's initial production rate ($ per flowing barrel, mcf or boe). Development capital includes the cost to drill, complete, equip and tie-in wells to existing infrastructure. As capacity becomes available within facilities, new wells are added to replace the volume. The number of wells required to replace such volume is a function of capital efficiency. Capital efficiency does not have any standardized meaning and therefore should not be used to make comparisons to similar measures presented by other issuers.

The Company uses the term "sustaining capital per boe", which is the additional development capital that is required by the business to maintain production and operations at existing levels on a per unit basis. It is calculated as sustaining capital divided by estimated ultimate recovery (EUR). EUR reflects the unrisked proved plus probable estimate. Sustaining cost per boe does not have any standardized meaning and therefore should not be used to make comparisons to similar measures presented by other issuers.

The Company uses the term "steam-oil ratio" (or "SOR"), which measures the average volume of steam required to produce a barrel of oil. This measure does not have any standardized meaning and should not be used to make comparisons to similar measures presented by other issuers.

Advisories

The Company uses the term “reserves replacement ratio”, which is consistent with other oil and gas companies’ disclosures. Reserves replacement ratios for a given period are determined by taking the Company's incremental proved reserves additions for that period divided by the Company's upstream gross production for the same period. The reserves replacement ratio measures the amount of reserves added to a company's reserves base during a given period relative to the amount of oil and gas produced during that same period. A company's reserves replacement ratio must be at least 100 percent for the company to maintain its reserves. The reserves replacement ratio only measures the amount of reserves added to a company's reserves base during a given period. Reserves replacement ratios presented as excluding economic factors exclude the impact that changing oil and gas prices have on reserves amounts.

IRR (internal rate of return) calculations shown in this presentation are based on holding several variables constant throughout the period, including: estimated WTI oil price per barrel priced in US dollars, foreign exchange rate, light-heavy oil differentials, realized refining margins, forecast utilization of downstream facilities, estimated production levels, and other factors consistent with normal oil and gas company operations. This measure is used to assess potential return generated from investment opportunities and could impact future investment decisions. This measure does not have any standardized meaning and should not be used to make comparisons to similar measures presented by other issuers. IRR calculations in this presentation are based on proved and probable reserves, except for the IRR calculations for the projects described below, in which cases the IRR calculations are based on resources.

Type well estimates referred to in this presentation have been prepared by internal qualified reserves engineers and in accordance with the Canadian Oil and Gas Evaluation Handbook.

The Spirit River gas resource potential drilling opportunities include 76 proved undeveloped and 47 probable undeveloped locations and 242 unrisked economic best estimate development pending contingent resource opportunities in Ansell and Kakwa, mainly focused in the Wilrich formation.

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 Activities, 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 may use certain terms in that disclosure that U.S. oil and gas companies generally do not include or may be prohibited from including in their filings with the U.S. Securities and Exchange Commission.

All currency is expressed in Canadian dollars unless otherwise directed.

Husky Energy

Appendix

2018 Guidance Summary

Last Updated April 26, 2018

Upstream Oil and Liquids	Capital Expenditures[1] ($ millions)	Production (mbbls/day)
Lloyd & Tucker thermal bitumen	835 - 860	101 - 103
Sunrise thermal bitumen	60 - 70	25 - 27
Lloyd Non-Thermal	85 - 90	42 - 44
Atlantic light	750 - 775	29 - 31
W. Canada Light, medium, heavy & NGLs	55 - 60	21 - 22
Asia Pacific light & NGLs[2,3]	- -	10 - 11
Total Crude Oil and Liquids	**1,785 - 1,855**	**230 - 237**

Natural Gas	($ millions)	(mmcf/day)
Canada	215 - 225	280 - 290
Asia Pacific[3]	130 - 150	200 - 210
Total Natural Gas	**345 - 375**	**480 - 500**

	($ millions)	(mboe/day)
Total Upstream	**2,130 - 2,230**	**310 - 320**

Downstream	($ millions)	Throughput[4] (mbbls/day)
Canada downstream	130 - 160	110 - 115
U.S. downstream	580 - 625	250 - 255
Downstream Total	**710 - 785**	**360 - 370**

Corporate Costs	($ millions)
Total Capital	100 - 110
Total Capital Budget	**100 - 110**

Other	($ millions)
Capitalized Interest	110 - 120
Corporate SG&A	175 - 225

Upstream	($ millions)
Downstream	1,275 - 1,325
Total Sustaining Capital	500 - 550
Total Sustaining Capital	**1,775 - 1,875**

Upstream Operating Costs	($/bbl)
Lloyd and Tucker thermal[5]	9.50 - 10.50
Atlantic Region light oil	18.50 - 19.50
	($/mcfe)
Resource Play Natural Gas	1.00 - 1.30
Asia Pacific Region Gas	1.00 - 1.25
	($/boe)
Total Upstream Operating Costs	**13.00 - 13.50**

Downstream Operating Costs[6]	($/boe)
Lloyd Upgrader	6.50 - 7.50
US Refineries	6.00 - 7.00

