Corporate Presentation

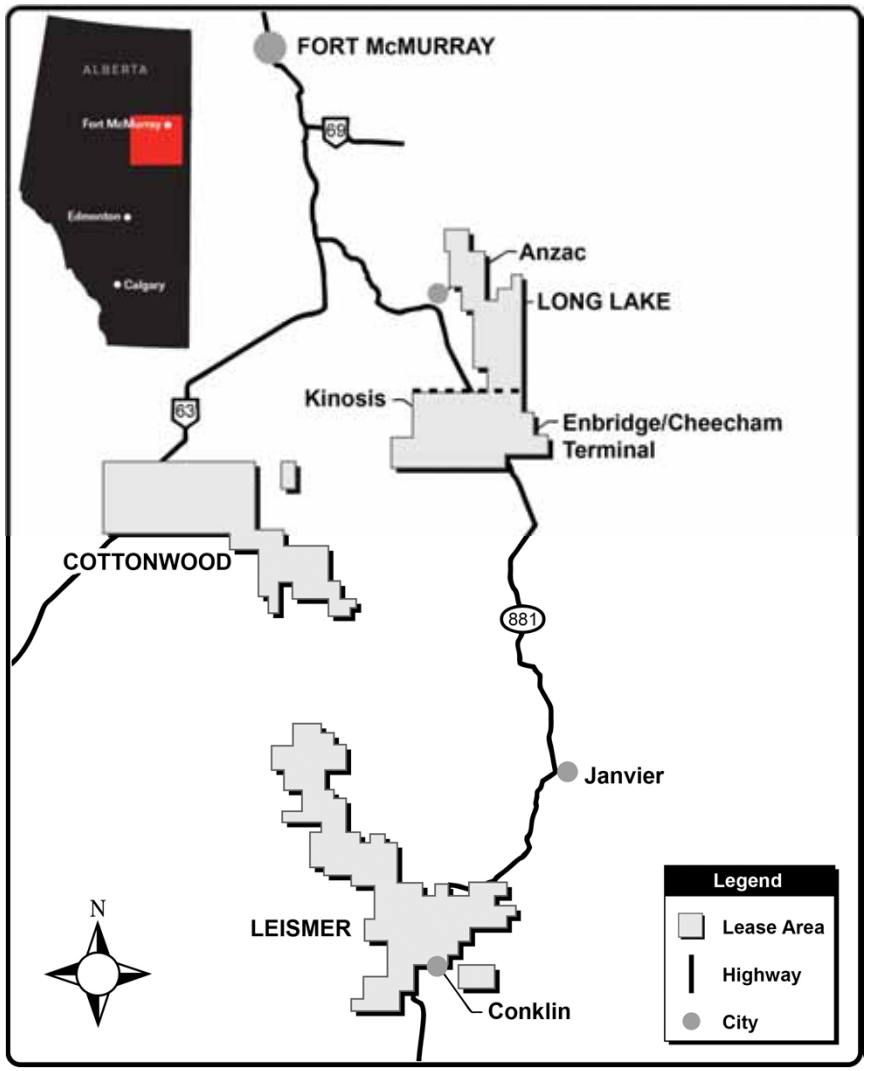
June 2011

OPTI CANADA INC.

Forward-looking information

- ***Reserves & Resources Estimates:*** The estimates of resources and of economically recoverable bitumen reserves contained herein are forward-looking statements. The estimates are based upon a number of factors and assumptions made as of the date on which the reserve and resource estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of regulation by governmental agencies and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. The estimates contained herein with respect to reserves and resources that may be developed and produced in the future have been based upon volumetric calculations and upon analogy to similar types of reserves and resources, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves and resources based upon production history will result in variations, which may be material, in the estimated reserves and resources.
- ***Other Forward-Looking Statements:*** Certain other statements contained herein are forward-looking statements, including statements relating to: OPTI's operations; anticipated financial performance; business prospects, expansion plans and strategies; OPTI's plans and expectations concerning the use and performance of the OrCrude™ Process and other related technologies; the cost, development and operation of the Long Lake Project and OPTI's relationship with Nexen Inc. Statements concerning resources and reserves are also forward-looking statements, as they reflect estimates as to the volume and nature of petroleum deposits that are expected to be found present when a project is developed, and, in the case of reserves, the expectation that the deposits can be economically exploited in the future. Forward-looking information typically contains statements with words such as “intends,” "anticipate," "estimate," "expect," "potential," "could" or similar words suggesting future outcomes. Readers are cautioned to not place undue reliance on forward-looking information because it is possible that expectations, predictions, forecasts, projections and other forms of forward-looking information will not be achieved by OPTI. By its nature, forward-looking information involves numerous assumptions, inherent risks and uncertainties. A change in any one of these factors could cause actual events or results to differ materially from those projected in the forward-looking information. Although OPTI believes that the expectations reflected in such forward-looking statements are reasonable, OPTI can give no assurance that such expectations will prove to be correct. Forward-looking statements are based on current expectations, estimates and projections that involve a number of risks and uncertainties which could cause actual results to differ materially from those anticipated by OPTI and described in the forward looking statements or information. The forward-looking statements are based on a number of assumptions which may prove to be incorrect. In addition to other assumptions identified herein, we have made assumptions regarding, among other things: market costs and other variables affecting operating costs of the Project; the ability of the Long Lake joint venture partners to obtain equipment, services and supplies, including labour, in a timely and cost-effective manner; the availability and costs of financing; oil prices and market price for the PSC output of the OrCrude™ Upgrader, foreign currency exchange rates and hedging risks; government regulations and royalty regimes; the degree of risk that governmental approvals may be delayed or withheld; other risks and uncertainties described elsewhere in this presentation or in OPTI's filings with Canadian securities authorities.
- Readers should be aware that the list of factors, risks and uncertainties set forth above are not exhaustive. Readers should refer to OPTI's current annual information form, which is available at www.sedar.com, for a detailed discussion of these factors, risks and uncertainties. The forward-looking statements or information contained in this news release are made as of the date hereof and OPTI undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable laws or regulatory policies.

Investment highlights



Long Lake Built & Producing

- Recent bitumen production approximately 28,300 bbl/d (gross)
- Upgrader producing hydrogen, oxygen, electricity, syngas & PSC™

Unique Position in Alberta Oil Sands

- Current production, near term expansion & long term growth
- Regulatory approval for 140,000 bbl/d of SAGD at Kinosis
- Bitumen production potential of 432,000 bbl/d (gross)

Addressing Financial Situation

- Low operating costs & high value sales products lead to strong margins
- Committed to strategic review to reduce leverage


➔ Long Lake: built & producing

Long Lake Project plant site

Long Lake Project up & running

Project ramping-up to expected peak capacity of 72,000 bbl/d bitumen upgraded to 58,500 bbl/d of PSC™ (~20,000 bbl/d net to OPTI)

- Plant producing all designed products: hydrogen, oxygen, electricity, syngas & PSC™
- Approximate 40 year 2P reserve life of the Project
- Anticipate that increased production & other operating enhancements will lead to improved net field operating margin (1)

(1) See Annual 2010 Management's Discussion & Analysis (MD&A) dated February 9, 2011 for full disclosure, risks & uncertainties.

Operations overview

Production ramp-up at SAGD & Upgrader facilities continues

Surface

- ➔ World class, state-of-the-art Upgrader operating, proving technology works
  - Syngas used to provide fuel, electricity & hydrogen
  - Produced over 11 million barrels of PSC™ - recent yield ~70-75%; expected to reach 80%
  - High on-stream time; 93% Q1 2011, 96% in April 2011
- ➔ Steam production ramping up
  - Recent steam injection rates of 132,000 bbl/d; expected capacity approximately 230,000 bbl/d

Subsurface

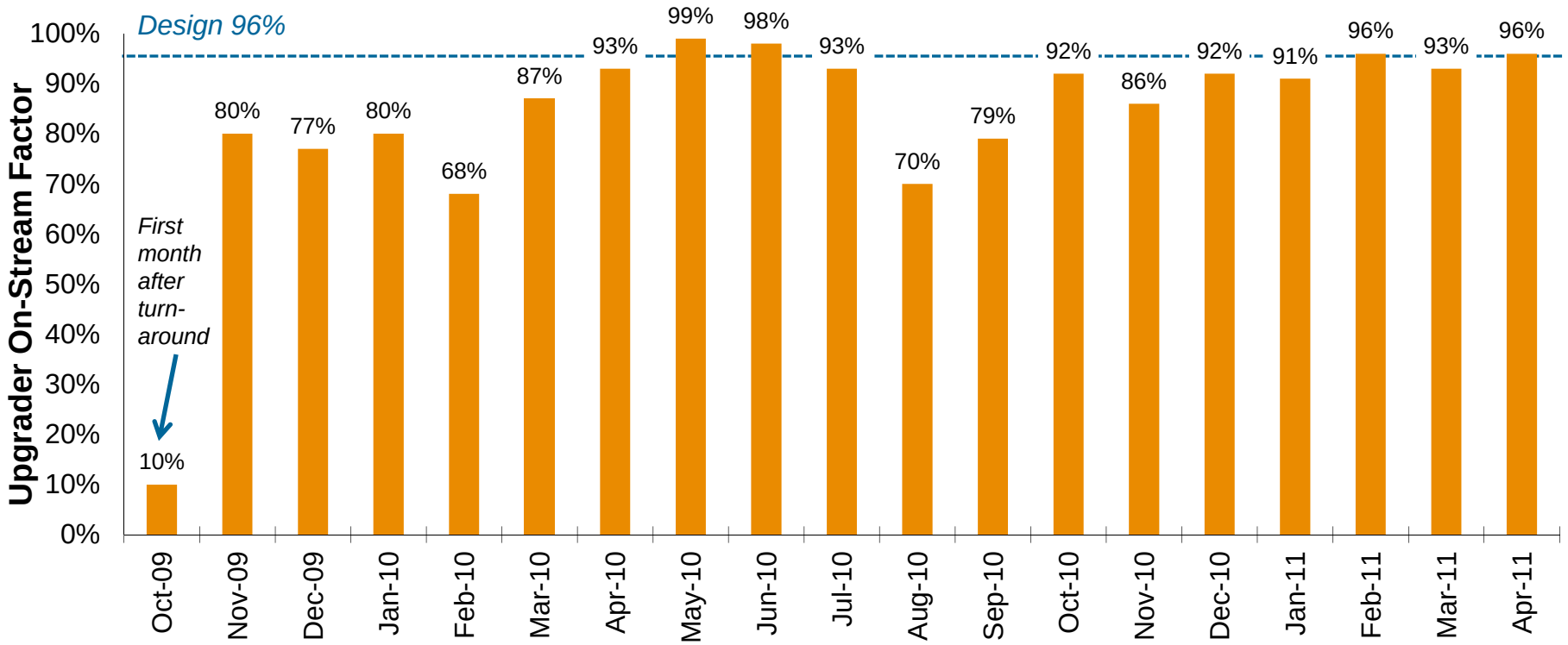
- ➔ Recent bitumen production rates approximately 28,300 bbl/d (gross)
- ➔ 83 well pairs capable of production, 6 currently in circulation mode
  - 90 well pairs expected to be capable of production by mid-year 2011
- ➔ Electric submersible pumps (ESPs) operational, allowing reduced operating pressure
  - Approximately 75 well pairs with ESPs, expect to install additional ESPs in 2011

PSC™ yield estimate includes butane. Produced PSC™ to April 2011. Recent steam rates as of April 24, 2011. Recent PSC™ yield as of late April 2011. Well pairs as of late April 2011. Recent bitumen production for week ending May 18, 2011.

Upgrader operational performance

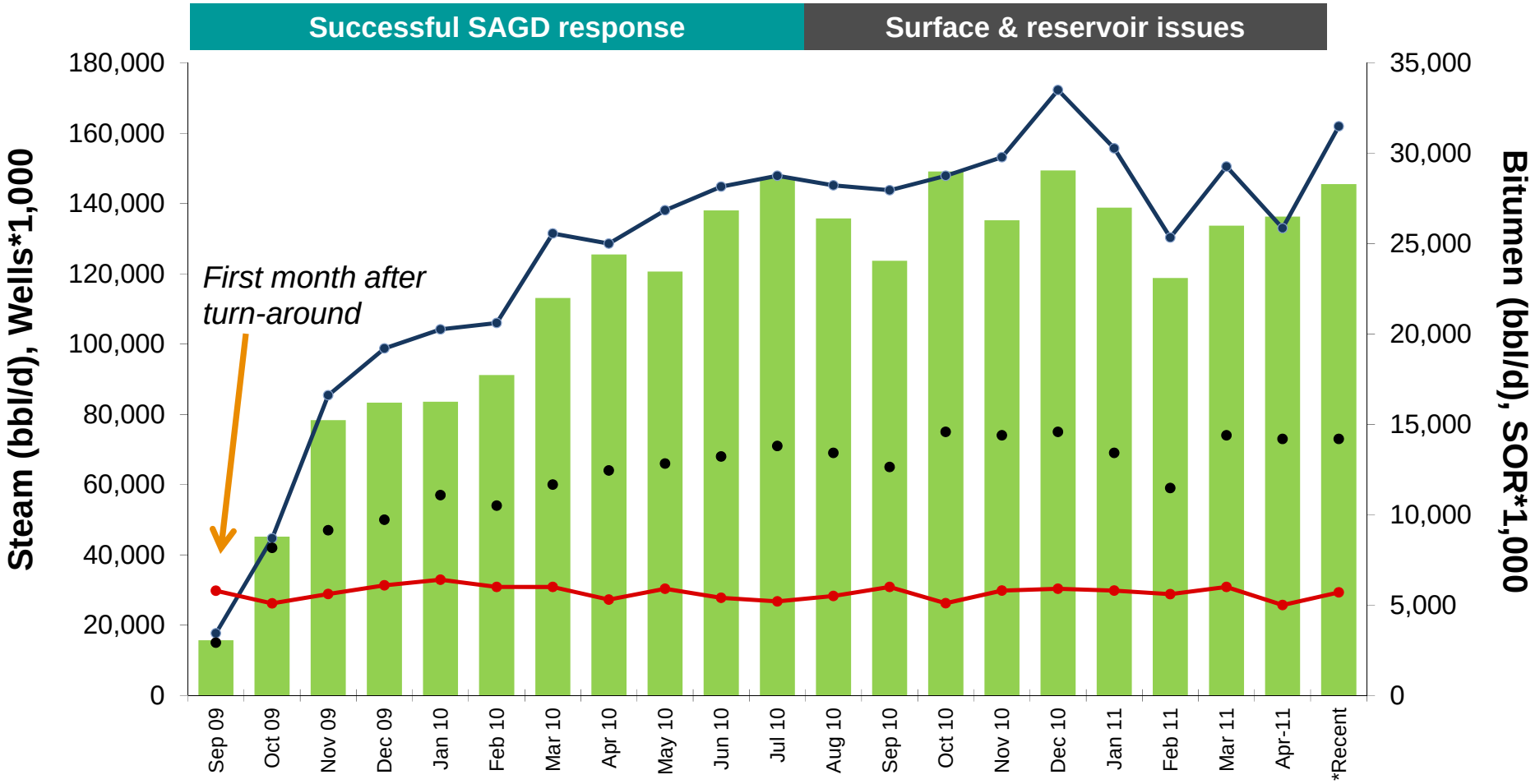
Upgrader on-stream time remains high and has improved substantially with operating experience

Upgrader On-Stream Factor



SAGD performance

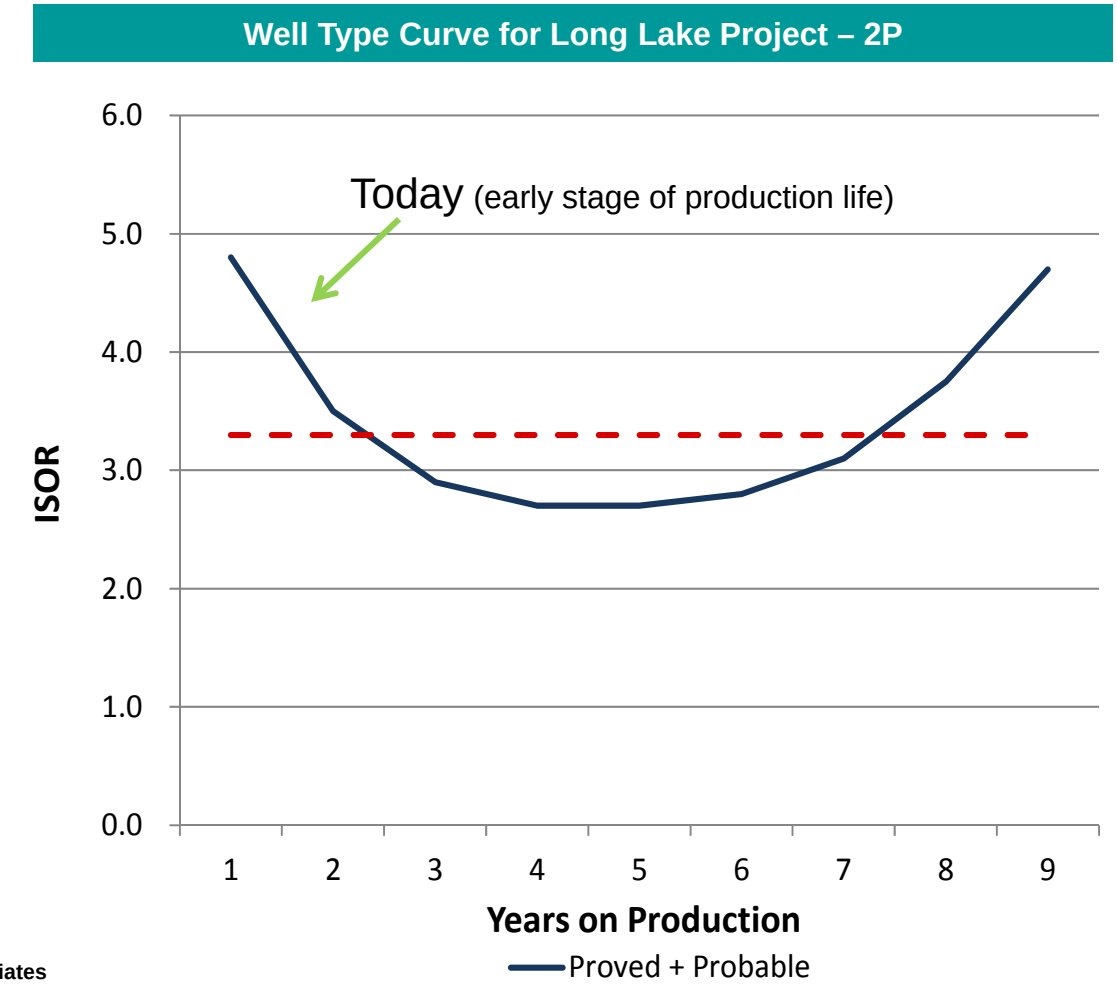
Working to resume ramp-up with consistent & reliable steam production



Bitumen, steam & SOR are monthly averages except for *Recent (estimated average week ended May 18, 2011).