1,2,3,4,5,6 see Slide Notes and Advisories

Sensitivity Table

From Q1 2018 Management's Discussion and Analysis[1]

Sensitivity Analysis	Q1 2017 Average	Increase	Effect on Earnings Before Income Taxes[(2)] ($ millions)	($/share)[(3)]	Effect on Net Earnings[(2)] ($ millions)	($/share)[(3)]
WTI benchmark crude oil price[(4)(5)]	$62.87	U.S. $1.00/bbl	91	0.09	66	0.07
NYMEX benchmark natural gas price[(6)]	$3.00	U.S. $0.20/mmbtu	-	-	-	-
WTI/Lloyd crude blend differential[(7)]	$23.92	U.S. $1.00/bbl	(2)	-	(1)	-
Canadian light oil margins	$0.044	Cdn $0.005/litre	13	0.01	10	0.01
Asphalt margins	$25.55	Cdn $1.00/bbl	8	0.01	6	0.01
Chicago 3:2:1 crack spread	$12.84	U.S. $1.00/bbl	122	0.12	95	0.09
Exchange Rate (U.S. $ per Cdn $)[(4)(8)]	0.791	U.S. $0.01	(59)	(0.06)	(43)	(0.04)

1,2,3,4,5,6,7,8 see Slide Notes and Advisories

Price Planning Assumptions

2017 vs. 2018 Five-Year Plan / Stress Case

Benchmark Prices – 2017 Base Case	2018	2019	2020	2021
WTI (US $bbl)	55.00	60.00	60.00	60.00
Chicago 3:2:1 ($/bbl US)	16.00	16.00	16.00	16.00
Heavy crude differential ($/bbl US)	14.00	14.00	14.00	14.00
AECO ($/mmbtu Cdn)	3.00	3.00	3.00	3.00
US/CAD exchange rate	0.78	0.80	0.80	0.80

Benchmark Prices – 2018 Base Case	2018	2019	2020	2021	2022
WTI (US $bbl)	60.00	60.00	60.00	60.00	60.00
Chicago 3:2:1 ($/bbl US)	16.00	16.00	16.00	16.00	16.00
Heavy crude differential ($/bbl US)	18.00	18.00	18.00	18.00	18.00
AECO ($/mmbtu Cdn)	2.00	2.00	2.00	2.00	2.00
US/CAD exchange rate	0.80	0.80	0.80	0.80	0.80

Benchmark Prices – $35 Stress Case	2018	2022
WTI (US $bbl)	35.00	35.00
Chicago 3:2:1 ($/bbl US)	12.00	12.00
Heavy crude differential ($/bbl US)	11.00	11.00
AECO ($/mmbtu Cdn)	2.25	2.25
US/CAD exchange rate	0.71	0.71

Price Planning Assumptions

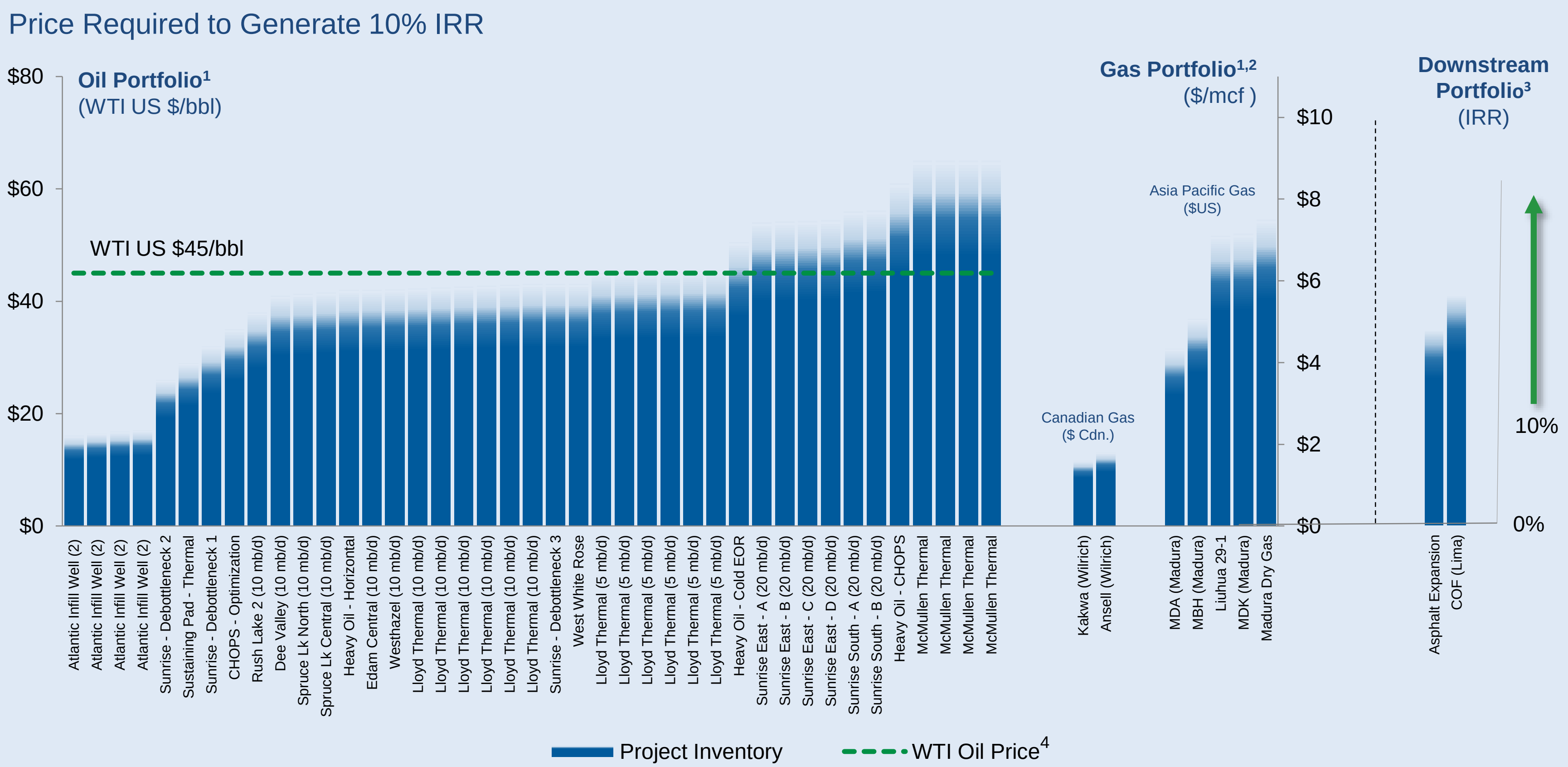
Other Cases

Benchmark Prices – $70 Flat Case	2018	2019	2020	2021	2022
WTI (US $bbl)	70.00	70.00	70.00	70.00	70.00
Chicago 3:2:1 ($/bbl US)	16.00	16.00	16.00	16.00	16.00
Heavy Crude Differential ($/bbl US)	18.00	18.00	18.00	18.00	18.00
AECO ($/mmbtu Cdn)	2.00	2.00	2.00	2.00	2.00
USD/CAD exchange rate	0.80	0.80	0.80	0.80	0.80

Benchmark Prices - $80 Flat Case	2018	2019	2020	2021	2022
WTI (US $bbl)	80.00	80.00	80.00	80.00	80.00
Chicago 3:2:1 ($/bbl US)	16.00	16.00	16.00	16.00	16.00
Heavy Crude Differential ($/bbl US)	18.00	18.00	18.00	18.00	18.00
AECO ($/mmbtu Cdn)	2.00	2.00	2.00	2.00	2.00
USD/CAD exchange rate	0.80	0.80	0.80	0.80	0.80

Selected Project Inventory

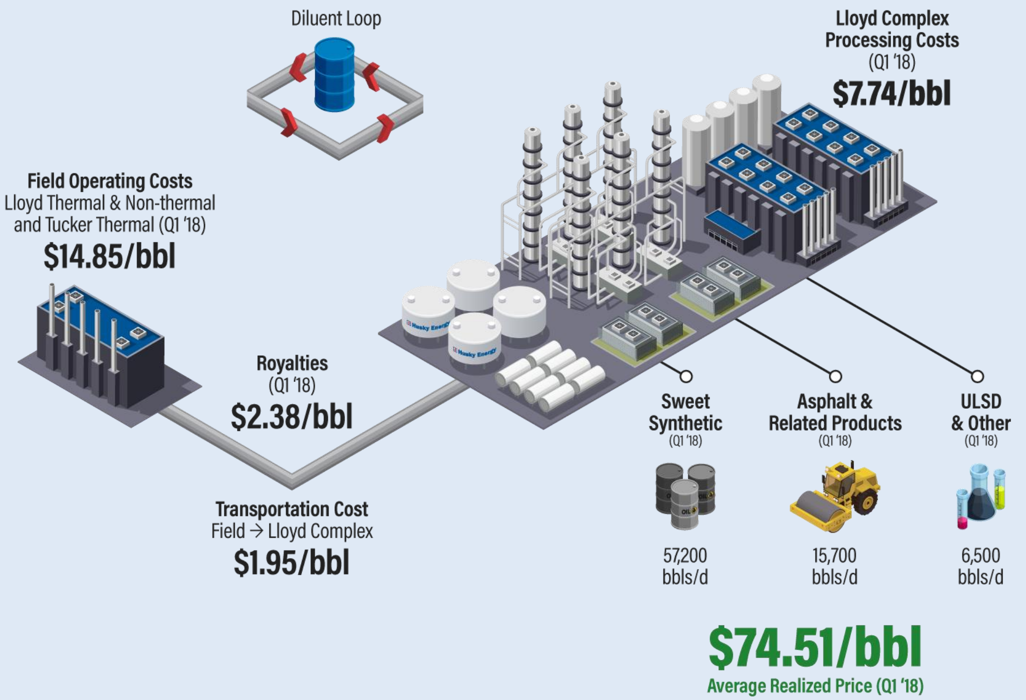
Price Required to Generate 10% IRR



1,2,3,4 see Slide Notes and Advisories

Lloyd Value Chain – Q1 2018

Lloyd Value Chain Operating Netback (per bbl)	$ / bbl
WTI Oil Price - $US	$62.87
WTI Oil Price - $CAD	$79.48
Lloyd Complex average realized product price	$74.51
Upstream operating costs *(average of cold and thermal)*	$14.85
Royalties	$2.38
Transportation cost	$1.95
Avg. Lloyd Complex processing cost	$7.74
Lloyd Value Chain Operating Netback	**$47.59**
Lloyd Upstream Operating Netback	**$14.35**