SOR by well type

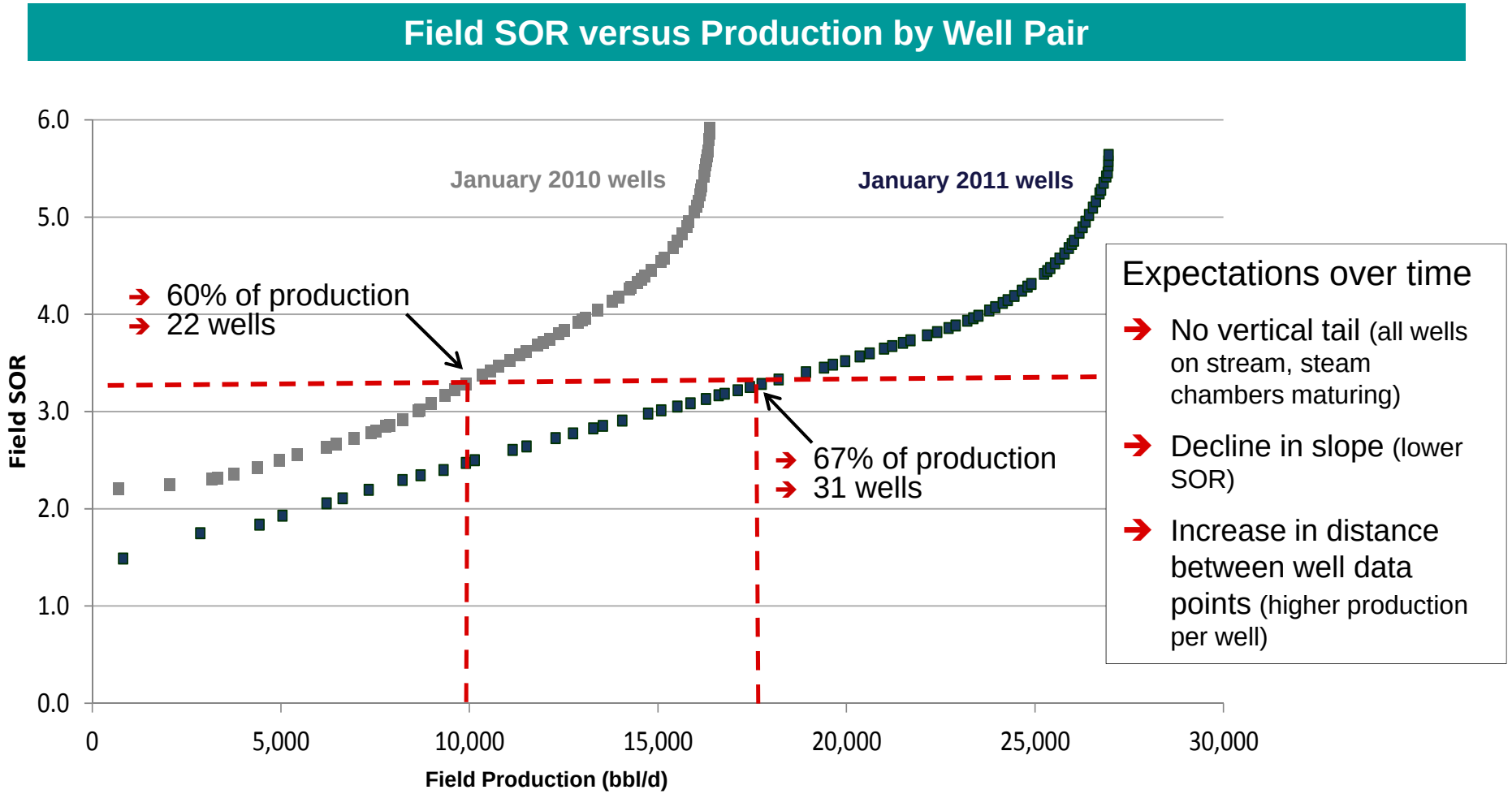
Typical SAGD well takes a number of years to reach optimal SOR



Source: McDaniel & Associates

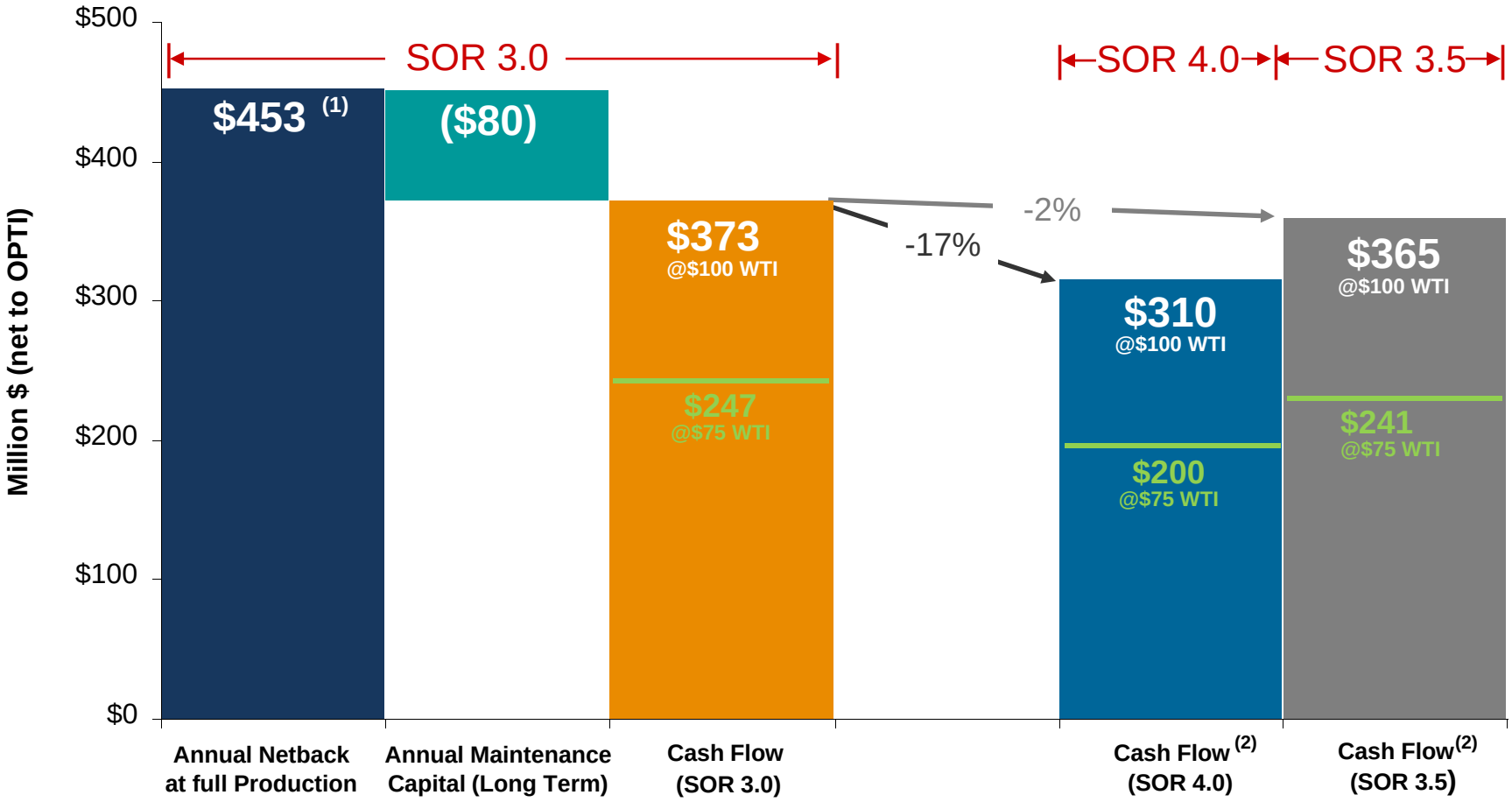
SOR & production

SOR improvements over one-year period



Reservoir sensitivities at full production

Long Lake generates strong cash flow at a broad range of SOR



(1) Cash flow is Annualized Netback (WTI US$100/bbl; F/X US$:CDN$ $1.00) less average long term annual maintenance capital
(2) One time facility modifications of ~$200 million (gross) are included
(3) See Annual 2010 MD&A dated February 9, 2011 for full disclosures

Project free cash flow

Facility reliability & bitumen production are key

- Positive field cash flow achieved in October & December 2010 at production of approximately 29,000 bbl/d
- Approximately 75% of our operating costs are fixed
- Expected increase in production is necessary to achieve improved net field operating margin

Achieving high bitumen production
is the single most important element to profitability

Returning to successful ramp-up

Multiple initiatives underway to increase bitumen production

Near Term (2011)

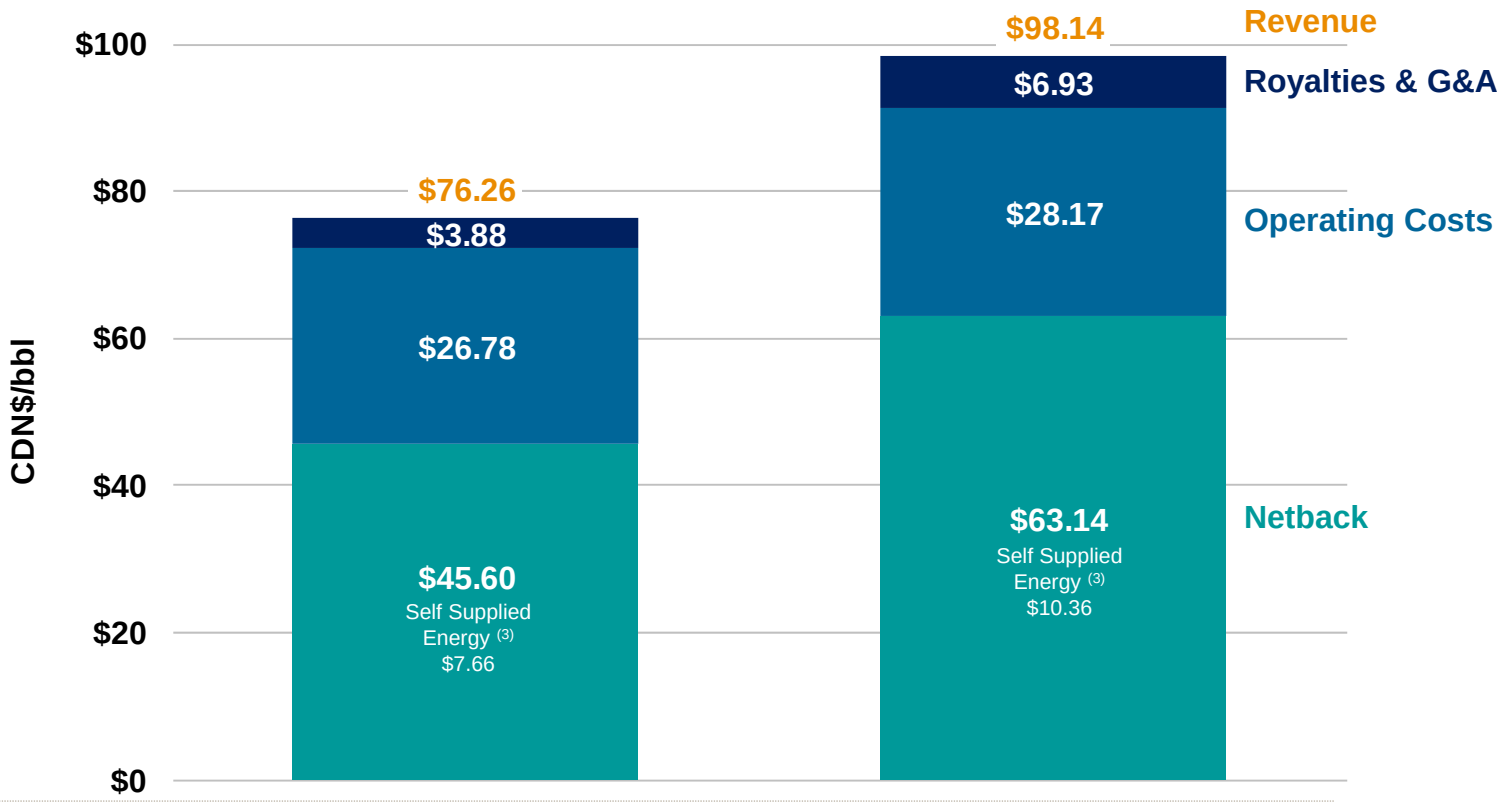
- ➔ Steam production & water treatment
  - Steam - Natural gas pipeline under construction
  - Water - Maintenance on remaining hot lime softener units
- ➔ Reservoir performance
  - Steam chambers developing; continue working through lean zones
  - Addition of well pairs

Longer Term (2012+)

- ➔ Underway - Construction of pads 12 & 13
  - 18 new well pairs
- ➔ Under consideration - Steam expansion project
- ➔ Under consideration - Diluent Recovery Unit (DRU)

Projected netbacks (1)

Strong netbacks at full production

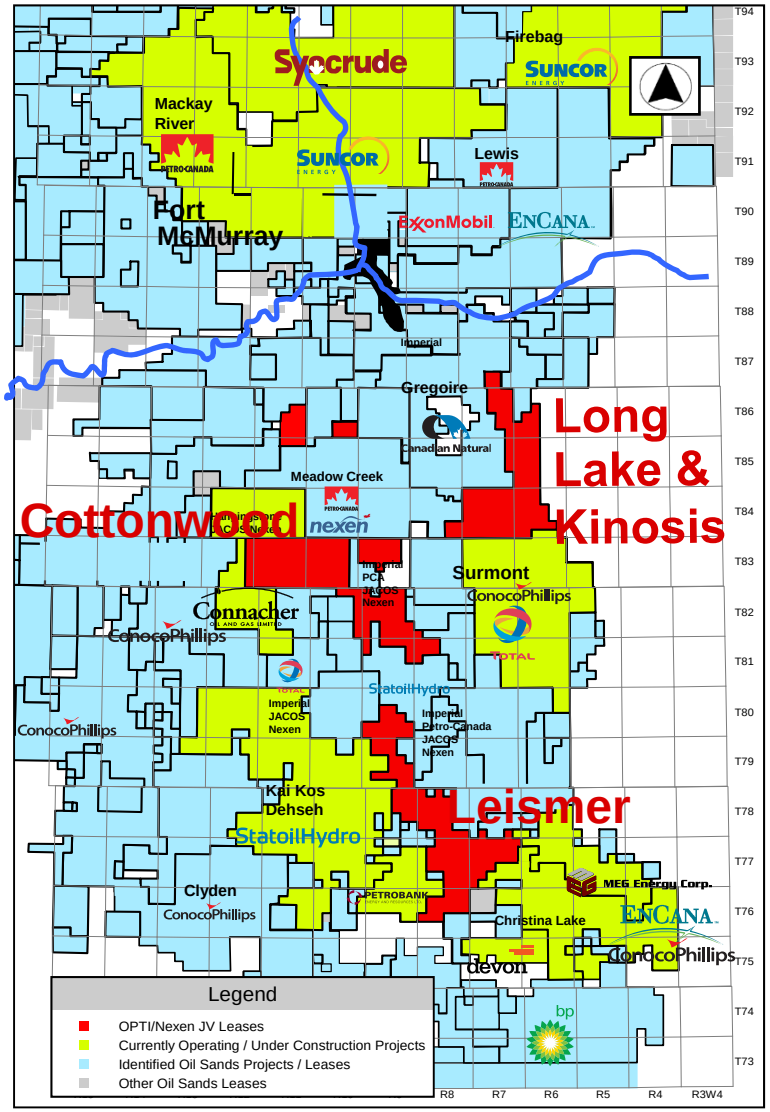


WTI in US$	**$75 / bbl**	**$100 / bbl**
Gas in US$	**$3.75 / mmbtu**	**$5.00 / mmbtu**
FX US$:CDN$	**$0.96**	**$1.00**
Heavy/Light Differential	**24% of WTI**	**22% of WTI**

(1) Pre-Payout netbacks. Refer to "Notes to Netback Slides" for additional assumptions
(2) Post-payout royalties estimated at $38.41 & $50.29 per bbl/d of PSC™ for US$75 WTI & US$100 WTI
(3) Total savings:
WTI US$75:Syngas - $4.13/bbl, Hydrogen - $1.30/bbl, Power - $2.23/bbl;
WTI US$100:Syngas - $5.67/bbl, Hydrogen - $1.78/bbl, Power - $2.91/bbl

- Significant asset value

World class joint venture

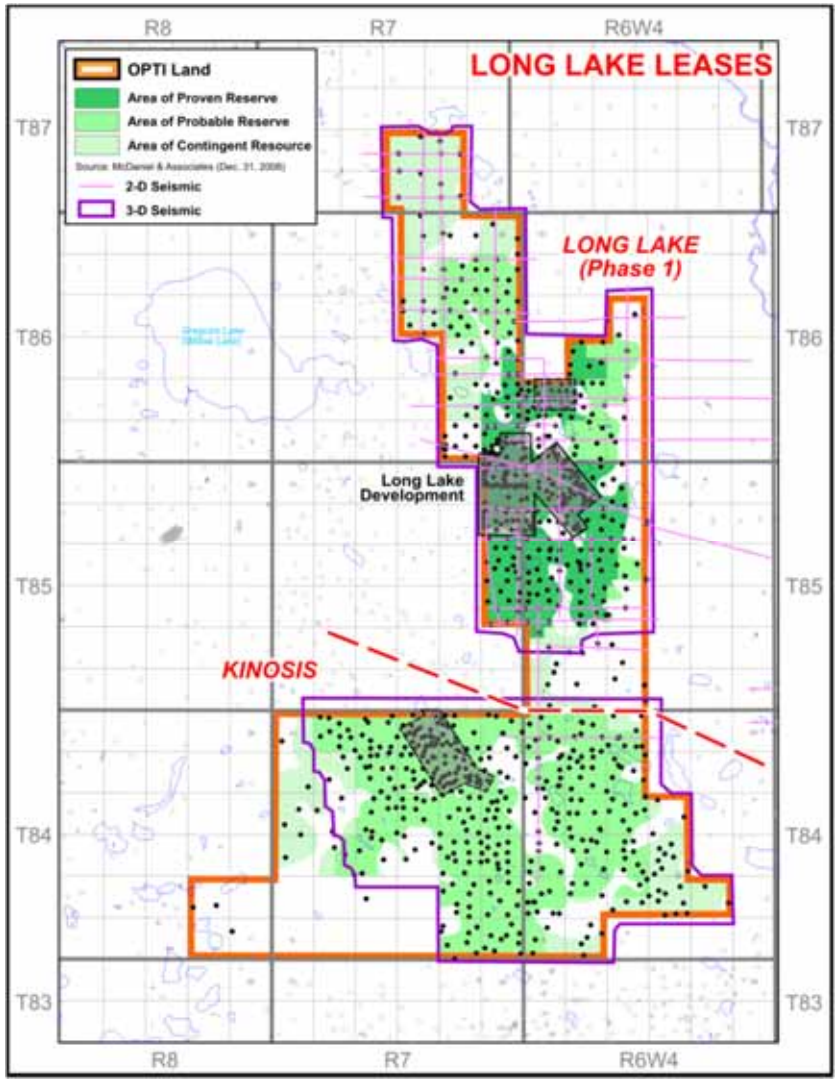


High value in-situ leases located in heart of Athabasca oil sands fairway

- Resource concentrated in 3 core land areas
- OPTI holds 35% working interest in each
- Resource estimate (1)
  - 729 MMbbl 2P Reserves
  - 1,100 MMbbl Contingent Resources (best estimate)
  - 335 MMbbl Prospective Resources (best estimate)

(1) See Annual 2010 MD&A - dated February 9, 2011 for full disclosures

Near term expansion • Kinosis



Planning 40,000 bbl/d (gross) SAGD stages for Kinosis

- Regulatory approval in place for 140,000 bbl/d (gross) of SAGD production
- Current economics favourable for SAGD expansions
- Ability to self-supply diluent
- Reserves & Resources (net to OPTI)
  - 390 MMbbl 2P Reserves
  - 152 MMbbl Contingent Resources (best estimate)

Future expansions • Kinosis

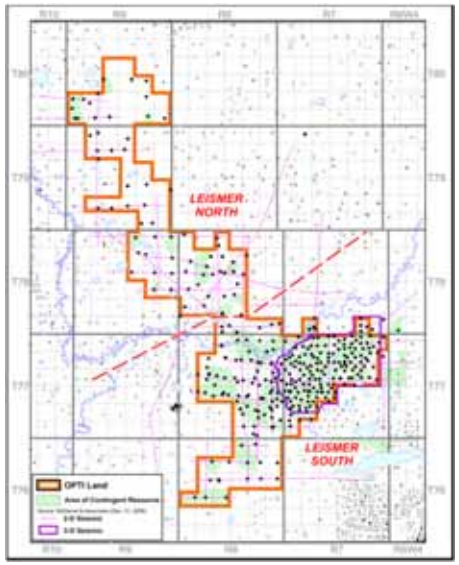
Kinosis represents an attractive near term expansion opportunity

- Ongoing planning of 40,000 bbl/d SAGD projects
  - Sanctioning decision expected in 2012
  - Current economic conditions favorable for SAGD development
- Simplified execution
  - Shorter development-to-production time
  - Smaller project improves site management & reduces capital
  - Ability to use operational expertise from Long Lake
- Spent approximately $21 million in Q1 2011 (to advance engineering & detailed execution plans)
  - At April 1, 2011 OPTI exercised deferred payment funding option to end of May 2011
  - OPTI retains all other rights for Kinosis under joint venture agreement