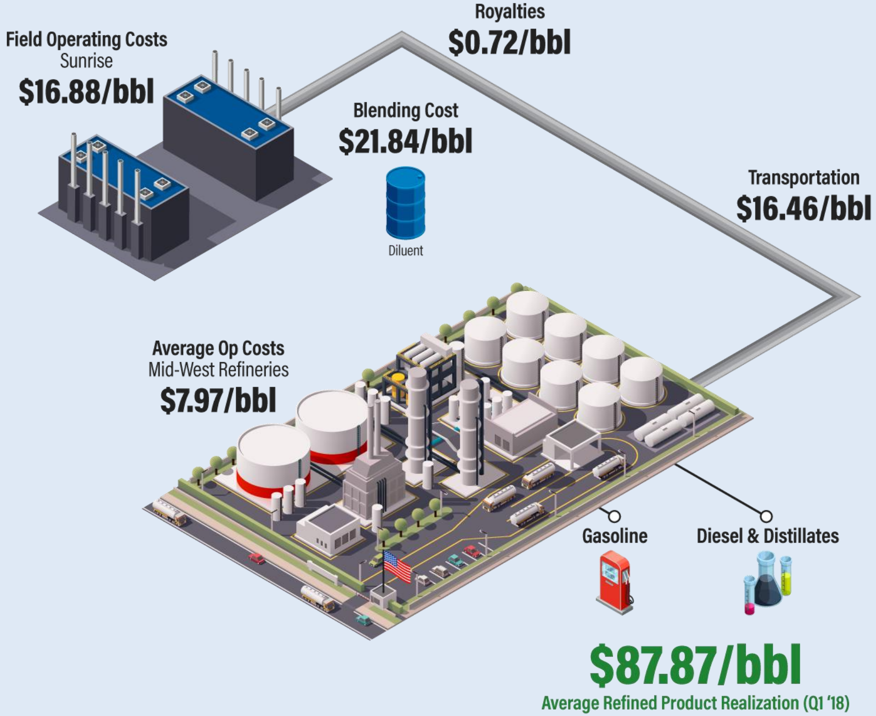


$33.24
(per bbl)

Incremental Netback From Integrated Operations

Sunrise Value Chain – Q1 2018

Sunrise Value Chain Operating Netback (per bbl)	$ / bbl
Brent Oil Price - $US	$66.74
Brent Oil Price - $CAD	$84.37
Toledo realized product price	$87.87
Sunrise operating costs	$16.88
Royalties	$0.72
Blending cost	$21.84
Transportation cost	$16.46
Midwest refining cost	$7.97
Sunrise Value Chain Operating Netback	**$24.00**
Sunrise Upstream Operating Netback	**($5.62)**



$29.62
(per bbl)

Incremental Netback From Integrated Operations

Innovation and Technology

Fact Sheet 1: Automation, Production Optimization, Remote Analysis and Subsurface

Automation

- Robotic Process Automation enhances procurement processes by eliminating repetitive reporting and data movement activities. Active Proof of Concept underway. Technology also under evaluation for use in other business areas (ex. Tax).
- Implementation of Digitate's Ignio Artificial Intelligence solution has resulted in a 90% reduction in completion time for IT incident requests.
- Evaluating application of ePermitting to automate the Work Permit life cycle (from creation to storage for auditing) for improved resource planning and safety at plant sites.

Production Optimization

- Partial Upgrading Diluent Reduction to increase netbacks, and lower costs and GHG emissions.
- Recently implemented an automated process using Machine Learning to control steam utilization for SAGD at Sunrise. Expected to result in increased steam production by1.5% - 3.0% and enhance process safety by minimizing pressure variability.
- Implemented low cost remote wellsite monitoring technology (Ambyint) to reduce Western Canada wellsite visits / operating costs. Currently deployed 69 devices on wells in Foothills and Rainbow Lake.

Remote Analysis

- Completed pilot using drones for visual pipeline right-of-way inspections in the Rainbow Lake area.
- Completed Proof of Concept using InSAR satellite image analysis for remote Geohazard identification at pipelines and facilities. Currently evaluating results.
- Currently using drones for safer flare stack and equipment inspections at multiple locations.

Subsurface

- Reduce geological core description time using AI for pattern recognition.
  - Husky currently collects high-resolution, multi-spectral photography of core samples from heavy oil wells for multiple uses.
  - Now working with Enersoft on a Proof of Concept to apply “Machine Vision” for recognition of geological features in the rock to enhance interpretation time
- Accelerate subsurface interpretation with Cloud computing.
  - Currently evaluating results of a pilot to test Schlumberger DEFLI Cognitive computing environment for geological modelling software.
- Shorten decision process for heavy oil well re-completion with Machine Learning
  - A manual well log inspection process is used to search for potential alternate reservoir zones before a well is abandoned.
  - Currently reviewing proposals from two technology companies to run a Proof of Concept to evaluate the effectiveness of Machine Learning methods to automate this process.

Innovation and Technology

Fact Sheet 2: Machine Learning

Heavy Oil SAGD Optimization AI Pilot

- Using analytics to optimize steam-oil-ratio (SOR) and production for SAGD thermal heavy oil projects.
- The results will be used to stabilize and improve production, increase efficiency in steam utilization and loss production prevention.

- Husky has been working with Artificial Intelligence companies since August 2017. Currently, we are doing a pilot involving 4 AI companies: SAS, IBM, WhiteWhale and DeLoitte.
- The pilot will leverage AI technologies to improve SOR (steam-oil-ratio) across all thermal producing properties.
- We have three-stage approach:
  - Stage 1: pilot – ongoing
  - Stage 2: small scale field implementation: Sandall or Paradise Hill. Timing: end of 2018
  - Stage 3: full field implementation: all producing thermal properties. Timing: 2019-2020
- The AI model will use historical data such as temperature, pressure, flow and other control values (steam, pump speed, choke, lift gas, etc.) as well as sub-surface events, outage and maintenance data to learn how to respond to events that occurred in the past.
- All of these “learnings” and then used as a predictive model to establish recommendations on how to standardize the future response in real time (efficient) and eliminate any human error (reliable).

Machine Learning for Sea-state Predictions

- Initial trials have yielded encouraging results for improved confidence in wave height prediction.
- Work is ongoing to advance predictive capability for other metocean conditions, including sea-ice trajectory prediction.

- Ocean state impacts offshore operations in the form of Non-Productive Time (NPT) and Waiting on Weather (WOW) events.
  - WOW accounts for 12% of drilling time in Husky’s Atlantic drilling operations annually. Improved prediction confidence can lead to significant savings related to rig time, ice management time and vessel deployment.
- Husky engaged with Microsoft through a working session in April, 2018. A preliminary machine learning model was built using actual and forested weather data to predict significant wave height.
- Encouraging results justify continued work towards a more robust model.
- The go-forward focus will be to refine forecast accuracy and confidence to provide optimized decision making.
- Husky is using Cloud-based “virtual machines” that are scalable to the problem at hand. The virtual machines learn from historical data utilizing varieties of regression analyses to build predictive models. More complex challenges, not yet solved by “off the shelf” algorithms, require more robust models that users create and test.
- An iterative approach (eg. ice modelling and weather forecasts) can ultimately result in better overall confidence in the predictions.

Husky Energy

Executive Management

Executive Management

Robert J. Peabody

President & Chief Executive Officer

Mr. Peabody was appointed as Husky Energy's President and Chief Executive Officer and member of the Board of Directors in December, 2016.

Career History and Key Accomplishments

He joined Husky as Chief Operating Officer in 2006, and has played a key role in the transformation of the Company.

Mr. Peabody started his career in Canada where he worked on early in-situ oil sands development.

Prior to joining Husky, Mr. Peabody worked for BP where he held leadership positions in Canada, the U.K. and the U.S. that included Upstream production in the North Sea, natural gas marketing, oil trading, chemicals and Group Strategy, Planning and Performance Management.

Education

Mr. Peabody holds a Master of Science in Management from Stanford University (Sloan Fellow) and a Bachelor of Science in Mechanical Engineering from the University of British Columbia.

Professional Memberships, Associations and Designations

Mr. Peabody is professional engineer and also serves as the Vice Chair of the Foothills Hospital Development Council, Calgary, Alberta. He is also a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

Executive Management

Jeff Hart

Acting Chief Financial Officer

Responsible for the financial management of Husky, including Controllers, Treasury, Tax, Credit and Internal Audit.

Career History and Key Accomplishments

Appointed as Acting Chief Financial Officer in April, 2018, Mr. Hart has extensive experience in progressively senior Finance roles at Husky.

Prior to his appointment, Mr. Hart was the VP, Controller for Husky, leading Upstream and Downstream Finance, Finance Process Governance and Projects, as well as Corporate Accounting and Reporting.
He joined the Company in September 2010, serving as Finance Manager for the Heavy Oil and Gas and Atlantic business units. He was promoted to Upstream Controller in October 2012. Prior to joining Husky, Mr. Hart held finance and commercial positions at Statoil and Imperial Oil.

Education

Mr. Hart has a Bachelor of Commerce degree from Saint Mary's University, Halifax, with finance and accounting majors.

Professional Memberships, Associations and Designations

Mr. Hart is a Chartered Accountant and a member of the Canadian Institute of Chartered Accountants.

Executive Management

Robert W.P. Symonds

Chief Operating Officer

Responsible for leading Husky’s Upstream (excluding Asia Pacific) and Downstream businesses, Mr. Symonds is also responsible for Exploration, Safety, Engineering and Procurement.