Future expansions • Leismer & Cottonwood

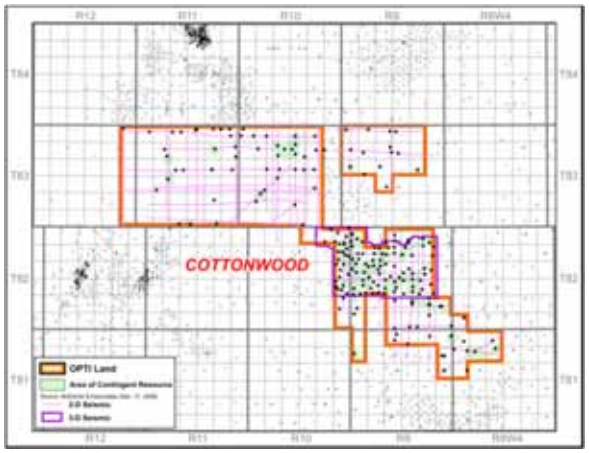
Potential for 216,000 bbl/d (gross) of SAGD production

Leismer



- Leismer & Cottonwood well-delineated with coreholes & 3-D seismic
  - 458 delineation wells on 275 sections
- Best estimate Resources (net to OPTI)
  - 798 MMbbl Contingent Resources
  - 335 MMbbl Prospective Resources

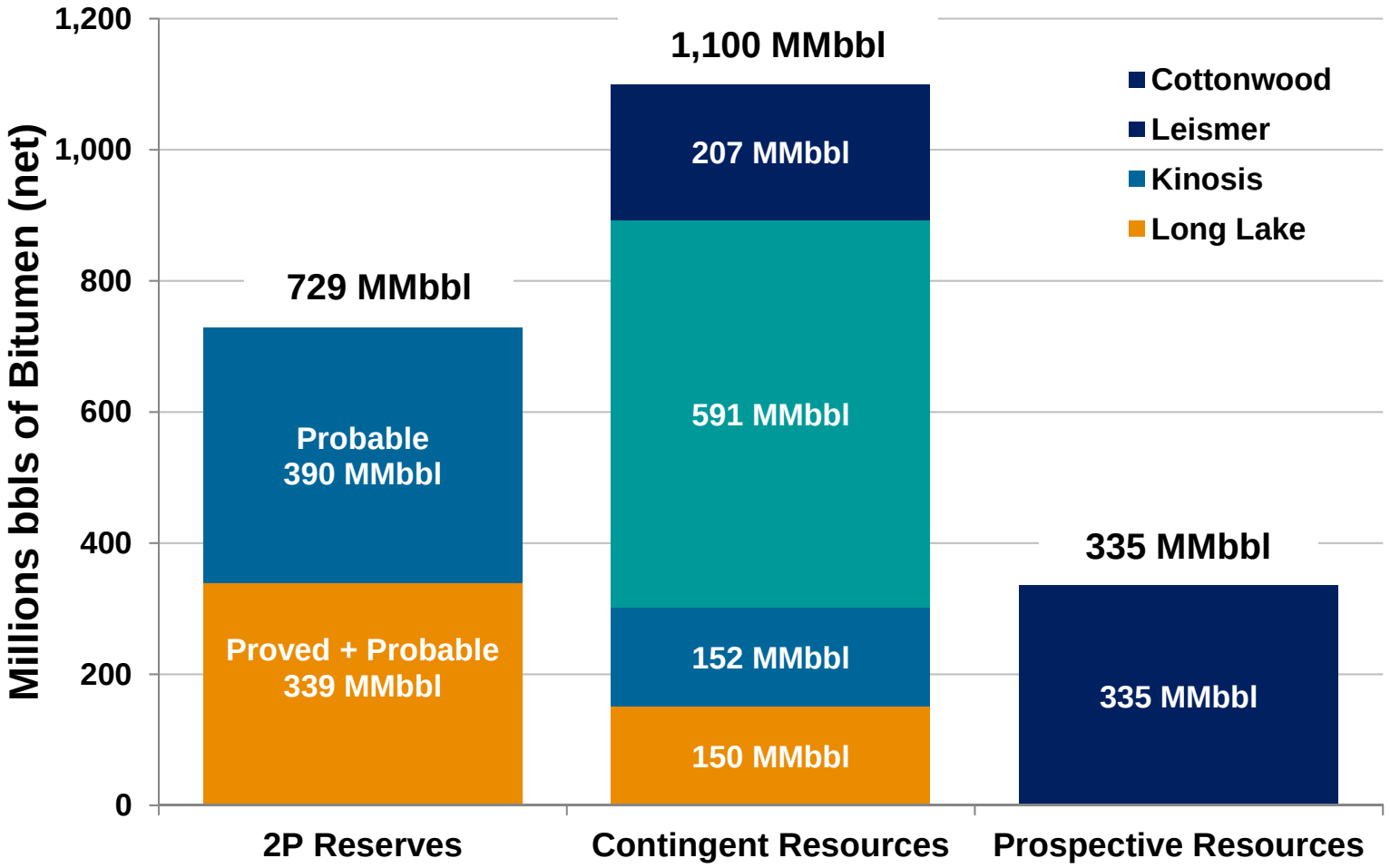
Cottonwood



- Leismer offset by Statoil Hydro's *Kai Kos Dehseh*, EnCana's & MEG's *Christina Lake,* Devon's *Jackfish*; Cottonwood offset by ConocoPhillips' *Surmont*, Jacos' *Hangingstone*, & Connacher's *Great Divide*

Significant reserves & resources

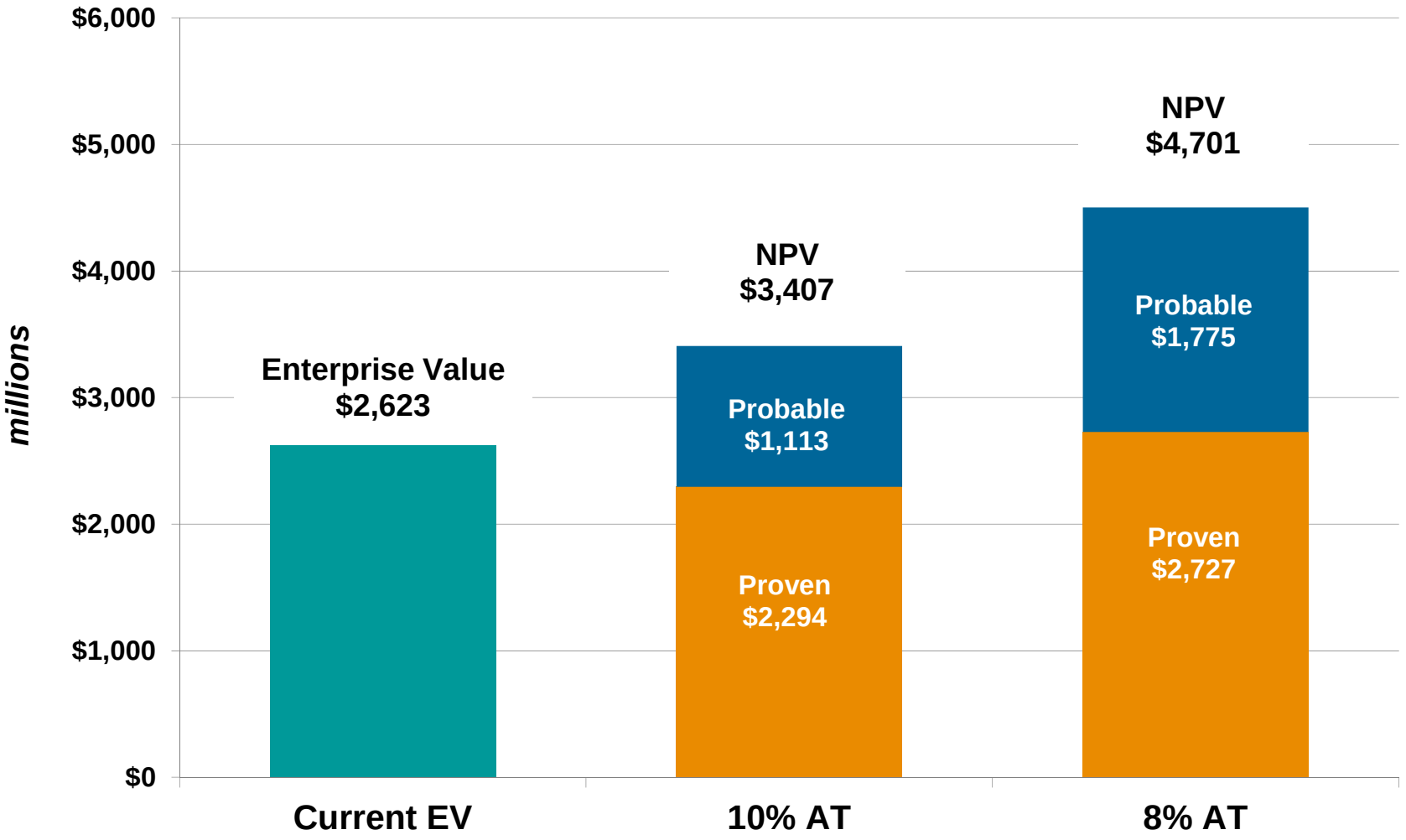
Significant proven + probable reserves & resources support growth



All amounts net to OPTI at December 31, 2010, as estimated by McDaniel & Associates.
Please refer to "Definitions and Cautionary Statements: Notes to Resource Slides" at the end of the presentation for additional information.

Significant reserves value

Enterprise Value vs. After Tax (AT) 2P Reserves NPVs (Long Lake & portion of Kinosis only)



NPV amounts net to OPTI at December 31, 2010, as estimated by McDaniel & Associates. Enterprise value as at March 31, 2011.
Please refer to "Definitions & Cautionary Statements: Notes to Resource Slides" at the end of the presentation for additional information.

- Financial situation

Current capitalization

Share price [1]	$0.24
Shares outstanding (basic)	282
Market capitalization	**$68**
Long-term debt [2] [6]	
Revolving credit facility [6]	$165
US$525 million 9% notes [4]	509
US$300 million 9.75% notes [5]	291
US$750 million 7.875% notes [3]	728
US$1,000 million 8.25% notes [3]	970
Working capital surplus [6]	(108)
Enterprise value	**$2,623**
Revolving credit facility (undrawn portion) [6]	25
Cash & cash equivalents [6]	287
Interest escrow account for 9.75% notes [2]	71
Liquidity [2] [6]	**$383**

All data presented in CAD $millions, except per share amounts

(1) As at close, March 31, 2011
(2) As at March 31, 2011 FX rate $1.00 CAD:$1.03 USD
(3) Due December 15, 2014
(4) Due December 15, 2012
(5) Due August 15, 2013
(6) As at March 31, 2011

Financial position

- Financial resources
  - Cash of $287 million at March 31, 2011
  - $190 million revolving credit facility with a maturity date in December 2011
    - $165 million drawn at March 31, 2011
  - Expected positive net field operating margin in 2011
  - Interest reserve account for US$300 million notes
- 2011 obligations
  - Interest payments on Senior notes of US$189 million
    - Excluding interest funded by our interest reserve account
  - Remaining capital budget of $97 million
    - Further costs may be approved in 2011
  - Remaining G&A costs of approximately $9 million
  - Potential foreign exchange hedging instrument liability of $102(1) million with a current maturity date of September 2011
- Pursuing a transaction under our Strategic Alternatives Review to address our leverage & liquidity position

(1) Accounting measurement at March 31, 2011

2011 capital budget

Priority: ramp-up bitumen production & improve project operations reliability

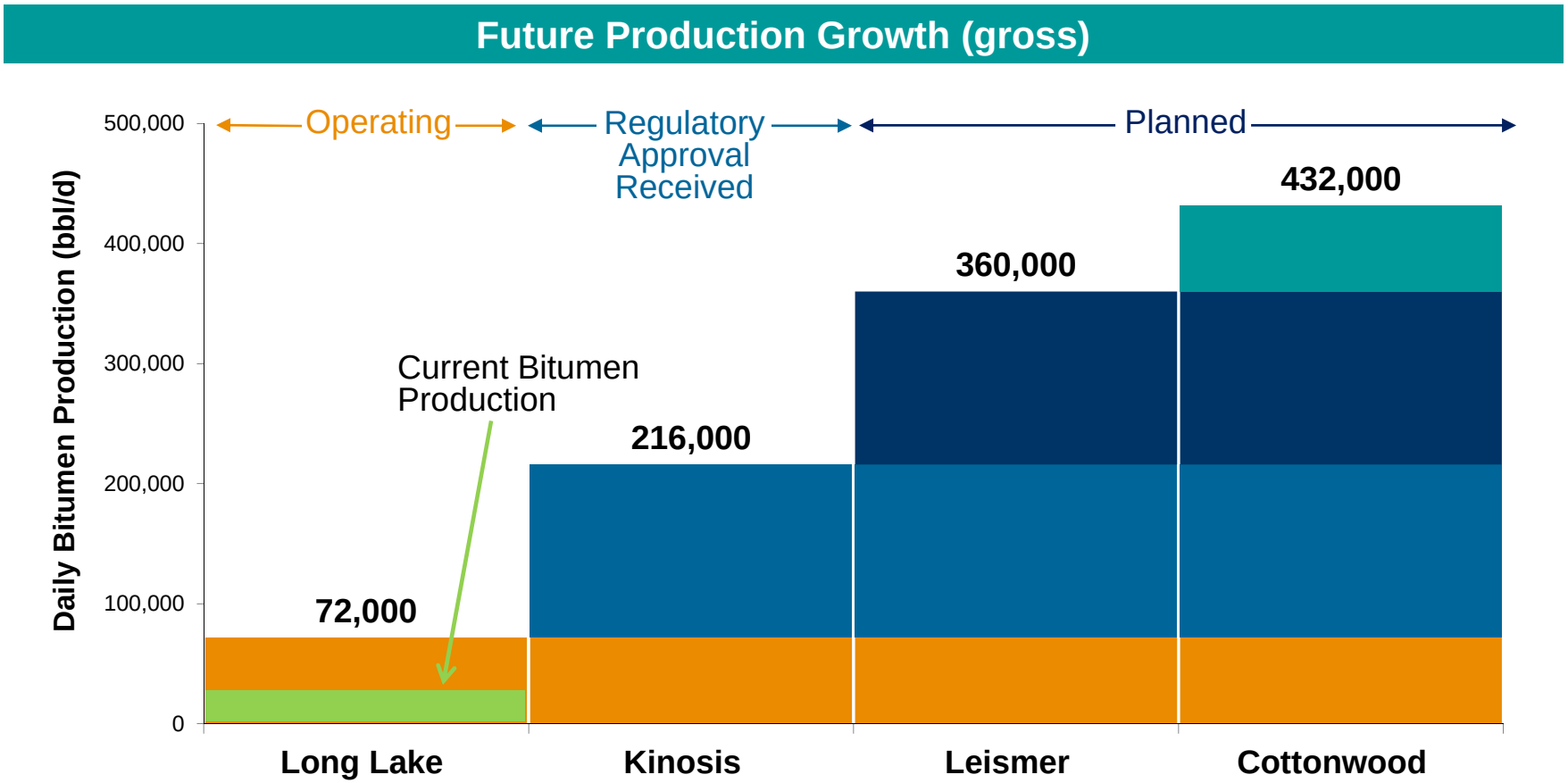
Capital Summary	
Long Lake	$122
Kinosis	$22
Leismer/Cottonwood	$6
Total	$150

- ➔ Long Lake
  - $53 million (net) for PAD 12 & 13
  - 15 down hole ESP installations (~90 ESPs in place by 2011 year end)
  - Engineering costs to evaluate additional steam capacity & Diluent Recovery Unit
- ➔ Kinosis
  - Principal spending on core hole delineation to end of March 2011
- ➔ Leismer/Cottonwood
  - Minimal spending
- ➔ Additional projects under evaluation
  - Steam expansion
  - Kinosis post March 2011
  - Diluent Recovery Unit (DRU)

Capital Summary net to OPTI. Table amounts in millions $CAD.

Moving forward

OPTI has a unique combination of current production, near term expansion & long term growth



Executing strategic alternatives review

- OPTI remains committed to its review of strategic alternatives for the Company to address its overall leverage position
- Strategic alternatives may include
  - Capital market opportunities
  - Asset divestitures &/or a corporate sale
  - Capital structure adjustments
- Scotia, TD & Lazard will work in a coordinated manner to review the full range of strategic options
- Our liquidity provides a limited timeframe to complete our review
- Our review is supported by
  - Expectations for production increases in 2011
  - Near term cash flow, approved expansion & long term development
  - Discounted enterprise value

Investment highlights

- Current production & high value sales product
- Significant asset value in Long Lake & future expansions
- Working toward Strategic Alternatives Review conclusion

➔ Appendix

OPTI quick facts

TSX Symbol	OPC
Market Capitalization (1)	$68 million
Enterprise value (1)	$2.8 billion
Shares outstanding (1)	282 million
2P Reserves	729 million bbl
Contingent resource	1,100 million bbl
Prospective resource	335 million bbl
Project bitumen design capacity	72,000 bbl/d (~25,000 bbl/d net to OPTI)
Project PSC™ design capacity	58,500 bbl/d (~20,000 net to OPTI)
Bitumen Production capacity (Project & future expansion developments)	432,000 bbl/d (~150,000 bbl/d net to OPTI)
Assets	Pure play oil sands development

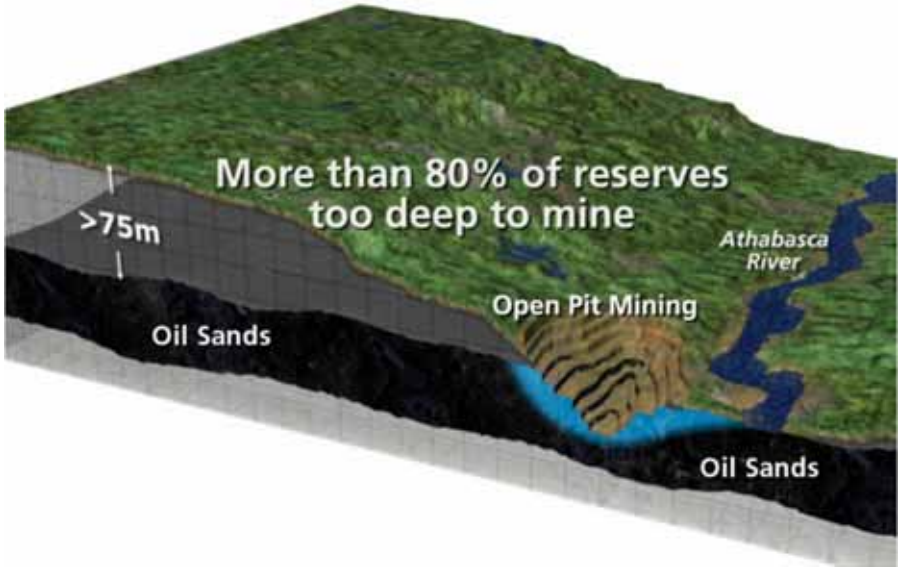
(1) As at March 31, 2011

OPTI Canada Inc. (TSX: OPC)

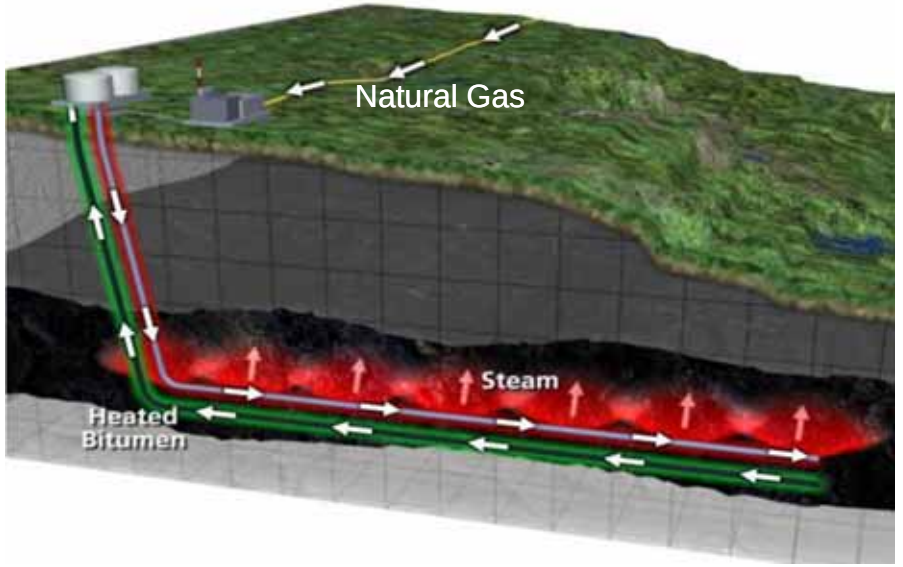
- Key corporate milestones
  - Established in 1999
  - Joint venture with Nexen in 2001 (Area of Mutual Interest in Athabasca area)
  - IPO 2004
  - SAGD start-up 2008
  - Upgrader start-up January 2009
- Business model
  - Focused on in-situ oil sands development in Alberta
  - Large resource base for future development