Career History and Key Accomplishments

Mr. Symonds was appointed Chief Operating Officer in February 2017. Previously, he held the role of Senior Vice President, Western Canada Production. Prior to joining Husky in 2011, he was Vice President, Canadian Operations with Enerplus Resources Fund in Calgary.

Mr. Symonds started his career with Shell, where he held a number of engineering and production/development-related roles in Western Canada, the North Sea, off Canada’s East Coast and Calgary. His senior level assignments included Vice President, Foothills Business Unit; Director of Corporate Strategies; and Vice President, Frontier Business Unit.

Education

Mr. Symonds holds a Master of Science in Petroleum Engineering from the University of Alberta and a Bachelor of Science (Chemical Engineering) from the University of Edinburgh.

Professional Memberships, Associations and Designations

Mr. Symonds holds a Professional Engineer designation and is a member of the Society of Petroleum Engineers.

Executive Management

James D. Girgulis

Senior Vice President, General Counsel & Secretary

Responsible for the legal function of the Company.

Career History and Key Accomplishments

Mr. Girgulis joined Husky in 1994 and was appointed to the position of Vice President, Legal & Corporate Secretary in 2000. He was previously General Counsel and Corporate Secretary of Husky Oil Ltd.

In 2012, he was made Senior Vice President, General Counsel & Secretary.

Education

Mr. Girgulis graduated from the University of Calgary with a Bachelor of Arts (Honours) in Sociology in 1978 and from the University of Alberta Law School with an LL.B. in 1981. He was appointed Queen's Counsel (Q.C.) in 2005.

Executive Management

Janet E. Annesley

Senior Vice President, Corporate Affairs

Responsible for the development of Husky's strategies and engagement approach with internal and external business stakeholders on sensitive or high profile issues having potential for significant strategic business and reputation impact.

Career History and Key Accomplishments
Ms. Annesley joined Husky from the Government of Canada, where she was Chief of Staff to the Minister of Natural Resources.

Prior to serving in government, Ms. Annesley worked at Queen's University, as a Vice President at the Canadian Association of Petroleum Producers. She spent 10 years at Shell Canada working in a variety of government relations, communications and stakeholder relations roles.

Education
Ms. Annesley holds a degree in Applied Communications from Mount Royal College, and Masters of Business Administration degrees from Queen's University and Cornell University.

Professional Memberships, Associations and Designations
Ms. Annesley is a fellow of the Royal Canadian Geographical Society, and is an Accredited Business Communicator with the International Association of Business Communicators.

Executive Management

Jeffrey E. Rinker

Senior Vice President, Downstream

Responsible for leadership and management of Husky's Downstream business.

Career History and Key Accomplishments

Mr. Rinker joined Husky in February 2017 as VP Downstream Value Chain with responsibility for crude oil and gas marketing, hydrocarbon supply chain planning and optimization, refinery feedstock supply, and U.S. refined product sales.

He came to Husky from the Austrian integrated oil company OMV, where he was a Senior Vice President for 11 years including assignments as director of Romanian Refining & Petrochemicals, manager of Integrated Value Chain, and most recently as the head of M&A.

Prior to that, he worked at BP for 16 years in various technical and management roles, including as the Optimization manager for the Toledo refinery of which Husky now owns half.

He has also held several board positions in the industry, including as a Director of PARCO, the largest oil refinery in Pakistan.

Education

Mr. Rinker graduated as a Chemical Engineer with honors from Carnegie Mellon University in 1989.

Executive Management

P. Andrew Dahlin

Senior Vice President, Heavy Oil & Oil Sands

Responsible for the management and expansion of Husky's growing heavy oil and oil sands portfolio.

Career History and Key Accomplishments
Mr. Dahlin was appointed Senior Vice President of Heavy Oil in 2017.

Prior to this appointment, he was Vice President of Operations & Projects in Western Canada, where he was a core contributor to delivering the transformation of Husky's Western Canada business.

Before joining Husky in 2011, Mr. Dahlin had a 19-year career with Shell (Europe, Middle East, Canada) in progressively senior technical, operational, commercial and management roles in their Upstream business.

Education
Mr. Dahlin holds a Master of Science in Petroleum Engineering from Imperial College in London, U.K., and a Bachelor of Engineering in Civil Engineering from the University of Surrey, U.K.

Executive Management

Carmen C. Lee

Vice President, Oil Sands

Responsible for the development and operations of the Sunrise asset.

Career History and Key Accomplishments

Dr. Lee was appointed Vice President of Oil Sands in 2018. Prior to this appointment, she was the Director of Planning for Upstream and Downstream where she led the development of the Long Range Plan. She joined Husky in 2008 as a geologist for Tucker Lake and progressed through senior roles before becoming the Tucker Lake Asset Manager in 2012.

Prior to joining Husky, Dr. Lee worked for Canadian Natural Resources as a geologist in thermal in-situ development and operations. Dr. Lee started her career in the mining industry as a field geophysicist working in remote areas in Alaska, Yukon Territories, and Nunavut.