Oil sands recovery

Mining versus In-situ



SAGD Process



- SAGD
  - First tested in 1984 – improvements continuously made in existing commercial operations
  - Recycle 90% of water used to create steam
  - Relatively minimal disturbance to surface lands

OPTI's integrated solution

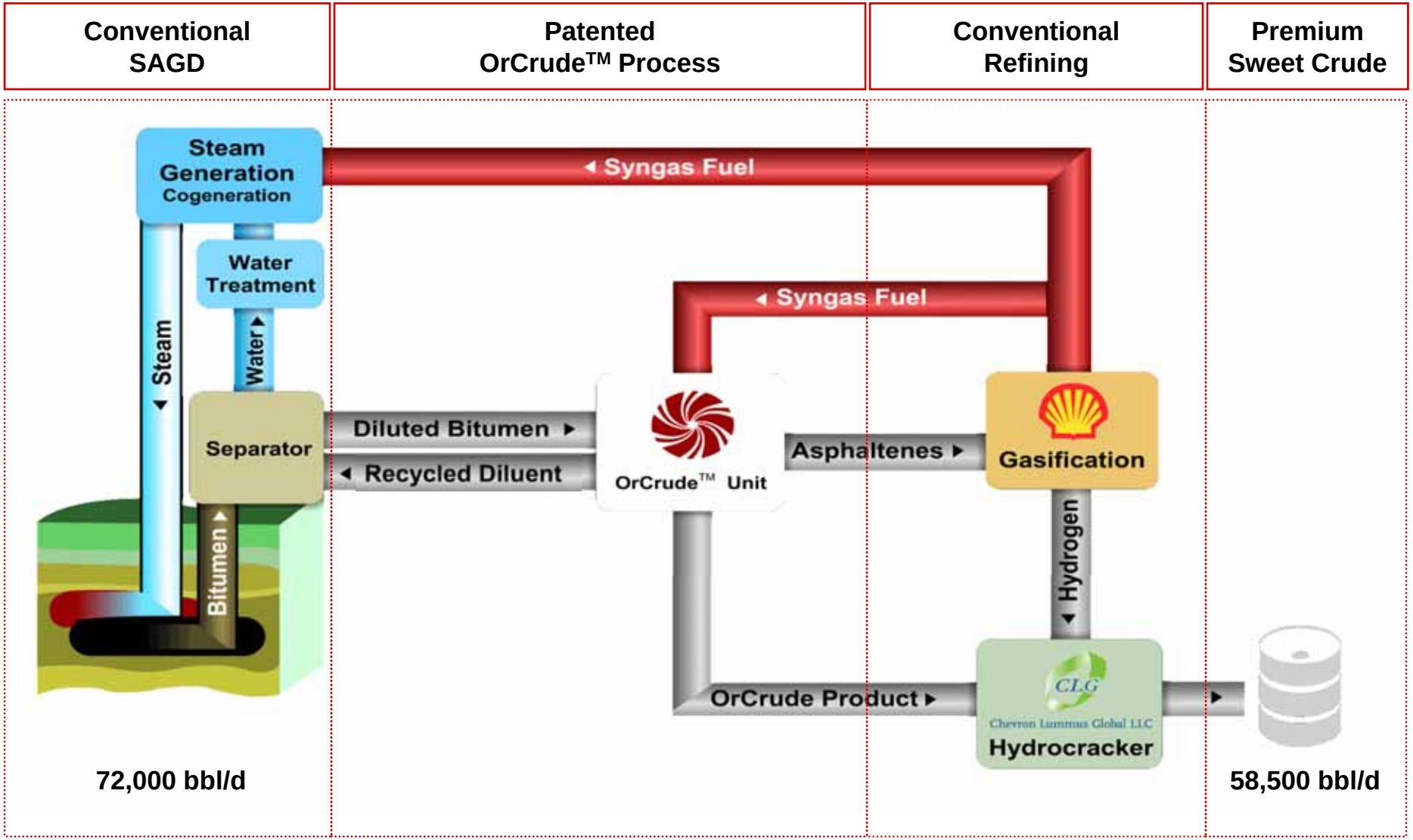
Challenges with Traditional SAGD

- Exposure to volatile natural gas costs
- Exposure to heavy oil differentials
- Exposure to rising diluent costs

OPTI's Integrated Solution

- Significantly reduced reliance on natural gas
- Integrated process will deliver 39^{o} API premium sweet crude oil
- No diluent required

Long Lake Project surface facilities



Premium product

PSC™ expected to receive premium pricing

- PSC™ expected to receive higher value relative to other synthetic crude oils as volumes continue to ramp up
- Two markets ensure strong sales price for PSC™
  - High demand by refineries due to superior characteristics
  - Used as diluent for bitumen producers
- The Project has produced over 11 million barrels(1) of the highest quality synthetic crude in North America

(1) From January 2009 to April 2011

In-situ reservoir comparison

Long Lake compares favourably with other major in-situ projects

Project	Pay Thickness (m)	Porosity (%)	Reservoir Depth (m)	Bitumen Saturation (%)	# of cores analysed (1)	Reservoir Pressure (kPa)
Long Lake	**40**	**34.9**	**253**	**74.9**	**155**	**1,200**
Firebag	37	33.8	285	80.0	164	800
Surmont	30	36.1	402	74.7	12	1,700
Christina Lake	25	34.7	399	80.4	32	2,000
Foster Creek	25	33.9	500	73.7	73	2,700
Mackay River	15-35	34.6	137	73.5	90	500

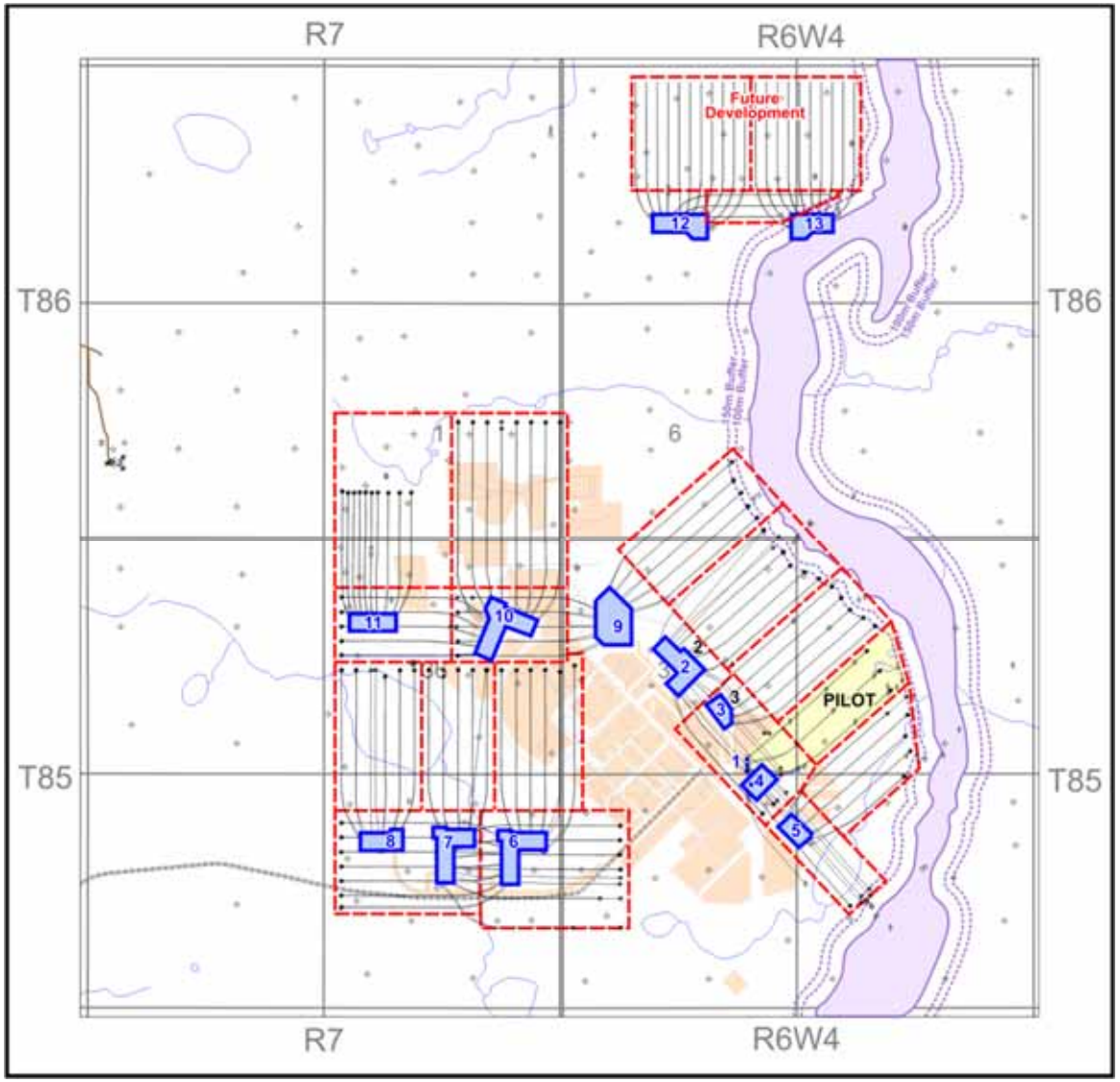
(1) Cores analyzed from public ERCB Data

Proactive approach to environmental issues

OPTI remains committed to responsible development

- Responsible water use
- No tailings ponds
- Reduced natural gas use
- Minimal surface disturbance
- Extensive monitoring for air emissions

Long Lake Project well pads



SAGD well pad

Definitions & cautionary statements

Notes to Resource Slides

These estimates represent the "best estimate" of our resources, are not classified or recognized as reserves, and are in addition to our disclosed reserve volumes.