Education

Dr. Lee holds a Doctorate of Philosophy in Sedimentology from the Postgraduate Research Institute for Sedimentology at the University of Reading, United Kingdom and a Bachelor of Science in Geology from the University of Calgary.

Professional Memberships, Associations and Designations

Dr. Lee is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA) and the Canadian Society of Petroleum Geologists (CSPG).

Executive Management

Gerald F. Alexander

Senior Vice President, Western Canada Production

Responsible for the leadership and management of Husky’s Upstream business in Western Canada, excluding Heavy Oil and Oil Sands.

Career History and Key Accomplishments

Mr. Alexander was appointed Senior Vice President, Western Canada Production in February 2017. Prior to his appointment, he was Vice President, Western Canada Development.

Mr. Alexander started his oil and gas career with Mobil Oil and Amerada Hess where he held a number of production/operations related roles in Western Canada. He joined Husky in 2000, after Husky acquired Renaissance Energy where Mr. Alexander was Chief Production Engineer. He has held progressively senior positions in production and development, including Manager of Ram River operations and General Manager of the Southern Alberta, South Saskatchewan business unit.

Education

Mr. Alexander holds a Bachelor of Science in Petroleum Engineering from the University of Montana and a diploma in Petroleum Technology from the Southern Alberta Institute of Technology.

Professional Memberships, Associations and Designations

Mr. Alexander is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA) and the Professional Engineers and Geoscientists of Saskatchewan (APEGS).

Executive Management

Trevor Pritchard

Senior Vice President, Atlantic

Reporting to the Chief Operating Officer, Mr. Pritchard is responsible for Husky's Atlantic region.

Career History and Key Accomplishments

Mr. Pritchard was appointed Senior Vice President, Atlantic Region in January 2018. Prior to his appointment, he was Vice President of Process and Occupational Safety, overseeing the Company's operational integrity and ensuring a safe work environment, and before that, General Manager, Operations in the Atlantic Region.

Before joining Husky, Mr. Pritchard worked at BP Shipping and at Northern Marine on the Seillean floating production, storage and offloading (FPSO) vessel project, becoming the Operations Chief Engineer. At Bluewater Services (UK) he had positions as Project Manager, Offshore Installation Manager and General Manager responsible for four FPSOs. He has supported the offshore industry on steering committees for the UK Step Change in Safety initiative and on sub-committees with the United Kingdom Offshore Operators Association.

Education

Mr. Pritchard has a master's degree in Risk Crisis and Disaster Management from Leicester University.

Professional Memberships, Associations and Designations

Mr. Pritchard is a qualified Chief Engineer for international seagoing vessels.

Executive Management

Robert M. Hinkel

Chief Operating Officer, Asia Pacific

Responsible for managing Husky's Asia Pacific assets, including China and Indonesia operations, exploration, new business development and commercial activity.

Career History and Key Accomplishments

With more than 35 years experience in the energy and mining industries, Mr. Hinkel joined Husky in 2010 as Chief Operating Officer, Asia Pacific. Prior to joining Husky, he held positions including President and CEO of Enventure Global Technology, a subsidiary of the Shell Group and President and CEO of Molycorp, the minerals and mining subsidiary of Unocal Corporation.

Mr. Hinkel has published articles and technical papers on the topics of Arctic drilling, commercialization of new technology, contractor safety management, and continuous operational Improvement.

Education

Mr. Hinkel graduated magna cum laude from the University of Texas at Austin with a Bachelor of Science Degree in Petroleum Engineering. He subsequently earned an MBA in International Management from Thunderbird University in Phoenix, Arizona.

Professional Memberships, Associations and Designations

Society of Petroleum Engineers (SPE), Lifetime Member

Executive Management

Bradley H. Allison

Senior Vice President, Exploration

Responsible for the leadership of Husky's exploration-related business, including geological and geophysical services.

Career History and Key Accomplishments

Mr. Allison was appointed Vice President, Exploration in June 2010 with responsibilities for resource capture and appraisal within the Western Canada Basin, Canadian Frontier and International regions, as well as geological and geophysical services and business development. Prior to his appointment, he was General Manager, Canadian/International Exploration. Mr. Allison joined Husky in 2002 as Deep Basin Exploration Manager. In 2012, he was made Senior Vice President.

Prior to joining Husky, Mr. Allison was Vice President and Chief Geoscientist with Advantage Energy Services Ltd. focusing on asset optimization and M&A evaluations. Mr. Allison started his career with Imperial Oil Limited, where he held a number of technical and management-related roles involving Western Canada exploration, Canadian Frontiers and Oil Sands. He also worked on an assignment with Esso UK working in the Central North Sea on both exploration and development projects.

Education

Mr. Allison holds a Bachelor of Science (Honours) in Geology from Mount Allison University.

Professional Memberships, Associations and Designations

Mr. Allison holds a Professional Geologist designation and is a member of the CSPG and AAPG.

Executive Management

Nancy F. Foster

Senior Vice President, Human & Corporate Resources

Responsible for Human Resources, Diversity, Real Estate, Corporate Services, Information Services and Corporate Responsibility.