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. It is also appropriate to classify as Contingent Resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. There is no certainty that it will be commercially viable to produce any portion of the Contingent Resources.

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. There is no certainty that any portion of the Prospective Resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

The resource estimates for Long Lake, Kinosis and Leismer are categorized as Contingent Resources. These volumes are classified as resources rather than reserves primarily due to less delineation and the absence of regulatory approvals, detailed design estimates and near-term development plans.

The resource estimate for Cottonwood is categorized as both Contingent and Prospective Resources. These Contingent Resource volumes are classified as resources rather than reserves primarily due to less delineation; the absence of regulatory approvals, detailed design estimates and near-term development plans; and less certainty of the economic viability of their recovery. In addition to those factors that result in Contingent Resources being classified as such, Prospective Resources are classified as such due to the absence of proximate delineation drilling.

Definitions & cautionary statements

Notes to Estimated Future Project Pre-Payout Netback Slide

We have provided below an update to our estimated netbacks and free cash flows for the Project that were last updated in our second quarter MD&A filed on SEDAR on July 15, 2010. The netback calculation at each West Texas Intermediate (WTI) price reflects higher operating costs and has been updated for lower natural gas prices, a stronger Canadian dollar relative to the U.S. dollar, a lower heavy/light crude oil price differential and lower electricity sale prices. The estimated annual free cash flows are based on a range of SORs. The long-term performance of our reservoir and respective SOR will be demonstrated over a number of years. Our rationale for providing this sensitivity is to provide a range of outcomes based on SOR, a key variable to our per barrel and annual netbacks. With additional knowledge of our reservoir gained through our ramp up to date, we have updated our estimate for SOR for the Project to between 3.0 and 4.0 and have therefore evaluated the impact of SOR within this range. This range captures our current SOR expectations for our existing well pairs at full production. We do not expect to reach full production, or this SOR range, until 2012 or later. The SOR for our original 90 well pairs is expected to be the high end of the range. We show netbacks and resultant free cash flows at full production due to the expected long-term life of our assets. We expect that the netbacks and annual free cash flows generated by our Project to be lower in the initial years following start-up than shown in this outlook due to the lower production volumes during ramp-up and an initially higher SOR. Management approved these netback and annual free cash flow calculations on February 9, 2011. For the per barrel and annual netbacks and annual free cash flows at a SOR of 3.0, we have assumed no additional steam capacity. In the annual netbacks and free cash flows for the SOR cases at 3.5 and 4.0, we have assumed that our planned steam expansion project has been approved and constructed. The one-time cost of the steam expansion project was not considered in the annual netback and free cash flow calculations as the capital expenditure impact is not significant over the life of the Project.

This financial outlook is intended to provide investors with a measure of the ability of our Project to generate netbacks and free cash flows assuming full production capacity. This outlook also intends to provide investors with an estimate of how our annual netbacks and resultant free cash flows at full production capacity could be impacted by the specified SOR range. We believe that the per barrel and annual netbacks and resultant free cash flows are the most appropriate financial measures to evaluate future Project performance. Corporate costs (other than corporate G&A expenses), interest, and other non-cash items are excluded from the estimates. The financial outlook may not be suitable for other purposes. The per barrel and annual netback and resultant annual free cash flow calculations as presented are non-GAAP financial measures. The closest GAAP financial measure to the calculations is cash flow from operations. However, cash flow from operations includes many other corporate items that affect cash and are independent of the operations of the Project.

The actual per barrel and annual netback and resultant free cash flows achieved by the Project could differ materially from these estimates. The material risk factors that we have identified toward achieving these netbacks and free cash flows are outlined under "Forward Looking Information" in our AIF. In particular, long-term SOR may be higher than we assumed, bitumen production may not reach our design rate of 72,000 bbl/d (25,200 bbl/d net to OPTI) or may require significantly more capital to be achieved, the SAGD and Long Lake Upgrader facilities may not operate as planned; the operating costs of the Project may vary considerably during the operating period; our results of operations will depend upon the prevailing prices of oil and natural gas which can fluctuate substantially; we will be subject to foreign currency exchange fluctuation exposure; and our netback will be directly affected by the applicable royalty regime relating to our business. The key assumptions relating to the netback and free cash flow estimates are set out in the notes beneath the tables.

The base assumptions used in the netback analysis are as follows:

- The annual and per barrel amounts are based on the expected yield for the Project of 57,700 bbl/d of PSC™ and 800 bbl/d of butane (20,100 bbl/d of PSC™ and 280 bbl/d of butane net to OPTI), and assume the Upgrader will have an on-stream factor of 96 percent. These numbers are cash costs only and do not reflect non-cash charges. See "Forward-Looking Statements."
- For purposes of these calculations, with regard to the WTI price scenario of US$75, we have assumed natural gas costs of US$3.75/mmbtu (millions of British thermal units), foreign exchange rates of $1.00 = US$0.96, heavy/light crude oil price differentials of 24 percent of WTI and electricity sales prices of $40.00 per MegaWatt hour (MWh). Revenue includes sales of PSC™, bitumen, butane and electricity.
- For purposes of these calculations, with regard to the WTI price scenario of US$100, we have assumed natural gas costs of US$5.00/mmbtu, foreign exchange rates of $1.00 = US$1.00, heavy/light crude oil price differentials of 22 percent of WTI and electricity sales prices of $52.00 per MWh. Revenue includes sales of PSC™, bitumen, butane and electricity.
- Costs are in 2010 dollars.
- Natural gas costs are based on an estimate for a 3.0 SOR.
- Includes approximately $1.00/bbl for greenhouse gas mitigation costs based on an approximate average 20 percent reduction of CO2 emissions at a cost of $20 per tonne of CO_2.
- Property taxes are based on expected mill rates for 2010.

Definitions & cautionary statements

Notes to Estimated Future Project Pre-Payout Free Cash Flows at a Range of Potential SOR

On a long-term basis, we estimate sustaining capital costs required to maintain production at design rates of capacity to be approximately $80 million per year (net to OPTI). The increase from the prior estimate of approximately $60 million per year (net to OPTI) is due to an increase in the average annual turnaround sustaining capital costs and an increase in the average annual number of new wells to be drilled throughout the life of the project. The netbacks as shown are prior to abandonment and reclamation costs.

This financial outlook is intended to provide investors with a measure of the ability of our Project to generate netbacks and free cash flows assuming full production capacity. This outlook also intends to provide investors with an estimate of how our annual netbacks and resultant free cash flows at full production capacity could be impacted by the specified SOR range. We believe that the per barrel and annual netbacks and resultant free cash flows are the most appropriate financial measures to evaluate future Project performance. Corporate costs (other than corporate G&A expenses), interest, and other non-cash items are excluded from the estimates. The financial outlook may not be suitable for other purposes. The per barrel and annual netback and resultant annual free cash flow calculations as presented are non-GAAP financial measures. The closest GAAP financial measure to the calculations is cash flow from operations. However, cash flow from operations includes many other corporate items that affect cash and are independent of the operations of the Project.

The actual per barrel and annual netback and resultant free cash flows achieved by the Project could differ materially from these estimates. The material risk factors that we have identified toward achieving these netbacks and free cash flows are outlined under "Forward Looking Information" in our AIF. In particular, long-term SOR may be higher than we assumed, bitumen production may not reach our design rate of 72,000 bbl/d (25,200 bbl/d net to OPTI) or may require significantly more capital to be achieved, the SAGD and Long Lake Upgrader facilities may not operate as planned; the operating costs of the Project may vary considerably during the operating period; our results of operations will depend upon the prevailing prices of oil and natural gas which can fluctuate substantially; we will be subject to foreign currency exchange fluctuation exposure; and our netback will be directly affected by the applicable royalty regime relating to our business. The key assumptions relating to the netback and free cash flow estimates are set out in the notes beneath the tables.

The base assumptions used in the free cash flow are as follows:

- Annual netback amounts are based on the expected yield for the Project of 57,700 bbl/d of PSC™ and 800 bbl/d of butane (20,100 bbl/d of PSC™ and 280 bbl/d of butane net to OPTI), and assumes that the Upgrader will have an on-stream factor of 96 percent. Notes (2), (3), (4), (6) and (7) in the Estimated Future Project Pre-Payout Netbacks table above apply to each of these Annual Netbacks. These numbers are cash amounts for OPTI's working interest share only and do not reflect non-cash charges. See "Forward-Looking Statements."
- Annualized Maintenance Capital, based on estimated sustaining capital costs required to maintain production at design rates of capacity, is expected to be approximately $80 million per year. For the SOR cases at 3.5 and 4.0, the long-term annual maintenance capital is not adjusted for the long-term maintenance capital expense or the initial capital expenditure (of approximately $200 million gross) for the potential steam expansion project, as these costs are not significant over the life of the Project. Please refer to notes (4) and (5) below for further information.
- For purposes of this calculation, we have assumed an SOR of 3.0 with no additional expenditures for the steam expansion project; all other assumptions are the same as noted under Estimated Future Project Pre-Payout Netbacks.
- For purposes of this calculation, we have assumed an SOR of 3.5 with completion of the steam expansion project, where current steam capacity would be increased in order to reach design capacity bitumen production rates. Higher operating costs of approximately $6 million at US$75 WTI and approximately $8 million at US$100WTI would result from incremental natural gas costs.
- For purposes of this calculation, we have assumed an SOR of 4.0 with completion of the steam expansion project. With an SOR of 4.0 and the inclusion of additional steam capacity bitumen production is projected to reach rates of approximately 64,500 bbl/d (versus the Project's design capacity of 72,000 bbl/d) on a gross basis. In this case, the annual netback is decreased by approximately $47 million at US$75 WTI and approximately $63 million at US$100 WTI due to approximately 5,000 bbl/d of feedstock purchases to supplement lower bitumen production levels and incremental natural gas costs.