Career History and Key Accomplishments

Appointed as Vice President, Human & Corporate Resources in 2011, Ms. Foster is an experienced human resources practitioner with extensive oil and gas experience, both domestically and internationally. In 2012, she was made Senior Vice President.

Prior to that, she was the Senior Vice President, Human Resources and Corporate Services at Nexen, responsible for strategic oversight and operation of all human resources functions for a global employee base. She also provided oversight of the supply management and corporate administration functions.

Education

Ms. Foster holds a Bachelor of Arts degree from McMaster University and is a graduate of the Harvard Advanced Management Program.

Professional Memberships, Associations and Designations

Ms. Foster has served on a number of industry-related committees, including the Alberta Economic Development Authority, CAPP and the Conference Board of Canada. She has worked on numerous charitable committees, including the Alberta Children’s Hospital Foundation, Child & Youth Friendly Calgary, Hospice Calgary, the United Way of Calgary & Area, and the YWCA of Calgary. Ms. Foster has been a member of the International Women’s Forum since 2012.

Executive Management

David A. Gardner

Senior Vice President, Business Development

Reporting to the CEO, Mr. Gardner is responsible for leading business development activities across Husky and building the Company’s capability and capacity in this strategic area.

Career History and Key Accomplishments

Mr. Gardner was appointed Senior Vice President, Business Development at Husky in December 2014. Before coming to Husky, he had a nearly 17-year career with BP, most recently as Director of Upstream Business Development, Europe & Africa, in London, United Kingdom.

Prior to that he was Vice President Business Development, Exploration Access, in London.

Previous BP roles included Mergers & Acquisitions Project Manager in Houston, Texas; Commercial Manager in Cairo, Egypt; and Strategy, Planning & Performance Manager in the Group Business Centre in London.

Education

Mr. Gardner has a Bachelor of Science with a Geology major and a German minor from The College of William and Mary in Virginia; a Masters in Geology from the University of Wisconsin — Madison; and an MBA, Finance & Entrepreneurship, from University of California, Los Angeles — The Anderson Graduate School of Management.

Professional Memberships, Associations and Designations

Mr. Gardner is a member of the Association of International Petroleum Negotiators.

Executive Management

Terry J. Manning

Senior Vice President, Engineering, Procurement & Project Management

Responsible for engineering, procurement and project management.

Career History and Key Accomplishments

Mr. Manning was appointed Senior Vice President, Engineering, Procurement and Project Management in May 2018. Prior to this, he was Senior Vice President, Safety, Engineering and Procurement. In his new role, Mr. Manning will have the responsibility for major projects.

Before joining Husky, Mr. Manning was Vice President, Capital Projects for Barrick Gold Corporation where he had accountability for Barrick's portfolio of megaprojects and development of project business systems. From 2002 to 2006, Mr. Manning was General Manager, Project Management Office with Suncor Energy Inc.

Mr. Manning has worked for Agrium, where he was Director of Projects, focused primarily on international project development, and prior to that at Cominco Ltd. where he started his career.

Education

Mr. Manning holds a Bachelor of Applied Science in Mechanical Engineering from the University of Toronto.

Professional Memberships, Associations and Designations

Mr. Manning is a member of Association of Professional Engineers and Geoscientists of Alberta (APEGA) and Professional Engineers and Geoscientists of British Columbia (APEGBC).

Executive Management

Jerry P. Miller

Vice President, U.S. Refining

Career History and Key Accomplishments

Mr. Miller was appointed Vice President, U.S. Refining in October 2015. As Vice President and General Manager of the Lima Refining Company, he is responsible for refining operations in the United States, including the Lima Refinery and the Superior Refinery. Mr. Miller was previously Husky's General Manager of the Lloydminster Upgrader in Alberta/Saskatchewan, Canada.

Mr. Miller joined Husky in 2008 as General Manager of U.S. Refined Products and New Ventures at the Husky Marketing and Supply business unit located in Columbus, Ohio. Before joining Husky, he was the General Manager of Asphalt and Energy Operations with Oldcastle Materials Group in Columbus, Ohio.

Mr. Miller retired from the United States Army National Guard as a Lieutenant Colonel. He served as an active duty infantry officer, airborne ranger and an instructor at the elite ranger school. Throughout his military career, Mr. Miller led several overseas deployments. In addition to earning the elite U.S. Army Ranger tab, he also received the Bronze Star and the Combat Infantry Badge.

Education

Mr. Miller holds a Master of Business Administration from Penn State University and a Bachelor of Science in Accounting from the University of Pittsburgh.

Professional Memberships, Associations and Designations

Mr. Miller currently serves the AFPM Board of Directors, and the AFPM Issues Committee. He has worked on numerous charitable committees, including the United Way, and the YMCA.

Investor Relations Contacts

Dan Cuthbertson
Director, External Communications and Investor Relations
dan.cuthbertson@huskyenergy.com

Rob Knowles
Senior Manager, Investor Relations
rob.knowles@huskyenergy.com

Todd McBride
Senior Investor Relations Analyst
todd.mcbride@huskyenergy.com

Contact us at www.huskyenergy.com
investor.relations@huskyenergy.com
1-855-527-5005